How to navigate this report:

Roll cursor over this graphic in the top right of each page, to view the contents list, move cursor down the list to choose chapter, then click.

A UK ‘dash’ for *smart* gas

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Contents

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Summary

Summary

The future role of natural gas in UK electricity generation is the subject of intense debate. The impending closure of several aging power stations, together with heightened interest in the potential benefits of shale gas, is increasing the appeal of natural gas as a way of enhancing energy security, lowering energy prices and reducing emissions. This is creating enthusiasm for new investments in gas exploitation and extraction which is being heralded by some as a new dash for gas. Yet, environmental concerns and large uncertainty about the future price and availability of natural gas give cause for caution; investment decisions today could turn out to be short-sighted and lock the UK into an expensive and unsustainable future energy system.

This policy brief aims to provide some clarity about the possible future role for natural gas in UK electricity generation, including its implications for energy security, cost and the environment. The analysis is based on a review of the most up-to-date and credible evidence on the opportunities and challenges presented by conventional and unconventional natural gas resources. It considers the UK's carbon constraints, international gas market dynamics, environmental impacts and technological progress.

Two key aspects influence the natural gas debate in the UK:

- interest in a renewed 'dash' for gas-generated power, motivated by the belief that there will be an abundant future supply of natural gas which will offer a sustainable price advantage over other forms of electricity generation; and
- interest in a 'dash' to exploit indigenous shale gas resources, motivated by the prospect of increased energy security and reduced exposure to international energy price volatility.

Analysis reveals that substantial investment in gas on the assumption of low prices and large unconventional reserves is a risky option. A lower risk option would be a 'dash' for *smart* gas, where natural gas is used judiciously in those areas where it offers the greatest value in decarbonising the power sector. This is a complex task which will require careful planning and difficult investment decisions. Nevertheless, some key lessons and recommendations can be identified.

First, natural gas will continue to play an important role in the UK energy mix over the coming decades, for both heating and electricity generation. Should gas prices fall, for example as a consequence of increasing worldwide supply of gas from unconventional sources, there could be positive consequences for the UK economy.

Second, low gas prices are not guaranteed and there are large uncertainties around future price forecasts. Several estimates, including by the International Energy Agency, indicate that gas prices in the UK and European Union are more likely to increase than fall over the next two decades. Too great a reliance on gas may turn out to be inconsistent with the UK Government's objective to insulate the economy from the risk of energy price rises by diversifying energy supply.

Third, extensive deployment of gas-fired power stations would not be consistent with the UK's carbon targets, unless it is accompanied by the widespread introduction of carbon capture and storage (CCS) technology. In the short run, the UK's emissions can be reduced by replacing coal-fired power stations with those fuelled by natural gas, which emit less than half the carbon dioxide per kilowatt-hour of coal-fired plants. But in the medium to long term, a heavy reliance on gas-fired power stations with unabated emissions would hinder the decarbonisation of the UK's power sector.

Fourth, there is great uncertainty around the actual size of UK shale gas resources and reserves that can be commercially extracted. The potential of shale gas is worth investigating, but future exploration and production will have to be subject to strict environmental standards upstream (e.g. at the wellhead to prevent fugitive emissions) and downstream (e.g. to ensure carbon dioxide is captured and stored safely). As noted by the International Energy Agency (2012), the shale gas industry will need to obtain a 'social licence to operate' in order to satisfy public concerns about its environmental and social impacts. This will require robust policies to minimise visual impacts and maintain strict environmental, health and safety standards in the production process. Furthermore, even in the most optimistic scenario, shale gas is not expected to render the UK energy independent and free from the need to import natural gas. In the short term, establishing a shale gas industry will face infrastructure challenges similar to those experienced by other new technologies, such as renewables. This means that the shale gas industry could take a couple of decades to reach maturity in the UK, and its scale could be constrained not only by resource availability and costs, but also by issues such as planning and public acceptability. As for its impact on prices, the UK gas market is likely to remain largely driven by wholesale prices charged by foreign gas suppliers. The effect of shale gas production on household and business electricity bills could therefore be limited.

Fifth, investment in complementary technologies, such as CCS, will be essential to ensure that future UK electricity generation is consistent with the emissions target legislated in the Climate Change Act (Her Majesty's Government, 2008), and is able to meet increasing demand in a cost-efficient way. In particular, it is important to find out as soon as possible whether gas-fired power stations fitted with CCS can become economically viable within the next decade or so. Furthermore, as electricity generation is expected to include increasing contributions from renewables and possibly significant levels of nuclear power, it will be crucial to consider the full range of flexibility options that can help to integrate both more intermittent and less flexible sources into the electricity system. These options include gas-fired power stations, but also measures such as energy storage, interconnection and demand management which, if developed in a timely fashion, can reduce the need for additional generation capacity.

In sum, natural gas will continue to be important during the transition to a low-carbon electricity system. But if the UK is to meet carbon targets in a least-cost way, there is only a limited window for baseload generation from gas-fired power plants with unabated emissions, during which time it should replace coal. Gas can only play a more significant role beyond the 2020s if CCS technology is deployed on a commercial scale.

Current Government thinking, most notably the UK Gas Generation Strategy (DECC, 2012e), does not appear to have fully acknowledged these challenges. In particular, the Strategy's central scenario builds on the assumption that by 2030 the carbon intensity of the power sector will be twice as high as the level recommended by the Committee on Climate Change in the fourth carbon budget (50g/kWh). More dangerously, the Strategy's recommendation that 'gas could play a more extensive role should the fourth carbon budget be revised upwards' (DECC, 2012e) could jeopardise the UK achieving its mandatory emissions targets at least cost.

Therefore, there is a risk that the implementation of the high carbon intensity scenarios in the Gas Generation Strategy through the Energy Bill could undermine efforts to decarbonise the UK power sector. While the replacement of coal-fired power stations with those fuelled by natural gas would help to reduce the UK's emissions, there is a danger that gas generation infrastructure would be locked in. Inconsistencies between the Gas Generation Strategy and UK decarbonisation ambition, combined with uncertainty regarding the outcome of the review of the fourth carbon budget in 2014, could be perceived by the private sector as a significant policy risk and could discourage investment in both low-carbon energy sources (renewables and nuclear) and the efficient gas plants that will be needed to ensure a flexible and secure future power system. Weakening the fourth carbon budget would require more rapid, and potentially more costly, emissions reductions after the 2020s in order to achieve the 2050 target.

Future energy policy will require a coherent portfolio approach to be successful. To secure the investment needed in new power plants and infrastructure this decade it is critical that clear and consistent policy decisions about the UK's electricity generation are made now.

1. Introduction

1. Introduction

The UK's resurgent interest in natural gas has been fuelled by recent developments in the United States, which have transformed global perceptions about its future role in global energy systems.

The shale gas 'boom' in the United States has decreased the country's dependence on energy imports and reduced wellhead prices. As a result, natural gas production[1] increased by 18.9 per cent between 2007 and 2011 (EIA, 2013a), annual net imports of natural gas fell by 48.6 per cent between 2007 and 2011 (EIA, 2012f), and the average wellhead price fell by more than 50 per cent in real terms between 2008 and 2011, to its lowest level since 2002 (EIA, 2012f). While natural gas consumption increased by 5.5 per cent between 2007 and 2011 (EIA, 2012f), coal consumption fell by 11.1 per cent (EIA, 2012f).

Fuel switching from coal to gas in electricity generation, together with efficiency gains in power generation and increased output from renewables, also contributed to a reduction of 8.7 per cent in energy-related carbon dioxide emissions in the United States between 2007 and 2011 (EIA, 2013b). Concerns remain over methane 'fugitive' emissions associated with shale gas production (see e.g. EPA, 2012; Howarth et al., 2011; Clark, 2011; Pétron, 2012), and over the amount of coal which has been freed up for the export market. Notably, annual coal exports from the United States increased by more than 80 per cent between 2007 and 2011 (EIA, 2012f), displacing more expensive natural gas from electricity generation elsewhere, especially in Europe. Even so, the experience in the United States suggests a useful role for natural gas in the short to medium-term as a bridge technology towards a low-carbon energy future, where it replaces coal and its extraction is duly regulated.

The discovery of shale gas resources in European countries, including the UK, has led to calls for its exploitation with expectations of similar benefits to those witnessed in the United States. In particular, it has been suggested that the potential availability of cheap and abundant natural gas could offer an attractive path to addressing three of the UK's most vexing energy challenges simultaneously: reducing energy bills, reducing emissions and enhancing energy security.

Dual fuel bills for the average household have increased by more than 40 per cent between 2006 and 2013, mostly because of an increase in the wholesale price of natural gas (Ofgem, 2013). Rising bills are rarely popular, not least at a time of economic hardship.

In addition, the UK is pursuing an ambitious target, set out in the Climate Change Act (Her Majesty's Government, 2008), to reduce its emissions of greenhouse gases by at least 80 per cent by 2050 compared with 1990 levels. To achieve this, the statutory Committee on Climate Change has advised the Government to decarbonise the power sector by 2050. Gas-fired power stations have a role on the path to meeting this target because they emit 57 per cent less carbon dioxide per kilowatt-hour (kWh) than coal-fired plants (DECC, 2012b).

1 This refers to dry gas, i.e. natural gas which remains after: 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e. gas after lease, field, and/or plant separation); and 2) any volumes of non-hydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable. Dry natural gas is also known as consumer-grade natural gas (EIA, 2004).

Furthermore, the production of natural gas in the UK has been declining in the last decade, as reserves in the UK Continental Shelf (UKCS) have more than halved. Since 2004 the UK has become a net importer of natural gas, with imports accounting for over 40 per cent of UK gas demand in 2011. High gas wholesale prices, together with relatively cheap coal (displaced by shale gas in the United States) have also led to a marginal yet noticeable shift towards coal for electricity generation. The proportion of electricity generated annually in the UK from natural gas declined from 46 per cent in 2010 to 40 per cent in 2011, while coal's share increased from 28 to 30 per cent (DECC, 2012b).

It is hoped that a renewed focus on natural gas, or what the media has called a new 'dash' for gas,[2] will bring prices down, reduce emissions and make up for falling conventional domestic resources. But can natural gas fulfil these promises in the same way that it has in the United States? This policy brief explores what a new 'dash' for gas really means for the UK, including its potential to change recent trends in production and consumption, its impacts on the energy system as a whole, and its implications for environmental responsibility.

To achieve some analytical clarity, this brief analyses two aspects that appear to be driving the debate:

- interest in a renewed 'dash' for gas-generated power, motivated by the belief that there will be an abundant future supply of natural gas which will offer a sustainable price advantage over other forms of electricity generation; and
- interest in a 'dash' to exploit indigenous shale gas resources, motivated by the prospect of increased energy security and reduced exposure to international energy price volatility.

Although the two are linked, each is discussed separately to better exemplify their implications in terms of costs, energy security and environmental impacts for the UK. The analysis concludes that the best option to ensure a clean, affordable and secure power system is rather a 'dash' for *smart* gas, where natural gas is used strategically in those areas where it adds most value and in compliance with greenhouse gas targets and other environmental legislation.

The analysis is based on a review of the most recent and robust evidence about the opportunities and challenges of an increasing role for conventional and unconventional sources of natural gas. The brief takes into account UK and European Union carbon constraints, gas market dynamics, environmental impacts, and learning (technological progress). The brief also proposes a range of recommendations for UK energy policy.

2 See article in 'The Independent', 9th September 2012: http://www.independent.co.uk/environment/climate-change/tories-dash-for-gas-risks-climate-target-8120153.html

2. A ‘dash’ for gas-generated power

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Interest in a renewed ‘dash’ for gas-generated power is based on the assumption that the UK could benefit from an era of abundant natural gas supply and relatively low prices (e.g. Institute of Directors, 2012). If so, a greater share of natural gas in electricity generation could potentially reduce electricity bills and help to reduce greenhouse gas emissions by displacing ‘dirtier’ energy sources like coal. Notably, natural gas emits 57 per cent less carbon dioxide per kWh than coal in UK electricity generation (DECC, 2012b), and the burning of coal was responsible for 22 per cent of the UK’s carbon dioxide emissions in 2011 (DECC, 2012h).

The prospect of more natural gas as a cheap source of electricity and heating is clearly attractive. However, the future price of natural gas in the UK is dependent on gas prices internationally, and the UK’s ability to use it to fuel electricity generation is constrained by environmental law (Her Majesty’s Government, 2008).

In the open UK energy market, it is European market forces, as much as national circumstances, which determine the wholesale price of natural gas. In particular, any expectation that the price of natural gas will become and stay low is questionable given the uncertainties around future international gas demand and supply (i.e. the size of possible reserves, their availability and their likely impact on prices). The International Energy Agency (2011), for instance, assumes that natural gas import prices will rise across the world up until 2035.

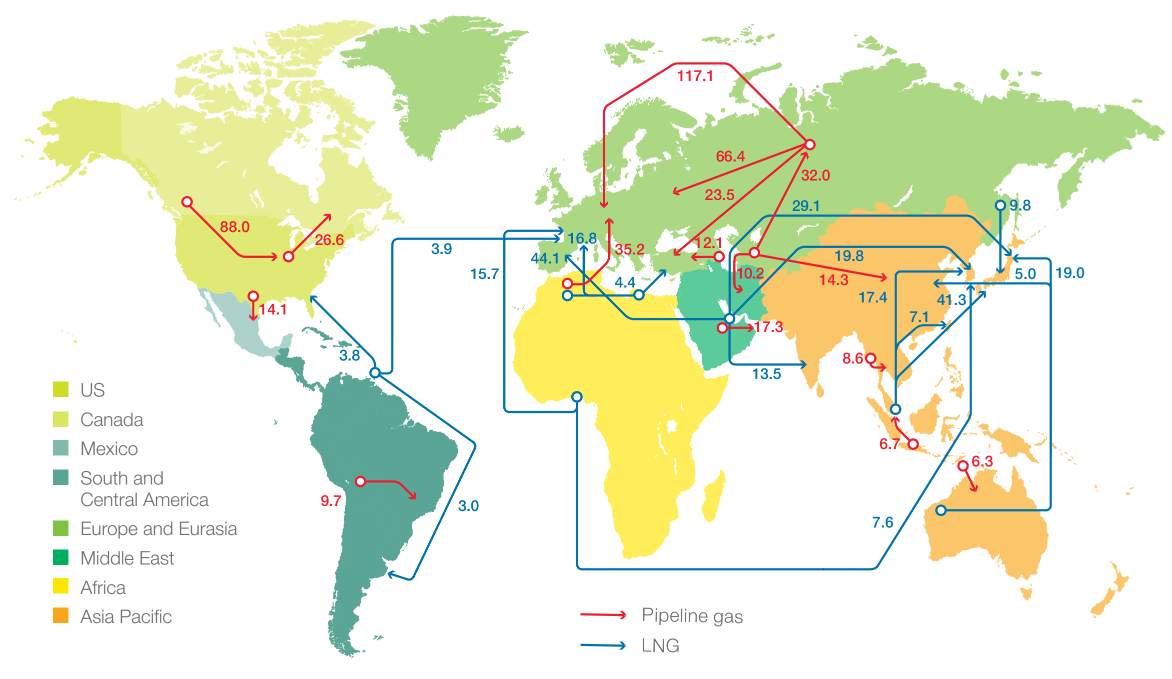
In addition, any increase in the amount of electricity generated from fossil fuels, in the medium to long term, could be inconsistent with the UK’s statutory carbon budgets and mandatory targets. Compliance with the carbon budgets may in turn have implications for the economics of natural gas, not least since gas-fired power stations are subject to both European Union and UK carbon price legislation.

2.1 Energy costs: market dynamics and gas prices

There is large uncertainty as to whether UK and, more broadly, European gas prices will decline in the same way as they have in the United States[2] – for example, due to new unconventional gas supplies (see Section 3). There are no certain answers about what future gas prices will be, but understanding the mechanisms that affect gas markets can provide greater clarity.

International trade in natural gas is constrained by high transportation and storage costs, arising from pipeline systems and expensive liquefaction processes. As a result, only one-third of global gas supplies are traded across borders, compared with two-thirds of oil (Rogers, 2012; see Figure 1). The natural gas industry is therefore dominated by a geographically segmented market structures, rather than globally integrated markets, like oil. There are three broad regional markets: North America, Europe and Asia. The UK could be considered as a fourth market as it is significantly more liberalised than the European market (see e.g. MIT, 2011). Each regional market has a different structure depending on its degree of maturity, the sources of supply, the dependence on imports and other geographical and political factors (MIT, 2011). European and Asian markets rely, to a varying extent, on long-term gas contracts which are ‘oil-indexed’ i.e. their price is influenced by the price of oil. The North American market is the most mature and liberalised and, as such, is less influenced by trends in the oil price. However, liquefied natural gas (LNG) markets are starting to change the traditional characteristics of international trade in natural gas. Price incentives to move gas from low- to high-value markets, together with a gradual retreat from oil-indexation and increasing modernisation and liberalisation of the LNG industry, are resulting in increasingly complex trading routes (JRC, 2012) and strengthening the links between regional markets.

Figure 1. LNG and pipeline gas – major trade flows worldwide (bcm), 2011



Source: BP (2012:29).

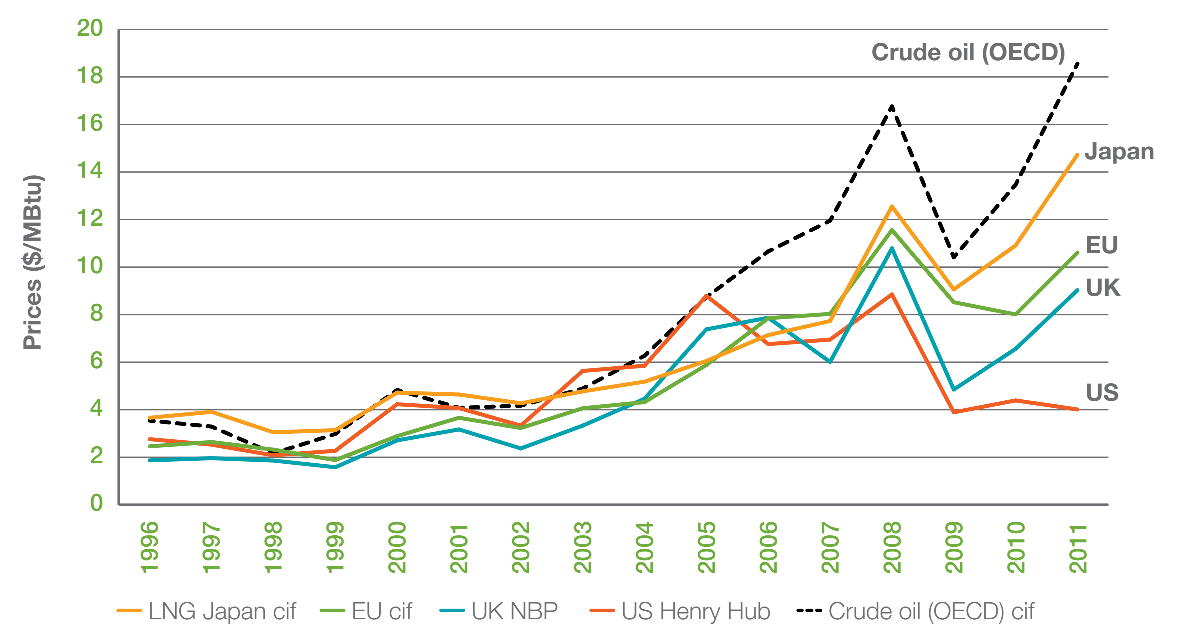
As gas markets are segmented, there is no global wholesale price. The distinct regional and local gas markets have different price-setting mechanisms and gas prices vary widely between regions (see Figure 2). In June 2012, spot gas was trading at as little as US$2.10 per million British thermal units[3] (MBtu) in the United States, compared with US$9.90 per MBtu in the UK, US$12 per MBtu for spot LNG in the Mediterranean and US$17.40 per MBtu for spot LNG in northeast Asia (IEA, 2012c).

Gas prices can be affected by unpredictable events. Sometimes the effects are large causing what is known as a *price shock.* For instance, the crisis at the Fukushima nuclear power plant following the Tōhoku earthquake in 2011, and its subsequent impact on Japan’s energy policy, led to a sharp increase in Japanese demand for gas imports between 2011 and 2012, pushing prices on the Asian market to record highs (IEA, 2012b).

Over the next five years, Asia and Europe are expected to import increasing amounts of gas. Imports by the Middle East and Latin America (IEA, 2012a) are also set to increase though not as sharply. The main demand will come from Asia with China being the fastest growing market. Supplies will mostly be provided in the form of LNG. Gas production in Russia, the United States and Middle East will continue to grow, while the African east coast appears to be the next new promising production centre. Significant LNG exports are expected also from Australia, which is set to become as productive as Qatar (IEA, 2012b). LNG exports are expected also from the United States (its net annual imports of natural gas decreased by 48.2 per cent between 2007 and 2011), although domestic factors such as security of supply, the cost of liquefaction and shipping, and limited LNG export capacity, may limit their volume (IEA, 2012a). It is uncertain whether the United States will re-enter world markets at a level that would materially impact gas prices in other regions. First, the domestic wholesale price for

3 A British thermal unit (Btu) is the energy required to heat 1 pound of water by 1 degree Fahrenheit. It corresponds to around 1,055 joules. It should be noted that while we use Btu (a measure of energy) for prices, we use cubic meters, a measure of volume, for gas quantities. A conversion table is provided in Annex I.

Figure 2. Wholesale prices for natural gas, 1994-2011 ($/MBtu)



Note: US prices are based on the Henry Hub (HH) index; UK prices on the National Balancing Point (NBP); Continental European prices are proxied by the German border price (BAFA); Asian LNG contracts are long-term contracts indexed to a basket of crudes imported to Japan (the 'Japanese Crude Cocktail').
cif = cost + insurance + freight (average price)

Source: BP Statistical Review 2012.

natural gas in the United States is envisaged to rise to about US$7.10-10.00 per MBtu by 2035 (IEA, 2012a). Secondly, if the United States does start to export LNG, this will most likely be to Asian markets, where prices are highest.

Given the uncertainty around future LNG exports and potential levels of natural gas production outside the United States, the complex linkages across gas and oil markets, as well as uncertainties about demand levels, it is difficult to forecast future wholesale prices. Most official estimates generally point to an increase in world gas prices, rather than a decrease, over the coming decades (see Table 1).

According to the International Energy Agency (2012a), in Europe, whether unconventional gas resources like shale gas (see Section 3) are successfully exploited (Golden Rules Case) or not (Low Unconventional Case), future import gas prices in 2035 are expected to reach between US$10.80 and US$13.10 per MBtu, compared to US$7.50 in 2010. Interestingly, in 2011 prices reached US$9.03 in the UK and US$10.61 in the European markets (BP, 2012). Greater unconventional gas supplies will have a moderating impact, so that import price assumptions are lower in the Golden Rules Case than in the Low Unconventional Case. Nevertheless, some of the existing natural gas import contracts based on oil indexation will continue to remain in force for many years, preventing prices from freely adjusting to changes in gas supply.

In the UK, wholesale gas spot prices used to be significantly lower than oil-linked gas prices in continental Europe, but since 2010 they have risen to levels that are closer to European prices, due to higher energy demand (driven by cold weather in 2010, for example), concerns about imports from key suppliers, tightening of the global LNG market and, until recently, the influence of higher coal prices in the power generation sector (IEA, 2011).

The UK Department of Energy and Climate Change (2012g) devised three scenarios for domestic gas prices. In its 'high' scenario, relatively elevated demand from Asia, low LNG supply and delays in the liberalisation of the European gas markets are expected to cause gas prices to increase even beyond the International Energy Agency's estimates, rising from around US$9.03[4] per MBtu in 2011 to US$16.40 per MBtu in 2020, and then plateauing at US$16.50 until 2030. In its 'low' scenario, higher LNG supply, slow economic growth and more competitive gas markets instead cause prices to decrease and stabilise at US$6.60 per MBtu by 2018. Between these two extremes, the central scenario suggests that UK wholesale gas prices could follow a path similar to continental Europe, reaching US$11.50 per MBtu by 2018, and remaining stable at that level until 2030.

Estimates by the UK Government Office for Budget Responsibility (Her Majesty's Treasury, 2012a) suggest natural gas prices will decrease. This forecast, however, is only for a short five-year horizon and is based on a slightly more simplified approach which takes into account only trends in oil futures prices and the Office for Budget Responsibility's own projections of oil prices (with a six month lag), which are expected to decline.

Table 1. Natural gas wholesale price forecasts by various sources (US$ per MBtu)

Source	Scenario	2013	2014	2015	2016	2017	2018	2020	2030	2035
IEA	Golden Rules	–	–	–	–	–	–	10.5	–	10.8
	Low Unconventional	–	–	–	–	–	–	11.6	–	13.1
DECC	Low	8.1	7.8	7.5	7.2	6.9	6.6	6.6	6.6	–
	Central	11.0	12.2	12.3	12.4	12.0	11.5	11.5	11.5	–
	High	13.9	14.3	14.6	15.0	15.3	15.7	16.5	16.5	–
OBR	–	9.27	8.97	8.53	8.15	7.84	7.60	–	–	–

Source: IEA (2012a), DECC (2012g), HM Treasury (2012).

2.2 Energy security: managing fluctuating demand and supply

Over the coming decades, the UK electricity system is expected to undergo a significant transformation. Older power plants will close down, electricity demand will rise due to the electrification of heating and transport, and the energy mix and characteristics of supply will change. In particular, an increased share of intermittent renewable sources will significantly affect the characteristics of the energy system.

Although compliance with UK carbon budgets will require a decrease in the share of gas in electricity generation, official estimates forecast an increase in the capacity from gas-fired power plants (e.g. National Grid, 2012; DECC, 2012e). Why is this so?

First, new power stations will be required to replace older ones. Around 12 GW of oil and coal-fired plants will close by 2016 under the Large Combustion Plant Directive.[5] Furthermore, 4 GW from aging nuclear power stations is due to be lost by the end of 2020. Beyond this, further coal-fired plant closures are likely because of tighter environmental requirements

4 All prices are converted from p/therm into US$/MBtu at an average exchange rate of 1.604 USD/GBP in 2011 – as in DECC (2012g).

5 Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants. OJ L 309, 27.11.2001. Available at: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:02001L0080-20070101:EN:NOT

introduced by the Industrial Emission Directive.[6] Overall, more than one-fifth of the UK's electricity generating capacity will be retired within the next 10 years. Ofgem (2012) has warned that there could be an imminent drop in spare electricity capacity from a margin of 14 per cent at present to only 4 per cent by 2015-16.

Some of the new power plants will be low-carbon (i.e. nuclear and renewables), while others will be fired by fossil fuels such as natural gas. Overall, emissions are expected to fall as these new plants will replace more carbon-intensive installations that currently run on coal – which on average produce more than twice as much carbon dioxide per kWh than those fired by natural gas.

Secondly, in the coming years, electricity generation capacity will need to increase due to the increasing intermittency of supply (due to a higher share of renewables) and higher demand (as more sectors will rely on electricity). National Grid (2012) envisages an increase in total UK electricity generation capacity from about 94 GW in 2012 (generating around 350 TWh) to almost 152 GW by 2030 (expected to generate about 400 TWh). Gas-fired power stations – specifically combined cycle gas turbine (CCGT) plants – play a role here because they can help to improve the flexibility of the electricity system, as supply can be ramped up and down quickly to meet sudden peaks of demand or make up for variability in renewable generation.

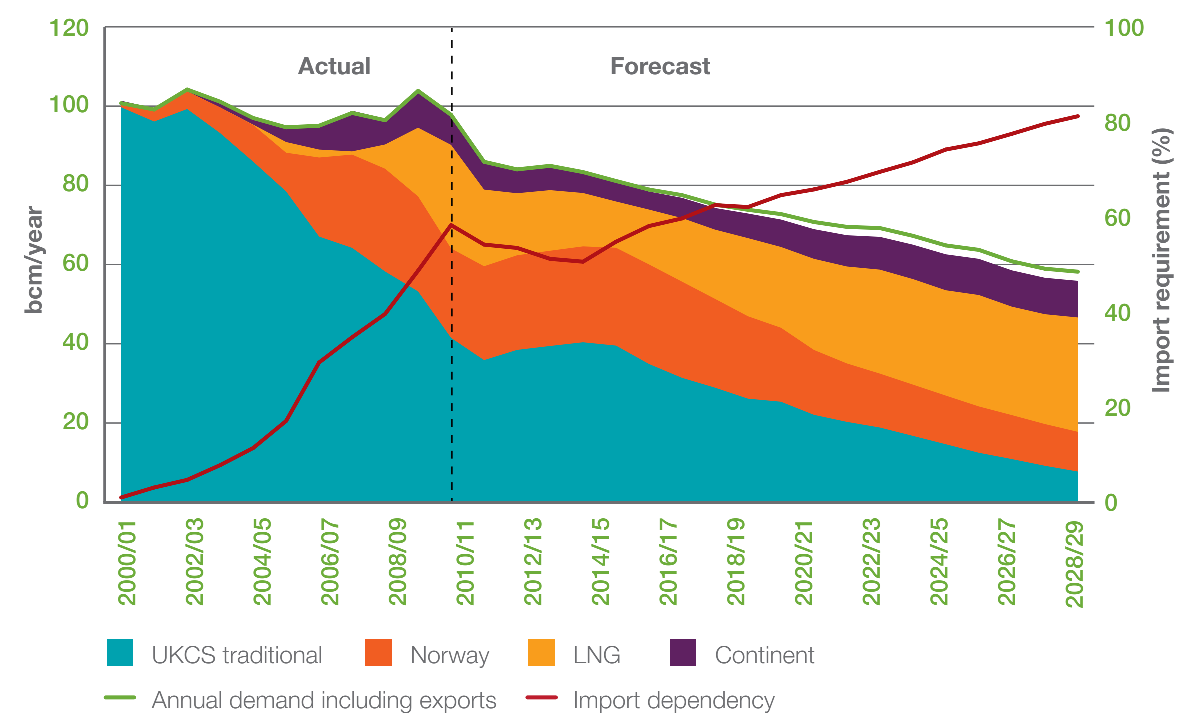
In light of these new challenges, the UK Gas Generation Strategy (DECC, 2012e) laid out three possible scenarios for the future composition of gas-fired power plant capacity (see Box 3 in Section 5). These would lead to different levels of 'decarbonisation' of the electricity system by 2030, namely average carbon intensities of 50, 100 or 200g CO_2/kWh. Of these, only the 50g CO_2/kWh scenario would be in line with the current UK carbon budgets, but the 100g CO_2/kWh outcome is taken as the 'central' scenario and one which 'represents a plausible outcome following Electricity Market Reform' (DECC, 2012e). This would imply the construction of about 26 GW of new gas-fired plants, such that capacity will be around 15 per cent higher in 2030 than today (see Figure 12). But as gas-fired power plants will have to be increasingly used for balancing, the actual output will be lower than today i.e. they will be used less efficiently.

There is also the possibility that a 200g CO_2/kWh scenario may be embraced should the fourth carbon budget be revised significantly upwards in 2014. This would be even less consistent with the recommendations of the Committee on Climate Change, which advises that even a target of 134 gCO_2/kWh would fail to fully exploit cost-effective opportunities for investment in low-carbon generation, and 'would result in addition of unabated gas plant to the system that would later become stranded' (CCC, 2010).

While gas-fired power plants can provide the flexibility needed to ensure that the electricity system is able to cope with an increased share of renewables and nuclear power generation, this will likely come at the expense of efficiency losses associated with operating at lower load factors than if they were providing base load. For instance, in the 50g CO_2/kWh scenario in the Gas Generation Strategy, 19 GW of new gas capacity is needed by 2030 but the average utilisation of CCGT plants in that year is only 15 per cent. Even in the 100g CO_2/kWh case the utilisation is only 27 per cent. This is a very inefficient use of investment and potentially large incentives may be needed to get new plants built. As pointed out in a study by Chignell and Gross (2013), once investment in fossil fuel power plants has been made there is an obvious risk that both the utilities provider and the Government may be tempted to make fuller use of the plants to earn a better return, at the expense of higher emissions.

6 Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control). OJ L 334, 17.12.2010. Available at: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32010L0075:EN:NOT

Figure 3. Annual gas supply forecast ('Gone Green' scenario)



Source: Based on National Grid (2012: pp.77).

To avoid such lock-in effects it will be crucial to keep investment in CCGT plant to an appropriate level, depending also on the development of carbon capture and storage (CCS) technology, and to focus on alternative options that can provide similar flexibility within a low-carbon power system.

A recent study for the Department of Energy and Climate Change (Strbac et al., 2012) highlighted the role that alternative balancing technologies – such as interconnection, flexible generation, storage, and demand management – can play in managing, at least cost, the severe challenges that the UK will face in the medium term.

A report for the Committee on Climate Change (Pöyry, 2010) assessed how electricity generation capacity requirements would change by 2030 if similar flexibility measures to those mentioned earlier[7] were introduced, assuming a decarbonisation target of 100g CO_2/kWh. With such measures in place, by 2030 gas capacity is estimated to range between 19 to 21 GW (depending on whether there will be further electrification of transport and heat), of which 18-19 GW would be CCGT and between 1 and 5 GW would be 'peakers' (usually open cycle gas turbines that are run only when there is peak demand). Should flexibility measures remain the same as today, instead, it is estimated that the capacity of gas-fired power plants in 2030 would be higher, ranging from 28 to 36 GW, of which 19-21 GW would be CCGT and 9-15 GW would be gas 'peakers'. While the latter scenario is estimated to still be consistent with the 100g CO_2/kWh target, carbon intensity would be lower if additional flexibility measures are adopted (this could be down to 58-70g CO_2/kWh, compared to 82-92g CO_2/kWh in the

7 These include: 'flexible generation', i.e. ex-ante time of use tariffs coupled with nuclear and CCS generation that can operate more flexibly than in the reference case; 'imported flexibility', i.e. ex-ante time of use tariffs coupled with expansion in the capacity of interconnection and bulk storage, and more flexible operation of CHP generation; and 'active demand management', i.e. active (or dynamic) management of demand, primarily from heating and transport (Pöyry, 2010).

absence of new measures). Flexibility measures are also estimated to reduce generation costs by 5-10 per cent in 2030 (although this does not include the effect of flexibility on total system costs e.g. once distribution costs are included).

2.3 Environmental responsibility: constraints from UK carbon budgets

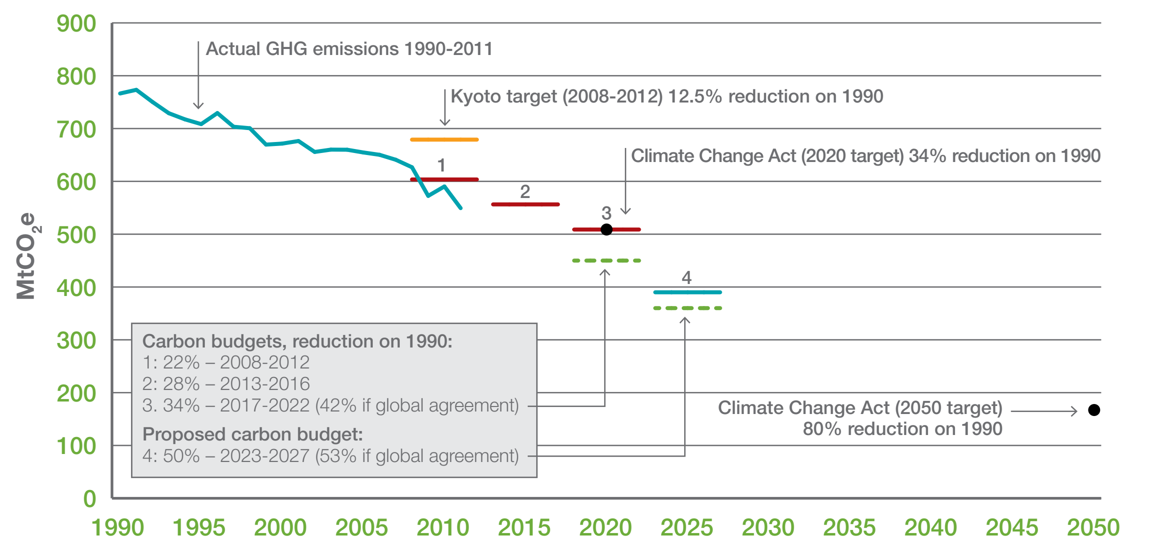
Ambitions for a large-scale increase in gas-generated electricity need to be consistent with the Climate Change Act which commits the UK to reducing its annual greenhouse gas emissions by at least 80 per cent by 2050 compared with 1990 levels (Her Majesty’s Government, 2008). A series of five-year carbon budgets,[8] the levels of which are recommended by the Committee on Climate Change and subsequently legislated by Parliament, define the path to 2050.

The four carbon budgets that have so far been legislated require a 50 per cent reduction in annual greenhouse gas emissions by 2025, the mid-point of the fourth (2023-27) carbon budget (CCC, 2010; see Figure 4). Although the fourth carbon budget is subject to a review in 2014, the UK’s climate change legislation defines a statutory constraint on the further use of fossil fuels with unabated emissions, including gas. The fifth budget for 2028-2032 will be set by the UK Parliament in 2016.

Meeting the economy-wide carbon budgets will require a gradual reshaping of the UK’s energy infrastructure. The power sector, in particular, will need to play a central role in meeting the budgets, since it is a major source of carbon dioxide emissions (about a quarter of total 2011 emissions; see DECC, 2012d) and it offers mitigation opportunities at the lowest potential cost (CCC, 2010). Furthermore, low-carbon electricity is assumed to provide the basis for the decarbonisation of other parts of the economy, such as surface transport, residential heating and perhaps parts of industry.

According to the Committee on Climate Change, the UK’s fourth carbon budget implies that the power sector will need to reduce its emissions during the 2020s, by adding between 30 and 40 GW of low-carbon plant capacity, assuming an electricity demand around 450 TWh. This is

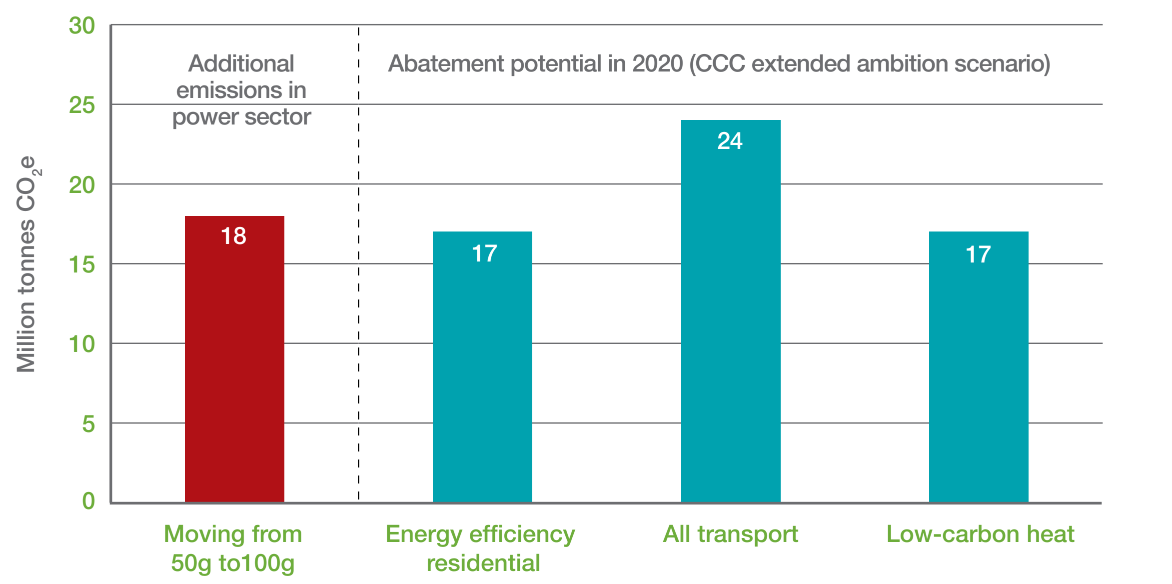
Figure 4. UK carbon budgets and targets to 2050



Source: Based on Bowen and Rydge (2011).

8 http://www.theccc.org.uk/carbon-budgets

Figure 5. Policy implications of a less ambitious decarbonisation target for the power sector



Source: Calculations based on CCC (2010: pp.106-107).

expected to reduce the average emissions intensity of electricity generation from around 500g CO_2/kWh today to around 50g CO_2/kWh by 2030 (CCC, 2010).

There has been some debate about the need to include a decarbonisation target for the power sector in the Energy Bill, which was introduced into the UK Parliament in November 2012. Whatever the merit of a formal carbon target for the power sector, it is clear that a deviation from the advice of the Committee on Climate Change could affect the UK’s ability to meet the fourth and subsequent carbon budgets.

A decarbonisation target of 100g CO_2/kWh (as considered in the central scenario of the UK Gas Generation Strategy) instead of 50g CO_2/kWh, for instance, would imply additional emissions of 18 million tonnes of carbon dioxide from the power sector in 2030. Figure 5 illustrates how such additional emissions would negate the benefits of reductions that could be achieved through some of the measures recommended by the Committee on Climate Change (2010), such as energy efficiency measures in residential buildings, low-carbon heat targets (about 12 per cent of heat from low-carbon technologies by 2030), or all transport-related policies (including biofuels and fuel efficiency targets, eco-driving and rail efficiency measures).

To be able to meet the overall fourth carbon budget, the additional emissions from the power sector would need to be offset by additional cuts in other sectors. Whether this would be economically sensible will depend on the future price of gas, which remains uncertain, as well as on the cost-effectiveness of alternative emission abatement measures in other sectors. Furthermore, some of the alternative mitigation measures may still be linked to the decarbonisation of the power sector (for example, in the case of switching to electric cars and heating), so a higher carbon intensity for electricity generation could have further knock-on effects on their cost and feasibility.

The future role of gas-fired power plants will also depend on whether their emissions can be captured with CCS technology. If CCS is effective and implemented, then a sustained use of gas for electricity generation could well be consistent with the carbon budgets.

3. A 'dash' for shale gas

3. A 'dash' for shale gas

The renewed interest in natural gas has been spurred by new opportunities for the exploitation of formerly inaccessible 'unconventional' gas fields. The discovery of shale gas resources in parts of the UK, the improvement of extraction technologies, the encouraging example offered by the United States, concerns about a rising dependence on imports, and recent increases in the wholesale price of natural gas, have all been factors that have contributed to making shale gas seem more appealing.

The amount of shale gas that can be (economically) extracted from UK shale plays, however, is still uncertain, and further exploration will be needed to clarify its real potential. Current estimates of technically recoverable resources in the UK are relatively modest in comparison to demand. Furthermore, it will be important to fully identify and address the environmental impacts of shale gas development, including the likely effect of exploration drilling and production infrastructure on local landscapes. The overall cost of managing shale gas impacts may be significant and will need to be taken into account when assessing its economic, environmental and social benefits and risks.

3.1 Overview: what is shale gas?

In the last three to four decades, formerly inaccessible 'unconventional' gas resources, such as shale gas, have become profitable to exploit thanks to improved exploration and extraction technologies, especially horizontal drilling and hydraulic fracturing (or fracking) (see Box 1). Shale gas extraction has been pioneered in North America, particularly in the United States, and is now being trialled elsewhere. The International Energy Agency (2011) has estimated that, under the right conditions, unconventional gas may be able to meet more than 40 per cent of the increase[9] in the global demand for gas by the year 2035, which is estimated to be around 35 per cent.

Box 1. Conventional and unconventional natural gas resources

Natural gas resources are generally classified as 'conventional' or 'unconventional', depending on where the gas is trapped. Conventional gas is typically found in discrete, well-defined reservoirs and can usually be extracted through vertical wells, with recovery rates of over 80 per cent of the original gas in place (IEA, 2011). Unconventional natural gas is found in less permeable rock formations – which implies that gas flows less easily through them – and is typically distributed over a much larger area than conventional gas. Extraction is more difficult and requires well stimulation measures, such as hydraulic fracturing (fracking), with recovery rates of around 15 to 30 per cent (JRC, 2012).

Unconventional gas is typically classified into three typologies, depending on the geology of the rock formations where it is found: tight gas, trapped in relatively impermeable hard rock, limestone and sandstone; coal-bed methane (CBM), trapped in the fractures and on the surface of coal beds; and shale gas, trapped in fine-grained sedimentary rock, called shale, characterised by very low permeability (JRC, 2012).

There are, however, substantial uncertainties about the recoverable volumes of unconventional gas, given the absence of production experience in most regions of the world. In this regard, it is important to make a distinction between the information regarding the amount of gas stored underground and the volumes that can actually be extracted. Three key definitions are frequently used:

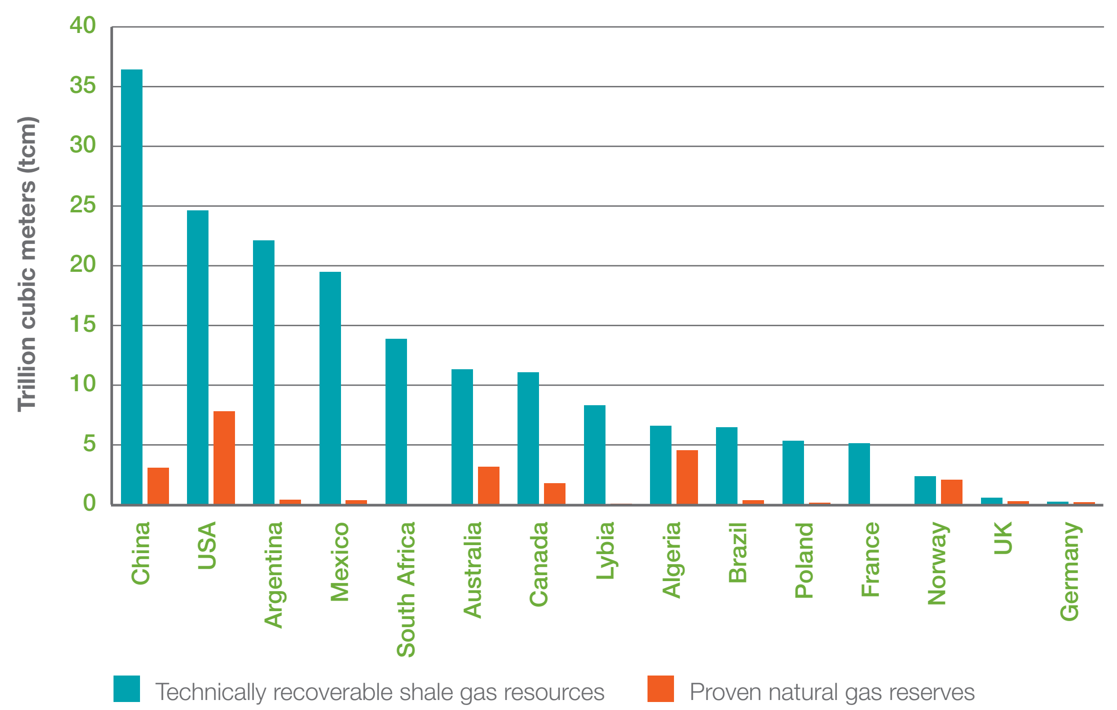
9 From 12,300 million tonnes of oil equivalent (Mtoe) in 2008 to 16,800 Mtoe in 2035 (IEA, 2012a).

- Gas in place (or simply *resources*): the entire volume of gas contained in a rock formation, regardless of the ability to extract it.
- Technically recoverable resources: the volume of gas resources considered to be recoverable with available technology.
- Proven reserves (or simply *reserves*): the volume of technically recoverable resources demonstrated to be economically and legally producible under existing economic and operating conditions (Royal Society, 2012).

According to the United States Energy Information Administration (EIA, 2011)[10] technically recoverable resources of shale gas across the world are likely to be about 200 trillion cubic meters (tcm), with the largest resource in China (36 tcm), followed by the United States (24 tcm) and Argentina (21 tcm). In Europe, technically recoverable shale gas resources are estimated to be up to 18 tcm, with the largest being in Poland (5.3 tcm) and France (5.1 tcm). The UK is estimated to have less than 1 tcm of technically recoverable resources (IEA, 2011; Pöyry, 2011).

By comparison, remaining recoverable resources of conventional gas worldwide are around 400 tcm, of which about half are considered proven reserves (EIA, 2011; see Figure 6 for a comparison of the countries with the highest shale gas potential). These would be equivalent to more than 50 years of production at current levels. Global proven reserves of shale gas have not yet been estimated.

Figure 6. Technically recoverable shale gas resources (top 10 world + top 5 Europe) and proven natural gas reserves, conventional and unconventional sources, 2009



Source: EIA (2011).

10 Other sources estimate similar amounts of proven reserves, with differences due to alternative definitions, estimation techniques and reporting standards (IEA, 2011a).

3. A 'dash' for shale gas

3.2 Energy costs: shale gas implications for wholesale prices and consumer bills

The costs of producing unconventional gas include capital, operational and transportation costs, as well as taxes and royalties. Capital costs are dominated by the construction of wells and are usually higher than for conventional gas because of the additional expense of multistage hydraulic fracturing. Production costs can vary greatly from one location to the next, and in Europe they could be about 50 per cent higher than in the United States (IEA, 2012a). European break-even costs for shale gas (i.e. the market value required to provide an adequate real return on capital for a new project) are expected to range between US$5.00 and US$10.00 per MBtu. These are likely to be within the same range as the future break-even costs for conventional gas, as domestic resources are depleted and new projects begin in less accessible, and therefore more expensive to exploit, Norwegian Arctic region gas fields (IEA, 2012a; see Table 2).

Table 2. Indicative natural gas wellhead development and production costs in selected regions (in 2010 values)

	Conventional gas (US$/MBtu)	Shale gas (US$/MBtu)
United States	3-7	3-7
Europe	5-9	5-10
China	4-8	4-8
Russia	0-2; 3-7*	–
Qatar	0-2	–

* The lower range for Russia represents production in the traditional regions of Western Siberia and the Volga-Urals; the higher range is for projects in new onshore regions, such as Eastern Siberia, offshore regions, and Arctic developments.

Source: Based on IEA (2012a).

Increasing global production of shale gas is likely to have an effect on global natural gas markets. The European Commission's Joint Research Centre (2012) estimates that the impact of shale gas could be extensive, but only when optimistic assumptions are made about production costs and reserves. In such a case, the global supply of (conventional and unconventional) natural gas as a whole would rise, and could provide up to 35 per cent of the world's total primary energy supply by 2040, overtaking oil's contribution. Shale gas will tend to be used within the regions where it is produced and could moderate the degree of growth of inter-regional LNG flows.

In the European Union, shale gas production is not expected to make the region self-sufficient in natural gas. In the best case scenario, it is estimated that shale gas will make up for declining conventional gas production and keep import dependence at around 60 per cent of total demand (JRC, 2012).

As long as the UK remains a substantial net importer of gas, it is reasonable to assume that its wholesale gas prices will largely depend on prices charged by foreign suppliers. Although domestic shale gas production could benefit the economy by generating jobs and tax revenues while displacing imports, it is unlikely that gas consumers would see much, if any, benefit in terms of reduced gas and electricity bills. Of course, if proven reserves turn out to be significantly larger than current official estimates, or if UK shale gas production was part of a major increase in unconventional gas production around the world, there could be a significant effect, at least (on projections by the International Energy Agency, 2012a) in moderating the increase in wholesale gas prices that would otherwise have taken place. In the United States, shale gas has led to a reduction in the wellhead price over the past few years. There is some evidence that this has reduced the price of gas purchased by power companies. However, monitoring by the United States Energy Information Administration (2012f) suggests that there has been little impact on the average price of electricity for households (which increased by about 4 per cent in real terms between 2007 and 2011), although the effect on gas for consumers has been marked (the average residential retail price of gas decreased by about 23 per cent in real terms between 2007 and 2011).

3.3 Energy security: impact of shale gas on gas imports

Conventional gas resources in the UK are depleting fast. After reaching its peak in 2000, UK conventional gas production by today has almost halved. Yearly production from the UK Continental Shelf declined from around 100 bcm in 2000-01 to 36 bcm in 2011-12 (National Grid, 2012). Due to decreasing extraction, the UK has become a net importer of natural gas since 2004, and net imports in 2011 accounted for over 40 per cent of UK demand (National Grid, 2012). More than half of foreign gas is imported by pipelines from Norway, Belgium and the Netherlands, while the rest is supplied as LNG by ship, mostly from Qatar (DECC, 2012c).

In the coming years, estimates based on data from Oil and Gas UK suggest that gas production from the UK Continental Shelf will fall further to 25 bcm in 2020-21, and to around 8 bcm in 2029-30 (National Grid, 2012). Assuming a future gas requirement of 73 bcm in 2020 and 57 bcm in 2030 for all uses[11] (as in the Gone Green Scenario[12] of National Grid, 2012), domestic gas reserves are expected to satisfy no more than 34 and 14 per cent of demand, respectively (see Figure 3).

Any further increase in the use of gas for power generation, without additional indigenous supply of natural gas, will require increased imports from outside the UK. This would expose the UK power system more acutely to potential price shocks caused by shortages or interruptions to supply caused by events in supplier countries. New domestic shale gas resources could therefore be seen as a welcome contribution if they could offset such increasing dependence on foreign fossil fuels. But how much UK shale gas is there and how much of it can be economically exploited?

The amount of shale gas that could be recovered in the UK is currently uncertain as very little exploration has been conducted. Preliminary assessments of the two main UK shale gas formations – the Bowland Shale in northern England and the Weald Basin in southern England (see map in Figure 7) – reveal significant differences between estimates.

With regard to the amount of gas in place, Cuadrilla, an oil and gas company, conducted test drilling in the area with the largest potential, the Bowland Shale basin in Lancashire. This revealed that gas resources in place could be up to 5.7 tcm (Cuadrilla, 2011). Estimates by the United States Energy Information Administration (EIA, 2011) of the resources in the Bowland Shale basin, based on analogies with similar known shale gas plays in the United States, were lower, at around 2.7 tcm.

11 Including for the power sector, for domestic, industrial and commercial uses and for exports.
12 A scenario developed by National Grid where the UK renewable energy and CO_2 emission targets are met.

Figure 7. Shale gas potential in Great Britain

Source: DECC (2012e).

As for technically recoverable resources, the latest available estimates by the British Geological Survey for the UK Department of Energy and Climate Change (DECC, 2012i) indicate that these could be about 150 bcm across the whole country, while the United States Energy Information Administration (2011a) has suggested that they are around 600 bcm for the UK. Independent research by the Energy Contract Company, a consultancy, suggests UK recoverable resources could be higher, at about 1.1 tcm (ECC, 2012[13]; see Table 3). The UK could also have greater resources of unconventional gas offshore, but its exploration and development is not considered economic at current gas prices (Oil and Gas UK, 2011).

13 As quoted in an article in the 'Financial Times', 26 September 2012: http://www.ft.com/cms/s/0/287378ee-0708-11e2-92ef-00144feabdc0.html#axzz29ZCQayyD

3. A 'dash' for shale gas

Table 3. Estimates of shale gas potential in the UK (bcm)

		EIA	Cuadrilla	BGS/ DECC	ECC
Bowland Shale	Gas in place	2,690	5,660	–	–
	Technically recoverable	540	900-1,200[14]	80-200	60-110
Weald Basin (Liassic shale)	Gas in place	60	–	–	–
	Technically recoverable	30	–	–	–
Total UK	Gas in place	2,750	–	–	–
	Technically recoverable	570	–	150	1,130

Sources: EIA (2011), Cuadrilla (2011), ECC (2012), DECC (2012i).

Despite differences between the estimates, it is apparent that UK resources are likely to be relatively modest compared to those elsewhere in Europe, such as France and Poland, where technically recoverable resources in each are estimated to be above 5 tcm (EIA, 2011).

At today's level of UK demand for natural gas (900 TWh per year, or around 80 bcm per year), current estimates of technically recoverable resources of shale gas would be equivalent to between 2 and 14 years of domestic gas consumption, assuming that it would be possible to extract all the gas. In practice the amount of gas that could be effectively produced (i.e. the proven reserves) is likely to be much less, because of economic, environmental and legislative constraints.

For the purpose of illustration, the United States Energy Information Administration (2012e) estimated proven reserves of shale gas in the United States to be around 2.8 tcm in 2010, almost one-tenth of its technically recoverable resources of 24.4 tcm. If a similar proportion could be extracted in the UK, the gas effectively produced would be equivalent to no more than 1.5 years of current demand.

As for the cost of extracting shale gas in the UK, it may well prove more expensive than in the United States, because of differences in geology, population density and regulation for example. Research by Gény (2010) suggests the cost could be perhaps 2 to 3 times higher. In terms of its impact on prices, UK shale gas would be marketed internationally and subject to international prices. The effect on domestic price volatility would be uncertain, but likely limited.

The timing of gas extraction in the UK is also uncertain. The shale gas sector in the United States has developed over the past 30 years and has only recently reached maturity (see Box 2). Even if it is assumed that knowledge and technology will be easily transferable to overseas from the United States, it could take several years or decades for the sector to reach maturity elsewhere.

14 Based on Cuadrilla's assumption that between 15 and 20 per cent of the gas in place could be extracted (ECC, 2012).

Some unconfirmed newspaper reports have suggested that the UK could have shale gas resources of between 36.8 and 48.1 tcm,[15] although it is not clear whether this estimate is for gas in place or technically recoverable resources – if it is the latter, it would be larger than the estimate by the United States Energy Information Administration for technically recoverable resources in China or any other country in the world, which seems highly unlikely. If the former, and using the assumption that 20 per cent of gas in place can be theoretically extracted with current technologies, technically recoverable resources would be between 7.4 to 9.6 tcm. Taking account of the observation that about one-tenth of technically recoverable resources of shale gas in the United States can be economically and legally extracted, proven reserves in the UK would be about 740 to 960 bcm, equivalent to between 9 and 12 years of current annual UK consumption of natural gas. This contrasts with the newspaper report which suggested that 'Britain could have enough shale gas to heat every home for 1,500 years'.

Box 2 The shale gas 'boom' in the United States

Unconventional gas as a potential source of supply in North America is far from new, but has remained marginal for decades. The first commercial well drilled in a shale reservoir dates back to the late 1820s. Although commercial production was well under way in the 1980s, the pace of development of unconventional reservoirs remained relatively slow.

It is only since 2006 that the industry has been witnessing an extraordinary acceleration of unconventional gas production, driven by the exploitation of a few shale gas plays, in particular the Barnett Shale in North Texas. The reasons for the increase in supply were technological developments (in particular the combined use of horizontal drilling and hydraulic fracturing), governmental subsidies, increasing (albeit volatile) gas prices since 2000, and easy credit availability for drilling for most of the 2000s. As a result, in 2010, unconventional gas accounted for more than half of total gas production in the United States.

The initial development of unconventional gas was the result of investments by small independent drilling companies, which first developed the specialised drilling technologies for exploiting shale gas. In the mid-2000s, larger independent companies assumed the leadership of the industry, contributing greatly to the acceleration of gas drilling and production. It is only since 2008 that multinational energy companies such as BG Group, BP, ExxonMobil, Shell, Statoil, Eni, and Total have started to play a bigger role in the unconventional gas sector.

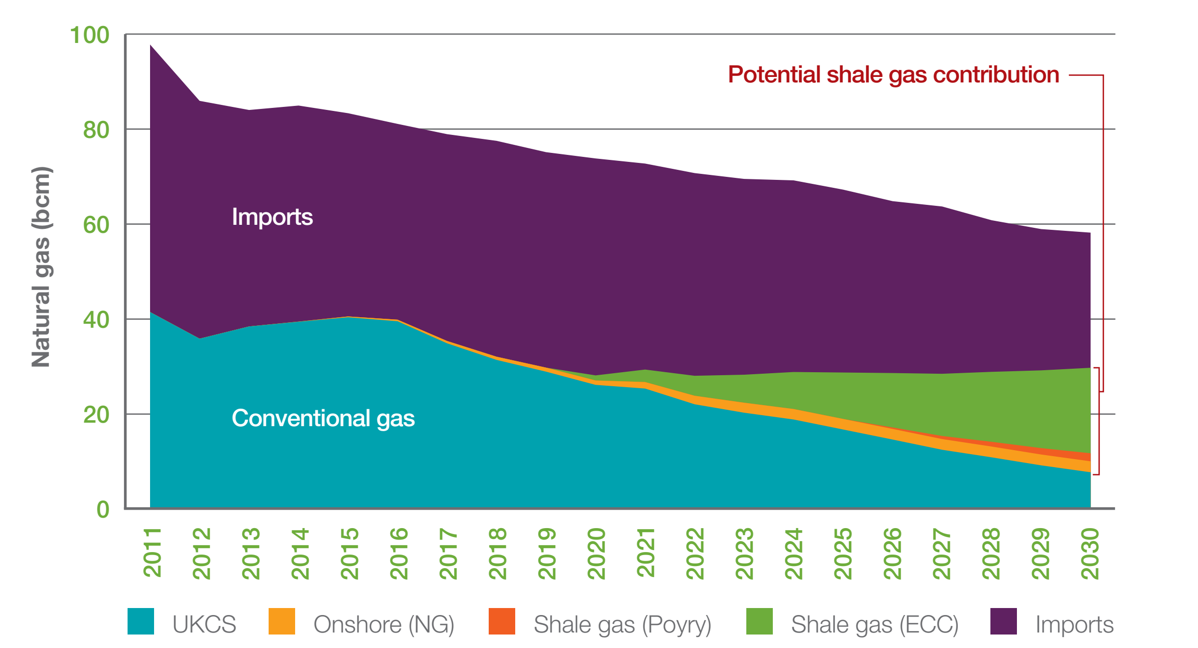
Source: Based on Gény (2010).

The International Energy Agency does not expect significant production of shale gas in Europe before 2020, due to the time needed for resource appraisal and development, and associated technical, environmental and regulatory issues (IEA, 2011). The recent UK Gas Generation Strategy envisages that 'shale gas production might commence in the second part of this decade', but 'any substantial contribution to the UK's gas supply is unlikely until further into the 2020s' (DECC, 2012e).

National Grid (2012) forecasts that production of 'onshore' gas (a mix of shale gas, CBM and biogas) could start from 2013-14 and gradually reach 2.3 bcm per year by 2030. The expectation of Pöyry (2011) is that between 1 and 4 bcm per year could be produced by 2030. A more optimistic estimate by the Energy Contract Company envisages that production could hit 21.7 bcm per year by 2030, equivalent to about half of current domestic production of conventional gas.

15 http://www.thetimes.co.uk/tto/business/industries/naturalresources/article3683377.ece

Figure 8. Future UK gas supply and demand



Source: Calculations based on National Grid (2012), Pöyry (2011) and ECC (2012).

At the same time, as mentioned in Section 2.2, reserves of conventional gas in the UK Continental Shelf are depleting. In 2011-12, production was around 36 bcm (approximately 400 TWh), compared to almost 100 bcm in 2000-01 (National Grid, 2012). Gas imports were about 50 bcm in 2011 (around 550 TWh), equating to more than 50 per cent of the total demand in that year (National Grid, 2012). More than half of foreign gas is imported by pipelines from Norway, Belgium and the Netherlands, while the rest is supplied as LNG by ship, mostly from Qatar (DECC, 2012c).

By 2030 domestic reserves of conventional gas are expected to satisfy no more than 13 per cent of demand (National Grid, 2013). Shale gas could help diversify domestic resources and therefore contribute to the UK's energy security. But its potential should not be exaggerated. Current data suggests that, even in the most optimistic scenario, shale gas might at best compensate for the decrease in domestic production of conventional gas (see Figure 8), while imports will continue to meet a significant share of demand in the coming decades.

3.4 Environmental responsibility: greenhouse gas emissions and other impacts

Several concerns have been raised about the environmental impacts associated with unconventional gas production. Some of these are similar to those experienced with conventional onshore gas production, while others are specific to shale gas operations – particularly fracking.

First, shale gas has higher production-related greenhouse gas emissions than conventional gas (IEA, 2012). This is because shale gas operations involve a larger number of wells and more hydraulic fracturing operations, both of which require energy, typically from diesel motors, which emit carbon dioxide. And, importantly, shale gas operations lead to more venting of gas during well completion. There is evidence that shale gas development in the United States has led to significant 'fugitive' methane emissions (e.g. EPA, 2012; Howarth et al., 2011; Clark, 2011; Pétron, 2012).

3. A 'dash' for shale gas

Some analysts have concluded that these have been so great as to eliminate the lifecycle greenhouse gas emission benefits of shale gas compared with coal for power generation (e.g. see Howarth et al., 2011), although this has been disputed (e.g. by Clark et al., 2011). A comparison between lifecycle greenhouse gas emissions for different time horizons (20 and 100 years)[16] carried out by Clark et al. (2011) indicates that emissions from power generated from shale gas can actually be equal to or lower than those from conventional gas (see Figure 9).

Given the lack of reliable data, there is a large variation in the estimates of historical impacts on climate change from shale gas production. It is apparent, however, that the consequences of shale gas exploitation for greenhouse gas emissions will depend crucially on effective regulation of production operations, especially venting. The United States is now seeking to regulate venting from shale gas wells, and the European Union is expected to follow suit.

It should also be noted that, in coal-producing countries like the United States, a switch from coal to gas generation can simply shift emissions elsewhere if the unburned coal is exported. This was confirmed in a study by Broderick and Anderson (2012), which suggests that more than half of the emissions avoided in the United States power sector may have been exported as coal. According to the Energy Information Agency (EIA, 2012b) the annual primary energy production from coal by the United States will increase by about 5.9 per cent between 2011 and 2040, and net exports of coal will rise by about 28 per cent.

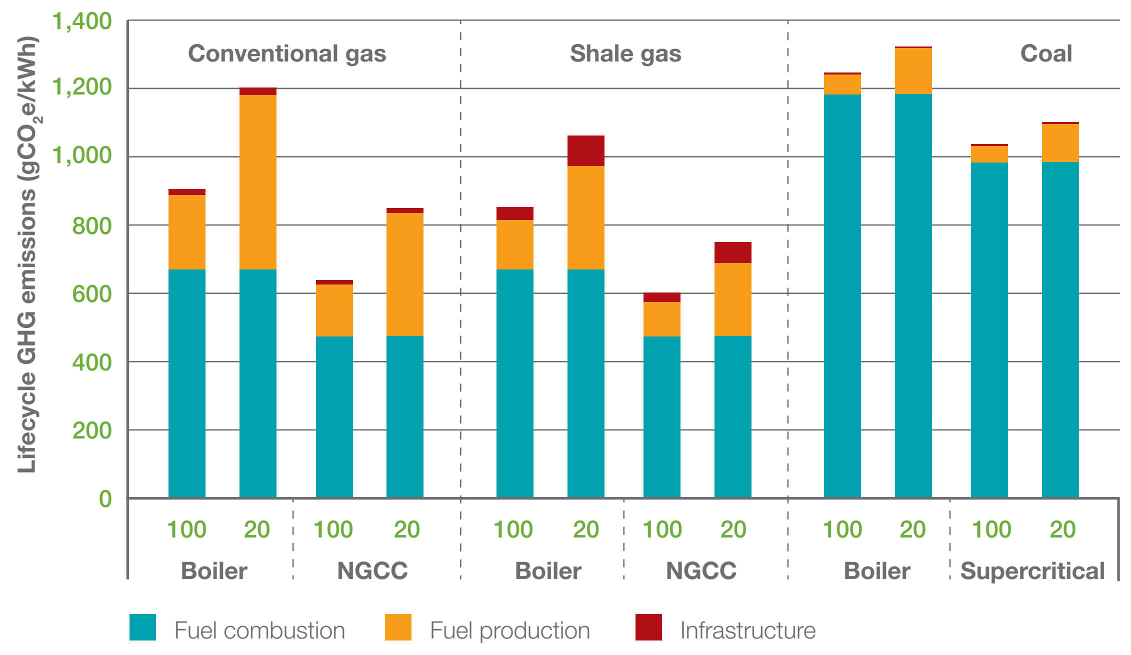
In the European Union, a recent analysis for the European Commission (AEA et al., 2012a) found that lifecycle greenhouse gas emissions from shale gas can be slightly higher than those from conventional gas, but significantly lower than emissions from coal. Greenhouse gas emissions per kWh of electricity generated from shale gas are estimated to be between 4 and 8 per cent higher than those from conventional gas obtained from within the European Union. However, if emissions from well completion are mitigated and utilised, the difference in emissions can be reduced to between 1 and 5 per cent (AEA et al., 2012a). In such a case, lifecycle emissions from European Union shale gas can also be 2 to 10 per cent lower than emissions from electricity generated from conventional pipeline gas obtained from non-Member States, notably Russia and Algeria. Lifecycle emissions from power generation that is fuelled by shale gas are estimated to be almost 41 to 49 per cent lower than those of electricity generated from coal.[17]

Besides greenhouse gas emissions, shale gas production can have a number of other environmental impacts. The possibility of water pollution is perhaps the issue that has received the widest public attention. This could be caused, for instance, by fracking fluid, faulty well construction (Royal Society, 2012; Osborn et al., 2011), or gas migration (Davies, 2011). There is much anecdotal evidence from the United States of water being polluted with methane, although the extent to which this is due to shale gas exploitation rather than natural causes is hotly disputed. At least one official report (EPA,2011) has concluded that fracking was a likely cause of ground water pollution in the United States. However, in the UK most aquifers used for drinking water lie within 300 metres of the surface, while fracking would normally take place at a depth of more than two kilometres. A joint report by the Royal Society and the Royal Academy of Engineering (2012) concluded that 'upward flow of liquids from the zone of shale gas extraction to overlying aquifers via fractures in the intervening strata is highly unlikely'. The same report judged that more likely causes of possible water contamination include faulty wells, and leaks and spills associated with surface operations.

16 When comparing the impacts of emissions from different fuels, a timeframe must be specified as greenhouse gases (e.g. carbon dioxide and methane) have different lifetimes in the atmosphere. The Intergovernmental Panel on Climate Change recommends using a 100-year time horizon when calculating greenhouse gas emissions in order to evaluate various climate change mitigation policies. When using a 20-year timeframe, the effects of methane are amplified as it has a relatively short perturbation lifetime (12 years), whereas carbon dioxide can last in the atmosphere for a long time (Clark et al., 2011).

17 On the basis of a representative 100-year measure of global warming potential for methane.

Figure 9. Lifecycle greenhouse gas emissions per kWh of electricity produced for 100-year and 20-year timescales of global warming potential



Note: NGCC = Natural Gas Combined Cycle.
Source: Based on Clark et al., 2011.

Fracking, however, requires greater water volumes than conventional gas production, with potential impacts on supplies. Recent analyses reveal that the production of 9 bcm/year of shale gas (equivalent to about 10 per cent of current gas demand) would require about 0.01 per cent of the licenced annual water abstraction for England and Wales (Broderick et al., 2011; Ward, 2012). While this appears to be a relatively small amount, impacts on water supplies may still be significant locally.

Shale gas extraction can also lead to earth tremors. These are considered highly unlikely to cause structural damage (AEA et al., 2012b; British Geological Society, 2012), but can have significant impacts on public acceptability. Notably, two small earth tremors were triggered by the first shale gas explorations in Lancashire in the UK, and led to a temporary suspension of operations. Blowouts are also possible, although their occurrences are considered to be rare (Royal Society & Royal Academy of Engineering, 2012). Furthermore, shale gas developments can lead to harmful emissions beside greenhouse gases, such as ozone precursors, diesel fumes, and other hazardous pollutants.

Other environmental impacts are related to land take and disturbance, given the larger number of wells required for extraction compared to conventional gas. In the UK, the Institution of Mechanical Engineers (2012) has concluded that 200 to 800 rigs would be needed for a moderate level of production of shale gas by 2025. Commercial shale gas extraction in the Lancashire area alone is expected to require around 400 production wells to be drilled at 40 sites (Regeneris Consulting, 2011). Each site (well pad) would likely cover several acres and include a containment pond, condensate storage tanks and compressor stations (Deutsche Bank, 2011). At European level, it has been estimated that approximately 1.4 per cent of the land above a productive shale gas site may need to be used to exploit the reservoir fully (AEA, 2012b). This could be of potentially major significance for large shale gas developments, especially in densely populated areas.

Noise can also be an issue. It is estimated that each well pad, assuming 10 wells per pad, would require 800 to 2,500 days of noisy activity (AEA et al., 2012b). Finally, shale gas developments can have negative impacts on local biodiversity and lead to higher traffic (due to lorry movements), with potentially significant consequences for the local population (AEA et al., 2012b). Both greenhouse gas emissions and other environmental impacts can be mitigated with existing technology. The International Energy Agency (2012) estimates that the additional cost of applying appropriate mitigation measures (a set of 'Golden Rules') would be limited. The overall financial cost of a typical shale gas well could increase by no more than 7 per cent, and possibly less in the case of larger development projects. But accurate monitoring and implementation of suitable regulations will be necessary to avoid or limit environmental damage.

It is worth noting that local environmental impacts can give rise to issues of public acceptability. For example, in France public concerns have led to a complete ban of fracking activities. While this has not been the case in the UK, local opposition to local infrastructure projects with significant visual impacts, like onshore wind turbines, are not uncommon (see e.g. Bassi et al., 2012). Careful planning will therefore be needed in order to keep local disruptions to a minimum and prevent developments in particularly sensitive areas.

4. A 'dash' for *smart* gas

Natural gas is, and will remain, a key fuel in the UK energy mix, not just for power generation but also for industrial and residential consumption. Households will continue to rely on natural gas for heating in particular, while low-carbon alternatives such as renewable heat are developed. Gas-fired power plants will continue to play a significant role in the coming years, both to maintain sufficient capacity margins, bearing in mind the closures of coal and nuclear plants expected in the next 10 years, and for system balancing, as increasing quantities of low-carbon generation come online, much of which is relatively inflexible (like nuclear) or intermittent (like several renewables).

Towards 2030 and beyond, UK carbon budgets imply that the primary role for gas-fired power plants is likely to be as back-up capacity for intermittent renewables or, if fitted with carbon capture and storage (CCS) technology, as a genuinely low-carbon energy source. A 'dash' for *smart* gas is about making the best possible use of natural gas in a low-carbon economy. This is a complex task which will require careful planning and investment decisions

4.1 A balanced role for gas in the UK

As noted in Section 2.3, electricity generation will be a key sector for UK emissions reductions. National Grid (2012) anticipates that, in a scenario where future renewable energy and emissions targets are met (the Gone Green scenario), an increasing share of transport and heat will have to rely on (cleaner) electricity. The generation of electricity is therefore expected to increase from about 350 TWh in 2011 to about 400 TWh in 2030 in Great Britain (National Grid, 2012).[18]

Over the same period to 2030, emissions intensity in the power sector will have to decrease sharply. For instance, to allow for a decarbonisation of the power sector to 79g CO_2/kWh, the amount of electricity generated from gas-fired power plants (including those fitted with CCS technology) would decrease from around 150 TWh today (DECC, 2012) to 70 TWh in 2030 (National Grid, 2012). In such a scenario, gas would account for less than 20 per cent of electricity generation in 2030, compared to 40 per cent today (see Figure 10).

National Grid (2012) assumes that by 2050 fossil fuels (either gas or coal) will only be used in power plants fitted with CCS technology. Their contribution could be up to 120 TWh, out of a total demand of 500 TWh.

Besides the fall in the gas required for electricity generation, gas consumption is expected to decrease also across other sectors. National Grid (2012) estimates that total gas demand will decline from 80 TWh in 2011 (DECC, 2012a) to about 70 TWh in the next decade, and reach around 60 TWh in 2030, if future emissions reductions targets are met (see Figure 11). As a result, natural gas would account for about 30 per cent of the overall UK energy mix in 2030, compared to 40 per cent in 2011.

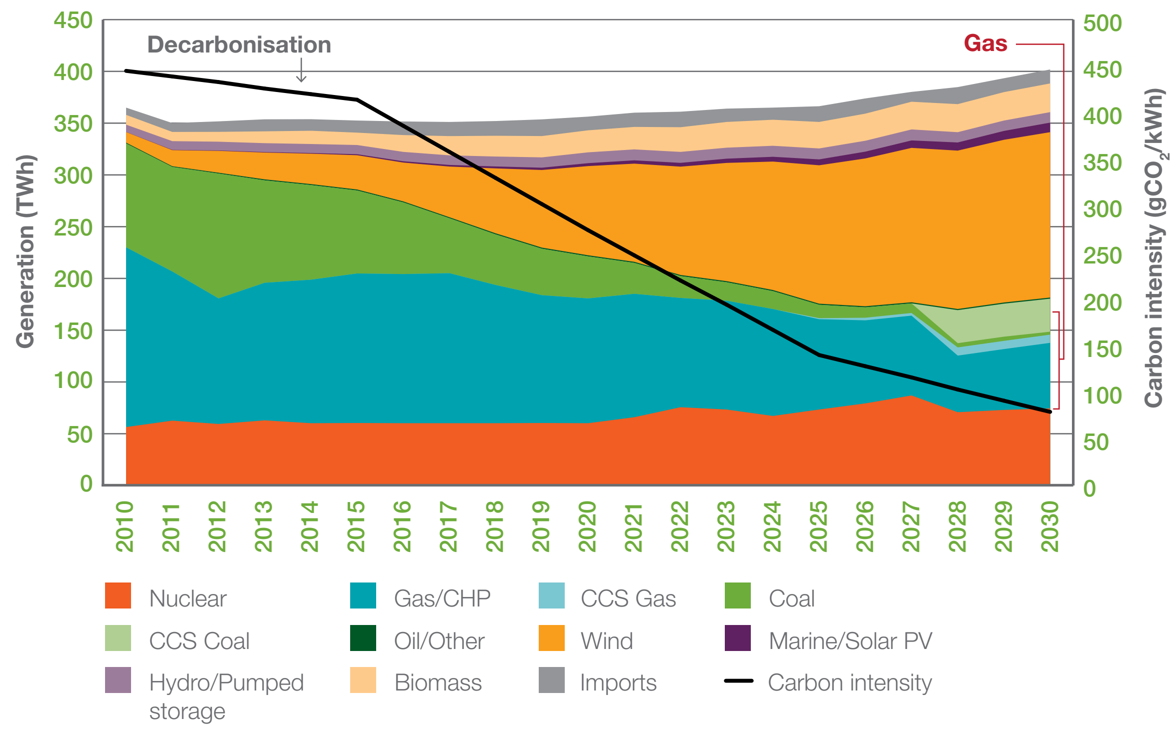
4.2 Policy implications

There are several reasons why some form of 'dash' for gas would be appealing for the UK. This brief analyses two aspects that appear to be driving the debate: interest in a renewed 'dash' for gas-generated power, motivated by the belief that there will be an abundant future supply of natural gas which will offer a sustainable price advantage over other forms of electricity generation; and interest in a 'dash' to exploit indigenous shale gas resources,

18 Gas and electricity projections by National Grid are for Great Britain only, rather than the whole UK, as this is where their networks operate. UK emissions targets have been scaled accordingly (National Grid, 2012).

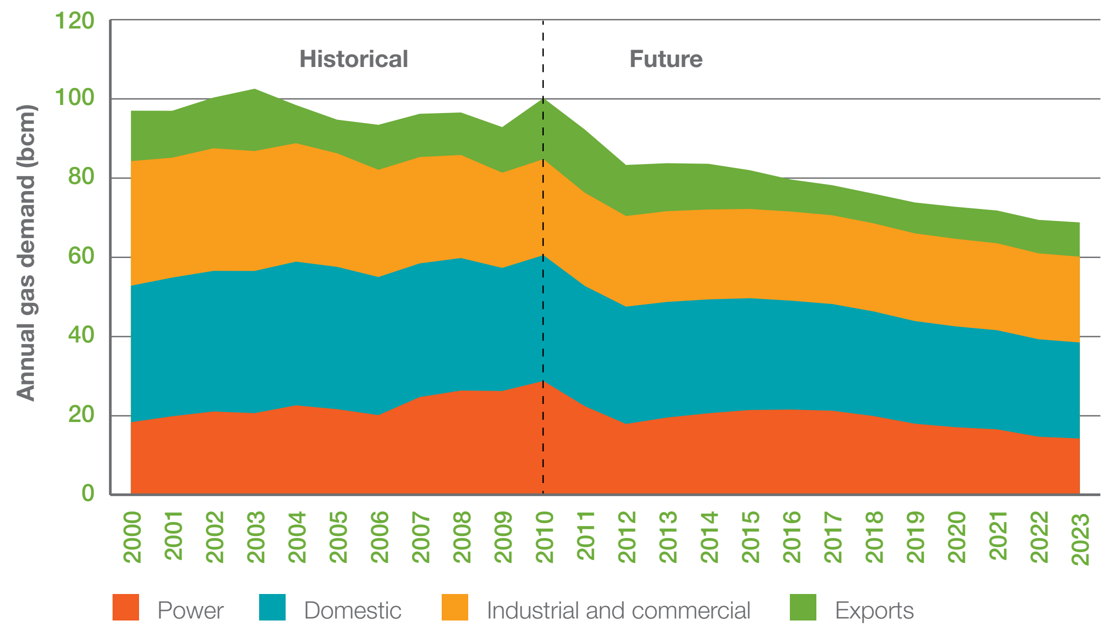
4. A 'dash' for smart gas

Figure 10. Electricity generation by fuel type and carbon intensity, Great Britain



Source: Based on National Grid (2012).

Figure 11. Total gas demand, Great Britain (Gone Green scenario)



Source: National Grid (2012).

motivated by the prospect of increased energy security and reduced exposure to international energy price volatility. The assumptions behind both are misguided.

To deliver a future power system that is clean, secure and cost-effective, a different approach is required, referred to here as a 'dash' for smart gas. This acknowledges that gas has an important role to play in displacing coal in power generation and providing flexibility within an electricity system supplied by a growing amount of intermittent renewable sources, as well as the need to meet the UK emissions targets.

The recent UK Gas Generation Strategy (DECC, 2012e) released by the Government in December 2012 (see Box 3) appears to combine elements of all three 'dashes' that have been described here. The Strategy states:

'The objective of this strategy is to reduce the uncertainty around gas generation for investors. The Government recognises that support for other forms of generation could undermine certainty for gas investors. We are therefore seeking to provide certainty for investors in both low-carbon energy sources and gas. To this end, we are setting a sustainable and affordable cap on the Levy Control framework out to 2020.[19] We are also reiterating that our approach to decarbonisation trajectories will continue to stay in step with other EU countries throughout the 2020s and consistent with a least-cost approach to our legally-binding 2050 decarbonisation objective and the 4th Carbon Budget.'

While the stated objective of the Gas Generation Strategy is to reduce investors' uncertainty, its approach may contribute to perceptions of policy risk as it includes carbon intensity scenarios for the power sector in 2030 that are inconsistent with the UK's current emissions targets, particularly the fourth carbon budget for 2023-27. Notably, the Strategy's 'central' scenario is based on a decarbonisation target for the power sector (100g CO_2/kWh in 2030) which is twice as high as the level assumed by the Committee on Climate Change when it recommended the fourth carbon budget. This target would require other sectors to provide the additional emissions cuts needed to meet the overall budget. More worryingly, the Strategy raises the prospect that 'gas could play a more extensive role should the fourth carbon budget be revised upwards', implying a possible weakening of the emissions targets for 2023-27 which could jeopardise subsequent progress towards the 80 per cent mandatory emissions reduction target for 2050 set in the Climate Change Act (Her Majesty's Government, 2008).

A further consideration is the scale of financial incentives that the UK Government will need to offer to private companies to encourage them to explore and exploit domestic shale gas resources. The Chancellor of the Exchequer has indicated that the Government will create an attractive tax regime for shale gas (HM Treasury, 2012b).

An energy policy that is cost-efficient and consistent with climate change objectives should take into account all the opportunities and challenges that future investments in additional gas capacity and generation would create. The analysis of the available evidence presented in this brief allows a number of conclusions to be drawn which can help inform decisions about the future role of natural gas in UK electricity generation.

19 The UK Government announced in November 2012, shortly before publication of the Gas Generation Strategy, a decision on the extension up to 2020 of the Levy Control Framework, which sets the upper limit on the amount that consumers can be charged to subsidise the development of low-carbon electricity generation. The amount of market support to be available for low-carbon electricity investment (under the Levy Control Framework) will rise from £2.35 billion today to £7.6 billion, in real 2012 prices, in 2020-21, which the Government has estimated will correspond to around or £9.8 billion in nominal 2020 prices. This is intended to increase the amount of electricity generated by renewable energy sources from 11 per cent today to about 30 per cent by 2030. The Framework will also support investment in new nuclear power stations and in carbon capture and storage.

Box 3. The UK Gas Generation Strategy

The UK Gas Generation Strategy (DECC, 2012e) laid out three possible scenarios for the future composition of gas-fired power plant capacity, which would lead to different levels of 'decarbonisation' of the electricity system: carbon intensities of 50, 100 or 200g CO_2/kWh. These are summarised in Table 4. The Strategy uses slightly different assumptions about electricity demand than those used in the fourth carbon budget, which can affect the cost of meeting a particular carbon intensity target.

Table 4. UK Gas Generation Strategy: future capacity scenarios

Decarbonisation Scenario in 2030	New CCGT by 2030 (GW)	Total CCGT (GW)	Generation (TWh)	Share of electricity (%)	Load factor (%)
Current (2011)	–	32	147	40%	48%
High: 50g CO_2/kWh	19	31	41	10%	15%
Central: 100g CO_2/kWh	26	37	88	22%	27%
Low: 200g CO_2/kWh	37	49	181	45%	43%

Source: Based on DECC (2012e); except 'Current' scenario from DECC (2012b).

The Strategy's 50g CO_2/kWh scenario would be in line with the UK's current carbon budgets. It assumes about 19 GW of new combined cycle gas turbine (CCGT) plants by 2030, which would keep overall gas capacity close to today's levels. Because the electricity generated by CCGT plants would largely be used for balancing purposes, plants would have to operate at low efficiency, so that their load factor in 2030 is expected to be only 15 per cent (compared with almost 50 per cent today). The commercial viability of building new gas capacity to operate at such low load factors is questionable. The UK Government's capacity market, as set out in the Energy Bill, should guarantee a minimum return for electricity generators to have capacity available, even if it is not used, helping to overcome the problem. Nevertheless, such a high reliance on low-efficiency CCGT could turn out to be a very costly way of providing flexibility, which might require substantial support from electricity consumers. In principle, fewer plants could be built and operated at higher load factors, if carbon capture and storage (CCS) technology were deployed and other flexibility measures (including storage, interconnection and demand management) were introduced.

The 100g CO_2/kWh 'central scenario' appears to be the option considered most plausible in the Gas Generation Strategy. It implies the construction of about 26 GW of new CCGT by 2030. The overall capacity of gas-fired power plants in that year will be about 15 per cent larger than today's levels, but the average load factor will decrease to 27 per cent (see Figure 12). Although the load factor is higher than in the 50g CO_2/kWh scenario, it is still unclear whether operating plants at such a low level of efficiency would be commercially viable. In addition, it is not obvious whether this scenario would be consistent with the objectives set in the fourth carbon budget. As the carbon intensity of the electricity sector will be above the 50g CO_2/kWh level recommended by the Committee on Climate Change (2010), additional emission cuts will be needed in other sectors in order to meet the overall UK carbon targets, but this is not explicitly acknowledged in the Gas Generation Strategy.

4. A 'dash' for smart gas

Box 3. The UK Gas Generation Strategy *(continued)*

The 200g CO_2/kWh scenario envisages a larger capacity of CCGT (about 37 GW of new plants) operating at a higher load factor of 43 per cent, assuming a higher output from (unabated) gas-fired power plants. It is based on the possibility that the fourth carbon budget will be revised upwards. This follows an earlier announcement by the Government that the fourth carbon budget will be revised in 2014 in light of the European Union's progress towards strengthening its 2020 greenhouse gas emissions target from a 20 to 30 per cent reduction on 1990 levels (Her Majesty's Government, 2011). Specifically, if the cap of the European Union Emission Trading System (EU ETS) is not strengthened such that it is in line with a 30 per cent target by 2020, the UK Government would consider loosening the fourth carbon budget[20] to realign it with the EU trajectory, as the budget sets the UK's traded sector emissions to fall at a faster rate than implied by the current rate of decline of the EU ETS (Gambhir and Vallejo, 2011). It is unclear, however, whether the European Union will have made a decision regarding its 2020 target by 2014, and therefore whether the trajectory for emissions reductions within the EU ETS would shift sometime after the revision of the fourth carbon budget. Reducing the ambition of the fourth carbon budget would also require bigger emissions reductions in later budgets in order to reach the 2050 target, with potential implications for cost-effectiveness. Furthermore, the Committee on Climate Change considered that a fourth carbon budget of 1950 Mt CO_2e was the minimum level of effort consistent with the mandatory 2050 target set in the Climate Change Act (Her Majesty's Government, 2008). In the Committee's own words 'any less ambitious target for 2030 would endanger the feasibility of the path to 2050' (CCC, 2010).

Figure 12. Gas capacity and generation in the UK Gas Generation Strategy central scenario (100g CO_2/kWh)

Source: Based on DECC (2012e), except 2011 data from DECC (2012b).

20 The current fourth carbon budget is 1950 Mt CO_2e, of which 690 Mt CO_2e from the sectors is covered by the EU ETS.

4. A ‘dash’ for smart gas

Ensure the electricity system is able to meet demand. Natural gas will continue to play an important role in UK electricity generation over the coming decades, under all scenarios, both for homes and businesses, and it will help to balance fluctuating supply and demand. Should gas prices fall, for example as a consequence of increasing supply of unconventional gas worldwide, this could have positive effects on the UK economy. Investment in additional technologies and measures to increase the flexibility of the electricity system will also be essential to meet demand, achieve climate change targets and ensure cost-efficiency. Several analyses (Pöyry, 2010; Strbac, 2012; Buckle and Thompson, 2009) have highlighted that the delivery of improved flexibility by 2030 requires decisions to be taken now, including about investment in energy storage, the upgrade of distributional networks and the development of infrastructure, particularly smart meters.

Prepare for higher gas prices. Low gas prices are not guaranteed. Several estimates, including by the International Energy Agency (2012a), indicate that gas prices in the UK and in the European Union are more likely to increase than fall, over the next two decades. The exploitation of unconventional gas resources has the potential to moderate such price increases, but the trend is still expected to be upwards. While projections should generally be considered with caution, given the high degree of uncertainty surrounding energy prices, current evidence suggests that betting on a sustained decrease in the wholesale price of natural gas would be very risky. This would also be inconsistent with the UK Government’s objective of diversifying energy price risks, and might increase the likelihood of locking the UK into a potentially expensive high-carbon future. Furthermore, evidence from the United States, and past experience in the UK, suggests that any reduction in the wholesale price of natural gas may not result in commensurate falls in electricity and heating bills for households and businesses.

Meet the carbon budgets. The UK carbon budgets set an upper limit on greenhouse gas emissions. Extensive gas-generated power, operating without CCS, would not be consistent with these targets. In the short run, some emissions from electricity generation can be reduced by replacing coal with gas, as has happened in the last few years in the United States. But in the medium term, gas without CCS will be too carbon-intensive to play a big role in the decarbonisation of the UK’s power sector. Strong UK Government support for research, development and deployment across a number of CCS pilot projects will be crucial to prove this technology is commercially viable, and to bring down costs (Imperial College London, 2011). Interestingly, the need to run combined cycle gas turbine (CCGT) plants with unabated emissions at low efficiency levels, in order to meet future carbon targets, makes the efficiency penalty imposed by CCS (which would allow the plant to operate at a higher load factor) more attractive. However CCS has a high capital cost and involves a significant loss of efficiency compared with fossil fuel plants that have unabated emissions. Market forces alone will not lead to its development and Government support is essential for its implementation on the scale and at the pace required. The roll-out of demonstration projects has been slower than required, and the development of CCS gas plant demonstrations has been particularly slow. Additional interventions will be needed, at least in the short term, to spur investments. The UK CCS Commercialisation Programme and other forms of support are encouraging (DECC, 2012f) and should be incorporated into the Energy Bill. The Member States of the European Union should also coordinate their CCS efforts and push ahead with pilot schemes, particularly for gas, including technology that can be retrofitted. Furthermore, while this policy brief does not consider whether or not a mandatory decarbonisation target for the power sector in 2030 would help to ensure that enough investment is made in low-carbon electricity generation, it should be noted that relaxing the emissions constraint for the power sector would require an attendant increase in emission reductions in other sectors of the economy, which could be more expensive to deliver. A detailed analysis is required of the most cost-effective options for compensating for the additional emissions from the power sector if its carbon intensity is not reduced to 50g/kWh by 2030.

Keep shale gas development within environmental and social constraints. The size of the shale gas resource that can be commercially exploited in the UK is unclear. However, it is likely to be relatively small in comparison with current and future levels of consumption. Therefore, while domestic shale gas production is undoubtedly worth investigating, and may be able to make a useful contribution to the UK economy, its potential should not be exaggerated. Current estimates suggest that shale gas could, at best, compensate for the gradual depletion of conventional reserves from the UK Continental Shelf. Furthermore, the production of shale gas will likely take more than a decade to develop in the UK. There are also significant social and environmental concerns that will need to be addressed if it is to be developed responsibly in the UK and Europe (IEA, 2012a), including risks of water pollution and fugitive emissions, and impacts on the landscape and local communities, which will need to be adequately regulated.

Overall future energy policy will require a coherent portfolio approach, as any decisions about electricity generation will have important repercussions on the whole energy system and on UK society.

5. Conclusions

The UK energy sector, particularly power generation, faces a period of transformation over the coming decades, in response to a number of driving pressures. First, there is a need to shift towards low-carbon energy sources to meet the UK's mandatory carbon target for 2050. This target is consistent with the international goal of reducing emissions in order to have a 50 per cent chance of avoiding rise in average global temperature of more than 2°C. Second, a large share of the UK's aging power plants and other energy infrastructure will have to be replaced over the coming decade as they reach the end of their lifetimes, requiring large amounts of investment. Third, there are concerns about the affordability and availability of electricity and heating for homes and businesses, particularly as the UK becomes more dependent on imports of natural gas.

All three drivers mean that there is an opportunity to overhaul the sector and shape it for the future, with a shift to low-carbon electricity generation. But this transformation will bring challenges, such as managing increased intermittency of electricity supplied by renewables and the relative inflexibility of nuclear power plants, while also meeting increasing demand. This will require changes in how the power sector operates.

This brief summarises the motivations and implications of a new 'dash' for gas. We conclude that, while it is clear that gas will continue to be an important energy source during the transition to low-carbon electricity, there are several reasons why it would be very risky for the UK to choose a 'dash' for gas-generated power and/or for shale gas on the assumption that European wholesale gas prices will be low in the future. If the UK is to achieve its emissions reduction target for 2050 in a least-cost way there is only a short window for unabated gas in power generation during which time it could usefully displace coal.

If the Government were to opt for a 'dash' for gas, this should be a 'dash' for *smart* gas i.e. a scenario in which natural gas is used to the greatest value in helping to decarbonise the UK economy and is accompanied by the implementation of strong upstream (e.g. at the wellhead) and downstream (e.g. capturing and strong carbon at gas-fired power stations) environmental measures to protect against fugitive emissions and other forms of pollution. This will require adequate policies to (i) maintain strict environmental, health and safety standards, including for shale gas exploration and extraction, and (ii) accelerate rapidly carbon capture and storage (CCS) technology research, development, demonstration and deployment, as well as research into the full range of options for improving the flexibility of the power sector.

A coherent energy policy is of paramount importance if the UK is to successfully channel investment into a portfolio of energy measures and technologies that will ensure a future energy system which is reliable, cost-efficient and environmentally sustainable. The UK Government must take care with its implementation of the Gas Generation Strategy such that it does not undermine efforts to decarbonise the power sector. While the replacement of coal-fired power stations with those fuelled by natural gas would help to reduce the UK's emissions, there are dangers of locking-in high-carbon electricity generation assets. Combined with the review of the fourth carbon budget in 2014 this could be perceived by the private sector as a significant policy risk and discourage investment in new low-carbon plants and infrastructure. A weakening of the fourth carbon budget would require more rapid emissions reductions after the 2020s, which may prove to be costly, in order to achieve the 2050 target.

While the science and economics of climate change, and the need for decarbonisation, are increasingly clear, many of the economic, financial, environmental and technological factors that shape the energy sector remain highly uncertain. Maintaining options in the face of this great uncertainty would be very valuable for the UK's economy.

Annex 1 – Conversion factors

Table A.1. General conversion factors for energy

Convert to:	bcf	bcm	MBtu	Mtherm	Mtoe	TWh
From:	Multiply by					
bcf	1	0.028	$1{,}074 * 10^{3}$	10,732	0.027	314.64
bcm	35.315	1	$37{,}900 * 10^{3}$	379	0.955	11.11
MBtu	$9.315 * 10^{-7}$	$2.638 * 10^{-8}$	1	$1 * 10^{-5}$	$2.52 * 10^{-8}$	$2.931 * 10^{-7}$
Mtherm	$9.315 * 10^{-2}$	$2.638 * 10^{-3}$	100,000	1	$2.52 * 10^{-3}$	$2.931 * 10^{-2}$
Mtoe	36.97	1.047	$39{,}681 * 10^{3}$	396.813	1	11.630
TWh	3,178	0.090	$3{,}412 * 10^{3}$	34.120	0.086	1

Note: bcf = billion cubic feet; bcm = billion cubic metres; MBtu = million British Thermal Units; Mtherm = million therms; Mtoe = million tonnes of oil equivalent; TWh = terawatt hour

Sources: IEA (2012), except Mtherm based on EIA (2012c).

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Glossary

Glossary

Term	Definition
Back-up capacity	A back-up reserve of electricity used when there is a major surge in demand and/or when electricity from intermittent renewable sources, such as wind and solar, is not in sufficient supply. It is typically provided by gas-fired power stations (combined cycle gas turbine plants), where electricity output can be increased and decreased relatively quickly in response to demand.
Carbon budget	A legally-binding limit on greenhouse gas emissions in the UK for a five-year period, set by the Government on the advice of the independent Committee on Climate Change. Each carbon budget provides a total cap on emissions, which should not be exceeded in order to meet the UK's emissions reduction commitments set in the 2008 Climate Change Act. So far, four carbon budgets have been set in law, covering the period from 2008 to 2027.
Carbon capture and storage (CCS)	A technology that can be used to capture carbon dioxide emissions which are released when fossil fuels are burnt in power stations. CCS stores carbon dioxide emissions underground (for example in underground structures like empty oil or gas reservoirs, or under the seabed), instead of releasing the carbon dioxide into the atmosphere as a greenhouse gas (DECC, 2012j).
Climate Change Act	A legislative act passed in November 2008, which sets out emissions reduction targets that the UK must comply with. The Act commits the UK to cutting its greenhouse gas emissions by 80% by 2050, compared to 1990 levels (Her Majesty's Government, 2008). To help the UK meet these targets, a series of five-year carbon budgets (see above) are set.
Carbon intensity (of the power sector)	The amount of carbon dioxide emitted by power plants per each unit of electricity generated. Usually measured in terms of grams of carbon dioxide per kilowatt-hour (kWh).
Coal-bed methane	A form of unconventional natural gas (mostly methane), trapped in the fractures and on the surface of coal beds.
Conventional gas	Natural gas typically found in sandstone, siltstone and limestone, in discrete, well-defined reservoirs. It is typically extracted through vertical wells and has relatively high recovery rates: usually over 80 per cent of the original gas in place can be extracted.
Energy mix	The combination of different energy sources (for example, fossil fuels like coal, oil and gas, or renewables such as solar or wind) used to make up the total energy supply.
EU Energy Roadmap 2050	Adopted in December 2011, the EU Energy Roadmap 2050 sets out aspirational targets for the European power sector to achieve 54-68% decarbonisation by 2030, and between 93-99% decarbonisation by 2050. It examines how to make Europe's energy production carbon-free by 2050, whilst ensuring a secure and competitive energy supply. The Roadmap examines a range of potential decarbonisation routes and scenarios, including energy efficiency, nuclear, renewables and carbon capture and storage (CCS).

Term	Definition
Flaring	The controlled burning of natural gas in the course of routine oil and gas production operations.
Fracking (hydraulic fracturing)	A technique used to extract shale gas trapped underground in rocks. Deep holes are drilled into shale rock. Water and other fluids (see fracking fluids) are pumped through the holes into the ground at high pressure to open up fractures in shale – a sedimentary rock with low permeability. This creates new fractures in the rock, and widens existing fractures, through which the gas can more easily move and subsequently be extracted into collection wells (Royal Society, 2012).
Fracking fluid(s)	A mixture of water, sand and chemicals pumped into shale rock under high pressure, to open up new fractures, or widen existing fractures in the rock (Royal Society, 2012).
Fugitive emissions (of natural gas)	Gas which is leaked or released during well development and production. Some of the operations leading to fugitive emissions are common to both conventional and unconventional gas. For example, methane can be emitted during the 'processing' stage (e.g. when removing heavy hydrocarbons and impurities to make the gas 'pipeline-ready') or during transport, storage and distribution of natural gas. Some additional fugitive emissions are specific to shale gas operations. They mostly occur during flow-back periods – when water that is forced under pressure into the shale (in order to fracture the rock to boost gas flow) returns to the surface accompanied by large quantities of gas; or during drill out – when plugs, which are used to temporarily seal off drilled well sections, are removed to release gas for production (Howarth et al., 2011).
Gas in place	The total volume of gas trapped in rocks. This measure does not take account of the actual ability to access or extract the gas (Royal Academy of Engineering, 2012).
Gas hub	A physical or virtual trading platform where titles to gas can be traded, bought or sold.
Levelised cost	The average cost of producing electricity over the lifetime of a generation plant, and therefore the price at which electricity must be sold to consumers for the supplier to break-even. It is calculated by dividing the lifetime capital and operational costs of a power source by total value of the electricity it generates, both discounted through time. It is usually expressed in units of currency per kWh or MWh, for example p/kWh or £/MWh.
Lifecycle greenhouse gas emissions (from natural gas)	Total greenhouse gas emissions generated by developing and using natural gas. These include direct emissions from end-use consumption (e.g. from gas combustion in power plants), indirect emissions from fossil fuels used to extract, develop and transport the gas, and methane fugitive emissions and venting during well development and production.
Liquefied natural gas (LNG)	Natural gas that has been liquefied by reducing its temperature to minus 162°C at atmospheric pressure. The cooling process reduces the space requirements for storage and transport by a factor of over 600 (IEA, 2013a).

Term	Definition
Proven reserves	The actual volume of reserves (in this case, shale gas) that can be feasibly extracted from a source, given pre-existing technical, economic, legal and operating conditions (Royal Academy of Engineering, 2012).
Shale	A fine-grained sedimentary rock, formed from mud, silt or clay deposits and organic matter (Royal Society & Royal Academy of Engineering, 2012). Has very low rock permeability, making it more difficult for fluids to pass through it.
Shale gas	A form of unconventional natural gas (largely methane) trapped underground in shale rock.
Tight gas	A form of unconventional natural gas (mostly methane) trapped in relatively impermeable hard rock, limestone and sandstone (JRC, 2012).
UK Gas Generation Strategy	Presented to Parliament in December 2012, it sets out the Government's view on the role gas can play in the UK's future electricity market. Its stated objective is to 'reduce the uncertainty around gas generation for investors'. The Strategy lays out three possible gas scenarios which would lead to different levels of 'decarbonisation' of the electricity system.
Unabated gas	Gas from power plants built without carbon capture and storage technology (CCS), hence whose emissions are left 'unabated'. CCS technology captures carbon dioxide emitted from fossil fuel plants to help reduce their climate change impact.
Unconventional gas	There are three main types of unconventional gas: tight gas, coal-bed methane and shale gas. These are found in less permeable rock formations than conventional gas. Low permeability means it is more difficult for fluids to pass through the rock – making unconventional gas found in these rock formations more difficult to extract. Hydraulic fracturing (fracking) and horizontal drilling are typically required to extract the gas. Recovery rates are lower than for conventional gas; typically only 15 to 30 per cent of the gas in place can be extracted.
Venting	The controlled release of gases into the atmosphere in the course of oil and gas production operations.
Wellhead price	The price paid at the mouth of a well for natural gas as it flows from the ground, without any processing or transportation provided.
Wholesale gas price	The price of natural gas at its point of delivery at a border or hub (see gas hub). Wholesale prices can be set in different ways. Some are linked to oil prices, through an indexation present in long-term supply contracts, as in Continental Europe and the OECD Pacific. Some are set through gas-to-gas competition (spot prices), and can be found in North America, the United Kingdom and parts of Continental Europe. Prices in many other regions are regulated: they can be set below costs, at cost of service, or be determined politically, reflecting perceived public needs (IEA, 2013b).

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