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Future Electricity Series

Part 1:
Power from Fossil Fuels

A report by
Carbon Connect

‘This report could not come at a better time. Debate about where our future electricity will come from is at an all-time high.’

Baroness Worthington and Charles Hendry MP

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FOREWORD

This report could not come at a better time. Debate about where our future electricity will come from is at an all-time high. Parliament is in the midst of scrutinising an Energy Bill containing once-in-a-generation electricity market reforms, and in the past few weeks the Government introduced a carbon price floor and announced significant developments in its support for shale gas and carbon capture and storage.

Fossil fuels - coal, oil and natural gas – have powered the UK through the industrial revolution and continue to provide most of our electricity, heat and transport fuel today. Climate change and our statutory climate change target of reducing carbon emissions by 80 per cent by 2050 have led us to reconsider the role of fossil fuels in our energy mix. Research looking at the cheapest way meet this carbon target has unanimously found that reducing carbon in the power sector is the first and most urgent action required. The Government's independent advisors on meeting carbon targets (the Committee on Climate Change) recommended that the Government begins by reducing carbon emissions from the power sector by around 90 per cent by 2030. Accomplishing this will entail generating more electricity from non-fossil fuel sources, such as nuclear, wind and biomass, and permanently removing the majority of carbon emissions from fossil fuel power stations using carbon capture and storage. Throughout this transition to a sustainable energy system, energy must remain affordable and secure.

This report examines what these challenges mean for the future role of fossil fuels in the power sector. It sets the scene for constructive, high quality debate and makes many valuable contributions itself in its findings.

Bias, myth and polarisation have all been unwelcome facets of the electricity debate over past months and have muddied the waters of what is an already complex puzzle. It is a puzzle in four dimensions – sustainability, security, affordability and time. These dimensions are reflected in the timeline that heads up this report. Establishing this as the framework for considering our future electricity options is the first step towards having a constructive, high quality debate. The second is to assimilate balanced and unbiased information about the options available, what we know about these options and, just as importantly, what we do not yet know. Carbon Connect's independent and politically neutral report does just that, drawing evidence from a large pool of existing research and contributions from a wide range of experts. It gives a holistic overview of the topic, focusing on particular pathways, key technologies and setting the record straight on commonly misunderstood areas.

The future of gas has dominated the energy debate in recent months, but this report restores much needed balance by clearly showing the uncertainty surrounding the future of UK coal power stations. There are risks of prolonged high carbon emissions from both gas and coal power stations and chapter one explains these risks, what the Government can do to mitigate them and why, on balance, evidence supports an ambitious power sector decarbonisation pathway to 2030. Chapter two explains that the Government's broad approach to supporting carbon capture and storage on fossil fuelled power stations as one of three key low carbon options (alongside offshore wind and nuclear power) is supported by the available evidence. However, many experts fear that the planned Government support will not result in the rapid and widespread deployment of carbon capture and storage, in and beyond the power sector, that energy system models indicate is needed to meet carbon targets cost effectively. The important contribution that unabated gas power stations will make to security of supply in the short and medium term

is explored in chapter three, although the exact extent will depend on the success of demand reduction, which should be a priority, and how much nuclear, carbon capture and storage and biomass capacity is deployed. The changing economics of fossil fuels is considered in chapter four, both in terms of absolute prices and price risk. The increasing price of carbon and the maturing of low carbon technologies are expected to make low carbon power options competitive with unabated fossil fuels by 2030. Finally, chapter five addresses the much discussed topic of shale gas and its development in the UK. It finds that the size and economic viability of shale gas reserves in the UK are highly uncertain, large scale production would be unlikely for at least a decade, and any impacts on the price the UK pays for gas are likely to be negligible.

Energy is a high stakes game, with consequences for every household, every business and every region in the UK. It is central to our economy, our security and our efforts to tackle climate change. For these reasons, Government will always hold the reins on energy, even when liberalised markets are charged with delivery. Energy will also remain a critical issue for politicians, who have been especially vocal on the topic in the build up to and since the Energy Bill was first read in Parliament last November. Rhetoric has frequently sought to exploit political divides, often ignoring areas of consensus and driving political uncertainty. This uncertainty has far-reaching consequences in a sector where power stations are built and operated by companies, often with international portfolios and investment opportunities. Consensus amongst politicians and parties is therefore particularly important in keeping investment flowing and the costs of finance down. Coming as we do from two different parties we want to highlight the value of acknowledging and building consensus as the UK sits on the brink of a potentially game-changing period of intense investment in electricity infrastructure.

We are supporting the Future Electricity Series because it recognises this important point. *Power from Fossil Fuels* has laid the foundations for a timely and high quality inquiry series that makes a valuable contribution to these debates. This report will be followed by similar reports on renewables and nuclear power and we look forward to working with you all on these over the coming months.

We would like to thank everyone who participated in this important inquiry, who generously gave their time and expertise during its course. We would also like to thank the esteemed members of the steering group for their time and hard work. Finally, we thank the Institution of Gas Engineers and Managers for their sponsorship to make this piece of work possible and Andrew Robertson and Fabrice Leveque for compiling the report.

Future Electricity Series Co-Chairs



Charles Hendry MP



Baroness Bryony Worthington

EXECUTIVE SUMMARY

Key finding

Pursuing a strategy where, during the 2020s, unabated coal capacity is minimised and unabated gas capacity is maintained near current levels and used increasingly as backup rather than baseload, is likely to be preferable on security, sustainability and affordability grounds.

Low Carbon

To achieve the UK's statutory 2050 carbon target, the amount of unabated fossil fuel generation in the power sector will need to reduce significantly. There is considerable evidence showing that reducing power sector emissions by around 80-90 per cent by 2030, followed by significant electrification of heating and possibly transport, is the most cost effective strategy to meet the 2050 target. The retirement of around a fifth of existing power plants over the next decade presents an excellent opportunity to expand low carbon capacity, permanently reducing sector emissions and achieving a recommended carbon intensity of around 50 gCO₂/kWh¹ by 2030.

The power sector is expected to more than half its carbon intensity by 2020, but what will happen in the decade to 2030 is less certain. The future of coal power stations and the success of nuclear and renewables build programmes will largely determine the emissions pathway during this decade. Unabated coal power stations are the most carbon intensive source of electricity and the future of many beyond 2016 is uncertain due to the unknown effect of tightening air pollution laws, carbon prices and fossil fuel prices upon the economics of these power stations. The economics of coal power stations and the amount of new low carbon capacity built in the 2020s will predominantly determine how much electricity is generated by unabated gas power stations. The main report outlines a number of steps that the Government can take to manage the risk of carbon emissions remaining high in the decade to 2030.

In reducing carbon emissions from the power sector, the role of fossil fuels will change. Unabated gas power stations are likely to play a much greater role than unabated coal because of their lower carbon intensity. Unabated gas power stations are also likely to be used increasingly as backup rather than baseload capacity. Today's capacity of unabated gas power stations could be maintained as a fleet of predominantly backup power stations, reimbursed through the proposed Capacity Mechanism until fossil fuel power stations with carbon capture and storage are proven and built. This strategy is achievable and consistent with the recommended emissions pathway for the power sector.

Beyond 2030, fossil fuels will only be able to provide large amounts of power if they are fitted with carbon capture and storage. There are significant benefits to keeping fossil fuels in the electricity mix, if carbon capture and storage can be proven.

Carbon Capture and Storage

The Government's approach in pursuing fossil fuels with carbon capture and storage as one of three key low carbon options for the power sector is consistent with available

¹ grams of carbon dioxide per kilowatt-hour of electricity

evidence. Whilst there is strong support for carbon capture and storage through the current demonstration programme, it is unlikely to result in significant levels of fossil fuels with carbon capture and storage being deployed by 2030, which models consistently indicate will be needed to achieve the 2050 target cost effectively. More rapid and widespread deployment of carbon capture and storage may be achievable by supporting industrial applications, and focusing on the development of shared transport and storage infrastructure, alongside existing plans for power sector demonstration and deployment.

There is strong evidence of the value of developing carbon capture and storage in future. Electricity supply will likely need to increase substantially between 2030 and 2050 as additional sectors such as heating and possibly transport are largely electrified. Doing so without abated fossil fuels would significantly increase reliance on renewable and nuclear deployment, which is likely to be more expensive and politically challenging. Carbon capture and storage could be at least as important in cost-effective decarbonisation outside the power sector. It is the only known option to decarbonise many industrial processes, could provide alternative low carbon energy vectors such as hydrogen for use in powering transport and could deliver negative emissions in conjunction with biomass combustion. Overall, it is estimated that without carbon capture and storage, total energy system costs could be £30-40 billion higher per year by 2050.

Energy Security

The UK power system faces short term operational challenges as around a fifth of existing capacity retires in the next decade and is replaced largely by intermittent capacity. Whilst the threat of dangerously low supply margins is real, this is a worst case scenario and several options are available to mitigate security risks. Mothballed gas power stations could be brought back online with early auctions and delivery under the proposed Capacity Mechanism. Demand reduction and demand side response could be a more cost effective means of meeting short capacity needs and so there are likely to be affordability benefits in holding Capacity Mechanism auctions for supply and demand-side measures at the same time.

Intermittent capacity, such as wind, is expected to increase threefold by 2020. In the medium term, unabated thermal power stations, including biomass and gas, will have an important role to play in managing this by providing additional flexibility. However, the extent of their role is dependent upon how cost effective and deployable alternative measures are, such as interconnection, storage and demand side response.

Beyond 2030, the electrification of heating and possibly transport will increase and change the profile of demand. Biomass power stations and abated fossil fuels are likely to be a cost effective way of meeting both capacity and flexibility needs. Bulk and distributed energy storage and demand side response from domestic users may be able to compete cost effectively. Developing and piloting these options could avoid locking out potentially advantageous future pathways.

Risks to the physical security of fossil fuel supplies will change as domestic production continues to decline and imports increase over the coming decades. Increased risks to supply from abroad are likely to be offset by an improved portfolio of import facilities and access to a wider variety of supplies. The political risk of interruptions and higher prices will increase, however, as the UK relies on supply chains over which it has less control. A low carbon strategy will diversify the electricity supply mix, enhancing the physical security of supply by spreading risks across a broader range of technologies.

Affordability

Price risk and volatility are important factors in assessing affordability, alongside the absolute costs of different technology options. Fossil fuel power is subject to a high degree of fuel price risk. Increasing fuel prices over the last decade have been the main driver of higher UK electricity bills. The UK will have very little control over the price it pays for fossil fuels in the future as markets become increasingly globalised and the UK becomes better interconnected to international markets.

It is expected that by 2030, low carbon generation will be cost competitive with unabated fossil fuel power stations. This assessment is based upon indicative carbon prices, expected increases to gas prices and expected cost reductions in maturing low carbon technologies. Nuclear and wind power benefit additionally from negligible or no fuel price risk. Pursuing a high gas consumption strategy therefore carries greater risks of higher costs and low benefits than a low carbon pathway that meets the recommended carbon intensity for the power sector in 2030.

Shale gas

The extent to which shale gas production has altered the US energy landscape and its potential to do the same worldwide has been one of the main drivers behind calls to re-evaluate the current low carbon strategy. Whilst global resources of unconventional gas (shale gas, coal bed methane and tight gas) could be large, how productive these deposits are and how much gas could be economically recoverable remains highly uncertain, with worldwide exploration and testing at a very early stage.

There are environmental risks arising from hydraulic fracturing that are still poorly understood – potential groundwater contamination from fracking fluid, and the level of fugitive methane emissions among them. Shale gas extraction requires significant volumes of water, produces local pollution and carries the risk of surface water contamination.

In the near term, only US shale gas production has reached volumes able to impact on world markets. US exports of gas towards the end of this decade will add to global supplies, although the impact on the UK looks to be a diversification of imports rather than significantly lower prices. Any longer term impact on global gas prices will only become clearer once exploration and testing, still at a very early stage in most countries, progresses.

The UK may have sizeable resources of its own, although there is currently not enough evidence to make a reliable estimate of their size, and economic viability. Social and economic factors are likely to slow UK development compared with that seen in the US, and significant volumes, if they develop, are not expected to be reached until the end of the decade. The main advantage of a domestic industry will be additional revenues and the diversification of supply. Our liberalised and highly interconnected market would prevent prices remaining artificially low compared with neighbouring markets.

LIST OF FINDINGS

LOW CARBON

Finding 1

Expected closures of unabated coal and oil power stations between now and 2016 will reduce power sector emissions intensity to around 300-350 gCO₂/kWh.

Finding 2

There is the potential for up to 91 per cent of the unabated coal power station capacity expected to remain in operation at the start of 2016, to continuing operating into the 2020s. There is a risk that these unabated coal power stations will cause the UK to exceed its carbon budgets if not enough low carbon capacity is built.

Finding 3

A similar amount of unabated gas capacity as today is likely to be needed through to 2030, to backup intermittent generation such as wind and meet peak electricity demand. Limiting its role to predominantly backup and peaking is consistent with a power sector emissions intensity of 50-100 gCO₂/kWh by 2030.

Finding 4

The continued need for a significant fleet of gas power stations from now to 2030 brings a risk of carbon lock-in that could undermine the UK's efforts to meet its 2050 carbon target unless managed by Government.

Finding 5

Once carbon capture and storage on gas power stations is proven, tightening the Emissions Performance Standard could be a useful means of ensuring that no new unabated gas power stations are built.

Finding 6

Government needs to manage the risk of carbon lock-in from unabated coal and gas power stations and can do so through the following:

- Incentivising new renewables capacity to be built in the 2020s at a rate similar to that in the 2010s.
- Using carbon pricing to improve the economics of unabated gas power stations relative to unabated coal.
- Designing and implementing a Capacity Mechanism that creates a market in which gas power stations are economic at low load factors, stimulating investment in existing and new power stations.
- Continuing to support the development of CCS for gas.
- Supporting lower carbon forms of gas power station, such as combined heat and power.
- Reforming existing Carbon Capture Ready requirements for new gas power stations so that they are more effective in ensuring that new power stations can be retrospectively integrated into future UK CCS infrastructure.
- Tighten limits under the Emissions Performance Standard for future unabated gas power stations once full chain CCS on gas has been proven.

Finding 7

Pursuing a strategy where, during the 2020s, unabated coal capacity is minimised and unabated gas capacity is maintained near current levels and used increasingly as backup rather than baseload, is likely to be preferable on security, sustainability and affordability grounds.

CARBON CAPTURE AND STORAGE

Finding 8

Whilst the Government's commitment and planned support for CCS is amongst the best in the world, it is unlikely to result in significant (10+ gigawatts) levels of CCS deployment by 2030 that models indicate the UK needs to achieve the 2050 carbon target cost effectively.

Finding 9

The Government must ensure that supported demonstration and deployment in the power sector establishes the technical, commercial and legal frameworks to facilitate privately funded investment in the power sector and in industry.

Finding 10

The Government's approach to developing CCS in the UK is currently focused on power sector applications. Greater commitment to CCS would provide more options for reducing carbon emissions in the 2020s, both in the power sector and in industry.

Finding 11

There are substantial benefits to keeping fossil fuels in the power mix if emissions can be limited using CCS. Electricity supply will likely need to rise significantly by 2050, and decarbonising the power sector beyond 2030 without CCS would be expensive and politically challenging.

Finding 12

Meeting the UK's 2050 carbon targets without CCS would cost the UK economy around £30-40 billion more each year, or approximately 1 per cent of gross domestic product, roughly doubling the expected annual costs of meeting carbon targets.

Finding 13

CCS has significant potential to reduce carbon in both the power sector and in industry, and to support the gasification of coal and biomass feedstocks to provide flexible low carbon energy.

Finding 14

The UK is well placed to become a world leader in CCS deployment, which would bring significant benefits.

Finding 15

There are many 'flavours' of capture technology and the Government must strike the right balance between spreading limited resources thinly by pursuing too many variants for too long and missing out on benefits by eliminating variants before their comparative potential is well understood.

Finding 16

Current Carbon Capture Ready requirements do not reflect the economic viability of connecting plants to transport and storage infrastructure, reducing the effectiveness of this as a measure to promote the retro-fit of CCS in the future.

Finding 17

Emissions limits under the Emissions Performance Standard will need to be tightened, once CCS is proven, to avoid reducing the potential market for CCS on gas in future.

SECURITY**Finding 18**

Physical risks to supply caused by the UK's increasing fossil fuel import dependence will be offset by a diversification of supplies. Political risks will increase however, as the UK relies on fuel supplies outside of its direct control.

Finding 19

Diversifying the generation mix to include more low carbon generation will reduce risks to physical security, although it will create new technical and market challenges.

Finding 20

There is a real threat of power shortages in the next few years, although at present, this is a worst case scenario and poses a risk similar in scale to those successfully managed before. A combination of market signals and the proposed Capacity Mechanism could mitigate the risk by incentivising currently mothballed gas power stations to be revived if needed.

Finding 21

Continuing to deliver security at lowest cost will be particularly challenging over the next five to ten years due to a confluence of:

- Electricity Market Reform causing an inevitable temporary hiatus in the building of new power stations
- High gas prices relative to coal eroding the economics of gas power stations and forcing some to be mothballed or consider closure
- A significant amount of old coal, oil and nuclear power station capacity closing
- Uncertainty over the future availability of electricity imports via interconnectors

Finding 22

Bringing forward first delivery under the Capacity Mechanism, currently scheduled for 2018, could be a useful tool in managing short term security risks cost effectively.

Finding 23

There could be affordability benefits in holding Capacity Mechanism auctions for supply and demand-side measures at the same time.

Finding 24

In the short to medium term, increased flexibility requirements from higher penetration of intermittent generation is best met by biomass and unabated gas power stations, until storage, demand side response and interconnection can compete at scale.

Finding 25

Energy storage, demand side response and interconnection could compete at scale with fossil fuel and biomass plants to provide system flexibility by 2030. Developing and piloting these technologies could avoid locking out potentially advantageous future pathways.

AFFORDABILITY**Finding 26**

Gas and coal generation are subject to higher degree of future price risk than alternative forms of generation.

Finding 27

Many forms of low carbon generation will be cost competitive with unabated gas by 2030, under central assumptions of future technology costs, carbon prices and gas prices.

Finding 28

Fuel price forecasts used in UK policy making, take account of likely short to medium term impacts from unconventional gas resources.

Finding 29

Investing in a high gas strategy carries greater risks of higher costs, and lower benefits, than an alternative low carbon pathway.

SHALE GAS**Finding 30**

In the event of cheap and plentiful domestic production, our liberalised and highly interconnected market would prevent UK gas prices remaining below that of prevailing European prices.

Finding 31

Imports of US shale gas are unlikely to have a large impact before the end of this decade, and will likely diversify imports rather than lower prices.

Finding 32

There is currently too little evidence on which to make reliable estimates regarding the size of UK resources, and their economic viability.

Finding 33

Socio-economic factors in the UK mean that large scale production would be likely to take at least a decade to develop.

METHODOLOGY AND STEERING GROUP

Carbon Connect carried out this inquiry between January and April 2013. Evidence was gathered by a conference held in Westminster on 30 January 2013, interviews with those working in and around the sector, written submissions, desk-based research and input from our steering group of industry and academic experts. The in this report are those of Carbon Connect. Whilst they were informed by the steering group and listed contributors, they do not necessarily reflect the opinions of individuals, organisations, steering group members or Carbon Connect members.

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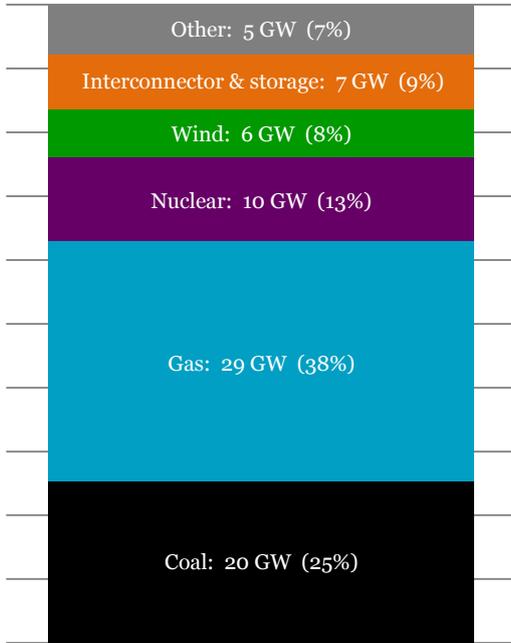
TIMELINE

	Present	Short Term <i>present - 2020</i>
Low Carbon	<p>Carbon intensity in 2012: ~470 gCO₂/kWh An increase on previous year due to increased coal generation.</p> <p>Unabated coal, oil and gas predominantly used for baseload generation.</p>	<p>200 gCO₂/kWh likely in 2020 by: - replacing around half of unabated coal with new renewables.</p> <p>Carbon capture and storage (CCS) full-chain demonstration. Development of market and regulatory frameworks for transport and storage needed to allow commercial growth in 2020s.</p>
Secure	<p>Capacity margins reducing as coal and oil capacity falls from 30 gigawatts in 2012 to 22 gigawatts in 2013.</p> <p>Concerns over worst-case scenario 'capacity crunch'. Mothballed gas plants may need to come back online and investing in electrical efficiency will reduce demand.</p>	<p>Increasing proportion of intermittent wind generation will increase the need for demand side response, interconnection, storage and flexible generation.</p> <p>UK continues to source more fossil fuels non-domestically, whilst interconnection with international markets mitigates physical security of supply risk.</p> <p>Shale gas exploration in the UK establishes a better picture of economically recoverable resources.</p>
Affordable	<p>Shift of the generation mix from more expensive gas to cheaper coal has limited the impact of high gas prices on consumers.</p> <p>Levelised cost of fossil fuel power is cheaper than nuclear or renewables, but more volatile due to significant fuel costs.</p> <p>There is no significant shale gas production industry in the UK.</p>	<p>By 2020, demand side response, storage and interconnection likely to be most cost effective means of backing up intermittent wind and solar alongside flexible generation, such as gas, biomass and coal.</p> <p>Carbon price floor increases costs of unabated fossil fuel generation, especially coal.</p> <p>International gas prices expected to remain high, although US exports of shale gas may ease liquefied natural gas markets.</p> <p>Any domestic UK shale gas production very unlikely to reduce prices as those in the UK are set through interconnected international markets.</p>

Medium Term <i>2020 - 2030</i>	Long Term <i>2030 – 2050</i>
<p>100 gCO₂/kWh achievable in 2030 by: - replacing most of remaining unabated coal with nuclear.</p> <p>50 gCO₂/kWh achievable in 2030 by: - as above, plus building renewables at the same rate as in 2010s to replace unabated gas generation. Unabated gas capacity remains at around 40GW, but load factors reduce.</p> <p>Models suggest that rapid deployment of 10+ gigawatts of CCS in 2020s is the most cost effective route to 2050 carbon target.</p>	<p>Power sector carbon emissions will need to reach near zero by 2050.</p> <p>Heat and possibly transport are likely to be decarbonised through electrification, mostly taking place after 2030. This will substantially increase demand for electricity.</p> <p>Providing enough low carbon electricity will be more difficult and costly without CCS for fossil fuel power plants. CCS is also required to decarbonise industry, and produce negative emissions through biomass combustion.</p>
<p>Distributed storage and demand side response in the domestic sector add further means of managing increased intermittency cost effectively.</p> <p>Remaining coal, biomass and gas power stations increasingly fall to backup generation as the volume of intermittent generation increases.</p> <p>UK conventional gas production reaches significant decline; shale gas extraction could slow growing import dependence.</p>	<p>Electrification of heat and possibly transport increases size and variability of demand, adding to the challenge of balancing and maintaining sufficient capacity.</p> <p>Developing CCS will allow fossil fuels to remain part of the mix, diversifying supply, and providing flexible thermal generation.</p> <p>UK conventional gas production reaches significant decline; shale gas extraction could help slow growing import dependence.</p>
<p>Nuclear and renewables could be cost competitive with unabated gas by 2030. Carbon price floor increases from £30 per tonne in 2020 to £70 per tonne in 2030.</p> <p>Investment in alternative grid management technologies likely to reduce need for overall system capacity and reduce costs of integrating intermittent generation.</p> <p>Thermal plants operating at low load factors are reimbursed through the Capacity Mechanism.</p> <p>Global production in shale gas <i>could</i> help supply meet growing demand, easing pressure on gas prices.</p>	<p>Carbon price floor increases from £70 per tonne in 2030 to £200 by 2050. Low carbon generation and fossil fuels with CCS become more cost effective than unabated gas.</p> <p>Demand side response, demand reduction, storage and interconnection likely to provide significant system benefits given scale of electricity demand and variability.</p> <p>Thermal plants operating at low load factors are reimbursed through the Capacity Mechanism.</p> <p>Global production in shale gas <i>could</i> help supply meet growing demand, easing pressure on gas prices.</p>

KEY NUMBERS

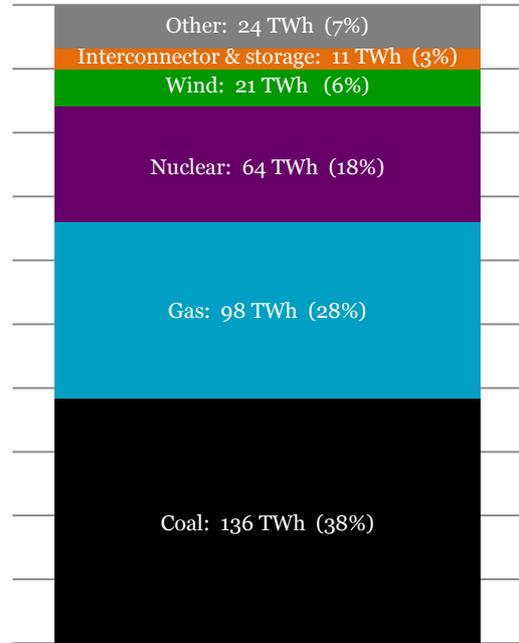
Capacity (2013)



Total capacity:

77 GW

Generation (2012)



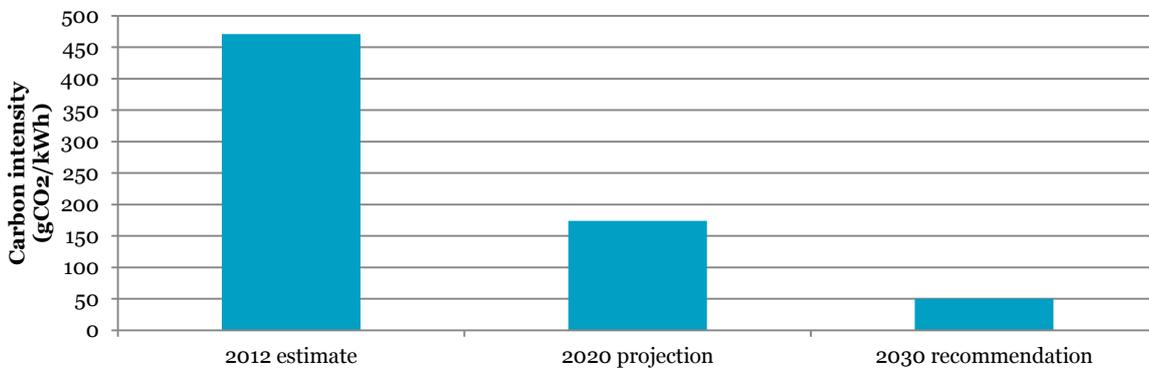
Total generation:

354 TWh

Notes:

- 1) GW is gigawatts
- 2) TWh is terawatt-hours
- 3) Capacity is Transmission Entry Capacity and includes embedded generation (Source: National Grid)
- 4) Generation is electricity supplied net of electricity used in generation (Source: DECC provisional data)

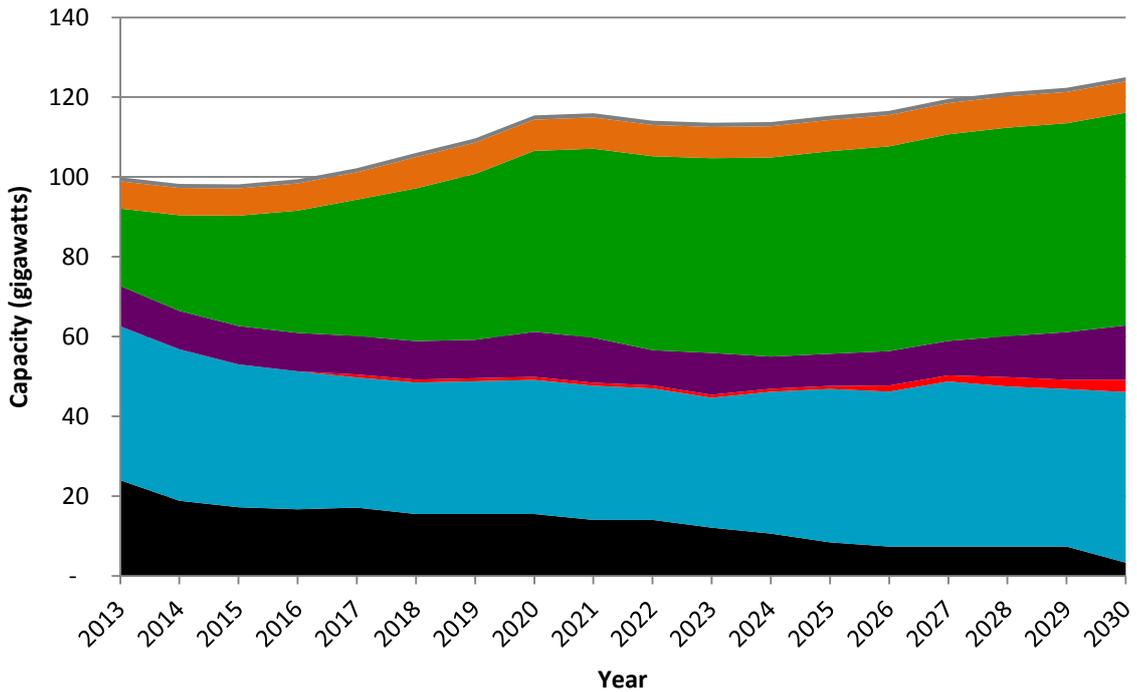
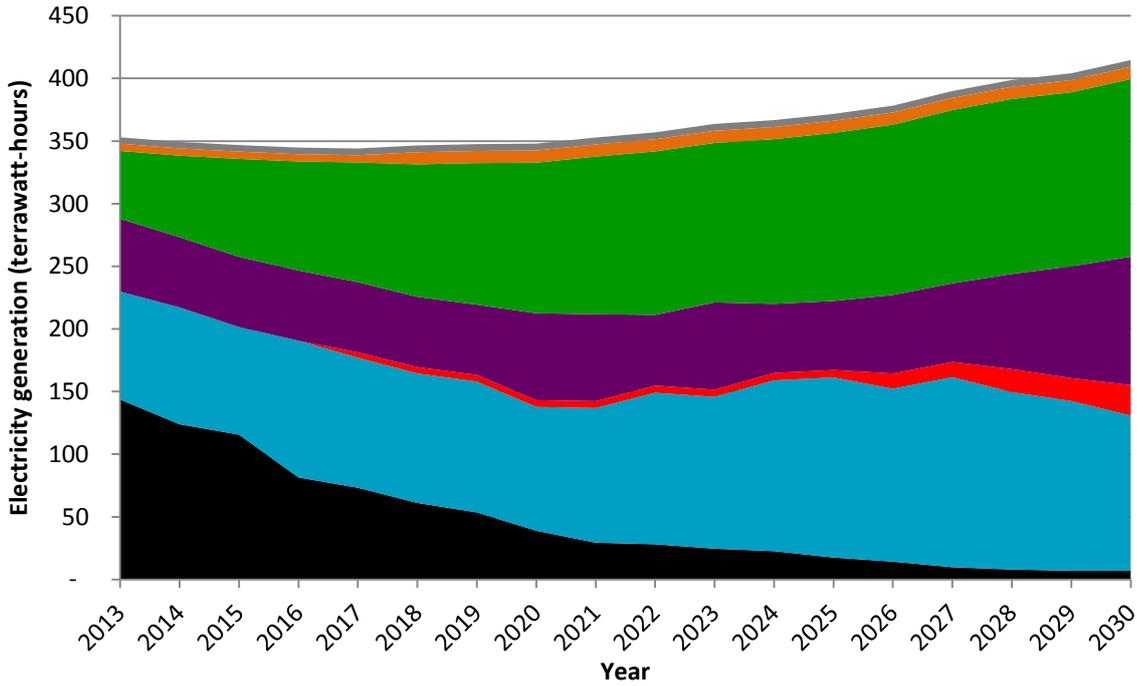
Carbon intensity of electricity supply 2012-2030



Notes:

- 1) 2012 is a Carbon Connect estimate based upon DECC Energy Trends Data
- 2) 2020 is a Carbon Connect projection based upon DECC Energy and Emissions Projections (central projection)
- 3) 2030 is the carbon intensity recommended by the Committee on Climate Change ('around 50 gCO₂/kWh')

DECC central projection of electricity generation and capacity by source



- Coal
- Gas
- Carbon capture and storage
- Nuclear
- Renewables
- Interconnection and storage
- Other

Source: Department of Energy and Climate Change, Energy & Emissions Projections (October 2012)

- Notes:
- 1) Electricity generation is gross generation less the amount of electricity used on station sites (own use)
 - 2) Capacity is installed capacity of all electricity producers including combined heat and power and autogenerators
 - 3) DECC is Department of Energy and Climate Change

1. LOW CARBON

1.1 The challenges

The UK is committed to reducing its carbon dioxide emissions, with the 2008 Climate Change Act setting a legally binding target to reduce greenhouse gas emissions by 80 per cent (on 1990 levels) by 2050. There is broad consensus that the UK power sector, responsible for 32 per cent of total UK carbon dioxide emissions in 2011², is the most practical and cost effective part of the economy to begin emissions reductions.

The Committee on Climate Change, the official body tasked with advising the Government on how to achieve emissions reductions, has recommended that the carbon intensity of the power sector be reduced to around 50 grams of carbon dioxide per kilowatt hour (gCO₂/kWh) by 2030³. In 2012, the carbon intensity of the power sector was around 470 gCO₂/kWh, produced from the burning of coal, oil and gas in power stations⁴. In 2011, coal and gas generation provided 30 and 40 per cent of total supply respectively and a small number of oil power stations provided an additional one per cent⁵. In 2012, coal provided 38 per cent of electricity and gas 28 per cent due to the economics of coal power stations becoming more favourable⁶. To reduce power sector emissions to around 50 gCO₂/kWh, the amount of electricity generated from unabated fossil fuels will have to reduce substantially.

The case for power sector decarbonisation

The Committee on Climate Change first recommended ‘the almost full decarbonisation of the power sector’ by 2030 in 2008⁷ and reiterated their advice in a recent letter to the Government, calling for a power sector decarbonisation target of around 50 gCO₂/kWh by 2030 to be legislated in the Energy Bill⁸. Various models of the future energy system used by the Committee on Climate Change, the Energy Technologies Institute and the UK Energy Research Centre, suggest that expanding production of low carbon electricity, followed by electrification of heating and transport is likely to be the most cost effective method of meeting the UK’s 2050 carbon target^{9,10, 11}.

The availability of proven and maturing low carbon technologies – such as nuclear, renewables and fossil fuels with carbon capture and storage (CCS) – to substitute for high carbon alternatives, and the potential for CCS technology to capture the emissions from fossil fuel generation, makes decarbonisation in the power sector the most cost effective route to reaching the 2050 emissions target¹². The old age of the existing power generation fleet and a large number of retirements over the next decade provide a good opportunity to expand the use of low carbon alternatives – a

² DECC (2012) Digest of United Kingdom Energy Statistics

³ CCC (2013) Letter to Ed Davey

⁴ Carbon Connect Analysis, based on DECC (2013) Energy Trends

⁵ DECC (2012) Digest of United Kingdom Energy Statistics

⁶ DECC (2013) Energy trends

⁷ CCC (2008) Building A Low Carbon Economy: The UK’s Contribution To Tackling Climate Change

⁸ CCC (2013) Letter to Ed Davey 29.02.13

⁹ CCC (2008) Building A Low Carbon Economy: The UK’s Contribution To Tackling Climate Change

¹⁰ ETI (2011) Modelling the UK energy system: practical insights for technology development and policy making

¹¹ UKERC (2013) The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios

¹² CCC (2011) Fourth Carbon Budget

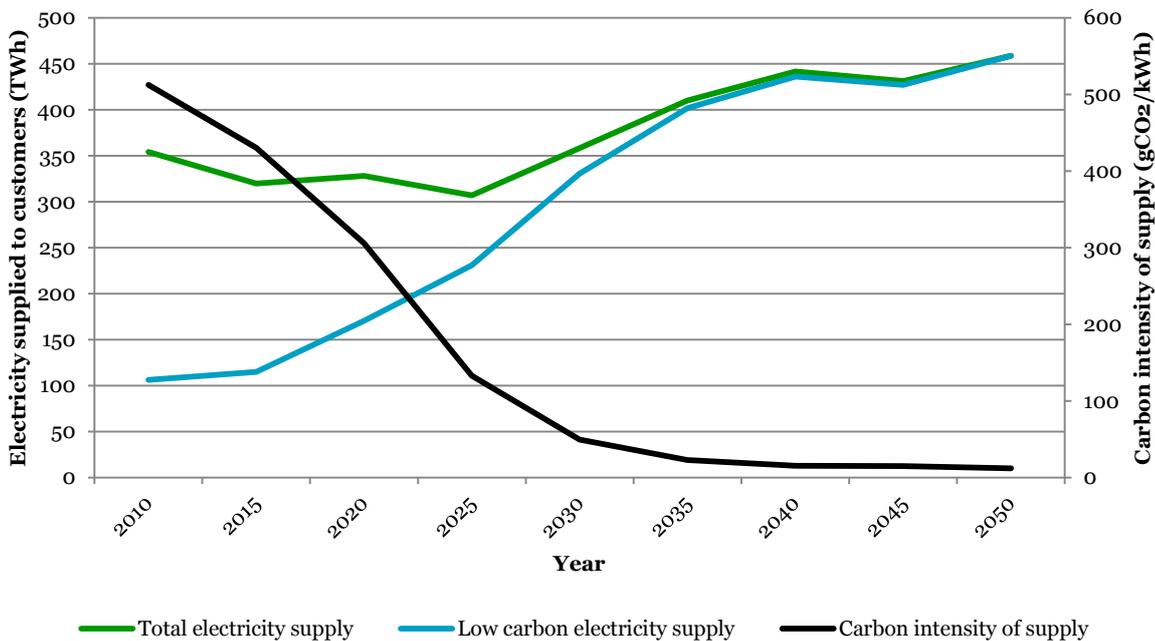
rare opportunity given the twenty to fifty-year lifetime of power generating infrastructure.

Expanding production of low carbon electricity will allow the electrification of a considerable proportion of transport and heating, which appears to be the most cost effective method to achieve significant carbon reductions in these sectors¹³. Without a significant increase in the use of low carbon electricity, other methods of abating emissions in these and sectors such as industry may prove costlier, and less effective. In more recent analysis by the UK Energy Research Centre¹⁴, carbon emissions are reduced in the transport sector by switching to biofuels or hydrogen fuel cells. Therefore the case for the electrification of transport is less strong than that for heat. This does not change their conclusion that power sector decarbonisation should be prioritised and pursued first.

Recommended emissions trajectory: around 50 g by 2030

Figure 1 illustrates the Committee on Climate Change’s recommended emissions scenario for the power sector. Emissions intensity falls below 300 gCO₂/kWh by 2020, facilitated by the retirement of old coal plants and an increase in renewables capacity, reaching around 50 gCO₂/kWh by 2030, before falling to nearly zero by 2050. This provides a cost effective pathway for carbon emissions reduction to meet the 2050 target, with increased low carbon generation allowing electrification of other sectors.

Figure 1: MARKAL trajectory for the power sector 2010-2050



Source: MARKAL modelling by University College London for the Committee on Climate Change (2010)

- Notes: 1) Carbon intensity calculations exclude the 'negative emissions' benefits of using biomass in conjunction with carbon capture and storage
- 2) TWh is terawatt-hour
- 3) gCO₂/kWh is grams of carbon dioxide per kilowatt-hour
- 4) MARKAL is MARKET ALlocation

¹³ CCC (2011) Fourth Carbon Budget

¹⁴ UKERC (2013) The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios

To achieve the recommended 2030 emissions intensity target of around 50 gCO₂/kWh, large quantities of low carbon capacity will be required. Energy system modelling underpinning this scenario suggests that 92 per cent of supply will need to come from a mix of nuclear, renewables and fossil fuels with CCS by 2030, with energy use becoming far more efficient¹⁵. With many nuclear power plants reaching the end of their lives by 2023, and a full chain carbon capture and storage plant yet to be constructed, this is a big challenge and will require the rapid and successful implementation of Electricity Market Reforms being undertaken by the Government.

1.2 What role for coal and gas in a decarbonised power sector?

Achieving a power sector emissions intensity of around 50 gCO₂/kWh by 2030 will require a significant reduction in the output from fossil fuel power stations. The relative economics of unabated coal and gas power stations will change over the coming decades as a Carbon Price Floor is introduced and steadily increases as of 1st April 2013. It is expected that this will reverse the recent preference for coal over gas, driven by low coal prices, due to coal's higher emissions intensity attracting a higher carbon price penalty. Table 1 outlines typical average emissions intensities for existing and new thermal power stations¹⁶.

Table 1: Estimated carbon dioxide intensity of thermal power stations

	Existing	New	CCS
Coal	899	735	132
Gas	396	319	58
Biomass	Unknown	Negative to max. 285 ¹⁷	Negative to Near Zero

Sources: DECC (2012) Digest of United Kingdom Energy Statistics
Parsons Brinckerhoff (2011) Electricity Generation Cost Model 2011 – Update
DEFRA (2009) GHG conversion factors for company reporting

Notes: 1) 85 per cent capture rate for coal and gas carbon capture and storage
2) Gas is combined cycle gas turbine
3) CCS is carbon capture and storage
4) All numbers are carbon intensities (grams of carbon dioxide per kilowatt hour)

Coal is over time twice as carbon intensive as gas power, making gas a more attractive method of providing greater volumes of generation within tightening carbon budgets. Over double the volume of gas generation can be accommodated, compared to coal, within any given carbon limit. On these grounds, gas capacity is preferred in an increasingly carbon constrained system and it is therefore likely that unabated gas power will increasingly dominate the mix of unabated fossil fuel power stations at least up to 2030.

These benefits of gas are weighted against the currently cheaper cost of coal and the added diversity and security benefits of maintaining both forms of generation in future. These factors are discussed in chapters on Affordability and Security.

¹⁵ CCC (2012) The Role of Gas in a Decarbonised Economy

¹⁶ Power stations that burn fuel – typically coal, oil, gas or biomass

¹⁷ DECC (2012) Renewables Obligation Banding Review Consultation Response

1.3 A declining role for coal

At the start of 2012, the UK had 30 gigawatts of coal and oil fired capacity¹⁸, which provided 38 per cent of total supply in 2012. This was an increase on 2011, when coal and oil provided 29 per cent of supply¹⁹, driven by the low price of coal relative to gas. Between the start of 2012 and 2016, tighter air pollution limits (non-carbon dioxide) are expected to cause a reduction in coal and oil capacity from 30 to 17 gigawatts. Around 11 gigawatts is due to plant closures and three gigawatts from biomass conversions²⁰ (see Figure 2). The EU Large Combustion Plant Directive requires that coal power stations fit flue gas de-sulphurisation technology to reduce emissions of sulphur dioxide, or run reduced operating hours before coming offline by the end of 2015. By April 2013, coal and oil capacity had reduced to 22 gigawatts with the retirement of several plants that had run through their remaining operating hours under the Large Combustion Plant Directive²¹. A further five gigawatts is expected to close or convert to biomass by 2016 when 17 gigawatts of unabated coal capacity is expected to remain in operation. Analysis based upon the Department of Energy and Climate Change (DECC) central energy and emissions predictions²² indicates that this could reduce emissions intensity to 300-350gCO₂/kWh by 2016 as output from coal and oil generation is replaced with new low carbon renewables. This puts the UK broadly on track with the Committee on Climate Change's recommended power sector emissions trajectory, up to this point.

Finding 1

Expected closures of unabated coal and oil power stations between now and 2016 will reduce power sector emissions intensity to around 300-350 gCO₂/kWh.

¹⁸ DECC (2012) Digest of United Kingdom Energy Statistics

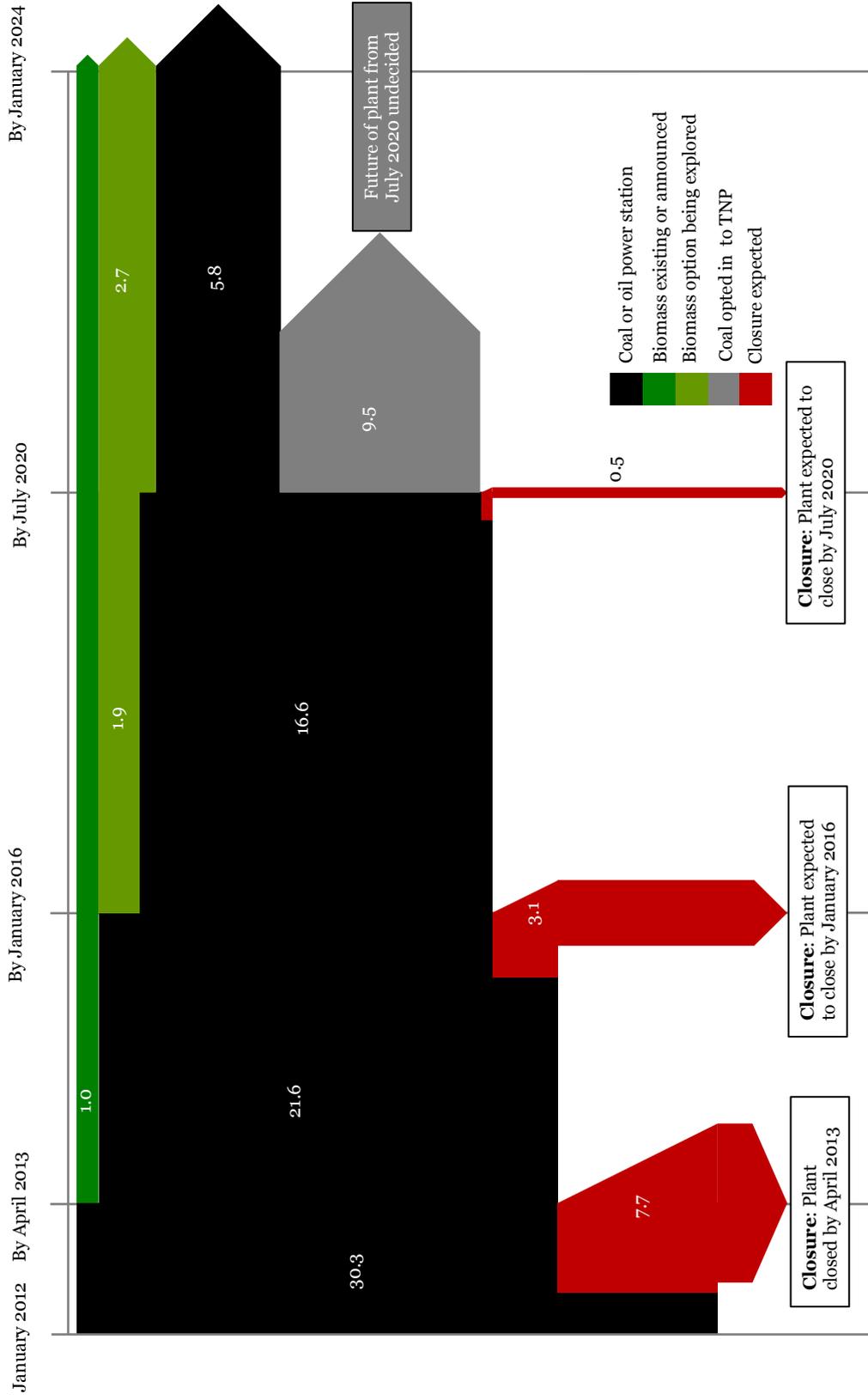
¹⁹ DECC (2013) Energy Trends

²⁰ Arithmetic inconsistent due to rounding

²¹ Kingsnorth, Cockenzie and Didcot A closed definitively, with Ironbridge and one unit at Drax converting to Biomass

²² DECC (2012) Updated Energy & Emission Projections

Figure 2: Future of coal and oil power station capacity (gigawatts)



Notes: 1) All numbers are plant capacities, in gigawatts, taken from National Grid Register of Transmission Entry Capacities (March 2013)

2) Where a biomass option is being explored, we have assumed it goes ahead.

3) Biomass conversion is assumed to lose 25 per cent of pre-conversion coal capacity.

4) Not all UK biomass capacity is shown, only conversions of coal power stations from January 2012 onwards

5) TNP is transitional national plan (see page 25 for explanation)

The 2020s

By 2020, between 6 and 15 gigawatts of unabated coal capacity could remain in operation. The speed at which these remaining power stations close, or switch to partial or full biomass burning will further dictate the rate at which power sector emissions fall. This will be driven by another tightening of air pollution limits, under the EU Industrial Emissions Directive, which will further restrict emissions of air pollutants (non-carbon dioxide). Power stations have four options:

- Opt-in, and comply with the new emissions limits by 2016.
- Opt-in to a ‘Transitional National Plan’, where limits will be reduced gradually between 2016 and 2020. From 2020, power stations must comply with new emissions limits.
- Opt-out, and run no more than 17,500 hours (or 729 days at full operation) between 2016 and final closure by 2023.
- Opt to run fewer than 1,500 hours per year (62.5 days) and be subject to higher emissions limits (removing the need to invest in new technology).

In the past, it had been suggested that the costs of fitting emission abatement technologies could be prohibitively expensive for most of the UK’s coal plants. However, the costs of installing technology to comply have been uncertain²³. At least four operators, representing around nine gigawatts of capacity, have explored fitting abatement technology²⁴, with several trials currently taking place. Low coal prices and potential reductions in the costs of abatement technology²⁵ have led to most plants opting in, either fully or under a Transitional National Plan, which will result in more unabated coal running between 2016 and 2020, and possibly beyond.

More coal running than expected?

Table 2 illustrates current thinking on the role of coal in 2025. DECC estimates that 8.4 gigawatts could still be in operation by 2025 providing 4.7 per cent of total supply²⁶. In its central scenario, sector carbon intensity would be around 150 gCO₂/kWh, broadly on track to meet a sector emissions intensity of 50-100 gCO₂/kWh. This analysis assumes average load factors for remaining unabated coal plants of 24 per cent – a predominantly backup or peaking role.

There is potential for 15 gigawatts of unabated coal power stations to remain in operation well into the 2020s. We assessed the impact that this could have upon power sector emissions, taking DECC’s latest central energy and emissions projections to 2030 and substituting enough coal power stations for gas power stations to maintain 15 gigawatts of unabated coal from 2020 to 2030. Under this ‘high coal’ scenario, coal provides 9-11 per cent of electricity throughout the decade and power sector carbon intensity stays at around 200 gCO₂/kWh for most of the 2020s, falling to around 150 gCO₂/kWh by 2030²⁷.

If more plant were to remain on the system, the failure to deliver adequate amounts of low carbon generation could allow these plants to operate more frequently, increasing emissions and endangering carbon budgets.

²³ Poyry – IED Briefing note

²⁴ E. ON, SSE, RWE, Scottish Power

²⁵ Power Engineering International (2013) The SNCR option for large coal boilers 01.02.13

²⁶ DECC (2012) Updated Energy & Emissions Projections

²⁷ Carbon Connect analysis based upon substituting coal for gas capacity in DECC’s latest central energy and emissions projections. In DECC’s central scenario, emissions intensity falls from around 170 gCO₂/kWh in 2020 to around 150 gCO₂/kWh in 2025 and to 100 gCO₂/kWh by 2030. Unabated coal provides 11 per cent of electricity in 2020 falling to two per cent in 2030.

Table 2: The role of coal in 2025

	Total coal capacity (GW)	Total coal generation (TWh)	Percentage of total generation (%)	Average load factor (%)	Percentage of total generation that is low carbon (%)	Total generation (TWh)	Carbon Intensity (gCO ₂ /kWh)
DECC Central Scenario	8.4	17.5	4.7	24	53	372	137
National Grid 'Gone Green'	10	13	3.5	15	65	366	140
High coal scenario ²⁸	15.1	42.6	11.5	31	53	372	211

Sources: DECC (2012) Updated Energy & Emissions Projections
National Grid (2012) Future Energy Scenarios

Notes: 1) GW is gigawatts
2) TWh is terawatt-hours

Finding 2

There is the potential for up to 91 per cent of the unabated coal power station capacity expected to remain in operation at the start of 2016, to continuing operating into the 2020s. There is a risk that these unabated coal power stations will cause the UK to exceed its carbon budgets if not enough low carbon capacity is built.

These risks will be mitigated by increasing costs for coal generators from the Carbon Floor Price, introduced on the 1 April 2013. Ensuring adequate low carbon generation is built will ensure that opportunities to run at high load factors are limited by the low marginal cost and zero carbon cost renewable and nuclear capacity. Unabated coal plants could also be exempted from the Industrial Emissions Directive if they choose to run less than 1500 hours per year. With payments for capacity provided through the proposed Capacity Mechanism, there could be some value in continuing to operate old unabated coal plants in a backup role (see chapter three).

Emissions Performance Standard - no new unabated coal

Retiring coal plants will not be replaced unless new plants are fitted with CCS technology. Current legislation prevents the construction of new unabated coal plants unless part of it is fitted with CCS, and the developer commits to full deployment when the technology is proven. This requirement will be further tightened by new legislation in the forthcoming Energy Bill. This will introduce a new Emissions Performance Standard, limiting new plants over 50 MW capacity to maximum emissions of 450 gCO₂/kWh (based on an 85% load factor). This will effectively prevent new build or renovated unabated coal plants from running as baseload.

²⁸ Assumes that 15.1GW of coal capacity that has opted in to the Industrial Emissions Directive continues to operate from 2016 to 2030. This replaces gas capacity and generation in an otherwise identical scenario to DECC's 2012 central energy projection.

1.4 The role of unabated gas in a 50 – 100g scenario by 2030

With new gas power stations emitting around 319 gCO₂/kWh, the majority of supply will need to come from low carbon sources. Table 3 compares the role of gas in different energy system models, achieving a 50g sector intensity by 2030. If this level is to be achieved, unabated gas will be limited to providing roughly 10 per cent of total supply (in these scenarios, some carbon emissions also come from fossil fuels with CCS).

Table 3: Unabated gas generation required under decarbonisation pathways

	Total gas capacity (GW)	New gas capacity (GW)	Total gas generation (TWh)	Percentage of total generation (%)	Average load factor (%)	Percentage of total generation that is low carbon (%)	Total generation (TWh)
DECC Central Scenario	31	19	41	10	15	78	410
National Grid 'Gone Green'	38	13	63	15	16	77	402

Sources: DECC (2012) Gas Generation Strategy
National Grid (2012) Future Energy Scenarios

Notes: 1) GW is gigawatts
2) TWh is terawatt-hours
3) New capacity is that built between now and 2030, excluding those currently in construction
4) DECC scenario reach 50 gCO₂/kWh by 2030 and National Grid scenario reaches 79 gCO₂/kWh.

Gas for capacity

An important feature of these results is the amount of unabated gas *capacity* that remains on the system, with a fleet roughly comparable to that of today. However, average load factors are only 15 per cent, much lower than current rates of 30 to 40 per cent. The implication is that these plants are predominantly run as backup for low carbon generation (nuclear, renewables and fossil fuels with CCS). With up to 60 gigawatts of intermittent generation connected to the grid by 2030, there will be a need for some flexible generation to provide backup capacity during periods of low wind, solar and marine output²⁹.

There are a number of options for providing both supply and demand flexibility: flexible generation, energy storage, interconnection to other countries and demand side response. Gas power stations, with their low capital costs and ability to cycle on or off rapidly, are currently amongst the most cost effective methods for providing flexible backup capacity at scale, although at the system level, a mix of solutions is likely to be most cost effective in future. The role of gas and other options for managing greater intermittency are explored in greater detail in chapter three.

There is a high degree of consensus between energy system models that unabated gas generation will continue to play an important role in providing flexible capacity at least to 2030. This view was expressed by the Government in its 2011 Carbon Plan:

²⁹ Poyry (2011) Analysing Technical Constraints On Renewable Generation to 2050

“Over the next two decades, gas-fired power plants will provide the flexibility that we will need to meet peak demand and manage intermittent generation from some renewables, as well as baseload generation capacity.”³⁰

Running this large fleet of unabated gas power stations at high load factors in 2030 will not be compatible with meeting the UK’s 2050 carbon target cost effectively.

The prospect of low average load factors has added to perceived uncertainty for gas generators. In reality, modelling suggests plants operating across a wide range of load factors, with more efficient plants running many more hours than older plants³¹. Plants can also expect to receive payments under the Capacity Mechanism (see chapter three) which would improve the economics of those running fewer hours.

Finding 3

A similar amount of unabated gas capacity as today is likely to be needed through to 2030, to backup intermittent generation such as wind and meet peak electricity demand. Limiting its role to predominantly backup and peaking is consistent with a power sector emissions intensity of 50-100 gCO₂/kWh by 2030.

1.5 A bigger role for gas by 2030?

The trajectory recommended by the Committee on Climate Change to 2030 is ambitious, but required if the 2050 target is to be achieved cost effectively. In recent years, political support for decarbonisation has waned, demonstrated by disagreement over the ratification of the Fourth Carbon Budget in 2011.

Decarbonisation of the power sector has also been criticised for potentially locking the UK into costlier forms of power generation, such as offshore wind, inflating domestic energy bills and harming UK competitiveness, especially in a future where global shale gas production brings down prices³². In this view, it could be cheaper to use unabated gas generation as a bridging technology until low carbon alternatives reduce in cost, and should be driven by carbon trading in the EU Emissions Trading Scheme, rather than technology support policies^{33,34}.

This view is supported by the Chancellor, George Osborne, who argued in 2012 that Government policy should:

‘..regard unabated gas as able to play a core part of our electricity generation to at least 2030 - not just providing backup for wind plant or peaking capacity’³⁵.

New scenarios modelled in the Government’s Gas Generation Strategy included a far greater role for unabated gas, that would lead to power sector emissions of 200 gCO₂/kWh by 2030³⁶, four times the Committee on Climate Change’s recommended level.

³⁰ DECC (2011) The Carbon Plan

³¹ DECC (2012) Gas Generation Strategy

³² Policy Exchange (2012) Gas Works? Shale gas and its policy implications

³³ Policy Exchange (2012) Fuelling Transition: Prioritising Resources For Carbon Emissions Reduction

³⁴ Green Alliance (2012) The Future of Gas Power

³⁵ Guardian (21/06/2012) <http://www.guardian.co.uk/environment/2012/jul/23/george-osborne-letter-ed-davey-gas-wind>

³⁶ DECC (2012) Gas Generation Strategy

The role of unabated gas generation within the scenarios is compared below. A 100 g intensity by 2030 would be roughly compatible with likely carbon budgets for 2030, although under this scenario unabated gas plants would run at higher load factors, at the expense of building some additional low carbon capacity.

Table 4: Share of unabated gas generation by 2030 in DECC scenarios

	Total gas capacity (GW)	New gas capacity (GW)	Total gas generation (TWh)	Percentage of total generation (%)	Average load factor (%)	Percentage of total generation that is low carbon (%)	Total generation (TWh)
DECC 50g in 2030	31	19	41	10	15	78	410
DECC 100g in 2030	37	26	89	22	33	65	404
DECC 200g in 2030	49	37	181	45	43	43	402

Sources: DECC (2012) Gas Generation Strategy
DECC (2013) EPS Impact Assessment

Notes: 1) GW is gigawatts
2) TWh is terawatt-hours
3) New capacity is that built between now and 2030, excluding those currently in construction
4) DECC scenario reach 50 gCO₂/kWh by 2030 and National Grid scenario reaches 79 gCO₂/kWh.

A high unabated gas generation strategy is incompatible with carbon targets

The 200 g scenario implies a significant increase on today's gas plant capacity and generation. This would be a change of strategy towards gas and away from low carbon generation, and would be incompatible with meeting the legally binding 2050 carbon target cost effectively. Given the key role of decarbonised electricity across the future energy system, this scenario would make the achievement of the 2050 target more costly and highly impractical.

A slower rate of decarbonisation in the power sector would compromise the technical and commercial development of the low carbon technologies that will be needed. Opportunities to deploy these at a later date may be limited if large investments in high carbon assets are made now. The majority of the 37 gigawatts of new gas capacity in the 200 g scenario would likely be in operation by 2050, limiting the opportunity to begin a large scale roll out of low carbon technologies after 2030 without scrapping some of this capacity before the end of its life³⁷. Commenting on the prospect of following DECC's 200 g scenario, David Kennedy, Chief Executive of the Committee on Climate Change, said:

“This would not be economically sensible, and would entail unnecessary costs and price increases. Neither would it be compatible with meeting carbon budgets and the 2050 target. Early decarbonisation of the power sector should be plan A – and the dash for gas Plan Z.”³⁸

³⁷ CCC (2010) The Fourth Carbon Budget

³⁸ CCC (2012) Committee on Climate Change website; accessed 13.02.13

With other countries expanding their production capacity in new technologies such as offshore wind, the UK would lose the opportunity to develop a leading manufacturing base of its own. Recent research carried out by Cambridge Econometrics suggests that a large UK deployment of offshore wind could boost gross domestic product by 0.8 per cent by 2030 should the majority of components be produced in the UK³⁹. Although the macro economic impact remains positive, it falls to 0.2 per cent of gross domestic product if the industry is developed elsewhere.

Slower power sector decarbonisation will also have a knock on effect on the decarbonisation of other sectors. Current estimates suggest that the most cost effective method to decarbonise heating and possibly transport will be through electrification. The absence of a mainly low carbon electricity supply would preclude this and reduce opportunities to produce alternative low carbon energy sources such as hydrogen, which could be produced through CCS. Alternative transition pathways appear more challenging and therefore at greater risk. Increasing the proportion of gas in the power mix would increase exposure of UK electricity prices to the volatility of gas prices, and reduce the diversity and security of supply. These issues are explored further in chapters three and four.

1.6 Managing carbon risk

A large fleet of gas power plants will likely be needed by 2030 even under a strict decarbonisation trajectory. The presence of this much unabated gas capacity creates the risk of higher carbon emissions should the delivery of low carbon generation be lower than expected. Any 'gap' in the supply of electricity left by the failure to build new nuclear or more renewables would be filled by these gas power plants. This would then impact on the use of electricity in other sectors, and overall decarbonisation. Policy measures can help reduce this risk:

- Support the development of CCS for gas generation
- Ensure Capture Ready rules for new gas plants are robust
- Prioritise the construction of gas plants with combined heat and power
- Support the development of low carbon gas
- Tighten limits under the Emissions Performance Standard for future unabated gas power stations once full chain CCS on gas has been proven.

Finding 4

The continued need for a significant fleet of gas power stations from now to 2030 brings a risk of carbon lock-in that could undermine the UK's efforts to meet its 2050 carbon target unless managed by Government.

CCS for gas

One gas CCS project has made it through to the Front End Engineering Design stage of the Government's CCS demonstration competition. It is very likely that a high level of gas capacity will be maintained at least to 2030. The commercialisation of gas CCS technology in the UK could allow this gas capacity to continue to play a significant role post-2030 while contributing towards meeting carbon targets. However, as outlined in the following chapter, development of CCS in the UK has been slow, and current carbon capture ready rules do not take account of practical and economic constraints facing CCS infrastructure development.

³⁹ Cambridge Econometrics (2012) A Study into the Economics of Gas and Offshore Wind; for Greenpeace and WWF

Combined heat and power

The efficiency of gas power plants can be further improved by fitting technology to capture and use heat that is normally wasted. This improves overall plant efficiency, and reduces the carbon intensity per unit of energy generated. Combined heat and power requires a local load that can use the heat, which is typically a large industrial heat user or a district heating network. These plants can also be configured to operate flexibly, either by switching from combined heat and power to power only or varying the heat output. The UK has 4.6 gigawatts of gas combined heat and power⁴⁰, the majority of which is installed in the industrial sector, with a technical potential of 24 gigawatts by 2020⁴¹. Although sizeable emissions from gas combined heat and power would not be compatible with long term carbon targets, prioritising gas combined heat and power would provide additional gas generation at lower carbon intensities, and allow the development of district heat networks. A targeted sector approach is likely to be needed to address current barriers to further deployment, and the inclusion of gas combined heat and power in Electricity Market Reform support measures.

Low carbon gas

There are significant opportunities to produce low carbon gas through the anaerobic digestion of waste and biomass. The resultant biogas can be injected into the gas grid, lowering the carbon intensity gas, or used directly for heat and/or power generation. Whilst it is not yet clear which of its uses in the energy system will be most cost effective⁴², development of this resource would open up further options to lower emissions of gas used for power generation.

The Emissions Performance Standard – constraining new coal, not new gas

The Emissions Performance Standard is expected to be introduced through the Energy Bill and will set a limit on carbon emissions from new or significantly upgraded fossil fuel power stations greater than 50 megawatts. The limit will be set at a level equivalent to a 450 gCO₂/kWh power station operating at 85 per cent load factor. Once power stations are consented under the Emissions Performance Standard, the limit to their emissions will be ‘grandfathered’ until 2045.

Existing planning rules prevent new coal power stations being built unless fitted with at least 300 megawatts of carbon capture and storage⁴³ and the developer commits to full carbon capture and storage deployment when the technology is proven. The Emissions Performance Standard, once in effect, will reinforce these requirements and limit the operating hours of any existing coal power stations that are significantly upgraded or receive life extensions.

The Emissions Performance Standard is not designed to constrain new unabated gas power stations, which will continue to play an important role in the short and medium term. ‘Grandfathering’ makes this explicit and is designed to prevent deterring investors in new gas power stations. There is some concern that the Emissions Performance Standard, as proposed, leaves open the possibility of high carbon emissions from gas power stations in the medium and long term. However, other policy measures are better suited to mitigating this risk. These include:

⁴⁰ DECC (2012) Digest of UK Energy Statistics

⁴¹ DECC (2012) The Future of Heating: A strategic framework for low carbon heat in the UK; This ignores cost effectiveness

⁴² CCC (2011) Fourth Carbon Budget

⁴³ The National Policy Statement for fossil fuel electricity generation (EN-2) requires that any new coal fired plant demonstrate CCS on at least 300MW (net) of the proposed generating capacity as a condition of its consent.

- Setting a sector-wide emissions target
- Supporting carbon capture and storage on fossil fuel power stations
- Awarding Contracts for Difference to sufficient nuclear, wind and biomass power stations to lower the average load factor of gas power stations whilst ensuring that a Capacity Mechanism is in place to allow gas power stations to remain economic

Carbon targets mean that the role of unabated gas is constrained in the medium term and virtually eliminated in the long term. The Emissions Performance Standard could therefore be a useful tool in constraining the emissions of future new gas power stations, once carbon capture and storage has been proven.

Finding 5

Once carbon capture and storage on gas power stations is proven, tightening the Emissions Performance Standard could be a useful means of ensuring that no new unabated gas power stations are built.

Finding 6

Government needs to manage the risk of carbon lock-in from unabated coal and gas power stations and can do so through the following:

- **Incentivising new renewables capacity to be built in the 2020s at a rate similar to that in the 2010s.**
- **Using carbon pricing to improve the economics of unabated gas power stations relative to unabated coal.**
- **Designing and implementing a Capacity Mechanism that creates a market in which gas power stations are economic at low load factors, stimulating investment in existing and new power stations.**
- **Continuing to support the development of CCS for gas.**
- **Supporting lower carbon forms of gas power station, such as combined heat and power.**
- **Reforming existing Carbon Capture Ready requirements for new gas power stations so that they are more effective in ensuring that new power stations can be retrospectively integrated into future UK CCS infrastructure.**
- **Tighten limits under the Emissions Performance Standard for future unabated gas power stations once full chain CCS on gas has been proven.**

1.7 Summary: unabated gas for backup is a lower risk option

Policy makers face three key challenges to achieving low carbon energy objectives:

1. Ensuring enough low carbon generation is built (cost effectively)
2. Ensuring enough flexible gas capacity is built to manage higher levels of intermittent generation
3. Managing the carbon risk from unabated gas and coal capacity

Unabated gas generation will have a role to play in either a high or low decarbonisation trajectory, but creates the risk of carbon lock-in. Unabated gas capacity will therefore need to be encouraged alongside, but without discouraging, investments in low carbon plant whilst continuing to support gas CCS.

As the Gas Strategy shows, recent attempts to create a more certain investment climate for gas power have resulted in a trade-off with low carbon capacity. Two competing visions of power sector decarbonisation have emerged:

- Unabated gas for backup: use gas mainly for backup generation and build significant volumes of low carbon capacity
- Unabated gas for generation: use gas at high load factors and build less low carbon plant (and possibly additional gas capacity)

Whilst a low carbon pathway will continue to see a role for significant gas capacity, a high gas consumption pathway excludes low carbon generation, jeopardising the achievement of carbon targets. Uncertainty created by the possibility of a high gas consumption strategy has increased the risks faced by investors in low carbon generation, and fed into the debate surrounding the current Energy Bill.

Although the Government has set an ambition to source 30 per cent of electricity from renewable sources by 2020⁴⁴, a specific carbon intensity for the power sector has yet to be legislated. This has led the Committee on Climate Change, supported by many businesses and non-government organisation, to call on the Government to introduce a power sector carbon intensity target for 2030 in the Energy Bill⁴⁵, to provide greater certainty to developers and investors in the low carbon supply chain, particularly in the decade following the 2020 renewables target.

Assessing the risks and benefits of both scenarios suggests that the former is better for achieving sustainability objectives; better for security (by creating a more diverse and independent energy system – see chapter three) and lowers economic risks, with likely economic benefits (see chapter four). Promoting both strategies simultaneously increases the risk of poor policy outcomes.

Finding 7

Pursuing a strategy where, during the 2020s, unabated coal capacity is minimised and unabated gas capacity is maintained near current levels and used increasingly as backup rather than baseload, is likely to be preferable on security, sustainability and affordability grounds.

⁴⁴ DECC (2009) UK Low Carbon Transition Plan

⁴⁵ CCC (2013) Letter from Lord Deben to Ed Davey

2. CARBON CAPTURE AND STORAGE

Figure 3: Carbon Capture and Storage: where is it being done already?

The components of CCS are not new. Carbon dioxide is often stripped from Natural Gas (and other industrial process such as Ammonia production) to improve the purity of the end product. Carbon dioxide has been transported at relatively low pressures for many years and, more recently at higher pressures (though less so on-shore) as it becomes a medium of choice for use in Enhanced Oil Recovery (*EOR*), where it is injected into mature fields to improve oil extraction. In the US, there are extensive onshore carbon dioxide pipeline networks, moving carbon dioxide from source to on-shore EOR sites. Experience of injecting carbon dioxide into offshore oil and gas reservoirs is less developed than onshore, although trials have been conducted in the North Sea. To enable industrial scale CCS, the UK would need to construct dedicated facilities between capture sites and storage facilities located off the coast.

2.1 Current approach to developing CCS

Table 5 illustrates the role of CCS with fossil fuels and biomass in different energy system models. These are compared to the Government's projection of CCS deployment at 2030 based upon existing policy.

The high degree of variance between models is caused by their different assumptions and priorities. All three models select the least cost path to achieving a set target – in this case, a near total decarbonisation of the power sector by 2050. Each model operates in a different manner and is highly dependent on input assumptions, such as fuel prices, carbon prices, technology costs and policy and investment hurdles. What can be concluded, however, is that when CCS applied to fossil fuels or biomass is cost competitive with other options, a not insignificant quantity is selected by each model. Comparing levels of deployment by 2030 with current DECC estimates, it is clear that expectations are well below those suggested by the models.

Table 5: Role of CCS in power generation, different energy models

	Capacity of plants with CCS by 2030 (GW)	Generation from plants with CCS 2030 (TWh)	Percentage of total generation 2030	Capacity of plants with CCS by 2050 (GW)	Generation from plants with CCS 2050 (TWh)	Percentage of total generation 2050
National Grid 'Gone Green'	5.5	40	10	not available	118	22
Carbon Plan 2011 (Core run)	10	not available	not available	28	159	33
ETI (ESME)	21	156	41	21	58	13
DECC Central Projection (for comparison) ⁴⁶	3.1	24.4	6	not available	not available	not available

Sources: DECC (2012) Gas Generation Strategy
National Grid (2012) Future Energy Scenarios
Energy Technologies Institute (2011) Modelling the UK energy system: practical insights for technology development and policy making

Notes: 1) GW is gigawatts
2) TWh is terawatt-hours
3) ESME is Energy Systems Modelling Environment
4) CCS is carbon capture and storage

2.2 UK progress on CCS

The UK was one of the first countries to recognise the potential value of CCS at the start of the 2000s. Despite this, progress has been slow, due to a poorly conceived initial demonstration programme, public concern that CCS demonstration would lead to the construction of new unabated coal plants, funding delays and policy uncertainty⁴⁷.

Globally, efforts to commercialise CCS technology continue apace, with a number of large scale industrial capture and storage projects due for completion in North America in 2013⁴⁸. These are driven by the economics of Enhanced Oil Recovery, and will have limited value in demonstrating cost effective CCS in a power generation capacity. CCS in the UK has incurred half a decade's delay. The first UK demonstration competition was launched in 2007 with a focus on CCS for coal generation, but concluded in 2011 when it became apparent that the costs of implementation and operation exceeded the value that could be derived from the last remaining project. A new competition to support up to two full chain demonstration projects was launched in 2012, based on the retained £1 billion capital budget and supported, for operation, by Feed in Tariffs with Contracts for Difference, a guaranteed price for electricity sold. From an initial eight projects, a final two were selected in March 2013 to negotiate terms on conducting detailed engineering and design studies, with the Government aiming to make a final

⁴⁶ DECC (2012) Energy & Emissions Projections

⁴⁷ Green Alliance (2012) The CCS Challenge: Securing a second chance for UK carbon capture and storage

⁴⁸ BNEF (2012) America Leads Race For World's First Large-Scale Carbon Capture And Storage Project

investment decision in 2015. It hopes to have projects commissioned and operating by 2018 at the latest⁴⁹.

Two projects have reached the final shortlist for funding under the Government's demonstration scheme, with two unsuccessful bids held in reserve:

Table 6: Projects shortlisted for funding from the Government's demonstration competition

Project Name and Location	Technology	Fuel	Size (MW)	Type	Demonstration Scheme Status
Peterhead, Scotland	Post-combustion	Gas	340	Retrofit	Final Shortlist
White Rose, Drax, Yorkshire	Oxyfuel	Coal	340	New build	Final Shortlist
Teeside Low Carbon Project	Pre-combustion (IGCC+CC*)	Coal	330	New build	Reserve
Captain Clean Energy Grangemouth, Scotland	Pre-combustion (IGCC+CC)	Coal	570	New build	Reserve

Source: Department of Energy and Climate Change website

Notes: 1) IGCC+CC is Integrated Gasification Combined Cycle with Carbon Capture
2) MW is megawatts

2.3 Post demonstration deployment

Whilst capital funding will alleviate the high upfront costs of these projects, the level of revenue support they receive through Feed in Tariffs with Contracts for Difference will be just as crucial. Although obtaining funding and finance will be essential, the first projects still face significant hurdles before they can begin construction and operation. Pipeline and storage infrastructure will need to be finalised as part of these projects, where significant legal and insurance uncertainties remain to be overcome⁵⁰.

The prospects for post demonstration competition projects, which will not receive capital funding from Government, are uncertain. Doubts have been expressed that one or two demonstration projects will not be sufficient to allow the regulatory, legal and commercial frameworks to develop to the extent that private finance can be mobilised to fund subsequent projects. Additional Government assistance, for example through the Green Investment Bank, may be required to secure further projects⁵¹.

The Government's aim is to make fossil fuels with CCS competitive with other low carbon sources of energy without subsidy by 2030⁵². Industry feedback suggests that the UK is already running behind schedule for delivering a viable CCS industry by 2030. Further delay following demonstration projects would mean that fossil fuels with CCS are not an option to fill any gap left by slower than expected nuclear or offshore wind development before 2030⁵³. Limited options for expanding low

⁴⁹ DECC (2012) CCS Roadmap

⁵⁰ Climate Wise (2012) Managing liabilities of European Carbon Capture and Storage

⁵¹ Ecofin & ETI (2012) Carbon Capture and Storage: Mobilising private sector finance for CCS in the UK

⁵² UKERC (2012) Carbon Capture and Storage Realising the potential?

⁵³ Green Alliance (2012) The CCS Challenge: Securing a second chance for UK carbon capture and storage

carbon supply beyond 2030 carry a greater risk of higher costs or failure to meet carbon targets.

Finding 8

Whilst the Government's commitment and planned support for CCS is amongst the best in the world, it is unlikely to result in significant (10+ gigawatts) levels of CCS deployment by 2030 that models indicate the UK needs to achieve the 2050 carbon target cost effectively.

Finding 9

The Government must ensure that supported demonstration and deployment in the power sector establishes the technical, commercial and legal frameworks to facilitate privately funded investment in the power sector and in industry.

Finding 10

The Government's approach to developing CCS in the UK is currently focused on power sector applications. Greater commitment to CCS would provide more options for reducing carbon emissions in the 2020s, both in the power sector and in industry.

2.4 Benefits of CCS in the power sector

The costs of electricity from fossil fuels with CCS are uncertain, due to the relative lack of technological development. However, estimates suggest that if a significant amount of technical and commercial development takes place, through a successful demonstration programme and subsequent commercial scale development, the cost of electricity generated from fossil fuels with CCS could be near those of other low carbon sources by 2030⁵⁴.

Continued use of fossil fuels

As described in chapter one, unabated gas can only provide around 15 to 33 per cent of electricity in 2030 (under 50 and 100 gCO₂/kWh scenarios respectively). Beyond 2030, its use will need to be very low if emissions targets are to be met. CCS technology would allow the use of gas and coal to continue and grow beyond 2030, which has several benefits.

Making fossil fuel generation compatible with carbon targets would diversify future supply. This would have both security of supply and affordability benefits, by allowing coal and gas to remain a part of the mix should future prices stabilise or fall.

Fossil fuel power stations provide supply flexibility, which will become increasingly important as use of intermittent sources such as wind, solar and marine energy increases, and patterns of demand shift due to the electrification of transport and heating. Coal and gas plants fitted with CCS may be able to provide these services at lower cost than alternative options, without the carbon penalty of unabated plants.

CCS for gas power

Technologies for CCS on gas are likely to be crucial for the power sector in the UK, given the continued role of these plants in the UK supply mix. Developing CCS for

⁵⁴ DECC (2012) Electricity Generation Costs

gas will mitigate the carbon risk from the large fleet of unabated plant likely to be on the system in 2030. A gap in supply left by insufficient low carbon generation will likely be filled by this unabated gas capacity, resulting in higher emissions, missed carbon targets and more costly abatement in other sectors or via purchases of emissions permits. The ability to retrofit CCS cost effectively would open up the potential to run these plants at higher load factors without compromising carbon budgets. Recent analysis suggests that post combustion CCS on gas could be one of the most cost effective forms of CCS with fossil fuels⁵⁵. It also has the advantage of substantially lower residual carbon dioxide emissions than coal (around 50 rather than 100 gCO₂/kWh)⁵⁶, which will increasingly translate into an additional affordability benefit as carbon prices increase.

One of three solutions for producing large amounts of low carbon power

DECC estimates that to achieve a 50 to 100 gCO₂/kWh power sector carbon intensity by 2030, 65 to 80 per cent of electricity will need to be generated from low carbon sources⁵⁷, with this share increasing to 92 per cent to meet the UK's 2050 carbon target⁵⁸. The Government's strategy sees fossil fuel power stations with CCS as one of the three main options for delivering this capacity, along with nuclear and renewables⁵⁹.

More choice, less risk

The value of CCS in the power sector comes into its own in the event that one of the other options fails or under-delivers. A gap in low carbon generation could appear, for example, if new nuclear fails to be built or offshore wind costs do not reduce as expected. Without CCS, a consistent message across energy system models is that stretching remaining low carbon technology options to high levels of deployment would increase costs dramatically^{60,61,62}.

Having a diversity of options is especially crucial given the expected increase in electricity demand by 2050, as its use in heating and transport increases. Estimates in the Carbon Plan suggest that by 2050, supply may need to increase by 37 to 77 per cent (on 2011 levels) alongside significant gains in energy efficiency⁶³. The analysis also showed that a future system heavily reliant on one option will likely be more expensive than one composed of a balanced mix⁶⁴. Costs may increase as practical and physical constraints are reached. For example, it is thought that a maximum of 40 gigawatts new nuclear capacity could be added around existing sites⁶⁵, with new locations for more power plants likely to face issues of public acceptability and higher costs. Site availability for onshore and offshore wind and feedstock supplies for biomass could constrain the maximum deployment of these technologies⁶⁶, whilst a large deployment of fossil fuels with CCS would also require an extensive network of pipelines to carry carbon dioxide from new plants to storage facilities, which may face public acceptability issues. Although high levels of deployment of each group of technologies is technically possible, a diverse mix reduces the need to push deployment to levels that are less economically and politically palatable.

55 CCC & Mott MacDonald (2011) Costs of low-carbon generation technologies

56 CCC (2010) Fourth Carbon Budget

57 DECC (2013) Impact Assessment: Contracts for Difference; p67

58 AEA (2011) Pathways to 2050 – Key Results

59 DECC (2011) The Carbon Plan

60 AEA (2011) Pathways to 2050 – Key Results (MARKAL Model Review and Scenarios for DECC's 4th Carbon Budget Evidence Base

61 ETI (2011) Modelling the UK energy system: practical insights for technology development and policy making

62 UKERC (2013) Low-carbon, resilient scenarios for the UK energy system in 2050

63 DECC (2011) The Carbon Plan

64 DECC (2011) The Carbon Plan

65 ETI (2011) Modelling the UK energy system: practical insights for technology development and policy making

66 CCC (2011) The Renewable Energy Review

Finding 11

There are substantial benefits to keeping fossil fuels in the power mix if emissions can be limited using CCS. Electricity supply will likely need to rise significantly by 2050, and decarbonising the power sector beyond 2030 without CCS would be expensive and politically challenging.

Figure 4: Three 'flavours' of carbon capture technology

Three types of capture technology can be used to capture emissions from fossil fuel combustion, providing different options for power generation and additional by-products, as described above.

Post combustion capture

Carbon dioxide is captured from exhaust gases following combustion of coal or gas in a standard power plant. Typically, flue gases are scrubbed with chemical solvents. Capture rates of 90 – 95 per cent could be achievable, and the technology can be applied to new electricity generating and industrial plants or retrofitted to old.

Pre-combustion capture

Involves modification to existing Integrated Gasification Combined Cycle (IGCC) power plant technology. An IGCC works by combusting coal or biomass to produce synthetic gas, which then drives a modified gas turbine. The synthetic gas can be further reacted and separated into carbon dioxide and hydrogen, which can then be used to drive a hydrogen-rich gas turbine or used in alternative applications such as transport. Capture rates could be 80 to 90 per cent, although this could increase with further technological development. There are no IGCC plants in the UK, so this option would require the construction of a purpose built facility. It also is less deployed worldwide, with supercritical combustion being the technology of choice for new coal power stations. Deployment at scale may also therefore require further technological development of the base IGCC coal or biomass power plant¹.

Pre-combustion for gas relies on the same concept, although natural gas is converted to synthetic gas in a reformation plant (commonly used in oil and gas refining). As with coal, synthetic gas is then separated into carbon dioxide and hydrogen. Pre-combustion gas capture costs are less certain than with coal, due to limited experience of using their hydrogen output with generating turbines¹.

Oxyfuel capture

Is applied to a conventional combustion plant. Fossil fuels are combusted in a boiler with oxygen to create steam and drive a turbine to produce electricity. Oxygen can be produced by an Air Separation Unit, and the flue gases are composed mainly of carbon dioxide and water vapour. Some of these are circulated to the combustion chamber, and the remainder are cooled to condense and remove the water vapour, leaving behind a stream of carbon dioxide gas. Overall capture rates can be up to 98 per cent. It can be applied to both new and existing power plants, and although currently being explored with coal generation, it could be applied to gas combustion.

2.5 Wider benefits of CCS

The role of fossil fuels with CCS for power generation will depend on the success of commercialising the technology, and its economics relative to other low carbon generation options. The value of developing CCS does not stop at the power sector, however. Analysis shows that there are wider benefits from adopting CCS technology across a decarbonised energy system.

Cost effective decarbonisation

Energy system models, concerned with finding the lowest cost pathways to decarbonisation, give CCS significant value. Scenarios modelled using the Energy Technologies Institute (ETI) energy system model, ESME, suggest that without CCS, the total annual cost of the UK's energy system (capital, operating and infrastructure costs) could be £30-40 billion⁶⁷ higher by 2050, more than doubling the cost of decarbonisation⁶⁸. This is because developing CCS in the power sector opens up future applications with industry, with biomass to create negative emissions, and in producing alternative low carbon energy vectors such as hydrogen and syngas. Sensitivity analysis of the ETI finding highlights the high system value of CCS, which is robust even under high assumptions of future CCS costs.

Finding 12

Meeting the UK's 2050 carbon targets without CCS would cost the UK economy around £30-40 billion more each year, or approximately 1 per cent of gross domestic product, roughly doubling the expected annual costs of meeting carbon targets.

Industrial emissions

CCS is likely to be the only viable means, other than fuel switching, of reducing carbon emissions from many industrial processes, such as steel, refining and chemical production⁶⁹. Direct emissions from all industrial sources are estimated to have accounted for 21 per cent of total UK carbon dioxide emissions, or 101 MtCO₂e, in 2012⁷⁰. By 2050, total UK emissions will need to have fallen to 160 MtCO₂e, so if emissions from industry remain as they are today, they will account for over half of total 2050 emissions. The Government has estimated that by 2050, 48 MtCO₂e could be captured from industrial processes per year⁷¹. The adoption of CCS by industry will depend on carbon prices in the EU Emissions Trading System, with economic concerns making UK only action unlikely for the time being. Creating a market for capture technologies, and financing early transport and storage infrastructure through development in the power sector will unlock the future benefits of carbon abatement in industry, as carbon prices begin to rise. Ensuring CCS infrastructure is in place will also enable carbon intensive industries to remain in the UK, or even encourage arrivals from abroad, under high future carbon prices in the EU.

Finding 13

CCS has significant potential to reduce carbon in both the power sector and in industry, and to support the gasification of coal and biomass feedstocks to provide flexible low carbon energy.

⁶⁷ 2010 Prices

⁶⁸ ETI (2011) Modelling the UK energy system: practical insights for technology development and policy making

⁶⁹ Element Energy (2010) Potential for the application of CCS to UK industry and natural gas power generation

⁷⁰ DECC (2012) Energy & Emissions Projections

⁷¹ DECC (2011) The Carbon Plan

Alternative low carbon fuels

CCS technologies can also be used to produce alternative low carbon fuels such as syngas and hydrogen, which provide additional methods to decarbonise heating and transport⁷², and opportunities to continue the use of existing gas infrastructure. Pre-combustion carbon capture with coal, gas or biomass produces syngas or hydrogen which could also be used for power generation through hydrogen gas turbines, in transport or injected into the gas grid. By providing alternatives, developing CCS reduces the potential costs of over reliance on a single solution.

Negative emissions

CCS fitted to biomass power stations is currently one of the only technologies that could offer the opportunity to permanently remove carbon dioxide from the atmosphere. Combusting biomass with CCS would create negative carbon emissions – the carbon absorbed by growing plants would be captured and permanently stored underground in the CCS process. These negative emissions could then be offset against those from harder to decarbonise sectors such as transport, for example by allowing greater use of petrol should alternative technologies prove costly. As with fossil fuels, pre-combustion carbon capture could provide a variety of energy vectors: electricity, syngas and hydrogen. Large scale use of biomass with CCS would require an increase in the domestic or international supply chain, supported by robust sustainability criteria to ensure that carbon reductions are actually achieved.

Global importance for reducing emissions

Fossil fuels look set to remain the dominant form of electricity generation worldwide, with coal meeting nearly half of the rise in global energy demand over the last decade and currently providing 40 per cent of total electricity production worldwide⁷³. Developing CCS technology will likely be the only way that significant global carbon reductions can be made, with the availability of cost effective CCS likely to facilitate reaching a global agreement on emissions reductions in future.

Export value and UK competitive advantage

The future size of the CCS market could present companies with expertise in the technology with very significant global export opportunities. It has been estimated that if the market for CCS develops, export opportunities for UK firms could be £3 - 6.5 billion a year by the late 2020s⁷⁴. The UK is well placed to make the most of this opportunity, with extensive oil and gas expertise and a large storage potential from depleted offshore oil and gas fields and saline aquifers. Recent estimates put the UK's carbon dioxide offshore storage potential at approximately 70 billion tonnes, which could be enough to store 100 years' worth of current emissions from the power sector⁷⁵. Although more expensive, offshore storage is a significant advantage due to the risks, and public acceptability of onshore carbon dioxide storage - public protest in Germany and the Netherlands has ended onshore storage hopes there.

Finding 14

The UK is well placed to become a world leader in CCS deployment, which would bring significant benefits.

⁷² ETI (2011) Modelling the UK energy system: practical insights for technology development and policy making

⁷³ IEA (2013) www.iea.com

⁷⁴ AEA (2010) Future Value of Carbon Abatement Technologies in Coal and Gas Power Generation to UK Industry

⁷⁵ DECC (2012) CCS Roadmap

2.6 Further policy challenges

Picking capture technologies

As outlined in Figure 4, there are several types of carbon capture technology compatible with coal or gas power generation. There is uncertainty regarding future technology and fuel costs, and the benefits will depend in part on the configuration of the energy system as it is progressively decarbonised. The Government must therefore ensure it strikes the right balance between encouraging a broad range of technologies within the funding resources available. In March 2013, the Government chose to enter final negotiations with a coal and a gas demonstration project, and will ideally enable both projects to be built to ensure CCS for both fuels is developed.

Finding 15

The are many ‘flavours’ of capture technology and the Government must strike the right balance between spreading limited resources thinly by pursuing too many variants for too long and missing out on benefits by eliminating variants before their comparative potential is well understood.

‘Capture ready’ requirements

CCS for gas power could provide several key benefits in future. Current legislation requires that new build plants show that they are carbon capture ready, by providing enough on site space for capture and compression equipment, as well as showing potential pipeline routes and storage sites. However, there are concerns that many of the currently consented plants are located too far from economically viable transport and storage infrastructure⁷⁶. With initial infrastructure likely only to develop at clusters around the first demonstration projects, many new gas plants could be built on which it would be difficult to apply CCS retrospectively. Emissions limits under the proposed Emissions Performance Standard will need to be tightened in future to avoid limiting the market for CCS on gas.

Finding 16

Current Carbon Capture Ready requirements do not reflect the economic viability of connecting plants to transport and storage infrastructure, reducing the effectiveness of this as a measure to promote the retro-fit of CCS in the future.

Finding 17

Emissions limits under the Emissions Performance Standard will need to be tightened, once CCS is proven, to avoid reducing the potential market for CCS on gas in future.

⁷⁶ Green Alliance (2012) The CCS Challenge: Securing a second chance for UK carbon capture and storage

3. SECURITY

3.1 The challenges

Energy security is fundamental to a resilient economy. Interruptions to supply can cause major disruption and price volatility, affecting all consumers. In its recently published Energy Security Strategy, the Government defines energy security as ensuring that consumers have access to the energy services they need (physical security) at prices that avoid excessive volatility (price security)⁷⁷. Risks to energy supply include technical problems, severe weather and interruptions to fuel imports.

Significant change in the UK power sector will create new challenges in maintaining the security of supply over the coming years. These include the retirement of up to a fifth of existing power stations during a period of policy and investment uncertainty, technical challenges relating to the addition of increasing amounts of intermittent generation and the continued decline of UK gas production. These challenges fit into three broad categories: physical security, day to day operational security (flexibility) and meeting peak demand (capacity).

3.2 Physical security

Involuntary interruptions can be caused by physical risks to supply such as an infrastructure failure or disruptions to imports of fuel. Physical disruption to supply impacts both those deprived of energy services and the market as a whole, through price volatility. The risk profile of technology options varies according to their technical and economic characteristics, with the greatest physical risk facing fossil fuel generation being supplies of fuel. This in turn is governed by the robustness and diversity of supplies and the infrastructure to deliver them.

How secure are fossil fuels?

Today, roughly half the UK's total annual gas needs are met by domestic production, mainly from the North Sea, with imports accounting for the remainder. Domestic production has been decline since 2000 as reserves have started to become depleted. The UK became a net importer in 2004, and by 2030, National Grid estimates that domestic production will have reduced to 28 per cent of 2011 levels^{78,79}. Coal production in the UK is also in decline, with imports exceeding exports for the first time in 2001. In 2012, domestic production provided 33 per cent of total coal supply⁸⁰, although the recent closures of the Maltby and Daw Mill mines will further reduce this production.

Declining domestic self-sufficiency does not automatically mean a greater threat to security, however. The UK has expanded its gas import facilities, with six pipeline connections to neighbouring countries and five Liquefied Natural Gas (LNG) import terminals, providing access to a wider variety of suppliers and markets. This offers more flexibility in the event that one or several routes are interrupted. Coal is relatively abundant on international markets and can be imported to the UK via existing port facilities.

⁷⁷ DECC (2012) Energy Security Strategy

⁷⁸ National Grid (2012) Future Energy Scenarios (Gone Green, includes some Coal Bed Methane and Shale Gas)

⁷⁹ This figure includes some unconventional resources

⁸⁰ DECC (2012) Dukes (adjusted with DECC (2012) Energy Trends provisional 2012 figures)

Increasing import dependence does, however, carry a higher degree of political risk. The security of imports is subject to events and forces outside of direct Government control. There is regional and international competition for gas supply contracts and the UK may have limited capacity for action in the event of major threats to supply or price volatility. For example, a closure of the straits of Hormuz in the Persian Gulf, could severely impact imports of liquefied natural gas from Qatar, on which the UK has increasingly relied in recent years⁸¹.

Short term risks to gas supply could be mitigated by increasing the UK's gas storage capacity. Stored gas can be used to cover a period of reduced imports, although the UK currently has less capacity than its European neighbours. The Government has recognised this risk and there are several new storage projects in the pipeline⁸². Developing UK shale gas would also provide more secure, domestic supplies, but as outlined in section six, it is too early to base any strategy on this assumption. Coal can be easily stored at volume, which would be an added benefit of future coal power generation fitted with Carbon Capture and Storage.

Finding 18

Physical risks to supply caused by the UK's increasing fossil fuel import dependence will be offset by a diversification of supplies. Political risks will increase however, as the UK relies on fuel supplies outside of its direct control.

Diversification reduces risk

Risks to the physical security of supply can also be limited by diversifying the supply mix and reducing reliance on any one option. This will be accomplished by increasing the proportion of low carbon generation on the system, which currently relies on coal and gas to provide 67 per cent of supply⁸³. An additional benefit of this strategy is that many low carbon generators carry lower physical risks. Wind, solar, hydro and marine technologies rely on prevailing weather or tidal resources. Whilst these can be highly variable on a day to day basis, they are a stable, reliable and domestic resource in the long term. Fuel for nuclear power stations is imported in much lower volumes, and is also regarded as relatively secure⁸⁴. Whilst low carbon generators provide physical security benefits over fossil fuels, the nature of their output creates new technical and market challenges, detailed below.

Finding 19

Diversifying the generation mix to include more low carbon generation will reduce risks to physical security, although it will create new technical and market challenges.

3.3 Maintaining capacity

The power system is run by keeping supply and demand in constant balance, following hourly, weekly and seasonal patterns of demand. Security of supply is maintained by ensuring that there is a sufficient margin of system capacity over and above demand peaks, allowing for unexpected reductions in supply and seasonal variations. The margin of capacity is measured by the de-rated capacity margin (see Figure 5), and all supply and demand-side measures can contribute: generating

⁸¹ Friends of the Earth (2012) Time to take our foot off the gas?

⁸² DECC (2012) Gas Generation Strategy

⁸³ DECC (2013) Energy Trends

⁸⁴ DECC (2012) Energy Security Strategy

assets provide power, whilst demand side response and energy efficiency can reduce or shift the demand peaks. The UK currently enjoys a historically high capacity margin due to new capacity commissioned before the recession and a reduction in demand since. This will reduce over the coming years with the retirement of old coal and oil power stations (see chapter one) and the addition of increasing amounts of intermittent wind power, which provide a lower de-rated capacity value.

In theory, the electricity market should ensure that new investment is brought forward in a timely manner. However, changes in the power sector are disrupting any investment signal created by reducing margins. In the short term, policy uncertainty created by Electricity Market Reform has led to an inevitable hiatus in investment. In the longer term, an increasing proportion of intermittent and less flexible supply will place higher flexibility demands on the system, which could challenge existing market arrangements. Sufficient capacity will need to be provided to cover infrequent but longer periods of low wind output, such as winter anti-cyclonic conditions where demand is high and wind generation can be low for a number of days. However, as a result of their lower marginal costs, nuclear and renewable generators take priority in supplying to the grid over coal and gas power plants - reducing their running hours and revenue. Under current market arrangements there would be a significant risk that fossil fuel power stations, some of which may be required to stay operational but run infrequently, do not recoup their initial capital investment and on-going costs. The Government's proposed Capacity Mechanism could reimburse power stations providing useful future capacity, lowering the risk that low load factors lead to them becoming uneconomic.

Figure 5: What is a de-rated capacity margin?

A standard indicator for security of supply is the de-rated capacity margin, which is the excess of available generation capacity to peak demand. In 2012, peak electricity demand was 63 gigawatts, whilst the installed capacity on the grid was 89 gigawatts⁸⁵. This latter figure must be adjusted, or de-rated, to account for the average availability of power plants, as in practice, no plant will run at its full output rating. This is due to inherent efficiency losses and allowances for periodic maintenance. Similarly, a 150 megawatt wind farm will not run at this capacity, due to the intermittency of the wind resource. Winter availability factors applied to UK power plants range from 86 per cent for gas plants to 20-22 per cent for wind⁸⁶. The capacity of the wind farm becomes 30 megawatt once it is de-rated for average availability, and 2012s capacity margin of 24 per cent is de-rated to 14 per cent. This is a more useful measure of resource adequacy as it takes into account the operational constraints of power plants.

Capacity Mechanism

Mindful of forthcoming power station retirements, the hiatus in investment caused by the development of electricity market reforms and the prospect of far greater amounts of low and zero marginal cost power stations, the Government has proposed to implement a Capacity Mechanism, to reward providers of future generating capacity, demand side response or demand reduction. The Government will assess future capacity margins and contract, via auctions, additional supply-side or demand-side measures to ensure that security is maintained.

⁸⁵ DECC (2012) Statutory Security of Supply Report

⁸⁶ Ofgem (2012) Electricity Capacity Assessment

Current proposals are for the first auctions to take place in 2014 for supply-side measures and 2015 for demand-side measures. Demand reduction and demand side response could be a more cost effective means of meeting short capacity needs and so affordability benefits could be missed if demand-side auctions are held a year after those for supply-side measures. The Government has said that the first auctions could, if needed, be held as early as autumn 2014 for capacity to be delivered in winter 2015/16⁸⁷.

3.4 The short term: 2013-2020

The retirement of a large proportion of old power stations will put current capacity margins under pressure. Between January 2012 and April 2013, coal and oil capacity reduced from 30 to 22 gigawatts, and by January 2016 only 17 gigawatts of coal is expected to remain in operation.

In the central forecast of Ofgem's most recent assessment, de-rated capacity margins will reduce from 14 per cent today to 4 per cent in 2015/16⁸⁸. Whilst the UK has had similar margins in the past, this could fall lower should one or several of the risks below take effect, increasing the likelihood of power shortages:

- Lower than expected low carbon delivery (coal-to-biomass conversions and wind)
- Old gas plants close and no mothballed or new capacity comes online before 2018
- Limited import or even export through existing interconnectors at periods of peak demand
- Unexpected nuclear power outages

Closing coal and oil capacity will be replaced with up to around ten gigawatts of new renewable capacity, although there is uncertainty about how much will be delivered. Up to three gigawatts of capacity could be provided by converting old coal plants to burn biomass, although only one gigawatt has been confirmed to date⁸⁹. New wind capacity could add five gigawatts between now and 2016⁹⁰. As of February 2013, 3.5 gigawatts of wind generation was under construction (both on and offshore), with a further seven granted planning permission⁹¹. It should be noted that the de-rated capacity value of a five gigawatt addition would be nearer one gigawatt (see Figure 5), implying a reduction in margins even if renewables deployment meets expectations.

Margins could be reduced further if old gas power stations close. These have faced poor economics in recent years, as the price of coal has fallen relative to gas, reducing plant running hours. Average load factors for gas power stations fell from 71 per cent in 1996 to 48 per cent in 2011⁹². Currently, 3.7 gigawatts of gas plants have been taken offline and 'mothballed' (kept ready to re-open, if conditions improve)⁹³, the most recent being the 700 MW Keadby plant in Lincolnshire in March 2013⁹⁴. Owners of gas power plants considering prolonging the life of their plant also face uncertainty regarding future revenue, as the growing proportion of

⁸⁷ DECC (2012) Electricity Market Reform: Capacity Mechanism – Design and Implementation Update

⁸⁸ Ofgem (2012) Electricity Capacity Assessment

⁸⁹ Reuters (2013) Drax says biomass plans making rapid progress; 19.02.13

⁹⁰ Ofgem (2012) Electricity Capacity Assessment

⁹¹ DECC (2013) Renewable Energy Planning Database as of February 2013

⁹² DECC (2012) Gas Generation Strategy

⁹³ DECC (2012) Gas Generation Strategy

⁹⁴ SSE (2013) Review of Thermal Generation Operations; 21.03.13

lower marginal cost renewables reduces opportunities for gas power stations to run economically.

Other factors could also add pressure to falling capacity margins. Volatile electricity markets in Europe could mean the UK is unable to import via interconnectors at times of low wind generation, or worse, could export at these times if prices abroad are high enough⁹⁵. With tighter margins, the unexpected shut down of a nuclear power station could also trigger power shortages. A capacity crunch could occur if one or several of the risks above takes effect, although, as discussed, this is a worst case scenario.

Finding 20

There is a real threat of power shortages in the next few years, although at present, this is a worst case scenario and poses a risk similar in scale to those successfully managed before. A combination of market signals and the proposed Capacity Mechanism could mitigate the risk by incentivising currently mothballed gas power stations to be revived if needed.

Finding 21

Continuing to deliver security at lowest cost will be particularly challenging over the next five to ten years due to a confluence of:

- **Electricity Market Reform causing an inevitable temporary hiatus in the building of new power stations**
- **High gas prices relative to coal eroding the economics of gas power stations and forcing some to be mothballed or consider closure**
- **A significant amount of old coal, oil and nuclear power station capacity closing**
- **Uncertainty over the future availability of electricity imports via interconnectors**

Solutions in the short term

With new nuclear unconfirmed and not likely to come online until at least after 2020, and no scope for new unabated coal plants to be built, a shortfall in biomass and wind deployment could be met by the re-opening of mothballed plants, and avoiding other plant closures. There is also a pool of around 15 gigawatts of gas power plant projects⁹⁶ with the necessary consents should new capacity be needed. In the short term, Ofgem estimates that up to 1.1 gigawatts of mothballed plant could return, and 1.4 gigawatts of new gas could come online if conditions are right by 2016/17⁹⁷. However, the continuing poor economic performance of gas relative to coal exacerbates the risks of early closure whilst decisions to renovate existing gas plants, or construct new ones, are affected by uncertain future revenues.

Demand reduction is an additional solution, available within the timescales required. Investing in demand reduction could lower overall demand and help reduce peaks, in turn reducing the need for additional supply capacity. Research to support the Government's recent consultation on Electricity Demand Reduction showed that the vast majority of demand reduction options were more cost effective

⁹⁵ Ofgem (2012) Electricity Capacity Assessment

⁹⁶ DECC (2012) Gas Generation Strategy

⁹⁷ Ofgem (2012) Electricity Capacity Assessment; New plant includes the recently confirmed 0.9 GW Carrington Plant

than supply-side measures. It showed that socially cost effective investments in demand reduction could result in a net reduction in of 69 terawatt-hours, or 22 per cent, of total projected electricity demand in 2020⁹⁸.

Demand Side Response (see Figure 6) could also be used to make short-term adjustments, shifting demand away from peaks, although the ability to make sustained reductions over several days would first need to be developed, possibly by staggering individual providers⁹⁹.

Finding 22

Bringing forward first delivery under the Capacity Mechanism, currently scheduled for 2018, could be a useful tool in managing short term security risks cost effectively

The aforementioned Capacity Mechanism could help bring forward these supply and demand-side measures, should they be needed in the short term. Early auctions and/or delivery could be a useful tool in meeting short term security risks cost effectively. Holding auctions for both, at the same time, could also mitigate the risk of contracting unnecessarily expensive solutions.

Finding 23

There could be affordability benefits in holding Capacity Mechanism auctions for supply and demand-side measures at the same time.

⁹⁸ DECC (2012) Electricity Demand Reduction: Consultation on options to encourage permanent reductions in electricity use

⁹⁹ Green Alliance (2012) The Future of Gas Power

Figure 6: Options for grid flexibility and capacity

There are a variety of options that can provide supply and demand flexibility and capacity. These operate over different timescales and are at various stages of technological development:

Flexible generation

Flexible generation is able to vary output easily and quickly. Coal, gas and biomass power stations are currently the main tools for ensuring that supply follows demand. Thermal generators also provide additional system services, such as frequency response and reactive power, and are able to cover extended periods of low intermittent generation.

Energy storage

Storing electricity for later use can help make use of excess supply from intermittent generators and provide rapid supply at times of peak demand. There are two types of storage: bulk and distributed. Bulk storage is typically provided by pumped hydro stations, of which the UK currently has 2.7 gigawatts capacity. In the future, alternative technologies using compressed air, thermal storage or batteries may develop at scale. Distributed storage is not yet used but would use the storage ability of small appliances spread across the network, such as electric vehicle batteries and hot water storage combined with electric heat pumps. These could store excess energy and lower peaks by shifting demand. Storage is more suited to providing additional supply over short periods of time, and may be of limited use during extended periods of low wind. Pumped hydro projects can take many years to construct, with alternative storage solutions at early stages of development.

Interconnection

Network cables connected to neighbouring countries allow the UK to both import electricity at times of high demand, and export at periods of high supply. This provides additional means to obtain supply and use excess generation. Interconnectors open up the potential for imports of cheaper electricity, but there could also be times when, despite low generation and high demand in the UK, higher prices in neighbouring markets create a demand for export, leading to increased prices here. The UK currently has interconnectors with France, Northern Ireland, the Netherlands and, since 2012, the Republic of Ireland, with a combined capacity of 4 gigawatts. New interconnectors of up to 7.2 gigawatts are being explored¹⁰⁰.

Demand side response

Demand side response is the active reduction of electricity consumption, usually to shift demand from high cost periods to lower cost ones. Demand side response could be used to reduce within-day demand peaks, reducing the total capacity needed on the system. It could also be used to manage longer periods of low wind generation, although this would likely require significant technical and commercial development¹⁰¹. National Grid currently contracts up to one gigawatts of demand reduction to balance the system¹⁰². This is provided by large commercial and industrial users, although the roll out of smart meters and smart appliances could

¹⁰⁰ Ofgem (2010) Existing, planned and future interconnection - Electricity Interconnector Policy

¹⁰¹ Green Alliance (2012) The Future of Gas Power

¹⁰² National Grid (2011) Operating in 2020

allow domestic demand side response to develop in the 2020s in conjunction with electric vehicles and heat pumps.

Demand reduction

Electrical demand reduction reduces the required capacity of power stations and in the vast majority of cases reducing demand for electricity is cheaper than increasing supply. Reducing electricity consumption that serves no value, changing the way we use electrical appliances and improving the electrical efficiency of appliances are all ways of reducing demand that are applicable to domestic, commercial and industrial settings. Demand reduction could play a crucial role in saving energy equivalent to 22 power stations alongside efficiency measures beyond the power sector¹⁰³. Some measures are already being implemented, for example the Green Deal and Smart Meters programmes are expected to reduce electricity consumption by around one or two per cent in 2030. The Government estimate that a ten per cent reduction in electricity consumption by 2030 could save around £4 billion¹⁰⁴.

3.5 The medium term: 2020-2030

The scale of response needed to accommodate large volumes of intermittent generation on the grid will reach a significantly greater level by 2020. Whereas today, electricity supply is adjusted to follow changes predominantly in demand, a system with large volumes of intermittent generation will also need to manage variability in the supply-side. This will require an increased ability to vary both supply and demand ranging from hourly and within-day to seasonal timescales. Flexible thermal generation such as coal, gas and biomass, alongside other measures (see Figure 6) can help manage this intermittency. On sustainability grounds, biomass is preferred over unabated gas which is preferred over unabated coal.

By 2020, the volume of intermittent capacity could be as high as 33 gigawatts¹⁰⁵, up from 11 gigawatts in 2012¹⁰⁶. National Grid expects that the grid will need to be able to adjust to changes in wind output of up to 15 gigawatts over two hours. It anticipates that this could be met by operating coal, gas and biomass plants more flexibly, alongside deployment of alternative measures consisting of 1.7 gigawatts of interconnectors and up to two gigawatts of Demand Side Response from industrial and commercial users. Bulk and distributed storage is thought unlikely to be available within this timescale. The effect on thermal generation is likely to be increased flexible operation across the majority of the fleet rather than a large volume of plant operating at very low levels, however¹⁰⁷. To cover for exceptional periods of low wind output, a sufficient (de-rated) capacity margin will need to be maintained, and the Government may have to contract through the Capacity Mechanism to ensure that marginal providers, required very infrequently, are adequately incentivised to remain open.

The need for new unabated gas power plants by 2020 will be driven by the scale of power station retirements and low carbon deployment. Some old gas plants may retire, as well as 3.8 gigawatts of nuclear capacity, currently scheduled to shut by 2020¹⁰⁸. New plants are likely to run at high loads in the early years of the decade, with older gas plants, alongside other capacity options, likely to provide less

¹⁰³ DECC (2012) Electricity Demand Reduction Consultation

¹⁰⁴ DECC (2012) Electricity Demand Reduction Consultation

¹⁰⁵ DECC (2011) Renewable Energy Roadmap

¹⁰⁶ DECC (2012) Renewable Energy Roadmap Update (Wind, solar and small scale hydro)

¹⁰⁷ National Grid (2011) Operating in 2020: Update

¹⁰⁸ DECC - Table of past and present UK nuclear reactors

frequently used backup capacity. The amount of new gas capacity required in this period will be determined by:

- Nuclear, coal and gas plant closures
- The future economics of coal power stations
- Biomass and nuclear deployment
- Performance of gas plants versus alternative options in Capacity Market auctions
- Reliability and availability of interconnectors to import at peak demand periods

National Grid's Gone Green scenario estimates that between 2015 and the early 2020s, up to six gigawatts of gas plant could retire, with up to 13 gigawatts of new plant constructed¹⁰⁹.

Finding 24

In the short to medium term, increased flexibility requirements from higher penetration of intermittent generation is best met by biomass and unabated gas power stations, until storage, demand side response and interconnection can compete at scale.

3.6 The long term: 2030 and beyond

The need for gas power stations from 2030 will be governed by the mix of intermittent and flexible capacity. The extent to which heating and transport are electrified will also be a major determinant, as these would increase and change the profile of demand, given patterns of use and the seasonality of heating demand¹¹⁰.

DECC's 100 gCO₂/kWh scenario, modelled in the Gas Strategy, indicates a need for 37 gigawatts of unabated gas capacity in 2030. This is comparable to gas capacity today although average load factors would fall 15 per cent. Similar scenarios modelled by the Government assume that interconnection increases to five gigawatts, although it is not clear to what extent distributed storage and demand side response play a part. Similarly, modelling by Cambridge Econometrics of a high wind pathway meeting the recommended 50 gCO₂/kWh carbon intensity in 2030, indicates that around 36 gigawatts of unabated gas could be needed in 2030.

Between now and 2030 there may be significant potential to expand the use of alternative measures for balancing supply and demand (outlined in Figure 6). Analysis of options in 2050 suggests that in a system composed entirely of intermittent renewables, deploying the full range of demand and storage measures to their full technical potential could reduce the need for backup generation to around six per cent of total supply¹¹¹. This suggests that alternative technologies can make a significant impact in managing intermittency, although they cannot entirely remove the need for some flexible supply capacity such as thermal power stations¹¹². These could be biomass or abated fossil fuel power stations.

Recent analysis suggests that using interconnection, distributed storage and demand side response to provide flexibility and capacity could bring additional cost savings by reducing the need for network upgrades and reducing the level of compensation

¹⁰⁹ National Grid (2012) Future Energy Scenarios

¹¹⁰ DECC (2012) Electricity System: Assessment of Future Challenges - Annex

¹¹¹ Poyry (2010) Options for low-carbon power sector flexibility to 2050

¹¹² Poyry (2010) Options for low-carbon power sector flexibility to 2050

paid to limit the output of intermittent generators¹¹³. These benefits apply across a range of different supply and demand scenarios. Whilst there could be advantages to using these measures rather than relying solely on building additional supply, they require more technological and commercial development before they are deployable at scale and their costs are better understood¹¹⁴.

Finding 25

Energy storage, demand side response and interconnection could compete at scale with fossil fuel and biomass plants to provide system flexibility by 2030. Developing and piloting these technologies could avoid locking out potentially advantageous future pathways.

¹¹³ Imperial & NERA (2012) Understanding the Balancing Challenge

¹¹⁴ Energy Research Partnership (2012) Delivering flexibility options for the energy system: priorities for innovation

4. AFFORDABILITY

High energy prices can dampen economic activity, drive inflation and reduce the UK's industrial competitiveness. The effects are most keenly felt by energy intensive industries such as steel and chemical manufacture, as well as lower income households who are forced to spend an increasing proportion of their income on basic energy services. Price volatility is an important factor for consideration alongside absolute prices, as this can impact adversely on businesses and other consumers attempting to manage their costs.

4.1 The challenges

Affordability is one of the Government's three energy policy objectives¹¹⁵, and it faces two major challenges. First, increasing international competition for resources has driven up coal, oil and gas prices, increasing energy bills in the UK which in turn has added pressure to consumers and businesses already struggling through a period of recession and low economic growth. Electricity prices have increased by 51 per cent since 2003¹¹⁶, driven mainly by the rising costs of fossil fuels, which still provide the majority of today's power generation and heating.

A second challenge is managing the large amount of investment needed to replace old power stations and upgrade network infrastructure. Between 2012 and 2020 up to 20 gigawatts of old power stations - a fifth of total capacity – are expected to close. These could be replaced with up to 30 gigawatts of new renewables and possibly new unabated gas plants. Significant investment is also needed in the transmission and distribution network, both to connect new sources of power and overhaul parts of an ageing network. The challenge for policy is to ensure that this investment takes place, and that it is done as efficiently as possible. Decisions made in the next few years will determine the shape of the power sector for decades to come, and in turn, the future costs of electricity. There are multiple uncertainties currently facing policy makers:

- How far and fast the cost of renewables may fall
- Future whole-life costs of nuclear power
- The future prices of fossil fuels
- The costs of Carbon Capture and Storage technology
- The future price of carbon

Although prices in the UK have risen sharply in recent years, it is worth noting that prices remain close to European and World averages. Household electricity prices have been third or fourth lowest in the EU 15 for the past four years, with prices similar to the EU 15 median for small and medium industrial consumers and slightly higher than the median for large and extra-large industrial customers¹¹⁷. However, the overhaul of old infrastructure and transition to lower carbon energy will require significant investment over the next decade, in turn increasing the cost of electricity in the UK.

¹¹⁵ DECC (2011) Planning Our Electric Future: A White Paper For Secure, Affordable And Low-Carbon Electricity

¹¹⁶ DECC (2012) UK Energy Sector Indicators 2012

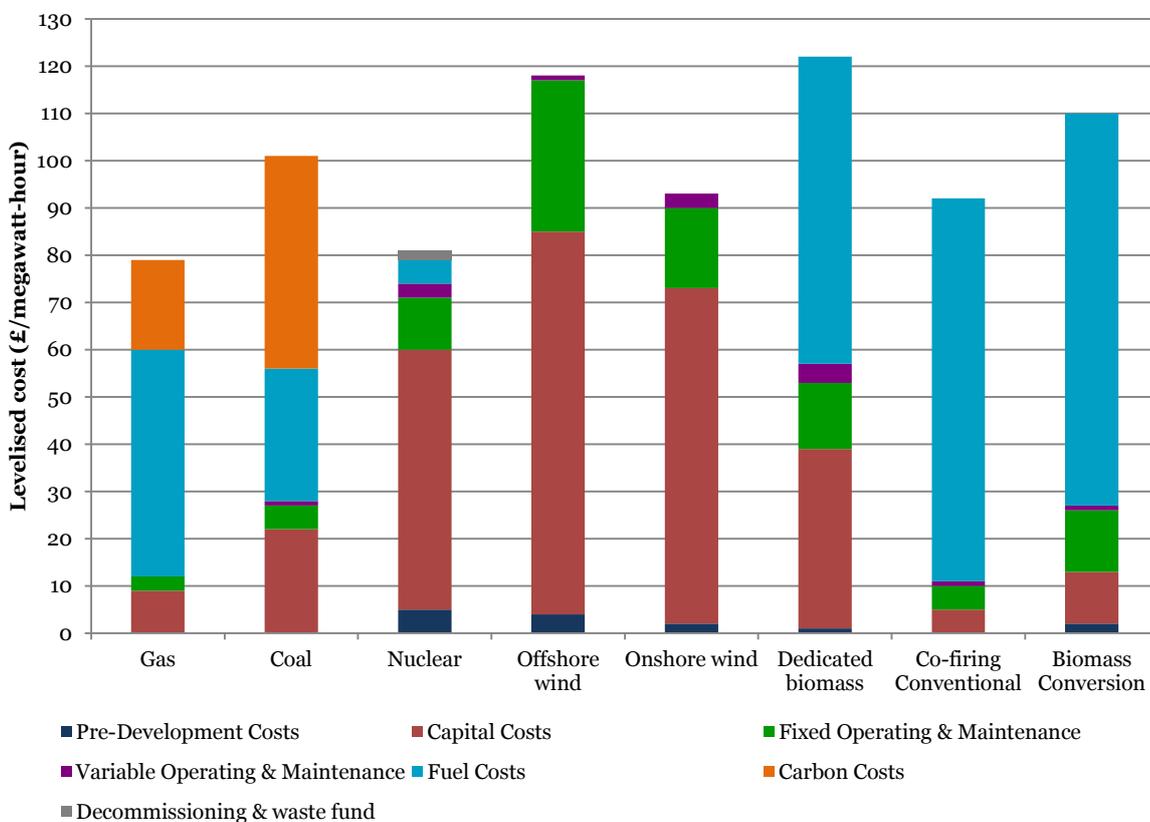
¹¹⁷ DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills

4.2 Cheaper today

Figure 7 compares estimated average, or levelised, costs of electricity generated by different sources, dividing total power station lifetime costs per megawatt-hour produced. It shows that unabated gas and nuclear, followed closely by onshore wind and biomass co-firing, to be the lowest cost forms of generation.

The orange bars in this analysis indicate carbon prices¹¹⁸, to reflect the introduction of the Carbon Price Floor, a tax on fossil fuels used for power generation, as of 1 April 2013. Excluding the cost of carbon, as was the case until the introduction of the EU Emissions Trading System in 2005, gas and coal become the cheapest forms of generation. This is why, historically, investment has flowed to these types of power plants and their use continues to grow worldwide. Carbon taxes will begin to ensure that fossil fuel power generation reflects the environmental costs of its associated carbon pollution.

Figure 7: Levelised cost estimates for projects starting in 2012



Source: Department of Energy and Climate Change, Electricity Generating Costs (October 2012)

- Notes:
- 1) Gas is combined cycle gas turbine
 - 2) Coal is advanced super critical with flue gas desulphurisation
 - 3) Nuclear is first of a kind
 - 4) Offshore wind is round two and onshore wind is UK and >5 megawatts
 - 5) Dedicated biomass is >50 megawatts
 - 6) 2012 prices assuming a 10 per cent discount rate

Whilst a useful starting point, it should be noted that this is a simplified analysis. It rests on numerous assumptions including capital, fuel, and operating costs as well as

¹¹⁸ £16 per tonne of carbon dioxide emitted

load factors and discount rates. System wide costs are also omitted. Generation connected to remote areas of the transmission or the distribution networks can create a need for upstream re-enforcements. Similarly, the intermittent nature of wind, solar and marine technologies creates new demands on the grid that may require additional investment in storage and interconnection (see chapter three).

Fuel price uncertainty

Figure 7 provides a useful breakdown of costs, and shows the extent to which the cost of electricity generated from fossil fuels is dictated by fuel prices – it accounts for approximately 80 and 50 per cent of the lifetime costs of electricity from gas and coal power plants (excluding carbon prices). Fossil fuel power generation costs will be in large part determined by these costs, which are difficult to predict. Capital dominates the cost of most low carbon alternatives - the on-going costs of wind, solar and marine are composed of smaller and more predictable operation and maintenance overheads. Similarly, nuclear fuel costs are a small proportion of total costs, although there is more uncertainty regarding the costs of decommissioning and waste management. The future cost of electricity from fossil fuels will be less predictable than that from alternative technologies.

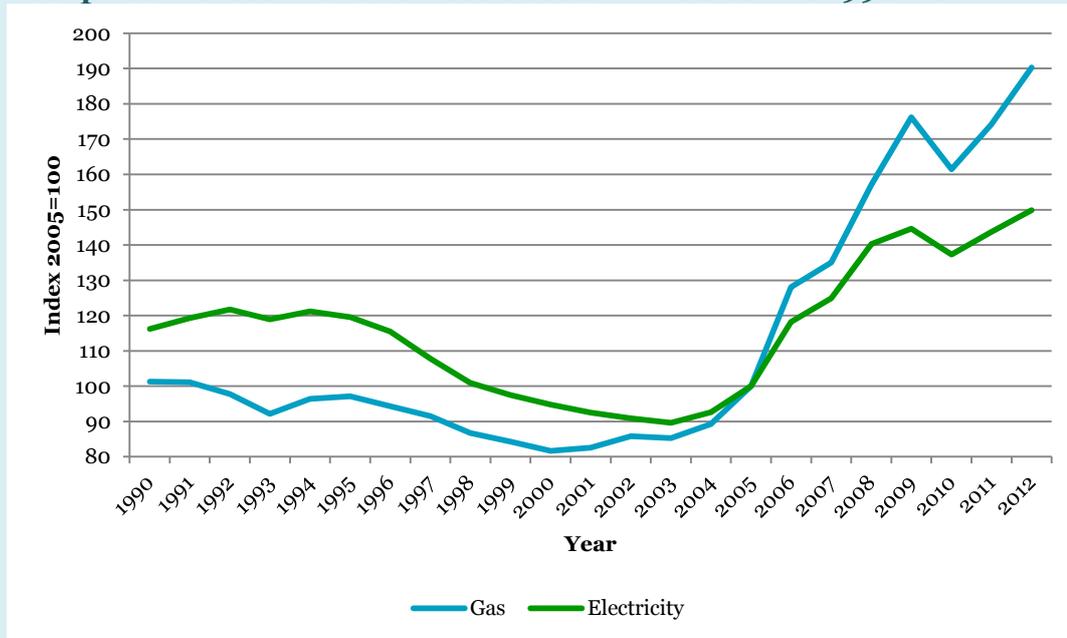
Finding 26

Gas and coal generation are subject to higher degree of future price risk than alternative forms of generation.

Figure 8: Recent fuel price impacts on electricity bills

The impact of fuel prices on electricity bills is illustrated by a look at the recent history of UK energy prices. The graph below plots the relative prices of coal, gas and electricity since 1990. The cost of electricity can be seen to rise alongside price increases in coal and gas, which provided two thirds of total generation in this period. In 2011, wholesale fuel costs accounted for 43 per cent of the average UK domestic electricity bill¹¹⁹.

Fuel price indices in the domestic sector in real terms 1990-2012



Source: Office for National Statistics, Retail Prices Index

Notes: 1) Deflated using gross domestic product (market prices) deflator

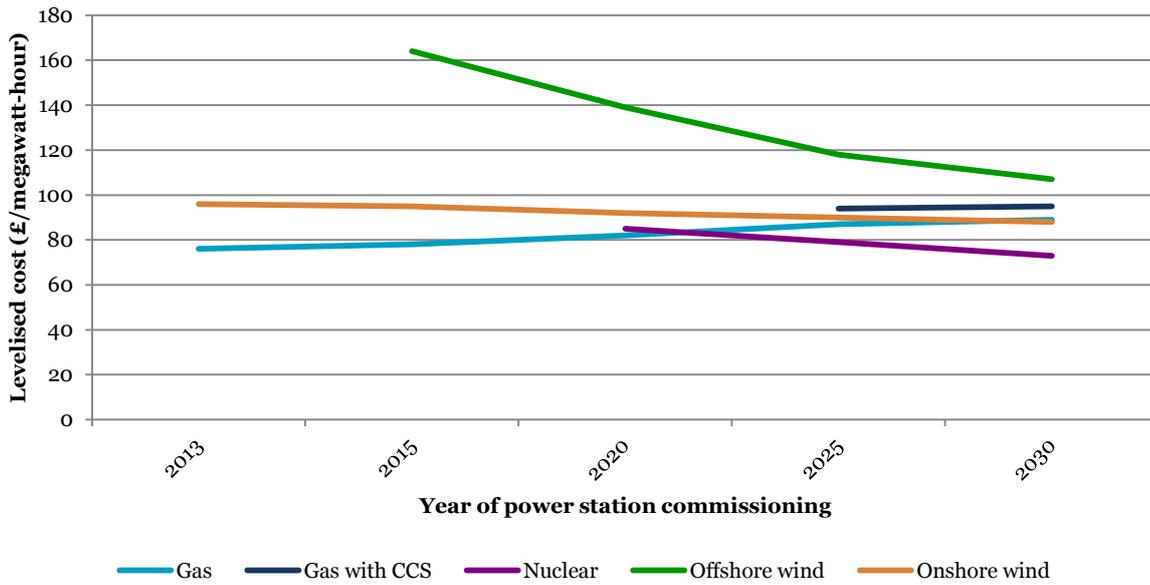
Rising fossil fuel prices were driven by increasing worldwide demand for energy, especially from rapidly developing countries such as India and China. Global demand for gas and coal grew on average 2.7 and 5.5 per cent per year over the last decade¹²⁰.

4.3 Cheaper tomorrow?

Figure 9 sets out recent analysis conducted by the DECC on how levelised costs (for new build plants) are likely to evolve between now and 2035. The analysis shows that unabated gas generation costs will increase, as the costs of low carbon alternatives fall over time.

¹¹⁹ DECC (2013) Estimated impacts of energy and climate change policies on energy prices and bills

¹²⁰ IEA (2013) www.iea.com accessed 02.01.13

Figure 9: Levelised cost of electricity generation 2013-2030

Source: Department of Energy and Climate Change, Electricity Generating Costs (October 2012)

- Notes:
- 1) Gas is combined cycle gas turbine
 - 2) CCS is non-retrofit post combustion carbon capture and storage
 - 3) Nuclear is European Pressurised Water Reactor, first of a kind/Nth of a kind
 - 4) Offshore wind is round three and onshore wind is >5 megawatts in the UK
 - 5) Central estimates given in 2012 prices assuming a 10 per cent discount rate

Whilst this is an approximation of the future, the underpinning analysis highlights three key variables that will decide how this picture evolves over time:

- Carbon prices
- Technology costs (new build nuclear costs, renewables cost reductions)
- Fossil fuel prices

Finding 27

Many forms of low carbon generation will be cost competitive with unabated gas by 2030, under central assumptions of future technology costs, carbon prices and gas prices.

We now explore the assumptions underpinning this analysis:

Carbon prices

The analysis above assumes that carbon prices rise according to the trajectory set out by the Treasury for the Carbon Price Floor, which was introduced on 1 April 2013. Under the trajectory, prices begin at £15.70 per tonne in 2013 and rise in a linear fashion to £30 in 2020 and £70 per tonne by 2030 (at 2009 prices)¹²¹. The introduction of the tax has increased the levelised cost of power from gas power plants by approximately 31 per cent¹²². How robust this assumption proves will depend on political commitment to the Carbon Price Floor. Treasury have confirmed

¹²¹ HM Treasury (2011) Carbon price floor consultation: the Government response

¹²² DECC (2012) Generating Costs Update; 2012 prices

the rate to 2015/16, and set an indicative price of £24.62 for 2017/18¹²³. Actual rates will be decided in annual Government Budgets.

The Carbon Price Floor is designed to ‘top up’ the cost of carbon within the EU Emissions Trading System, whose carbon prices have been deemed too low to encourage a shift in investment away from carbon intensive generation. At the start of 2013, the price of carbon fell to record lows of less than £4 per tonne. A large disparity between UK and EU carbon prices will increase overall energy costs in the UK relative to European neighbours. If low prices continue, there may be increased pressure from business to see Carbon Price Floor rates set lower than is currently projected. The proposed compensation scheme for energy intensive industries would help moderate this risk.

Technology costs

The analysis above also relies on anticipated construction and operating costs. These are well understood for mature technologies such as coal and gas power stations - those of less mature technologies are less certain. Onshore wind is now being commercialised at scale and is becoming cost competitive with gas generation. Although nuclear reactors are a long established technology, there are uncertainties regarding UK construction costs, with the last plant completed in 1995. The costs of future offshore wind development at sites further off the coast and in deeper water are less certain, although the industry has targeted a levelised cost of £100 per megawatt-hour for projects reaching financial close in 2020, which is significantly below the estimate in Figure 9. Other technologies, such as marine energy, are at an early demonstration phase, with a large, but highly uncertain, potential to reduce costs.

Figure 9 shows central estimates based on recent research. Analysis by Redpoint Energy, a consultancy that has conducted modelling both for the Government and the Committee on Climate Change, suggests that if technology costs are lower than forecast, a low carbon relative to a high gas strategy would, in total, save consumers a total of £50 billion in power sector costs by 2045 (in net present value terms), and impose costs of £18 billion should technology costs turn out higher, and future gas prices lower, than assumed¹²⁴.

Fuel price costs

Fuel prices are the greatest variable that will affect future fossil fuel generation costs. The analysis in Figure 9 uses DECC’s ‘central’ gas price estimates. Whilst it is exceptionally difficult to predict future fuel prices, given the complexity of UK and world markets, they are unavoidable if costs are to be compared. Figure 10 compares DECC’s latest price projections, alongside an estimate produced by the International Energy Agency (IEA).

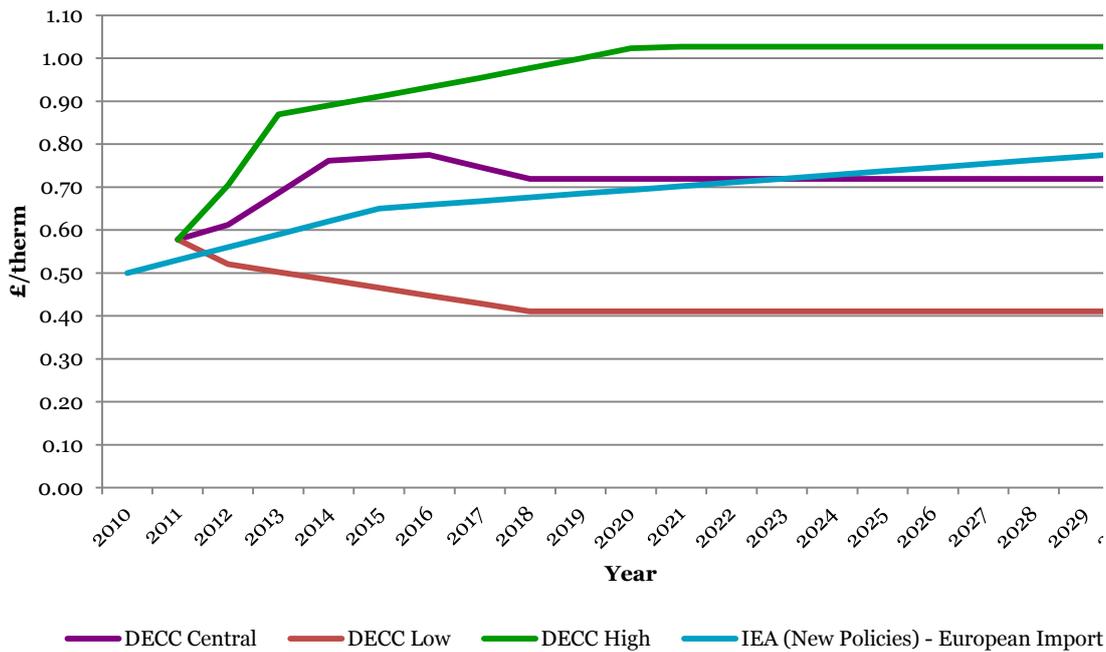
There are five key variables which set prices in the DECC scenarios¹²⁵:

- Levels of economic growth in Europe
- Demand for gas in Asia
- The global availability of Liquefied Natural Gas (LNG) supplies
- How closely linked oil and gas contracts remain in future
- The extent to which EU attempts to liberalise gas markets are successful

¹²³ HM Revenue & Customs (2013) Carbon price floor: rates from 2015-16, exemption for Northern Ireland and technical changes

¹²⁴ Redpoint (2012) Modelling the trajectory of the UK power sector to 2030 under alternative assumptions

¹²⁵ DECC (2012) Fossil Fuel Price Projections

Figure 10: Wholesale gas price projections 2010-2030

Source: Department of Energy and Climate Change, Fossil Fuel Price Projections (October 2012)

- Notes:
- 1) Series adjusted using consumer price index where not originally in 2012 prices
 - 2) IEA series represents European Import Price rather than National Balancing Point price
 - 3) 2012 prices
 - 4) DECC is Department of Energy and Climate Change
 - 5) IEA is International Energy Association

The central estimate, upon which the forecast in Figure 10 is based, sees prices spike over the next few years, before they stabilise at roughly 15 per cent higher than today's. This assumes moderate European economic growth, continued growth in Asian demand for gas, moderate liberalisation of European gas contracts and markets and tight global supplies of LNG until capacity increases towards the end of the decade.

To what extent is shale gas reflected in these forecasts?

A key question in the debate over the use of gas in the power sector is the extent to which forecasts of future gas prices match recent developments in unconventional gas. DECC's near term assumptions appear in line with our analysis in section six, whereby US shale gas helps ease tight global LNG supplies towards the end of this decade. The 'low' future price scenario, where by 2020 gas prices reduce by 20 per cent on those of 2012, could happen if global LNG supplies become plentiful, Asian demand is subdued and there is continued low European economic growth. This estimate was revised downwards in 2011 to reflect more optimistic projections of US gas supplies and the possibility of exports to the UK¹²⁶, with a minor adjustment upwards in 2012.

The International Energy Agency estimate of future European import prices anticipates growing global shale gas production¹²⁷. As Figure 10 shows, this forecast compares favourably with DECC's central gas price projection. It should be noted

¹²⁶ DECC (2011) Gas Price Projections

¹²⁷ International Energy Agency (2011) World Energy Outlook

that these forecasts rest on numerous other assumptions regarding supply, demand, regional markets and economic growth. However, it does appear that the short term impacts of shale gas exports from the US, and some longer term effects, have been taken into account in DECC's estimate. The 'central scenario' appears to compare favourably with the IEA forecast, although it is higher than other available estimates¹²⁸. Ultimately, the main conclusion to draw is that a wide range of gas prices is possible in future, and policies should be tested for a variety of outcomes.

Finding 28

Fuel price forecasts used in UK policy making, take account of likely short to medium term impacts from unconventional gas resources.

4.4 Affordability of high vs. low gas strategies

Given the uncertainty surrounding future gas prices, it is useful to compare the outcomes of the competing strategies under different gas price futures. If a low carbon trajectory is pursued to 2030, where power sector emissions intensity falls to around 50 gCO₂/kWh, gas generation will contribute approximately 10 per cent of electricity supply. In the alternative, high gas generation scenario (outlined in chapter one), the sector carbon intensity is 200 g, with gas providing up to 45 per cent of total supply. This is broadly comparable to the levels of gas generation seen over the last decade.

Gas prices rise moderately (central price projection)

In analysis conducted by Redpoint Energy for the Committee on Climate Change, a low carbon strategy in a world where the 'central' gas price assumption (outlined above) holds true, consumers would face significantly lower power sector costs (total generation, carbon and network costs) equivalent to a total saving of £23 billion by 2045¹²⁹ in present value terms, compared to a strategy where unabated gas provides 67 per cent of total generation by 2030. The saving would be of the order of £40 billion should gas prices follow the 'high gas' scenario in Figure 10¹³⁰.

Very low gas prices

If gas prices follow DECC's 'low' trajectory, where global LNG supplies become plentiful (driven in part by US shale gas) and Asian demand growth slows, the analysis shows slightly higher costs from pursuing a low carbon strategy. By 2045, consumers would have incurred additional costs of £1 billion. The benefits of lower gas prices are offset by increasing carbon prices (which reach £200 per tonne in 2050). The additional cost of following this strategy, should fuel assumptions turn out wrong, at £1 billion, is far lower than the additional costs - £23 billion - of the high gas strategy in a high gas price world. A strategy of gas for capacity, rather than energy, carries less risk (£1.3 billion) than the alternative high gas consumption strategy. Given the low capital costs of unabated gas plants, it would make sense to use these to provide capacity, rather than high volumes of generation, in future.

Finding 29

Investing in a high gas strategy carries greater risks of higher costs, and lower benefits, than an alternative low carbon pathway.

¹²⁸ DECC (2012) Fossil Fuel Price Projections

¹²⁹ Net Present Value, discounted at 3.5%

¹³⁰ Redpoint Energy (2012) *Modelling the trajectory of the UK power sector to 2030 under alternative assumptions*

5. SHALE GAS

5.1 Introduction

Shale gas is one of a number of ‘unconventional’ gas resources that have become increasingly economically viable in recent years, alongside coal bed methane, which is gas trapped in coal in intact seams, and tight gas which is gas trapped in low permeability hard rock, limestone or sandstone. Shale and tight gas are found within deposits of very low permeability rock, which in contrast to standard reservoirs of oil and gas, must be ‘stimulated’ to force the gas contained within the rock out. This process is known as hydraulic fracturing, or ‘fracking’, and involves injecting large quantities of water mixed with chemicals and sand at high pressure into the gas bearing rock. The extraction of unconventional gas has become economically viable thanks to the improvements in fracking technology and directional drilling, which allows wells to be drilled horizontally along deposits, increasing the area that can be stimulated to produce gas from a single well ‘pad’ on the surface.

In the US, where fracking experimentation and exploration first began twenty years ago¹³¹, shale gas production has grown rapidly from nine per cent of total consumption in 2007 to 35 per cent in 2011¹³². Commercial production is yet to take place outside the US, although estimates have suggested that global unconventional gas resources could be as large as those of conventional resources¹³³. However, how much gas could be economically recoverable from these deposits remains highly unclear, with worldwide exploration and testing at a very early stage.

The full environmental impacts of unconventional gas extraction are unclear, with uncertainty regarding methane emissions (highly active greenhouse gas) and risks that fracking fluid could find its way into and contaminate groundwater supplies. Shale and tight gas extraction is also water and land intensive, with impacts on the local environment. The extent to which public acceptance can be gained is likely to condition the extent to which global production expands.

Why does it matter in the power sector debate?

In recent years the role of unabated gas generation in the UK’s energy strategy has become increasingly contested. The extent to which shale gas production has altered the US energy landscape, and its potential to do the same worldwide, has been the one of the main drivers of criticisms of a diminishing role for gas generation in the UK. This had fed hopes that recent estimates of future UK gas prices could be significantly wrong, leading to calls to re-evaluate the current low carbon strategy^{134,135}. Conversely, the environmental risks highlighted by experience in the US have created a vocal protest movement against fracking, and protests against a second ‘dash for gas’ for power generation.

5.2 The current state of play

Although commercial shale gas production continues to grow in the US, it has yet to take place elsewhere. Production of coal bed methane and tight gas is also

¹³¹ Chatham House (2010) *The Shale Gas Revolution: Hype and Reality*

¹³² EIA (2012) *Summary statistics for natural gas in the United States, 2007-2011*

¹³³ IEA (2011) *Are We Entering A Golden Age Of Gas?*

¹³⁴ Policy Exchange (2012) *Gas works? Shale Gas and its Policy Implications*

¹³⁵ Global Warming Policy Foundation (2012) *The Shale Gas Shock*

concentrated in the US, although this has begun in Australia and Canada. Despite the more advanced development of unconventional extraction in these locations, estimates of their economically recoverable resources are still contested and exhibit a wide variability, due to the unpredictable nature of the resource and continued technological developments¹³⁶.

Global resources

Assessments of the unconventional resources outside of these countries are at a very preliminary stage, and exhibit an even greater degree of variance¹³⁷, with the majority relying on existing data, with limited testing in the field. The International Energy Agency has estimated that globally, unconventional gas resources could be large - perhaps equivalent to current conventional gas reserves¹³⁸. A more recent survey of existing estimates by the UK Energy Research Centre suggested that global *technically recoverable resource* could be roughly half the size of the conventional resource¹³⁹. It is important to note that this figure is the resource that is estimated to be potentially recoverable with current technology, *regardless of economics*. Preliminary resource estimates should be treated with caution as they are based on existing geological data and will need to be verified by extensive testing in the field. Only this can confirm the presence and quantities of gas. The next step is to assess the economic viability of a resource, which can only be completed once several wells have been *production* tested. Ultimately, the ability of unconventional gases to add to global production will depend on their economics relative to other sources.

Outside the US, development of unconventional gas extraction is at a very early stage. Test wells have been drilled in Argentina, Australia, Poland, Hungary, China and the UK, whilst Indonesia, South Africa and India have plans to encourage exploration and development. In Europe, Poland is at the most advanced stage, with test drilling conducted by several companies. Results however have been poor, and estimates of the reserves there - once seen as some of the most promising in Europe - have been reduced to a tenth of their original size¹⁴⁰. Analyses agree that outside North America and Australia, unconventional gas extraction is unlikely to reach large levels until after 2020¹⁴¹. This is due to the length of time needed during the exploration and testing phase, likely bottlenecks in the supply of equipment and expertise and the process of obtaining licenses and land access in more regulated markets such as Europe. It is US shale gas production that is most likely to have any impact on energy markets in the near term.

How could it impact UK gas supplies, and prices?

In theory, a growth in shale and other unconventional gas extraction worldwide would bolster supplies and allow these to keep pace with rising global demand, which is expected to double by 2035, easing upward pressure on prices. Lower global and regional prices could help reduce the costs of gas in the UK. With the UK increasingly reliant on imports to meet its gas needs, domestic onshore production could diversify supplies, alleviate a growing import dependence and bring economic benefits, such as downward pressure on prices, a reduction in the UK's balance of payments deficit, and regional employment opportunities.

Although there is currently little evidence to show that the US shale gas boom will be replicated globally, if this does take place, the impacts on the UK will depend on the

¹³⁶ UKERC (2012) A review of regional and global estimates of unconventional gas resources

¹³⁷ UKERC (2012) A review of regional and global estimates of unconventional gas resources

¹³⁸ IEA (2012) Golden Rules for a Golden Age of Gas

¹³⁹ UKERC (2012) A review of regional and global estimates of unconventional gas resources

¹⁴⁰ Chatham House (2012) The 'Shale Gas Revolution: Developments and Changes

¹⁴¹ BP (2012) World Outlook 2030, Chatham House (2012) &The 'Shale Gas Revolution: Developments and Changes

location of new production sources and the evolution of what are currently *regional* gas markets across the world. Gas can be transported at volume by pipeline or ship, which constrains its movement around the globe and limits inter-regional flows, resulting in highly regionalised gas markets. Whilst the development of Liquefied Natural Gas (LNG) infrastructure around the globe will increase inter-regional flows, infrastructure and shipping costs will continue to structure patterns of trade. The UK currently meets half its gas needs through domestic offshore production, with imports from the European and LNG market providing the other half. European imports arrive via four separate pipelines from Norway, two interconnectors with Belgium and the Netherlands, whilst LNG arrives via five import terminals. Imports via pipeline are contracted via the UK and European market, whilst shipments of LNG tend to be agreed with less flexible, longer term agreements¹⁴².

As part of the European market, unconventional gas produced on the continent could reach the UK via pipeline, whereas that produced further afield would be delivered by the more globalised, but currently limited, LNG market. Likewise, if production were to take place at volume and reduce prices in the UK, our liberalised and highly interconnected market would likely see cheaper gas sold to more expensive markets abroad.

Finding 30

In the event of cheap and plentiful domestic production, our liberalised and highly interconnected market would prevent UK gas prices remaining below that of prevailing European prices.

What impact this decade?

Initially, unexpected reductions in US imports caused an oversupply in LNG markets, which caused prices to fall, along with post-recessionary effects, in 2010¹⁴³. This over supply has been rebalanced by growing demand in Asia. Chinese gas demand has continued to rise, and the Japanese decision to shut down its fleet of nuclear reactors after the Fukushima accident in 2011 led it to increase LNG imports¹⁴⁴. US shale gas has also had an indirect impact on other energy markets: a switch to gas has reduced US coal imports, reducing world prices. As a result, coal generation has become cheaper relative to gas, and increased its share of generation over the past year in the UK and EU.

Potential exports of US shale gas have fed hopes that the UK could have access to more affordable gas in future. It is important to note that low gas prices in the US are not due to the cheap cost of shale gas, but rather a glut in supply that was constrained by limited export opportunities. The costs of unconventional gas extraction are higher than those of conventional resources, due to the greater volume of wells and drilling required¹⁴⁵. Combined with the added costs of compression and transport via LNG, and competition for contracts, US exports will likely reflect prevalent LNG market costs. Centrica announced the first deal to import LNG from the US in March 2013, although deliveries will not begin until 2018, if it decides to send them to the UK¹⁴⁶. Looking further ahead, there is uncertainty about the extent to which the US could become an exporter. It currently has 24 LNG import terminals, little used since the start of the shale gas boom¹⁴⁷.

¹⁴² Ofgem (2012) Gas Security of Supply Report

¹⁴³ Chatham House (2010) The Shale Gas Revolution: Hype and Reality

¹⁴⁴ IEA (2012) Medium Term Gas Market Review

¹⁴⁵ BP (2010) Response to DECC consultation on unconventional gas

¹⁴⁶ Reuters (2013) Centrica seals first US natural gas deal; 25.03.13

¹⁴⁷ US EIA (2012) US natural gas imports at lowest level since 1992; 15.03.2012

Conversion to export is expensive, and only one plant currently holds a license for export. It is not yet clear how many more will be granted, with intense debate between industrial groups keen to exploit cheap gas, and gas producers keen to exploit opportunities for export¹⁴⁸. US demand for gas is also expected to increase rapidly as both industry and power sectors take advantage of lower prices, reducing the potential size of any exports¹⁴⁹.

Finding 31

Imports of US shale gas are unlikely to have a large impact before the end of this decade, and will likely diversify imports rather than lower prices.

5.3 Prospects beyond 2020

In the longer term, current analysis suggests that although the US becomes self-sufficient in gas by 2035, demand will keep pace, resulting in little change to the global balance of supply and demand^{150,151}. If unconventional gas extraction is to make a big impact on gas markets, this will likely depend on developments outside the US. Progress in other parts of the world has been limited thus far, with production in Europe not expected to be substantial until after 2020. Exploration in Europe has also encountered public opposition, with France and Bulgaria imposing bans on fracking.

The UK

Although the development in the UK is behind that of Poland or Argentina, progress here is fairly indicative of countries in the early stages of exploration. Early assessments conducted by the British Geological Survey and US Energy Information Administration identified several potential shale gas deposits, in Lancashire, Yorkshire and the South. These preliminary estimates are listed in Table 7 to give an idea of scope. It is important to note that the estimates below use notional figures for the amount of gas that could be economically extracted. Until wells are production tested, the full costs of production will not be known. To date only one company, Cuadrilla Resources, has been exploring shale gas in the UK, with three test wells drilled.

¹⁴⁸ Reuters (2013) U.S. Energy Dept still reviewing comments on natural gas exports; 19.03.13

¹⁴⁹ IEA (2012) World Energy Outlook

¹⁵⁰ IEA (2012) World Energy Outlook

¹⁵¹ BP (2012) World Outlook 2030

Table 7: Estimates of UK shale gas potential

	Year	Technically recoverable reserves
DECC & British Geological Society (BGS)	2010	74 – 158 bcm
US Energy Information Administration (US EIA)	2011	565 bcm
Cuadrilla Resources	2011	600 bcm (Bowland Shale)
<hr/>		
Total UK gas consumption	2011	82 bcm

Sources: DECC (2010) The unconventional hydrocarbon resources of Britain's onshore basins - shale gas
 EIA (2012) World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States
 Cuadrilla 2011 <http://www.cuadrillaresources.com/what-we-do/about-natural-gas/> (assuming 10% extraction rate)
 DECC (2012) Digest of UK Energy Statistics (UK gas demand 2011)

Notes: 1) bcm is billion cubic metres

The BGS - DECC estimate is, in total, equivalent to approximately 1.5 years' worth of UK gas consumption, whereas the EIA and Cuadrilla estimates represent seven years¹⁵². Although these levels would not make the UK self-sufficient, they would diversify supply and help slow the UK's growing import dependence.

The British Geological Survey is carrying out a further examination of the Bowland shale to map deposits in more detail and provide greater certainty over the scale of the potential resource, the results of which are expected to be released in 2013. Although this will improve on current estimates, more test drilling will need to be carried out before the picture becomes clear. Drilling in the UK was suspended in 2011 after fracking at Cuadrilla's wells caused two minor earth tremors near Blackpool. Although the suspension was lifted at the end of 2012, the company has since postponed drilling at one of their three wells until 2014, pending an environmental assessment¹⁵³.

Finding 32

There is currently too little evidence on which to make reliable estimates regarding the size of UK resources, and their economic viability.

Timeframe

Shale gas production has been slow to develop in the UK. If exploration is successful, DECC suggests that production could begin to take place in the second half of this decade, although any substantial contribution to the UK's gas supply is unlikely until further into the 2020s¹⁵⁴. This was echoed by a recent report by consultancy Wood Mackenzie, which predicted that domestic shale gas is unlikely to reach significant levels before 2025¹⁵⁵. These views are informed both by the time needed for the exploration phase and UK-specific factors that could slow development.

Well productivity typically falls rapidly after fracturing, requiring new wells to be drilled into the shale and the re-fracturing of old ones¹⁵⁶. The ability to spread drilling operations rapidly, over a large area, was a key ingredient in achieving high

¹⁵² HOC (2012) Shale Gas; ECC Committee report

¹⁵³ Guardian (2012) Fracking company Cuadrilla halts operations at Lancashire drilling site

¹⁵⁴ DECC (2012) Gas Generation Strategy

¹⁵⁵ Wood Mackenzie (2013) UK Shale Gas – fiscal incentives unlikely to be enough

¹⁵⁶ DECC (2012) Gas Generation Strategy

volumes in the US¹⁵⁷. There are several key differences between the US and UK that are likely to slow down, and increase costs, of production here:

- The UK is more densely populated than the US, limiting the amount of land for development and increasing the need to gain local community acceptance.
- Fracking requires large volumes of water to be transported to and from site, creating significant visual, noise and traffic pollution, increasing the likelihood of public opposition.
- Under the UK's legal framework mineral rights belong to the crown, rather than the landowner, as is the case in the US, reducing the incentives for those leasing their land for extraction.
- A more rigorous regulatory and planning structure than the US may slow expansion to new well sites.

Public acceptance is likely to be a critical issue, with an intensely polarised public debate on the future of fracking in the UK, and several protests targeting current test wells in Lancashire. This, in addition to a greater regulatory burden, is likely to increase the costs of obtaining a 'social license' to operate in the UK, which will ultimately add to the costs of extraction.

Finding 33

Socio-economic factors in the UK mean that large scale production would be likely to take at least a decade to develop.

Unresolved environmental risks

Unconventional extraction is not without controversy. Of most concern are the as yet un-quantified risks from fugitive methane emissions released during drilling, and potential for the water and chemicals used - 75 per cent of which remain in the ground after fracking - to contaminate groundwater supplies. Fugitive emissions will increase the lifecycle carbon emissions of shale gas, and more detailed surveys are currently under way in the US.

Water use

The large volumes of water required to extract shale gas will create additional stresses on water resources, and return water will need to be strictly managed to avoid local pollution. Frack water returns to the surface lightly radioactive and containing additional chemicals¹⁵⁸. Studies by the Environment Agency on return water from Cuadrilla's test wells found higher than permitted levels of sodium, chloride, bromide, iron, lead, magnesium and zinc¹⁵⁹. Firms in the UK are required to store waste water in closed tanks, and pollutants must be removed before water can be returned to the environment. Whilst work on a regulatory regime has been conducted by DECC, the Health and Safety Executive and the Environment Agency, its efficacy if and when production activity grows remains to be tested.

UK summary

It is currently unclear what size resources the UK may have, and how economically viable these will be. If viable resources are discovered, it is likely to be several years before production begins, and large volumes are unlikely before the next decade. The risks of groundwater contamination and the carbon impact of fugitive

¹⁵⁷ Chatham House (2010) The Shale Gas Revolution: Hype and Reality

¹⁵⁸ Royal Society (2012) Shale gas extraction in the UK: a review of hydraulic fracturing

¹⁵⁹ Environment Agency (2011) North West - North West - Monitoring of Flowback water

emissions must be better understood before unconventional gas extraction is treated as simply *more* natural gas. These sentiments were echoed by Energy and Climate Change Select Committee in its 2011 report on shale gas, which concluded that in the UK, it is 'unlikely to be a game changer' to the same extent that has occurred in the US¹⁶⁰. This sentiment was further echoed by energy industry representatives at an additional evidence session held on the subject by the Energy and Climate Change Committee in January 2013¹⁶¹.

The Government has so far been supportive of developing unconventional gas in the UK. As well as conducting resource estimates, an *Office of Unconventional Gas and Oil* was set up within DECC at the end of 2012. Several tax incentives were announced at Budget 2013 to encourage investment in the industry, and the Government will consult on proposals to ensure local communities benefit from shale gas projects in their area.

¹⁶⁰ UK Parliament (2011) ECC Committee Report: Shale Gas, Vol. 1

¹⁶¹ UK Parliament (2013) The impact of shale gas on energy markets: Oral Evidence: HC 785-iii

ABOUT CARBON CONNECT

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