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Energy and Climate Change Committee

Shale Gas

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The Energy and Climate Change Committee

The Energy and Climate Change Committee is appointed by the House of Commons to examine the expenditure, administration, and policy of the Department of Energy and Climate Change and associated public bodies.

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Contents

Summary

Shale gas resources in the UK could be considerable—particularly offshore—but are unlikely to be a "game changer" to the same extent as they have been in the US, where the shale gas revolution has led to a reduction in natural gas prices. UK domestic shale gas resources could be used to increase our self-reliance, but they are unlikely to have as large an impact on our security of supply due to the limited extent of the resource. Elsewhere in Europe the impact of shale gas could be considerable; for example, Poland has potentially large shale gas resources, and the development of a Polish shale gas industry could reduce the extent to which Poland relies on imported natural gas. It is important for the UK to monitor the development of the fledgling shale gas industry in Poland, in terms of both our own prospects and the evolution of national and EU regulation in reaction to the development.

UK legislation needs to take account of the challenges unique to shale gas exploration and production; specifically the use of large volumes of hydraulic fracturing at multiple wells, which requires large volumes of fresh water and chemicals, as well as generating large volumes of waste water requiring treatment. There is no evidence that the hydraulic fracturing process poses any risk to underground water aquifers provided that the well-casing is intact before the process commences. Rather, the risks of water contamination are due to issues of well integrity, and are no different to concerns encountered during the extraction of oil and gas from conventional reservoirs. However, the large volumes of water required for shale gas could challenge resources in regions already experiencing water stress.

The Environment Agency needs to ensure that companies declare the type, concentration, and volume of all chemicals added to the hydraulic fracturing fluid. The Agency must ensure that they have the resources necessary to detect these chemicals in water supplies should an incident lead to potential contamination of water resources.

Shale gas has the potential to shift the balance in the energy markets that the Department of Energy and Climate Change has tried to create away from low carbon electricity generation. The UK needs to manage this risk if its aim is to increase the proportion of the UK's energy from renewable sources. DECC should revisit the assumptions it has made during its considerations of reform to the electricity market.

The increased availability of natural gas through the production of shale gas could lead to a switch away from coal electricity generation to gas. This would be a positive move, particularly in terms of its potential to reduce future emissions from developing economies. But DECC needs to be cautious in its approach to natural gas as a transition fuel to a low carbon economy. Although gas emissions are less than coal, they are still higher than renewables. The emergence of shale gas—and the likelihood that it will lead to the increased use of gas in power plants—means that we need to pursue with increased urgency the development of carbon capture technology suitable for gas as well as coal.

The environmental and climate risks posed by shale gas need to be balanced with its potential contribution to energy security. On balance, we feel that there should not be a

moratorium on the use of hydraulic fracturing in the exploitation of the UK's hydrocarbon resources, including unconventional resources such as shale gas. However, DECC needs to monitor closely the current exploratory activity in the Bowland Shale in order to both assess the likely impact of large scale shale gas extraction in the UK and also to promote public confidence in the regulation of this activity.

1 Introduction

1. Shale gas is an "unconventional" fossil fuel, which means that additional procedures are required to extract it beyond regular drilling. Many such unconventional sources of oil and gas were formerly too difficult (or uneconomic) to extract until recent advances in drilling technology. A combination of directional drilling and a process called hydraulic fracturing have made accessible large amounts of natural gas locked up in the tight pores of shale formations at depths of 2 km or more. Recent successes in the United States have driven prospecting across Europe. In 2010, Cuadrilla Resources Holdings Limited ("Cuadrilla") began drilling near Blackpool in the Bowland Shale (which runs from Preston to the Irish Sea).

2. Current estimates from the British Geological Society suggest that the UK's current shale gas resources are equivalent to approximately 1.5 years of current gas consumption or 15 years of the UK's current LNG (liquefied natural gas) imports.[1] More recent figures from the US Energy Information Administration (EIA) estimate that the UK has technically recoverable shale gas resources equivalent to 5.6 years' worth of consumption or 56 years' worth of LNG imports.[2] The EIA report estimates that shale gas adds 40% to the world's technically recoverable natural gas resources, mostly in China and the US.[3]

3. We launched our inquiry on 24 November 2010. We received 24 submissions of written evidence, for which we were grateful.[4] We held four oral evidence sessions during our inquiry. A full list of witnesses can be found at the end of this Report.[5] We would like to express our thanks to all those who contributed to our evidence-gathering. As part of our work on this inquiry we visited the site of Cuadrilla's UK exploration activities near Blackpool (the only shale gas operator in the UK) and also travelled to Washington DC and Fort Worth, Texas to meet state and national legislators, environmental activists and companies involved in shale gas exploration and production.[6] We are extremely grateful to those who took the time to meet us and provide us with first-hand knowledge of the opportunities and challenges facing both those who extract shale gas and those who regulate and monitor extraction activity.

4. In this Report we consider the prospects for shale gas in the UK, the risks and hazards associated with shale gas, and the potential carbon footprint of large-scale shale gas extraction. We also consider the implications for the UK of large-scale shale gas production around the world. The report continues with an analysis of the prospects for shale gas in both the UK and abroad and the likelihood of rapid depletion of reserves. Chapter Four examines the policy implications for the Government of the establishment of a shale gas industry in the UK, and the regulatory challenges to be faced by the Department of Energy and Climate Change and its agencies. Chapter Five analyses the environmental risks

[1] See Box 1 p 13

[2] US EIA, *World Shale Gas Resources: An Initial Assessment of 14 Regions outside the US*, April 2011, p 3

[3] US EIA, *World Shale Gas Resources: An Initial Assessment of 14 Regions outside the US*, April 2011, p 4

[4] List of written evidence, p 76

[5] Witnesses, p 75

[6] See Annex 1: Note of the visit to the USA

associated with shale gas, including water and air contamination. Finally, in Chapter Six we consider the potential carbon footprint of shale gas and the implications of this for the UK's emissions and climate change targets.

2 Background

What is unconventional gas?

5. "Unconventional" gas is still "natural" gas, composed, like North Sea gas and other "natural" gas" mostly of methane. Cuadrilla's CEO, Mark Miller, explained that the term "unconventional" refers "to the type of reservoir [not the technology used] […] the techniques are the same as you would use for a 'conventional' well", adding that the technology "is used in the entire [oil and gas] industry, not just in shale gas".[7] "Unconventional" is an "industry term coined years ago to describe the type of reservoir, it is not the process".[8] Jonathan Craig, Fellow of the Geological Society of London, described "unconventional gas" to us as an "additional […] not a new resource".[9] The Minister of State for Energy, Charles Hendry, told us that shale gas "is [extracted from] a new [type of] strata, but using an existing technology […] it is a new application for an old technology".[10]

6. There are three main types of unconventional gas: shale gas; tight gas; and coal-bed methane. Shale gas deposits are trapped within shale rocks. Usually the shale rock is both the source of the gas and the means of trapping it. Shale gas resources are referred to as "plays" rather than fields and they generally cover large geographical areas. Both shale and tight gas are dispersed over much wider areas than conventional gas, meaning many more wells need to be drilled to extract the same amount of gas as from conventional resources. "Thermogenic" shale gas is formed at depth under the influence of heat—the gas is often "wet", meaning the methane is mixed with other gases. In comparison, "biogenic" shale gas is formed by the action of bacteria at shallow depths, and is usually "dry" (which means that it is mostly methane)—these shallow resources can also overlie conventional oil and gas reservoirs. Professor Richard Selley of Imperial College London told us: "Shale gas has been produced since 1821 [...] the renaissance of shale gas has been [driven by] an increase in energy prices in the States obviously, but also technology".[11] He added that "The […] properties of shale vary from rock formation and from place to place",[12] which could be better understood if further geological research into shale gas was funded.[13]

7. "Tight gas" refers to gas deposits found in low permeability rock formations—this means the pores in the rock are connected poorly. In order to extract the gas the rock must be fractured to allow the gas to flow. The International Energy Agency (IEA) definition of tight gas is based upon a gas reservoir that cannot be developed by vertically drilling because of the lack of natural flow.[14]

7 Q 124

8 Q 161

9 Q 185

10 Q 283

11 Q 3

12 Q 70

13 Q 68

14 International Energy Agency, *World Energy Outlook 2009 , p 398*

8. Coal-bed methane, also known as "coal-seam gas", is natural gas contained in coal-beds. Professor Selley told us that there "is quite a long track record of coal-bed methane extraction abroad and in this country",[15] to which Nigel Smith, of the British Geological Society, added "there is a problem with CBM in the UK and Europe compared to America [...] we do not know why [...] probably the permeability of the coals are much lower in Europe and for the UK".[16]

The "quiet revolution" in Shale Gas

9. While geologists have been aware for many years that natural gas deposits existed in shale formations, it is only in the last 12 years in the US that the rate of shale gas production has increased dramatically. This "quiet revolution"—as BP's ex-CEO Tony Hayward described it—has been facilitated by the combination of "hydraulic fracturing" and horizontal drilling.[17] After drilling down vertically to above the shale formation, the drill is steered until the bore becomes horizontal and straight drilling resumes. Most fossil fuel reservoirs are much wider than they are tall, so horizontal drilling exposes significantly more reservoir to the well bore. Hydraulic fracturing, commonly referred to as "fracing" or "fracking" [both pronounced with a hard "k" sound], is the process of creating fissures, or fractures, in underground formations to allow natural gas to flow. The pressure to create these fractures is generated by the injection of a fluid—known as hydraulic fracturing fluid—down the well and into the shale gas formation. Water and sand comprise around 99% of the hydraulic fracturing fluid, the remainder being a mixture of chemicals. The newly created fractures are "propped" open by the sand, which allows the natural gas to flow into the wellbore and be collected at the surface.

10. The techniques used to harvest these gases have raised concerns about the potential environmental impacts. These concerns are both about the above ground infrastructure required and its visible impact, and also about the invisible and possibly unknown effects of fracking. But the Minister of State for Energy, Charles Hendry MP, told us that "horizontal drilling has been something that we have seen in this country and the North Sea for many years".[18] IGas Energy's CEO Andrew Austin told us that "these techniques [hydraulic fracturing and horizontal drilling] have been used elsewhere for many years, both onshore and offshore, with a strong safety and environmental record in the UK".[19] Professor Selley told us that in recent years the "technique […] has improved in leaps and bounds in terms of the drilling mud systems, the fracturing techniques [...] the drilling techniques [...] the number of wells that you can drill off a single pad, so you are minimising the environmental impact: you can get now up to 16 wells off a single pad".[20]

15 Q 60

16 Q 61

17 Tony Hayward, *The Role of Gas in the Future of Energy*, 8 October 2009, www.bp.com

18 Q 281

19 Q 161

20 Q 4

UK Onshore Drilling

11. Trying to put the issue of onshore drilling in perspective, Professor Selley told us that there "is a line of oil and gas fields around the Weald [...] There are fields there that have been producing [conventional] oil and gas for 100 years [...] there was an oil field at Formby [...] BP have done a brilliant job at Wytch Farm".[21] Wytch Farm in Dorset is the "the largest onshore oil field in Western Europe"; the Geological Society cite it as a demonstration that the industry can "successfully exploit resources […] while meeting the highest environmental and social standards".[22] Wytch Farm oil field was discovered by British Gas in the 1970s, and has been operated by BP since 1984. The Geological Society stated that "BP has set world standards in environmental protection and community engagement, using horizontal drilling at distances of more than 10km, keeping the size of well sites […] to a minimum".[23]

Moratoriums

12. The concern about the impact of more widespread use of hydraulic fracturing has produced political reactions. One of the principal concerns has been about the impact of the chemicals added to the hydraulic fracturing fluid, particularly on underground water aquifers. In May 2010, the Pennsylvania state legislature passed the Marcellus Shale Bill that enforced a three-year moratorium on further leasing of exploration acreage until a comprehensive environmental impact assessment has been carried out.[24] On 3 August 2010 New York State issued a temporary moratorium on new shale gas activity. This moratorium suspended the issuing of "new permits for horizontal drilling which utilizes the practice of hydraulic fracturing in the state" until after the US Environmental Protection Agency (EPA) has reported on its study of shale gas.[25] This EPA study is into the potential impacts of hydraulic fracturing on drinking water, and is due to publish preliminary findings in 2012.[26] It is interesting to note that Cuadrilla (exploring for shale gas near Blackpool) intend to undertake exploratory hydraulic fracturing in combination with vertical drilling, rather than horizontal drilling, so a New York-style moratorium would not apply to their activities.[27]

13. At the US federal level, on 9 and 10 June 2010 two identical bills named the Fracturing Responsibility and Awareness of Chemicals (FRAC ACT) were introduced in both the US House of Representatives (HR2766) and Senate (S1215). These bills were proposed in the previous session of Congress and never became law.[28]

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[21] Qq 26–27

[22] SG15a

[23] SG15a

[24] "Pennsylvania lawmakers say bill that halts drilling in Marcellus Shale aims to protect forest", *Pennsylvania Live*, 28 March 2010, www.pennlive.com

[25] Bill A10490A-2009, State of New York, April 2010

[26] US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011

[27] Ev 78 (Cuadrilla)

[28] S. 1215: Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, US Senate, June 2009, www.govtrack.us/congress/bill.xpd?bill=s111-1215

14. In response to our call for evidence, WWF stated that it did not believe that shale gas production should be allowed to take place in the UK. At the very least it considered that "no permits should be granted for shale gas activity [...] until there is a robust scientific consensus demonstrating exactly what the risks are".[29] The Tyndall Centre thought that issues relating to local pollution "leaves little doubt that in the absence of a much improved understanding of the extraction process shale gas should not be exploited within the UK".[30] On 26 January 2011 the Labour Party called for a temporary halt to drilling for shale gas while its safety is checked.[31]

15. On 2 February 2011, French Minister for Ecology Nathalie Kosciusko-Morizet announced that France would be conducting an assessment of shale gas's environmental impact. The French Environment Minister added that no authorisation for work on shale gas would be given before the outcome of this mission.[32]

16. On the other hand, Jonathan Craig—a Fellow of the Geological Society of London—told us "the fracing of wells has been going on traditionally since the 1950s […] the first well that was fraced ever in the world was […] in the 1820s".[33] He added that "having bad cement jobs on your wells" can result in contamination of local water aquifers, "but that is exactly the same in conventional hydrocarbon exploration […] the fracs themselves are not the cause of contamination".[34] Tony Grayling of the Environment Agency told us the Agency would not advise the Government that a moratorium was "necessary on the grounds of environmental risks as we understand them at the moment".[35]

17. **Mitigation of the risk to water aquifers from hydraulic fracturing relies on companies undertaking the proper measures to protect the environment from pollution. However, there is no evidence that the hydraulic fracturing process itself poses a direct risk to underground water aquifers. That hypothetical and unproven risk must be balanced against the energy security benefits that shale gas could provide to the UK. We conclude that, on balance, a moratorium in the UK is not justified or necessary at present. But evidence must continue to be collected and assessed. We recommend that the Department of Energy and Climate Change monitor current drilling activity in the Bowland Shale formation extremely closely during its early stages in order both to assess the likely environmental impact of large scale shale gas extraction in the UK and also to promote public confidence in the regulation of the activity.**

[29] Ev 100 (WWF)

[30] Ev 86 (Tyndall)

[31] "The Labour Party calls for shale gas drilling halt", *BBC News Online*, 26 January 2011

[32] "French Ministers Addresses Shale and Environment", *BBC News Online*, 4 February 2011

[33] Q 198

[34] Q 198

[35] Q 240

3 Prospects for Shale Gas

UK Shale Gas Estimates

18. There have been estimates that the UK could be producing 10% of its current gas needs from shale gas if it could be extracted at a commercial rate, but the British Geological Survey (BGS) noted that this figure was based on figures from the US a year ago, when "shale gas contributed about 10% of their needs", which in 10 years' time would be "30% or more".[36] They estimated that—by analogy with similar producing shales in the US—the UK's shale gas reserve potential could be as large as 150 bcm (billion cubic metres). This is equivalent to approximately 1.5 years of the UK's current gas consumption, or 15 years of the UK's current LNG (liquefied natural gas) imports.[37] However, the Barnett Shale in the US—which was used as an analogy for UK shale potential in the BGS's calculation—is described by the Tyndall Centre as "an above-average producer due to its low clay content [which allow fractures to form more easily]". The Minister told us that DECC's "initial feeling is that there will be reserves [in the UK] but it will not be on the scale of Poland or the United States and it will be more complicated to extract here than it will be in other countries".[38]

19. In April 2011 the US Department of Energy's independent statistical and analytical agency, the Energy Information Administration (EIA) published their report *World Shale Gas Resources: An Initial Assessment of 14 Regions around the United States*.[39] This report estimated that the UK had 20 trillion cubic feet of technically recoverable shale gas resources, or 560 bcm. This is equivalent to 5.6 years' of the UK's current gas consumption, or 56 years' worth of LNG imports.[40] The EIA estimated that in Europe, the two most promising countries were Poland (3,740 bcm) and France (3,600 bcm), while globally the US (17,240 bcm) and China (25,500 bcm) have the largest estimated technically recoverable shale gas resources. The report estimate that shale gas could increase world technically recoverable gas resources by 40% to approximately 452,000 bcm.

20. However, the Geological Society of London admitted that "there is currently no clear consensus within the Earth Science community regarding the quantity of these [unconventional] resources" either in the UK or Europe.[41] Professor Selley of Imperial College London told us that one of the problems with a lot of non-conventional petroleum—oil and gas—is it is very hard to work out the reserves. The Geological Society believed that further research will improve understanding, "for example, by helping identify 'sweet spots' in gas plays" [42].

[36] Ev 71 (BGS)

[37] See Box 1, p 13

[38] Q 324

[39] US EIA, *World Shale Gas Resources: An Initial Assessment of 14 Regions outside the US*, April 2011

[40] See Box 1 p 13

[41] Ev 92 (GSoL)

[42] Q 3

21. The British Geological Survey (BGS) believed that the lowest shale gas exploration risk lies where "source rocks have accompanying conventional hydrocarbon [oil and gas] fields". Figure 1 shows UK shale gas prospects including the Upper Bowland Shale[43] (the source rock for the Irish Sea conventional fields, and where Cuadrilla are exploring), and both the Kimmerage Clay and Lias[44] of the Weald Basin (source rocks for the North Sea and English Channel fields).[45] Cuadrilla pointed out that "these same shales are the source of hydrocarbons found in most of the UK's conventional oil and gas".[46] With regard to this, the BGS noted that as conventional and unconventional sources of oil and gas both derive from the same source rocks, there will be some relationship between their productions.[47]

Box 1—Units and Equivalents

The BGS estimateD that—by analogy with similar producing shales in the US—the UK's shale gas reserve potential could be as large as 150 bcm [billion cubic metres]. This is very large compared with the 2–6 bcm estimate of undiscovered onshore conventional petroleum.

In 2009 the UK total demand for natural gas was approximately 1,000,000 GWh [giga/billion Watt-hours] of energy. This was equivalent to approximately 100 bcm. So the UK shale gas reserve potential was equivalent to approximately 1.5 years of the UK's current gas consumption.

DECC statistics stated that in 2009 the UK imported 110,579 GWh of liquefied natural gas [LNG]. This was equivalent to approximately 10 bcm. So the UK shale gas reserve potential could replace LNG imports for approximately 15 years.

Current wholesale gas prices are approximately 53p/therm.' This would mean that 150 bcm of gas was worth approximately £28 billion. If the Government takes approximately one third of this in tax, the UK gets about £9 billion.

1 tcm = 1 trillion cubic metres = 1000 bcm 1tcf = 1 trillion cubic feet = 28 bcm

22. Nigel Smith of the BGS told us:

> There are probably four good plays that they [industry] could try [...] the Namurian; the second one would be the Weald and the Wessex Basin [...]; the third one is also quite risky, and that is the Cambrian play in central England, going into Wales; and then the fourth one would be looking in the fold belts [where once flat, stacked geological strata have become curved or bent on a regional scale].[48]

[43] Namurian Stage rock containing organic matter from 313-326 million years ago.

[44] Jurassic Stage rock containing organic matter from 145-199 million years ago.

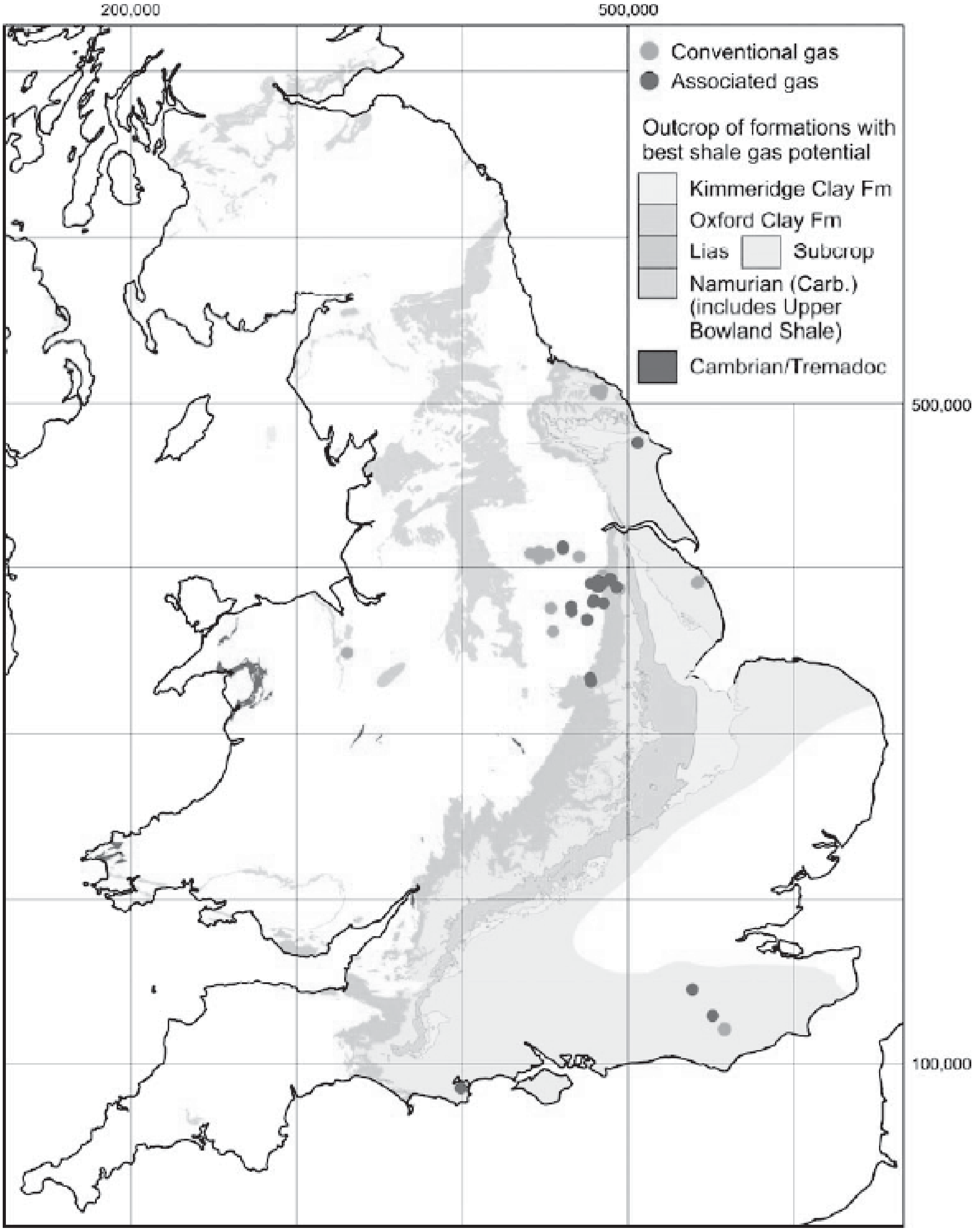
[45] Ev 71 (BGS)

[46] Ev 78 (Cuadrilla)

[47] Ev 71 (BGS)

[48] Q 17

Figure 1—Onshore Shale Gas Resources of Great Britain



Source: DECC, The Unconventional Hydrocarbon Resources of Britain's Onshore Basins-Shale Gas, December 2010, Cover

23. Regarding the potential amounts available, Nick Grealy—of gas policy website *No Hot Air*—told us, "I do not think people really quite understand the amounts of gas that are available [...] the United States, from 2007 to 2009, increased their estimates of available resources by 40% over two years [...] we may even be looking to an increase on that".[49] The Minister told us that, "In terms of the global impact of shale [...] it is a game changer". However, in terms of the UK's own shale gas deposits, he said "it is too early to know at the moment".[50]

24. **We conclude that shale gas resources in the UK could be considerable. However, while they could be sufficient to help the UK increase its security of supply, it is unlikely shale gas will be a "game changer" in the UK to the same extent as it has been in the US. It is more likely that in countries such as Poland—with a larger reliance on gas imports and greater potential shale gas resources—the impacts of shale gas production will be significant.**

UK Exploration and Production

25. Cuadrilla Resources Holdings Limited ("Cuadrilla") describe themselves as an "English independent oil and gas company based in Lichfield, Staffordshire, pursuing an unconventional hydrocarbon [oil and gas] exploration programme".[51] Cuadrilla has drilled two wells so far; the first at Preese Hall-1, the second at Grange Hill-1. Cuadrilla began drilling for shale gas at Preese Hall-1—located approximately five miles east of Blackpool—in August 2010.

26. Cuadrilla completed Phase 1 of the exploration at Preese Hall-1 in December 2010, during which they found indications of natural gas.[52] Phase 2 of the exploration commenced in 2011 and is expected to last three to six months. CEO of Cuadrilla Resources, Mark Miller, told us, "Once we have completed the wells in the exploration phase we will try to test those wells, see how commercial they are [...] so we can make a commercial decision whether we want to drill additional wells".[53] Mr Miller explained to us that exploration data is "kept confidential in the early stages".[54]

27. IGas Energy (IGas, or Island Gas) was set up in 2003 to "produce and market domestic [UK] sourced gas from unconventional reservoirs, particularly coal bed methane (CBM)". Coal-bed methane, also known as "coal-seam gas", is natural gas contained in coal-beds and is often extracted using hydraulic fracturing technology. It is normally exploited from virgin coal seams when the coal-bed itself is considered commercially sub-optimal. The CEO of IGas Energy, Andrew Austin, told us that his company has "pilot operations ongoing in coal bed methane [CBM] right now, producing gas from our site at Doe Green in Warrington and generating electricity and selling that".[55]

[49] Q 178

[50] Q 279

[51] Ev 78 (Cuadrilla)

[52] Ev 78 (Cuadrilla)

[53] Q 118

[54] Q 121

[55] Q 122

28. IGas production licences "cover a gross area of approximately 1,756 km^2 across Cheshire, Yorkshire, Staffordshire and the North Wales coast".[56] Based on "contingent recoverable resource estimates" IGas believe they have "enough gas to supply electricity to over seven per cent of UK households for 15 years".[57] While IGas has focussed on CBM resources, they have identified "a significant potential shale resource within its acreage" which preliminary estimates put at "1.9 trillion cubic feet [53.2 bcm]". [58]

International Prospects and UK-US Comparisons

29. According to the US Energy Information Administration (EIA), during the last decade, US shale gas production has increased fourteen-fold; it now accounts for 22% of gas production and 32% of total remaining recoverable gas resources in the US. By 2030, the EIA projected that shale gas would represent 14% of total global gas supplies.[59] At a recent oil and gas conference in Houston, ExxonMobil's America's Vice President for Natural Gas, Steve Kirchoff, stated his belief that "unconventional sources of natural gas could represent 70% of US gas supplies by 2030".[60]

30. Dr Ken Morgan, Professor of Geology and Director of Texas Christian University's Energy Institute, has discussed the opportunities for shale gas as a fuel in the transport sector. An increase in the number of vehicles capable of using natural gas fuel would allow the US to use shale gas production to displace some of its oil imports. Of the 16–17 million barrels of oil the US imports per day, he told us that 10 million barrels is imported, and 70% of that is used for transport.[61] Dr Morgan noted that there are less than 150,000 natural gas vehicles (NGVs) in the US at the moment, but he believes that the US could be on the verge of entering the "Golden Age of Natural Gas".[61]

31. Schlumberger describes itself as "the leading oilfield services provider".[62] Schlumberger's Chief Operating Officer of Oil Services—Paal Kibsgaard—has said that "We are convinced that the brute force approach [in other words, drilling many individual wells until a viable "play" of gas was found] established in North America will not be practical overseas, either from a financial or an operational standpoint",[63] adding that "We need to establish a workflow and corresponding technology offering built around a better evaluation of shale gas reservoirs […] the goal will be to only drill the best wells, and only stimulate the best intervals, while we continue to look for [fracturing] solutions that further minimize the usage of both water and proppant [sand]".[63] Andrew Gould—Schlumberger's Chief Executive of Oil and Gas Services—has said that the "drilling and producing of shale

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[56] Ev 75 (IGas)

[57] Ev 75 (IGas)

[58] Ev 75 (IGas)

[59] US Department of State, *Global Shale Gas Initiative (GSGI),* May 2011, www.state.gov/s/ciea/gsgi/index.htm

[60] "Unconventional Gas may form Majority of U.S. Supplies", *Natural Gas for Europe*, 19 November 2010, http:*//naturalgasforeurope.com/?p=5365*

[61] Ken Morgan, "Shale Gas—the Game Changer", TCU Energy Institute, www.zeitenergy.com/presos/Morgan.pdf

[62] "About Schlumberger", *Schlumberger,* www.slb.com/about.aspx

[63] "Schlumberger COO: Current Shale Methods Won't Work Overseas", *Natural Gas for America*, 23 February 2011, http://naturalgasforamerica.com/?p=2006

gas in Central Europe will be very different from doing so in the southern United States for financial and logistical, social and regulatory reasons”.[64]

32. Cuadrilla’s Executive Director Dennis Carlton told us that the current UK regulatory regime “is a better system than [in] North America in that […] every well has its own drilling plan”.[65] The Minister also claimed that the UK has a “much more cohesive system of regulation […] that applies across the whole of the country.[66] DECC described UK regulation as “well-designed with clear lines of responsibility among several different bodies including DECC, the HSE, the respective Environment Agency, and Local Planning Authority”.[67]

33. Shell drew our attention to existing shale gas exploration in Sweden, Germany, Ukraine, South Africa and China as well as coal-bed methane assets in Eastern Australia and China.[68] Table 1 on page 17 sets out the estimated global unconventional natural gas resources in place. Professor Stevens of Chatham House noted that a National Petroleum Council Report in 2007 estimated global unconventional gas resources at five times conventional gas reserves,[69] whilst Shell quoted an International Energy Agency estimate that unconventional gas resources were equivalent to 123 years of current global production.[70] However, whilst the figures seem exciting, Jonathan Craig of the Geological Society told us that the “real issue is how much of that gas is producible technically and commercially […] there are resources […] a significant portion—maybe 20% to 30%—of those are technically producible. You then have an economic overlay [to consider] on top”.[71]

34. ExxonMobil Exploration and Production Poland (EMEPP), based in Poland, told us that they were awaiting analysis of drilling results from two wells (as of April 2011) to see whether there further operations, including hydraulic fracturing, will take place at these sites.[72] They have also undertaken surveys in three other areas, and have commenced them in a fourth. ExxonMobil told us that they believed, “unconventional resources will increasingly contribute to European supply” and that they expected it to contribute “about 10% of total supply by 2030”.[73]

[64] “Schlumberger Chief Say Shale Gas in Europe Faces Challenges”, *Natural Gas for Europe*, 13 October 2010, http://naturalgasforeurope.com/?p=4270

[65] Q 163

[66] Q 280

[67] Ev 66 (DECC)

[68] Ev w19 (Shell)

[69] Ev w24 (Chatham House)

[70] Ev w19 (Shell)

[71] Q 190

[72] Ex w40 (Exxon)

[73] Ev w40 (Exxon)

Table 1—Global Unconventional Natural Gas Resources in Place (trillion cubic metres)

	Tight	Coal-bed	Shale	Total
Middle East and North Africa	23	0	72	85
Sub-Sahara Africa	22	1	8	31
Former Soviet Union	25	112	18	155
Asia-Pacific	51	49	174	274
North America	35	85	109	233
Latin	37	1	60	98
Europe	12	8	16	35
-Central and Eastern	2	3	1	7
-Western	10	4	14	29
World	210	256	456	921

Source: memorandum from DECC (Ev 57)

35. The Oxford Institute of Energy Studies (OIES) identified a number of barriers to unconventional gas exploration in Europe. It believed that to take advantage of such resources there were five requirements for European governments:

- a much more R&D-based and "sweet-spot" focused approach to drilling (identifying areas of high productivity);
- new technology developments that reduced the number of wells needed, allowed for the reduction and recycling of water volumes used in fracing operations, and gave the ability to drill longer laterals;
- government incentives and regulatory reform,
- the expansion of a home-grown trained service workforce; and
- financial compensation to local communities.[74]

36. DECC identified the following factors when comparing the US situation to that in UK, Europe and the rest of the world:

- a lack of production experience outside of the US leads to uncertainties about the extent to which other resources can be exploited;
- the price required to incentivise investment will depend on the productivity and cost of the well;

[74] Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", *OIES*, December 2010

- Europe has a well developed regulatory framework;
- Europe has a high population density compared to the US;
- US law grants landowners rights over hydrocarbon resources rather than conferring ownership on the state;
- poor gas infrastructure in developing economies; and
- unconventional exploration technology and expertise is generally confined to the US.[75]

37. **We conclude that it is important for the UK to monitor the development of shale gas in Poland—the "barometer of Europe" on this issue—both in terms of exploration and regulation. We are concerned that there could be adverse competitive consequences for the UK if Poland unilaterally develops its shale gas resources within the EU, particularly if their energy policy is driven by energy security—in spite of the environmental concerns associated with hydraulic fracturing—owing to their reliance on imported gas.**

The Risks of Rapid Depletion of Shale Gas

38. "Decline rates" describe the rate at which the production of gas or oil wells decline over time. For illustrative purposes, the two extremes of the decline curve are shown in Figure 2. Using arbitrary data, this figure demonstrates the two characteristic ways that gas reserves can decrease with time—the pessimistic decline rate sees the reserve deplete rapidly to zero, while the optimistic decline rate sees a more gradual decrease in the reserve followed by a long period of production at a low level. The commonly held view is that the decline curve of shale gas wells flattens out over time, but maintains a low level of production for a significant period—this is the optimistic ("hyperbolic") view.[76] A smaller group of commentators believe that production will fall to very small levels relatively quickly—this is the pessimistic ("exponential") view. Professor Paul Stevens of Chatham House observed "although unconventional gas resources were estimated to be five times those of conventional gas, there was concern that [due to the nature of unconventional reservoirs] their depletion rates are much faster".[77]

39. Cuadrilla (who take the hyperbolic view) told us that the only "scientific method currently available to estimate these [depletion rate] factors for UK shale formations is by analogy to commercial North American shale plays", adding that "long-term shale gas production decline rates remain projections rather than based on scientific facts".[78] They explained that "in common with other unconventional gas wells, [a typical shale gas well] will witness steep early production decline rates—typically of around 30% to 40% for one to two years—followed by up to 50 years of commercial life at low decline rates, typically 5% to 7%". OFGEM told us that "experience from the US indicates that although

[75] Ev 57 (DECC)

[76] "Debate over shale gas fires up", *Financial Times*, 10 October 2010

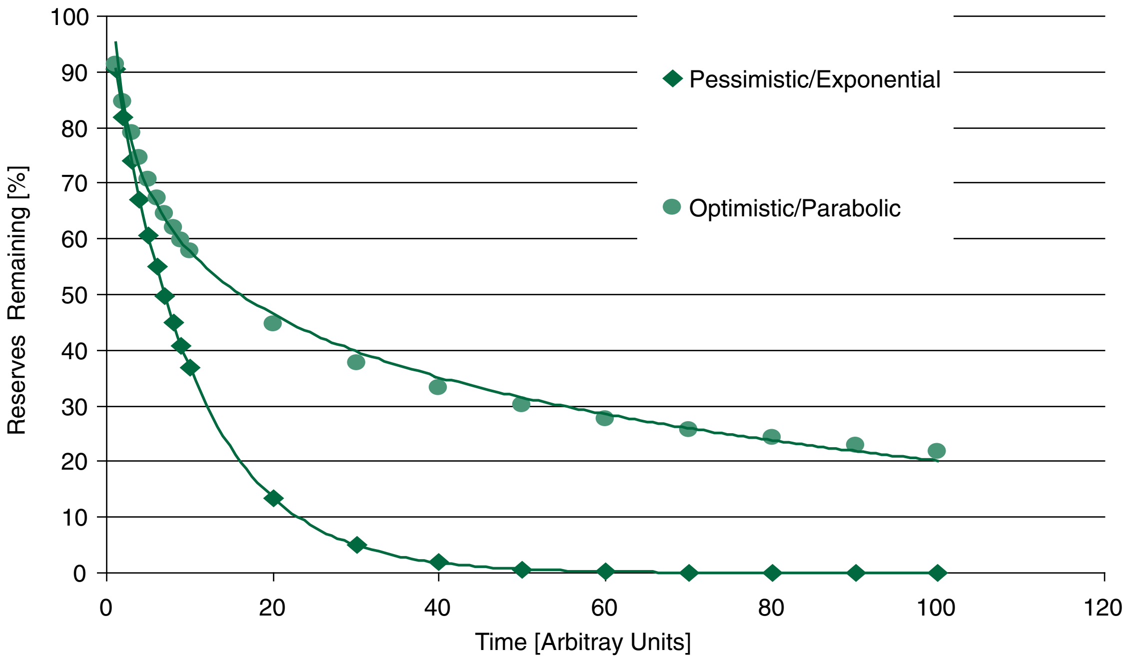
[77] Paul Stevens, "The 'Shale Gas Revolution': Hype and Reality", *Chatham House*, September 2010, p vi

[78] Ev 78 (Cuadrilla)

unconventional gas wells deplete faster than conventional wells production levels can be improved by re-fracturing of wells”.[79]

40. The pessimistic view of depletion rates raises the spectre of abandoned well heads scattered over the landscape. Over the past decade shale gas exploration and production has moved from rural to urban areas in Texas. One of the issues encountered has been abandoned wells—with production levels too low to be economic—that can then not be built upon. The Texas Railroad Commission, the State’s oil and gas regulator, now requires operators to hold bonds with the authorities (proportional to the number of wells they are working on) in order to discourage abandonment of well ownership. This goes to fund an “orphaned wells” plugging programme, which is a cleanup programme set up to deal with Texas’ legacy of old abandoned wells.

Figure 2—Optimistic and Pessimistic Shale Gas Depletion Rates



41. **In the crowded UK we cannot afford to risk the creation of contaminated and abandoned sites where shale gas production has stopped. The prospect of such a risk must be carefully considered when licences and other permissions are granted. We recommend that DECC should require that a fund be established to ensure that if wells are abandoned they can be “plugged”. Such a fund could be established through a levy on shale gas well drilling or an upfront bond. Arbitrary**

The North Sea and Offshore Shale Gas

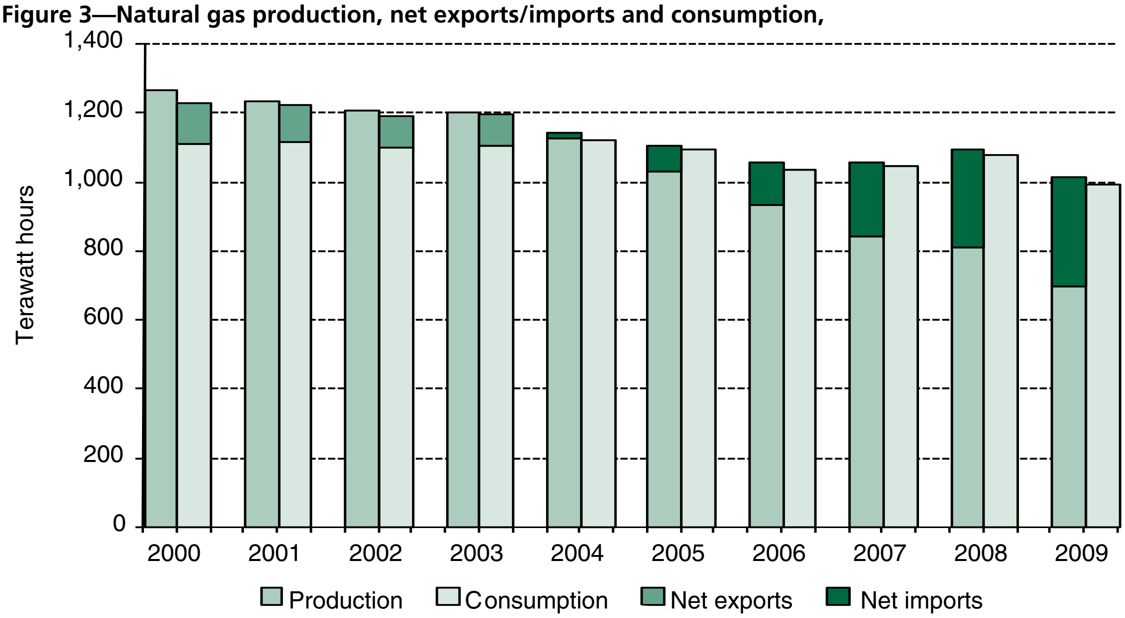
42. Conventional oil and gas production from the North Sea is in decline, and while there is still the potential for significant new discoveries, they are unlikely to match the billion barrel fields that were found in the 1970s. It is interesting to note that the decline of UK gas

[79] Ev w13 (Ofgem)

production has been much quicker than that of oil. Figure 3 shows that imports of gas grew gradually from 2004 until by 2009 they were equivalent to 32% of consumption. In 2009, 58% of the imports came from Norway, 16% came from the Netherlands, 2% came via the Belgian interconnector, and 25% were LNG imports.[80]

43. When pipeline transportation of natural gas is not possible, the gas can be cooled to minus 162°C at which point the methane condenses into a liquid, known as LNG.[81] This cooling to a liquid reduces the volume of the gas by approximately 600 times. This LNG can then be shipped in an LNG tanker over long distances. Shipping LNG is an expensive process and therefore requires high natural gas prices to make it worthwhile. The most expensive part is building and running the liquefactions plant that cools and condenses the gas into a liquid. Once LNG has reached its destination, it needs to connect to a re-gasification terminal with storage facilities and connections to regional gas pipelines.

Figure 3—Natural gas production, net exports/imports and consumption,



Source: DECC, Digest of UK Energy Statistics 2010, Chart 4.1 p 97

44. The British Geological Survey (BGS) told us that UK "offshore shale gas would have the size to affect the [potential reserve] figures more dramatically [than onshore]", especially as "UK onshore basins are small in comparison with UK offshore and US onshore basins".[82] However, the BGS reports for DECC on unconventional resources did not investigate offshore potential. The Tyndall Centre says "the costs [of offshore shale] […] would make such projects economically unviable at current market prices".[83] The Geological Society believe that if the UK were to look into offshore for unconventional gas, it would require a pioneering approach on the part of the UK as the expertise does not exist anywhere else.[84] But it is also interesting to note that deepwater drilling was once considered "unconventional".

[80] DECC, *Digest of UK Energy Statistics 2010*,Chapter 4 p 100

[81] Morgan Downey, *Oil 101*, Wooden Table Press, 2009, p 176

[82] Ev 71 (BGS)

[83] Ev 86 (Tyndall)

[84] Ev 92 (GSoL)

45. Nigel Smith of the BGS told us "I think if we went offshore, we could become [self] sufficient [in gas]",[85] he added that "UK onshore basins are small in comparison with UK offshore basins".[86] Describing the magnitude of difference between offshore and onshore deposits, Mr Smith told us, "say five to ten, something like that. It is massive, the North Sea".[87] In a discussion of the potential benefits of offshore drilling, Professor Selley of Imperial College London told the Committee that "you don't have people for a start".[88] Nigel Smith added that it "is [also] easier to acquire [...] [geological information, and in many cases it] already exists[s] so in a lot of ways the data is better offshore".[89] On offshore shale gas exploration, Cuadrilla's CEO Mark Miller told us "in general the procedures would be the same […] all the issues are identical whether you are onshore or offshore. It is only the type of equipment that you work with [that is different]".[90]

46. The Minister believed that if shale gas development was going to occur offshore "it would be likely that it would be horizontal drilling reached from onshore facilities".[91] DECC's Simon Toole then referred to operations like this at BP's Wytch Farm oil field, "where there is a concentrated set of wells [comparable to multi-well pads] that go out under near the shore".[92] The Minister added that DECC's view at the moment was that "the costs for doing this offshore are so great that it is not going to be viable with the price of gas where it is".[93]

47. **There is substantial evidence that UK offshore unconventional gas resources could dwarf the potential onshore supplies. While these might be economically unviable at present, "uneconomic" reserves can become economic quickly as technology and prices shift. We recommend that DECC encourage the development of the offshore shale gas industry in the UK, working with HM Treasury to explore the impacts of tax breaks to the sector.**

Gas Pipelines Transmission Networks

48. National Grid Gas (NGG)—owner and operator of the national gas transmission system throughout Great Britain and the Isle of Grain (Kent Coast) LNG import facility—says there are likely to be technical challenges surrounding the transmission of shale gas, "in particular the UK requirements for gas quality and for [network] entry capacity [requirements]".[94] SSE (formerly Scottish and Southern) stated that the UK's "existing gas distribution work, which is one of the most developed in the world" could offset the higher production cost of shale gas.[95] Chatham House's Professor Paul Stevens pointed out that

[85] Q 63

[86] Ev 71 (BGS)

[87] Q 37 [Smith]

[88] Q 44

[89] Q 45

[90] Q 158

[91] Q 281

[92] Q 281

[93] Q 283

[94] Ev w7 (NG)

[95] Ev w9 (SSE)

access to the gas grid in the US is based upon "common carriage", which means "any gas supplier can gain access to the grid even if it is already operating at full capacity".[96] Whereas, in Europe, access is based upon "third part[y] access", which means if the system is operating at full capacity "there is no access unless dedicated new pipelines are built".[97]

49. Scotia Gas Networks (SGN) is the UK's second largest gas distribution company, with 5.7 million customers and 74,000 km of gas mains.[98] It believed that as shale gas wells will be distributed over a wide area across the UK, they were "likely to need large numbers of smaller scale connections to gas distribution networks than typical gas wells".[99] However, SGN also noted that "the [already] large scale and wide coverage of the gas distribution network could […] increase the speed at which shale wells can connect to the system".[100]According to Shell, shale gas was likely to meet regional and national market demands in the first instance, as rapid growth in unconventional gas production was "likely to require new investment in European gas transport infrastructure" to facilitate pan-European sales.[101]

50. However, it is interesting to note the potential option to generate electricity on site at the shale well. An example of this is Cuadrilla's Elswick site, located near Blackpool, which we visited in March. The Elswick site was commissioned in July 1996, and is a natural gas to electric generation power plant, which means the power plant sits on top of the gas formation, negating the need for gas transmission (sometimes referred to as "gas-to-wire").[102] It has been producing natural gas and generating electricity since 1998, and originally produced 1MW of power.[102]

51. The Minister told us he thought it was more likely that shale gas would be extracted and used for generating electricity on site than transported through pipelines: "I think Cuadrilla's interest has been their closeness to the electricity grid rather than their closeness to the gas grid".[103] As well as being input directly into the grid, the Minister suggested to us that electricity generated from shale gas could "be linked into a renewable resource [such as wind generated electricity] and, therefore you have the gas that is available to generate the electricity when the renewable resource is not there".[104]

52. During our recent visit to the US, we met with the Mayor of Fort Worth in Texas. There, the shale gas industry began by exploring in rural areas, but then encroached upon the city itself as it had identified "sweet spots" where the gas could be more easily extracted. "Sweet spots" were described by Nigel Smith of the BGS as "places where you get higher productivity".[105] The Mayor told us that that pipelines—which transport the extracted shale

[96] Ev w24 (Chatham)

[97] Ev w24 (Chatham)

[98] Ev w11 (SGN)

[99] Ev w11 (SGN)

[100] Ev w11 (SGN)

[101] Ev w19 (Shell)

[102] "Elswick Gas Field", *Warwick* Energy, www.warwickenergy.com/oandg/OAGelswick.htm

[103] Q 316

[104] Q 317

[105] Q 20 [Smith]

to compressor stations before it is injected into the gas mains—had become a major issue, and one they wished they had dealt with at the outset. Each operator could have their own set of pipelines, leading to multiple sets across the city. They acknowledged that a lot of unnecessary duplication could have been avoided if companies had been made to work together and share pipelines.

53. There is a suite of environmental legislation, including Environmental Impact Assessment (EIA) that is applicable to pipelines for the onshore oil and gas industry in England, Scotland and Wales. The aim of EIAs is to determine the likely effects of new developments on the environment, and ensure these effects are taken into account before the development is allowed to go ahead. The Town and County Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999 and the Environmental Impact Assessment (Scotland) Regulations 1999 require an EIA to be undertaken for "pipelines for the transport of gas […] and a length of more than 40 kilometres". For smaller gas pipeline projects, an EIA is only required "if the development is likely to have a significant effect on the environment" as determined by the local authority.[106]

54. **Planning for any new gas transport infrastructure required to exploit shale gas should take into account the opportunity to minimise disruption and costs by sharing pipelines between different companies operating near to each other. We recommend that the Government consider amending the Town and County Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999 to require Environmental Impact Assessments for smaller gas pipeline projects, with the aim of avoiding unnecessary duplication of infrastructure.**

[106] "Environmental legislation applicable to the onshore hydrocarbon industry (England, Scotland and Wales)—4. Environmental Impact Assessment", *DECC Oil and Gas*, www.og.decc.gov.uk

4 UK Policy Implications

Gas Markets and Prices

55. Professor Paul Stevens of Chatham House told us that "gas is essentially a regional rather than a truly global market because of the 'tyranny of distance' […]—the high cost of transporting gas, which is a high-volume, low-value commodity—restrict[ing] trade to specific regions [and leading to] a range of regional prices".[107] He added that compared to oil "gas has much less flexibility in terms of transport and trade".[108]

56. DECC noted that the extent to which shale gas production in the US affected global markets depended on the "extent to which it exceeds, or falls below, market expectations and therefore helps push the global market into over- or under-capacity". The US's net imports are projected to fall from 2.6 tcf [72.8 bcm] in 2009 to 1.3 tcf [36.4 bcm] in 2025 and 0.3 tcf [8.4 bcm] in 2035.[109] However, the Geological Society believed that the impact of US shale gas on global gas markets is often overstated and any reduced US dependence on LNG has been largely offset by rapidly increasing demand in the Middle East, Latin America and South and East Asia.[110]

57. Professor Paul Stevens believed it was possible that shale gas could replicate the conditions in the oil industry in the 1970s that led to the formation of OPEC, and could lead to the formation of an "Organisation of Gas Exporting Countries (OGEC)" to control supply and prices.[111] OPEC was formed in the 1960s, but it was not until the 1970s (when OPEC countries controlled the majority of the world's spare oil capacity) that they began to set production quotas in order to influence international oil pricing.[112] Professor Stevens observed that since "Eleven gas-exporting countries attended the first ministerial 'seminar' in Tehran in 2001 which resulted in the establishment of the Gas Exporting Countries Forum (GECF) […] there has been constant speculation about the possibility of the GECF turning into an OGEC and trying to behave like a cartel". He added that "if prices stay low or go even lower […] there is a strong incentive for GECF to step in to try to defend falling prices […] it was precisely this mechanism that prompted the creation of OPEC in 1960". However, Jonathan Craig—Fellow of the Geological Society of London—told us that the distribution of "unconventional gas resources is much wider than that of conventional resources, so a lot of countries come into play" making "the chances […] quite slim" that an OPEC-like cartel for gas could form.[113]

58. Scotia Gas Networks (SGN) believed that if "the availability of the gas resources increase through the production of shale gas, wholesale prices could be reduced" which would result in the increased use of gas and potentially lead to lower greenhouse gas

[107] Paul Stevens, "The 'Shale Gas Revolution': Hype and Reality", *Chatham House*, September 2010, p 1-2

[108] Paul Stevens, "The 'Shale Gas Revolution': Hype and Reality", *Chatham House*, September 2010, p 1-2

[109] Ev 57 (DECC)

[110] Ev 92 (GSoL)

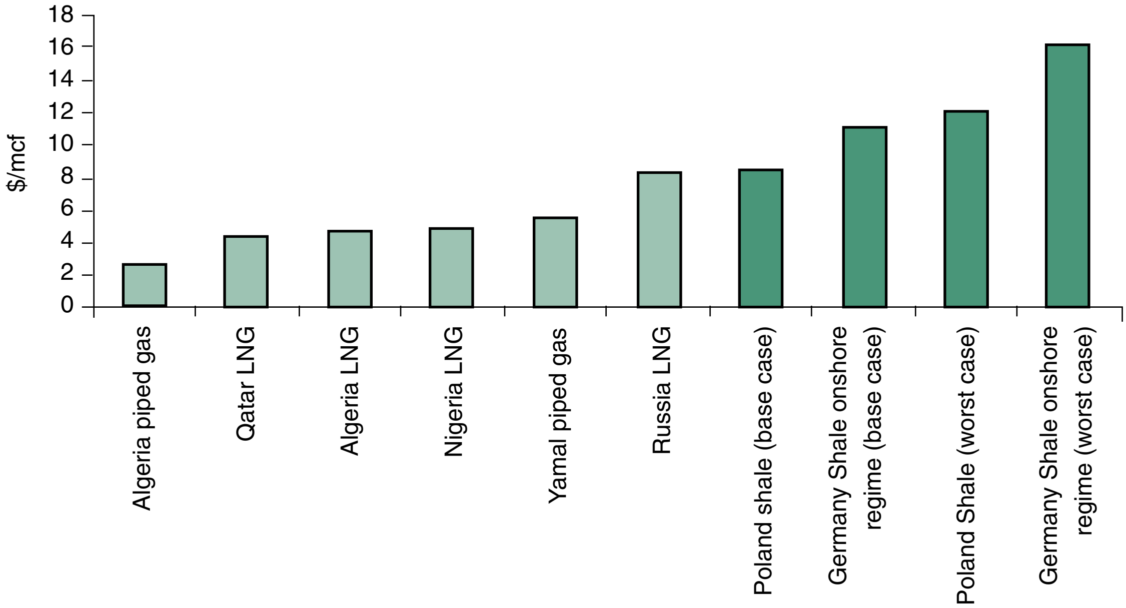
[111] Paul Stevens, "The 'Shale Gas Revolution': Hype and Reality", *Chatham House*, September 2010, p vi

[112] Morgan Downey, "Oil 101", *Wooden Table Press, 2009,* p 11

[113] Q 180

emissions. However, SSE believed that owing to the relatively high production cost of shale gas most of the potential resource will not be commercially viable unless the whole sale price of gas were to rise in the future.[114] They added that the discovery of large shale gas resources around the world could benefit the UK through further reducing wholesale prices by widening the gap between supply and demand. However, Mr Mitchell (Chair of the Blackpool Green Party) believed that the "cost of the processes involved in fracking, disposal of waste and of infrastructure, including new roads and treatment centres, will add to energy prices".[115] Figure 4 is a chart from the Oxford Institute of Energy Studies (OIES) estimating the costs of European shale gas production versus other new sources of supply in 2020 (note \$/mcf means \$ per thousand cubic feet).

Figure 4—estimated costs of European shale gas versus other supplies in 2020



Source: Memorandum from Ofgem (Ev w13)

59. Further cost analysis from OIES calculated that unconventional natural gas would have a break-even price of \$8-12/mcf (\$8-12/28.3 cm or \$8-12/MBtu), which led them to the conclusion that unconventional gas "will hardly be cost competitive with gas imports over the next decade". [116] They added that to ensure production subsidies would be needed if future gas prices fail to reach a level close to \$10/mcf.[117]

60. The International Energy Agency (IEA) has estimated that recoverable unconventional gas reserves could cost between \$2.70/MBtu and \$9/MBtu (\$3–9/mcf or \$3–9/28.3cm) to produce, but it noted that production costs in North America were "declining significantly over time and are now towards the lower end of that range—hence becoming competitive with conventional supplies".[118] Shell pointed out that in Europe, Wood Mackenzie (a global energy consultancy) has estimated that "the costs of developing unconventional gas would

[114] Ev w9 (SSE)

[115] Ev w36 (Mitchell)

[116] Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", OIES, December 2010, p 101

[117] Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", OIES, December 2010, p 102

[118] Ev w19 (Shell)

have to fall by a minimum of 20% for European gas shale to be economical with current European gas pricing".[119]

61. According to the OIES "the pricing of unconventional gas volumes will have to be sustained at a level above $8-10/mcf" in order for it to be economic, which is "higher than historical prices and current market expectations".[120] Gas prices are currently indexed to the price of oil, and the OIES believed that unconventional production was incapable of moving gas into a spot market (where the price is quoted for immediate delivery of a commodity). They believed that "unconventional gas will not be a price setter at a European level", adding, "the arrival of large new gas volumes could have a downward effect on prices, as it has in the US, but this seems unlikely".[121] However, Professor Paul Stevens of Chatham House noted that "it appears most observers currently expect shale gas economics to be superior to those for conventional gas […] we could see shale gas setting such a low price that conventional drilling suffers significantly".[122]

62. The Geological Society's Jonathan Craig cited another independent assessment made by Wood Mackenzie that determined the break-even price of unconventional gas as "about $5 per mcf […] in the European countries [it] tends to be a bit higher […] because drilling costs tend to be rather higher".[123] He told us that "the gas price in the US at the moment is lower than that […] a lot of the shale gas operations in the US are probably marginally economic".[124] Nick Grealy disagreed with that assessment, telling us "the history of shale gas has been one of continuous improvement in the economics and how much is produced". [125]

63. The Executive Chairman of Devon Energy stated that high natural gas prices of $11 were "kind of like a Saturday night drunk […] It may feel good at the time" but it was not sustainable.[126] However, he explained that the then current market price of $3.75 was too low for the industry to maintain gas production in the long term.[126] As can be seen in Figure 5 (based on data from the US Department of Energy's Energy Information Agency), US gas prices were low for many years but began to rise steeply in the late 1990s before falling back to 2000-levels in 2010.

[119] Ev w19 (Shell)

[120] Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", OIES, December 2010, p 102

[121] Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", OIES, December 2010, p 102

[122] Paul Stevens, "The 'Shale Gas Revolution': Hype and Reality", *Chatham House*, September 2010, p 8

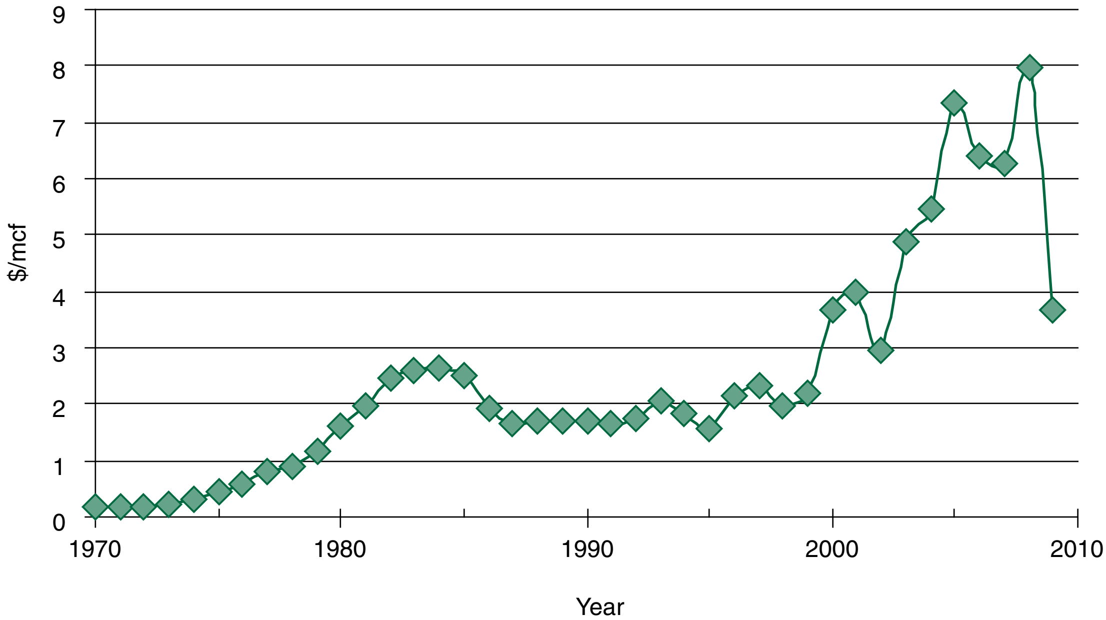
[123] Q 182

[124] Q 182

[125] Q 182

[126] "Natural gas price seen as too low to sustain production", *Star*-Telegram, 6 October 2010, www.star-telegram.com

Figure 5—US Natural Gas Wellhead Price (Dollars per Thousand Cubic Feet), 'Natural Gas Navigator',



Source: US Department of Energy's Energy Information Administration.

64. The Minister told us "I don't think we are expecting this [shale gas] to have the same [impact in terms of] price change as it has in the United States, where the significance has been greater than we think it could possibly be in the United Kingdom".[127] Jonathan Craig agreed when he told us that unconventional gas production in the UK will "Make a contribution but not a big enough contribution that is going to have a major effect on the prices of gas in the UK".[128]

65. We conclude that a glut in shale gas production could drive the price of conventional gas down, but there is uncertainty as to the extent of this. If there were to be a fall in prices it is unlikely to be as dramatic as that seen in the US.

Security of Supply

66. According to the Oxford Institute for Energy Studies (OIES), "The rise of unconventional gas production, and in particular shale gas, has been the greatest revolution in the US energy landscape since the Second World War".[129] However, they believe that in the UK production would have to overcome very significant challenges including "land availability and access, logistics operations, and service sector capacity" in order to contribute significantly to security of supply.[129] Nonetheless, Richard Selley, of Imperial College London, told us that "The opportunity for developing indigenous gas resources on land in this country is a tremendous one from the security point of view".[130]

67. Jonathan Craig—a Fellow of the Geological Society of London—believed that it was "too early to say at this point in time how big [the contribution of shale gas to UK energy

[127] Q 307

[128] Q 186

[129] Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", OIES, December 2010, p100

[130] Q 64

security] will be".[131] He added that "our old conventional [North Sea gas] fields are declining very rapidly […] it is estimated that [globally] by 2020 we need to replace about 70% to 75% of our existing production with new sources of natural gas, both conventional and unconventional".[132] Nick Grealy, of the gas policy blog *No Hot Air*, believed "the whole thing about energy security is a bit of a red herring. Right now, 88% of our supplies come from the North Sea […] most of our imports come from Norway and the Netherlands", countries with a strong record of supplying gas to the UK.[133]

68. Shell believed that "unconventional gas resources […] could enhance the diversity of gas supplies to Europe and the UK".[134] With the caveat that "Large scale discoveries of shale gas resources do not necessarily mean large scale production will follow", OFGEM stated that such production "is likely to improve the security of supply outlook".[135] Regarding the definition of "energy security", the Geological Society added that this "may be achieved by means other than moving towards self-sufficiency based on domestic resources", in other words, importing from secure suppliers.[136] They saw the possibility of a positive impact on security of gas supply, but not before 2020.[137]

69. The Geological Society quoted BP's view that the "usable shale gas resource in Europe is limited, and that any impact is likely to be local rather than pan-European".[138] They added that outside of Europe, the only significant shale gas resources that might impact on UK energy policy were to be found in North Africa and Russia, the implication being that other countries are unlikely to export their resources to us.[139] However, as Russia still has "significant untapped conventional resources" they are likely to pursue them first before they begin exploiting shale gas.[140] Jonathan Craig argued that the discovery and production of significant amounts of shale gas in the US has "allowed us to move away from the need to look for gas resources in some more difficult environments around the world, particularly in the Arctic".[141]

70. The UK Government appears to take a more upbeat view of the potential of indigenous shale gas resources to contribute to energy security. The Minister told us that, "We are now net importers of gas. We are very committed indeed to getting the resources that we can from the North Sea, but if there are gas resources that are available to us onshore as well, we believe it is the national interests that those should be developed".[142]

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131 Q 175

132 Q 176

133 Q 177

134 Ev w19 (Shell)

135 Ev w13 (Ofgem)

136 Ev 92 (GSoL)

137 Ev 92 (GSoL)

138 Ev 92 (GSoL)

139 Ev 92 (GSoL)

140 Ev 92 (GSoL)

141 Q 179

142 Q 305

71. **Shale gas has the potential to diversify and secure European energy supplies. Domestic prospects—onshore and potentially offshore—could reduce the UK's dependence on imports, but the effect on energy security is unlikely to be enormous. We conclude that energy security considerations should not be the main driver of policy on the exploitation of shale gas.**

Government Support for Shale Gas Production

72. The Oxford Institute for Energy Studies (OIES) identified a set of catalysts, both policy and market-based, that triggered the "revolution" in unconventional gas production in the US:

- Policy-based: tax credits, lack of restrictive regulations (on land-access, permitting and environmental aspects.)
- Market-based: increasing profitability of gas operations, technological developments, credit availability, and a competitive service industry.[143]

Professor Stevens of Chatham House noted that in the US the Crude Oil Windfall Profit Tax 1980 introduced a tax credit on unconventional fuel production that remained in force until 2002, whereas in Europe "only Hungary has any form of tax advantage for unconventional gas".[144]

73. As far back as 1985, research undertaken by Imperial College London concluded that the UK had considerable potential for shale gas exploitation, but that exploration was not then economically viable under the prevailing tax regime.[145] Current wholesale gas prices are approximately 53p/therm.[146,]This would mean that 150 bcm (billion cubic metres)—the UK shale gas reserves estimated by the British Geological Survey—of gas would be worth approximately £28 billion.[147] Despite the tax advantage of the shale gas industry in the US, evidence to us suggested that the unconventional gas industry in the UK was not seeking a similar benefit in this country. Andrew Austin told us that IGas Energy was "seeking to demonstrate that we can make it at the current tax rates and under the current regime", to which Cuadrilla's Dennis Carlton added "there is no need at this point in time for [tax breaks or] incentives to be put in place".[148] Neither Nick Grealy nor Jonathan Craig the Geological Society saw a need for the Government to subsidise the shale gas industry in the UK.[149] In written evidence to us, the Geological Society stated that several policy instruments were available to the Government beyond tax breaks should it wish "to

[143] Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", OIES, December 2010

[144] Ev w24 (Chatham)

[145] Ev 74 (Selley)

[146] Written evidence received from Centrica in connection with oral evidence on 16 December 2010. And then you can add the note afterwards [Note: 1 therm = 100,000 BTU (British Thermal Units) = 30 kWh = 2.8 cm of gas]

[147] DECC, *The Unconventional Hydrocarbon Resources of Britain's Onshore Basins-Shale Gas*, December 2010, p1

[148] Q 174

[149] Q 183–184

influence resource prices in order to stimulate investment", including "subsidies [...] feed-in tariffs [...] regulation, and carbon pricing".[150]

74. The Minister told us that "I can't see any reason for changing support the support that is offered [...] I think it would be market-driven, but [...] subject to very strict safety and environmental protections".[151] Regarding tax credits for shale gas production, the Minister told us that "would ultimately be a matter for the Chancellor" adding that in the North Sea "the tax regime has adapted in order to encourage development".[152]

Renewables versus Shale Gas

75. Friends of the Earth were concerned that the exploitation of large amounts of shale gas could undermine investment in renewable energy, adding that gas is "already threatening renewable investment, even before shale gas is considered".[153] The Tyndall Centre agreed: "if money is invested in shale gas then there is a real risk that this could delay the development and deployment of [zero-carbon technologies]".[154] While DECC argued that if unconventional gas production displaced high carbon fuels such as coal, there could be "reduced emissions in the short- to medium-term", they also admitted that this could reduce the incentive for investment in "the low-carbon alternatives required to meet longer-term emission goals".[155] Professor Stevens of Chatham House posed the question "who will commit large sums of money to expensive renewables" in a world where low carbon gas is abundant and cheap.[156]

76. DECC believe that if gas was to play a long-term role in UK energy policy, this would "suggest a greater need for effective CCS [carbon capture and storage] technology for gas plants".[157] They add that, alongside "tighter national emission targets and policies to support innovation and deployment of low-carbon technologies", gas could be an "effective bridge to help deliver greater near-term [emissions] reductions".[158] Professor Kevin Anderson, Director of the Tyndall Centre, questioned whether shale gas could act as a "bridge" to a low-carbon economy: "We need to make that transition to renewables as a matter of some significant urgency. If that is the case, then any mechanism that takes away the incentives to move towards renewables cannot be a good deal".[159] However, Nick Grealy—of the gas-commentary blog *No Hot Air*—told us, "Gas is low carbon. It is not zero carbon [...] we can't make the perfect the enemy of the good".[160]

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[150] SG15a

[151] Q 320

[152] Q 321

[153] Ev w38 (FoE)

[154] Ev 86 (Tyndall)

[155] Ev 57 (DECC)

[156] Ev w24 (Chatham)

[157] Ev 57 (DECC)

[158] Ev 57 (DECC)

[159] Q 74

[160] Q 19

77. During evidence given to our Electricity Market Reform inquiry, Professor Dieter Helm compared investment in wind to investment in gas-fired electricity generation:

> We are projected to spend—I don't know—£100 billion on the offshore wind programme, which is over nine or 10 years, so £10 billion a year [...] Ask yourself the following question [...] if you close some coal stations quickly today and replace them with gas CCGTs [combined cycle gas turbines] quickly today, how much would you have to close, and bring on those CCGTs in two to three years' time, to achieve the same reductions as the £100 billion being spent on wind [...] it would probably cost less than £10 billion.[161]

78. IGas Energy made the case that the UK Government's commitment to renewable energy sources would require "new, low-carbon, flexible gas-fired power plants to compensate for the intermittency of wind generation".[162] SSE agreed. However, they also acknowledged that this would also lock carbon into the UK's energy system for a number of decades.[163]

79. As to whether shale gas and renewables could be used in parallel in order to meet climate change targets, Professor Anderson believed that it was not possible to use a fossil fuel to meet the UK's 2°C target.[164] He told us that "shale gas would take about as long [to deliver the UK's targets] as a lot of the renewables", while at the same time locking carbon into the energy mix.[165] Jennifer Banks of WWF questioned whether there would even be enough shale gas produced before 2020 to create the bridging effect.[166]

80. An Emissions Performance Standard (EPS) is one method whereby the UK could try to ensure that a potential influx of shale gas into the UK does not disincentivise investment in more-expensive, but lower carbon, renewables. An EPS is in essence a measure to limit the amount of carbon dioxide (CO_2) that can be emitted from electricity generating power stations. In this case it could be used to ensure that gas power stations providing base load electricity would be unable to operate after a certain date without carbon capture and storage technology (CCS), and increase the incentive to invest in lower carbon renewables. In our 2010 report on Emissions Performance Standards we concluded that an EPS offers a more certain and predictable way to prevent lock-in to high carbon infrastructure than other means.[167]

81. The Minister told us he was "wary" about referring to gas as a "transition fuel", adding that "we have to start explaining what is going to be required in terms of emission levels and what is going to be required in terms of CCS retrofitting […] [so people can make] investment decisions".[168] Mr Hendry added that the UK could not meet its carbon

161 Energy and Climate Change Committee, Fourth Report of Session 2010–11, *Electricity Market Reform*, HC 795, Ev 16

162 Ev 75 (IGas)

163 Ev w9 (SSE)

164 Q 79

165 Q 81

166 Q 83

167 Energy and Climate Change Committee, First Report of Session 2010–11, *Emissions Performance Standards,* HC 523, para 37

168 Q 306

reduction commitments "without moving heating away from gas. We can do that to some extent through biogas; we can do it through renewable heat".[169] DECC add that if shale gas proved to be commercially extractable, they would expect the "main effect of shale gas to be to reduce our dependence on imported gas, rather than displacing renewables".[170]

82. **Conventional sources of natural gas in the North Sea are diminishing. We conclude that if a significant amount of shale gas enters the UK market (whether from domestic sources, imported from another European country, or from the global market via LNG) it will probably discourage investment in more-expensive—but lower carbon—renewables. The UK needs to manage this risk in order to achieve its aim of generating more electricity from renewable and other low carbon sources This could be done through the progressive implementation of an Emissions Performance Standard (EPS) that would prevent gas power stations operating as base load providers after a certain date unless fitted with carbon capture and storage.**

83. We conclude that shale gas has the potential to shift the balance in the energy markets that the Department has tried to create away from low carbon electricity generation. We recommend that the Department take account of the impact of shale gas in its decisions on reform of the electricity market and its expectations of future investment in the energy industry.

LNG

84. Before their "shale gas revolution", the US imported significant amounts of liquefied natural gas (LNG), but these imports began to decrease with the increase in production of domestic shale gas. According to US Energy Information Administration (EIA) statistics, US LNG imports fell by almost a third between 2005 and 2010.[171] This "displaced" LNG can therefore become available elsewhere in the world".[172] There is even the prospect of US LNG exports.[173]

85. The British Geological Survey predicted that shale gas production around the world "will temporarily reduce the importance of the large LNG exporters"[174] such as Qatar (the world's largest LNG exporter).[175] DECC statistics indicate that in 2009 the UK imported the equivalent of approximately 10 bcm of LNG.[176] Jonathan Craig, however, argued that the increased availability of LNG will not eliminate the market and competition for LNG.[177]

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169 Q 307

170 Ev 66 (DECC)

171 "US Natural Gas Imports by Country", *US Energy Information Administration*, www.eia.doe.gov/dnav/ng/ng_move_impc_s1_a.htm

172 Q 178

173 "Chesapeake Energy wants to export LNG", *PennEnergy Research*, www.pennenergy.com/ Paul Stevens, "The 'Shale Gas Revolution': Hype and Reality", *Chatham House*, September 2010, p vi — Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", *OIES*, December 2010, p99

174 Ev 71 (BGS)

175 "The Global Liquefied Natural Gas Market: Status and Outlook", *US Energy Information Administration*, www.eia.doe.gov/

176 DECC, *Digest of UK Energy Statistics 2010*, Chapter 4.5, p113

177 Q 188

86. The Minister noted that "in the United States they may wish to turn what was intended to be import infrastructure [for LNG] into export infrastructure",[178] but he saw no prospect of that happening in the UK: "the North Sea […] is inevitably in a decline […] Of the 20-plus gigawatt of consented plant [by DECC], over 60% is gas […] that will require us to have import capacity".[179]

Regulatory Challenges

87. All rights and ownership of the hydrocarbon resources of Great Britain (and the UK territorial waters) are vested in the Crown by the Petroleum Act 1998. The Secretary of State for DECC awards licences to search for and extract these resources during licensing rounds; the next onshore licensing round will be the 14th. Safety is overseen by the Department of Work and Pension's Health and Safety Executive, while environmental concerns are monitored by the Department for the Environment, Food and Rural Affairs' Environment Agency and the Scottish Environmental Protection Agency (SEPA). Simon Toole of DECC told us that these four key agencies—have "established a regular set of meetings to ensure that [they] keep abreast of shale gas development". [180] DECC added that this group has been meeting "fairly regularly since 11 February [2011]".[181]

88. Onshore licences do not include any rights of access, making it the licensee's responsibility to "obtain all the relevant authorisations and planning permissions from the respective authorities and landowners".[182] In 1996 the then Department of Trade and Industry simplified the onshore licensing regime for the 8th Licensing Round with the introduction of Petroleum Exploration and Development Licences (PEDL).[183] PEDL's are composed of three terms; the Initial Term requires the completion of "Work Programme"; the Second Term requires completion of a "Development Programme"; and the Third Term is the production phase. During a new licensing round, applications for PEDLs are made for a number of unlicensed 10 km by 10 km blocks, corresponding to the Ordnance Survey grid. In Northern Ireland, onshore licences are granted by the Energy Division of the Department of Enterprise, Trade and Investment.[184] All EU Member States are required to follow guidelines laid down in the 1994 Hydrocarbons Licensing Directive 94/22/EC.[185] However, there is no specific mention of shale gas, or unconventional gas in UK legislation.

89. Evidence to us was mixed on whether specific regulation was needed for the extraction of shale gas. IGas believed that there was a need "to ensure a robust licensing and regulatory system that protects the public while maximizing the rate of extraction".[186] Shell

[178] Q 312

[179] Q 314

[180] Q 293

[181] Ev 66 (DECC)

[182] British Geological Society, *Onshore Oil and Gas*,www.bgs.ac.uk/

[183] "Licensing: Licence Types", *DECC Oil and Gas*,www.og.decc.gov.uk/

[184] British Geological Society, *Onshore Oil and Gas*,www.bgs.ac.uk/

[185] The Hydrocarbons Licensing Directive Regulations 1995 (SI 1995/1434)

[186] Ev 75 (IGas)

commented that as unconventional gas exploration required more wells to be drilled "regulators will need to review whether they have the appropriate framework and resources available to deal with the increased level of well permitting, environmental permitting and legislation, production license permitting etc".[187] However, IGas believed that the UK regulatory system was already "more rigorous and effective than in many countries" as the "onshore industry has inherited the culture of safety that has pervaded the UK offshore oil and gas industry since the Piper Alpha disaster".[188] Cuadrilla agreed that the UK already "possesses a strict regulatory framework governing onshore oil and gas exploration, including unconventional".[189]

90. DECC "does not believe that there is a requirement for UK oil and gas legislation to specifically refer to unconventional gas" as the technologies used for exploration and production are not new.[190] However, Professor Stevens of Chatham House observed that unconventional exploration "techniques are so different from conventional operations that they are simply not part of the existing regulations [in Europe]", adding that the "laws and regulations covering oil and gas exploration and development in Western Europe do not even make reference to unconventional gas".[191]

91. Nick Grealy told us that "Regulation is to be welcomed and will not add any significant costs to shale exploration".[192] Professor Anderson added, "I think just relying on existing legislative framework for a new process is not sufficient".[193] The US EPA is due to report preliminary findings on the effects of hydraulic fracturing on drinking water in 2012.[194] Interestingly, the Oxford Institute for Energy Studies (OIES) believed that the "US needs to clear its environmental debate before Europe can fully embrace unconventional gas".[195] DECC told us that "Planning and environmental considerations are likely to limit the number of surface locations from which wells can be drilled".[196]

92. We examined the Minister on whether UK should take the initiative within the EU to start discussing a common set of standards for shale gas. He responded:"my nervousness about common standards is that they end up being the lowest common denominator, and standards get driven down rather than driven up [...] [we] should be the gold standard that others should aspire to".[197] He noted that in the EU, "Energy remains a retained policy area. It is not something where there is a European competence".[198] DECC believed that the

187 Ev w19 (Shell)

188 Ev 75 (IGas)

189 Ev 78 (Cuadrilla)

190 Ev 66 (DECC)

191 Ev w24 (Chatham)

192 Ev 96 (Grealy)

193 Q 116

194 US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011

195 Florence Gény, "Can Unconventional Gas be a Game Changer in European Markets?", *OIES*, December 2010, p101

196 Ev 57 (DECC)

197 Q 294

198 Q 295

UK had a "robust regime which is fit for purpose" and will ensure that unconventional gas operations are carried out in a "safe and environmentally sound manner".[199]

93. **We recommend that UK legislation and regulation should take specific account of the challenges unique to shale gas exploration and production; specifically, the combination of hydraulic fracturing and horizontal drilling at multiple wells that requires large volumes of water and chemicals, and leads to the production of large volumes of waste water that must be managed and disposed of.**

94. **We note that stronger environmental regulations and increased population density means that in the UK, and Europe more broadly, shale gas development here will follow a different route to that of the US. Although energy is not an EU-level competence, the UK Government will need to work with its European partners to ensure, so far as is possible, a reasonable degree of level competition between domestic shale gas producers.**

95. **We recommend that the UK Government monitors carefully the regulatory approach adopted by Poland and any other EU countries where shale gas exploration and production takes place. We recommend that the Government explores the possibilities of common environmental standards within the EU for shale gas exploration and production.**

[199] Ev 66 (DECC)

5 Environmental Risks of Shale Gas

DECC's 14th Onshore Oil and Gas Licensing Round

96. In July 2010 DECC published a Strategic Environmental Assessment (SEA) for the draft plans of their forthcoming 14th round of onshore oil and gas licensing.[200] Tony Grayling—Head of Climate Change and Sustainable Development at the Environment Agency—told us that, as at March 2011, the final version of DECC's SEA has not yet been published.[201] SEA's are required under European Directive 2001/42/EC and implemented through the UK's Environmental Assessment of Plans and Programmes Regulations 2004.[202] Individual projects can also require an Environmental Impact Assessment (EIA) under the 1985 EIA Directive.[203] DECC's SEA on onshore oil and gas licensing states that:

> Besides the use of larger quantities of water than other methods of extraction, the production and environmental management methods required to provide suitable environmental protection with regard to this activity are well established (i.e. are techniques already used to stimulate production in conventional gas development).[204]

97. As at April 2011, DECC was still considering responses to a consultation on this SEA.[205] They intended to issue a Government response as soon as was "practical", and would then be in a position to "invite applications" for licences.[205] The licensing round would cover:

- onshore oil and gas exploration and production (which included shale gas);
- virgin coal-bed methane exploration and production; and
- natural gas storage in hydrocarbon reservoirs.[200]

The SEA of DECC's draft plans for the 14th onshore licensing round assessed the potential impacts of onshore licences on: geology and soils; landscape; water environment; air quality; climatic factors (long term weather patterns); and health.[206] We were told that DECC had sufficient expertise to perform a thorough SEA for the 14th Onshore Round. DECC's Director of Oil and Gas Licensing, Exploration and Development did not consider that "there is any particular technical or environmental impact of shale gas that we are not capable of understanding".[207] The Minister added that DECC is "one organisation among a number that are involved in the environmental and safety monitoring of these issues [...]

[200] DECC, *SEA for a 14th and Subsequent Onshore Oil & Gas Licensing Rounds—Environmental Report*, July 2010

[201] Q 229

[202] The Environmental Assessment of Plans and Programmes Regulations 2004 (SI 2004/1663)

[203] Environmental Impact Assessment Directive (85/337/EEC)

[204] DECC, *SEA for a 14th and Subsequent Onshore Oil & Gas Licensing Rounds—Environmental Report*, July 2010 p 2

[205] "14th Onshore Licensing Round", *DECC Oil and Gas*, www.og.decc.gov.uk

[206] DECC, *SEA for a 14th and Subsequent Onshore Oil & Gas Licensing Rounds—Environmental Report*, July 2010 p28

[207] Q 285

the environment agencies involve the HSE and the local planning authority, whereas with the coal-bed methane it is the Coal Authority”.[208]

Environmental Permitting

98. The Environment Agency’s principal aims are to “protect and improve the environment, and to promote sustainable development.[209] The Environment Agency (EA) is responsible for issuing the environmental permits currently necessary to undertake shale gas exploration and production. Professor Anderson of the Tyndall Centre told us: “I trust the relevant authorities and scientists and the Environment Agency to come up with the appropriate legislative framework, but they need to be given the time to think through these sets of issues, to look at what happened in the US, to learn from their experience there”.[210] The EA believed that “there is a robust regulatory regime in place to ensure any environmental impacts from unconventional gas [...] are minimised” and that “the regulatory regime in the UK will continue to be sufficiently robust as it is to manage and minimise the environmental risks from [unconventional gas] […] we will, of course, keep that under review”.[211] WWF on the other hand told us that “A spokesperson from the Environment Agency told WWF that ‘the Environment Agency is currently developing policy at the national level on shale gas permitting’ and that ‘fracking’ will probably not be able to go ahead without a permit”.[212]

99. The EA addressed environmental concerns on a site-by-site basis as they “assess the need for, and respond to, applications for environmental permits […] we apply a proportionate risk-based approach to preventing pollution and protecting the environment”.[213] Local EA staff have assessed the potential impact of Cuadrilla’s operations (in the north west of England) on the water environment and have “decided that, at present, it does not require permitting under the EPR [Environmental Permitting Regulations 2010]”.[214] A permit under the EPR was required “where fluids containing pollutants [...] are injected into rock formations that contain groundwater” and a permit may also be needed if the activity posed a risk of “mobilising natural substances that could then cause pollution”.[215] The permit would specify limits on the activity and any requirements for monitoring. If it was decided that “the activity cannot affect groundwater” a permit would not be necessary.[216] It would be the EA’s decision as to whether groundwater was present or not.

100. The Environment Agency noted that if shale gas took off on large scale, and in the “majority of cases we don’t deem that an environmental permit is required”, it would mean

[208] Q 285

[209] “About Us”, information on the Environment Agency website, www.environment-agency.gov.uk/

[210] Q 86

[211] Ev 106 (EA), Q 207

[212] Ev 100 (WWF)

[213] Ev 106 (EA)

[214] Ev 106 (EA)

[215] Ev 106 (EA)

[216] Ev 106 (EA)

that the Environment Agency "will not be getting any […] income that will cover the costs of […] site-by-site assessments".[217] Tony Grayling added that in such a scenario, the Environment Agency would have to have a discussion with DEFRA and DECC on "having a proper assessment of what our resource needs will be going forward".[218]

101. **We recommend that the Government consider the future funding for the Environment Agency should the shale gas industry expand in the UK. As the situation stands, shale gas operators are unlikely to explore in areas where the Environment Agency will determine there is a risk to groundwater, so an Environmental Permit will not be necessary. However, the Environment Agency will still be expected to monitor for contamination and pollution, without being able to recover costs through the issuance of a permit.**

Hydraulic Fracturing

102. The successful injection of hydraulic fracturing fluid to release shale gas should result in natural gas production without the contamination of underground sources of drinking water, but this relies upon the integrity of the well and the correct fluid design. However, as Professor Richard Selley of Imperial College London told us, "there are different types of shale gas formations that respond differently to different type of fracturing".[219] The fluid design is determined by the often-unique geology of the particular shale gas formation.

103. There are many naturally occurring substances in the shale formation, and the process of hydraulic fracturing can affect their "mobility", which means their ability to move around and potentially enter a water source. These substances can include: naturally occurring "formation" fluid (such as brine) found in the shale rock; gases, such as the target natural gas (mostly methane), carbon dioxide, hydrogen sulphide, nitrogen and helium; trace elements of substances such as mercury, arsenic and lead; naturally occurring radioactive material (radium, thorium, uranium); and "volatile organic compounds" (VOCs) that easily vaporise into the air, such as benzene.[220]

104. Hydraulic fracturing can be repeated as necessary to maintain the flow of gas to the well, but there are concerns about the cumulative effects of such repeated fracturing. For example, the effects of repeated high-pressures on the well components, such as the casing and the cement.[221] Nigel Smith, of the British Geological Survey, told us "they are going to fracture probably every three or four years […] They will do their best to keep it going as long as they can".[222]

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217 Q 211

218 Q 211

219 Q 6

220 US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 30

221 US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 30

222 Q 33

Possible Contamination of Drinking Water

105. We heard during our visit to the US, that the US Environmental Protection Agency (EPA) believed that—from evidence it had gathered so far—that "if hydraulic fractures combine with pre-existing faults of fractures that lead to [drinking water] aquifers or directly extend into aquifers, injection could lead to the contamination of drinking water supplies by fracturing fluid, natural gas, and/or natural occurring substances".[223]

106. During the fracturing process, some of the hydraulic fracturing fluid may flow through the artificially created fractures to other areas within the shale gas formation, in a phenomenon known as "fluid leakoff". Fluid leakoff during hydraulic fracturing "can exceed 70 percent of the injected volume if not controlled properly", which could result in fluid migrating into drinking water aquifers.[224] In comparison, coal-bed methane formations are mostly shallow, so where hydraulic fracturing is used there is a risk that it could be happening in—or very near to—shallow drinking water supplies.[225]

107. The US EPA has stated that proper well construction is "essential for isolating the production zone from USDWs [underground sources of drinking water], and includes drilling a hole, installing a steel pipe [casing] and cementing the pipe in place".[226] There is therefore a risk of groundwater pollution from improperly constructed wells.[227]

108. DECC thas stated that while there might have been cases of well integrity failure on some US shale wells, they "do not believe that such a situation would occur in the UK".[228] They added that the operator was obliged to ensure that the well design is "safe and fit for purpose", and that this obligation was "checked very carefully by the Health and Safety Executive".

109. Professor Selley of Imperial College London observed that the process of artificial fracturing was as "old as Moses, [it] has been used in the petroleum industry for decades".[229] In contrast, the Tyndall Centre referred to "the 'novel' risks associated with hydraulic fracturing", namely contamination of water supplies by the hydraulic fracturing fluid or methane—the latter was associated with (in-)famous images of people in the US setting their tap-water alight.[230]

110. The moratorium on hydraulic fracturing in New York State was a result of concerns surrounding environmental risks, in particular the potential contamination of water supplies. DECC believed that cases of contamination in the US have been the result of "some incompetent operators [who] have allowed gas to contaminate shallow [water]

[223] US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 31

[224] P.S. Glenn, "Control and Modeling of Fluid Leakoff during Hydraulic Fracturing", *Journal of Petroleum Tech 37(6)*, June 1985, p 1071

[225] J.C. Pashin, "Hydrodynamics of CBM Reservoirs in the Black Warrior Basin", *Applied Geochemistry 22(10),* October 2007, p *2257-2272*

[226] US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 27

[227] Ev w32 (Co-op) and Osborn et al, "Methane Contamination of drinking water accompanying gas-well drilling and hydraulic fracturing", *Proceedings of the National Academy of Sciences,* 9 May 2011

[228] Ev 66 (DECC)

[229] Ev 74 (Selley)

[230] Ev 86 (Tyndall)

aquifers, which should not be possible with proper well casing design".[231] The Geological Society has stated that there "is no recorded evidence of this [contamination], and [they have] good reason to think it untrue, since the process takes place at depths of many hundreds of metres below the [water] aquifer".[232] With regard to the issues of fugitive methane emissions during shale gas exploration and production, the Geological Society believed that this "is very unlikely to be due to hydraulic fracturing, since this occurs at depths of several thousand metres beneath the surface".[233]

111. During our visit to the US, we heard little concern from environmental groups, state or federal regulators, or academics on the environmental impacts of the hydraulic fracturing process itself. Any instances of methane contamination of groundwater were either blamed on poor well construction (an issue that applies to conventional as well as unconventional hydrocarbons) or were thought to pre-date any hydrofracing activity.

112. In Washington DC we met the US Department of Energy's (DoE)Deputy Assistant Secretary for Oil and Gas, Christopher Smith, who presented us with their 2009 publication "Modern Shale Gas Development in the United States: A Primer". This report discussed naturally occurring radioactive material (NORM), which some soils and geologic formations contain in low levels. The report described "when NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water [which flows out of the formation during production], or, under certain conditions, precipitates out in scales or sludges".[234] However, the DoE concluded that because the public did not come into contact with shale gas field equipment for extended periods of time "there is very little [radiation] exposure risk from gas field NORM".[235]

113. **We conclude that hydraulic fracturing itself does not pose a direct risk to water aquifers, provided that the well-casing is intact before this commences. Rather, any risks that do arise are related to the integrity of the well, and are no different to issues encountered when exploring for hydrocarbons in conventional geological formations. We recommend that the Health and Safety Executive test the integrity of wells before allowing the licensing of drilling activity.**

114. **We recommend that the Environment Agency should insist that all companies involved in hydraulic fracturing should declare the type, concentration and volume of all chemicals they are using.**

115. We recommend that before the Environment Agency permits any chemicals to be used in hydraulic fracturing fluid, they must ensure that they have the capabilities to monitor for, and potentially detect, these chemicals in local water supplies.

[231] Ev 57 (DECC)

[232] Ev 92 (GSoL)

[233] Ev 92 (GSoL)

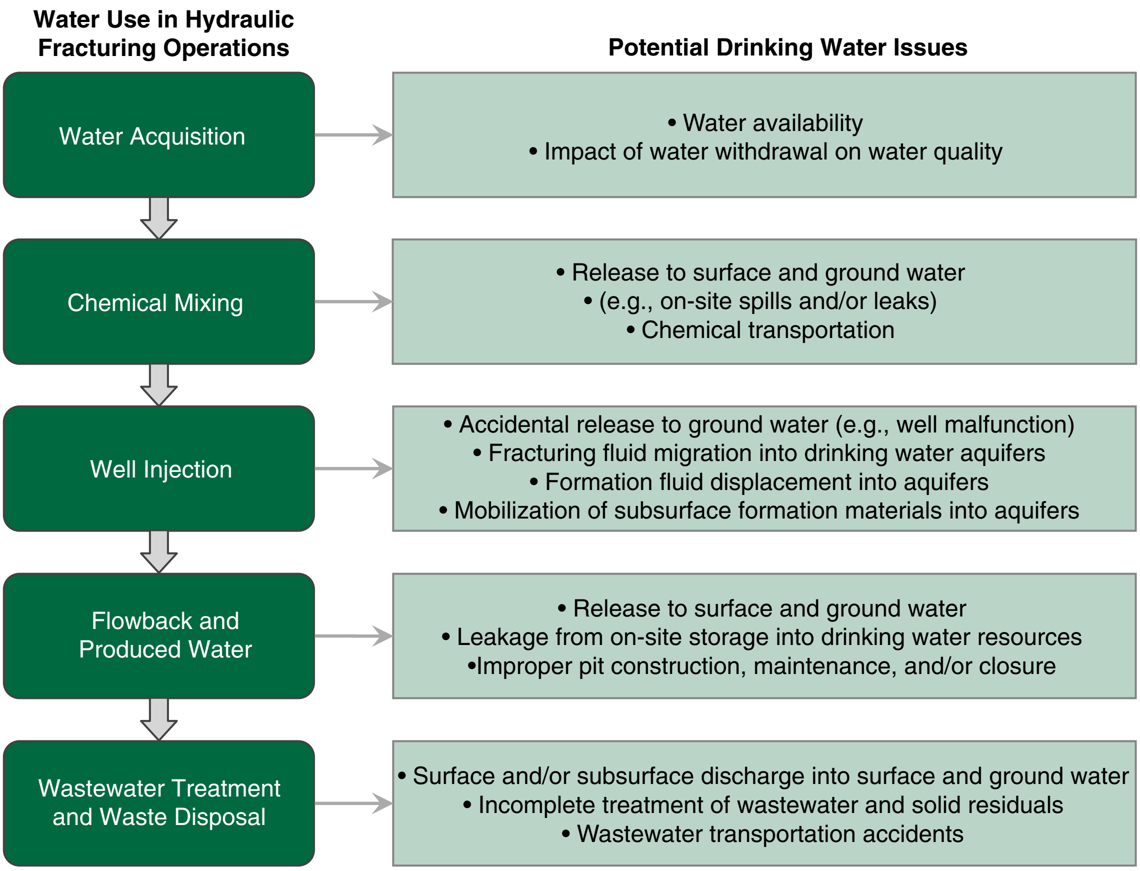
[234] US Department of Energy, *Modern Shale Gas Development in the United States: A Primer*, April 2009, www.netl.doe.gov

[235] US Department of Energy, *Modern Shale Gas Development in the United States: A Primer*, April 2009,

Volume of Water Required

116. The Tyndall Centre estimated that "a six well [shale gas exploration] pad takes between 54–174 million litres of water" which is "equivalent to 22–69 Olympic size swimming pools", or between 9-29 million litres per well.[236] In comparison, according to the American Petroleum Institute (API) the water usage in shale gas plays ranges in the US from 7.5–15 million litres of water.[237] Figure 6 gives flow chart of water use during hydraulic fracturing, and at each stage identifies the potential risks to drinking water as seen by the US Environmental Protection Agency.

Figure 6—Water Use in Hydraulic Fracturing Operations



Source: US EPA, Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water, February 2011, p 14

117. During peak shale gas production in the Barnett Shale, Texas, the total amount of water required represented 1.7% of the estimated total freshwater demanded by all users (domestic and commercial) within the Barnett Shale area.[238] Whether the withdrawal of this much water from local surface (reservoirs or rivers) or ground water sources (aquifers) has a significant impact will vary depending on the location and the time of year. It is possible to offset the large water requirements for hydraulic fracturing by recycling the fluid that flows back up from the well (known as "flowback" fluid).[239] It is estimated that

236 Ev 86 (Tyndall)

237 American Petroleum Institute, *Water Management Associated with Hydraulic Fracturing,* Guidance HF2, June 2010

238 L.P. Galusky, "Fort Worth Basin Natural Gas Play", *Barnett Shale Water Conservation and Management*, April 2007

239 US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 20–21

between 10–40% of the original fluid injected is recoverable.[240] By adding additional chemicals and more freshwater this can be reused. However, high levels of total dissolved solids (TDS) and other dissolved constituents can present challenges to recycling.

118. The removal of such large volumes of water could put stress on drinking water supplies, especially as it is not possible to recycle the majority of it.[239] The Campaign to Protect Rural England (CPRE) believed that "fostering a water intensive industry [in the UK] which is likely to increase demand for a scarce resource is highly questionable".[241] Professor Anderson of the Tyndall Centre explained that "even in wet parts of the world, which is where some of these shales are, there are often issues of water supply throughout the year, and this [hydraulic fracturing] will be another pressure on that water supply system".[242]

119. In their 2006 report "Underground, Under Threat – The State of Ground Water in England and Wales" the Environment Agency stated that in the north west of England—where Cuadrilla are exploring for shale gas—11% of water is supplied by groundwater (which represents 5% of all the groundwater abstracted in the UK).[243] Data for the rest of the UK is shown in Figure 7.

120. During its shale gas exploration in the US, Shell stated that it had "reduced its use of freshwater by about 50% by reusing treated fracturing water".[244] WWF believed that it was "possible to recycle wastewater and should shale gas production take place in the UK this should be mandatory".[245] Asked whether the Environment Agency should be regulating the amount of water that is recycled, Mr Marsland, Groundwater Manager for the Environment Agency, told us that they "would certainly encourage them to recycle […] [but] [there could be complexities in recycling in terms of the [increasing] concentration of pollutants".[246]

121. However, the potential abstraction of such large volumes of water needed for fracking, and the subsequent lowering of the water table, could also affect water quality by: exposing naturally occurring minerals in the aquifer to an oxygen-rich environment—the resulting chemical changes could alter their solubility, causing chemical contamination of the water; stimulating bacterial growth, which could cause taste and odour problems; causing an upwelling of lower quality water from deeper within an aquifer.[239] The US EPA believed that "large volume water withdrawals from ground water can also lead to subsidence and/or destabilization of the geology".[247] Additionally, large water abstractions may lead to an increase in the concentration of contaminants in surface water resources.[248]

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240 R.D. Vidic, "Sustainable Water Management for Marcellus Shale", *Temple University (Philadelphia)*, March 2010

241 Ev w8 (CPRE)

242 Q 113

243 Environment Agency, *Underground, Under Threat—The State of Ground Water in England and Wales*, 2006, p 11

244 Ev w19 (Shell)

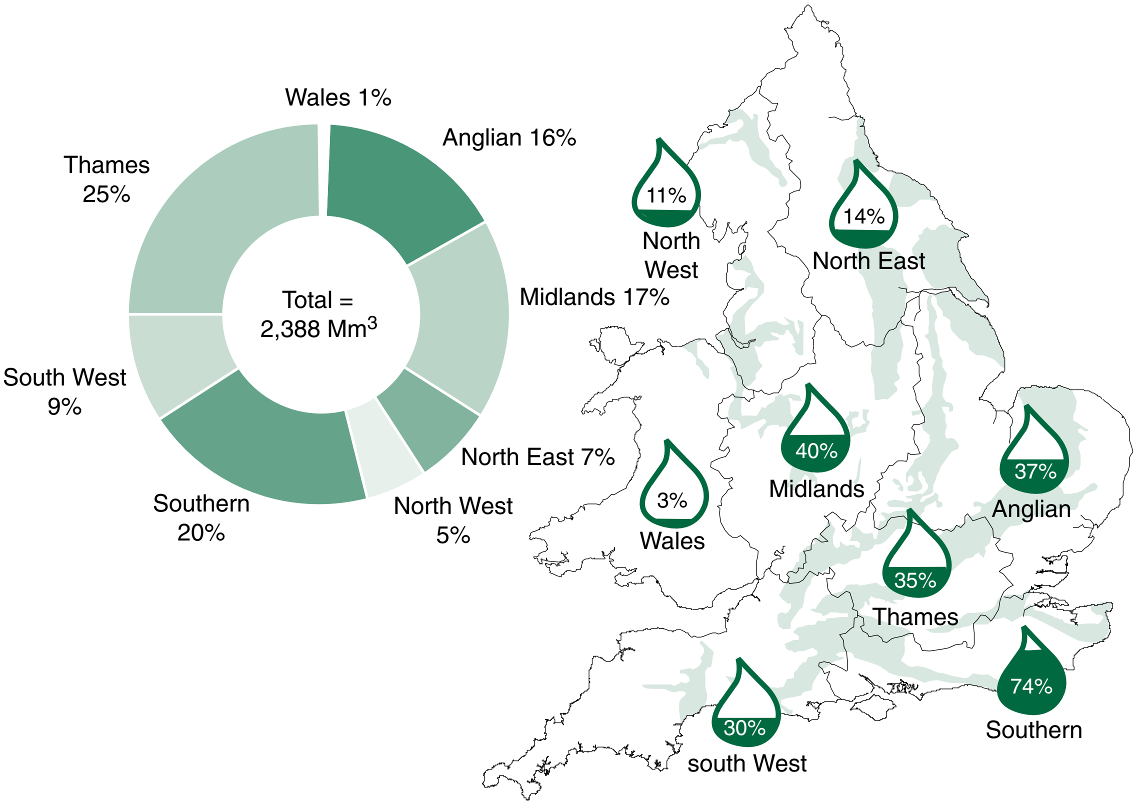
245 Ev 100 (WWF)

246 Q 255

247 US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 21

248 "Water Withdrawals for Development of Marcellus Shale Gas in Pennsylvania", *Pennsylvania State University*, October 2010, p 8

Figure 7—Chart showing percentage of total groundwater abstracted in 2003, and a map showing percentage of water in each region supplied by groundwater



Source*: Environment Agency, "Underground, Under Threat—The State of Ground Water in England and Wales", 2006, p 11*

122. Mark Miller estimated that Cuadrilla would probably use "about 1,000 cubic metres total for our drilling process and probably another 12,000 [cubic] metres for the fracturing process […] 13,000 cubic metres [in total] […] about five Olympic swimming pools".[249] Mr Miller added that in a year they might use 20 Olympic swimming pools-worth of water in their future operations.[250] Cuadrilla bought their water from the mains (through United Utilities) and "as often as we can, we will", Mr Miller told us.[251] He also said that United Utilities "know their availability of water and they [would] curtail us if they feel we would be taking too much […] we are just an industrial customer like anybody else".[252]

123. Asked about the volume of water required for hydraulic fracturing operations, Jonathan Craig of the Geological Society told us that "only 30%, of the fractures that we make are contributing gas to the well. We need to either use less fluid, so that we only frac the 30% that we need to frac, or get much more efficient about the fracing so that we create more fractures that are contributing".[253] Nick Grealy made the comment to us that while "3 million gallons sounds alarming […] four million gallons is the irrigation for a golf course

[249] Q 125

[250] Q 125

[251] Q 126

[252] Qq 125–126

[253] Q 201

for 28 days".[254] Jonathan Craig added that "a typical shale gas field in the US might have 850 wells in it […] this is different from conventional exploration […] it is basically 100,000 barrels of water per well".[255]

124. Tony Grayling of the Environment Agency told us that "in terms of large scale usage of water from the environment, an abstraction licence is required from the Environment Agency and we wouldn't license unsustainable abstraction".[256] The Environment Agency told us that the water required for hydraulic fracturing is considered in the same way as any other industrial process.[257] Mr Grayling added, "I don't think you can single out this activity among all the other water-use activities for special treatment".[258]

125. **We conclude that there is only a small risk that the large volumes of water required for hydraulic fracturing will place undue stress on the water supply, though this could be more significant at times of drought in low rainfall areas. We recommend that the Environment Agency should have the power to prescribe the minimum amount of water recycling that takes place during unconventional gas exploration, on a site-by-site basis that takes into account the water stresses particular to the region.**

Waste Water Treatment and Disposal

126. After the high-pressure injection of the hydraulic fracturing fluid has induced fractures in the shale formation, the pressure is decreased and the direction of fluid flow is reversed, "allowing fracturing fluid and naturally occurring substances to flow out of the wellbore to the surface [over a period of several weeks for shale formations, and potentially longer for coal-bed methane]; this mixture is called 'flowback'".[259]

127. The toxicity of these substances varies considerably, with the naturally occurring metals exerting various forms of toxicity at low concentrations (even though they are essential nutrients).[260] Flowback and produced water from hydraulic fracturing operations are held in storage tanks and waste impoundment pits prior to or during treatment, recycling and disposal.

128. Flowback liquid (from the fracturing process) and "produced" water (which comes from the shale formation during gas production) can be managed through disposal or treatment, which may then be followed by discharge to surface water bodies or reuse.[261] The primary options for dealing with this wastewater are:

- inject underground through a disposal well (onsite of offsite);
- discharge to a nearby surface water body;

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[254] Q 202

[255] Qq 203,207

[256] Q 229

[257] Q 232

[258] Q 234

[259] US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 35

[260] US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 32

[261] US EPA, *Draft to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water*, February 2011, p 40

- transport to a municipal wastewater treatment plant;
- transport to a commercial industrial wastewater treatment facility; or
- reuse for a future fracturing procedure either with or without treatment.[262]

129. Tony Marsland of the Environment Agency told us that the wastewater from Cuadrilla's operations near Blackpool would be "going to a specialist waste treatment plant in East Yorkshire—a specialist water and gas plant—for specific treatment and disposal".[263] Asked whether the Environment Agency was confident that current waste treatment plants were capable of detecting and dealing with the chemicals and contaminants found in flowback water, he added that it "is up to the waste treatment facility to determine whether it has the capacity and can treat that particular waste stream […] they have to make sure they can meet their own [obligations under their] permits before they can discharge [it]".[264]

130. Chair of Blackpool Green Party, Philip Mitchell (who submitted evidence on his own behalf) highlighted the risk of "inadequate numbers of treatment centres to process this waste [and] the risk to locally produced food [from contamination]".[265] SSE believed that while there were hazards connected with the management of the large amounts of chemically contaminated waste water used in the hydraulic fracturing process, "closed loop water systems are being developed by industry to reduce water" required.[266] Regarding the availability of waste treatment centres should shale gas exploration expand in the UK, Mr Miller told us that the existing waste facilities, have really been established to handle some of the fluids coming from offshore [oil and gas exploration], and that is a pretty big industry […] even if shale gas got pretty active […] [it wouldn't] exceed the capacity that was set up to service the North Sea.[267] Dennis Carlton of Cuadrilla added that that shale gas exploration companies could always "drill a disposal well" if expansion of the industry became inhibited by the capacity of waste treatment facilities.[268]

131. Regarding the disposal of flowback and produced water from hydraulic fracturing operations, the Environment Agency's Head of Groundwater, Tony Marsland, told us: "We certainly don't need any more regulation. The Environmental Permitting Regulations would cope with this".[269] As to the environmental impacts of shale gas production, particularly in terms of the management and disposal of the large quantities of water involved, the Minister of State for Energy, Charles Hendry MP, told us that, "the Environment Agency should lead on these matters, as they have an absolute responsibility for environmental protection".[270]

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262 J.A. Veil, "Water Management Technologies used by Marcellus Shale Gas Producers", *Argonne Nat'l Lab*, July 2010

263 Q 242

264 Q 246

265 Ev w36 (Mitchell)

266 Ev w9 (SSE)

267 Q 157

268 Q 157

269 Q 261

270 Q 336

132. **We recommend that DECC and DEFRA ensure that the Environment Agency monitors randomly the flowback and produced water from unconventional gas operations for potentially hazardous material that has been released from the shale formation. In order to maintain public confidence in the regulators—and in the shale gas industry—we recommend that both water and air be checked for contamination both before and during shale gas operations.**

133. **We encourage the Government to insist that as the shale gas industry develops, companies are required to work together in order to optimize the use of waste water treatment plants, to minimise both the number of plants and the distance waste water has to be transported.**

Air Pollution

134. DECC's Strategic Environmental Assessment for their forthcoming 14th Onshore Oil and Gas Licensing Round states that the:

> existing [air quality] regulatory controls on transport, power generation and gas flaring are regarded as adequate […] EIA [Environmental Impact Assessment] to support planning and other consents would be expected to give due consideration to the potential implications of the planned activity on attainment of local and regional air quality plans.[271]

135. During our visit to the US, the Department of Energy provided us with a report that described how "some air emissions commonly occur during [shale gas] exploration and production activities [...] NOx, volatile organic compounds [VOCs, such as benzene], particulate matter, SO_2, and methane".[272] NOx gases are responsible for the brown haze around areas of industry, and contribute to: acid rain; the destruction of lake ecosystems; and the formation of ozone smog, which has been linked to illness and death. In Texas, the US Environmental Defense Fund (an environmental organisation) expressed concern that "regulatory agencies were inadequately monitoring air quality, we analyzed the state's data and found that air pollutants including benzene […] were being emitted from the wells".[273]

136. A study prepared for the US Environmental Defense Fund, stated that "[shale] gas production [...] can impact local air quality and release greenhouse gases into the atmosphere".[274] The Fund identified various methods to capture methane and other gases that were released during well completions (when the well is made ready for production)—the use of these methods was known as a "green completion". Such completions not only reduced emissions of methane (if the methane was to be vented to the atmosphere), carbon dioxide (if the methane was to be flared) and other compounds (such as benzene, that can cause localised pollution and health problems), but they also captured products that could be sold by the operator. These green completions included methods to capture methane

[271] DECC, *SEA for a 14th and Subsequent Onshore Oil & Gas Licensing Rounds – Environmental Report*, July 2010, p82

[272] US Department of Energy, *Modern Shale Gas Development in the United States: A Primer*, April 2009, www.netl.doe.gov

[273] "Can we tap shale gas safely", *Environmental Defense Fund*, 7 December 2010,http://solutions.edf.org

[274] Al Armendariz,"Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements", *Environmental Defense Fund*, www.edf.org

and VOC compounds during well completions, and the control of VOC from gas "condensate" tanks through the use of vapour recovery units.[275] The Environment Agency is not yet familiar with "green completion" technology, but should there be any commercial development of shale gas in the UK they would "require operators to use Best Available Techniques for the management of shale gas emissions".[276]

137. The US EPA told us that about half of shale gas wells in the US generated liquid hydrocarbons (not oil) known as "wet gas". This contained molecules that were heavier than methane, collectively known as "condensates". The Environment Agency told us that they were not concerned by condensates as they expected "most shale wells [in the UK] to produce a high quality gas that will not need refining so there will be no gas condensates".[277]

138. Tony Grayling told us that the Environment Agency was "not expecting big air quality implications [...] the Government have oversight of the implementation of the Air Quality Directive [...] the Environment Agency has to have regard to the National Air Quality strategy".[278] The Environment Agency "would prefer that if methane is being discharged that it was flared, because obviously that converts it to carbon dioxide, which is a much less potent greenhouse gas [...] but we would respect the Health and Safety Executive's judgment about what is safe".[279]

139. The Environment Agency told us that they would only monitor the emissions from shale gas operations if the activities involved "the refining or large scale combustion of gas [flaring]".[280] The Agency only expected flaring to be done on a small scale, so an environmental permit would not be necessary. If the shale gas operator were to flare gas on a large scale, they would be required to monitor for oxides of nitrogen, volatile organic compounds, sulphur dioxide and methane.[281]

140. **We recommend that the Environment Agency should have the powers to insist that—in collaboration with the Health and Safety Executive—planned onshore venting and flaring of natural gas for extended periods are not permitted.**

Shale Gas and Local Communities

141. The Tyndall Centre also described more "run of the mill" impacts of shale gas exploration and production such as "vehicle movements, landscape, noise and water consumption".[282] The Campaign to Protect Rural England (CPRE) raised these issues and stated they were: "concerned to ensure that any shale gas extraction in England does not

[275] Al Armendariz,"Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements", *Environmental Defense Fund*, www.edf.org

[276] Ev 107 (EA)

[277] Ev 107 (EA)

[278] Q 263

[279] Q 265

[280] Ev 107 (EA)

[281] Ev 107 (EA)

[282] Ev 86 (Tyndall)

cause unacceptable damage to the countryside".[283] The CPRE made the point that "onshore shale gas production […] [is] likely to be visually and ecologically intrusive" and would face "significant opposition on the grounds of landscape and wildlife conservation and rural character and amenity"[284].

142. Another barrier to shale gas development in the UK is the population density. For example, England has a population density of 383 per km^2, whereas the US has a population density of 27 per km^2.[285] SSE) believed that this was particularly relevant as "shale gas resources are spread more thinly over much wider areas" and so would require more drilling activity. The Geological Society stated that the "physical footprint[s] associated with onshore [shale gas] exploitation, are very large compared to conventional hydrocarbons".[286] However, Cuadrilla argued that drilling many shale gas wells (up to 16) from the same "pad" increased the efficiency of gas gathering and production facilities, and that this method "also significantly reduces the visual impact of shale gas production at the surface".[287] Shell agreed, saying that "advances made in drilling horizontal wells […] mean that horizontal wells can replace many vertical wells", reducing the landscape footprint of shale gas exploration.[288]

143. The British Geological Society pointed out that "lack of benefit to locals (in contrast to the US) and […] the relatively densely populated state of the UK is also a hindrance to development". In the US, landowners owned the oil and gas under their land, while in the UK "the Crown controls the right to produce hydrocarbons".[289] Professor Paul Stevens of Chatham House noted that in "Europe […] the state will reap the financial rewards of the resource and provide no financial incentive for the local community".[290] The Oxford Institute for Energy Studies agreed that "land access will remain challenging as long as there are no financial incentives for landowners".[291] The Dutch Energy Council has officially advised the Dutch government that "landowners and tenants [must] benefit financially from unconventional gas development on their land" if there was to be public support for shale gas exploration.[292]

144. Comparing the development of shale gas in the UK and the US, the Minister told us the "issue of land ownership is a very critical one".[293] He added that in the UK, individual landowners have to give their consent to those who have been granted exploration licences, which is not always the case in the US. DECC explained that a recent case before the Supreme Court had ruled that where a landowner "unreasonably refuses to agree access, where he demands unreasonable terms, or where the fragmentation of land ownership

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283 Ev w8 (CPRE)

284 Ev w8 (CPRE)

285 Paul Stevens, "The 'Shale Gas Revolution': Hype and Reality", *Chatham House*, September 2010

286 Ev 92 (GSoL)

287 Ev 78 (Cuadrilla)

288 Ev w19 (Shell)

289 Ev 57 (DECC)

290 Paul Stevens, "The 'Shale Gas Revolution': Hype and Reality", *Chatham House*, September 2010

291 Florence Gény, "Can Unconventional Gas be a Game Changer in European Gas Markets?", *OIES*, December 2010, p100

292 "Dutch Energy Council embraces unconventional gas", *European Energy Review*, 9 February 2011

293 Q 280

means a licensee cannot agree terms with everyone" then the Mines (Working Facilities and Support) Act 1996, as modified by the Petroleum Act 1998, provided a method by which a licensee could seek "ancillary rights [of access] through the courts".[294] DECC pointed out that this was a far from common procedure.

145. The Geological Society also explained that "social and psychological barrier[s] to the development of shale gas" were likely to be greater than physical (land) restrictions: "Open spaces may be more highly valued in light of their relative scarcity [in the UK]".[295] However, they cited the example of BP's Wytch Farm in Dorset, "the largest onshore oil field in Western Europe", as a demonstration that the industry can "successfully exploit resources […] while meeting the highest environmental and social standards". They also added that "if shale gas were to be used to supply local energy needs […] such developments might be regarded more positively".[296]

146. The Minister thought it "quite challenging to see how" shale gas operations might encroach upon densely populated urban areas, as we witnessed in Fort Worth, Texas.[297]

147. **We conclude that the development of the UK shale gas industry will be different from the US—greater population density and stricter environmental legislation in Europe will give a greater incentive to drill fewer, better wells that take advantage of multiwell pad technology and horizontal drilling to minimise the impact on the landscape.**

148. **We recommend that the Environment Agency and the Department of Energy and Climate Change take lessons from unconventional gas exploration in the US, especially at the state-level where much of the expertise lies. The US has a great deal of regulatory experience of dealing with the issues of water contamination, the volume of water required, waste water treatment and disposal, air pollution, and infrastructure challenges. The UK Government must use this experience to ensure the lowest achievable environmental impacts from unconventional gas exploitation here.**

[294] Ev 66 (DECC)

[295] SG15a

[296] SG15a

[297] Q 218

6 Carbon Footprint of Shale Gas

149. During our visit to the US, the Environmental Defense Fund (an NGO) gave us a presentation on greenhouse gas emissions from natural gas. It began by noting that over a 20 year time period, the "global warming potential" (GWP) of methane was 72 times that of carbon dioxide, while over a 100-year timescale it was 21–25 times. This was because methane and carbon dioxide have different lifetimes in the atmosphere. However, the Sierra Club (another NGO) told us that fugitive methane emissions could easily be prevented through regulation and enforcement.

150. The Environmental Defense Fund also told us that there was uncertainty in the upstream (coal mining, gas production, processing, coal transportation, gas transmission and gas storage) emission estimates that fed into these figures. This was significant, as a larger proportion of gas emissions lie upstream in gas relative to coal. If the upstream emissions (carbon dioxide and methane) were twice as high, draft estimates suggested that gas would be approaching 1134 kg CO_2/MWh, with coal at around 1300 kg CO_2/MWh. On gas leaks, the break-even gas leak rate (that would make the climate impacts of gas the same as coal over 20 years) could be as low 4–6 %. In addition, methane also acted with aerosol particles (sulphates in the atmosphere) to increase global warming. In the US, 4.2% of gas produced on onshore leases was currently vented to the atmosphere or flared—the US Government Accountability Office estimated 40% of this could be captured economically.

151. Professor Kevin Anderson, Director of the Tyndall Energy Centre, believed that "if you want to abide by your own commitments under the Low Carbon Transition Plan, the Copenhagen Accord, various EU agreements and so forth [...] then there simply is not the emission space available in the timeframe that we have to utilise shale gas".[298]

152. The British Geological Survey stressed to us that "the overall greenhouse footprint of [...] shale gas, including direct and indirect emissions of both CO_2 and methane, is not yet fully understood".[299] According to DECC, the carbon footprint of shale gas "depends on the extraction process and emission management [...] [and could] be increased further by fugitive emissions of methane".[300] The Tyndall Centre agreed that "the key difference between the [carbon] footprint for shale gas and conventional gas is the extraction process".[301]

153. However SSE believed that domestically produced shale gas would have the advantage of not "needing to be processed and transported over vast distances", partially offsetting any carbon emissions from production.[302] Nick Grealy, publisher of the gas-commentary website *No Hot Air*, added his opinion that it was important to note that natural gas could

[298] Q 74

[299] Ev w1 (WCA)

[300] Ev 57 (DECC)

[301] Ev 86 (Tyndall)

[302] Ev w9 (SSE)

provide immediate "partial decarbonisation of the electricity sector", while other technologies aim for "full decarbonisation at some point several decades away".[303]

154. IGas Energy also argued that onshore unconventional gas supplies "offer potential carbon savings relative to gas sourced offshore or from overseas" noting "Russian gas […] has a carbon footprint which is 30% greater than domestically produced gas".[304] The UK currently gets less than 2% of its gas from Russia, and this arrived indirectly.[305] However, about 40% of the EU's total gas imports come from Russia.

155. WWF believed that "the majority of the world's fossil fuel reserves need to stay in the ground".[306] The Tyndall Centre added that without "a meaningful cap on emissions of global GHGs, the exploitation of shale gas is likely to increase net carbon emissions [...] [however] carbon budgets should ensure that shale gas use in the UK should not add to UK emissions".[307]

156. The Campaign to Protect Rural England (CPRE) drew attention to evidence from Canada that showed "the majority of existing wells in Quebec leak methane" despite industry claims.[308] According to WWF, a preliminary review of shale gas emissions by Cornell University "suggests that there is approximately a 1.5% methane leakage rate for the oil and gas industry and that therefore emissions from coal may be similar to those from natural gas".[309] The Cornell paper itself stated "A complete consideration of all emissions from using natural gas seems likely to make natural gas far less attractive than oil and not significantly better than coal in terms of the consequences for global warming".[310]

157. Jennifer Banks of the WWF told us: "Shale gas inevitably uses more energy than conventional gas exploration because of the hydraulic fracturing process and the injection of high pressure water into the ground".[311] Professor Kevin Anderson believed "there would be very little difference between [conventional and unconventional gas] when you looked at their overall CO_2 emissions once combusted".[312]

158. Simon Toole of DECC told us that "we have legally binding carbon emission reduction requirements […] [but] under every scenario we have looked at […] oil and gas and hydrocarbons will play a significant role to come for some decades […] That is why we have, for example, said that carbon capture and storage future projects should be looking at gas as well as at coal".[313] He added that "by the 2030s […] we ought to be looking at zero emissions from electricity generation […] but I don't see a way in which we can meet our

303 Ev 96 (Grealy)

304 Ev 75 (IGas)

305 Jim Watson, "UK Gas Security: Threat and Mitigation Strategies", *University of Sussex*, January 2010

306 Ev 100 (WWF)

307 Ev 86 (Tyndall)

308 Ev w8 (CPRE)

309 Ev 100 (WWF)

310 Robert W. Howarth, "Preliminary Assessment of the Greenhouse Gas Emissions from Natural Gas obtained by Hydraulic Fracturing", *Cornell University*, 1 April 2010

311 Q 71

312 Q 71

313 Q 304

security of supply obligations and try to keep prices affordable without having hydrocarbons in that mix".[314]

159. **We conclude that in planning to decarbonise the energy sector DECC should generally be cautious in its approach to natural gas (and hence unconventional gases such as shale gas). Although gas emissions are less than coal they are higher than many lower carbon technologies.**

Substituting Coal for Gas

160. WWF believed that "while it makes sense to burn lower carbon fuels such as gas […] this argument is only valid where there is evidence that gas is being used as a direct substitution, not in addition, to coal".[315] They added that any "new 'dash for gas' driven by the shale gas boom could seriously undermine the UK's ability to meet […] [emissions reduction] targets".[316] WWF also noted that "the average emissions from a new CCGT [combined cycle gas turbine] power station are around eight times higher than the CCC's recommended target of 50g CO_2/kWh by 2030".[317] Jennifer Banks was concerned that "gas may displace renewable energy".[318]

161. Professor Anderson pointed out that "[Gas] is very cheap to build at about £350 a kilowatt, much cheaper than renewables, much cheaper than coal, much much cheaper than nuclear". However, he added "we need to make that transition to renewables as a matter of some significant urgency […] any mechanism that takes away the incentives to move towards renewables cannot be a good deal […] there simply is not the emissions space available in the timeframe that we have to utilise shale gas".[319] It was the Tyndall Centre's opinion that "shale gas would still only be a low-carbon fuel source if allied with, as yet unproven, carbon capture and storage [CCS] technologies".[320]

162. The Tyndall Centre, however, found there was "little evidence […] that shale gas is currently or expected to, substitute, at any significant level for coal [in the US]".[321] They pointed out that in the International Energy Agency "Blue Map Scenario"—which leads to a 50% reduction in global emissions by 2050—"power generation and fuel switching [coal to gas, for example] accounts for only 5% of required emission reductions".[322] Professor Selley of Imperial College believed that "shale gas may however be a temporary stop gap […] until replaced by nuclear or renewable energy sources".[323] However, the Geological Society's Jonathan Craig told us that the "US are very much looking at using natural gas

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[314] Q 304

[315] Ev 100 (WWF)

[316] Ev 100 (WWF)

[317] Ev 100 (WWF)

[318] Q 74

[319] Q 74

[320] Ev 86 (Tyndall)

[321] Ev 86 (Tyndall)

[322] Ev 86 (Tyndall)

[323] Ev 71 (BGS)

[…] to reduce their dependence on coal […] in order to cut their carbon emissions […] [gas] need to make a contribution [to emissions] in the UK as well”.[324]

163. The Minister told us that it was not DECC’s expectation that “shale gas in the United Kingdom would lead to a greater use of gas, but it would lead to a replacement of import […] we are not expecting to see this lead to a surge of extra gas plants”. Q 300

164. **Shale gas could lead to a switch from coal to gas for electricity generation, thereby cutting carbon emissions, particularly projected emissions from developing economies. We conclude that this will help to reduce the impacts of climate change, but will not be sufficient to meet long term emissions reduction targets and avoid the worst effects of global climate disruption.**

165. **The emergence of shale gas increases the urgency of making carbon capture and storage (CCS) technology work for gas as well as coal. We recommend that both gas and coal carbon capture technology should be pursued in parallel and with equal urgency.**

[324] Q 192

7 Conclusion

166. The process of hydraulic fracturing has been described as "old as Moses" and certainly has been used in the petroleum industry for decades. However, it is only in the last decade that we have seen the effects of shale gas exploration and production on a large scale, as the combination of hydraulic fracturing and directional drilling have made the resources economically viable. Unconventional gas is just "natural gas" from a different type of rock. Whilst the term "unconventional" refers to the type of reservoir in which the gas is found, the techniques for accessing it are the same as you would used for a conventional well. Shale gas exploration is still in its infancy in the UK and the rest of Europe, which gives us the opportunity to learn from US experience and make regulations that are evidence-based. While hydraulic fracturing itself poses no direct risk to underground water aquifers, there is a risk of contamination through a failure in the integrity of the well, but these risks are no different than those encountered when exploiting oil and gas from conventional reservoirs. We are, however, concerned about the large volume of water and chemical additives required for hydraulic fracturing each well, and the large volumes of waste water generated, especially as commercial shale gas production requires so many more wells than conventional gas.

167. As shale gas exploration progresses in Poland, the UK needs to work with the rest of Europe to ensure that shale gas policy and regulation is not driven primarily by concerns about energy security. In regions already experiencing water stress—the number of which might increase as a result of climate change—the water required by hydraulic fracturing could exacerbate the situation. The volume of waste water generated must not outpace the capacity and capability of treatment facilities to deal with it nor with the availability of disposal sites. The industry should recycle as much of the waste water generated as practicable.

168. The UK could have a large amount of shale gas offshore, and we encourage the Government to incentivise exploration of this potential resource. However, estimates of the UK's onshore shale gas resources suggest that there will not be a "shale gas revolution" in the UK based on domestic resources alone—nevertheless, they could make us more self-sufficient by reducing our reliance on imported natural gas. If significant amounts of shale gas enter the natural gas market it will disincentivise investment in renewables and other lower carbon technologies. The UK Government needs to manage this risk in order to achieve its aim of generating more electricity from renewable sources.

169. The Government needs to be cautious in its approach to natural gas as a transition fuel to a low carbon economy. Although emissions from gas power plants are less than from coal, they are still higher than many lower carbon technologies. The main component of natural gas is methane, which is a greenhouse gas far more potent the carbon dioxide. However, the main source of this methane would be through leaks (or so-called "fugitive emissions") from the well and/or pipelines, which can be easily minimised through appropriate regulation and enforcement. Furthermore, the emergence of shale gas—and the likelihood that it will lead to the increased use of gas in power plants—means that we need to pursue with increased urgency the development of carbon capture technology suitable for gas as well as coal.

Recommendations

Background

1. Mitigation of the risk to water aquifers from hydraulic fracturing relies on companies undertaking the proper measures to protect the environment from pollution. However, there is no evidence that the hydraulic fracturing process itself poses a direct risk to underground water aquifers. That hypothetical and unproven risk must be balanced against the energy security benefits that shale gas could provide to the UK. We conclude that, on balance, a moratorium in the UK is not justified or necessary at present. But evidence must continue to be collected and assessed. We recommend that the Department of Energy and Climate Change monitor current drilling activity in the Bowland Shale formation extremely closely during its early stages in order both to assess the likely environmental impact of large scale shale gas extraction in the UK and also to promote public confidence in the regulation of the activity. (Paragraph 17)

Prospects for Shale Gas

2. We conclude that shale gas resources in the UK could be considerable. However, while they could be sufficient to help the UK increase its security of supply, it is unlikely shale gas will be a "game changer" in the UK to the same extent as it has been in the US. It is more likely that in countries such as Poland—with a larger reliance on gas imports and greater potential shale gas resources—the impacts of shale gas production will be significant. (Paragraph 24)

3. We conclude that it is important for the UK to monitor the development of shale gas in Poland—the "barometer of Europe" on this issue—both in terms of exploration and regulation. We are concerned that there could be adverse competitive consequences for the UK if Poland unilaterally develops its shale gas resources within the EU, particularly if their energy policy is driven by energy security—in spite of the environmental concerns associated with hydraulic fracturing—owing to their reliance on imported gas. (Paragraph 37)

4. In the crowded UK we cannot afford to risk the creation of contaminated and abandoned sites where shale gas production has stopped. The prospect of such a risk must be carefully considered when licences and other permissions are granted. We recommend that DECC should require that a fund be established to ensure that if wells are abandoned they can be "plugged". Such a fund could be established through a levy on shale gas well drilling or an upfront bond. (Paragraph 41)

5. There is substantial evidence that UK offshore unconventional gas resources could dwarf the potential onshore supplies. While these might be economically unviable at present, "uneconomic" reserves can become economic quickly as technology and prices shift. We recommend that DECC encourage the development of the offshore shale gas industry in the UK, working with HM Treasury to explore the impacts of tax breaks to the sector. (Paragraph 47)

6. Planning for any new gas transport infrastructure required to exploit shale gas should take into account the opportunity to minimise disruption and costs by sharing pipelines between different companies operating near to each other. We recommend that the Government consider amending the Town and County Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999 to require Environmental Impact Assessments for smaller gas pipeline projects, with the aim of avoiding unnecessary duplication of infrastructure. (Paragraph 54)

UK Policy Implications

7. We conclude that a glut in shale gas production could drive the price of conventional gas down, but there is uncertainty as to the extent of this. If there were to be a fall in prices it is unlikely to be as dramatic as that seen in the US. (Paragraph 65)

8. Shale gas has the potential to diversify and secure European energy supplies. Domestic prospects—onshore and potentially offshore—could reduce the UK's dependence on imports, but the effect on energy security is unlikely to be enormous. We conclude that energy security considerations should not be the main driver of policy on the exploitation of shale gas. (Paragraph 71)

9. Conventional sources of natural gas in the North Sea are diminishing. We conclude that if a significant amount of shale gas enters the UK market (whether from domestic sources, imported from another European country, or from the global market via LNG) it will probably discourage investment in more-expensive—but lower carbon—renewables. The UK needs to manage this risk in order to achieve its aim of generating more electricity from renewable and other low carbon sources This could be done through the progressive implementation of an Emissions Performance Standard (EPS) that would prevent gas power stations operating as base load providers after a certain date unless fitted with carbon capture and storage. (Paragraph 82)

10. We conclude that shale gas has the potential to shift the balance in the energy markets that the Department has tried to create away from low carbon electricity generation. We recommend that the Department take account of the impact of shale gas in its decisions on reform of the electricity market and its expectations of future investment in the energy industry. (Paragraph 83)

11. We recommend that UK legislation and regulation should take specific account of the challenges unique to shale gas exploration and production; specifically, the combination of hydraulic fracturing and horizontal drilling at multiple wells that requires large volumes of water and chemicals, and leads to the production of large volumes of waste water that must be managed and disposed of. (Paragraph 93)

12. We note that stronger environmental regulations and increased population density means that in the UK, and Europe more broadly, shale gas development here will follow a different route to that of the US. Although energy is not an EU-level competence, the UK Government will need to work with its European partners to ensure, so far as is possible, a reasonable degree of level competition between domestic shale gas producers. (Paragraph 94)

13. We recommend that the UK Government monitors carefully the regulatory approach adopted by Poland and any other EU countries where shale gas exploration and production takes place. We recommend that the Government explores the possibilities of common environmental standards within the EU for shale gas exploration and production. (Paragraph 95)

Environmental Risks of Shale Gas

14. We recommend that the Government consider the future funding for the Environment Agency should the shale gas industry expand in the UK. As the situation stands, shale gas operators are unlikely to explore in areas where the Environment Agency will determine there is a risk to groundwater, so an Environmental Permit will not be necessary. However, the Environment Agency will still be expected to monitor for contamination and pollution, without being able to recover costs through the issuance of a permit. (Paragraph 101)

15. We conclude that hydraulic fracturing itself does not pose a direct risk to water aquifers, provided that the well-casing is intact before this commences. Rather, any risks that do arise are related to the integrity of the well, and are no different to issues encountered when exploring for hydrocarbons in conventional geological formations. We recommend that the Health and Safety Executive test the integrity of wells before allowing the licensing of drilling activity. (Paragraph 113)

16. We recommend that the Environment Agency should insist that all companies involved in hydraulic fracturing should declare the type, concentration and volume of all chemicals they are using. (Paragraph 114)

17. We recommend that before the Environment Agency permits any chemicals to be used in hydraulic fracturing fluid, they must ensure that they have the capabilities to monitor for, and potentially detect, these chemicals in local water supplies. (Paragraph 115)

18. We conclude that there is only a small risk that the large volumes of water required for hydraulic fracturing will place undue stress on the water supply, though this could be more significant at times of drought in low rainfall areas. We recommend that the Environment Agency should have the power to prescribe the minimum amount of water recycling that takes place during unconventional gas exploration, on a site-by-site basis that takes into account the water stresses particular to the region. (Paragraph 125)

19. We recommend that DECC and DEFRA ensure that the Environment Agency monitors randomly the flowback and produced water from unconventional gas operations for potentially hazardous material that has been released from the shale formation. In order to maintain public confidence in the regulators—and in the shale gas industry—we recommend that both water and air be checked for contamination both before and during shale gas operations. (Paragraph 132)

20. We encourage the Government to insist that as the shale gas industry develops, companies are required to work together in order to optimize the use of waste water treatment plants, to minimise both the number of plants and the distance waste water has to be transported. (Paragraph 133)

21. We recommend that the Environment Agency should have the powers to insist that—in collaboration with the Health and Safety Executive—planned onshore venting and flaring of natural gas for extended periods are not permitted. (Paragraph 140)

22. We conclude that the development of the UK shale gas industry will be different from the US—greater population density and stricter environmental legislation in Europe will give a greater incentive to drill fewer, better wells that take advantage of multiwell pad technology and horizontal drilling to minimise the impact on the landscape. (Paragraph 147)

23. We recommend that the Environment Agency and the Department of Energy and Climate Change take lessons from unconventional gas exploration in the US, especially at the state-level where much of the expertise lies. The US has a great deal of regulatory experience of dealing with the issues of water contamination, the volume of water required, waste water treatment and disposal, air pollution, and infrastructure challenges. The UK Government must use this experience to ensure the lowest achievable environmental impacts from unconventional gas exploitation here. (Paragraph 148)

Carbon Footprint of Shale Gas

24. We conclude that in planning to decarbonise the energy sector DECC should generally be cautious in its approach to natural gas (and hence unconventional gases such as shale gas). Although gas emissions are less than coal they are higher than many lower carbon technologies. (Paragraph 159)

25. Shale gas could lead to a switch from coal to gas for electricity generation, thereby cutting carbon emissions, particularly projected emissions from developing economies. We conclude that this will help to reduce the impacts of climate change, but will not be sufficient to meet long term emissions reduction targets and avoid the worst effects of global climate disruption. (Paragraph 164)

26. The emergence of shale gas increases the urgency of making carbon capture and storage (CCS) technology work for gas as well as coal. We recommend that both gas and coal carbon capture technology should be pursued in parallel and with equal urgency. (Paragraph 165)

Annex 1: Note of the visit to the USA

In March 2011, we made a visit to Fort Worth and Austin in Texas, and to Washington DC. In Fort Worth we met with local shale gas industry representatives, environmental NGOs, academics and local federal officials. In Austin we held meetings with State regulators, oil and gas service industry representatives, and the Lt. Governor. In Washington DC we met federal energy and environment officials, as well as Congressmen from States where the shale gas industry was already developed (Texas) or developing (Pennsylvania). We discussed the lessons that each of these had learned over the past decade as the shale gas industry expanded in the USA.

Participating Members:

Mr Tim Yeo (Chair)

Dr Phillip Lee   Albert Owen   Dr Alan Whitehead

Sunday 6 March 2011

Briefing hosted by the Foreign and Commonwealth Office, with Andy Pryce (Deputy Consul General in Houston) and Dr Liz Kane (First Secretary, Energy, British Embassy).

Monday 7 March 2011

Meetings with:

Chesapeake Energy, and a visit to a Barnett Shale gas production and model site.

Mr Mike Moncrief, Mayor of Fort Worth, Sarah Fullenwhider, City Attorney, and Randle Harwood, Gas Well Management officer for Fort Worth

Dr Armendariz, US Environmental Protection Agency Administrator for the Region

ExxonMobil and XTO

Dr Bruce Bullock, Director of the Maguire Energy Institute at Southern Methodist University, and Dr Ken Morgan, Director of the School of Geology, Energy and the Environment at Texas Christian University.

Tuesday 8 March 2011

Briefing from Mr Rod Nelson, Vice President of Communications at Schlumberger.

Meetings with:

Mr Ramon Alvarez and Mr Scott Anderson, Environmental Defense Fund.

Meeting with Mr John Tintera, Gil Bujano and Ramon Fernandez of the Texas Railroad Commission.

Representatives of the Texas Commission on Environmental Quality.

Lt. Governor of Texas David Dewhurst

Wednesday 9 March 2011

Meetings with:

Mr Bill Stevens, Executive Vice President of the Texas Alliance of Energy Producers, and State Representative Jim Keffer, chair of the House Energy Resources Committee.

The Sierra Club.

Dominick Chilcott, FCO Deputy Head of Mission in Washington DC, and Nick Bridge, FCO Counsellor for Global Issues in Washington DC.

Thursday 10 March 2011

Meetings with:

Mr Christopher Smith, Deputy Assistant Secretary of Energy for Oil and Gas, US Department of Energy.

Ms. Leslie Cronkhite, Office of Groundwater and Drinking Water, US Environmental Protection Agency.

Ambassador Richard Morningstar, Special Envoy for Eurasian Energy, US Department of State.

Congressman Mike Doyle, Democrat—Pennsylvania

Congressman Gene Green, Democrat—Texas

Annex 2: Note of the visit to the Blackpool

In March 2011, we made a visit to Cuadrilla Resources shale gas exploration sites near Poulton-le-Flyde close to Blackpool, Lancashire. We met their senior site staff and were given a tour of the drilling facilities. Cuadrilla were over-engineering the well casing in order to reduce the possibility of the underground water aquifer—through which they drilled—becoming contaminated by natural gas or hydraulic fracturing fluid. At their Elswick site we saw a small power plant on top of gas well, an example of a facility that negated the need for gas transmission by producing electricity and transmitting that instead.

Wednesday 2 March 2011

Participating Members:

Mr Tim Yeo (Chairman)

Albert Owen   Christopher Pincher   Dr Alan Whitehead

Meetings with Cuadrilla's Mark Miller, Chief Executive, and Dennis Carlton, Executive Director.

Tours of:

Grange Hill 1, where exploratory drilling was underway.

Preese Hall 1, where drilling was complete and they were preparing for their first exploratory hydraulic fracture.

Elswick 1, which was commissioned in 1996 and previously owned by British Gas. The conventional gas reservoir underwent hydraulic fracture stimulation in 1993, and has a small generator on top that has been supplying electricity since 1998.

Formal Minutes

Tuesday 10 May 2011

Members present:

Mr Tim Yeo, in the Chair

Dan Byles
Dr Phillip Lee
Christopher Pincher
Sir Robert Smith

Draft Report (*Shale Gas*), proposed by the Chair, brought up and read.

Ordered, That the draft Report be read a second time, paragraph by paragraph.

Paragraphs 1 to 169 read and agreed to.

Annexes and Summary agreed to.

Resolved, That the Report be the Fifth Report of the Committee to the House.

Ordered, That the Chair make the Report to the House.

Ordered, That embargoed copies of the Report be made available, in accordance with the provisions of Standing Order No. 134.

Written evidence was ordered to be reported to the House for printing with the Report (in addition to that ordered to be reported for publishing on 25 January, 2 February and 22 March).

[Adjourned till Wednesday 11 May at 9.30 a.m.]

Witnesses

List of printed written evidence

List of additional written evidence

(published in Volume II on the Committee's website www.parliament.uk/ecc)

List of Reports from the Committee during the current Parliament

The reference number of the Government's response to each Report is printed in brackets after the HC printing number.

Session 2010–12

First report	Emissions Performance Standards	HC 523 (807)
Second report	UK Deepwater Drilling–Implications of the Gulf of Mexico Oil Spill	HC 450 (882)
Third report	The revised draft National Policy Statements on energy	HC 648
Fourth report	Electricity Market Reform	HC 742
First Special Report	Low carbon technologies in a green economy: Government Response to the Committee's Fourth Report of Session 2009-10	HC 455
Second Special Report	Fuel Poverty: Government Response to the Committee's Fifth Report of Session 2009-10	HC 541
Third Special Report	The future of Britain's electricity networks: Government Response to the Committee's Second Report of Session 2009–10	HC 629

Oral evidence

Taken before the Energy and Climate Change Committee

on Wednesday 9 February 2011

Members present:

Mr Tim Yeo (Chair)

Dan Byles	Christopher Pincher
Barry Gardiner	John Robertson
Ian Lavery	Laura Sandys
Dr Phillip Lee	Sir Robert Smith
Albert Owen	Dr Alan Whitehead

Examination of Witnesses

Witnesses: **Nigel Smith**, Geophysicist, British Geological Survey, and **Professor Richard Selley**, Petroleum Geologist, Imperial College London, gave evidence.

Q1 Chair: Good morning, and welcome to the Committee. I think we are going to make a start with you, on your own, if that is okay, because I am sure you have time constraints and I am afraid we do as well, so we will press on.

This is the first public session of our inquiry into shale gas. You will have to treat us, certainly me, as a new reader and not intimately familiar with a lot of the technical aspects of this. It is one of the reasons why we wanted to embark on the whole process. If some of our questions seem basic, you will have to take account of the fact that it is a new subject, though I think a lot of us have been interested in energy issues for a very long time and are familiar with most of the sort of policy background. I wonder if, to begin with, you could just explain a bit more about what is meant by "unconventional gas" and, in particular, is it the way gas is extracted, or the source from which it is extracted that makes it unconventional, or perhaps both?

Professor Richard Selley: In the ordinary way, petroleum forms from mud, from shale, in a huge area of the earth's crust where it has been buried, and oil and gas migrates up to the surface and dissipates in natural seepage. Occasionally it is trapped underground in what we would call conventional traps like an upfold of rock, and there we can measure the porosity and permeability, calculate the amount of reserves and extract it.

Non-conventional hydrocarbons include a range of things, one of which would be shale gas, where there is gas that is still in the shale, which is what we are all about today. There is also oil shale, where again there is oil still trapped within the shale; coal bed methane, where there is methane gas trapped within coal seams; tar sands, such as the Athabasca tar sands and the Malagasy tar sands at Bemolanga; and gas hydrates.

Q2 Chair: Are there great differences therefore between different types of unconventional gas?

Professor Richard Selley: Different types of unconventional gas. There is shale gas; there is also what is called tight gas in tight sands—low permeability sands. There is gas in gas hydrates. This is a particular form of ice, which contains methane gas within it, which is probably far more important than shale gas.

Q3 Chair: Why is there now therefore a sudden interest in shale gas?

Professor Richard Selley: Shale gas has been produced since 1821 in the Appalachians. What has driven the renaissance of shale gas has been an increase in energy prices in the States obviously, but also technology. In particular, that would include the ability to drill horizontally. In the old days, when I first went in the oil industry, all we could do was drill straight down, now we can drill horizontally. You can actually steer the drill bit almost like driving a car along the particular horizon of rock that you are interested in. That is a big improvement.

Fracturing, which is a very old technique, as old as Moses, has been used in the oil industry since the 1940s, but there are new techniques of fracturing. Also, seismic has improved. One of the problems with a lot of non-conventional petroleum is it is very hard to work out the reserves, unlike conventional petroleum in a conventional trap. You can image the oil and gas and you can see over a period of time how the fluid contacts move as it is produced. With non-conventional resources, especially shale gas, it is very hard to work out how much is there. The analogy that I have often used is that you should think more about water supply, aquifers and hydrogeology, than about conventional petroleum geology. However, with seismic now it is possible to image some of these shale gas "reservoirs" within major shale gas formations.

Q4 Dr Lee: Morning, Professor. A question on exploration: how tried and tested is this exploration?

Professor Richard Selley: Shale gas exploration has been going on since 1821, when it was really a cottage industry, very low tech, virtually being done by farmers, no fracturing or anything like that. The technique now has improved in leaps and bounds in terms of the drilling mud systems, the fracturing techniques that are available, the drilling techniques and, in particular, the number of wells that you can drill off a single pad, so you are minimising the environmental impact: you can get now up to 16 wells off a single pad.

Q5 Dr Lee: To what extent are these new techniques tested before business starts?
Professor Richard Selley: Yes, this is the nice thing about UK shale gas exploration, of course. It has been tried and tested in the States, and they have drilled hundreds if not thousands of shale gas wells using the new technology, using the new drilling technology and using the new artificial fracturing technology, so there is a wealth of experience that we can draw on in this country without making any mistakes that they might have made.

Q6 Dr Lee: That is a nice caveat at the end. That was the purpose of my question. To a certain extent, we drill blind, do we? Are we sure that the techniques that have been used in America are applicable to the geological environment that one would find in Britain?
Professor Richard Selley: Even in the States the cliché is "there is shale gas and there is shale gas". There are different types of shale gas formations that respond differently to different types of fracturing.
Dr Lee: So that is potentially yes.
Professor Richard Selley: It will be a learning curve—
Dr Lee: So it is potentially yes to that question.
Professor Richard Selley: Yes.

Q7 Dr Lee: In terms of each well, how often do you do the fracturing process—the hydrate fracturing process?
Professor Richard Selley: I am not a plumber; I am a geologist. I suspect you will be hearing evidence from reservoir engineers who can answer that better than I do, but it is possible to repeat fracture over a period of years, what is called a workover.

Q8 Dr Lee: Is the expertise in that area predominantly based in the US?
Professor Richard Selley: At the moment, but of course now Shell are drilling wells. They have already drilled a shale gas well in Sweden. There is a lot of drilling activity going to take place this year across the rest of Europe, probably in South Africa too.

Q9 Christopher Pincher: Professor Selley, you say you are a geologist, so you might not be able to answer all of this question, but have a go. It comes in two parts. First of all, how deep on average are shale gas drill wells? Secondly, given that you have to drill vertically and then drill horizontally, is there any significant cost implication of that horizontal drilling, which must be much more technically challenging?
Professor Richard Selley: Yes, indeed. It is more expensive to drill horizontal wells than a straight up and down well, yes.

Q10 Christopher Pincher: In terms of the depth one normally goes?
Professor Richard Selley: The depths will vary. The early shale gas wells were virtually from the surface. Do you prefer feet or metres, Chair?
Chair: I am relaxed with either myself, but if we want to be 21st century we should probably use metres.
Professor Richard Selley: There have been shale gas wells produced drilling within tens or hundreds of metres. Now, it is not uncommon to go thousands of metres—way below the aquifer, if that is your next question. *[Interruption.]*
Chair: Mr Smith, welcome. We made a start as all of us probably have some time deadlines we have to meet, but I hope you were not unnecessarily troubled by the security getting in. We have just made a start so far. We are asking a series of questions and feel free—please both of you feel free—to answer them, but if one of you prefers to leave it to the other, that is also fine.

Q11 Dan Byles: Leading on nicely from your point about the aquifers, there has been quite a lot of media hype, I think, about shale gas being blamed for all sorts of things from mini earthquakes to flocks of dead birds to burning water from the taps. Is there any evidence for any of that?
Professor Richard Selley: I am glad you asked me that question. The famous one that is in the Gasland film, which many of you I am sure have seen on television—the Weld County event. the Colorado Oil and Gas Commission carried out a report on those gas seeps in 2008, and they concluded that it was shallow biogenic gas—marsh gas. that is. Of course, you do not hear about that on television because it is rather dull to have a talking head say, "Well actually, it has been there already."
The other example that has attracted attention is the Parker County one in Texas, the Range Resources well, where again there are claims of aquifers being polluted. Again, that pollution had occurred before any shale fracturing went on. The gas that has been recovered contains not just methane but also nitrogen, and that does not occur in the Barnett shale, the deep shale that has been fractured. That is almost certainly from the Strawn shale, which is much shallower. When you look at these individual claims, they often showed up what we call the Francis Drake effect: it is something that has already been there, but the oil company gets the blame for it.

Q12 Dan Byles: Can you just elaborate a bit more? You said it is not coming from the deep shale, but it is potentially coming from another shale?
Professor Richard Selley: From shallow shale that was conventionally drilled a number of years previously. It is nothing to do with recent shale gas fracturing.

Q13 Dan Byles: Is there any evidence that either gas from shale gas drilling or the fluid used as part of the fracturing process, either of those products, have ever contaminated drinking water supplies?
Professor Richard Selley: Not that I am aware of, but I do not claim to know everything.

Q14 Dan Byles: Are there any other risks associated specifically with shale gas that would not be associated with conventional gas or conventional hydrocarbon exploration or drilling that you are aware of? I keep looking at Professor Selley, but obviously these questions are open to either of you.
Nigel Smith: The Tyndall report has mentioned a few examples. I think we need to look into them carefully to see whether they apply to the UK or Europe. Some of them will not apply, I think. One that I have looked into, the one in Ohio that they mention—number 2—is a conventional well anyway. It is targeted at conventional sandstones, deeper than the shales, so we do not know exactly where the gas is coming from originally.

Q15 Dan Byles: Would you agree with that, Professor Selley?
Professor Richard Selley: Yes.

Q16 Dan Byles: Just one final question, Chair, if I may. Some people have referred to the casing used to separate the well from aquifers; do you think that it is that casing that would protect aquifers, or do you think that is not necessary and, because of the levels of the depth that you are drilling, that is a non-issue?
Professor Richard Selley: That casing is routine anyway and I am sure you will hear expert evidence from Cuadrilla on this. In any well that is drilled to several thousand metres, you will have, within the zone of the aquifer, three, maybe four, steel cylinders with concrete between them because as the well is drilled, they will drill down, pull the drill string out, set some casing, pump down cement and cement it in, go in with a narrower drill bit, drill another few hundred or thousand metres, go in with a second string of casing, pump in cement, and so on. In the shallow zone where the aquifer is, and we are only going to be talking here of to 300 metres, you have got three or four concentric tubes of steel cemented in place. It is quite difficult; it would be quite an agile methane molecule to get through that.

Q17 Albert Owen: If we could go now to the UK prospects, you mentioned earlier, Professor, Shell exploring in Sweden, but what are the prospects for Britain and are we relying too much on comparisons with the US, which we have read a lot about in the papers that we have been given?
Professor Richard Selley: I think the BGS have done a very detailed study on that, but I am quite in favour of the Weald, the Jurassic shales of the Weald, as well as the carboniferous, which is being looked at at the moment. I am sure there is more potential outside the Cheshire basin, yes, indeed.
Nigel Smith: I agree with that, yes. There are probably four good plays that they could try—well, three good ones, and one very risky. The first one would be the Namurian; the second one would be the Weald and the Wessex Basin the Professor was talking about; the third one is also quite risky, and that is the Cambrian play in central England, going into Wales; and then the fourth one would be looking in the fold belts, which the Americans are starting to do now, so there is evidence that you can produce gas even within fold belts.

Q18 Albert Owen: The basis of my question is: are we looking too much to America? Can we not research and fund the research in the UK here specifically for the prospects of the United Kingdom?
Nigel Smith: We have done as much as we can with the data that we have. The problem is that, with the legacy data that was acquired for conventional hydrocarbon exploration, they targeted the limestones, the sandstones, the reservoirs. For example, the cores are nearly all in that, the cuttings and even the side wall cores, so there just is not enough evidence about the shales and how they are going to perform as a reservoir.

Q19 Albert Owen: Professor, you mentioned Sweden and Shell going out there. Is that an area we should be looking at as a Committee?
Professor Richard Selley: It is very interesting because the particular rock formation in Sweden and northern Poland is something called the Alum shale. We have that equivalent and this is what Dr Smith alluded to: Cambrian shales in the Worcester Graben, which are time equivalent of a very well known organic rich shale.
Albert Owen: It would be worthwhile us looking at that in greater detail as well as the Americans.
Professor Richard Selley: Indeed, yes.

Q20 Albert Owen: The other question I wanted to ask relates to exploration companies. They are going to come along, but you have identified to the British Geological Survey work on sweet spots and places where they can go and get immediate results. Should we be pointing them towards that or should there be greater research?
Professor Richard Selley: The "sweet spot" is a colloquial term, meaning within a reservoir where we already know we have got petroleum. You can often identify areas with very high porosity and permeability, often seismic, and those are referred to as sweet spots. They are within a reservoir rather than a whole sedimentary basin where the term we would use for that is a "play".
Nigel Smith: If you are drilling out the whole source rock, there will be places where you get higher productivity. They will be the sweet spots. If you can predict them in advance, great, but a lot of cases you will not be able to.

Q21 Albert Owen: It is a bit hit and miss then.
Nigel Smith: Well, you will know where the source rocks are—they will be quite well mapped out.
Professor Richard Selley: The nice thing is that now with seismic, it is possible to identify some of those sweet spots from seismic. Especially the latest trick is, while you are fracturing, you can have your geophones listening to the shockwaves coming back and the fracturing energy source will help you to define the sweet spot. Then you are going with your cunning drilling and you aim straight for it.
Albert Owen: Fascinating.

Q22 Dr Lee: I am looking at this rather beautiful DECC map of shale gas resources of Great Britain in colour. You said you had a legacy of data. How accurate is this map?
Nigel Smith: I think that probably the oil companies are going to go in close to the existing boreholes so, if you can see there, there are a few red spots and green spots showing the actual gas discoveries or gas fields. Then there will be lots of other wells that are being drilled deeply into the carboniferous in northern England, and I think the oil companies will be going in close to where those existing wells are.

Q23 Dr Lee: It has already been mentioned that you can drill—was it—16 times from one site?
Nigel Smith: Sixteen wells, yes.

Q24 Dr Lee: Is there a tendency just to sort of move slightly further away and try again or is it, "Right, okay, we're going to go 100 miles down the road and try it"? What is the sort of strategy? The reason I ask, I just wonder whether, say it went over my constituency: are they going to try in Crowthorne and go down the road to Sandhurst and then across to Fitchampstead? I am going to end up with a constituency full of trucks?
Nigel Smith: Cuadrilla, they started with a big licence in Lancashire and it covers all of what we call the Permo-Triassic Basin, the West Lancs Basin, which stretches from the coast to Pendle Hill and the Carboniferous outcrops. They have got three wells they are going to put down. They have already drilled one. They have got two more that are about five kilometres apart. They are going to start in one area where they think they have got a good—where is the best target. If it is not successful there they will try somewhere else within their licence.

Q25 Dr Lee: Is there a strategy of how far away they go? I mean, this is huge swathes of British countryside. It is not like you have got a small target. Is there a tendency, "Right, we have done Berkshire; we will go to Hampshire"? Do you think?
Nigel Smith: It is difficult to know. We will have to wait for the next round of licensing from DECC.

Q26 Dr Lee: It is just that the uncertainty of the data slightly concerns me and that this might end up being a bit of a "close my eyes and throw a dart."
Nigel Smith: No, it will not be.
Professor Richard Selley: To a certain extent that is the risk of petroleum exploration. We can have ideas, we can have fantasies and decide, well, we think the gas or the oil is there, but it is a high risk business.
Dr Lee: The difference being that we are dealing with populated areas, not the North Sea.
Professor Richard Selley: Chairman, can I put this into perspective? There is a line of oil and gas fields around the Weald paralleling the North Down to the South Downs. There are fields there that have been producing oil and gas for 100 years. Not many people know that.

Q27 Dr Lee: What—from shale gas?
Professor Richard Selley: No, this is conventional petroleum.
Nigel Smith: Also it is true in the East Midlands as well. I mean, that helped in the Second World War effort. Does anybody know there was an oil field at Formby? These things were developed. BP have done a brilliant job at Wytch Farm drilling out laterally, even offshore, yet, quite a few people in the general public do not even know it is going on.

Q28 Dr Lee: In terms of water contamination, how many tests have been done in those areas since?
Nigel Smith: I do not know of any water contamination in any of these onshore fields.

Q29 Dr Lee: If you are not looking, forgive me, you are not going to find it, are you?
Nigel Smith: No, but it would be reported. You cannot keep anything quiet these days, I would say. The local authority would find out.

Q30 Chair: I am interested in your references to these areas that we are not aware of. You said that north Weald, I think, was an area where oil has been produced.
Nigel Smith: Yes, Palmer's Wood.
Professor Richard Selley: Yes, along the North Downs.

Q31 Chair: Are the volumes meaningful? Given what the potential is, we are told, from shale gas and, indeed, the expected demand for gas in the next 20 years, are the volumes that are being produced in these quite sensitive areas without anyone noticing significant?
Nigel Smith: Only at Wytch Farm, I would say.
Professor Richard Selley: Wytch Farm in terms of the volumes, but they have a significance out of all proportion to their reserves in times of war. The Nottingham oil fields, for instance, in the Second World War, were crucially important to this country at that time. There is a security angle to this.
If I can just come back to Wytch Farm for a moment, it is worth pointing out that I think Sandbanks is an estate with the highest property values in the country and yet there is an oil field underneath it, and I wonder how many people know that.
Chair: Yes, it raises a new line of inquiry.

Q32 Dr Whitehead: I am trying to understand the combination of the relative economics and extractability of shale gas. Certainly, in terms of the techniques, it appears that there would be likely to be a fairly rapid decline in output after you have undertaken the initial fracturing, and presumably as a reasonably small area of capture from each fracture, which therefore limits the output per drilling. What are the decline rates like in terms of that?
Professor Richard Selley: That is an interesting question. I looked into this because in the old cottage industry style shale gas production, a single well would produce for 30, 40 years, but at a very low rate, but one well would do for a housing estate or a farm or a school, or something like that. I have been trying to get data on decline rates for modern high tech

fracturing. The USGS has produced data on this and done a lot of modelling, but it is all fairly short term—for three or four years, something like that. As I say, I am only a geologist, not a plumber. I think the reservoir engineers could give you better answers to that decline rate.
Nigel Smith: There is a decline rate in all exploration anyway. In some of the biogenic shales in America, there are much shallower wells and they have a different profile to these fractured shales from greater depth, like the Barnett, so they all have a different decline rate.

Q33 Dr Whitehead: I mean I take the parallel of Wytch Farm, which I am reasonably familiar with because I happen to live fairly near it. That is a couple of wells and a nodding donkey with some horizontal drilling out, so it is a very tidy long-term operation. The question of decline rates with shale gas suggests to me the possibility that you would have a large number of wells in a particular area, which would then be in various rates of decline, and presumably would then have to be capped off and made safe, and then moved on, or is that a mistaken view of what a shale gas exploitation process might look like?
Nigel Smith: I think they are going to fracture probably every three or four years and there is going to be a jump in production again. It is going to go like that. It is going to be an overall decline but there are going to be jumps. They will do their best to keep it going as long as they can.

Q34 Dr Whitehead: You say "as long as we can". You mentioned, Professor Selley, a well that would conventionally last for about 30 or 40 years, which seems quite a short time in terms of conventional production. Is that right?
Professor Richard Selley: No, I do not think so.

Q35 Dr Whitehead: The process of refracturing, I presume on the basis of the steerability of drills that, roughly speaking, what you would do is you would have one horizontal drilling and then your refracturing would be at various angles around the central drill. Is that right? Is that how it would work?
Nigel Smith: The difference from some of the old exploration is that they used to do it all from vertical wells. Now they will be drilling horizontals and they will be perhaps splaying out in different directions from one pad site. They are going to do a much more thorough job over a much larger area before they move on to the next point, or if that is in the next licence the other company will do it.

Q36 Dr Whitehead: Do you have or is data known about the extent to which, if you have one drilling point, then with refracturing around that drilling point there is presumably a likely finite life for that whole operation to reach the point at which refracturing, because everything has in fact been gathered as it were, becomes unsustainable?
Professor Richard Selley: I think it might be sensible to address those questions to the engineers when you have them in to give evidence, rather than us.

Q37 Christopher Pincher: I was also taken by this rather fine colourful map of the onshore deposits, but can we talk about offshore shale gas for a moment? The briefing note I have says that "UK onshore basins are small in comparison with UK offshore basins". Can you say what the magnitude of difference is between offshore and onshore deposits?
Nigel Smith: I cannot offhand, but I would say five to ten, something like that. It is massive, the North Sea.

Q38 Christopher Pincher: That is where it is—in the North Sea?
Nigel Smith: Well, that is where they start, yes, where the existing infrastructure is. They might start drilling from the onshore into the offshore or perhaps across a bay or something like that, where they can connect up their wells. I think that is quite likely. I mean, they have already drilled once in southern England from the coast into the offshore. They have also drilled on the Moray Firth from the onshore towards a field that is offshore, so there is a precedent for that, but the oil companies say it is the cost. I am sure they will make proposals or think about developing shale gas offshore, but it is the cost at the moment that stops them.

Q39 Christopher Pincher: What do they say is the cost? What sort of price are they talking?
Nigel Smith: I have not seen the figures. They will know the cost. You can ask them perhaps.

Q40 Christopher Pincher: Given your background and experience, and given that you said that there is shale gas in the North Sea where we have conventional drilling platforms, what do you think the opportunities are for drilling for that gas offshore compared with onshore? What is the relative opportunity?
Nigel Smith: I would say it is more in terms of time—20 years forward, perhaps.

Q41 Christopher Pincher: As I understand it, if we drill offshore, then we would be pioneering because nobody else is doing that. Why is that? Has nobody else found any offshore shale gas anywhere?
Nigel Smith: Bear in mind the Americans are the only ones who have any production at the moment. There are one or two other discoveries in Argentina. There was one mentioned recently, but they are the only people who are producing from shale. They have got a huge continent to work on, massive basins, not a lot of deformation in those basins, so they are going to pick off the easy things first, learn how to do it, and then eventually we will all be able to go offshore.

Q42 Christopher Pincher: Professor Selley, do you have a view?
Professor Richard Selley: I think it all depends on the economics. I am sure the technology is there to look for and produce shale gas offshore, but I suspect at the moment it is an economic issue rather than a technical one.

Q43 Christopher Pincher: Based upon the economics, at the risk of leading witnesses, given that

America, the only other interested party in shale gas at the moment, is focusing onshore because that is where they have their deposits, and because you say that we have a magnitude of opportunity different offshore, do you think we should be putting our efforts into offshore shale gas production rather than focusing on onshore?
Nigel Smith: I like to walk first before I run.
Professor Richard Selley: Quite.

Q44 Christopher Pincher: What sort of challenges? You have alluded to some of the challenges drilling onshore for shale gas. Are there any different challenges drilling offshore?
Professor Richard Selley: You don't have people for a start offshore.

Q45 Christopher Pincher: You mean residents complaining, yes, right. Are there any others?
Nigel Smith: It is easier to acquire seismic as well: straight lines, 3D surveys, they already exist so in a lot of ways the data is better offshore.

Q46 Christopher Pincher: Is the fracturing easier to achieve offshore than onshore for any particular reason?
Nigel Smith: There will not be any environmental problems there either, I would say. As for the saline water, it depends how saline it is. Maybe you could just put it into the seawater.

Q47 Dan Byles: We had Professor Dieter Helm giving evidence a few weeks ago and he said, in his opinion, increasing use of conventional gas sources around the world meant that for policy planning purposes we could now consider gas to be an unlimited resource. I am curious to know what your thoughts are on that.
Professor Richard Selley: I preface my remarks by saying I am a geologist, not an energy expert, but the quotation I came across yesterday was that the United States' gas reserves are now energy equivalent of the oil in Saudi Arabia.

Q48 Dan Byles: Is that the remaining oil in Saudi Arabia or the oil that Saudi Arabia has in stock?
Professor Richard Selley: Good question. I think the remaining oil. I am not endorsing that. I am just passing that on—a factoid.

Q49 Dr Whitehead: Could I ask a question about cost, but on the basis of trying to understand the relationship between the recovery process, from what I assume is a very substantial but diffuse, what might be, field of shale gas, as opposed to a far more limited but concentrated field, say, of conventional gas? The process of conventional gas, as you say, would be to make a discovery, find the trapped pocket, which may be large, put one or more wells down into it and extract the gas over a period of time, whereas shale gas recovery presumably would have to, as it were, repeatedly approach whatever the field is by a whole series of relatively small fracturing operations.
Professor Richard Selley: That is why earlier I said it may be more useful to use the analogy of hydrogeology than petroleum geology. Looking for oil in a conventional sense, with seismic, we can map the trap. We can now image the oil and the gas within it, and we can see those fluid contacts moving as the field depletes. The trouble is with non-conventional hydrocarbons, and shale gas in particular, it is very hard to define the limits of the productive reservoir. These shale formations go on for hundreds of kilometres; one does not know the extent that they could be producing.

Q50 Dr Whitehead: It just appears to me on the basis of just that fact comparison that the relative costs of extracting conventional gas from a field and undertaking shale gas extraction must be very substantially different, as will the environmental activity relative to the two in order to allow that extraction to take place. Presumably, therefore, if you look at the life cycle cost of both techniques then shale gas inevitably, however easy the extraction may look, must come in at substantially greater, I guess.
Professor Richard Selley: It is interesting, the States now, the shale gas boom is over because the gas price is so low that the number of rigs that are actively drilling for shale gas is declining and they are moving on now to oil shale exploration instead.
Dr Whitehead: There presumably is a point at which to some extent sort of shale gas exploration defeats itself.
Professor Richard Selley: Market forces.

Q51 Dr Whitehead: What is that point? Is there analysis?
Nigel Smith: If the gas price goes down the more marginal, more difficult, expensive fields will be dropped, but the good ones will carry on. That is how it would work.

Q52 Dr Whitehead: How do we know which is a good one?
Nigel Smith: The companies will know. We do not need to know.
Professor Richard Selley: We are just geologists, not economists.

Q53 Dr Whitehead: I presume from a geological point of view you have mentioned the difference between being able to pretty much determine what a conventional gas field is looking like, its extent and its extraction rate and its likely available reserve, which you cannot do as far as shale gas is concerned. I am almost reminded of the notion of sticking pins repeatedly in a pin cushion to see—
Nigel Smith: I think we know roughly where the shale is. There are places in Derbyshire, for example, where you would not drill, but to the south you might, to the north you might. I think it is fairly well defined based on existing exploration. There are always going to be successful fields and less successful fields.

Q54 Dr Lee: I think this is probably the fastest we have gone through a series of questions at one of our meetings since I have been here because of the succinctness of your answers—maybe it is the style of

a geologist, but it seems that you are pretty certain about things. There is a certainty to your information.
Nigel Smith: No, there is no certainty.

Q55 Dr Lee: Forgive me for this open question from an ignorant position, but is there anything you are not sure of, that you are concerned about or that you have concerns about? Is there any uncertainty about the exploration of shale gas?
Professor Richard Selley: Surely, repeatedly in our evidence we have passed, ducked the question and said, "You would do better to ask the engineers, better to ask the economists," and so forth.
Dr Lee: But the engineers are relying upon your work.
Professor Richard Selley: Yes.
Dr Lee: You must have an opinion.
Professor Richard Selley: Yes, we have an opinion, yes.

Q56 Dr Lee: Which you are not prepared to share? What I mean is you deal in fact, which is fine, you are scientists; but is there an area where you think, "I wonder what will happen when they drill there."
Professor Richard Selley: Yes, I mean it is experience.

Q57 Dr Lee: Geologically, is there a concern? Are we sure about where the aquifers are for sure, 100%? Are we sure? Without wanting to suggest for a second that it necessarily contaminates water, my point is the level of uncertainty that I am trying to get down to from a geological perspective.
Professor Richard Selley: I think what we can be certain about geologically in terms of shale gas in this country is that we are able to map the shale units. We can do that from outcrops, studies from boreholes, studies from seismic. We can measure how much organic carbon they contain, where we have got well data.
As to the extractability of gas from those shale units, that is a matter for the engineers. Again, I return to this: think hydrogeology rather than petroleum geology. If we were looking for potential petroleum geology, yes, we can map the traps. We can now generally see the oil-water contact and the gas-oil contact, and the engineers, as that field is depleted, you can often see those surfaces moving. There we can be pretty robust, but if I come back to shale gas, it is much more fuzzy. Think hydrogeology, think aquifers, rather than a confined, restricted trap.

Q58 Dan Byles: I just want to briefly come back to the points that Alan was making: what we think the medium to long-term impact on the energy markets, the economics of energy of shale gas are. I think we are all aware that higher energy prices mean that more marginal oil and gas fields are worth exploring, when energy prices come down they are not. Do you think that large reserves of shale gas in the United States will effectively have a sort of capping effect on prices? As prices reach a certain amount, suddenly it is worth digging out the shale, which has a dampening effect again. Is that a reasonable thought?
Nigel Smith: Yes, I think so, because the other sources of gas that we are relying on, I think the price will tend to come down if they do not have to supply the US.

Q59 Dan Byles: Basically, shale gas is going to almost put a bit of a ceiling on gas prices that perhaps was not there before? Whenever gas prices spike suddenly it is worth going and tapping a source. Overall, is it a fair summary of your view that there is currently no real evidence that shale gas is any more dangerous than any other sort of hydrocarbon or exploration. It is another source of energy to be tapped for the UK when the economics say that it is right to do so, based on price and cost? Is that a fair assessment?
Nigel Smith: Yes, I agree.

Q60 Albert Owen: Earlier on, Professor, you were describing to us—from my perspective, I am very elementary in this—but you were talking about coalbed methane as another unconventional type of gas. Is it an "either/or" here? The way you describe how coalbed methane would be available, I presume it is in existing coalmines, and they are easy to get to. I know you are going to say it is probably for the engineers or it is economics, but I am just saying, from your perspective, do you think it is easier to tap that and get that resource out than it is to speculate in the way that we have been about the shale gas?
Professor Richard Selley: There is quite a long track record of coalbed methane extraction abroad and in this country. It began when they discovered that, when the coalmines were operating, they were venting all this methane into the atmosphere anyway, so why not collect it and use it? It is a different technology.

Q61 Albert Owen: They know the seams. It has all been mapped out. It has all been dealt with. Surely, that is easier to find and probably easier to extract than shale gas?
Nigel Smith: There are a lot of licences at the moment where companies are looking for coalbed methane, but there is a problem in the UK and Europe compared with America. It comes back to the point you were making, Phillip, that we do not know why. It is probably the permeability of the coals are much lower in Europe and for the UK compared to America. I am looking at exactly the same age of coals. I am not comparing Carboniferous coals with Tertiary coals. It is the same carboniferous coals.

Q62 Albert Owen: Do you see it as an either/or or do you think we can be exploring both equally?
Nigel Smith: I think Nexen and Island Gas, for example, is one company that is operating in Cheshire and Lancashire. They have been looking for CBM and they are starting to develop the first pilot field now at Doe Green. They are also thinking about the shale gas underneath. There could be a trade-off because you are trying to dewater the coal seams before you can produce the gas. There is a nice graph that you can see where the water is declining as the gas increases. That is the best scenario. It may be you could use that water that you have extracted from the coal to start

injecting into the shale deeper down. It could work very well together.
Albert Owen: That is interesting.

Q63 Christopher Pincher: A question about gas consumption. Since the turn of the century, we have become a net gas importer. By 2009, about 32% of our consumption was imported. I just wondered if we maximise the potential for onshore shale gas, and also offshore, what impact could that potentially have on our import rates? What could the offset effect be?
Nigel Smith: I think if we went offshore, we could become sufficient, but not just in the onshore, no. It is going to be a small contribution, I think.

Q64 Christopher Pincher: You are saying if we went offshore and we explore this to its full potential, we could effectively reverse the import effect that we have had since the turn of the century?
Nigel Smith: It is a difficult prediction but I will stick by it. What about you?
Professor Richard Selley: It is security of supply. The opportunity for developing indigenous gas resources onland in this country is a tremendous one from the security point of view. I do not think that is a point that needs to be laboured.

Q65 Chair: Even though that might be more expensive than the alternative sources?
Professor Richard Selley: Indeed. What price can you put on security?
Chair: That is clearly a political judgement.

Q66 Dr Whitehead: In terms of its exploitation onshore, one of the arguments, for example, on offshore wind as opposed to onshore wind, is the question whether, provided the cost is not too disproportionate, having large wind farms well offshore is preferable to having a smaller number of wind turbines on top of a whole series of hills. Is there a similar analogy with shale gas exploration? When it is in my mind, it is assuming that one is looking in a geological formation for shale gas in a slightly uncertain way, that there would therefore perhaps be in a particular area two or three dozen wells producing over a period of time, producing the same sort of energy output as you might get from a number of wind farms or you might get from one well of conventional gas.
Professor Richard Selley: Pass. I am only a geologist.

Q67 Dr Whitehead: You have no view or opinion on what that would look like? That drilling process in terms of the geological formations that one is looking at?

Q68 Chair: Would we understand all this better if we funded some more research into surveying for shale gas?
Professor Richard Selley: Absolutely.
Nigel Smith: Of course.

Q69 Chair: Now there's a surprise. If it is possible to stand back and look at the alternative ways in which we might want to spend our money—clearly, you have got a professional interest in all this—but would that be a sensible thing? Obviously, we are looking at a completely blank sheet of paper in terms of what we might conclude when we have done this inquiry. We are coming to the end of this session, but my impression is there is a huge potential there. It may be expensive. There are a lot of uncertainties. Would it be a sensible use of money, in terms of giving a return on it to try and reduce that uncertainty by funding a bit more research?
Professor Richard Selley: Yes.

Q70 Chair: What could we hope to learn if we did that?
Professor Richard Selley: It is a cliché in shale gas that there is shale and there is shale. The petrophysical properties of the shale vary from rock formation and from place to place. By that I mean the porosity, the permeability, the degree to which they will respond to fracturing. There are critical physical properties that we need in a shale. If it is too soft or it is still too clay, it is not going to fracture. If it is too indurated and metamorphosed, it will not fracture at all. There are lots of petrophysical properties of the shale that we would need to research.
Nigel Smith: We also need to know about the gas contents of shales, so that when—I mean, if there was money, for example, for boreholes—we drilled into the shale, we would take the cores, package it up so it could be analysed and find out exactly how much gas is in the different shales. It is the sort of work the oil companies will be doing, but we can contribute.
Chair: Thank you very much. It is illuminating for us. I think some of us are starting from a fairly limited base of knowledge on this issue, but you have helped us quite a lot. Thank you for coming in.

Examination of Witnesses

Witnesses: **Jennifer Banks**, Energy and Climate Change Policy Officer, WWF-UK, and **Professor Kevin Anderson**, Director of the Tyndall Energy Centre, University of Manchester, gave evidence.

Q71 Chair: Good morning, welcome to the Committee. Thank you for making time to see us. As I said at the start, certainly I am starting from a relatively uncluttered mind on this issue, so we look forward to hearing what you have to say.

Could I ask generally whether it is right to say that the carbon footprint of shale gas may be a bit larger than conventional gas, but it is still a lot smaller than coal?

Jennifer Banks: I think that Kevin will probably go into the findings of the Tyndall Centre. Shale gas inevitably uses more energy than conventional gas exploration because of the hydraulic fracturing process and the injection of high pressure water into the ground. One of the questions is to do with methane emissions, which may be about 1.5% of the total gas produced, which are called fugitive emissions, and may be basically methane that is escaping in the production and transportation process. There is certainly more research required on that issue. A paper by Robert Howarth recently suggested that it may significantly decrease the advantage of gas over coal to the point where the emissions may be equal. That was a preliminary paper, which has been criticised in some quarters, but it certainly would merit more investigation.

Professor Kevin Anderson: It depends whether you have good practice or bad practice. There is plenty of bad practice in normal gas extraction. There are examples throughout history of very bad practice in the petrochemical industry. If you imagine you had very good practice and you compared that between natural gas and shale gas, I think it would be fair to say, as much as we can from the evidence to date, that there would be very little difference between the two when you looked at their overall CO_2 emissions once combusted—their greenhouse gas effects. Of course at the moment, we do not have that much experience of producing shale gas, so it is likely that good practice will come over time. At least initially, I think there is a much higher risk of these other sets of issues, these fugitive emissions, but these are not things that a stringent regulatory framework could not look to overcome in the medium term.

I had not thought about this before but that would be a very good reason why not to rush ahead with this until you were sure you had the best practice you can envisage now and you had a "learning by doing" while you pursued shale gas in its infancy in this country. Overall, your comment is correct. The shale gas emissions do not, at the moment, appear to be that different from natural gas once combusted.

Q72 Chair: As it happens, are there fugitive emissions from other forms of fossil fuel? I mean this is not a problem that is confined to unconventional gas?

Professor Kevin Anderson: No, there are fugitive emissions from all sorts—if you play around with fossil fuels you will have fugitive emissions.

Jennifer Banks: I agree. That appears to be an issue with gas in general that maybe has not been looked into as much as it could have been.

Q73 Chair: In terms of trying to establish what best practice would be, clearly there has to be some practical experiments to do that.

Professor Kevin Anderson: Yes, of course, we have had some practical experiments in the US. What we require, I think, initially would be to learn from history. It seems a reasonable approach to take, yet we have not done that. We have not looked in detail at what has happened in the US. What we know in the US is that some of the states there now have a moratorium on further development pending an inquiry—an independent scientific inquiry. That seems a reasonable route to go down. It is hard, I would suggest, to argue different to that, in the absence of an independent scientific inquiry, we will go ahead. It would seem a strange position to hold. I think that we should at least wait to hear back from the EPA in the US.

As the previous witnesses suggested, shale is not necessarily shale. They vary in their petrochemical properties very significantly. I think you would then also have to say we needed one in the UK that looked at the types of shale we have here and the differences across the shale here, and try to draw lessons from the US study once that is published. All these are very good and sound reasons why a prudent nation would not rush ahead with it.

Q74 Dan Byles: You have referred to the possibility of not rushing ahead in the UK, but it seems that we are on the cusp of making a series of investment decisions that we are going to have to live with for decades, particularly with regards to electricity production. Surely, it makes sense to try to actively switch from coal-fired electricity production to gas-fired electricity production in the medium term?

Jennifer Banks: We would not argue with the fact that, yes, gas does have significantly lower emissions when it is combusted than coal does. One concern that we have is very much that prospects for building new coal-fired power stations in the UK are relatively limited at the moment. It does not appear that coal is going to play a massive part regardless of whether we press ahead with shale or not. The concern is more to what extent gas may displace renewable energy and to what extent meeting our carbon budget and our decarbonisation targets could be threatened if there was another dash for gas or too much investment in new gas generation.

Professor Kevin Anderson: I think there are a lot of issues in what seems like quite a simple question there that, if you want us to unpick, we can do.

Dan Byles: Please do.

Professor Kevin Anderson: Certainly, there is a serious risk if we decide to move down the gas route—if you look at the planning applications for new power stations at the moment, basically, we are building gas and the Chinese are building coal We are not doing any renewables of any significant proportion relative to what we need to be doing, relative to the amount of gas stations. Gas dominates. If we have more available gas here that offers potentially security of supply benefits. That would tend to put even more emphasis on the future of gas. Of course, it is very cheap to build at about £350 a kilowatt, much cheaper than renewables, much cheaper than coal, much much cheaper than nuclear. There are a whole set of incentives there why you might go down that route, which would of course have a significant impact of moving or continuing to hold us on a high carbon future pathway. We need to make that transition to renewables as a matter of some significant urgency. If that is the case, then any mechanism that takes away the incentives to move towards renewables cannot be a good deal.

To unpick this, this is a Energy and Climate Change Committee. It has to have a view on climate change. I do not know what position you take on this. If you take the position that this is in the spirit and the letter of what the UK has signed up to—that is to keep below 2º centigrade; below 2º C is very different from a 50% to 60% chance of exceeding 2º C—if you want to abide by your own commitments under Low Carbon Transition Plan, the Copenhagen Accord, various EU agreements and so forth, if 2º C is important, then there simply is not the emission space available in the timeframe that we have to utilise shale gas. That is a simple mathematical outcome of the analysis. We could have changed that if we had started responding 20 years ago to climate change, but we did not. We are now in 2011. We have basically used up all of our emission space. By the time you get shale gas out of the ground, start to put it into a power station or elsewhere, it is too late because our emissions need to be down to basically zero.

If, however, you hold to not meeting our obligations under various international treaties, if you hold to a view that we should have perhaps a 60% chance of exceeding 2º C, which is now fixed in legislation—that is the interim budget from the Committee on Climate Change—so a 60% chance of achieving the things that we claim to be obligated to achieve, then there is a very small emission space available. Even there, though, the Committee on Climate Change, with a 60% chance of exceeding 2º C, 63% chance, has said that the electrical industry would need to be fully decarbonised by 2030. That means there will be no shale gas in it, because you would probably have very little shale gas out there significantly entering the system by 2030. We will have some, but of course we will also have existing gas supplies and gas networks anyway.

Whether you take the CCC's view of, "Let's significantly breach our international obligations on 2º C," or whether to take the spirit in the letter of, "We must not exceed 2º C," both of those would suggest there is no emission space, no reasonable emission space for shale gas, certainly in electricity. Even if you put it into heat, you start to very significantly erode emission space.

It all comes from about which position you want to take on this. If you take a stringent 2º C, the maths are absolutely clear. If you take the CCC view of a 60% chance of exceeding it, there is a minor emission space there. Again, as Jenny points out, if you are also then distracting your attention away from renewables, you have a whole set of cascading issues that will move us away from any reasonable targets.

Q75 Dan Byles: You are basically saying that although gas might be a transition fuel towards a low carbon future, there is enough conventional gas globally to manage that envelope in which we will be relying perhaps more on gas than coal before we move forward into effective low carbon technology?

Professor Kevin Anderson: Yes, but the bit that goes alongside it—I am sorry, all these things become quite complicated—is: are you asking the question about the UK or globally? If we increase our use of gas and reduce our use of coal, if the economists are right and they always tell us they are, then the price of coal worldwide will drop. The price of coal worldwide will drop and there is an energy-hungry world out there. Emissions are probably going back up to a 3% to 4% growth rate. At the moment, increasingly, the global economy is dominated by India and China and some other countries indeed, but with very high coal consumption. If the price of coal drops in an energy-hungry world, I would even, in this case, agree with the economists. You are probably going to see an increase and uptake of coal use elsewhere.

The climate does not care where the CO_2 comes from, whether it is from gas, from coal, from the UK or from China. It only sees the total amount that comes out. You cannot see the UK in isolation if you are interested in climate change. From a climate change perspective, we may move from coal to gas. The climate does not care. It will see more CO_2. It will be used in addition to the coal around the globe and that is all that matters from a climate change perspective.

Q76 Dan Byles: You both said that in the States there is little evidence that the increased use of shale gas has led to any decrease in coal. Is that right? Why do you think that is? What is the extra shale gas being used for? Is it simply meeting increased demand?

Professor Kevin Anderson: Yes. I mean, the whole world has had an economic downturn, but what is interesting the economic downturn was nowhere near as great as people thought in terms of the emission drop. It is about 1.3%, as most people were estimating a drop of about 3% or 4%. That was principally because India and China hardly had any dent at all. We are now coming out of that—we are seeing emissions probably this year going up by 3% to 4% per annum. We need to be doing the opposite, going in the opposite direction at probably twice that rate. We are completely going in the wrong direction. The idea now is discussing unconventional fossil fuels. We can discuss those, but we have to completely park the climate change agenda.

Q77 Dan Byles: Do you think a more sensible use of the potential for a world with increased lower priced gas, which seems to be on the cards, will be to try and use that gas in the transport sector, particularly in the freight sector, rather than in electricity production? Would that have a better environmental impact?

Jennifer Banks: I cannot answer that one. I am not sure, but I think that there is a very big question mark over whether gas is going to be cheap in the long term. We are seeing a glut at the moment because there has been over-investment in, for example, liquefied natural gas, but obviously there is a lot of uncertainty in the market and prices may well go up because at the moment investors have been stung. I cannot comment on the bulk of your question, but I would contest the fact that we can rely on long-term cheap gas.
Professor Kevin Anderson: Even if we could, I mean, yes, some of that would no doubt be used for transport. If the price of gas was very cheap, we would be using it all over the place because we can drive cars with it, we can heat our homes.

Q78 Dan Byles: From an environmental point of view, would that be better than using diesel and petrol, for example, if we are looking for better ways to use the gas while at the same time trying to keep our emissions down?
Professor Kevin Anderson: Do you mean from an environmental or climate change perspective?
Dan Byles: Sorry, I mean climate change.
Professor Kevin Anderson: From a climate change perspective, no, I probably think it had very little impact at all because the problem is we all want to use more energy. We all want more energy, we want it easily accessible and we want it now. It would perhaps be a benefit if there was a carbon cap and we knew that we were going to deliberately substitute for other forms of higher carbon energy, but we have no evidence of that. There is no global carbon cap, there are no agreements globally on what we are going to bring emissions down to. As it stands at the moment, it looks like in the US that, with what has happened there, the Republicans will effectively stop any significant shifts in the US introducing any strong climate change legislation, which will affect the world processes in this, whether you bring the Non-Annex 1 countries, India and China, on board.
There is nothing out there at the moment that suggests we are going to have any meaningful global cap in the short to medium term. I hope I am completely wrong about it. I hope we will have a meaningful cap, but it does not appear we will. While we have no meaningful cap, while we have global GDP going back up to the levels, if not higher than it was before, while emissions continue to rise, we will just burn everything we can take out of the ground. The only way to stop this burning is to keep it in the ground. It is an uncomfortable conclusion, but we have put ourselves in this position in 2011 because of our apathy globally to do anything about climate change.

Q79 Albert Owen: I want to develop these arguments. You asked the question, Professor, are we talking about UK or are we talking about internationally and globally? Well, this Committee has a remit to scrutinise the UK Government and its policies. That is why we are having this inquiry on shale gas now in the UK. I hear what you say about the commitments to the international obligations to which we have signed up, but there again there are three strands to what the Government energy policy is. That is obviously low carbon emissions and meeting our target; it is also energy security and energy efficiency. If we take those three broad ones, I think the question my colleague, Dan, was pursuing there is that if we move from coal to gas in the short and medium term, then we are lowering our emissions, but also we are helping the energy security issue as well. That is we are going to be—we have built large refineries in Milford and the Isle of Grain to bring in that gas. There is a potential that we could have shale gas, and it could be another, as you said, a dash for gas within the UK.
I know Friends of the Earth and others are concerned that that will push the renewables investment to one side, but could they not run in tandem? Could you not sort of be cutting emissions by moving from coal to gas in the short term? We do not know. You heard the first evidence session how much shale gas we have, but it could assist us in that short term of keeping energy prices down, which a lot of people want as well, and the research and development could still be done in the renewable area. Maybe the offshore wind might be reduced slightly, but other renewable energies will be found. Is there not a way? You said it is very difficult. I am posing very difficult points, but it is something that the UK Government has to balance.
Professor Kevin Anderson: I am not saying it is difficult. I am saying it is impossible. There is a significant difference in this case between the two. You cannot produce new shale gas as a fossil fuel. You cannot use any additional fossil fuels you may find, maybe including coalbed methanes and meet our 2º C target. Remember these are not my commitments. These are not my suggestions. These are commitments that we have.

Q80 Albert Owen: Can I just pin you down to the UK itself now? What I am saying to you is that a lot of what we are talking about, low carbon, is not going to come onstream until much later than we would all like. That is not going to happen, so I am talking about that interim period. What I am saying is we are not going to have the wind farms that are planned now overnight. We are not going to have new nuclear coming on for low carbon, so we are going to have a period where we are either going to have a very high energy crisis or we are going to have to fill that gap but be more secure in ourselves. Shale gas is one way of looking at that.
Professor Kevin Anderson: First, I do not think you can see the UK in complete isolation because the UK sets policies that are based on global positions. It takes a view of what the global position is, so I do not think you can isolate the UK from the climate change objectives.
I agree with you completely on the security supply issue. If we can have gas, or any energy source that we produce in the UK, of course including lots of renewables, then that improves our security of supply. That is a benefit. In terms of the price, you may have a point there, but it is not that clear. Do any of you know what you are paying roughly at the pump at the moment per barrel? About $300 a barrel is what you

pay at the pump. What are you paying for your electricity? 10, 12, 15 pence per kilowatt hour; it does not cost that much to generate. We do not have to worry too much about prices. We are already paying very high prices that are way beyond the production costs of any of these things, and our society survives with them. There are big fuel poverty issues, but these can be dealt with in other ways. All I am simply saying, we are paying very high prices for energy today and it is not necessarily related to the production of that energy or generation of that energy. We have flexibility here to move the prices one way or another. They are not a product of the cost of production.

Security supply is important. Prices, we have other flexibility there. The low carbon agenda, I bring you back to. If we want to meet the obligations that we are committed to and, of course, in that there is no time dimension that people tend to suggest that, if we do not do it today, we can put that off and we can do it tomorrow with some other technologies. That does not work in science. The climate science is absolutely and utterly clear about this. It is about cumulative emissions, and we are so high on the emissions budget now that there is no emission space. If we do not do it now, then in the future we simply will breach the target.

Q81 Albert Owen: You do accept there could be a gap there? There could be a gap where we will have to rely on imported coal and imported gas because the new nuclear and renewable investment is not going to come onstream?

Professor Kevin Anderson: Then nor is the shale gas—I mean the shale gas would take about as long as a lot of the renewables. We choose not to go down these particular routes, but of course we have not looked at energy demand, which is where I would suggest—I mean I would suggest—

Q82 Albert Owen: I did mention it in my opening remarks.

Professor Kevin Anderson: In efficiency, yes, but that is not the same thing as demand. In terms of energy demand, I think we can have very significant changes in the UK, if we wanted to, and that could dwarf all of these benefits that we are talking about here in a much shorter timeframe. Again we choose not to—

Q83 Albert Owen: Believe you me, there is a lot of agreement in what we are all saying. What I am saying is that you are saying that conclusively is shale gas is not an insurmountable problem, in your opinion.

Professor Kevin Anderson: Not in relation to the climate change, no.

Jennifer Banks: Can I just come in there? There are several reports that have been published on the kind of transferability of shale gas to Europe as opposed to the boom in the US recently. Florence Gény of Oxford University and Paul Stevens, who spoke at event on shale gas last night here, have both basically concluded that there are a lot of factors that are different. There are a lot of reasons why what has happened in the US cannot be replicated here. Certainly, neither of them believe that there will be a significant amount of shale gas produced in the UK before 2020, which I think sort of breaks down the bridging argument.

Q84 Dr Whitehead: Assuming for a moment that someone does attempt to extract shale gas and taking into account the points about the overall issue of the advisability of incorporating that into an energy economy, the process, as far as I understand, involves pumping water and some sand into a pipe that has been drilled and then extended horizontally. The rock around the horizontal pipe has been fractured and the sand holds the fractures open and the water forces the sand into the fractures; then the gas is extracted. That sounds quite a benign process, but I understand that there are other chemicals involved in that process, which we are told are found in every household—but I have rat poison in my household.

Jennifer Banks: I think it depends whether you are talking about the US or the UK. In the US, there has been a vast amount of chemicals, which the companies have not been obliged generally to disclose. They have been able to not disclose them on the grounds of commercial sensitivity. Some of those chemicals that have been pumped in—and it is generally between 2% of what they call the “fracing mixture”, and it is quite low in Cuadrilla’s case, but down to about 0.5%. Some of those chemicals have included benzene, which is a known carcinogen, and in some cases diesel. The list is very long and the Tyndall Centre report has found that a lot of them are classed as harmful to human health. In the UK at the moment, Cuadrilla are not planning to use substances that appear particularly harmful to human health. I think one thing that does need to be pointed out is that there are fluids present in the shale rock itself, formation fluids, which may include naturally occurring radioactive material, benzene, arsenic and mercury, so it is not just the chemicals that you are putting in; it is also that there can be harmful substances within the rock itself.

Professor Kevin Anderson: I agree with that. While the UK, if it had a stringent regulatory framework here that did not permit some of the chemicals that had been used in the US to be used here, and that could be the case, there is still the risk at the moment of mobilising these other sets of chemicals. If we go back to the previous speakers here, they made the point that we do not really understand the different types of shale gas. We need to understand that all those particular areas you go into in some detail to know the porosity, the permeability—all of these things that they said quite clearly that they did not have a handle on. They are site specific. Until you understand the site specific, how can you make a prudent precautionary judgement on issues in mobilising these sorts of chemicals?

There is of course some—I think it would be fair to call it—anecdotal evidence from the States, at least initially, that there could be some issues of mobilisation of chemicals within the shale to surface and groundwaters. That is one of the reasons, of course, that the inquiry in the States by the EPA has been undertaken. Again, it would seem a wise thing to do to investigate that.

Q85 Dr Whitehead: But I mean the water, as I have described the process, is then pumped out and dispersed. The question in my mind is where and how? Assuming these chemicals are, by that point, firmly in the water, what processes are envisaged or might be envisaged to disperse that water in a reasonable manner, assuming it has a number of chemicals found in every household in it?
Jennifer Banks: In the US, it is either put into temporary open storage pits or into tanks. I understand that, in the UK, open storage pits would not be legal, so I think we would be looking to put them in tanks. The waste water, I believe, Cuadrilla are pumping underground into some kind of deep well. In the US, some of the water has been treated by municipal water treatment facilities, and there has been a lot of concern about the fact that they are not equipped to deal with that degree of contaminated water. It is certainly something that needs to be looked into and robust regulation would need to be present.

Q86 Dr Whitehead: Forgive me for not fully understanding this. The drilling in the UK would be likely to be followed simply by the pumping of water into underground storage with no further treatment and that would be it?
Jennifer Banks: I understand that that is what Cuadrilla are doing, but it is not something that I have a huge amount of detail on. I do not know whether you have?
Professor Kevin Anderson: No, but this is the point where really what we need to have, before you proceed with this, is a stringent regulatory framework. I have every confidence that the Environment Agency, if they are given the task of dealing with this, would deal with it appropriately, but that needs to be thought through and not rushed. I trust the relevant authorities and scientists and the Environment Agency to come up with the appropriate legislative framework, but they need to be given the time to think through these sets of issues, to look at what has happened in the US, to learn from the experience there, to look at the EPA study when it comes out in the US and possibly to conduct their own. This is all a time-consuming process which goes back to the same argument as before that, from the environmental perspective, apart from the climate change perspective, we need to delay whilst we carry out and conduct these checks and measures.

Q87 Dr Whitehead: Are you aware of what sort of volumes might be involved?
Jennifer Banks: Of waste water?
Dr Whitehead: When we talk about the fact that the water going into the fracturing process, 98% to 99% of the fluid that is going into the fracturing process is water and a little bit of sand; 1% of a huge volume is rather more than 1% of not very much, so I have no idea what the sort of volume following a drilling process would then be put into an underground storage or processed and what that would involve.
Jennifer Banks: I have seen a lot of different sources for how much water is required. I have some data from Schlumberger Water Services, who are involved with the hydraulic fracturing industry, which estimated about 91,000 m^3 of water per well. Now, the Tyndall Centre—

Q88 Dr Whitehead: Is that per well per fracturing or per well in the life of the well?
Jennifer Banks: I think it is per well over the life of the well. The Tyndall Centre's figures were lower and I think that reflects the fact there is a lot of uncertainty and there are a lot of different shale plays with different characteristics. Similarly the amount of water that flows back, which would then need to be dispersed as waste water, seems to vary hugely. 60% is one figure that I have seen but I think that it very much varies. So in terms of 60% that would be around I think 54,000 m^3 of water per well.
Professor Kevin Anderson: We have the numbers in our report, which are based on US experience, but again as Jenny says and as the previous witness was saying these are very dependent on the actual petrochemical properties of the shale at the time. But given there is a huge range, the adjective you might apply is "a very large quantity of water". That is what is happening. We are not talking about small quantities of water; we are talking about very significant quantities of water that will have to be treated.

Q89 Dr Lee: I see the Tyndall Centre is quoted saying, "There are a number of documented incidents [of groundwater pollution] in the US with principal causes being improper construction and/or operator error", yet the Geological Society here says there "is no recorded evidence" of contamination and think that it is unlikely in any case. How do you respond to that?
Professor Kevin Anderson: In the US they are saying it?

Q90 Dr Lee: Yes, basically, and I think I am right in quoting our previous witnesses that they do not think there have been any cases of water contamination. What is your response to that?
Professor Kevin Anderson: Well, as you say, the anecdotal evidence is that there is water contamination, sufficiently so that the EPA think it is worth—

Q91 Dr Lee: When you say anecdotal, what do you mean?
Professor Kevin Anderson: Well, in the absence of any scientific investigation at the moment, until we get the EPA study, I would suggest that is probably the first time we will have a real handle on it. Once you get the EPA study then we will know. This is how science works. You observe something, you do a hypothesis and then you go and investigate it and what we have observed at the moment is something that anecdotally, and I think it is important to note that and we probably did not emphasise that sufficiently—

Q92 Dr Lee: What do you mean by that? Is this someone sort of chatting in the bar afterwards?
Professor Kevin Anderson: Well, almost all science starts off with anecdotes. You see observations around you. If an apple falls out of a tree, then another apple falls out of a tree—

Q93 Dr Lee: What I mean is, is somebody actually collecting some water and seeing some more benzene?
Professor Kevin Anderson: Yes.

Q94 Dr Lee: Is that actually happening?
Professor Kevin Anderson: Yes, that has been happening in the States. Now, whether of course that links to the actual fracturing processes that are going on nearby is a different issue—whether that is actually causal, and that is the bit that is really important here. That is why I think it is important. I am not saying environmentally that this could not be made an appropriate technology from an environmental perspective as any other petrochemical industry technology, so the same for natural gas. What I am saying is that we need to understand the mechanisms behind these observed events, of which there are many now in the US. It may well be that some of these are just natural processes and some of these perhaps were occurring before anyone even started fracturing or drilling, but maybe that is not the case. In the absence of an inquiry, it would seem wise again, I say, to hold back on that. And it does appear that in the US it has been sufficiently serious, there have been sufficient numbers of anecdotal evidence, that eventually anecdote becomes something which is serious enough to investigate and that is what—

Q95 Dr Lee: I beg to differ on those. Anecdotally, MMR causes autism. The fact that it was nonsense does not seem to have—
Professor Kevin Anderson: How do you know it is nonsense?

Q96 Dr Lee: Because no actual proper, scientific research paper since has ever repeated the initial claim.
Professor Kevin Anderson: That is exactly my point: "no proper".

Q97 Dr Lee: So my point is if you work upon anecdotal evidence or poor science by some chap trying to make a name for himself because it is good copy for the newspapers, it does not necessarily get to an appropriate conclusion. I say that as someone who is of the right politically but is particularly concerned with our impact upon the environment, so I am not sitting here defending big oil.
Professor Kevin Anderson: But I think you are defending—

Q98 Dr Lee: I am just slightly anxious about the use of the word "anecdotal" when it comes to something like this area because, clearly, if shale gas is as big as we all assume it is, this is profoundly important in terms of those of us who want to see action on climate change. If we are going to actually deal with shale gas, I would suggest that we should deal with proper evidence instead of just talking about, maybe, "We have heard a rumour here and there". Along those lines, I note that a previous witness said that they had been drilling in the Appalachians since 1821. Are there any public health reports on increased incidence of particular health conditions in the area where they have been drilling for a long period of time?
Professor Kevin Anderson: I do not know about the second one, so I cannot comment on that. On the first one I think you answered your own question because there was anecdotal evidence that there were issues with the MMR vaccination, and as you said, we then had a scientific inquiry that showed it was rubbish, but the point is that you had a scientific inquiry.

Q99 Dr Lee: The point is in the process a lot of damage was done in that particular area to people's perception of science, people's perception of truth, and whether to trust governments or organisations and that is why I am just a bit anxious about basing it upon anecdotal evidence.
Professor Kevin Anderson: You do not base it on anecdote—I want to make this very clear. What I am saying is that we observe things in the world, and that all observations in science are like this. Of course, when you observe something you do not know it is fact or scientifically caused by this issue over here until you do the investigation but, if you have a build up of anecdote that suggests this may be the cause, you then undertake, as we did with MMR, a scientific investigation. Now it may then show, "Look, there is no link at all." That is perfectly reasonable, but what is important there is that you undertake a scientific investigation. So anecdote and science are bedfellows and they should be bedfellows.

Q100 Dr Lee: But in terms of water contamination, clearly what the general public are worried about and what is driving the debate in America are health implications, yet you are not aware of any specific studies about any health. In the same way, when they set up nuclear power stations, there were suggestions of increased rates of leukaemia and so on in particular areas. Are we saying that there are no studies in place or no studies that have been done about the mapping of particular conditions? For instance, cancer rates can show some really odd localised patterns in this country. All doctors know this. Why is that? I do not know the answer to that question. Does such evidence exist in America where they have been drilling for a period of time on land? Are there pockets of particular cancers? I just suggest that. I am not saying there is, but are there; and if so, is there any ongoing investigation into that?
Jennifer Banks: I cannot answer that question. I think the point would be that, if contaminants are getting into groundwater sources like aquifers and then into people's drinking water and if those contaminants are things like benzene, then I am sure that science knows what the consequences for human health may be. The question is: are they getting into these water sources? ProPublica, which is basically an investigative journalism organisation in the US that has done a particular investigation of shale gas, has found over 1,000 cases of contamination which have been documented by state and local government in just five US states. That has been quoted in quite a few reports. I cannot comment on exactly what methodology they have used to draw together those cases but it would certainly merit some more investigation as to exactly what that is.

Cabot Oil & Gas have just paid out $4 million to 14 families in Dimmock, Pennsylvania, and are also, I believe, replacing their original water with water that is clean. That is quite a well documented case of contamination. I think one of the issues has been that people's drinking water is not tested prior to drilling so it is extremely difficult to prove after drilling, when chemical contaminants or methane are found in the water, exactly what the source of that is because yes, it is true that these are areas which have oil and gas, so it may be that methane or other contaminants were present beforehand—but then again it may not. I think that there have been examples where the gas has been found to be thermogenic.

I would echo Kevin's point really: it is about having more scientific investigation and it is becoming quite polarised at the moment. What we are calling for is independent peer reviewed, scientific investigation on this issue.

Q101 Dr Lee: That is my point. When it becomes polarised then it ends up being fashionable to be anti whatever it is, irrespective of the evidence, and I personally would not want to see that because you never end up with a satisfactory conclusion.

One final thing, and I have seen a report—the Catskill Mountains in New York State environmental report—and on the basis of that report New York State then passed a moratorium that then was overruled by the Governor; I think I am getting the chronology of events right. How is it that they, in that particular agency in New York State, they are pretty concerned about the potential for environmental pollution, be it in terms of gross pollution, in terms of what you see with trucks on the surface, but also the danger to the water source of New York State, which obviously serves New York City, so you are talking about a huge population. How is it they came to those conclusions, published that report and effected a change in the State's legislation at the time, and yet the US EPA 2004 report was, "No worries"? Have you any comments on that? I do not quite understand how—in view of the fact that this drilling has been going on for some time, that onshore oil and gas exploration—the report by the national agency in 2004 said "Clean bill of health," but a State report in 2009 pretty much reads like, "We should not be doing this until we are really, really sure"?

Jennifer Banks: My understanding is that the 2004 report was more desk-based and was relatively limited in scope.

Q102 Dr Lee: So it was not very good?

Jennifer Banks: I would not want to comment on its quality, I have not read it, but that has been a criticism of it and presumably—I mean, the fact that the EPA have now announced another, much more comprehensive investigation would appear to back that up.

Professor Kevin Anderson: And it is also five years in between and there are the issues about the quantity as well, because if there is a risk issue, if you only drill one well at one pad and that is all you ever do then the risks are very small. If you drill six wells, ceteris paribus, you have got six times the risk. In 2001 the shale gas was just about 1% of US gas demand. It is now at 14% I think—that is approximate but something like that—so what you get is a much higher level of extraction now, and obviously the more you extract for the same risk per unit of anything the overall risk goes up. If you have a high population density like you now have in the catchment of the water going to New York then it would seem wise that you would do the inquiry on the basis of the risk there.

Q103 Dr Lee: I guess my point is about trust. I drew the analogy with MMR; essentially trust was eroded because the whole thing was badly handled. It is about representatives of the general public—they want to trust that the agencies doing the work are doing a decent job. Okay, well if one government agency or state agency says this and another one five years, five years is not a long time at all in the scheme of oil and gas exploration, but the reality that things change significantly in that period of time. I would be suspicious about that. It is about trust and the fact that the agencies are independent as you say, Ms Banks. It is that sense of independence, i.e. they are not being influenced in any way. Can we be sure that the report that comes in 2012 is fully independent of any economic or political influence, in the light of that 2004 report?

Professor Kevin Anderson: My understanding and knowledge of the EPA from the past, which is not as great as it is for the EA in the UK, I have as much trust in the EPA as I do in the Environment Agency here—I have no problems with the Environment Agency over here. I trust that the report will be done as well as it can be done within the budget that they have and the constraints and timeframes that they have. Similarly I would trust the authorities over here to do the same thing.

As you say, the MMR was badly handled, and that is not to say that the process by which you go from anecdote to scientific investigation to making and drawing a conclusion is not correct. I think it is correct, but it has to be handled well in this case and as you say, trust is very important. I do not want any of the comments that I am making, or my colleagues who wrote this report, to suggest that we do not trust the appropriate authorities in the UK. We do, but we want them to have the scientific wherewithal to make informed judgments.

Jennifer Banks: The only thing I would add to that is that from what I have read I think there may be a bit of tension. There is political pressure for the EPA report to be concluded as early as possible and I think that possibly the scientists behind it would potentially like longer than may be available.

Q104 Albert Owen: You have just actually repeated what I heard you saying earlier, Professor Anderson. You have trust in the Environment Agency, and surely whenever there is a planning application, whenever there is a licence, then the Environment Agency would be one of the bodies that would be contacted very early on. And again, Ms Banks, you have said with regards to quality of water, surely that would be monitored now in the beginning, when the licence is issued, and there would be continuous monitoring when exploration takes place. If you have confidence in the Environment Agency then really what is the problem? I know we want as much scientific evidence as possible but the Environment Agency has said it previously had come up with some different evidence in different parts of the world. Surely we now have to concentrate on public health as the main issue but we have the confidence in our agencies, which you said you have, to monitor it.

Professor Kevin Anderson: To monitor it, yes, but I do not think you should do something and then monitor it. I think you should think about—

Q105 Albert Owen: You have an impact study in the beginning, you test the quality of water and if obviously it was right and then immediately there is exploration you would have a change. I mean in my area we had an aluminium smelter, there was fluoride issues there. They monitored it from day one and on a regular basis monthly and then yearly data was available. That would be available, would not it?

Professor Kevin Anderson: I would suggest you normally do things in advance and if we are going to improve the Thames Barrier you do not just put up a design and then monitor it to see how it goes then change it. You would think in the first place, "How shall we do this correctly?"

Q106 Albert Owen: I realise that, but what I am saying is, yes, let us wait for the evidence and if it is clear in America that is not to say, "Oh, it is clear in America, let us not monitor it, let us not really be robust, let us put health and safety issues to one side." There will be strong monitoring of that just as there is, as Dr Lee mentioned, of nuclear power stations and things. There is regular monitoring there of clusters and various things, so that will be monitored, that is my point.

Professor Kevin Anderson: I am sure it will be, yes.

Q107 Albert Owen: And you have confidence in the Environment Agency to do that?

Professor Kevin Anderson: To monitor that, yes. I do not have a problem with that once it goes ahead.

Jennifer Banks: The only thing I would add there is that I actually rang up and spoke to someone at the Environment Agency just to try and find out a little bit more about exactly what the regulations would be. They said that shale gas exploration would probably be subject to environmental permitting regulations and I think that reflects the fact that at the moment, because it has not been done, it is not something that they have considered. There needs to be time for there to be proper consideration of the procedure that should be put in place. I would say that also environmental impact assessments need to be mandatory.

Albert Owen: That is very important. Thank you.

Q108 Christopher Pincher: If we can just put aside the health science and the climate change questions for a moment, though not to forget about them of course, one of the biggest issues that one comes across when one tries to implement some sort of infrastructure project is local opposition because of the effect on the local landscape—the local green valley being torn up and concreted over. I just wonder if you can give us an indication of what you think the impact on the landscape is of the development of an onshore shale gas drilling operation.

Professor Kevin Anderson: This is an issue of aesthetics. If you are digging things up, obviously there are biodiversity issues associated with that, but beyond that thinking about the relatively high population density that we have in the UK, there will be aesthetic issues associated with this. Now, the petrochemical industry has a mixed track record on that. There are some very good examples of what can be done to minimise the aesthetic impact and there are some bad examples. If it is done well then, from what we can understand and certainly from the previous evidence of what we have seen in the US, it will be a much more significant impact than the current production at, say, Wytch Farm which was discussed earlier. I do not think it will be, from what we can see in the US, as minor as that. The fracturing operations have to be carried out more regularly and there seems to be more of an ongoing process to maintain the supply of shale gas than there is with, say, Wytch Farm.

It does appear that the aesthetics will be more significant than some of the other petrochemical activities in the UK currently, but some of these are aesthetic issues—although as I say there are some biodiversity ones—which I suppose good practice could mitigate but you cannot eliminate. Then it is an issue of local planning, hopefully with a process whereby the local population can get engaged as to whether they think this is a viable approach to go down or not. We see the issues with wind turbines and other forms of power generation, but I do not think we can just look at Wytch Farm and say, "Well, actually we just took that out as good practice. That is what shale gas is going to look like." I think it is going to look, from what we can understand, more significant than that with more dynamic issues in relation to transport and issues such as that.

Q109 Christopher Pincher: We will come on to that in a moment, if we can, but in terms of the size impact on the landscape we heard from the previous witnesses that you can put down 16 drills in one pad. The question is how big is a pad and is it different from the size of a sizeable wind farm, for example?

Jennifer Banks: I think the Tyndall Report said that a well pad would be between 1.5 and 2 hectares. I think that was based on there being six wells per pad, so if you had 16 then I think probably the pad would be larger. Obviously, wind turbines are spread out over a larger area, whereas a pad is more compact. The Tyndall Report found, I think, that to produce around 10% of the UK's gas supply needs from shale would require about 3,000 wells, which clearly is a lot of wells, so it could impact quite heavily on particular areas where the shale resources are concentrated. There is an issue with the volume of traffic that would create, although I acknowledge that Cuadrilla are, I think, piping water in, which does to some extent reduce the amount of traffic.

Q110 Christopher Pincher: How much concreting needs to go on? When you put down a—*[Interruption.]*—of concrete to bed it in do you have a similar sort of issue with the drilling?
Professor Kevin Anderson: I do not know the details of that but if you look at the ones in the US generally my experience, having previously worked for quite a long time in the petrochemical industry, you have a 1.5 to 2 hectare site with your wells on that you expect to be concreted or hard core of some sort. That would be your normal expectation. As I said before, for 10% of UK gas, if say there were 2,500 to 3,000 wells, say there were 10 wells per pad, it could be up or could be down from that, then you are talking about 300—these are very approximate figures based on the US experience—about 300 well pads at about 1.5 to 2 hectares per piece. Making the comparison with wind turbines is a useful comparison in some ways, but of course a wind turbine is the fuel source and the generator, whereas in this case this is the fuel source. You still need the power station, you still need the pipelines, the rest of the infrastructure. If you are going to make a comparison you have got to make a fair comparison. The wind comes free and is blowing in the air. In this case the fuel will have to go from here to a gas-fired power station.

Q111 Christopher Pincher: And given where the fuel is, under the ground, as we have heard from previous witnesses, in five or six areas in the country, it presumably requires a fair bit of pipeline to get it to the power stations.
Professor Kevin Anderson: It will do, yes, but the UK is very good at putting in pipelines and the remedial activity afterwards. However, it is costly and it is in the short term pretty destructive in terms of the ecosystems you have to go through, but additionally in terms of things like road infrastructures and so forth. It is something we are well practiced at, though. We have pipelines all over the country already, so I do not see it being any different to any other process. That is not to say it is not without significant impacts.

Q112 Christopher Pincher: What about the road infrastructure you just mentioned? Do you feel that where the gas happens to be—I think the Cambrian base, the Welsh border was an area that was mentioned—is that an area which has particularly good road infrastructure?
Professor Kevin Anderson: I will let you judge that.

Q113 Christopher Pincher: Well, what about water? You mentioned that a lot of water is required to do the fracturing. Do we have enough water in the UK to do that work? Is that going to be a limiting factor given that extraction from rivers is already quite considerable for housing estates and so on?
Professor Kevin Anderson: It is certainly a consideration. I do not think it is necessarily a limiting factor because you have a host of competing demands and you might decide that one of the other ones you are prepared to forgo. But we are aware in the UK that there can be issues. I live in the Peak District and we had a hosepipe ban this year. It is hard to believe that in the Peak District we could ever have a hosepipe ban but we did for quite a long time. We know that, even in wet parts of the world, which is where some of these shales are, there are often issues of water supply throughout the year, and this will be another pressure on that water supply system. So, I do not think it should be ignored. I do not think it is necessarily going to stop you going ahead but it is certainly a consideration, and a serious consideration, as to: are you prepared either to increase the scale of the water supply structure nearby or are you prepared to forgo some other activity to allow you the water necessary for this process? Because there are very large quantities of water involved.

Q114 Chair: Do you think that onshore drilling in the UK is sufficiently regulated?
Professor Kevin Anderson: Of shale gas? We do not know. The other ones—I do not know the regulations sufficiently well for the other work that we have done. Overall I have colleagues who have worked quite closely with some of the petrochemical extraction in the UK, and by and large it has been done relatively well. I had far more concerns when I worked offshore, which I did for quite a number of years. Basically no one can see it out there and people can see it on land, so it is relatively well regulated simply because of that visual pressure, if you like.
Jennifer Banks: Apparently, at the moment our oil and gas regulations do not mention shale drilling, so that is an issue, but I would not comment on conventional regulation. It is not my area.

Q115 Chair: Do the provisions of the EU Water Framework Directive apply to fracturing?
Jennifer Banks: With regards to Article 11 3J which was brought to my attention, if we were injecting something that was not water into groundwater then that would be a problem, but the idea of shale drilling is that these substances are not injected into groundwater sources and that the wells are considerably deeper. I have not been able to get a legal opinion on this. I can inquire and get back to the Committee if we envisage there is a problem. It should probably be investigated.

Q116 Chair: The assumption which you just described presumably is the one on which the decision to allow any kind of activity is predicated?
Jennifer Banks: I am presuming so. It does not appear that the EU considers it to be a problem. I do not know whether you have any information?
Professor Kevin Anderson: No, that is my understanding as well. The problem here is that we are talking about a new process and a new process requires standing back and thinking about the legislative framework. I think just relying on existing legislative framework for a new process is not sufficient.

Q117 Albert Owen: I am conscious of the time and also the answers we have already been given. It will be a short question and really only warrants a one-word answer. I think I know the answer to it but, for the record, should there be a moratorium on shale gas exploration in the UK until 2013, when the EPA is likely to have its report out?

Professor Kevin Anderson: Yes, for environmental reasons, and the moratorium should last for probably another few decades for the climate change best perspective.

Jennifer Banks: I largely agree with him.

Chair: Good, thank you very much indeed for coming in.

Tuesday 1 March 2011

Members present:

Mr Tim Yeo (Chair)

Ian Lavery
Albert Owen
Christopher Pincher
Dr Alan Whitehead

Examination of Witnesses

Witnesses: **Mark Miller**, CEO, Cuadrilla Resources, **Dennis Carlton**, Executive Director, Cuadrilla and **Andrew Austin**, CEO, IGas Energy, gave evidence.

Q118 Chair: Good morning and welcome to the Committee. We are embarked on this inquiry into shale gas, an interesting and topical subject, and I think the inquiry is already attracting quite a lot of interest. For the avoidance of doubt, I am happy for it to be known that we are visiting Blackpool tomorrow, so we can discuss that if that is helpful. Could I ask just generally to start off with if you could tell us about—I think it is correct to call it—the unconventional exploration, what you are engaged in currently and what that might lead to by way of production?
Dennis Carlton: Yes, I can address that. At the current time we are in the first phase of exploration. We have drilled one well to total depth, about 9,200 feet. It is called the Preese Hall No 1 well, which you will see tomorrow, and that well is currently being prepared for a fracture stimulation job probably in the next two to three weeks. The second exploration well we are drilling is the Grange Hill No 1, and that well is currently drilling at about 6,000 feet and you will also see that well tomorrow.
Of course, the first part of any successful shale gas play is the exploration part, and that is the part we have taken so far. We have built maps based on all the geologic data, subsurface data, geophysical data, outcrop data and selected drill sites to prepare for drilling. Once we have completed the wells in the exploration phase we will try to test those wells, see how commercial they are, and get some type of established flow rates so we can make a commercial decision whether we want to drill additional wells. If, for instance, those wells are successfully drilled, completed and show a commercial rate then we put those wells into production. We also will be able to look at a well that is in production—it's not a shale gas well, but you'll see tomorrow—that will probably either sell the gas through a pipeline system but more likely will sell gas into the electric grid system; you either sell the gas as electrons or molecules.

Q119 Chair: How long will this take? Give me a feel for the timetable you expect.
Dennis Carlton: The exploration phase has been going on for—the actual desk work exploration phase has been going on for two to two and a half years. We started drilling the first well in about August 2010. It took about 90 days to drill. The second well we expect to take about 45 to 60 days. The initial wells always take longer than you expect. The fracture stimulation work will be carried out over a two to three-month period. We want to make sure we collect sufficient test data to know if we want to drill additional wells or not. We are talking, from start of drilling a well to completion of the well, anywhere from minimal size about four months and a more realistic time schedule, about six months.

Q120 Chair: If you find this will you go into production yourselves or will you engage someone else to do that?
Mark Miller: Our plan, as Dennis said, is in three parts. It's explore, evaluate and then decide. We have a number of licence areas outside of the UK as well, and over the next two years we are going to look at those and when we see ones that look like they have potential then we look at putting together a field development plan. But with that said, we do currently have a five-year business plan that includes a provision for production in it.

Q121 Chair: When you are doing this, and if you treat me as a new reader on this subject, do you want to keep the data you find very confidential? Are there competitors breathing down your neck who might try and steal a march on you?
Mark Miller: You do keep it confidential in the early stages, but all that has to be public after a certain amount of time and so we keep confidential what we have right now but, that being said, we have been very open with operations, with the media, the local councils and the public, so it isn't totally confidential to the point that we don't invite people by to look at the operations; we do that quite a bit.

Q122 Chair: Do you have a view about how the prospects for shale gas and coal bed methane compare in this country?
Andrew Austin: I can probably speak to coal bed methane a little bit more. We basically have pilot operations ongoing in coal bed methane now, producing gas from our site at Doe Green in Warrington and generating electricity and selling that. We've drilled nine wells at eight different locations over the last five years. My view is that coal bed methane can be quite a material input to the energy mix in this country and shale gas, ultimately if that can be demonstrated to be commercial and can be flowed at the right rates, could also be a big important part of the mix. I think the most important part of that is its ability to displace imports of other gas from other places, both in terms of security of supply but also in terms of carbon footprint.

Q123 Chair: Are the steep decline rates an anxiety?
Andrew Austin: In coal bed methane it is a different shape of production curve to shale. For coal bed methane you have quite a flat production curve that drops off over a period of time, so then producing for 15 to 20 years on the basis of US and other Australian analogues. That is not so much of an anxiety, from my perspective, but I am sure that is one of the things these gentlemen are going to be looking at.
Dennis Carlton: Yes, if I can give a little bit of colour on that. For the typical shale gas well that we're looking for in the UK, we expect the initial potential flowing rate, the IPF, to be in the range of 2.5 to 5 million cubic feet per day. As Andrew mentioned, the production profile is different than a coal bed methane. We will see probably 50% decline from the initial potential over the first year to 18 months, followed by about a 20% to 25% decline—it's a hyperbolic curve—and then at that point anywhere from 5% to 7%, maybe 8%, decline for the next 25 to 30 years. A lot of flush production, as we say, in the early stages and then a long production life.
Mark Miller: It is not uncommon in some of the North American shale plays to have shales that have been drilled 50 to 60 years ago and still are producing at commercial rates today. After you undergo your initial decline then you have a pretty stable production for a long, long time.

Q124 Chair: In terms of technology, we are using technology that has been developed principally in the United States, are we, for exploration and production?
Mark Miller: Not solely in the US, but the US has probably developed a lot of the technology used in shale gas, but it is a good point maybe to catch up and talk about this term "unconventional" because we are not using unconventional technology. When people talk shale gas or unconventional gas, the term "unconventional" refers to the type of reservoir that we are in. The techniques are the same as you would use for a "conventional" well, whether it is an oil or gas well, so the technologies that are out there today that weren't there, say, 20 years ago are related to our ability to locate from surface, using new seismic technologies, the resource, and then to really understand what is going on down hole. With the ability to do computer modelling, we can model reservoirs, we can do fracture mapping and understanding where hydraulic fractures go. We can do a better job of analysing cores and one of the great advances is just the ability to steer a drill bit, to be able to sit at surface and know the azimuth of your borehole and the location of your drill bit. These are the technologies that are advanced. I guess the other one to mention is just really overall equipment efficiency—more horse power in smaller packages and things like that. But it is technology that is used in the entire industry, not just in shale gas.

Q125 Ian Lavery: Obviously, huge volumes of water are required in the fracturing process, which gives notes for concern. I am reading about some of the millions and millions, perhaps billions, of litres of water required. What measures have you put in place to ensure that the fracturing activities don't place extreme stress on the water resources in the UK?
Mark Miller: I will just talk about the volumes we are using and then talk about—because it sort of leads into the answer to your question—what we are doing with our shale, which is probably going to be typical of what is done in a lot of other areas. I will just focus on what we are doing right now. We will probably use about 1,000 cubic metres total for our drilling process and probably another 12,000 metres for the fracturing process. That is a big number, 13,000 cubic metres, but just to put it in perspective, it is about five Olympic swimming pools. Again that is no small volume, but in a year we may use 20 Olympic swimming pools.
We buy our water commercially from United Utilities. They know their availability of water and they curtail us if they feel we would be taking too much. But just in looking at the numbers that they produce, one of the interesting statistics we came across is that each day, every day, United Utilities in the north-west loses about 408 million litres of water just to leakage in lines. When we look at what that means in terms of oil and gas wells, if we were to consume the water equivalent to the leakage, we would have to drill 11,000 of our wells in a year. A different way to look at it is to say that the total amount of water that we are using is about 0.08% of what goes to industry and the public out there every day, and that is if we were to drill four wells per year.

Q126 Ian Lavery: Where does the water come from? It is from the mains or is it delivered from other parts of the UK?
Mark Miller: Right now we are buying from the mains and as often as we can, we will. I think in most of the areas that we have proposed we will be able to buy from the mains. In getting our licence with them and everything they tell us how much we can take on a daily basis so that the line pressure does not drop, and we are just an industrial customer like anybody else.

Q127 Ian Lavery: Are you recycling any of the mains water in the hydraulic fracturing process?
Mark Miller: Our intent is to do that, we have not fractured yet, but normally the rule is that when you can you do, partly because you don't then have to buy additional water. But you recycle what you can and then if there is any water that you can't recycle, if the salinity gets too high, you have to take that to a disposal facility.

Q128 Ian Lavery: When you extract huge volumes of water from the shale gas during the process this can often cause subsistence and destabilisation, what are you doing to ensure that that doesn't happen?
Mark Miller: First of all what we extract from the shale will be mainly water that we are putting in during the frac treatment, with a very small volume of produced water thereafter. As a good rule of thumb—I am only quoting because we have not done a job yet—we expect we will get returns similar to some of the North American shale plays, and that is somewhere around 20% to 30% of the water you put in comes

back. That on its own doesn't result in any subsidence. I have a core here I just brought along to show you what the shale looks like. When you look at this and try to compare it to oil and gas plays around the world where there has been subsidence, you look at the nature of this rock and it's just not compressible. The other thing to remember is that in order for it to subside, we have to take a large volume of something out of it so that the pore space is collapsed.

But typically in an oil and gas well and typically in shales you may get 20% to 30% of the gas out and the rest stays in place. You never actually collapse the pores. That is not something that occurs in shale; it may occur in some really high porosity oil zones in other places in the world. For example, in Holland you can get subsidence, but it is a different type of reservoir altogether.

Andrew Austin: Just in terms of, again, the coal bed methane produced water and the usage of water. We tend to use our own produced water and then wherever possible use that to inject back into the process. We are seeking not to take water out of the system but, again, the numbers are materially lower.

Q129 Ian Lavery: Is there a problem with the water quality?

Mark Miller: Is there a problem with the water quality?

Ian Lavery: Yes, with the extraction of large volumes of the water, is there a problem. Does it have an impact on the water quality in the well?

Mark Miller: Are you talking about when we pull it out will it be a problem for disposal?

Ian Lavery: Yes.

Mark Miller: We anticipate not, but we will not know until we pull it out. We don't expect it to be, but we have a programme set up so that when we do start removing water from the well we will test for a number of components in the water. We visited the sites where disposal takes place currently for drill cuttings and any drilling mud will also take place when we go ahead and bring back any frac water that we can't recycle. One of the natures of the visit is to make sure we understand how it is going to be handled and to look at the permits they have in place with the Environment Agency to ensure that what we are bringing to them fits. Even if they would say, "Well, we'll take it" we want to make sure that it is in compliance with what the Environment Agency has permitted. We will be monitoring that. We don't expect it to be a problem, but we will certainly know before we break through.

Q130 Albert Owen: You mentioned the Environment Agency there, which monitors quality and concentrations of the chemicals added as well. Can I ask, again as very much a novice here, why you do not use pure water. Why do you need to add chemicals to it? The concerns are not just about the volume of water; they are about the acidity and the chemicals added.

Mark Miller: We use almost pure water. The first thing, just to put some numbers to it, is that 99.8% of everything that goes into a frac fluid is fresh water bought from United Utilities, plus sand. That makes up the bulk of it. But that still leaves about 0.2% of additives. What do we add—

Albert Owen: On a huge volume of water.

Mark Miller: What's that?

Albert Owen: It is only 0.2% but it is a big volume of water.

Mark Miller: It is, but as a dilution factor it is relatively small. Now, what do we put in and why? We put in a friction reducer. You can imagine when you are pumping down a steel pipe at high velocity you generate friction, and that friction results and manifests itself at the well head as additional pumping pressure. In accordance with the well design, you cannot exceed your well head pressure so what would happen is you would have to slow the rate down to offset the friction. You put a friction reducer in and it just really makes the water slippery and kind of puts it in laminar flow and enables us to get the injection rate we want without excessive friction.

The other product is really just a biocide and there is any number of them out there. What they are for really is to make sure that when we take water that should pretty fresh and pretty clean from the mains and we put it into a tank, it sometimes can be in the tank for maybe several days before we frac or sometimes potentially a week, you don't want bacteria growth in it, so it is really just to make sure that what we put down the well is pure. Bacterial growth in a well can basically shut off the permeability of what you have just done with the fracing.

Q131 Albert Owen: So it is an anti-corrosion?

Mark Miller: No, it is an anti-bacterial growth. The water itself coming out of the mains is probably fresh enough on its own, but you put just a little bit of this in, and it is a real small amount. Something like a gallon of this goes into 20,000 gallons of fresh water.

Q132 Albert Owen: You are talking my language a little bit, but the concerns that people have is that here in the UK you are only going to add a couple of chemicals; are you just suggesting that?

Mark Miller: Right.

Albert Owen: But in America they do far more.

Mark Miller: They might.

Q133 Albert Owen: Why?

Mark Miller: I don't know, I mean I am not an expert on what they are doing over there, but let me talk just a little bit about fracing in general. Somewhere I saw a number of lists, like there are 576 different chemicals. There is nobody, I would venture to guess, uses more than four or five chemicals in any one frac treatment but different formations, different sandstones or limestones require different types of chemicals. The worst on the list are really things you put into conventional oil wells to make sure you prevent paraffin precipitation or you dissolve asphaltenes, but they are not needed in a shale. The one interesting thing about the shale fracs is that they use these simpler chemicals for a particular reason. We don't want to build viscosity in our fluid like you would typically do in conventional reservoirs because we don't have the same type of leak-off. What we are really trying to do is we are trying to get our thin low-viscosity water to enter these little tiny natural fractures that we find in our cores and open those things up. They can be two sand grains wide and so shale is intentionally designed to be simple, not just because of the environment but because scientifically it works.

Q134 Albert Owen: The Environment Agency will be monitoring the volumes of water you use, the extraction you use from the mains, yes? The amount.
Mark Miller: Yes.

Q135 Albert Owen: Then the concentration of the acid, and then if you are not recycling it, you are putting it in a disposal tank, that will be monitored before it is disposed.
Mark Miller: Yes. We are doing the testing on it. They make periodic inspections of a well site and one of the things they look at is when they come out they look at our delivery tickets just to ensure that we are always delivering any waste products to the approved sites that are permitted for it.

Q136 Albert Owen: Sorry, you leave them in a settling tank and then the chemicals will be taken—
Mark Miller: No. We are talking about a few different things. Right now we are disposing of drill cuttings, so when the little rock chips come out we have to haul those somewhere, and we have one particular landfill for that. There is another, our drilling mud, and we have to dispose of that. That is a different type of landfill and when we get ready to take our water, that will be one of the same landfills, but in a permitted disposal area.
We have not yet fraced a well and had to haul water away, but that will be monitored, so we will look at all the trace elements coming back in it, we will know what it is and if it exceeds anything on the permit then we will have to do something different—

Q137 Albert Owen: What would that something different be then?
Mark Miller: You have to find a site where you can dispose of that, but the numbers in the permit, the base line, are much higher than what we expect to get back. They are much higher than what you typically get back in a shale well.

Q138 Albert Owen: Because you use less chemicals you are thinking that it is going to be an easier and safer method of disposal than the Americans use, in the main?
Mark Miller: Yes, I guess we didn't design a system necessarily for easier and safer disposal, that's a benefit of the system. We designed the system we had on what we think will work in the shale. Simpler is always better. It is simpler for us, it is lower cost, it is simpler to pump the job itself, but a big bonus is that it is a safer system to dispose of. We just won't be using what some of the companies use over there. We do not have a need to do it here.

Q139 Albert Owen: Would you be permitted in the Environment Agency guidelines? Is it because we have got stronger regulations here?
Mark Miller: I don't know how to necessarily compare them because over there it is a state by state thing, but my initial reaction is that you would have equally strong or stronger regulations in some areas. We have agreements with the Environment Agency and a regulatory process. We have disclosed to it all of our chemicals that are going into the system and if, for example, we are a third of the way in and we say, "You know what, we need to build 10 centipoise viscosity and we need to put a small gelling agent in," then we have to select something on the approved list. There is any number of products out there, and additives, that we are convinced we could put in. But the one thing we are not doing is giving a short list and telling everybody we are going to do this knowing full well we have something else ready to go. Just from a scientific point of view, until you do a few of these you can't really say, "We will never change anything".

Q140 Albert Owen: Can I ask Mr Austin about coal bed methane exploration? Are any toxic chemicals added there?
Andrew Austin: No.

Q141 Albert Owen: Not at all?
Andrew Austin: No, not at all. Basically the wells we have got on production right now are literally drilled as laterals in the coal. We have fraced one well at Doe Green, we fraced that simply with pure—with produced water from the well primarily and pure water from the Utilities. We didn't add any proppant into that in the first instance just to see what the range of the frac would be. We may now look at re-entering that and fracing that with sand as a proppant, but we do not need to add anything extra into the water at all in our cases because we are dealing at shallower depths in more permeable coals with less pressure environments than for shale.

Q142 Albert Owen: But the Environment Agency will be monitoring you in the same way?
Andrew Austin: Yes, we have a licence from the Environment Agency for that site. We are engaged with them in terms of what we were able to take out of the ground and what we put into it. As a natural part of producing CBM you do produce water, which is mildly saline, brackish water. We have to have those permits in place and we found the Environment Agency informed and engaged in dealing with them.
Mark Miller: If I could make just one more point there. You were talking about the dilution of the toxic chemicals. I talked about a friction reducer, and the main compound in that is polyacrylamide, which is used in facial creams and contact lenses and also as a bonding agent to seal soil. It is a product that isn't toxic. It isn't in the list with benzene and toluene and those things, it is a common product. The biocide is really a product that is—as I said there is a number of them out there, but we will be selecting one from a list that is used in treating drinking water.
A third additive is one that is not really mixed into the frac fluid but is a diluted weak concentration of hydrochloric acid and muriatic acid. It is put in just in front of the frac fluid in a very small volume, maybe

200 to 300 gallons and it is only for the purpose of initially opening up the perforations that we put through the pipe and allowing us to start a fracture treatment. It is very dilute going in and then it is chased by the 12,000 cubic metres of water and becomes really diluted at that point. It is the same product that is used in the food industry. In fact it is used in the processing of beer so it is—

Chair: We won't go there.

Mark Miller: Anyway, so I just want to make that point, when we talk about toxic chemicals we are not using anything off the list of the—

Q143 Albert Owen: You would be happy to drink the residue?

Mark Miller: There is a lot of things I wouldn't drink in my household but that is—

Albert Owen: I asked this of somebody in a sewage plant and they said that the end product is so good that they would be able to drink it.

Mark Miller: Who said that?

Albert Owen: Somebody from a sewage plant.

Mark Miller: Okay, well, I mean and maybe that is true. I probably wouldn't do it but that is—

Q144 Albert Owen: You would not take up the challenge?

Mark Miller: I probably wouldn't worry about it, it is so dilute but, you know—

Q145 Christopher Pincher: You might get the chance tomorrow.

Albert Owen: I will have a beer tonight.

Christopher Pincher: To line your stomach. You are pumping swimming pools full of usually treated water down a steel pipe to fracture the shale. You said that you use computer modelling to work out what sort of geological formation you are working with. The US Environmental Protection Agency said that, "Predicted and actual fracture lengths still differ frequently and it is difficult to accurately predict and control the location and lengths of fractures". Do you really have any control over the fractures that you are creating? If you do, what do you do to try and control that?

Mark Miller: Let's talk about that statement. First of all, you do not ever have control in the sense that you can make a fracture go a certain way. It is always going to go along the path of least resistance. I would disagree with the statement that fractures differ from what is modelled. If your modelling were using micro-seismic data in the process of fracture mapping, you can see with real precision how far the fracture goes, how wide it goes and how high it goes. In our case we can't use micro-seismic because you have to have a twin well. On our very first well, we can't do it. As we go forward, if we develop this project, we will get to the point where we can run it. But what you can do through taking cores is look at similar shale formations in the US. It's like a type analysis where you say, "This type of shale or this Young's modulus and this Poisson's ratio and all those mechanical properties of the rock result in fractures that grow in a certain length, width and height". I think we do have a pretty good handle on it. The modelling software today is as good, with any software, as the input data. Now, if we were to shortcut this and not take these kind of cores and really study them, we would have a difficult time using one of those models with confidence. But we have invested a lot into our core acquisition and core analysis and we have a pretty good handle on what is going to happen. Generally, as a rule of thumb, a fracture grows up the same distance as it grows out. It has no reason to continue growing up or continue growing down in any one direction. The upward growth is usually terminated as soon as it hits some kind of impermeable hard rock. In our case, nothing would grow past the Manchester Marl, which is a formation up the hole that is a normal cap rock for some of the shallower gas-producing sands. We are confident we have a pretty good handle on how this is going to grow.

Q146 Christopher Pincher: If I say to you that you can predict the way the fractures will go, but you can't control them, is that an accurate summation?

Mark Miller: Yes, it is.

Q147 Christopher Pincher: A lot of water leaks off, as I understand it, stays underground, and I am told that that can exceed 70% of the volume that is injected, so it doesn't seem to me to be leak-off, that is flood-off. The question is what is the risk of that leaking into aquifers, into water supplies and what kind of effects will it have?

Mark Miller: Okay, so the same thing. In this instance we talk about leak-off, we are generally referring to that which goes into the matrix of the rock. In this case, because there is almost no way to really get water into something this hard, what you are doing is you are water-wetting the face of the fracture. You open thousands, literally thousands, of small micro-fractures and you put sand in there. There is a lot of water stays in that sand pack, then water wets the sand grains and water wets the face of the fractures and maybe penetrates a very small amount of the actual matrix of the rock. That is why we get the easy water back, which is perhaps 30% and would be consistent with what you are saying—that 70% stays in place. Now what happens to what stays in place? Generally over the next 50 years it will be produced back; it will give it up as we produce gas in real small amounts, but as far as being able to get back to the surface, it cannot physically go through 5,000 feet of solid rock and find its way up there. If it could, it would already be doing it, so it can't do that, so the only pathway is if you have a faulty well bore. That becomes an issue of well design. If you do a proper design and put the right casing strings in, you pretty much eliminate the chance of this finding its way into a shallow zone.

Q148 Christopher Pincher: We know all about faulty well design, don't we, after Deepwater Horizon, so how confident are you that your well design for any particular geological formation is secure?

Mark Miller: We are very confident. We use industry best practices and we have an independent examiner look at our well design. In our case, we are probably over-designing by running more casing strings than are really needed and running them deeper than needed. So we are very confident that we have put back-up systems in place so it just would be near impossible to breach our well bore and get into the ground. But I would like to point one thing out. When I say "near impossible" it can lead to, say, a small percentage of it. In our case, I would say almost not at all. But the thing that is very important to understand about well leaks is that, if they happen they do not cause permanent damage to an aquifer or a situation out of control. It is very easy to go in with today's instrumentation, pinpoint the location of a leak and then pump what we call a remedial cement job, where you put cement out through that leak and fill the back side and then there is a way to test it to make sure it worked. It is called the bond log. You run a third instrument and it shows you the actual bond between the cement and the casing and shows you that you have eliminated the channel. If something like that happened from a well bore, it is repairable. Typically, it is a three to five-day process to do it.

Q149 Christopher Pincher: You mentioned the independent reviewer of the well design. Who employs the independent reviewer?
Mark Miller: Excuse me?
Christopher Pincher: The independent reviewer of the well design that you mentioned just now, who employs that group of individuals?
Mark Miller: We pay them a fee to do it, but there is a list of four of them that I know from around the UK that are on the approved list for the HSE. Their role is to look at our well design; they don't necessarily have the authority to overrule, but they make recommendations to the Health and Safety Executive, which can overrule it and recommendations to us. If we put a well design together and they see any part of the process that doesn't have dual barriers—just as an example, where we don't have sufficient isolation in containment in our well bore—they will flag that and say, "Step 13 in your programme says you are going to do this, but at this point in time you don't have enough barriers". So we have to go back then and re-do our design. They get a very small amount for their hourly work, but basically out of the four of them one always has to look at the design and recommend to the HSE and to us if they see anything they would like to see changed before we proceed.

Q150 Christopher Pincher: One last question. How easy is it to determine the cause and effect? If you do have polluted water in an aquifer, is it possible to determine very easily that the cause of that is leak-off, for example?
Mark Miller: It is. We do a lot of testing on the front end, so we have tested ground water, we have tested water from water wells and ponds, streams and soil samples, and we are even testing for things like radio activity at outcrops. We are just trying to get a baseline of everything that is out there. Then as we bring our fluid back we monitor it, so we say, "Here is the base line, and here's what is coming out of the well". If there is a change and that change matches something on our list then for sure it is coming from our well and we would run one of those logging tools down and say, "Okay, it is our problem, we'll go pinpoint the problem and repair it". But, as you can imagine, problems can crop up that have absolutely nothing to do with an oil or gas well. People say, "What's new in the area? Somebody drilled a gas well so that's the reason there's a problem." That is why we at the beginning of our drilling we went around and established a baseline of streams and soils and different things.

Q151 Christopher Pincher: If you spot that something is different from what you expect, do you stop drilling while you investigate or do you continue working?
Mark Miller: The answer is yes. If we spotted it while we were drilling, we would certainly stop drilling and repair the problem, but normally when you hear about contamination found in water it happens in the production phase, so we are a long way from that. As I said, we are going to explore and then evaluate and then decide. We are potentially several years from that. But that is usually when you see it. It's when you start crushing up the casing and flowing a stream of gas on a day-by-day basis that if there is a leak it will finally work its way into something. But as soon as we saw it we would isolate that well, pull it out of production and repair the problem.
Dennis Carlton: I might add that in the case of potential contamination of a shallow water aquifer by natural gas, somebody has gas in a water well for instance, there are ways of typing the gas molecule that is in that particular well. We can take our gas, type it and compare the two to see if one is a biogenic gas versus thermogenic gas or, indeed, if our molecules of gas are contaminating the shallow water aquifer. In that case, as Mark mentioned, we can make a repair to the well if necessary.
Also we can compare water chemical analyses to determine whether any of our water is leaking into a shallow water aquifer. In other words just a pure chemical analysis; if we have a certain element or chemical compound in our produced water and it shows up in a water well then we will know that there is a potential problem. There are ways to identify the problem.

Q152 Chair: Following on from this, tell us a bit more about the flow-back. How much of the fracturing fluid returns to the surface as a result of the flow-back?
Mark Miller: That would be somewhere between 20% and 30%. That is what we are expecting, and that is consistent with a number of the shale plays around the world and, in particular, North America. When we say 20% to 30%, that is probably what we would get back in the first 60 days, and then for the remainder of the life of a producing well you will always get small amounts back. You might reach a point where there is 50% back, but the next 20% would come over years of production.

Q153 Chair: You treat that when it comes back to the surface, do you?
Mark Miller: What we do is we dispose of it, but we test it first. We test it to make sure it meets the

requirements of the disposal area where we are going to take it, but it is tested then disposed of. If it needs treating—for example, if it falls outside the guidelines of what is available at any disposal area—then you do have to treat it. There is various equipment and processes out there available to the industry. They are expensive, but it is not a dead-end street if we come up with something that doesn't fit within the realm of what is allowable to disposal areas. But right now we think we are well within the guidelines of standard disposal for oil and gas wells.

Q154 Chair: What are the risks of spillage or seepage during this period?
Mark Miller: So we are talking at the surface now?
Chair: Yes, surface.
Mark Miller: There is always risk, but one of the things we do that is different than what a lot of the North American operators do is that we don't use earthen pits to store flow- back fluids or to store drilling mud or cuttings. Everything we do is in a steel tank so that is the start of it. You don't have to worry about a plastic liner leaking and leaking into the ground. But even a tank under the right conditions can leak at a valve or something. The much bigger failsafe is that when we build a well site, the first thing we do is put a heavy plastic material; it is one heavy enough that if you try to take a knife and pierce it, it will be very difficult. It is not a thin plastic roll-out layer but they put this under the entire well site and they build a dyke around it. When you come and look at the site tomorrow we will show you that and show you just how hard that is. That is about 18 inches down under the gravel. Let's say, for example, some fuel spilled from a tank or some hydraulic fluid. It would probably be contained in the gravel, which is to be dug up and removed when we reclaim the site. But let's say it was so big that the gravel alone couldn't contain and filter it, it has got nowhere to go but out to the dykes around the location and they feed into a holding tank where you can skim it off.
It would be pretty difficult to see any scenario where something could happen out there where we could have leakage go straight from the surface, straight down to the groundwater.

Q155 Chair: Do you test routinely for the presence of any dangerous substances that might have escaped by some method or other?
Mark Miller: We test all the waste materials and we test our frac flow-back when we get to that point. As I said, we have established a baseline of getting all the fluid compositions around the site and soil samples before we have drilled. We have not yet got to the point where we have set up a programme of routine testing. It certainly would be relatively easy to take periodically some stream water or pond water or something from nearby, or soil samples.

Q156 Chair: Are you already having to treat waste water as it is?
Mark Miller: To date, all we really have is what we call the drilling mud, which is a freshwater-based mud. We call it mud. When you see it tomorrow you will see that it looks like muddy water but it has clay in it; that is the main compound. That has to be tested when we deliver that to the landfill.

Q157 Chair: If we see shale gas production developing in this country, will there be a need for lots of waste treatment centres as a result of that?
Mark Miller: I don't know; I guess I am not familiar enough yet with how many are out there and where they are at. I have only really looked at what we are using. I suppose it is possible, but the oil and gas industry and a lot of the waste facilities we are using have really been established to handle some of the fluids coming from offshore, and that is a pretty big industry. I don't think the amount that we would be bringing to it, even if shale gas got pretty active, would really exceed the capacity that was set up to service the North Sea.
Dennis Carlton: If indeed it did, we could drill a disposal well or contract with somebody who has a disposal well to increase the volume capacity.

Q158 Dr Whitehead: Are these procedures identical if you are drilling on land or if you are drilling, say, in shallow water?
Mark Miller: The drilling procedures?
Dr Whitehead: The waste water disposal and the use of water and so on.
Mark Miller: I am not an expert on the offshore, but the actual drilling process is the same other than that the equipment, of course, is different. The process is the same of protecting shallow aquifers and disposing of hazardous fluids. There is always some fluid coming out of wells that can be tested and deemed fit to put right into the North sea. There are other fluids that could be from a stimulation or a fraction treatment, because they frac offshore as well by boats and large vessels, and if there is flow-back water that doesn't meet that criteria then they bring it to these land-based facilities over on the coast. In Hull there is a large disposal area.
Dennis Carlton: Or in some cases they take the water that may need to be disposed of and reinject it into the formation that they produce from.
Mark Miller: I would have to say in general the procedures would be the same. The drilling procedures, everything, well control, all the issues are identical whether you are onshore or offshore. It is only the type of equipment that you work with.

Q159 Dr Whitehead: If there is production, how will you dispose and transport the waste water away?
Mark Miller: If there is production?
Dr Whitehead: Yes.
Mark Miller: One of the things you will see tomorrow is the producing site that we have up at Ellwood. It has a tank on site and when you get to the disposal part you get to where you have a tank out there that maybe has to be loaded out and disposed of once a year, maybe twice a year at the most. We would truck it away from that location over to the disposal site.

Q160 Ian Lavery: Looking at the permitting procedure, it is not clear under what Act shale gas would be or should be regulated. There is a lot of conflict and a lot of ambiguity, depending on who you believe. Can you explain what the procedures are for companies such as yours to obtain a licence or a permit for unconventional gas exploration or production?

Mark Miller: Sure. I will start off answering that question by going back and saying the reason there is no definition in any of the regulations about unconventional or shale gas is because the process of getting it is no different than any other well, so when you construct a well it doesn't matter whether we are going to produce from a sandstone or a shale, the process is the same, even right down to hydraulic fracturing.

Let's talk about the process for a minute. When we decided that we wanted to get a licence over here the process that we had to go through started with DECC. You have to wait for a licensing round to come up and then you look at available licence blocks that are out there. You may decide that you want to make an application for a certain block so you have to, in your application, first demonstrate that you have an understanding and you define the hydrocarbon resource that you are going after. Then you have to put a good work plan in place and demonstrate that you have the ability to explore properly for that and that you have a chance of success in your exploration. Then the third thing you have to do is you have to go ahead and demonstrate that, even though you have a great work plan, you have the technical team in place to execute the work plan and you also have the financial backing. DECC evaluates all applications coming in under a number of criteria, but that is probably the short list to make sure you know what is there, you know how to get it and you have the financial backing and the team in place to do it.

Once the licence is awarded, then you have annual follow-ups to show—you say, "This is what I am going to do in year one, two and three" and you have to go ahead and submit reports and follow up on your obligations to DECC to give them information as it comes in about what you are doing. Typically, from the time that you get a licence you may have, in our case, two years of studying the area just to know where we want to put our first well or our first couple of wells. When we have arrived at that decision, the next thing is to get a planning permit, and we deal with the county councils on that. Part of the planning application for them is to go in and define the project, make sure it is clear what you are going to do and what equipment is going to be involved, and you have to do various studies. We have to do, as a minimum, different environmental studies, including ecology, we have to look at noise, light, traffic issues, and so all that is done before we submit the application. They evaluate the application on that and approve or reject it based on how the studies turned out and how well your plan will work within all the issues of light, noise, traffic.

Then when they finally issue you a planning permit, it typically comes with 15 to 20 conditions and says you can proceed but you have to follow these things. One of the big ones in every planning permit is protection of groundwater. We have to demonstrate to DECC that we have a plan in place to protect groundwater and they work closely with the Environment Agency to ensure that we have identified the groundwater sources and that the plan we are putting in place sufficiently protects it.

Once we have the DECC licence and the planning permit, to carry through and say, "We are ready to start drilling" we have to work with the Health and Safety Executive. They have—I brought one along—a guide to borehole sites and operations regulations. This basically outlines the different publications you have to read, the different directives. In a nutshell, the HSE look at our well plan along with the well examiners and they make sure that we are following industry best practices; they have a whole list of checkpoints. I mentioned earlier double barriers. We can't have any scenario where we go in and say, "We only have one valve in place when we should have two". They check your entire process against that and they check the type of casing we are running, they check the metallurgy on it. We have to identify all these things in order to go ahead and get approval from them to proceed. Then once we do proceed, they have a very rigorous follow-up procedure. Every Monday we have to give them a detailed list of the operations in the previous week. For instance, we did a blow-out preventer test and we have to show them that everything we have done follows what is required from the work plan that they approved. They follow up on that and, of course, they follow up on routine site visits and they also make sure that the general work environment from a safety standpoint for the employees out there is a safe work environment.

That is a quick overview of how you get the licence, how you get the planning permit and how you get then finally the permission to drill.

Q161 Ian Lavery: Do the permitting procedures deal explicitly with unconventionals?

Mark Miller: It doesn't mention unconventionals because unconventionals are only a term that we as an industry coined years ago to describe a type of reservoir. It is not the process. There is no such thing as an unconventional well or a conventional well; there is only an unconventional reservoir, and that only means that the gas is stored in the same place that it is generated. That is the short definition of an unconventional reservoir, but there is no distinction in the drilling procedures and the well construction procedures for unconventional and conventional wells. They are done exactly the same way.

Q162 Ian Lavery: Do you think the current procedures for licensing and for permits are fit for purpose or do you think they probably need reviewing?

Mark Miller: My opinion is, in comparing it to how things were done in North America, that they are fit for purpose. When you try to go the other way and say a standard well has to meet all these criteria, you tend to end up checking the boxes and maybe have things pertaining—I will use North America as an example—to a shale well in Pennsylvania that may not pertain to the same shale well in Ohio. What really matters is that you look at every well on an individual basis. So even up there in the Bowland shale there are differences between our first well and our second well and we have to identify them. There is a difference in depth and a difference in some hole conditions, so we have to tailor a programme that meets the satisfaction of both the HSE and the independent examiner for each well we drill. We don't have a standard Bowland Shale design and say, "This is approved and all wells will look like this". I think it is a better process doing it that way.

Andrew Austin: Can I just add something to that? I do think the system is fit for purpose because it is fit for the techniques and the places in which we are operating whether the gas has come from, as Mark said, an unconventional reservoir or a conventional reservoir. The regulation needs to ensure that the techniques employed and the way in which we deal with the surrounding environment are handled correctly. To that extent, as these techniques have been used elsewhere for many years, both onshore and offshore, with a strong safety and environmental record in the UK, the system is fit for purpose.

Q163 Ian Lavery: The EU water framework directive prohibits the injection of substances containing substances other than those resulting from the operations into geological formations from which hydrocarbons have been extracted. Does this apply to fracing?

Dennis Carlton: Yes, is the answer. Any water or hydrocarbons, which is probably not the case, but water that is produced from an exploration or production well would need to be tested, as Mark mentioned, and can be injected into a certified injection well.

Q164 Ian Lavery: It is interesting to hear that basically there is a lot of ambiguity, a lot of conflicting reports from different organisations regarding the permit, but you feel that there isn't any ambiguity, it is straightforward?

Mark Miller: I think it is very straightforward. It is the same permitting process used in the North sea and it is based on requiring that we use industry best practices and that we do not short-cut anywhere. I think it is a very good system.

Dennis Carlton: It is a better system than North America in that it is not a cookie- cutter type. It is fit for purpose. Every well has its own drilling plan.

Q165 Christopher Pincher: Can I ask you about community involvement and engagement? These well sites are pretty big. If you are drilling up to 16 wells from one pad, it is quite a large site and whereas in the United States landowners own all the gas beneath their land we are not perhaps quite so far-sighted here. I wonder what you do to try and ensure that the local community is engaged in your work and supports it. How do you help them?

Dennis Carlton: Let me just clarify a point; in North America, not all the surface owners own the mineral state. There is a separation in some places where the mineral rights have been sold off to a different entity and/or the mineral rights are state-owned, so there is not always a good relationship between the surface owner and the mineral rights owner. There can be a conflict, so to speak.

Q166 Christopher Pincher: Do you see any conflict here between local communities and the work you do?

Dennis Carlton: No, it has been pretty refreshing. The locals have been very supportive of our well sites and it is not any different than working in North America. We have to approach the landowner, the surface owner, to see if that particular person would entertain the possibility of having a well site on his land, and negotiate a deal. In fact, in the States it is a one-time payment for access to a surface, whereas in the UK it is an annual payment and it escalates through time, based on a set schedule. It is probably three to four times more expensive to obtain a well site in the UK than in the US.

Q167 Christopher Pincher: But is there anything specific or tangible that you tend to do to ensure that the local communities are interested in engaging?

Andrew Austin: We have now obtained planning permission at, I think, 13 different sites around our various acreage, and a lot of it comes through in the planning process. Through the sheer nature of the planning process you are required to engage with the local community, required to get community feedback on your plans, and that all forms part of that engagement and consultation before making a planning application. It is very important to do that. In our experience a lot of the issues with the community are about perceptions rather than the actual practice of what happens afterwards. I think when someone arrives and says, "We'd like to drill a well in the area" people's immediate assumption is that the rig will remain there on site. Once people realise that the rig comes and then goes, that helps in terms of their comfort about what is being carried out. We have conducted site visits for local communities, and engaged with local community groups and community associations to allow them to come to the sites to understand what is happening during a drilling process and afterwards. We have also found it is very important to take elected councillors from different areas where we are applying for planning permission to existing sites and sites that we have abandoned—just assay wells—and show them the before and after. There is quite a lot of apprehension before people physically see what happens, but once people have seen what happens on the ground and the sites in a production phase, a lot of those concerns go away. We also spend a lot of time, as I am sure the gentlemen from Cuadrilla have as well, making sure that our sites are landscaped. We plant a lot of trees around the outside and make the impact as low as possible.

You are entering the area where someone else lives, of someone else's environment, and you have to go in and engage with that community and you have to work with them, because if you do not, it is a recipe for a lack of success from us and a lack of trust from the community, so it is absolutely imperative.

Mark Miller: We echo that; we have done the same. One of the quickest ways to reach a lot of the local population is through the media, so we have been very open to anybody who wanted to come out, whether they are TV filming crews, or radio, newspaper and magazine interviewers. Also, we engage closely with the local councils. We have an open door invitation within the realms of what we can do safely, but if somebody shows up and is interested in asking questions about the well, we will certainly talk to them, and if somebody from the media wants to take pictures or run a story on it we have been very open and invited people round. We have had some requests from one of the local councils just to engage in some small things; they have a tree planting day every year and they wanted to know if that was something we would participate in. It's a small investment and we are going to engage in those kinds of things just to, I guess, show our support for local projects. That is important to them and so it is something that we are certainly interested in doing.

Q168 Christopher Pincher: You have a community helpline, I understand?
Mark Miller: We've got a what?
Christopher Pincher: A community helpline.
Mark Miller: Our website is just about to be launched. The one that is on there now is temporary, so yes, we do have one and it has not been accessed because the full website should go out probably some time this week. But that is really just set up for people who don't want to come by the site but say, for example, "Well, how do I know what chemicals you are putting in?" We won't always have the ability to sit with every resident and explain what we put in, but we will certainly answer those questions by phone or by return email and there will be some sites where we just say, "Here are various aspects of our operation, come on and look and see what we are doing".

Q169 Christopher Pincher: How many calls have you had? Has the phone rung yet?
Mark Miller: There has not been any yet, but it is only because the website is just ready to be released.
Andrew Austin: We have had calls from people during drilling processes and we made sure that mobile numbers were available to people if they had any concerns. Interestingly, the only concerns we have ever heard from people around our areas where we have been operating have been around light and light spill. People are very, very sensitive, even in what you might think are really quite highly lit areas, about changing light in their curtains and things like that, much more so than noise. We have never had any issues around noise, it has always been around light. Where you can deal with that in a safe way by reducing the lighting of a site that operates 24 hours a day, you try and do so, but obviously there are safety issues around that.

Q170 Albert Owen: What do you think are the main challenges for unconventional gas development in the UK?
Mark Miller: I think what are challenges might also manifest themselves as opportunities. I think experienced work force is one. If this was to become a large-scale operation, experienced work force and a large base of service equipment would be needed. In the end, if one or more of these shale plays proves successful that will come, so the challenge might be that we have to wait a little bit. This is one of the reasons why we brought a lot our own service equipment, just so that we could carry out our exploration programme without a lot of delays, but if it was to go to production and more than one operator was in here working more than one base, you would build up the work force fairly quickly.
I mentioned opportunities, and I think it is a really important part to look at. When you look in other active oil and gas areas you build a certain expertise with the local population, and over time the number of people employed in a given area far exceeds what is needed for the rigs.

Q171 Albert Owen: Just on that, we are not seeing an Americanisation of this industry? If it develops, we are going to see UK and Europe expertise used as well?
Mark Miller: Certainly we are actively recruiting EU and UK residents to be trained and work in a work force so we—

Q172 Albert Owen: Sorry to cut across, are you using best practice from Europe as well?
Mark Miller: The industry best practice is not really divided continentally, it is a collection of best practice from around the world that is published through the International Petroleum Council and the American Petroleum Institute. There isn't necessarily a European best practice; they may differ by requirements, but the best practice everybody is pretty much in agreement with. But going back on the expertise and how that can be a benefit, even though it is in shortage now, we always cite Aberdeen. If you look at the work force in Aberdeen, the oilfield work force far exceeds what is needed to go out and service the rigs. Where do those people work, then? They work in other countries. So you start to export talent of people who live in the UK and can get jobs outside of the country on a rotation basis. I would say that would be the challenge for the initial start-up. That will be overcome early on. If you have some success in unconventional exploration, then the service sector will take care of itself.

Q173 Albert Owen: Mr Austin, from your perspective what are the challenges and is this a UK industry in the future?
Andrew Austin: Yes, I do think it is a UK industry for the future. I think, as Mark was saying, there is a lot of opportunity for jobs. I think we do need to grow a service sector to support it and that will, by definition, have to be UK-based. You cannot bring everything in from overseas, you basically have to develop that here. I think the other challenge is that we still need to see more evidence in different basins of the right sort of commercial flow rates that can make this work financially, and I think our activity and the activity of Cuadrilla and others will hopefully demonstrate that over the next couple of years.

Q174 Albert Owen: A final question to you. You mentioned the finances. Have you had discussions with Government about tax breaks for the industry?
Andrew Austin: We have not had any direct discussions with Government about tax breaks. We do fall within the Small Fields Allowance in terms of the

lack of application of supplementary charge, so we are seeking to demonstrate that we can make it economic at the current tax rates and under the current regime. But obviously as the business develops it does have a large contribution to make for UK Plc in terms of jobs, economic activity and security of supply.

Dennis Carlton: Yes, we echo those same sentiments; there is no need at this point in time for incentives to be put in place.

Chair: We are out of time, and we have some more witnesses to talk to as well, so thank you very much for coming in this morning. It was very helpful and interesting from our point of view.

Examination of Witnesses

Witnesses: **Nick Grealy**, Publisher, No Hot Air (Gas Policy Website) and **Jonathan Craig**, Fellow of the Geological Society, Chair of Petroleum Specialist Group, gave evidence.

Q175 Chair: Good morning and welcome to the Committee. Perhaps I could start off with a general question. How far do you think unconventional gas production can contribute to the UK's energy independence and indeed our security of supply?

Nick Grealy: I think one of the main problems that we have in Europe is that right now nobody has any gas to show and it is all relatively academic. We can extrapolate from the US experience and from geology, but it is highly unlikely that there is not at least some shale gas in the UK and certainly in Europe.

Jonathan Craig: I think it is too early to say at this stage. We are in the very early stages of exploration for shale gas in the UK. There is a lot of work that needs to be done. Certainly comparison with international shale gas plays would suggest that there is some potential, and I expect eventually that shale gas will make a contribution, but I believe it will be one part of a mixed scenario that will involve other energy sources in addition to shale gas. I think it will be one element and it will make a contribution, but it is too early to say at this point in time how big that contribution will be.

Q176 Chair: Okay. If there is a contribution will it be on a Europe-wide level or will it just be localised to those countries that have reserves?

Jonathan Craig: I think it is very important that we see the issue as far as the UK is concerned in a global context. The gas market in the world these days is a global issue, so it depends where you look around the world. You really have to take both conventional and unconventional gas together—shale gas is one source of unconventional gas obviously, but tight gas from conventional reservoirs, coal bed methane, plus our conventional gas fields, which have been producing natural gas for some time. If you take the global picture, one of the things we have to take account of in terms of new gas supplies around the world is the fact that most of our old conventional fields are declining very rapidly. On a global scale, it is estimated that by 2020 we need to replace about 70% to 75% of our existing production with new sources of natural gas, both conventional and unconventional. On a world scale, there is a need for additional gas resources, certainly. In the UK context then, we would be looking at that sitting within a European market, and clearly there are both conventional gas supplies in Europe and additional new gas supplies of conventional gas. There is of course conventional gas that comes to Europe from North Africa, for example, or from Russia. So those are all independent supplies, and a number of European countries in addition to the UK are looking to build their own shale gas resources—Germany, France, Poland, in particular. All of those countries are looking to build their own indigenous gas resources from shale gas, and they could be available both for local domestic consumption or they could go into the European gas network and be supplied more widely across Europe, including to the UK.

Nick Grealy: I do not really have much to add on that.

Q177 Chair: I suppose if we find we have significant shale gas reserves here and we start to exploit them, is there a risk that we are simply perpetuating a situation in which Britain, for an important component of its energy supplies, is dependent on gas, eventually most of which will have to be imported?

Nick Grealy: I certainly feel that the whole thing about energy security is a bit of a red herring. Right now, 88% of our supplies come from the North Sea. You often hear of 50% of imports, but most of the imports come from Norway and the Netherlands. Cuadrilla have mentioned that they hope to supply 10% to 15% of UK demand. That would be in the area of 12 bcm, which is greater than the entire LNG imports of 2009, for example. So we could displace LNG entirely.

Q178 Ian Lavery: Could conventional gas production lead to a global gas war similar to the one that we see for oil?

Nick Grealy: I wouldn't think so because the amount of gas that is available is really game-changing. I do not think people really quite understand the amounts of gas that are available. For example the United States, from 2007 to 2009, increased their estimates of available resources by 40% over two years and in the next one, which comes out in May, we may even be looking at an increase on that.

India, for example, has recently said that its resources were 40 trillion cubic feet and Schlumberger says that now it probably has in the area of 2,000 to 3,500 trillion cubic feet. This is how things can quickly change overnight. Here in the UK we are very used to an idea that gas is running out, whereas in the

United States the problem is no longer one of supply but of creating demand.
Jonathan Craig: It depends where you look in the world. The US story is in some ways quite unique. Based on today's estimates, the US uses about 22 tcf of gas a year, and if you take their combined conventional and natural gas and unconventional resources today, at current consumption rates that is about 100 years' worth of supply. The US effectively has a very strong position in terms of its own supply of gas for the future. One of the things that has done is displaced LNG, so LNG then becomes available elsewhere in the world on the stock market so it can be transported around the world. Clearly if you go to, for example, India, India is expected to have a four-fold increase in its energy demand by 2035 and is struggling to find sufficient gas to fulfil its requirements for the future. So it has a very strong urge to develop its indigenous shale gas resources and to bring in spot gas from LNG particularly from the Australian shelf, for example. A global market is developing, but it depends where you are, what your indigenous supply is and what that displaces elsewhere that becomes available on the global market.

Q179 Ian Lavery: What impact does the production of unconventional gas in the US have on the global gas market?
Jonathan Craig: Well, the US in the past has taken LNG shipments from elsewhere in the world to meet its demand for gas. Now that it has developed quite significantly its own unconventional gas resources, it no longer has quite the same need for buying in that gas as LNG, so that then becomes available in a wider market.
Nick Grealy: There are also a number of projects in the United States, and also on the west coast of Canada, to export gas. There is a 3 tonne vault in the Gulf of Mexico and also they are just announcing now that the Cove Point terminal near the Marcellus in Pennsylvania is getting ready to export gas, and we would be the closest customer physically.
Jonathan Craig: One of the things this has done, which I think is important, is that it has allowed us to move away necessarily from the need to look for gas resources in some more difficult environments around the world, particularly in the Arctic. If you went back five years ago, 10 years ago, the Arctic was seen as the place we were going to get our gas resources from in the future, particularly the Russian Arctic, which has huge conventional gas resources. Because now the US has developed its unconventional gas resources, the need to address some of the difficult environmental problems that would occur if we were to try and develop gas resources in some of these high Arctic areas, has gone away to a large degree. We are much less focused on those areas now. It has changed the geography in terms of where we want to look for gas resources around the world.

Q180 Ian Lavery: As the shale gas production increases, conventional gas prices could eventually fall. Is there a risk that the major gas-producing companies might form a cartel to control the production of unconventional gas, similar to OPEC?
Nick Grealy: No, I cannot imagine that happening at all. Number one, the main countries at present are in North America, so I wouldn't imagine the United States would suddenly gang up on the rest of the world, at least in that respect.
Jonathan Craig: One of the things that is important to note is that the distribution of unconventional resources is much wider than that of conventional resources, so a lot of countries come into play that are not, if you like, the traditional big players in the oil and gas market. Poland is a prime example in Europe; it has a long history of conventional exploration that has declined over the years, and has been able to revitalise its unconventional network and resources in a country that traditionally was not part of that market. That occurs quite widely around the world, so a lot of other countries come into play. The chances of a limited number of countries forming a cartel that would have a real impact is quite slim.

Q181 Christopher Pincher: With respect to the United Kingdom, you said that we were in the early days of exploration here; we do not quite know how much unconventional gas we have. But do you think that it will be competitive with imported conventional gas in the next decade? The Oxford Institute for Energy Studies suggests that it will not be.

Q182 ***Jonathan Craig:*** Well, I think all these things at the end of the day come down to price. Now if you look at the independent studies that have been done on unconventional sources of gas around the world, so this would be both shale gas and tight gas and coal bed methane, then the independent assessments by people like Wood Mackenzie—Wood Mackenzie is one of the big analyst companies that we use a lot in the industry to give us independent advice on where the market is going—have looked at all of the major unconventional gas developments that are going on around the world and they come up with a price of about $5 per mcf as being the breakeven point. If your price is below that, then you are struggling to make things economic. Now that clearly varies depending on the type of gas, so, as I think has been mentioned already this morning, coal bed methane tends to have a lower breakeven price because it is much shallower, tight gas in conventional reservoirs does not require quite the same technology, so that tends to have a slightly lower breakeven price. In fact the breakeven price for shale gas in the European countries tends to be a bit higher than that, because drilling costs tend to be rather higher, so I think it is simply a question of economics. What is the price going to be in the market for the different sources of gas? But $5 is around about the breakeven point for unconventional resources around the world. That is traditionally considered to be roughly where it lies today.
Now the interesting thing is that, of course, the gas price in the US at the moment is lower than that. The US gas industry, the unconventional gas industry, has largely kept going on the basis of the fact that it hedged its sales in advance, so it booked to sell its gas at a higher price in the future than the current gas

price. Coupled with that is the fact that a lot of the smaller companies in the US have had a big injection of cash from major international gas companies, which have provided them with the money to keep going. But there is a general view that, on US gas prices today, a lot of the shale gas operations in the US are probably marginally economic.
Nick Grealy: I would disagree on that, and I would point out the history of shale gas has been one of continuous improvement in the economics and how much is produced, and so on. For example, recently Cabot Petroleum said that their cost of gas in the Marcellus Shale in Pennsylvania was about $1.30, and we also have interesting things in the United States where we have the development of shale oil—that is to access oil using unconventional techniques, including hydraulic fracturing and horizontal drilling. In that case then, we are going to have a situation in which they have to get rid of the gas so that they can access the oil, and that is the situation that I am told has led to the export potential of the Gulf of Mexico. Basically, they can give that gas away and, in fact, if they do not give that gas away they lose a large amount of $100-a-barrel oil.

Q183 Christopher Pincher: That is the United States. Do you anticipate the need for a subsidy here to encourage UK drilling?
Nick Grealy: No. With respect, from what I see of the activities of your Committee, you are used to a large amount of people coming here and saying, "We need a subsidy for CCS, we need a subsidy for wind, we need a subsidy for nuclear" and so on. The shale gas industry wants to give you money. It wants to participate. Going back to the Cuadrilla example of about 12 bcm, that would be a corporation tax take alone of somewhere in the area of £350 million per year, not to mention all the other benefits. This is where shale is unique, in that nobody is here with their hand out. That is why many of the enemies of shale such as Gazprom, the World Coal Council and the WWF are all united in perhaps being scared of losing their markets or their market share of fear.

Q184 Christopher Pincher: We can leverage the best practice in the United States, and the technology that is being used there, which you seem to suggest is driving down prices, but Mr Craig you mentioned that the drilling costs in Europe tend to be a little higher than they might be here. Why is that?
Jonathan Craig: Yes, that is partly because of the depth of the formations that we are drilling to, so the wells have to be somewhat deeper than they are in a lot of the US shale gas plays, so it is partly to do with that, and it is partly to do with things like the fact that labour costs, and so on, are slightly higher in Europe than they are, for example, in India or China. There tends to be that element to it. I would agree; I don't really see a need for a subsidy, particularly for unconventional gas in this country. The gas is the same gas whether it is conventional or unconventional, as has been said several times this morning. It is just the reservoir that is different. We use exactly the same technologies as we use for conventional gas. I think it is often perceived that shale gas is a new thing. The first natural gas use in the world was in 1821 in Fredonia in Pennsylvania state in the US, and that came from a shale gas reservoir; it was shale gas that was used. This is not a new business, if you like; it has been around for close on 200 years and the technology that we use is exactly the same technology. The issue for the industry is simply that we have a different type of reservoir to deal with.

Q185 Christopher Pincher: Let's not call it new, let's call it an additional resource.
Jonathan Craig: It is additional, it is not a new resource.

Q186 Christopher Pincher: Which is now hopefully coming on stream. Do you see this additional resource could lead to a fall in the wholesale gas price?
Jonathan Craig: Not particularly. As I said, in the UK I can see it will make a contribution but not a big enough contribution that it is going to have a major effect on the price of gas in the UK.
Nick Grealy: This is where I disagree with Jonathan and Wood Mackenzie and Florence Gény and a number of other people. I am quite bullish about gas, but I am realistic. I would say that I have been looking at it for about three years and the number one mistake that I made was to underestimate the impact. It has gotten cheaper, it has been found in myriad locations worldwide and it looks extremely positive. By 2020 in the United States unconventional is going to become the dominant form of production, so therefore perhaps we need a new name.
Jonathan Craig: By 2020 unconventional gas will be 50% of US gas production, so it will be a 50–50 split.
Nick Grealy: I say to people, okay, it is conventional to dig gas out from 4,000 metres below the Barents Sea, freeze it, take it to Norway, then take it to the UK, but it is unconventional to dig it out of a field near Blackpool. It is a bit bizarre.

Q187 Chair: You have referred to the fact that the growth in unconventional production in the US has cut demand for LNG, which presumably therefore means there is more LNG available for the rest of us in Europe. Is that greater availability of LNG here likely to have any disincentive effect on investment in developing unconventional resources here?
Jonathan Craig: No, I would not imagine so. Clearly, there are all sorts of good reasons for wanting to develop indigenous sources of gas, energy security being one of them, employment being another one, development of technologies, and so on. So fundamentally at the end of the day price will determine where you buy your gas.

Q188 Chair: Do you think that the effect on LNG availability will be a long-term one?
Jonathan Craig: Yes, I would say certainly it will be. Again, it depends where you are in the world, so places like China and India are going to need huge quantities of gas, some of which again will come from their indigenous shale gas and conventional gas resources, but they will continue to need to bring in

significant quantities of gas from outside, so I think it will be a long-term market, absolutely.

Nick Grealy: What one should understand is that the world LNG market was 243 billion cubic metres in 2009 and the UK used only 10.24 bcm of that, so less than 4%. The major dominant customers are Japan and Korea, which if you combine them consume 121 bcm. Certainly in Japan, as we know, there is no long-term demand growth and it is probably going to shrink. In India and China, I am sure all the LNG bulls have pushed that scenario, but China, for example, is 7.6 bcm. Many people say that it will go up to four times that by 2020, but that would still make their requirements smaller than the LNG import requirements of Spain, for example. One has to understand that China has multiple sources of supply—indigenous, imports from Turkmenistan, Myanmar, and so on. I think that they are not going to suck up all this gas and price us out of the market.

Q189 Christopher Pincher: I was going to ask one question on the international prospects for, particularly, shale gas. Outside the US do you anticipate any significant shale gas production in the next nine or 10 years?

Jonathan Craig: Outside of the US, absolutely. There are a number of places in Europe, for example. Poland is one of those, which is likely to be tested within the next couple of years. The first two wells have already been drilled. The big unknowns again come back to India and China, both of whom are very keen to develop their indigenous resources because of their demand for energy for the future. India has just put in place its first pilot—the second one has just been drilled, so they are currently in the process of testing—as has China. The results in both of those seem to have been, from a technical perspective, quite good. I would not be at all surprised to see both of those come on stream within the next 10 years, yes.

Nick Grealy: The US State Department has something called the World Shale Gas Initiative and there have been presidential level Memorandums of Understanding between China and India, for example, but there are a number of other countries—Chile, Argentina, Uruguay, Colombia, Morocco, Jordan, Turkey, Poland, and I think some other countries in Eastern Europe. Basically, shale is almost ubiquitous. Some people say that if you drill deep enough, you will eventually run into some. I think that is a very good point of Jonathan's. The history of the hydrocarbon industry has been to go and drill in the Arctic and never mind polar bears or pollution or anything like that. Now, it can be very choosy and I think that certainly people are saying in the United States, where there is a moratorium in New York State, that they are going to shoot themselves in the foot, because they are going to come and say, "Guys, we have got so much gas from Pennsylvania and Alberta and Ohio and Texas and Louisiana that we don't really need you guys any more". That really shows you how we have gone from fears of supply to a question of demand. We really have to soak up this gas in a number of ways, generation being an obvious one.

Q190 Christopher Pincher: If you can go anywhere and find shale gas, which is what you appear to be suggesting, do you assume that the places where it can be found are really going to go for it? Do you think there is an opportunity for this to be a game-changer in international gas supply?

Nick Grealy: Yes, certainly I would think so. When I first spoke to the US State Department, about 18 months ago, I thought that this would be something for commercial gain, but they are looking at it from a political viewpoint and saying that local energy is sustainable energy and it makes the world a less dangerous place if people are not competing for gas supply. There is plenty of economics in the US Energy Department and the Commerce Department, but the State Department has a completely political viewpoint, and I know that it has engaged with the FCO here.

Jonathan Craig: I think the only word of caution I would put in is that when we look around the world certainly there are vast resources of in-place shale gas, so you are quite right, many places where you go and drill you will eventually come across a shale that contains gas. The real issue is how much of that gas is producible technically and commercially? That is the difficult question for us when we come outside of the US. We have a reasonably good idea in the US because we have been building the industry up over the years. Outside of the US, it is still an open question. There are resources there, absolutely. A significant portion—maybe 20% to 30%—of those are technically producible. You then have an economic overlay on top of that says, "Okay, at what price?"

Q191 Chair: Theoretically, if there is such an abundance—I take your caveat about the price—could it impede a switch to low-carbon electricity generation? If people suddenly get lots and lots of gas, clearly that is significantly lower carbon than coal, but it is nowhere near where we need to be in 20 years' time if we are going to be able to reduce carbon emissions to the level that people are now suggesting.

Nick Grealy: Gas is low carbon. It is not zero carbon. It is not the only alternative, but I think there are no ideal alternatives anywhere in energy. I think that one has to consider the cost and the availability, and so on. In the UK, for example, if we replaced coal generation and especially replaced it more with a localised generation, with a number of CHP-size plants spread around the country, some people have said that you could save up to 70% of the carbon emissions from a coal plant, and for nothing. Well, as I said, for a contribution from the gas industry to the Government. You could save money. I think it was Voltaire who said that we can't make the perfect the enemy of the good. The perfect is an 80% reduction by 2050, whereas a number of people are saying, "Look, we can get to a 50% reduction by 2030, by which point perhaps there are going to be other advances in energy storage—solar, and what have you." But we run a risk of choosing winners today that may not be winners and will be made completely irrelevant. I am thinking here of CCS especially and possibly offshore wind.

Q192 Dr Whitehead: You have said that shale gas is relatively low carbon and essentially the same as non-shale gas in terms of its carbon content. That is about a little over half per kilowatt hour, the carbon emissions from efficient coal. In terms of the UK's road map 2050, you would have to see shale gas as, yes, cheaper but still very much a transitional fuel. But a number of countries in the world such as Poland in Europe and South Africa, are almost wholly coal-dependent. Would you see shale gas, bearing in mind its potential abundance as more an area-specific longer term transitional solution, but not so much in the UK?
Jonathan Craig: I think the 50% figure is the figure that is usually quoted in terms of carbon emissions. Burning natural gases produces 50% less on average than burning coal. I read the other day a quote from Aubrey McClendon who is the CEO of a company called Chesapeake, which is one of the biggest players in the US. He said that natural gas, and he was talking about both conventional and unconventional natural gas, as being, "America's greatest new opportunity because it will free us from dirty coal and dangerous foreign oil". That, if you like, sets the context from an energy security position and also from a carbon position. The US are very much looking at using natural gas, and shale gas as one of the components of natural gas, to reduce their dependence on coal for coal-fired power stations in order to cut their carbon emissions. It clearly is something that is going to make a contribution and it needs to make a contribution in the UK as well.

Q193 Ian Lavery: Looking at the future investment in shale gas, the shale gas prospects are already impacting on the confidence of energy investors. Is there an appetite for energy investors to invest in shale gas at this point in time?
Jonathan Craig: Are you talking specifically about the UK or generally?
Ian Lavery: The UK and then generally.
Jonathan Craig: Generally, certainly. It is, if you like, the hot topic in the oil and gas industry these days. Most companies have relatively recently set up teams that are exclusively devoted to looking for unconventional resources, shale gas being the prime one, in a number of different areas around the world. So yes, indeed, in the global industry I would say today there is considerable appetite, for looking for shale gas resources around the world. One of the reasons of that is synergies with existing operations, so if you already have a position in a country developing conventional oil and gas resources then it makes a lot of sense, if you like, from an economic and commercial perspective to also invest in shale gas in those regions. It very often tends to be on the back of existing operations around the world.
In terms of the UK, I think it is in its very early stages. I think it is mirroring very much what the US did, in that a small number of very small companies, niche companies, went into the market to test the potential and having established that particular plays looked as if they were going to be productive, the bigger companies came in and provided the funding to develop that. I think that is probably the way that the UK market will develop as well.
Nick Grealy: Certainly in the case of Poland, basically you have a number of small companies there and they are hoping that once they discover some gas all of a sudden Exxon Mobil or one of the big guys will come round calling. 21% of all M&A activity last year was in shale gas and it is a very hot topic in the United States. There have been mega-billion investments by China, Reliance Industries of India and the European ones, Total and Statoil, and so on.
Jonathan Craig: Again, you see China, India, their companies going out into the world because of their energy crisis, their need for energy security, and they are investing around the world in these plays.

Q194 Ian Lavery: Mr Craig, you corrected Mr Pincher, saying that this is not a new fuel—1821 I think it was.
Jonathan Craig: 1821, indeed.
Ian Lavery: It is amazing that it is not a new fuel but it has not come to the fore yet. People like ourselves are very buoyant about it, very upbeat about it. If this hype with regard to shale gas turns out to be wrong in 10 years' time, is there a distinct possibility that the UK could have under-invested in conventional gas resources?
Jonathan Craig: I do not personally see that at this point in time the unconventional industry is taking away investment from the conventional industry. The company that I work for, for example, is putting about 7% of its total exploration budget into unconventional resources around the world. That gives you a view of the amount of investment that we are putting into the two sides. Again, we are trying to build up an industry and test the market. We need to understand whether some of these shale gas plays will produce or not. I think we need to take a very cautious approach and at this stage it is very much about testing the opportunity, testing the deliverability of some of these plays before we make a decision about putting significant amounts of money into investment and developing things. We are only going to develop them, if you like, if they work.
Nick Grealy: I think at this point, in Europe especially, we have this major issue that everything we are talking about here is academic. We need to have somebody in Europe to say, "Yes, we have made a game change in discovery,", and I feel that over the next year we are going to have game-changing discoveries in at least two areas of Europe. By game-changing I would say places where the combination would be at least twice the size of the resource of the North Sea. That changes a lot. I hope I am right.

Q195 Ian Lavery: That is very interesting. Do you see that in the very near future there will be a change from coal to gas in the UK in the electricity-generating sector, or do you believe that gas will just be subsumed by the continued increase in the demand for electricity?
Nick Grealy: I think people do not understand really that in the developed countries, in the OECD, all energy use—gas, electricity and oil—is moderating. A lot of people are saying, "Oh, that was because of the recession", but the peak for electricity in the UK was, I believe, in 2005. I believe that peak demand for gas

was in 2006 and for oil even slightly earlier than that. Basically we are seeing the impact of energy efficiency in many small ways. Anybody who buys a refrigerator, even a bigger refrigerator, will find that it is 40% more efficient than the one it replaced. Over the course of a 20-year lifetime of a major appliance or a central heating boiler we are going to see a decline. National Grid say that themselves; I think they are looking at a drop in UK gas demand by something approaching 1% a year over the next 20 years, which could be taken into electricity.

Ian Lavery: Very briefly, Mr Yeo, it would be very interesting to hear, but I know we are constrained by time, why it has taken nearly 200 years for shale gas to come to the fore. It is an issue for another time.

Q196 Chair: Would you like to say something about that? The same question occurred to me. If this was such a good idea and was first discovered in 1821, what have we done in the meantime?

Jonathan Craig: Well, that comes down very largely to, first of all, gas prices, to some degree, but also to technological advances, clearly, and the biggest technological advance, as has already been pointed out, is the ability to drill horizontal wells. That is something that has only been really possible in the last 20 years or so. The ability to steer drills really accurately within relatively thin shale horizons has been one of the big game changes in terms of technology. If you like, that is why it has taken us so long; the change of technology has allowed us to do that.

Q197 Chair: Do these technology changes also require a change in the legislative framework? Do we need to revise how we regulate oil and gas exploration and production in the UK to reflect what may be some new challenges?

Jonathan Craig: The technology is new but it is not distinctive to unconventional resources. We use horizontal wells in conventional fields, so, if you like, the technology is the technology, irrespective of whether it is conventional or unconventional, whether it is tight gas or shale gas or conventional oil fields. We already have a history in all of those areas of using the same technology, both the technology of horizontal wells and the technology of fracing wells. So I would say, no, not particularly.

Nick Grealy: I would say that the regulation of right now appears to be working. The only other thing that I am slightly concerned about is the treatment of water when it comes back up, the flow-back, but I think you have to understand that in Pennsylvania water is 18 cents a gallon. That gives everybody an 18 cent-a-gallon incentive to use less water. So less water in, less water out. But the Environment Agency in this country is already very well placed to do it. We just have to make sure that if we are in a happy position of having a few hundred shale wells, the amount of regulators is increased.

Q198 Chair: The US EPA is investigating the impact of fracturing on drinking water. I slightly subscribe to the conventional view that they are a bit more cavalier about environment issues over there than we are here. Why would we not want to wait and see what that report produces?

Jonathan Craig: I think again you have to understand here that this is not new technology, so the fracing of wells has been going on traditionally since the 1950s. Interestingly, the first well that was fraced ever in the world was also in Fredonia in the 1820s in the shale gas reservoir, but again it is not new technology. One of the things that happens here is that, as an industry we have been looking very hard to try and understand—it was a question that came up earlier—how confident we are about where the fracs go when we frac the reservoirs.

A body of work has been published very recently, last year, that looked at all of the frac jobs that have been run in two of the main shale gas plays in the US, in the Marcellus and the Barnett, which are two of the big shale gas plays. They use micro-seismicity, which has been talked about earlier today, to measure where the fractures go within the rock—how far up and down they extend from the shale gas horizon that you are looking at. What that work has demonstrated is that there is no connection between the fracs that you make in the shale gas reservoir and the shallow aquifer. There is not a direct connection between the two, there are several thousand feet of rock sitting between the two.

That does not negate the issues that we have been talking about earlier this morning, for example, of having bad cement jobs on your wells that allows them to connect the shale gas reservoir with the near service. But that is exactly the same in conventional hydrocarbon exploration. It is exactly the same, for example, in carbon sequestration, in geothermal energy, so the issue, if you like, is not shale gas being in some way different. It is the same technology and the same issues apply both in conventional and unconventional reservoirs. The cases that are demonstrated of some contamination of the near-surface aquifers is either due to the fact that there has not been a proper cement job across a big fracture in the rock, which has allowed a conduit to go to the surface, or due to the fact that the cement job behind the metal casing that we put inside the well has not been properly secured and the gas has leaked up the inside of the well. But the fracs themselves are not the cause of contamination.

Q199 Dr Whitehead: But there is a difference between conventional and unconventional, obviously, inasmuch as you do require large amounts of reasonably pure water for unconventional?

Jonathan Craig: Absolutely.

Q200 Dr Whitehead: Disregarding the very small amount of chemicals that go in. Do you have an estimate for the amount of water, and this is presumably reasonably purified water, that would be required to produce a cubic metre of unconventional gas?

Jonathan Craig: Well, I can tell you that for an average frac job in a US well today, they use about 100,000 barrels of water. Now a barrel—a difficult conventional measure of volume that we use in the industry—is about 35 imperial gallons. You are looking at around 3.5 million gallons of water to do a conventional frac job. Now you put that water at high pressure into the formation in order to break the formation to create the cracks and, as was mentioned earlier on, you get back about 20% or 30% of that water. The rest of the water stays within the formation.

Q201 Dr Whitehead: Bearing in mind in various parts of the UK there is a substantial water shortage and difficulty of sourcing water, to what extent, if you had a substantial development of unconventional gas across UK land, would that cause any sort of competition for water resources?
Jonathan Craig: Sorry, I will just finish this bit and then come back to you. I mentioned previously that there is an issue about how much you can economically produce from some of these shale gas reservoirs. Globally, water is a big issue, so if we are looking at some of the shale gas plays that exist for example in India, in Rajasthan, there you have an area which is already desperately short of water for agriculture. It is going to be a huge issue to develop shale gas reservoirs in places like that, because you need these large supplies of water. One of the things that the industry is trying to do is to reduce the volume of water that is required to frac some of these wells.
We run what are called production logs—we run a tool through the well that looks at where the gas production is coming from, from which fractures that we have made in the rock. Typically today, the industry works on the basis that something like 30%, only 30%, of the fractures that we make are contributing gas to the well. We need to either use less fluid, so that we only frac the 30% that we need to frac, or get much more efficient about fracing, so that we create more fractures that are contributing. A lot of energy is going in the industry these days into reducing the amount of fluid that is required. Clearly, if you have areas where there is already a shortage of water for domestic use, for agriculture, then that is a big issue, absolutely. It is something that needs to be taken into consideration.

Q202 Dr Whitehead: Sticking with the UK, do you consider that at any stage being an issue for the UK or even parts of the UK in terms of its existing and likely future water resources for population and for agriculture, which may be diverted for gas production?
Nick Grealy: I pick up on a point Mark Miller made about comparative use. If five Olympic swimming pools sounds alarming and 3 million gallons sounds alarming, but it is literally a drop in the ocean. Four million gallons is, and the Chairman would appreciate this, the irrigation for a golf course for 28 days. That would last underground for maybe 10 years. Preece Hall, the well that you will see tomorrow, the first one, was built in a corn field. Now technically if you are worried about water displacement, although shortage of water is obviously not an issue as you will probably see tomorrow in Lancashire, irrigation for a corn field of five acres in one growing season is the same amount of water that would be used in a shale well.

Q203 Dr Whitehead: Is that over a year?
Nick Grealy: Yes. So if you really want to save water, dig up the cornfields and do a shale well.
Jonathan Craig: The only difference, I guess, is the issue of declining rates in wells, as was talked about earlier on. Obviously you need to drill a lot of wells in a shale gas field in order to keep the production levels up, so a typical shale gas field in the US might have 850 wells in it, something of that order. This is different from conventional exploration in that we are not drilling one well here, another well over here; we are drilling a lot of wells.

Q204 Chair: 850 wells for one field?
Jonathan Craig: Is not an untypical number.

Q205 Dr Whitehead: Does each of those take that amount of corn field type of water?
Jonathan Craig: You have to frac each well.

Q206 Dr Whitehead: That is 850 corn fields you use?
Chair: Or golf courses.
Jonathan Craig: It is not per year, you only frac the well at the start to get the production and then you move on to the next well.

Q207 Dr Whitehead: Maybe you need to refrac it?
Jonathan Craig: You might need to refrac it, but it is basically 100,000 barrels of oil per well.
Nick Grealy: Certainly people in the States have said that it is less than one half of 1% of water resources and Talisman in Quebec said that even if they had full production, they would only use one half of 1% of the total, compared to 2% for the car wash industry.
Chair: Okay. I am sorry to say we are running out of time. We might perhaps write to you with two or three more questions that we have not been able to cover this morning, but I think we are going to lose our quorum presently. Thank you very much indeed. Very interesting evidence, and we are very grateful to you for coming in.

Tuesday 29 March 2011

Members present:

Mr Tim Yeo (Chair)

Dr Phillip Lee
Albert Owen
Laura Sandys
Sir Robert Smith
Dr Alan Whitehead

Examination of Witnesses

Witnesses: **Tony Grayling**, Head of Climate Change and Sustainable Development, Environment Agency, and **Tony Marsland**, Groundwater Manager, Environment Agency, gave evidence.

Q208 Chair: Good morning. Sorry to have kept you waiting a bit. There is a lot of interest in this subject and it seems to be growing as we go along with our inquiry, so we are very glad to have you here this morning. You may be aware that the Minister is not available today so we don't have quite the time constraint that we thought we were up against. Thank you for coming in.

Your written evidence to us said that you believe the current regulatory regime is sufficiently robust to deal with unconventional gas. Do you envisage that position might change if the shale gas industry develops in the way that now appears possible and could become quite a significant element in UK energy resources?

Tony Grayling: As it stands, we think the regulatory regime in the UK will continue to be sufficiently robust as it is to manage and minimise the environmental risks from this activity. We will, of course, keep that under review in partnership with Government and with our fellow regulators, but I think it is important to understand that we do have a robust regulatory regime that works on a site-by-site assessment basis. If we judge at any particular site there are significant risks to the environment, we will require an environmental permit that will limit pollution and keep environmental risks to a minimum and if necessary, of course, we will stop the activity altogether. The regulatory regime enables us to do that.

Q209 Chair: Have you had discussions with DEFRA and DECC specifically about the adequacy of the regime in relation to shale gas?

Tony Grayling: Yes, we have had discussions. We have set up a co-ordination group, which includes DECC and DEFRA, ourselves, the Scottish Environment Protection Agency and the Health and Safety Executive. We have a fairly regular dialogue on this subject, not least because it has drawn so much attention recently, and we have discussed the adequacy of the regulatory regime with them.

Q210 Chair: We went up to see Cuadrilla's work near Blackpool. That did not require, as I understand it, a permit under the Environmental Permitting Regulations 2010.

Tony Grayling: That is correct. Cuadrilla has planning permission for five exploratory sites. We have so far assessed three of those sites and in each case judged that there was not a significant risk to the environment from the activity and that therefore environmental permitting was not required. It is very important from our perspective that we take a proportionate and risk-based approach and that we don't stand in the way of legitimate activity if it isn't an environmental risk. Nevertheless, we understand that this is a relatively new activity in this country and so we are putting in place some extra monitoring. For example, we know now that the first fracking was carried out on the first site at Preese Hall yesterday by Cuadrilla and we will be sampling the waste waters that are produced and the emissions just to double check that our judgment was correct.

Q211 Chair: Speaking personally, I very much support your stance about not wanting to create unjustified obstacles to legitimate exploration activity. At the same time it seems to me—this is even a little bit true in America, which the Committee visited earlier this month, where they tend to be rather more cavalier about these things than here—public confidence in what is something rather new can be quite fragile and easily damaged. Therefore, at the outset it would be understood, I think, by most people if you were leaning over on the side of extra caution while we try to understand this and, as I have said, public confidence may then gradually build up.

Tony Grayling: I think that is a reasonable comment and it is why we are going to do some monitoring, perhaps beyond what we normally do at what we consider to be a relatively low environmental risk activity. We have been very careful in our site-by-site assessment. Our colleagues in the relevant region have frequently been on site to inspect and have been in close touch with Cuadrilla about their plans. I am glad to say that Cuadrilla have been open with us about the sort of chemicals that they are going to be using and about the sort of procedures they are going to be going through. We have interventions at various points in the process. We are consulted by the local authority when planning permission is sought. We get information from the company and make an assessment about the activity.

The reason we haven't required environmental permitting in this case is because there is no groundwater at risk and because there is no nearby surface water or subsurface aquifer that is at risk. Indeed, the nearest use of groundwater for drinking water supplies is about 13 km from the site. So we have made a proportionate and risk-based judgment.

Q212 Chair: Have you had any discussions with the United States Environmental Protection Agency or any of the state-level environmental agencies in the US?
Tony Grayling: I have had informal contact with my colleagues in the US Environmental Protection Agency, and we are keeping an eye on what is going on over there. We have also reviewed some of the evidence that has come out of the United States and my colleague Malcolm Fergusson, who is head of Climate Change, participated in a seminar in Brussels last week that included speakers from the US Environmental Protection Agency. So, yes, we have been keeping in dialogue with them and understanding what they are up to and what the evidence coming out of the United States is.

Q213 Chair: In terms of the Agency's own resources, and given the constraints that you and other public bodies are under, if there were to be a rapid expansion of shale gas development in this country, are you satisfied that you would have the resources that are needed to monitor that?
Tony Grayling: I don't think it is an immediate concern, because even if the activity does take off at scale, it is going to take some years. For example, I would not expect that to be a major issue for the current spending review period. However, if in the majority of cases we don't deem that an environmental permit is required, it means that we will not be getting any charge income that will cover the costs of our site-by-site assessments to see whether permitting is necessary. I guess that if that takes off on a large scale, we would need to have a discussion with our sponsoring Department, DEFRA, and colleagues in the Department of Energy and Climate Change about that, having made a proper assessment of what our resource needs will be going forward.

Q214 Albert Owen: Can I move on to hydraulic fracturing and the chemical composition of fracturing fluid, and you have just mentioned something on this. Are companies who use hydraulic fracturing in the UK required to declare to you the ingredients and indeed the composition of the fluids?
Tony Marsland: Yes. We expect all the companies to disclose all the chemicals that they are using prior to our assessing whether a permit is needed. If they don't supply that information, we have powers under the Water Resources Act to require that information and we can serve a notice on them to require that data. If we decide that a permit is needed—if it is, say, a groundwater activity and there is a discharge into groundwater—all the chemicals that are discharged that present a risk to groundwater would have to be specified on the permit, which would, of course, be on the public register.

Q215 Albert Owen: From the experience in America, many of the companies say they have a trade secret. That gives them an advantage by using a certain mixture of chemicals, and only 100 out of some 260 that are used there are declared and monitored by the EPA. Would there be circumstances here then when ones that are not monitored could be used?
Tony Marsland: No. We would expect them to declare everything and certainly when it comes to environmental safety we wouldn't regard that as a good reason for not disclosing that information.

Q216 Albert Owen: They would have to disclose everything to you. Okay, I am clear on that. If they said there were some trade reasons for not doing it, how would you deal with that?
Tony Marsland: We would have to see whether that was a reasonable request. They could always come forward and ask for that but, as I have said, we don't think, in terms of environmental safety, that is a legitimate reason if there is a risk to the environment.

Q217 Albert Owen: Cuadrilla is the only company that you have been involved with thus far in the UK, and it says that it uses a different method from what is used in America. I am concerned about other companies coming on site, using different methods and saying that they have a proven track record. How vigilant would you be to ensure that all those chemicals are declared, and how would you monitor the matter?
Tony Marsland: We would still request from each operator what chemicals it was using, and we would need to have that determined and to assess whether a permit is needed in the first place. If an operator were to operate without a permit and it needed one, we could serve a notice requiring a permit. It would be an offence under the Environmental Permitting Regulations.

Q218 Albert Owen: Would you always take samples before exploration activity and then would you monitor that further on for comparative reasons?
Tony Marsland: We wouldn't routinely sample everything. We would expect disclosure beforehand, and if we assessed that there was no risk, then clearly there would be no reason to sample. So it depends on the risk; we have to be proportionate and risk-based in what we do.

Q219 Albert Owen: I am no expert in this field and I am probing you. There are some chemicals that are banned in certain dosages, but certain amounts could be used. Would that be allowed?
Tony Marsland: We would clearly want to assess the quantities and concentrations to assess whether there was a risk, and if we felt that that was unacceptable, then we wouldn't allow it to happen.

Q220 Albert Owen: But you have a criterion now—it is a certain chemical percentage per litre.
Tony Marsland: We can only assess what operators say they are proposing to use. Certainly, the chemicals that Cuadrilla has come forward and said that it is using are not a concern to us given the situation in which they are being used and the particular activity that is going on. Clearly, if somebody else came forward, we would have to do that on a case-by-case assessment.

Q221 Dr Lee: Can I just clarify what you are saying? You are depending on them to tell you what is in the fracking fluid.
Tony Marsland: Yes, we need to know.

Q222 Dr Lee: If you are depending on them to tell you, how do you know what to check for?
Tony Marsland: It would be a requirement that they disclose to us the chemicals.

Q223 Dr Lee: But if they are using something that you are not checking for you wouldn't know.
Tony Marsland: If we felt there was a concern, we would take check samples.

Q224 Dr Lee: But, with respect, the concern would only show itself if there was an environmental pollutant that then led to something that was tangible, such as illness, so you wouldn't know, would you?
Tony Marsland: If we felt there was a risk for the environmental situation from the activity, then we would undertake monitoring.

Q225 Dr Lee: But how would you know that there was a risk when you were not being told what was in it?
Tony Marsland: There would be an inherent risk in terms of the type of activity and environmental setting. Clearly, if there was a low risk in terms of the setting, we wouldn't have to go into too much detail with respect to the chemicals being used. If there is a high risk then we would obviously expect a higher degree of scrutiny of the chemicals. We would expect full disclosure in that case.

Q226 Dr Lee: I don't know how I assess the risk of something without knowing what is in it.
Tony Grayling: We would expect full disclosure of what is in it, and if we weren't getting full disclosure we would use our powers under the—

Q227 Dr Lee: You won't know though, will you? You wouldn't know whether you were getting full disclosure.
Tony Grayling: I think on the whole we will know, because on the whole we will be dealing with bona fide, respectable companies. I agree there is the possibility that a company would seek to hide something from us, and we do do random checks to ensure that that is not a widespread occurrence.

Q228 Dr Lee: Do you check the fracking fluid?
Tony Grayling: Well, in this case, for example, with Cuadrilla we will be checking the fracking fluid. But the other side of it is the risk to the environment depends on whether there is a receptor in the environment, in this case groundwater, which could be polluted in a way that could be harmful to people or the environment, so there is more than one component to the assessment.

Q229 Dr Lee: Sure, of course. You need the potential for the pollutant to get into the system, I understand that. We are going to discuss the various ways where that might happen, depending on how the drilling goes, but I just wanted to pare down to the nitty gritty. The reality is that there is trust in the system.
Tony Marsland: There has to be an element of trust. There is another check, though, in that when they come to dispose of the liquids, if they are disposing back to the environment that would have to be sampled and assessed and the impact on the environment assessed before a permit was granted if it was going back to the environment. If it is going to a waste carrier or a waste treatment facility they would require analysis of the fracking fluid and obviously they would have to find out what chemicals were in that water. So there are checks in the system.

Q230 Sir Robert Smith: I remind the Committee of my entry in the Register of Members' Interests related to oil and gas as a shareholder in Shell.
What I wanted to pursue was the other side of the equation of where the water comes from and the volumes potentially involved. The DECC Strategic Environmental Assessment of the forthcoming 14th Onshore Oil and Gas Licensing Round states that it feels that the amount of water used will not be expected to be significant for most operations, although large quantities of water may be expected to be used for hydro-fracking operations in relation to shale gas. Do you share that analysis?
Tony Grayling: I think that we share that analysis. Indeed, we are a statutory consultee on strategic environmental assessments and we inputted into the development of the SEA, the final version of which has not yet been published by the Department. But it depends on what you mean by large volumes, of course. We don't, on the other hand, assess that there is likely to be a significant risk to water resources on a larger scale—the country's water resources. Again, the important thing to understand there is that in terms of large scale usage of water from the environment, an abstraction licence is required from the Environment Agency and we wouldn't license unsustainable abstraction of water from the environment. Of course there are some cases where that licence is held by the company that is supplying water, and that is true in the case of United Utilities, which is supplying Cuadrilla, but we would not license United Utilities to make unsustainable abstractions of water from the environment.

Q231 Sir Robert Smith: Out of interest, are you monitoring the actual amount of water used by Cuadrilla then, or is that really an issue between it and its supplier?
Tony Grayling: That is an issue between it and its supplier. It has provided us with some information about the volume of water that it is using, and my understanding is that it is a very small fraction of the total supply that United Utilities delivers in its area.

Q232 Sir Robert Smith: In that area, it is mainly surface water. I think there is a concern that if other sites were moved to it, there would be groundwater where large abstraction might be more problematic.
Tony Grayling: Again, I think we would make a site-by-site assessment, and we would only grant an abstraction licence if we thought that the amount of

water being abstracted was sustainable, and we are quite clear about that.

Q233 Sir Robert Smith: Is it just like any other industrial water process?
Tony Grayling: Yes.

Q234 Laura Sandys: Having spoken to other parts of the Environment Agency about water issues, and particularly in the southern region, where groundwater is absolutely essential. Certain parts of the southern region are in crisis—they really have some serious issues. Do you not feel that this form of activity, and particularly if it spread around the country, could create even more of a problem when it comes to abstraction, and do you not feel that there are certain areas that really should be identified as being too much at risk at the moment to allow for any more industrial abstraction?
Tony Grayling: Site-by-site assessment is the name of the game, so we would certainly have a different view depending on where the activity was in the country and whether it was in a water-stressed area or not, although this activity would have to be treated like any other industrial activity that requires water use. When I have looked at the British Geological Survey maps of where shale gas resources may be in the British Isles, it does not look to me as though it involves the most water-stressed areas of the country, but we will have to wait and see. They are mostly in the northern parts of Britain rather than in the south-east[1].

Q235 Laura Sandys: But looking into the future, where we are going to possibly have, through climate change, even more stresses and water might need to be transported round the county, do you feel that the overall water resource that we have can sustain this form of industrial activity?
Tony Grayling: You have raised a serious point about the long-term management of our country's water resources. We do a lot of analysis on what the impacts of climate change are likely to be. For example, we have translated what the UK climate projections might mean for river flows, and if we look to the middle of this century then in many rivers we might see late summer flows cut by half or more as a result of climate change. So we are going to have some very serious challenges to the management of our water resources, particularly in areas that are already water stressed, such as south-east England. But on the other hand, I don't think you can single out this activity among all the other water-use activities for special treatment, if you like. I think it has to be treated on a level playing field, and we would make a site-by-site assessment. Our assessment of whether that water use is sustainable now in 2011 might well be different from whether our assessment in 2050, if we are still around, is sustainable, and it will change over time. But I think in the immediate term we don't think that this potentially new industrial activity, if it takes off, is likely to be a major factor in the management of the country's water resources.

Q236 Dr Lee: Do you have any concerns about the actual fracking process itself?
Tony Marsland: In terms of the chemicals or the interference?
Dr Lee: Just the whole process. Well, in terms of drilling down; the actual whole process of fracking.
Tony Marsland: From what we understand of the actual fracking process, it has quite a limited impact on the sub-surface environment. Certainly where it is taking place at the moment, it is unlikely to impact on groundwater resources, because it is so deep and there are capping layers over the target formation. In terms of the chemicals that are being used and the return fluids, we have assessed the range of chemicals that Cuadrilla has indicated that it may use, and we are satisfied that there is not a particular risk to the environment from those, particularly in the sense that at the moment they are tankering the liquid off site to a treatment facility. The liquid is not going to be disposed of to the environment. If Cuadrilla were to wish to discharge that back to the environment, then clearly it would need an environmental permit and most likely it would need treatment before final disposal, if indeed it was acceptable to be disposed to the surface environment.

Q237 Dr Lee: There was a recent article in *The New York Times* about radioactive salts that have been flushed out of the shale. Do you have any concerns along those lines and do you intend to test for their presence?
Tony Grayling: Again, it is a site-by-site assessment. We don't anticipate problems with the current site but nevertheless, partly again for public confidence, we will be doing some sampling and measuring radioactive substances if there are any in the waste waters that come out of the fracking process, just to be doubly sure. We don't think the rock formations in question at the moment are likely to cause problems in relation to radioactivity.

Q238 Dr Lee: In terms of the actual fracking, seeing the size of these things and how they go down, it is like a series of sort of concentric circles and you drill in between and get down to where the shale is. It was suggested to us—I forget which agency it was; it was one of the environment agencies in Texas—that there was potentially a problem with the pipe's integrity having drilled down. Do you check the integrity before extracting, allowing the water to be pumped in the same way, for instance, that when pipes corrode you send a pig—that is what it is called, isn't it—that goes through to check, and it X-rays the integrity of the pipe to make sure there aren't any cracks that have formed during the process of drilling down? Is there any of that going on? It struck me that that was the weak point in terms of the potential for aquifer pollution, because you are drilling through the water table. Once you are down below then, fine, because there is no danger of pollution, or very little, from below. The problem is that the pipe itself may have some cracks in it from the process of being sited.

[1] *Note from the witness:* "Factually this is not correct. The BGS Report indicates that the Weald basin (Kent/Sussex/Surrey) is the second largest shale gas prospect and this underlies an area of water stress"

Tony Grayling: We have to be satisfied about the design and construction of the well site. Again, in this case, we are. We expect the operator to do those kinds of checks on its own drilling works. It is not something that we would do directly, but we are satisfied.

Q239 Dr Lee: Would you prefer to check before the well goes into operation?
Tony Grayling: I think again you have to take a proportionate approach, and I think that it is the producer's responsibility to demonstrate that it has constructed the well correctly. In this case, I believe that it has put a concrete lining in down to a considerable depth, which helped to satisfy—
Tony Marsland: It is not just the agency that is interested in the integrity of that, because the Health and Safety Executive would also be concerned with respect to any risk from failure of casing and risk to human health.

Q240 Dr Lee: But at present we are back to the trust the company situation, are we?
Tony Marsland: We would expect good well design in the first place. We would expect to see those designs at planning application stage to ensure that the basic design was such that it wouldn't fail, and we would expect the company to test the construction and the operation of the site so that it didn't fail. But certainly from reports we have had from the States, well integrity is a greater issue than the hydraulic fracturing itself, so it is something that we would emphasise.

Q241 Dr Lee: Finally, they have a moratorium in place in New York State and they are waiting for the Environmental Protection Agency, the US EPA, to report next year, I think it is. Do you think that we should wait until then?
Tony Grayling: First, whether there is a moratorium or not is a policy matter, so that is not a decision for the Environment Agency but one for Government, but I don't think we would advise that a moratorium is necessary on the grounds of environmental risks as we understand them at the moment. We do think that the existing regulatory regime is robust enough to manage and minimise the risks.

Q242 Chair: Does that imply that you think the regime operated by the Americans is insufficiently robust or that there are special factors, particularly I think in relation to the water supply for New York, that justify a more cautious approach in Pennsylvania?
Tony Grayling: I don't know the exact circumstances of New York, and obviously the legislative framework is different in the United States with some federal legislation and then some specific state-by-state regulation. I don't know the reasons why New York might have wanted to put in place a moratorium. I believe there are one or two others in place, for example in Quebec, but I think nevertheless we don't think that it is necessary with the robust regulatory regime we have in the United Kingdom.

Q243 Albert Owen: You mentioned about the disposal of waste water treatment and Cuadrilla. Could I just clarify this, because I didn't quite catch it? Is it taking it to a municipal plant to get it treated?
Tony Marsland: No, it is going to a specialist waste treatment plant in East Yorkshire—a specialist water and gas waste plant—for specific treatment and disposal.

Q244 Albert Owen: So Cuadrilla takes it straight there, or does it do some work on it before?
Tony Marsland: I believe Cuadrilla take it straight there for disposal.

Q245 Albert Owen: You will have to forgive me for my ignorance in this, but is the waste injected into land or does it go into the sea?
Tony Marsland: I'm not sure what the disposal route is for that particular plant but it would be operating under an environmental permit and would have its own conditions.

Q246 Albert Owen: But those are the two options.
Tony Marsland: Yes.

Q247 Albert Owen: Are you confident that the current water treatment plants are capable of detecting these chemicals, dealing with them and filtering them?
Tony Marsland: It is up to the waste treatment facility to determine whether it has the capacity and can treat that particular waste stream. It is a contractual arrangement between the waste carrier, the waste treater and the operator. So they have to make sure they can meet their own permits before they can discharge.

Q248 Albert Owen: I understand that. If Cuadrilla has some fluid that they have taken them and this specialist treatment plant is not certain there are certain chemicals in it and refuses to treat it then what happens?
Tony Marsland: It is up to the operator to find an authorised disposal route.

Q249 Albert Owen: But you are confident in general that the water treatment plants in the United Kingdom, the specialist ones, can treat it up to a very high standard of chemicals? They deal with industrial waste now?
Tony Marsland: They deal with industrial waste all the time, yes.

Q250 Albert Owen: And you don't think this is anything specific to be concerned about with the shale gas?
Tony Marsland: Not from what we have seen so far. Clearly we are going to be taking baseline samples and data from the Cuadrilla operation to get some UK-specific information, but based on what we know so far we think it is no different to any other waste stream.

Q251 Albert Owen: I understand your relaxed approach now, because there is a small amount of drilling in a specific area. But if this industry were to

develop across the United Kingdom—we have talked about different water tables in different areas and about different treatment—isn't it practical now to look at waste disposal areas for an industry that could develop and could have a significant volume of water waste?
Tony Marsland: It is difficult to second-guess what developers are going to come forward with at this stage, but clearly it will be assessed on a case-by-case basis and each waste treatment stream and method of disposal would have to be assessed, based on the merits of that particular instance.

Q252 Albert Owen: Some people have said that in certain areas we don't have the number of treatment plants. Would that then be a barrier to its developing? I am talking about joined-up thinking.
Tony Marsland: If there isn't sufficient waste treatment capacity that clearly could be a barrier to development, just as if there wasn't water availability that could be a constraint on development, but it clearly is up to the operator to determine and sort this out when they are proposing their development in the first place.

Q253 Albert Owen: Even contained in the north-west, as Cuadrilla is now, are you aware of different waste treatment plants working together for expansion in that area?
Tony Marsland: I have no specific knowledge of that at the moment.

Q254 Albert Owen: Because there are just one or two drilled.
Tony Marsland: There is just one. Two boreholes have drilled but there is only one waste stream occurring at the present time, and it is going to East Yorkshire.

Q255 Albert Owen: So there is no plan that you are aware of, either the DECC or yourselves, for the expansion of the industry?
Tony Marsland: Not at this stage.

Q256 Chair: Just going back to the amount of water that is used in this whole process and the extent to which the water resources that are needed could be limited by recycling water in the process, should you be regulating the amount that is recycled, given that there are some difficulties, because of what has happened to the water in the process you can't recycle it all? Is that something that you should be regulating?
Tony Marsland: We would certainly encourage them to recycle, where that is feasible, but clearly we have to have regard to the fact that there could be complexities in recycling in terms of the concentration of pollutants increasing, and there would probably have to be some final disposal of that liquid, which could complicate the disposal routes. But we would encourage them to try and recycle water, encourage efficient water use, and of course in some parts of the country water availability may be a driver for recycling.

Q257 Chair: I appreciate all that, and it is good that they should be encouraged to recycle, but given that there are risks involved in recycling water that has already been contaminated in certain ways, is that an aspect that you would be regulating just to make sure that they are not recycling water that should not be recycled?
Tony Marsland: It depends what they are doing with the recycled water, of course. If they are putting it back down into the hole from where it came—in Cuadrilla's case, it is going back into a formation where there is no groundwater—then the risks are fairly low. In a different environmental setting the risks may be higher, and we would have to judge that on a case-specific basis.

Q258 Laura Sandys: There are obviously treatment possibilities, but there is also in the US injection of waste water back into the geological formations. Do you feel comfortable about how that can be regulated? We were also told by some environmental organisations that this could promote greater seismic activity. Is that something that you feel the Environment Agency has the competency to manage and to assess?
Tony Marsland: In terms of the waste water going back into the ground, as long as they are not taking liquid waste from elsewhere, then there is no bar in law for them to put the recycled water back into the ground, but they may require a permit. Certainly if they are discharging back into groundwater they would require a groundwater activity permit under the Environmental Permitting Regulations, so that would have to be controlled by ourselves with conditions on it. They may not require a permit if they are just taking water from the hole and putting it back down the same hole. That becomes mining waste.

Q259 Laura Sandys: There are some questions about whether there is seismic activity potentially associated with underground injection wells.
Tony Marsland: Yes. We have no knowledge of that in terms of experience of that being caused in this country. I am aware of some instances in Arkansas where there have been some reports about seismic activity, but we have no details of that.

Q260 Laura Sandys: Do you feel that we have the expertise in the UK, whether it is the Environment Agency or DECC, to look at some of the wider risks and assess that, or do you think that maybe the Environment Agency and DECC need to do a little bit more research?
Tony Grayling: We have some of our own geologists, for a start, so we do have some expertise, but we also work with others like the British Geological Survey, which has a lot of expertise in that area.
Tony Marsland: We would expect the Survey to get involved. The Survey has been involved in advising DECC on shale gas and coal bed methane. Certainly with something like this, the risk of seismic activity, we would expect them to engage.

Q261 Laura Sandys: As a group I don't know whether we have received any evidence from the British Geological Survey. So from that point of view, do you feel that the partnership works and that it has expertise to assist you and work closely with you?
Tony Marsland: The BGS certainly has, yes.

Q262 Dr Whitehead: My understanding of the practice in certain parts of the United States—certainly in Texas—is that the aim of disposing of some of the fracking water, but also the water arising from the extraction of gas itself, is to re-inject it into aquifer levels below that where the fracturing has taken place, not back into the fracturing zone itself. Were such a practice to come to the UK, would that, in your view, require any additional regulation or investigation, or would it raise any concerns about the extent to which that injection would have integrity?
Tony Marsland: We certainly don't need any more regulation. The Environmental Permitting Regulations would cope with this. If they were injected back into groundwater, as I said earlier, they would require an environmental permit and that would have to be subject to conditions so that they did not cause pollution to either the environment or to drinking water. When you said discharged back into an aquifer, I would be quite concerned if it was going back into an aquifer that was used for drinking water purposes or other purposes to support the environment or man's activities.

Q263 Dr Whitehead: The claim is that these would be very deep aquifers, well under the level of groundwater or drinking water.
Tony Marsland: If they are very deep and isolated from the rest of the environment then that is something that could be permitted, but it would be subject to controls to make sure that it was a safe activity.

Q264 Sir Robert Smith: One of the other concerns, certainly from the States, is the emissions to the air. People think that you drill down to get gas but of course you don't just get pure, ready-to-burn gas coming at the right volumes, and especially in the early stages of completing the well. What is your understanding of DECC's assessment of the air quality implications of venting or flaring?
Tony Grayling: At the moment, we are not expecting big air quality implications. You are right that the Government have oversight of the implementation of the Air Quality Directive and its daughter directives, and there is a system, as you will know, of local air quality management where local authorities are in the lead. But the Environment Agency has to have regard to the National Air Quality Strategy, and if we felt that emissions from the activity were likely to breach air quality standards then we are in a position to regulate that through, I believe, environmental permitting. The gas is likely to be a mixture, as you have suggested, but it is also quite likely to be very predominantly methane, from experience elsewhere, with rather smaller quantities of other pollutants potentially.

Q265 Sir Robert Smith: In the early stages, is that vented or flared?
Tony Grayling: That is a good question and I don't have a direct answer. I don't know whether you do, Tony. I do know that we don't regulate the flaring and venting. That is in the Health and Safety Executive's territory rather than ours.

Q266 Sir Robert Smith: Although there is an environmental impact, obviously, because methane is far more of a greenhouse gas than—
Tony Grayling: Yes. We would prefer that if methane is being discharged that it was flared, because obviously that converts it to carbon dioxide, which is a much less potent greenhouse gas on a molecule-to-molecule basis, but we would respect the Health and Safety Executive's judgment about what it is safe to do in those circumstances.

Q267 Sir Robert Smith: If condensates were captured, do you regulate whether those are properly stored and any leakage concerns?
Tony Grayling: We have the power to regulate emissions to air.
Tony Marsland: Under the Environmental Permitting Regulations, there are powers. The local authorities and ourselves share these responsibilities, so it depends precisely what they are doing.

Q268 Sir Robert Smith: Is it clear that there is no—
Tony Marsland: It is clear in the regulations. I'm afraid I'm not an expert on air emissions, so I couldn't give you chapter and verse. We would have to come back to you.

Q269 Sir Robert Smith: Maybe someone could write to us with a bit more—
Tony Marsland: Yes, we could come back to you with details on that.
Sir Robert Smith: That would be helpful. Thanks.

Q270 Dr Whitehead: A practice in some wells in the United States, so I understand, is that at the point of completion—that is after the fracturing is complete and before production begins—a process of flushing out the system, cleaning it up and getting it ready for production is undertaken, which among things leads to the vent of considerable amounts of methane into the atmosphere, which may be dealt with by flaring. But also there are processes under way called green completion that captures the gas and also disposes of material prior to production. Has the Agency investigated those arrangements and would the Agency consider whether that might be practice or best practice as far as what should happen upon completion in the UK?
Tony Marsland: I am not clear precisely what you are talking about. Is it air emissions, water or a combination of the two?
Dr Whitehead: A combination.

Tony Marsland: A combination. On the water side, I have already indicated that it depends on the proposed disposal route. It should be permitted one way and another. We would have come back to you on the detail of the air side. So far, I am not aware that we have had detailed proposals for that from Cuadrilla.

Chair: Do any of my colleagues have any other questions that they want to ask? Thank you very much for coming in. I am sure we shall want to keep in touch on this issue.

Tuesday 5 April 2011

Members present:

Mr Tim Yeo (Chair)

Dan Byles
Dr Phillip Lee
Albert Owen
Christopher Pincher
Sir Robert Smith
Dr Alan Whitehead

Examination of Witnesses

Witnesses: **Charles Hendry MP**, Minister of State, Department of Energy and Climate Change, and **Simon Toole**, Director of Oil and Gas Licensing, Exploration and Development, Department of Energy and Climate Change, gave evidence.

Q271 Chair: A warm welcome to the Committee again, Minister. We are very glad to see you here. You know there is a lot of interest in shale gas now, not just in this country but elsewhere. Could I ask why the Department ran an inquiry into unconventional gas last year without making that call for evidence public, and why it was not mentioned to us when you submitted written evidence?
Charles Hendry: As far as we were concerned, it was a very routine part of departmental activity. We wrote out to a number of people who were involved and had views on shale gas exploration. I am afraid it was a genuine oversight that we did not advise the Committee about it at the time and, as you know, I have written subsequently to apologise for that oversight.

Q272 Chair: I think it was clear to us that in the United States, the suspicion about the environmental effects of shale gas has been greatly increased by the reluctance of the companies—and in some cases the regulators—to disclose to the public what is actually happening, the sort of materials that are being used and the techniques. That lack of transparency is likely to retard rather than advance the development of shale gas, therefore an omission, which of course I entirely accept was not deliberate, is unhelpful in terms of boosting public confidence. Can you assure us you will make extra efforts to be more transparent than usual in anything that is done in relation to shale gas, because of that public concern in the background?
Charles Hendry: I could not agree with you more, Chairman. I think that it is absolutely important, in terms of carrying public confidence in all aspects of energy policy, that there is as much transparency as possible. I think if people see that there are things going on behind doors, which they cannot understand and they don't know about, they become suspicious, often without it being warranted, therefore the more open we can be, the better. That is why we have a general practice that everything that can be published on our website is so published and, once again, I do apologise that the Committee wasn't advised formally, as it should have been, about the call for evidence.

Q273 Chair: Thank you, and of course we accept your apology. In terms of Cuadrilla—which I think, at the time, is the only shale gas operator in the UK—was the failure to ask them to give evidence also an oversight?
Charles Hendry: In terms of what the—
Chair: When you were asking for evidence in private, it seems a bit strange that the one company that has already started to operate in this country was not among those that you asked for evidence.
Charles Hendry: May I ask Simon Toole to explain exactly how we chose the companies and the organisations that we asked for evidence on that occasion, just to give a greater clarity on that?
Simon Toole: Yes. As the Minister said, it was a fairly low key consultation with the main focus on overseas activity, and I think it was an oversight that we did not contact Cuadrilla, whose main focus is here in the UK.

Q274 Chair: So, who did you ask?
Simon Toole: I think it was a general request out to the industry. I'm not sure. It wasn't done by the UK exploration part of the Department. I think it was a general invitation. I'm not sure if there were specific invitations passed to any particular companies.

Q275 Chair: You can't issue a general invitation in private, can you?
Simon Toole: No, sir.

Q276 Chair: So you must have had a list of people you decided you wanted to have views from?
Simon Toole: Yes, there must have been and perhaps we could let you know what that was.
Chair: I think we would like to know, as there seems to be so much secrecy about this, who they were and why they were chosen.
Charles Hendry: We are more than happy to provide that information to the Committee. Perhaps we can write to you in depth afterwards to clarify exactly the process: how it was chosen; who helped us identify the appropriate organisations and why others were not on that list.

Q277 Chair: Do either of you know, as of now, how many submissions you received?
Simon Toole: I think there were four submissions, and we were referred, I think, to two papers.
Chair: Four submissions were made public.
Simon Toole: Yes.
Chair: So we know about those. Were there any others?
Simon Toole: Not that I am aware of.

Q278 Chair: We have found there is quite a lot of interest in the subject. We received 23 memoranda when we published our call, so what you have said in the last five minutes increases, rather than decreases, the mystery surrounding this process.

Charles Hendry: I think, Chairman, at the time that this was done, this was seen as being a routine operation within the Department. The degree of interest that is in shale gas at the moment wasn't there at the time and this was seen as a more routine process. To the extent to which it came across my desk, it would have been something that seemed to be a very sensible thing to do to ask people who may have views to contribute to do so. It wasn't a forensic investigation such as the work that you are doing now. We have been very pleased to see the work of the Select Committee to look into this. We have been pleased to contribute to it.

I made it very clear I wanted to go and see for myself what companies like Cuadrilla were doing and to understand on the ground exactly the impact that was having, so one shouldn't see this as being the totality of the Department's interest in this issue. It was one small element of a much wider interest.

Q279 Chair: What are the other bits of work you have been doing to establish what people think about this?

Charles Hendry: People write to us. We respond to those requests that we have received; we liaise with the Environment Agency to make sure that they are satisfied about the safety aspects and the environmental aspects or the HSE on safety. As I say, I personally went to look at the only site in the United Kingdom to understand exactly what the process involves and how it goes forward.

Q280 Dr Whitehead: Could you give us your feeling about the extent to which shale gas might be—to coin the current phrase—a game changer in the UK, in the same way it has quite evidently been in the United States? Do you think there are parallels that can be drawn in terms of, for example, the substantial change in the composition of gas supplies within the USA that have come about as a result of shale, and to what extent do you think that might be replicated in the UK?

Charles Hendry: I think it is too early to know. In terms of the global impact of shale, yes, it is a game changer and that affects us as well. The increased availability of LNG, for example, as a result of America becoming an exporter of gas rather than an LNG importer, is something that has global impacts.

In terms of what the United Kingdom's own shale deposits may contribute, as I say, I think it is too early to know that at the moment. If they were there on the scale to which they are available in the United States, this would be the equivalent of about 900 million barrels of oil equivalent, which is about one-twentieth of the known remaining reserves that we have offshore, so it is not a game changer in the same way. It would not have the same impact on prices, we think, because of the flexibility of the UK market and the different sources of gas that we have coming into it.

We recognise, as well, that there will be some very challenging areas where this might happen. In some of the very heavily populated parts of the country, there has to be approval given by those whose land is being drilled underneath, and this could make things much more complicated, because approval from landowners is not required in the United States.

Q281 Dr Whitehead: What other ways do you think that the development of shale gas in the UK might differ from the US? Are there any particular points that you consider will be key points of difference and, under those circumstances, to what extent is that likely to enhance or deter development of shale gas generally?

Charles Hendry: I think the issue of landownership is a very critical one. I think that is going to make a significant difference because for every piece of land that they wish to drill under, apart from where there are very small parcels of land owned by a range of different people, individual landowners have to give their consent. That will be more problematic than the system that applies in the United States. I think we have a much more cohesive system of regulation. We have one that applies across the whole of the country. In the United States they have differences in different parts of it, and so different states take different approaches and, therefore, we can more readily enforce the standards that we wish to see adhered to in terms of environmental issues.

Q282 Dr Whitehead: Do you think issues such as concentrated power drilling, horizontal drilling, and so on, have posed particular issues in the UK as opposed to the US, or do you think those sorts of techniques may be relatively easily manageable as far as UK drilling is concerned?

Charles Hendry: The horizontal drilling has been something that we have seen in this country and the North Sea for many years, so this is not a new technology.

Dr Whitehead: There aren't farms on top of the North Sea, are there?

Charles Hendry: No, there aren't, and I think it will be much more problematic to get this at sea, and if it was going to happen offshore then it would be likely that it would be horizontal drilling reached from onshore facilities.

Simon Toole: We have had experience with the Wytch Farm oilfield, where there is a concentrated set of wells that go out under the near shore, so we have experience of concentrated drilling. As the Minister says, landowners have a big role to play and, if their consent is not forthcoming, there is a rather complicated system of ensuring that access can be had if the courts have seized. It is a rather more controlled system than in the States, but technically I don't think there are going to be any insurmountable barriers to it.

Q283 Dr Whitehead: Presumably, if you are drilling half a mile horizontally on land, everything above that half mile can potentially be a barrier to that drilling.

Simon Toole: Potentially, you may have to access the courts to get access.

Q284 Dr Lee: To develop Alan's point a bit, in America it was suggested to us—and apologies for my lateness—that there may be significant shale gas under the North Sea. Would companies that wanted to try to develop that technology get support in the same way that CCS is getting support? I say that because I wonder whether the combination of access to a significant amount of water—seawater—could then be processed on a rig, and it could all become part of the same system whereby you wouldn't have the water problems that shale gas attracts; you wouldn't have the ownership because Her Majesty owns it. It would all be more straightforward once the technology could be developed. More importantly, we could then export that technology, decades down the line, when offshore shale gas deposits will become more economic.
Charles Hendry: I think our view at the moment is that the costs for doing this offshore are so great that it is not going to be viable with the price of gas where it is remotely at the moment. In particular, if it was done from an offshore drilling facility, the additional costs of that are going to be extremely high indeed, so the likelihood would still be that this would be horizontal drilling from a land-shore farm. Therefore, similar issues would apply in relation to the planning consents for that in general, until it gets offshore, as would apply for an onshore facility.
In terms of the support for CCS, I am not quite clear what you are suggesting.
Dr Lee: My point is that it is a new technology that is yet to be scaled up and we are making a big commitment. I think that is a good thing. My point is: is there any other fund that could be drawn upon or do you envisage thinking of any other fund where, clearly, the economic benefits or the economic viability of it is not currently the case? You never know how long it will be until that may be the case, and I wouldn't want us to get caught on the hop in terms of not having the technology to develop the fields if necessary.
Charles Hendry: I think, in terms of the funding that is available for CCS, that is part of our commitment to develop low-carbon technologies. It is clear that that is a technology that offers major potential. Again, it could be a potential game changer. The world is all looking at how each individual country can help to move that technology forward, and the approach that we have taken of additional Government funding to try and bring that through is very separate from anything else that would be available.
Shale gas is not essentially a new technology. It is a new strata but using an existing technology broadly in order to release it. The principle of fracking goes back to the 1930s, so it is a new application for an old technology.

Q285 Dan Byles: In July last year, the Department published the *Strategic Environmental Assessment for a 14th and Subsequent Onshore Oil & Gas Licensing Rounds*. Do you expect that licensing round to be dominated by a surge of applications for shale gas licences?
Charles Hendry: We are still hoping this will move forward in the course of this year. That is the appropriate timescale to which we are working to. Personally, I don't have an expectation for what will be in it. Simon, perhaps you can add to it in terms of anything that you are hearing.
Simon Toole: I don't think we are expecting a surge in applications for shale gas. I think we will probably see a continued interest in shale gas. You have to bear in mind there are also people looking at coal-bed methane and there are people looking at more conventional gas and, indeed, oil. Personally, I wouldn't expect the entire round to be dominated by shale gas. We are still at the stage where it is not clear that it will work here in the UK, but I am fairly sure we will get applications for—
Dan Byles: You expect there to be some, at least?
Simon Toole: Yes.

Q286 Dan Byles: Interestingly, the *Strategic Environmental Assessment* basically seems to say that extracting shale gas is well-established and only refers to larger quantities of water as being significantly different for shale gas versus other types of gas. Do you think DECC has enough expertise on shale gas to be able to perform a thorough SEA for the 14th onshore round?
Simon Toole: Yes, I think we understand the principles of shale gas. It is not hugely different from the techniques that are used elsewhere. In coal-bed methane there is quite a lot of water produced as well. There has traditionally not been as much fracking used in coal-bed methane, but we are fairly familiar with the fracking process. It is used quite a lot offshore, particularly in the southern basin. I don't think there is any particular technical or environmental impact of shale gas that we are not capable of understanding. There is a second stage to all licences. Once we have issued the licence and someone wants to actually do something, there is then a second process run, in this case, by the local authority, where guidelines are issued that make sure that the particular activity that is going to happen is done safely and with due regard to the environment. That wide survey, the SEA, is not the last part of the picture in terms of protection of the environment or any other aspect.
Charles Hendry: Can I just add on to that? I think it is important to emphasise that we are one organisation among a number that are involved in the environmental and safety monitoring of these issues. Clearly, the environment agencies involve the HSE and the local planning authority, whereas with coal-bed methane it is the Coal Authority, so there are a range of others who have appropriate expertise
I think what we have also shown, for example in the North Sea area, is that we have brought in the necessary expertise to ensure that we carry out our legal obligations properly, and that where we have, for example, been significantly staffing up in the number of inspectors, we have gone to great lengths to ensure that we bring in the people who have the right expertise to do that work.

Q287 Dan Byles: It is interesting that there are a number of issues that the Committee learned about on its visit to the US, which I wasn't on, such as concerns over benzene emissions, mobilisation of radioactive

materials and hydro-vacuum chemicals, and so on. The SEA does not make mention of any of these concerns. How would you account for that?
Simon Toole: For instance, for radioactive materials, the well that is currently being drilled is going to be monitored for radioactivity, so I think the SEA is taking the approach that these are known problems. There is radioactivity produced in southern gas fields and, indeed, in northern oilfields. We are used to that sort of aspect of it and I think the SEA took the approach that that is regular oilfield activity.
Charles Hendry: We will also look at any evidence from elsewhere where shale gas is being developed so, if there is evidence coming through from the United States that means that we need to put in place any different assessments, we are very happy to learn from that experience as well. We don't see this as a static process. We see this as something that is, as I say, an old technology with a new application, therefore the way in which we monitor that and assess it needs to evolve in time as well.

Q288 Dr Lee: I think it was last week that the Environments Agency came to see us. On two separate occasions, I asked them about checking for components of fracking fluid, and then I asked them about checking the integrity of the pipe once it was drilled, and on both occasions, they said that they were trusting the company to tell them. I found that quite concerning in that the general public's perception will be, "Well, we trusted companies to drill safely in the Gulf of Mexico. Look what happened". What is your view of the fracking fluid and declaring every part of it and, indeed, the view that the Environment Agency takes, where it only checks for the components that they have been told have been put in the fracking fluid? Therefore, if they are not told, they won't check for it, which sort of defeats the object almost.
Charles Hendry: I think one has to strike the right balance between appropriate monitoring and regulation and putting too many burdens on a legitimate business. The fracking fluid is 99.75% water. There is some sand in that as well and then there are three other chemicals that I understand are added to that. Any fluid that is put in underground is then brought back and kept in steel containers, and so it is quite simple to check the integrity of that system and to make sure it is captured. They have matted, with an impenetrable mat, the entire ground surface around it, so if anything should spill, it can't leach back into the ground.
I think one thing I found from going to Cuadrilla was that I ended up being very impressed by the level of safety steps that they had put in place, and with every question that I—or, indeed, people who know much more about this than I do—asked of them, they were able to give us very comprehensive answers to how they had addressed it already.

Q289 Dr Lee: But if you are disposing of that dirty water, where are you disposing of it? If you are selling it on as a contract to a company to process and dispose of that water and if they don't know what is in it—and, with respect, regarding percentages, you can put a bit of botulinum toxin on a teaspoon and kill a population. It is not the percentage that matters. It is the volume that is toxic enough to cause illness.
Simon Toole: In the case of the fluids used by Cuadrilla, the small proportions are of relatively benign chemicals, I think.

Q290 Dr Lee: My point is that you don't know, because you have not checked for it because you are relying on them telling you. This is what surprised me: there wasn't a list of 100 chemicals that they routinely check for. There wasn't. It was, "Well, they come along and tell us what they've put in it and we check for it". My point is that you are probably right; it is not necessarily a problem, but the perception is that we are trusting the industry to behave responsibly with the environment. I would suggest that public trust in the industry at the moment is probably at a low because of Macondo in terms of its respect for the environment. I wonder whether we should perhaps be a bit more proactive instead of reactive.
Charles Hendry: Those are appropriate matters for the Environment Agency. They are the ones who must be satisfied about the environmental conditions and any impacts of the work that is being carried out. Clearly, that may be something that you wish to focus on in the report that you make in due course, but from the point of view that we come at in the issuing of licences, we clearly have a different range of issues that we need to be satisfied about. Part of our process, if we were minded to go to issue a permit to extract, is that we advise the EA at that time. We have to make sure they have the appropriate planning consents, so what we have to try to make sure of is that there is a joined up process where all the bodies that need to be involved are involved at the appropriate time.
As I say, you may wish to say that that should be more proactive and reactive as far as the Environment Agency is concerned, and there may be lessons we can learn from the States in which that is carried out but, as Simon was saying regarding the additives: one is essentially a lubricant, which is a benign product in turn to facilitate the work. From my understanding of what is involved, there is no reason why they should be using toxins as part of that process.

Q291 Dr Lee: One final question with regards to the actual pipe down to where the fracking takes place. In America, one of the environment groups—I think it was the Sierra Club—expressed concern that you can drill a pipe, you can encase it in concrete, but the problem is that the actual act of drilling can cause weaknesses in the pipe that could then lead to future fracture of that pipe, so when you are extracting the dirty water through the water table, you do not actually know that the pipe itself is intact. In the same way that you could put these so-called pigs through pipes to check with the X-ray, I wondered whether a further check in the system could be—and this is their suggestion—that you checked the pipe before commencing operations following the initial drilling.
Simon Toole: There are tools that you can run on a wire line into a well to check whether or not you have damaged the pipe. You can check the thickness of the wall of the pipe. You can spot if there are any holes

or spots in it. It is usually used when you have used second-hand pipe and you have been drilling at an angle for some time so there is an obvious place where wear could have happened. I am sure, if it was appropriate, that one should check for worn or damaged casing. The tools are there to do it.
Charles Hendry: I think it is important to remember as well that the pipe is then encased in concrete. So the first part is to drill down to about 1,000 metres below where the aquifer is, then that pipe itself is encased in concrete. Then they drill down further to the level where the shale gas is, so at that point it is not just the pipe itself; there is a concrete coating around that as well.

Q292 Christopher Pincher: My apologies also for being late. I blame the Jubilee Line.
My point follows on from Phillip's point, because when we first began this inquiry some evidence was given about concerns about pollution of aquifers. Subsequently, we have heard there is no way, because of the depth at which one does fracking versus the depth of aquifers, that the aquifers can be polluted simply by fracking. Pollution can only occur by a weakness in the well itself, and if there is a weakness in the well and aquifers are affected, that effect is probably only going to be quite temporary. It is not as if you are creating some kind of radioactive effect in the water that will last for 1,000 years; it is a half-life effect. Is that something that you accept as an analysis, or do you think that there is any particular issue with aquifers if they are polluted?
Charles Hendry: I think the priority is to stop there being any spreading of the gas into the aquifers at all, and that is why the structure of the process has been designed as it is: to drill down below the aquifer level, concrete that in, then drill down further again so that the gas then is coming up through an area that is both piped and surrounded by concrete. The entire purpose of that process is to ensure that the aquifer cannot be affected. Everything that is being done is to ensure that nothing can get into the aquifer rather than to deal with a problem once it has occurred, because, while it may be of a temporary nature, what that does in terms of public opinion and what it does in terms of making people question the whole approach towards shale gas development will be very fundamental.
I think the industry—and Cuadrilla specifically as this is the only company doing this in the United Kingdom—have rightly put in place a sort of belt-and-braces approach to protect the aquifers.

Q293 Christopher Pincher: Just one more question. In terms of the drilling, I know that they drill, then they cement, and then they drill and they cement. In terms of the number of cases created around the actual well pipe that Cuadrilla are producing in the UK, is that different from the number of drills and then cements that they set in the United States, do you know?
Charles Hendry: We have a common standard here so we will have a much more uniform approach, whereas different states have different approaches, and so my understanding is that this is more robust than some states in the United States than in others.
Simon Toole: One would certainly expect an early casing across any aquifer, because you wouldn't want the same string being used for productions as is protecting the aquifer. In the States, I think, as the Minister says, there seems to be a whole range of regulation and different approaches, so we can't really compare. The best practice would be to ensure that you have isolated the drinking aquifers from any production activity by a string.

Q294 Albert Owen: Just for clarification, Minister, you have said that you would learn lessons from the United States with regards to the purification of the water and the treatment of the water afterwards. The Environment Agency, as I understand it, said they would do it on a case-to-case basis, but if you had firm evidence from some of the robust states in America, then you would insist to the Environment Agency that they would have to monitor certain things that came out of that evidence in the States before licences would be issued. Is that correct?
Charles Hendry: The Environment Agency is independent in this respect. It can't be dictated to by Government, and rightly so, but we can clearly give indications of areas we want them to be satisfied by. In the early stage of development, the water that has been used is going to be shipped away and then specially treated, I think somewhere in the eastern coastline of the United Kingdom. There may be issues if it moves forward to a greater stage of development where the producers will want to treat it for themselves, and then I would ask that the Environment Agency should use the best available knowledge from anywhere to ensure that we have the highest standards available here.
Simon Toole: Can I just add that we, with the HSE and the Environment Agency, who are three of the key agencies here, have established a regular set of meetings to ensure that we keep abreast of shale gas development, know what is going on in the States and have a unified approach over here. We are working particularly closely with the other agencies on this to make sure that there aren't any gaps.

Q295 Chair: In answer to an earlier question, I think you said that you did not see—at this stage, at any rate—shale gas being a game changer for the UK. However, there are some other EU countries where it could be quite significant; Poland being a problem, for example, so it could be a game changer in another sense, within the EU perhaps, and possibly a helpful one if it reduced our dependence on imports from outside the EU.
This Committee was pretty robust in dismissing any suggestions that there should be an EU-wide regime for regulating offshore drilling, but do you see some possible merit in having a common approach across the EU to the application of environmental standards for shale gas? If there was a situation where a country like Poland was willing to allow the development of shale gas there with less stringent environmental protection built in, that might place Britain and other EU countries at some sort of competitive disadvantage. Given the, I think, often superior approach to regulation that we have: a risk-based

approach or a principles-based approach rather than a box-ticking exercise of the sort, for example, that we thought that the US offshore oil regime suffered from—I think they are now going to change it to be a bit more like ours—would it be a good idea for Britain to take an initiative within the EU to start discussing the possibility of common standards for shale gas?

Charles Hendry: I think my nervousness about common standards is that they sometimes end up being the lowest common denominator, and sometimes it means that standards get driven down rather than driven up. What we would be keen to see, as I think we have argued successfully with our European counterparts on offshore, is that we have some of the highest standards anywhere in the world, and that should be the gold standard that others should aspire to. Our anxiety was that if one moved towards a European standard, it could actually lead to a diminution of those standards and that would be something we would find unacceptable. Therefore, those same concerns could apply elsewhere.

Where I think the EU can play a very useful role is sharing information and making sure that best practice is understood while leaving it to individual nation states as to how they handle that themselves. The Polish population will be as anxious as the British population that this should be done right and, therefore, it is in the interests of the companies operating in those countries that they should work to higher standards. I think we also recognise that the reason why it will develop faster in different countries isn't just the availability of shale gas and the fact it may be in more remote areas than in built up areas, for example, in the United Kingdom, but that it may also represent their response to their existing energy pattern and where they get their gas from. Domestic gas production offers them a significant political benefit in Poland, whereas of course we have already had that benefit here. We would expect it to develop at different rates in different countries, but I am not yet persuaded that common European standards would enhance that.

Q296 Chair: I do not share your optimism that the Polish people are going to be in the forefront of demanding higher standards in the exploration of shale gas. Poland has not exactly been helpful in the debates about the emissions from coal-fired power stations. In fact they are regarded as one of the recalcitrant, backward-looking EU members in that respect, and if they are to have perhaps the largest proportion of shale gas reserves of any EU member, I think to rely on the environmental sensitivities of the Polish people to ensure that higher standards are set in Poland is a little rash.

Charles Hendry: I think one can also ask the question: is it right for countries that have no shale gas development potential realistically at all to be setting the standards that should be employed in the domestic market of a country that may be thousands of miles away or many hundreds of miles away? Energy remains a retained policy area. It is not something where there is European competence. We have seen some very useful work being done by the Commission to address common issues, but the regulation of energy matters remains a matter for nation states. I think it is very hard to hold a line between saying, "We think there should be common standards for shale gas development, but, we think, for the North Sea, where we think our standards are so very good, it shouldn't apply there". We believe that we do have the gold standard for the North Sea activity and we believe that we will have extremely high standards for any development of shale gas, so we would be concerned about anything that could potentially lead to the dilution of those standards.

Q297 Sir Robert Smith: I should remind the Committee of my entry in the register of Members' interests relating to oil and gas, in particular a shareholding in Shell.

We have touched quite a lot already on the fact that you are confident that there is no specific need for legislation or regulatory change, specifically for shale gas. You have also said that you are monitoring a lot of what happens in the States. Is that monitoring a passive monitoring or do you actively seek out lessons they have learnt already? They are obviously further down the line on shale gas as a big part—

Charles Hendry: It is a combination of both. For example, as you say, we are at an earlier stage in that process. Should an application come forward for an extraction licence then at that point we would need to look at what restrictions may be put at that. At that point, one looks more actively at evidence from elsewhere. At this moment, we are not at that stage. No such application has come forward, so it is a more passive monitoring at present.

Q298 Sir Robert Smith: One of the things that came up last week with the Environment Agency related to where flaring fits into the whole environmental impact, because they don't have a say on flaring. That is a matter for the HSE, but the HSE are not there to assess environmental impact; they are there to assess safety, so is there a need to consider where flaring fits into the regulatory system?

Simon Toole: We have to issue consents for flaring. For shale gas, obviously the purpose of the exercise is not to flare the gas; it is to produce and sell it. You do need to flare gas when you are testing. What we do is make sure that flaring is the minimum that is needed to achieve the technical objectives of the exercise, which should be the company's objective too, and we also make sure that it is done with technology that minimises both the noise and the atmospheric intrusion of that flaring. There is quite a lot of technology for onshore flaring that attempts to make it inconspicuous and make sure that there is full combustion so you don't get smoke. So we do look at flaring. For shale gas, a particularly long period of flaring should not be needed.

Q299 Sir Robert Smith: I understood that in the Australian production system, one of the things about shale gas is that if there is any disruption to the export pipeline then you do need to flare, because it is not the kind of process you like to shut in for any length of time.

Simon Toole: I must admit I wasn't aware that that was a feature of shale gas, but with coal-bed methane you do need to be careful because there is always a water problem with coal-bed methane. For shale gas, I wasn't aware that there was a "no shut in" approach.
Sir Robert Smith: All right.

Q300 Dr Whitehead: How does the Department calculate the carbon footprint of gas in general, including shale gas, which presumably has no different carbon footprint, in principle, from ordinary gas?
Simon Toole: For shale gas, we haven't done any work on the carbon footprint because at the moment there is so little activity. I think, for normal production, it is fairly well known what the inputs to a production system are: there is a little bit of venting; there is a little bit of flaring and obviously there are the operational emissions. I think there is a reasonably well known path for working out what the carbon input for a given energy output is.

Q301 Dr Whitehead: What would the carbon footprint of gas be, compared with coal? What would the Department consider that to be?
Simon Toole: I think it is something in the order of twice.
Dr Whitehead: Twice, yes.
Simon Toole: I think there are definite reports on that. That is just my memory.
Charles Hendry: It is not our expectation that the availability of shale gas in the United Kingdom would lead to a greater use of gas, but it would lead to a replacement of import and, therefore, the totality of the gas that should be consumed is likely to remain broadly the same. We may get some small, local generation of gas built up on the back of a shale gas farm, but in general we are not expecting to see this lead to a surge of extra gas plants.

Q302 Dr Whitehead: Does the Department take into account the different lifetimes of methane and carbon dioxide in the atmosphere, and therefore the fact that the multiplier for methane in the atmosphere, in the shorter term, is substantially greater than the multiplier for methane in the long term in the atmosphere?
Simon Toole: I know methane has a 28 multiplier over carbon dioxide, if it is just emitted as a gas. Of course, with all these, you are burning the gas. We are not expecting there to be a great amount of leakage, and I know that leakage in the States is one of the things you've probably heard about, but leaking methane is a safety hazard and an environmental harm. We wouldn't expect methane to be directly emitted into the atmosphere in any significant quantity as a result of these activities.

Q303 Dr Whitehead: So the apparent measurement of methane of 72 times that of carbon dioxide in the shorter term, the global warming potential, as opposed to that of about 21 to 25 times in the very much longer term, is something that DECC has not taken into account in its calculations, or does it do that?
Simon Toole: I am afraid I don't do the calculations of footprints of various fuels. I would imagine we probably take internationally recognised measures of comparators. In terms of methane, we would not expect there to be significant direct emissions of methane into the atmosphere from shale gas. It would be burnt and the greenhouse gas would be carbon dioxide rather than methane.

Q304 Dr Whitehead: What was told to us by the US Environmental Defense Fund appears to cast some question marks on the assumption that you have set out, that gas in general is about 50% of the carbon footprint of coal. If you take the 20-year effect of methane in the atmosphere together with perhaps 3% to 4% leakage, the actual carbon footprint of gas and coal looks rather similar. Would you consider that to be an issue in thinking about shale gas, or do you think that with rigorous checks on leakage, which obviously is an issue in terms of the production of gas as opposed to the mining of coal; that is, coal is mined and it doesn't leak anymore, whereas—
Sir Robert Smith: It does leak methane.
Dr Whitehead: Yes, coal mines leak methane, which can be captured, but certainly one of the problems that we encountered in the United States was some fairly systematic leaking at various stages of the production process, including venting, on site storage, transport, and so on.
Charles Hendry: I think, in terms of leaks from the wells, we have already covered the need for casing, and if you have methane leaking from the well, you probably also have a problem with your aquifer, so we would not expect there to be direct leaks from the well.
In terms of transportation, again, I don't know how it is done in America, but we would be seeking not to have any direct methane leaks. I am afraid I can't comment on your 78 versus 28 because I am not that familiar with these calculations, but we would not expect shale gas to be any more detrimental in terms of carbon footprint than, say, gas produced offshore in the southern basin.
I think we would welcome more information on the work that is being done in the States, and we are happy to look into that further and then perhaps to write with some of our conclusions back to the Committee in that respect. It hasn't featured heavily in the approach that we have taken so far. As with all of these areas, the science, the technology and the approach that is being taken evolves over time, so if there are things that we can learn from that that would have implications not just for shale gas but for gas more generally, then that is something that we would need to take into account.

Q305 Dr Whitehead: I think the underlying point I wanted to test your thoughts on was that whether one takes a lower view of the carbon footprint of methane, as opposed to coal or the high view, do you think, in terms of climate change, the planet overall would be able to take the consequences of the additional emissions from a new source of gas, a new source of fossil fuel, and still keep within the temperature change limit of two degrees, or perhaps in the words

of Dieter Helm—and I paraphrase—to all intents and purposes now, gas is a limitless supply, but the problem is that if we do extract it all, we will fry.
Simon Toole: Our clear view is that we have legally binding carbon emission reduction requirements. We are working towards those. We also recognise, under every scenario we have looked at, that oil and gas and hydrocarbons will play a significant role to come for some decades, and that is why we are looking at how one mitigates the effects of those. That is why we have, for example, said that carbon capture storage future projects should be looking at gas as well as at coal. Over time the world has to move, and the Committee on Energy and Climate Change has said that by the 2030s that we ought to be looking at zero emissions from electricity generation. That means a development of CCS to go with gas, but I don't see a way in which we can meet our security of supply obligations and try to keep prices affordable without having hydrocarbons in that mix.

Q306 Albert Owen: Do you see it, Minister, as a transitional energy source? We have dirty coal, and this could fill the gap and ease the burden on emissions and then give plenty of time for new nuclear and renewables to come on board, so we would reduce our emissions and meet our targets far easier if shale gas was in plentiful supply.
Charles Hendry: Gas certainly has, to our understanding—and notwithstanding the evidence that Dr Whitehead has been putting forward—a much lower carbon emission threshold than coal does. Therefore, certainly gas plant is better than dirty old coal. It is not as good as coal with carbon capture and, therefore, one of the great challenges for the world in this decade is to take forward carbon capture technology.
I also think it is a question of the balance between domestically produced and imported sources of gas. We are now net importers of gas. We are very committed indeed to getting the resources that we can from the North Sea, but if there are gas resources that are available to us onshore as well, we believe it is in the national interests that those should be developed, as long as that can be done—

Q307 Albert Owen: So it can help energy security and reduce emissions?
Charles Hendry: On both sides, and therefore it also helps with affordability. We are, certainly for the next few years ahead, in a relatively benign position as far as gas is concerned. The gas price today compared with the oil price shows the extent to which that has begun to differentiate, particularly in the United States. We wouldn't expect that same differentiation to happen in the United Kingdom through the development of shale gas, because it is unlikely to be so plentiful. It is a useful step towards all of our objectives.
I am wary about referring to a transition fuel, because I think if we want people to build new gas-fired power stations, they have to believe that they have a long term future. Therefore, what we have to start doing is explaining what is going to be required in terms of emission levels and what is going to be required in terms of CCS retrofitting in due course, in order for people to have a long term outlook against which they can make investment decisions.

Q308 Chair: You said that you didn't think that shale gas would produce a significant increase in gas consumption in the UK but might have some import substitution effect. It is possible, though, isn't it, that if the abundance of shale gas worldwide turns out to be as some people expect, that the gas price generally might become significantly lower, which would make gas more attractive, perhaps, as a heating fuel in this country and therefore there might be some increase compared with business as usual?
Charles Hendry: We cannot meet our carbon reduction commitments without moving heating away from gas. We can do that to some extent through biogas; we can do it through renewable heat, but we have to find better ways of providing heat in our homes than by using gas for it. That is going to be one of the most fundamental parts of the change that we need to drive through, but we have to—as you rightly say, Chairman—have an understanding of the impact of this on consumers. Consumers understand the need for security of supply; they understand the need to decarbonise, but they are also concerned about how much they are being asked to pay for it, especially so in the case of some of the larger energy users, such as companies. They will want to continue to be able to access gas, especially if the outlook for that looks more affordable than had looked the case even just two or three years ago.

Q309 Chair: What I was suggesting, really, was that the challenge of getting people to switch from the use of gas as an important source of heating fuel, which we understand and support may become greater if the relative price of gas falls compared with the alternatives.
Charles Hendry: I think that would be the case, but I don't think we are expecting this to have the same price change as it had in the United States, where the significance has been greater than we think it could possibly be in the United Kingdom. Therefore, there may be some slight change in the price, but we think it is unlikely to be that significant given the extent to which gas is traded on a European level, rather than purely on a domestic level.

Q310 Chair: There is, of course, nothing we can do about the pace at which other countries, including the US, decide to develop their shale gas. It is their decision. If it was quite dramatic, as it might be in the US, and if it becomes easier for people in America to use gas rather than some other low-carbon sources, nuclear or some forms of renewable that could also make it harder for the global targets for reducing greenhouse gas emissions to be achieved. That will mean that the progress towards cutting global greenhouse gas emissions could be slowed down if the effect of shale gas is not to substitute for coal but is actually to divert people away from lower-carbon sources.
Charles Hendry: I think there are a couple of big "ifs" that go with that. If it was to replace renewable,

clearly it would slow down that process or indeed halt it. If it was replacing old, unabated coal, it would help in terms of meeting the carbon reduction requirements. I think it depends what it is doing in that respect.

It would also inject a greater urgency to the need to deal with CCS on gas. I think we are already seeing that in terms of the number of projects that are being proposed where they will now be looking at gas, which didn't really seem likely even just two or three years ago, so we are seeing a significant change in that area as well. It could be that there could be a greater use of gas with CCS, which, therefore, is entirely in keeping with low-carbon commitments, or indeed it could be by replacing some of the older unabated coal plants, which again would be helpful.

Q311 Sir Robert Smith: Does it not make it all the more important that other measures or incentives to the markets, such as emission trading being sorted out, become all that more important if the underlying fuel costs are going to start to be soft or falling?

Charles Hendry: That is certainly one of the reasons why the Chancellor announced in the Budget that there will be a carbon floor price. We want to give greater certainty to investors, and it is not just the people who are in low-carbon technologies who want to know where the carbon floor prices are going to be. It is people who are investing in gas who need to know how it is going to affect them as well. It would be very much better if this could be done on a European-wide basis. We are in no doubt whatsoever that we would have preferred to have a more robust EU ETS, but in terms of the major investment decisions that are necessary, the signals simply weren't going to be there relying on that. That is why it has been necessary for us to look at a clearer signal for the United Kingdom.

I think there are already indications that other European countries are going to follow suit and say they now see that as being the right way forward, so I think that will, of itself, help to give greater clarity to investors.

Q312 Sir Robert Smith: You did also mention in passing—which I can't really ignore—the Government's policy of maximising resources from the North Sea. Certainly I accept that has been DECC's ambition and strategy, but clearly you understand that a lot of my constituents, after the Budget, don't quite see that message coming out from the Government anymore. What is being done to try to rebuild relationships and confidence with the investors?

Charles Hendry: We had started a process with PILOT where we had restructured it; we had narrowed down its focus; we had made it much more targeted at delivering real outcomes; looking at decommissioning; what were the barriers to investment; looking at shared infrastructure issues. We have started that process with the industry and there is some very important work to be done. As for non-fiscal measures that will make the North Sea more attractive, what is going to make it more attractive for people to invest in the marginal fields? What is going to make it more attractive for some of the smaller operators to come in who have such an important role in maximising the returns? How we are going to make sure that the infrastructure is appropriately used? That is completely separate from the fiscal issues.

The decision that the Chancellor took was to say, "Look, at these times, it is right that we try to balance the load that is carried by industry, including the oil and gas sector, and by the public". I think the Chancellor made the right call in saying that we therefore needed to redress that balance, because many of the investment decisions taken when the last change to the supplementary charge was made occurred at a time when gas prices were not much more than half where they are today—well, oil prices were just over half where they are today. Therefore there was a very significant difference in terms of the background that applied when people were making their investment decisions then, and the price they are getting today.

We understand that any increase in tax is not welcome. We had a meeting with the industry last week, with the Treasury and with the Secretary of State for Scotland, where we said that we are keen to talk with them about how some of those issues will be taken forward—we understand that there are particular concerns about how that may relate to gas—and we are very committed indeed to keeping that dialogue open.

Sir Robert Smith: Obviously the Committee will return to this when it focuses the inquiry on that, but I couldn't let that remark pass without some observation.

Q313 Chair: Just talking about LNG for a moment, do you think that what is happening in the US is already affecting the global LNG industry?

Charles Hendry: It has made it more difficult to get investment in some of the new plant, I think, because in the United States they may wish to turn what was intended to be import infrastructure into export infrastructure. We also recognise that gas-exporting nations want security of demand as much as we want security of supply, and they need to have a clearer idea of where that is going to be sourced in the future than they have at the moment. As we are starting to see the development of some harder-to-reach gas reserves that are therefore more expensive to reach, we need very significant infrastructure investment, either in LNG or pipelines, to make them realisable. The plentiful supply of cheaper gas makes those investment decisions that much more difficult.

We are very committed to having more routes to market. That is why we have supported the development of the Nord Stream gas corridor and why we want a southern corridor as well. We think we need to find new ways of getting gas into the European market, and we think LNG has a very important part to play in that respect, and that is further enhanced by the £2 billion long-term contract that Centrica have signed with Qatar for the next three years, which shows how that can enhance our gas security over a longer period.

Q314 Chair: As the US moves from being an importer of LNG to possibly being an exporter, that obviously makes LNG more available for Europe. Is that likely to deter the development of unconventional gas in the UK?
Charles Hendry: These things are all driven by price, so it could be that a much more plentiful supply will make that change, but there are going to be companies that have been set up with the specific purpose of looking at the availability of unconventional gas, and that is what they do. They are not going to move into the LNG sector; they are not going to move into building supermarkets. They have been set up for that single purpose, so I think they will continue to try and take that forward but, at the end of the day, whether they decide to move from exploration to extraction will depend on the gas price that applies at the time.

Q315 Dr Whitehead: In the United States, LNG has moved, in theory, from being an import industry to an export industry in the terminals that were built over the last few years; in theory, they could be used for export but, by and large, they are now standing idle and the number of investors are querying the wisdom of putting all this money into these terminals for nothing. Could you envisage a similar outcome in the UK if shale gas even takes a modest proportion of the UK production, or is that offset by falling volumes of North Sea gas and, therefore, the economy balances itself? Are there dangers in the UK that the LNG investment may become a stranded asset in the way that appears to be happening in the US?
Charles Hendry: I can see no prospect of that. I think that when we look at the outlook for the North Sea and for the UK Continental Shelf, it is inevitably in a decline. We hope that increased levels of investment will slow the rate of decline. Therefore, shale gas would perhaps slow that rate of decline but it wouldn't actually stop it and reverse it. We also believe that the role of gas is moving forward. As we see a shift from coal-fired plants to gas-fired plants, that of the 20-plus gigawatt of consented plant, over 60% is gas. There is a greater interest in using gas in the mix than has been the case in the past, and that will require us to have import capacity. I think one of the strengths of the UK system at the moment is the range of import sources—both the pipelines to Norway and also the LNG facilities—and I can't see any prospect of that being made redundant by the development of shale gas.

Q316 Chair: On the question of pipelines, is it difficult for a new entrant in the UK to contribute gas to the grid? Will incumbents automatically make room for this or will they have to build new pipelines?
Charles Hendry: No, they wouldn't have to build new pipelines. We would hope that they can tap into the grid network, but what is perhaps more likely to happen is that they would generate on site. Very close to where Cuadrilla is working is a well-established gas facility using local gas but which generates electricity on site. The local community isn't even aware it is there, it is such a quiet facility. I think that is the more likely way: connecting into the electricity grid rather than into the gas network.

Q317 Chair: One of the problems that we were informed about in the US was that a lot of shale gas companies build their own pipelines in order to get the gas to a place where it can enter the grid. Is that not an issue that is going to arise in this country?
Charles Hendry: It could. We are obviously a much more compact country even than somewhere like Texas, where I believe the Committee has been to, so in terms of the length of pipeline that would be necessary in order to connect into the grid, it would be much shorter here. That would be required to be done to a standard. The gas being put into the grid would need to be of a standard acceptable to the national grid, so that could happen, but I think it is more likely that we are going to see people using it for generating electricity on site. I think Cuadrilla's interest has been their closeness to the electricity grid rather than their closeness to the gas grid.

Q318 Sir Robert Smith: Do you see the same grid connection problems that bedevilled new generation capacity from renewables heating, or is shale gas more likely to be situated where there is still potential capacity in the grid?
Charles Hendry: There are a whole range of different ways in which this could be done. It can be put directly into the grid; alternatively it can be linked into a renewable resource and, therefore, you have the gas that is available to generate the electricity when the renewable resource is not there. I think one thing that we are going to see is a very much more flexible approach with people coming up with very imaginative solutions rather than one standardised approach that applies everywhere.

Q319 Chair: One characteristic that is very noticeable in certain parts of the US is the way in which shale gas, and therefore the pipeline infrastructure as well, encroaches on very urban areas. They have put them in the middle of cities. Do you envisage that ever being permitted in this country?
Charles Hendry: I think it is quite challenging to see how that will happen in this country. I think, if you look at the map of where much of the shale gas is, it is under some of the world's more expensive real estate. Therefore, getting people's consent to it happening will be more complicated. There are also parts of the country where it can be developed on very open farmland, and I think that we are more likely to see the applications coming forward in those more open areas with single landlords rather than those with multiple landlords. They have to get permission from the individuals concerned. If that is not forthcoming, they can get a court order to try to get a compulsory permission, but that is a much more complicated process and applies in the States where the same ownership issues don't exist.

Q320 Dan Byles: Would you like to see an expansion of unconventional gas extraction?
Charles Hendry: Would I like to see it?
Dan Byles: Yes.
Charles Hendry: I see it as part of our response to our energy security challenges. If we have domestic sources of gas that can be retrieved safely and heed all

the environmental consequences, I have no objection whatsoever. Regarding the extent to which we are producing gas domestically, I would rather we were doing it domestically than having to import it.

Q321 Dan Byles: You want to leave it to the market, though, to decide whether or not to invest in shale gas. Your answer to Phillip suggests that you don't see the need for the Government to change in any way the support that it might offer to the industry.
Charles Hendry: No, I can't see any reason for changing the support that is offered to the industry. I think it would be a market-driven exercise, but, as I say, subject to very strict safety and environmental protections.

Q322 Dan Byles: Doesn't that run contrary to some of the evidence that we have seen, though? I mean, the Oxford Institute for Energy Studies have identified a number of catalysts that stimulated unconventional gas production in the US, for example, and among those catalysts were policy catalysts such as tax credits and a favourable regulatory regime. Shell has expressed the opinion that exploration and production companies will need positive Government support, and Professor Stevens, who is Senior Research Fellow in Energy at Chatham House, has said that basically the UK Government needs to decide whether it wants to intervene and thereby encourage greater investment in gas supplies generally and shale gas in particular.
Charles Hendry: It would ultimately be a matter for the Chancellor if he wanted to introduce new field allowances, recognising that this is a specific part of the market that would otherwise not be developed. What has happened in terms of the development of the North Sea, more generally, is that the tax regime has adapted in order to encourage development, so it is a question of looking at specific challenges and seeing how they can be overcome.

Q323 Dan Byles: So you don't rule out changes to the tax regime to try to stimulate unconventional gas?
Charles Hendry: I don't even comment on it, Mr Byles. I leave that entirely to the Chancellor.

Q324 Dan Byles: Would he not discuss that with DECC, do you think, if he was doing it not for the purpose of raising revenue but for the purpose of stimulating investment in a particular area of unconventional gas?
Charles Hendry: Of course there is close dialogue between us. We make sure that we both understand the needs of each Department and the perspectives of each Department, but we do that in private rather than in front of Select Committees.

Q325 Dan Byles: Could I just perhaps ask: if it turns out that the market is not bringing forward the investment that DECC has said they would like to see in shale gas, is it something that you would perhaps look at again?
Charles Hendry: At the moment, we are still trying to get an understanding of how likely it is as a technology to develop in the United Kingdom. As you know, we have only just one company that is actively exploring, and they have yet to decide whether there is anything that would justify their going forward to extraction. We are still waiting to see how large this potential is in the United Kingdom. Our initial feeling is that there will be reserves, but it will not be on the scale of Poland or the United States and it will be more complicated to extract it here than it will be in other countries, but of course we will constantly monitor the situation and see if our assessment changes.

Q326 Dan Byles: It has been suggested that the lack of an onshore service industry in the UK could hinder development of unconventional gas not just in the UK but across the whole of Europe. Is that a view you share?
Charles Hendry: I think, at the moment, it is an industry so much in its infancy that that is inevitably the case. One of the things that impressed me about the Cuadrilla approach was that they have brought in all of their own equipment for providing that support service, but they have also said that that will be available to others as well, so they are not using it to lock others out; they are using it to see how this can develop a wider industry.
I think what would then happen in due course, if the market shows it is viable, is that supply companies would set up to provide that equipment for them in terms of the compressors to pump in the fracking fluids. The drilling technology equipment tends to be brought in rather than individually owned, but in due course that would then become a more developed market. At the moment, where we have only one company exploring seriously, it is hard to see how that supply chain could open up at this stage.

Q327 Chair: My heart is warmed by the knowledge that you have a close dialogue with the Treasury, and I envisage perhaps tea and crumpets over there or maybe a late night whiskey in your Department. Can you tell us, as Minister of Energy, on which day you were informed by the Treasury of the inclusion of a one-off supplementary charge on North Sea oil and gas production announced in the Budget?
Charles Hendry: Chairman, I have never discussed my discussions with the Treasury on Budget matters. I think that those are issues that have to take place in private in advance of announcements being made, and that is something that is a part of the process that can only work if it is kept in confidence.

Q328 Chair: So I would be right to conclude that you were not consulted about this but were simply informed it was going to happen?
Charles Hendry: You wouldn't be right in concluding that, because that wasn't remotely what I have just said. The final decision is for the Chancellor, but of course we are putting information into the Treasury continuously on a range of different issues.

Q329 Chair: If I was wrong to conclude you did not know anything about it, I therefore have to assume that you support this policy?
Charles Hendry: Of course, and as I said earlier, I thought the Chancellor was right to make an

assessment that the balance needed to be redressed to protect consumers at a time when there was significant extra gains being made for people who were developing offshore. We understand it is not popular. That is why we have had the discussions with the industry. That is why we are continuing to look at whether there are areas where we can respond to some of the concerns that have been expressed, but I think the Chancellor made a judgment that I do support.

Q330 Chair: So you consider the companies were making too much money out of the North Sea?
Charles Hendry: They were certainly making more than they had expected to make, and at a time—
Sir Robert Smith: Over the lifetime of their investment?
Charles Hendry: Looking at the price of oil today compared with where it was when the last supplementary charge was made, where it has almost doubled—not quite but almost—they are clearly making significantly more than they had anticipated at the time, but we are committed to working with the industry to identify the barriers to investment. Those charges are still significantly lower here than they are in Norway, for example, and also we are committed, as I say, to working with the industry to see how we can make this an attractive place for people to invest.

Q331 Chair: This is an interesting new principle. If companies are making more than they are expected to make, they must now pay, in effect, higher taxes. Does that mean that those companies who unfortunately have found that for some reason they are making less than they expected to make will be rewarded by a cut in their taxes?
Charles Hendry: The Chancellor has also said that if the price drops—and he suggested $75 a barrel—he will look at stopping this, and that is an area where there is room for discussion as to what is the appropriate level. This is clearly linked to much higher returns than had been anticipated. It is clearly also associated with a time when consumers had been hit very hard indeed by the prices that they are paying at the pumps, and a desire by the Chancellor to try to address that, but to do that in a way that was fiscally neutral.

Q332 Dr Whitehead: As far as the discussions—and I can't speculate on what refreshments were provided—with the Treasury were concerned, was the decision to put £4.94 over EU ETS as a starting point for the carbon floor price a surprise to you, or was it, all along, not a surprise and therefore within the assumed consultation that appeared to suggest a 1p addition to the carbon floor price? Were you in on it all along or was it something that was offered to you—DECC—as a late night surprise over the drinks or the tea?
Charles Hendry: I wouldn't want the Committee to get too carried away with the thought of massive hospitality provided by the Treasury to discuss these issues. You will be aware that there was a package of measures that were consulted on at the same time. The Treasury were leading on the carbon floor price; we were leading on the other elements of market reform. Therefore, we were closely involved in their thinking on carbon floor; they had been closely involved in our evolving thinking on the market reform aspects. At the end of the day, we will make the recommendations for the right way forward, but we will have to get agreement from other Government Departments on our areas. Similarly, on issues that are tax-led, the Treasury makes the final decision, but I was not surprised by where we ended up.
Dr Whitehead: You were not surprised?
Charles Hendry: I was not surprised.

Q333 Christopher Pincher: Minister, when you are next having beer and sandwiches at the Treasury in these austere times, I wonder if it is worth making the point that, as I understand it, only 8% of shale gas wells turn out to be commercially viable. Perhaps there needs to be some sort of incentive at the test drilling stage to encourage companies to drill for shale gas because of those heavy up-front costs in terms of time and cash.
Charles Hendry: It is something that will need to be looked at, but I believe there is no pressing need to do so at this stage. We have a company that has been prepared to commit significant resources to the development through the work that Cuadrilla is doing at the moment. I think that shows that the market is working appropriately. We will have to see, in relation to the 14th round later on, how much interest comes forward, but my suspicion is that we will see significantly more interest than we have seen in the past, and that will show that businesses are keen to invest on that basis. As I say, it is up to the Chancellor to provide extra field allowances if he believe it is important for different types of development, and that is something that could be considered by the Treasury and by the Chancellor in due course.

Q334 Sir Robert Smith: One thing, I think, that is causing the most frustration among many of those involved in trying to invest in the North Sea is that when the Government produces some of the arguments in defence of its actions it almost makes matters worse. Regarding the comparison with Norway, Norway has always had a high tax regime. It has also had a different allowance regime, but it has been put to us that it also had a stable regime, and when investors are making a 20-year commitment, what they want to know is the stability and then work out the bottom line. If the bottom line changes half way through that causes frustration, and the other thing that causes frustration, certainly among the smaller entrants in the North Sea, is they are not selling on the spot market at $115 a barrel. They have already sold this year's oil at $28 a barrel. And why is it that hedge funds are not being taxed on the extra profits they are making rather than those who are doing the real job with real construction and real investment on the shop floor?
Charles Hendry: I hope you will appreciate that the sort of taxation for hedge funds is slightly outside my own ministerial responsibilities, and it may be that the Committee would wish to have a Treasury Minister come and give specific evidence on some of the taxation issues. We understand that any possible

change in this respect was not going to be popular. I think it is reasonable to point out that when Norwegian companies are talking about their future investment in the United Kingdom, it is absolutely clear that they will continue to be taxed less heavily in the United Kingdom than they are in Norway, and that is a relevant competitive factor.

Sir Robert Smith: They are also looking at a much more challenging and difficult investment environment in terms of the costs involved and the commitment they are having to make. That heavy oilfield has been sitting there waiting for someone to unlock it for years because it is such a challenging environment and such a costly investment.

Charles Hendry: That is why we are also looking at some of the other issues that are involved, and I hope the Committee won't lose sight of the very important work that needs to be done on issues like decommissioning, infrastructure and abandonment, and on a range of other issues on which we want to continue to work with the industry.

Q335 Albert Owen: Just go back, Minister, to what you said to the Chair with regards to the Chancellor's decision to tax oil and gas at a higher rate and the windfall tax, I agree with the principle of a windfall tax, particularly for oil. I think it was logical to do it, but I am not so certain about gas. The concern I have—and I think this is a matter for DECC—is that that might be passed on to consumers, the domestic market, businesses and households as a consequence because, as I understand it, it is trading below the $75 price that the Chancellor put in. Are we either going to see the gas companies paying less tax as a consequence of the stabiliser, and therefore the Treasury won't get the extra money that it thought it would, or are we going to see that passed on to the customer?

Charles Hendry: As you will appreciate, some of the companies most involved in that have already been to see the Treasury to explain why they believe that gas is a separate issue in terms of oil matters, and the Treasury have made it very clear they want to have further discussions on those issues. I think that it is a Treasury-led issue inevitably, in these matters, to try to come to the right solution that will continue to encourage and stimulate the level of investment that we believe is necessary and desirable and recognises the way in which the markets work.

Albert Owen: No, I understand that, but I am concerned about the domestic consumer having to pay more as a consequence, and I think that is a matter, with respect, for DECC, because we have had discussions before when you have given evidence, and we would have had a debate last night if it wasn't for other important statements. These are the kind of issues that worry the consumer, and I am linking it into specific DECC issues. Isn't there a concern that that tax would be passed on?

Charles Hendry: Clearly, oil is a internationally traded market and, therefore, there is no direct link between the price of oil in terms of the revenue for the offshore companies in the North Sea and the price at the pumps here. The gas tends to be brought into the United Kingdom and not exported in the same way, although the interconnectors can work both ways, so we do export gas from the United Kingdom as well. It is still an internationalised market but less so than on the oil side.

We will have to look very carefully on the impact on consumers. Clearly, at the end of the day, everything that is done in this area has an impact on consumer prices, and at a time when consumers are very nervous and anxious about price rises across the spectrum, unwelcome increases in gas prices are something that we would need to look at very carefully indeed to see if there were any other unintended consequences.

Q336 Dr Whitehead: A brief question on environmental impacts of shale gas production and, in particular, the management and disposal of the large quantities of water that are involved, both in terms of the fracturing process itself and water rising from a number of wells, which is usually heavily mineralised and needs to be disposed of in some way. Would you categorically rule out either the disposal of that water through any sort of conventional water treatment arrangements in the UK or its injection into deep aquifers underneath the water table, as is the case in the US on a number of occasions?

Charles Hendry: I think people would be more reassured if the people who are responsible for environmental protection, rather than a Minister, gives them that assurance, because it is the Environment Agency's job to make sure that the side effects of any actions are fully understood, and I would rather it were they, as professionals and experts in this area with appropriate qualifications, who made those assurances than a Minister.

Q337 Dr Whitehead: Do you not think the Department should take a view on this in terms of the particular circumstances that shale gas presents as far as the UK exploitation is concerned?

Charles Hendry: I think that, as a Minister, I should be guided by the evidence that is put forward by the scientific experts. Therefore, this should be an area where we respond rather than make absolute statements or qualified statements that may ultimately prove to be inadequate, and therefore it is better that the Environment Agency should lead on these matters, as they have an absolute responsibility for environmental protection.

Chair: Thank you very much indeed for coming in, and for answering questions that may have gone a tiny bit wider than just shale gas for a minute or two, but we much appreciate your presence.

Written evidence

Memorandum submitted by the Department of Energy and Climate Change

Introduction

UK Onshore Oil & Gas Activity in General

1. The onshore oil and gas industry has been operating in the UK for well over 60 years and production, although currently only 1.5% of overall UK oil & gas total, nevertheless contributes usefully to UK security of supply and to the UK economy.

2. Close cooperation between the industry and the planning authorities has allowed the industry to develop with minimal environmental impact. Alongside DECC licences and consents, all exploration and development activities also need to be authorised by the Health & Safety Executive .

3. Recent years have seen continued interest in onshore oil and gas activity as the response to the 13th Round in 2008 proved. That Round saw a good outcome with 97 licences awarded in total confirming the continuing commercial attractiveness of onshore oil and gas exploration opportunities in the UK, and there was renewed interest in coal bed methane.

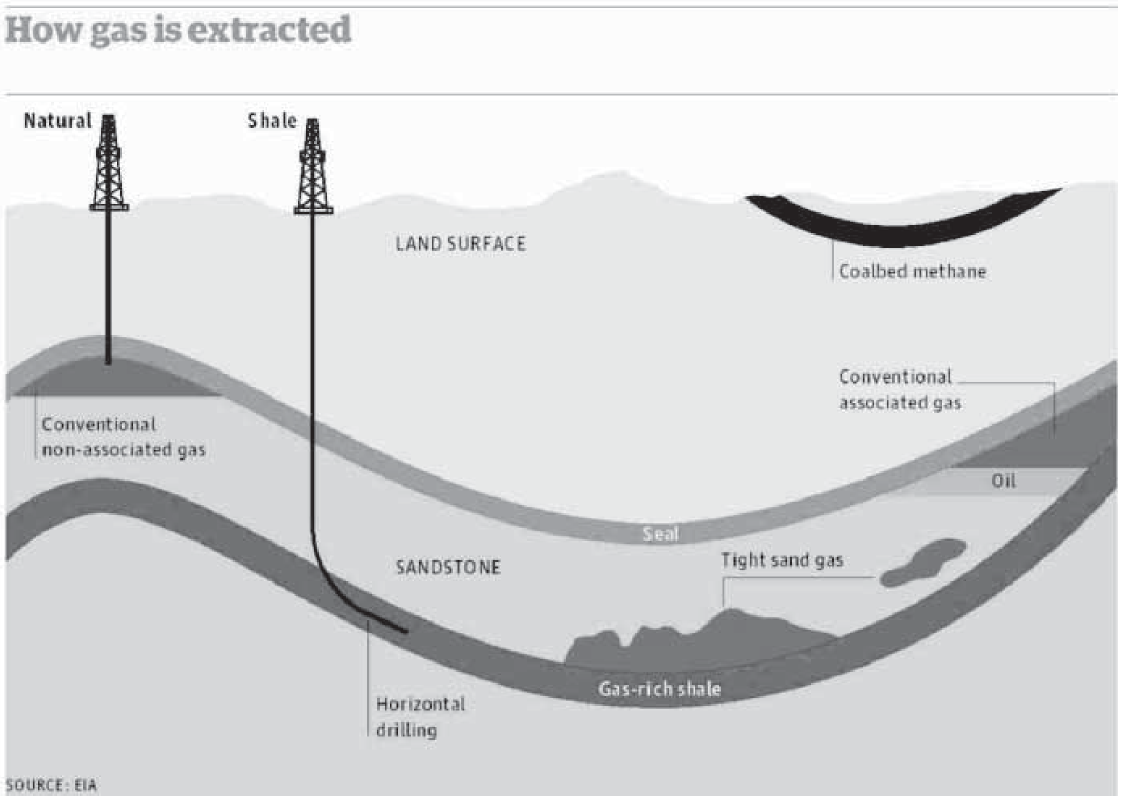
4. Current estimates suggest that overall onshore potential proven and probable reserves equate to around 1.5%–2% of the UK's overall reserves. Government wants to ensure that operators get the opportunity to explore and develop onshore—and licensing is the first part of this process.

5. There are currently some 28 UK onshore oil fields and 10 onshore gas fields in production. Overall UK onshore oil production is around 24,000 barrels per day (2009). BP's Wytch Farm field (Dorset) is the largest onshore oil field in Europe, and, although production peaked over a decade ago, the field still produces around 20,000 barrels a day (around 83% of UK onshore oil production).

Unconventional Gas

6. In the UK, as elsewhere, gas (and oil) is predominantly produced from permeable rock formations such as sandstones. But there have been many attempts over the years to develop other kinds of petroleum resources. The commercial development of "unconventional" gas resources has been limited until the last decade, when new production techniques have enabled a rapid development of shale gas.

7. Natural gas can also be extracted from coal deposits by drilling ("coal bed methane" or CBM—also known as "coal seam gas"). The energy of coal can also be exploited by gasifying the coal in the ground ("underground coal gasification" or UCG), though the gas produced is not "natural gas" (ie, predominantly methane), but a mixture of combustible gases.



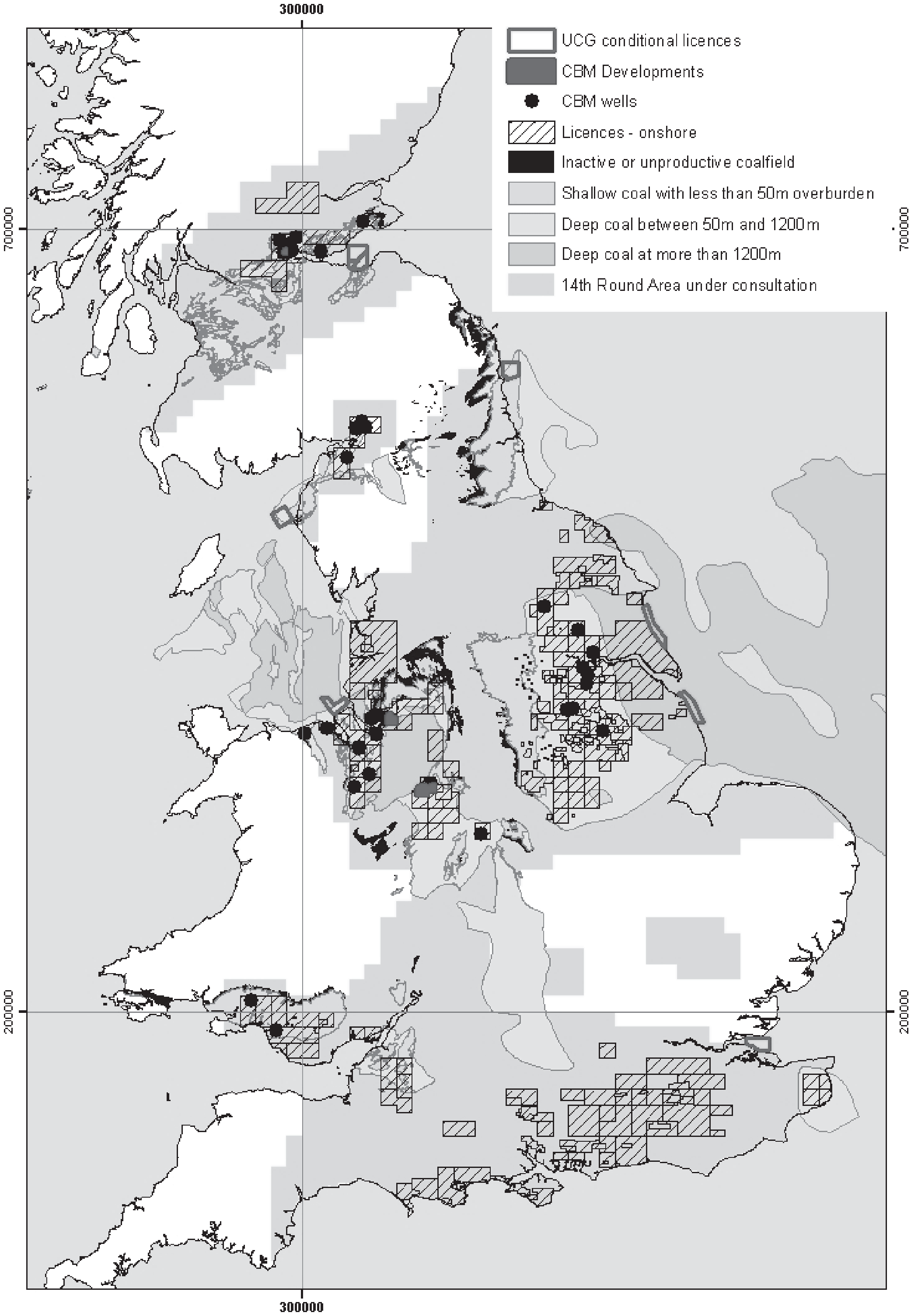
Conventional versus unconventional shale gas, tight gas and coal bed methane (CBM)

UK Potential & Licence Rounds

8. Although there may be significant resources of unconventional gas in the UK, this has not so far been demonstrated. It should not be assumed that the commercial success of shale gas and CBM in the US will be transferable to the different geological and other conditions of the UK. We are however encouraging exploration and appraisal actively for both shale gas and coal bed methane. The Coal Authority is similarly encouraging exploration and appraisal for underground coal gasification actively.

9. DECC aims to launch a new (14^{th}) onshore round this year, and expects a fair amount of interest from the industry, for both conventional and unconventional prospects.

10. The map below shows the location of CBM wells drilled, the three approved CBM developments, the Underground Coal Gasification licences awarded by the Coal Authority, the current onshore licences and the area under consultation which may be offered in the 14th licence round.

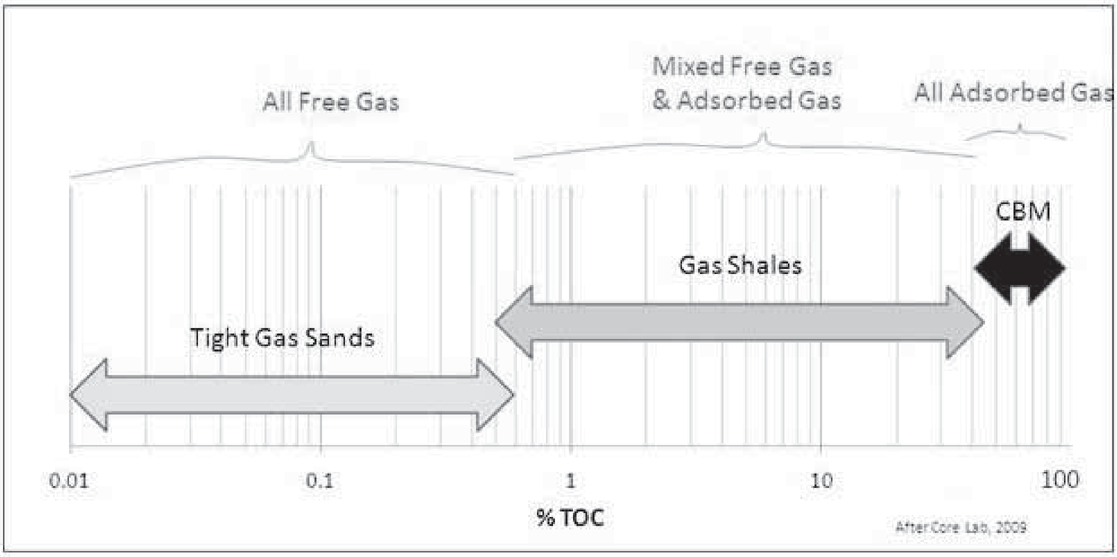


Map showing onshore licences, coal bed methane activity, and potential 14th Round licence acreage.

Shale Gas

11. **The Technology**—Shale gas is natural gas produced from shale. Shale has low permeability, so gas production in commercial quantities requires fractures to provide permeability. Although a small amount of shale gas has been produced for years from shales with natural fractures, the shale gas boom in recent years has been due to modern technology in hydraulic fracturing where fluid is pumped into the ground to create fractures to make the reservoir more permeable, then the fractures are propped open by small particles, and can enable the released gas to flow at commercial rates. Horizontal drilling is often used with shale gas wells, with lateral lengths up to 10,000 feet within the shale, to create maximum borehole surface area in contact

with the shale. The US experience suggests that successful production techniques are quite specific to particular formations.



Ranges of Total Organic Carbon in typical tight gas sand, shale gas, and coal bed methane prospects

12. As the diagram above shows, there is a continuum of unconventional gas prospectivity from tight gas sands, gas shales to coal bed methane (CBM).

13. Some conventional sandstone wells that failed to flow gas are being re-examined in light of American tight gas successes and 56 billion cubic metres (bcm) of tight gas potential reserves have been identified in the sandstone reservoirs of the Southern North Sea.

14. Gas can be found in the pores and fractures of rocks but also bound to the matrix, by a process known as adsorption, where the gas molecules adhere to the surfaces within a shale or a coal.

15. **UK Potential—**While there is growing interest in European potential for shale gas, the UK potential is as yet untested. The UK shale gas industry is in its infancy, and ahead of drilling with fracture stimulation and testing, there are no reliable indicators of potential productivity. There is variable data available on the geology, depending on whether oil and gas exploration has been undertaken and the extent of existing seismic data available.

16. A DECC commissioned British Geological Survey (BGS) study has recently concluded that, with the present state of knowledge about relevant UK geology, the only means of estimating the resource is by analogy with similar shales which have been successfully exploited in America. The study has been placed on DECC's Oil and Gas website and can be found via the following weblink: https://www.og.decc.gov.uk/upstream/licensing/shalegas.pdf

It is also attached to this report for ease of reference.

17. If the prospective shale area of UK shale gas potential did prove to be as prolific as the analogous basins in the US, it could be of the order of 150 bcm of gas (900 million barrels of oil equivalent). To put this in context, this compares with the UK's overall remaining conventional oil and gas reserves of some 20 billion barrels (including offshore).

18. However it is not yet clear whether there is any economic shale gas resource in the UK, as testing of our shales may show them to be less productive that those in the US. In addition, bearing in mind planning and environmental issues, it would be unrealistic to assume that the drilling density achieved in the US (thousands of wells) could be replicated in the UK. So this figure may be more representative of the theoretical top end reserves, rather than what it might be ultimately recoverable through practical development.

Coal Bed Methane (CBM)

19. **The Technology**—In addition to exploiting methane from abandoned and existing coal mining operations, the opportunity also exists to exploit methane which is still locked into the reserves of coal and coal measures strata that remain unworked. This concept is referred to as Coal Bed Methane since it involves directly drilling into unworked coal and coal measures strata to release methane held (or adsorbed) within the coal. CBM offers a method of extracting methane without detrimentally affecting the physical properties of the coal.

20. **UK Potential**—In the last 5 years over 40 CBM exploration and appraisal wells and 12 pilot production development wells have been drilled. IGAS and Nexen are generating electricity from CBM production, a first

for the UK, at their Doe Green development, near Warrington and are currently flow testing in Staffordshire at Keele Park as part of the Potteries CBM development. In Scotland, Composite Energy drilled 18 multi-lateral wells in their Airth CBM development, which is currently suspended, but produced water and gas in 2008 and 2009.

21. The theoretical CBM resource in the UK is estimated to be 2900 billion cubic metres (bcm) using only coals with the right depth, thickness, gas content, and separation from underground mine workings. Given that the 2009 annual UK natural gas consumption was approximately 86 bcm this corresponds to about 33 years consumption. However, the part of this CBM resource that is economically viable to produce is likely to be very much smaller, possibly around 10% or less. This is largely due to perceived widespread low seam permeability, low gas content, resource density and planning constraints. More drilling and testing is necessary to refine the estimate. At the moment only modest amounts of CBM gas has been shown to be economic and realistic estimates of the size of the resource are not possible until drilling and production demonstrates more generally the economics of production in UK conditions. A BGS study on UK CBM potential is available on DECC's Oil & Gas website at: https://www.og.decc.gov.uk/upstream/licensing/cbm.pdf

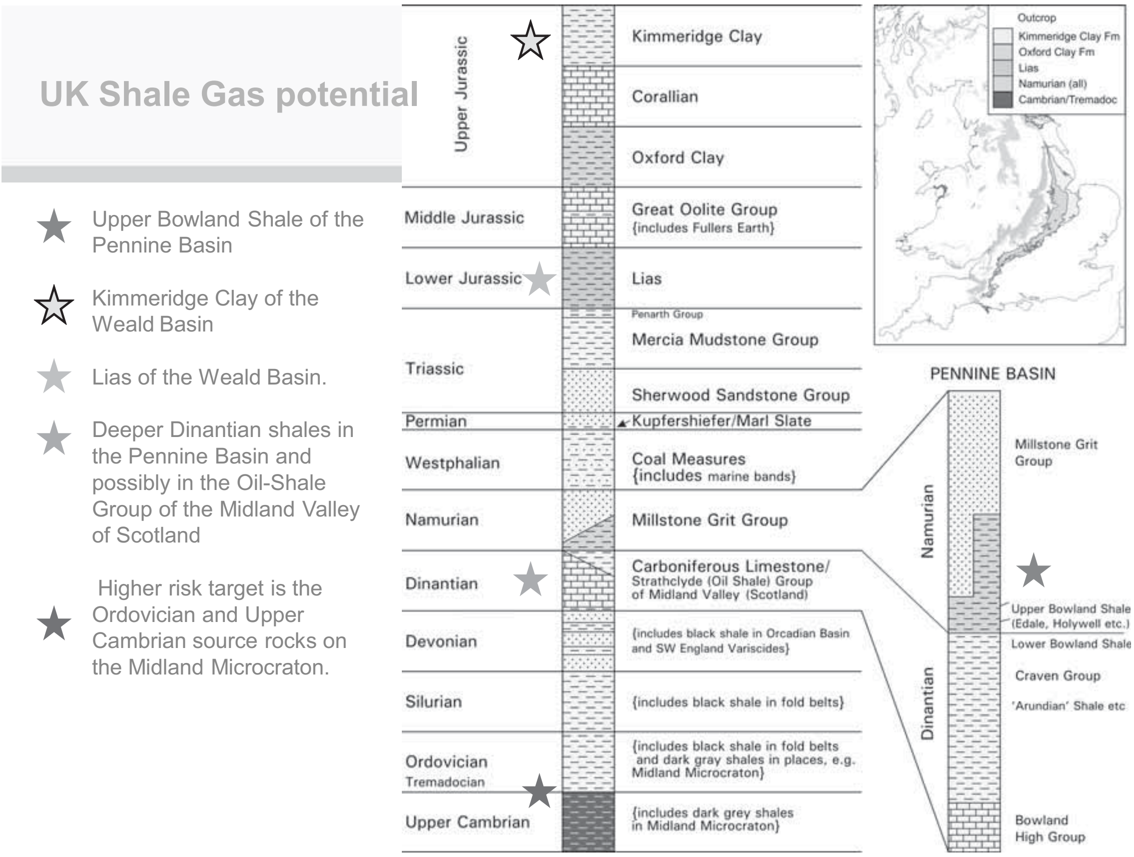
Underground Coal Gasification (UGC)

22. **The Technology:** UCG is the partial in-situ combustion of a deep underground coal seam to produce a gas for use as an energy source. It is achieved by drilling two boreholes from the surface, one to supply oxygen and water/steam, the other to bring the product gas to the surface. This combustible gas can be used for industrial heating, power generation or the manufacture of hydrogen, synthetic natural gas or other chemicals. The technique has not yet been demonstrated to be commercial anywhere in the world, though there is one long-running project in Uzbekistan.

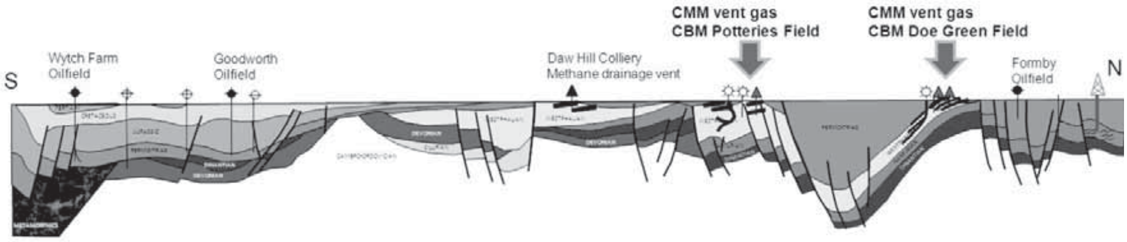
23. **UK Potential:** Although trials were conducted in the UK as long ago as the 50s, the technical and economic viability of underground coal gasification (UCG) has not to date been demonstrated. It is too early to judge, therefore, what contribution this fledgling technology might make to future UK energy needs. Notwithstanding, there is active interest in the sector's potential. The licensing body, the Coal Authority, has over the last year or so granted 14 Conditional Licences for UCG (all in relation to undersea reserves). DECC is monitoring progress with interest and continues to work with other parties (the Coal Authority, Environment Agency) to help ensure clarity around the regulatory aspects of the process.

What are the prospects for shale gas in the UK and what are the risks of rapid depletion of shale gas resources?

24. The Namurian Bowland Shales in the Lancashire basin (which are the source rock for the Irish Sea fields) are the most prospective, but also the Jurassic Kimmeridge and Lias shales (source rocks for the North Sea and English Channel fields) are being considered in the Weald basin in southern England. Indications of gas have often been encountered while drilling through these shales for conventional exploration of sandstone and limestone.



25. The first UK exploration well designed to evaluate shale gas potential, using state-of-the-art fracture stimulation and testing procedures, is currently drilling west of Blackpool (Cuadrilla's Preese Hall 1 well), shown on the far right (North end) of the diagram below.



Cross section from England's south coast to the Lancashire basin near Blackpool

26. Reserves can be estimated for conventional oil and gas prospects by applying a recovery factor to the hydrocarbons in place, but for shale gas, the reserves are dependent upon the number of wells drilled, the success of the fracture stimulation, and the use of horizontal drilling to increasing the area that can be drained around each borehole.

27. Shale gas success can only be measured after a number of wells are drilled and tested. The initial production rates and ultimate recovery of gas for each well then are averaged to estimate the reserves in the various parts of a large shale gas play.

28. An estimate of UK potential can only be made by analogy to productive areas. On an area basis, comparing the size of the prospective UK Namurian Carboniferous (Upper Bowland Shale) shale to the Barnett Shale play in Texas, the Lancashire basin could potentially yield up to 133 bcm of shale gas. If the onshore UK Jurassic shale gas play is analogous to the Antrim Shale in Michigan, the Weald/Wessex basin could potentially yield 6 bcm recoverable shale gas. There is higher risk potential in older shales, and some offshore potential too.

29. However, as noted above, it is difficult to imagine that a US model for shale gas development, with thousands of wells in each trend, can be replicated in the UK. Planning and environmental considerations are likely to limit the number of surface locations from which wells can be drilled, but there is hope that a smaller

scale development with numerous horizontal wells from central sites could be economically viable. But it is too early in UK shale gas exploration to know if commercial development can be established.

30. Unlike some other countries where landowners own the oil and gas under their land, in the UK the Crown controls the right to produce hydrocarbons. DECC licenses these rights to exploit oil and gas resources; and, together with the environmental control through the planning system (by Local Authority supported by the Environmental Agency and other consultees), and safety regulation (by the Health and Safety Executive), this should result in a well ordered development of the resource. This has already been achieved with the UK's long experience of development of its more conventional onshore oil and gas resources.

Risks of Rapid Depletion of Shale Gas Resources?

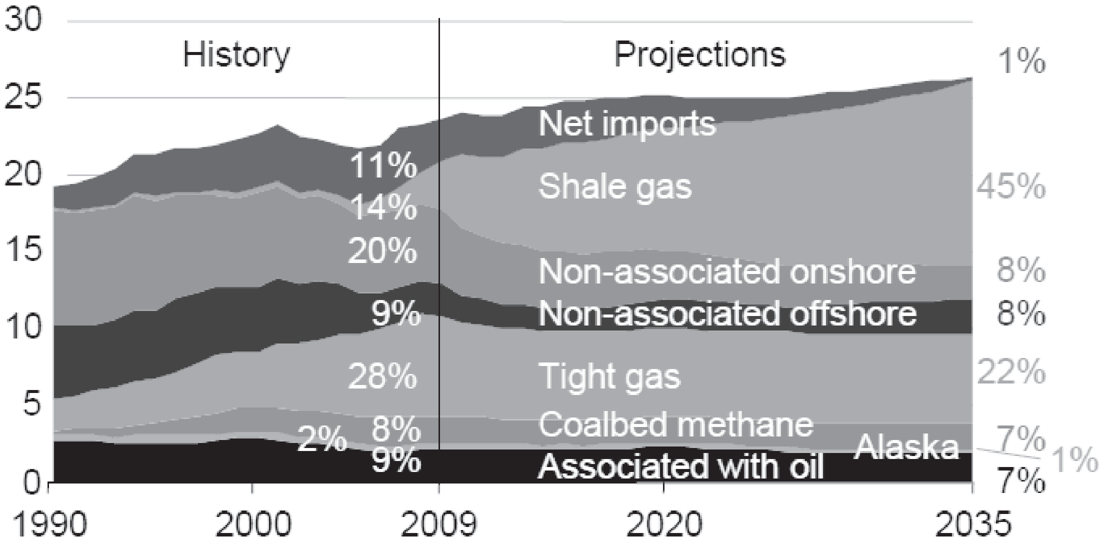
31. While there has been debate in the industry regarding the forecasting of future shale gas production profiles, it is too early to know what decline rates we might experience. We don't yet have UK data to estimate the initial production rate, the initial rate of production decline, and the degree to which that initial decline rate flattens out over time. We have significant potential reserves—but no proved prospectivity for shale gas, and only pilot production data for CBM.

What are the implications of large discoveries of shale gas around the world for UK energy and climate change policy?

Prospects for further production in the US

32. Production of unconventional gas in the US is expected to increase with the growth in unconventional gas production being driven largely by shale gas production rising from 14% of total consumption (around 3 trillion cubic feet) in 2009 to 45% (around 12 tcf) in 2035, according to the EIA (US Energy Information Administration) chart below.[1]

U.S. DRY GAS PRODUCTION (*TRILLION CUBIC FEET A YEAR*) BY SOURCE: 1990—2035.



Source: US Energy Information Administration

33. This growth is expected to help put downward pressure on the US's demand for imports. The US's net imports peaked in 2007 at around 3.5 trillion cubic feet of gas, most of which was imported from Canada. The US's net imports are projected to fall from 2.6 tcf in 2009 to 1.3 tcf in 2025 and 0.3 tcf in 2035. The EIA are expecting imports of gas from Canada and from LNG to fall over the next two decades.

34. The EIA has continued to revise up its expectations for shale gas production and the impacts this will have on the US market. For example in contrast to the Annual Energy Outlook 2010 reference case, the EIA now:

— Has doubled the technically recoverable unproved reserves of shale gas;

— Projects higher shale gas production;

— Projects lower US prices;

[1] NB: 1 tcf is equal to around 28.3 bcm.

— Projects lower total U.S. net imports of LNG (due in part to less world liquefaction capacity and greater world regasification capacity, as well as increased use of LNG in markets outside North America); and

— Assumes the Alaska pipeline will not be constructed as projected due to both the projected lower US prices and higher capital costs which makes this unattractive.

It should be noted that such projections are sensitive to a number of assumptions, relating for example to the pace of technological innovation and economic growth.

35. The impact of further growth in gas production in the US on global markets will depend on a number of factors:

— The extent to which the increase in production is offset by increases in US demand for gas;

— The extent to which it exceeds, or falls below, market expectations and therefore helps push the global market into over- or under-capacity; and

— Whether the US will be able, and the extent to which it will be able to export natural gas in other markets.

Prospects for unconventional gas production in the rest of the world

GLOBAL UNCONVENTIONAL NATURAL GAS RESOURCES IN PLACE *(trillion cubic metres)*

	Tight	*Coalbed*	*Shale*	*Total*
Middle East and North Africa	23	0	72	95
Sub-Sahara Africa	22	1	8	31
Former Soviet Union	25	112	18	155
Asia-Pacific	51	49	174	274
Central Asia and China	10	34	100	144
OECD Pacific	20	13	65	99
South Asia	6	1	0	7
Other Asia	16	0	9	24
North America	39	85	109	233
Latin	37	1	60	98
Europe	12	8	16	35
Central and Eastern Europe	2	3	1	7
Western Europe	10	4	14	29
World	210	256	456	921

Source: Rogner (1996), Kawata and Fujita (2001), Holditch (2006). Taken from World Energy Outlook 2009 table 11.3, International Energy Agency.

36. While North American production is expected to continue to increase, there are significant uncertainties over the extent, the timing and the location of production elsewhere in the world. This is due to a number of factors including:

— the limited understanding of reserves: The table above shows estimates for the unconventional gas reserves thought to be in place in various regions across the world. On these estimates, the resource could be very large. For comparison, global consumption of gas is around 3 tcm per annum.[2] However, comprehensive assessments are few and far between. And there is a lack of production experience outside the US, which leaves substantial uncertainty about how much of the resource might ultimately be producible. Nonetheless, the current IEA estimate is that around 380 tcm could be recoverable based on current data. This compares to an estimated 404 tcm of recoverable conventional reserves and 184 tcm of proven gas reserves;

— prices: the price required to incentivise investment will depend on a number of factors, such as the productivity and cost of the well, access to transport infrastructure etc. The IEA has estimated recoverable unconventional resources can be produced at prices between $2.7/MBtu[3] and $9/MBtu in the US;

— environmental controls and population density: unconventional production is more land intensive than traditional methods. Either factor could restrict development, particularly in Europe which has high population density and a well developed regulatory framework;

— land ownership: US legislation differs from most, including that in Europe, in that it grants landowners rights over hydrocarbon resources rather than conferring ownership on the state. This has provided a huge incentive for landowners to agree to invasive drilling on their property. The lack of such an incentive could be particularly significant in parts of Europe with strict planning laws;

[2] WEO 2010, Table 5.1, Primary natural gas demand by region and scenario (bcm), page 181.

[3] Millions of British thermal units.

- — availability of infrastructure: the US and Canada have highly developed gas grids, something that is lacking in China, India and some other potential sources of unconventional gas; and
- — access to technology and expertise: the technology required to exploit unconventional resources is highly specialised and has been largely, though not entirely, confined to the US.

37. Notwithstanding the uncertainty it is clear that there is potential for additional gas to be brought to market in large volumes. Should this be the case, there could be significant impacts on global energy markets and climate change.

38. **Price implications**—The unexpected growth in unconventional gas production in the US has already, in conjunction with other factors, helped to depress UK and global spot wholesale gas prices over the course of 2009 by reducing the US need for LNG imports, although recently UK wholesale prices have rebounded strongly. Over the medium and long-term, the impact of new sources of unconventional gas on prices is uncertain. Increased supply of gas via increased production of unconventional is likely to reduce gas prices going forward. However, instead there might be upwards pressure on gas prices if expectations of unconventional gas being brought to market leads to under-investment in conventional gas or other energy sources. The EIA expects unconventional gas to exert downward pressure on natural gas price. Natural gas wellhead prices in AEO2011 (in 2009 dollars) only reach $6.53 per thousand cubic feet in 2035, compared with $8.06 in AEO2010 due in part to increased estimates on recoverable shale gas resources.

39. **Security of supply**—there is potential for security of supply to be improved due to the opportunities for consuming countries to diversity across a wider range of sources of supply.

40. **Climate implications**—increased unconventional production would result in lower emissions if it displaces fuels such as coal that are associated with higher emissions. However, the potential downside from reduced emissions in the short- to medium-term is that this reduces the incentive to invest in developing and deploying the low-carbon alternatives required to meet longer-term emission goals. If gas was to play a major longer-term role, this would suggest a greater need for effective CCS technology for gas plants. Tighter national emission targets and policies to support innovation and deployment of low-carbon technologies could be used to reduce these risks. With such measures, the increased use of gas could be an effective bridge to help deliver greater near-term reductions.

41. To reduce the uncertainty posed by these issues, the Department intends to closely monitor developments and will consider the need for additional research to improve our understanding of the implications for policy. In the meantime, DECC is continuing to liaise with the energy industry and academia as knowledge and experience develops.

What are the risks and hazards associated with drilling for Shale Gas?

42. The safety risks and hazards associated with drilling for shale gas should be no more onerous than those associated with drilling for any other hydrocarbons by a borehole (for instance, the worse case being a blow out leading to the release and possible ignition of gas).

43. The process of extending the borehole to the shale formations of interest, will follow those used for conventional drilling of oil and gas wells, with a number of casings of reducing diameter being run and cemented to form a conduit to surface. The principle of dual barriers to any potential flow of fluid will be maintained and equivalent safety features for the production phase of shale gas will be in place i.e. sub surface safety valves.

44. The risks to people from drilling a borehole for hydrocarbons under a production, or exploration and appraisal, license will be regulated by the Health and Safety Executive (HSE).

45. UK legislation requires the operator to assess not only the risks and hazards above ground but also those associated with the sub surface aspects of the operations. The operator must notify HSE of any proposed drilling operations which will allow a dialogue to start on the management of the risks that have been identified.

46. More generally environmental risks of shale gas development have received some media attention in the US and have even resulted in a hydrofrac drilling ban in the state of New York which flanks the successful Marcellus shale trend. It is claimed that some incompetent operators have allowed gas to contaminate shallow aquifers, which should not be possible with proper well casing design.

47. The use of large quantities of water for fracture stimulation in areas with limited water supply and the safe disposal of the recovered fluids have also been reported as contentious in the US. Public health concerns there have resulted in a demand for greater transparency regarding the chemical composition of the fracture stimulation fluid and the US Environmental Protection Agency have recently changed their requirements. In the US, where the landowner owns the mineral rights, directly benefiting from drilling, consent to dense drilling has been allowed with reported possible negative effects on local communities.

How does the carbon footprint of Shale Gas compare to other fossil fuels?

48. The carbon intensity of natural gas from shale formations varies between various shales and depends on the extraction process and emission management. Both the greater number of bore holes required to be drilled

for shale gas in relation to field gas and the process of hydraulic fracturing of the rock add to the energy and carbon footprint of the extraction process. This carbon footprint can be increased further by fugitive emissions of methane released directly to the atmosphere as a result of the fracturing process.

49. Little investigation has been undertaken into the size and variability of greenhouse gas emissions from the extraction process and even less has been conducted on the potential impact of fugitive methane emissions. Estimates of the carbon intensity of shale gas should therefore be treated with caution until peer-reviewed work is available. However, providing that fugitive emissions of methane can be managed adequately, shale gas can be expected to have a carbon intensity greater than that of natural gas from conventional fields, but significantly lower than that of coal.

January 2011

Further memorandum submitted by the Department of Energy and Climate Change

My written submission to your enquiry on shale gas regrettably did not mention that we had issued a call for evidence to improve our understanding of the prospects for global unconventional gas production. I thought I should write to correct that oversight.

DECC has been monitoring the development of unconventional gas for some time via a number of means, for instance through taking information in the public domain, and attending stakeholder events, As I explained in my letter to you of 28 February, we decided last year to ask a number of organisations including academic institutions, NGOs and private businesses to contribute further to our understanding.

DECC published the commissioning letter for the call for evidence and all non-confidential responses on our website on 25 February. These total four responses from companies and also three reports, Where consultees requested we did not publish a response (for instance for reasons of commercial confidentiality) we have not made these public, For ease, the results of the consultation can be found at:

http://www.decc.gov.uk/en/content/cms/what_we_do/change_energy/int_energy/policy/gas_markets/gas_markets.aspx

Our main conclusions from the responses we received were:

— The unexpected growth in unconventional gas production in the US has already, in conjunction with other factors, helped to depress UK and global spot wholesale gas prices over the course of 2009 by reducing the US need for LNG imports. However, as the global economy emerged from recession during 2010 and gas markets have tightened, UK wholesale prices have rebounded strongly. There is now a substantial gap between US and UK spot prices.

— The prospects for unconventional gas production outside North America are uncertain. Most analysts suggest that a range of factors make unconventional gas more costly and harder to access in regions outside of North America. Moreover, there is a greater abundance of conventional gas in many regions outside of North America which would reduce the need for unconventional gas production.

— It is unlikely that significant production of unconventional gas will occur in Europe in this decade. Development in Asia and Australia could come on-stream earlier than this, Given the uncertainties around when, and the degree to which, unconventional gas will be produced outside North America,

I therefore take a cautious view of the implications of gas security of supply, my officials will continue to monitor progress closely.

I hope this is helpful.

March 2011

Supplementary memorandum submitted by the Department of Energy and Climate Change

1. *Who was asked to submit evidence to DECC's inquiry into unconventional gas and how were these organisations chosen? Was the Environment Agency asked to contribute, if not, why not?*

Last year DECC contacted the following organisations and experts:

— BG Group;

— BP plc;

— Centrica plc;

— Chatham House;

— Douglas Westwood Ltd;

— Exxon Mobil Corporation;

— International Energy Agency;

— IHS Cambridge Energy Research Associates;
— Oxford Institute for Energy Studies;
— Shell U.K. Ltd;
— Dr Pierre Noel, Electricity Policy Research Group, University of Cambridge; and
— Professor Dieter Helm, University of Oxford.

The list was put together by DECC and FCO officials, and included companies with an international view of the prospects of unconventional gas production and experts, that it was thought at that time would be able to provide useful information.

The focus of the call for evidence was relatively tight—for example, it did not focus on specific environmental, health or safety issues regarding production in the UK (considerations in relation to that have been made within the DECC/HSE/EA/SEPA group referred to in Q3 below).

Given the scope of the call for evidence—that is, on the prospects for global production of unconventional gas—it was judged that the information we hoped to receive (together with other sources of information eg in the public domain, attending stakeholder events, etc) would be sufficient to enhance DECC's understanding in this area. The call for evidence was routine and just one part of DECC's ongoing work on unconventional gas. It was not intended to be of itself a forensic or comprehensive investigation around all aspects of unconventional gas. We continue to welcome further information on the matter, particularly as this an evolving area.

In the interests of transparency, having undertaken the call for evidence DECC was proactive in requesting where submissions could be published; where permission was received they were published on DECC's website[4] on 25 February 2011. Charles Hendry wrote to the Committee's Chairman on 28 February to draw attention to the call for evidence and the published contributions to ensure that the Committee was aware of the work.

In view of the international scope of this call for evidence DECC did not consult the Environment Agency, whose role in relation to unconventional gas extraction is ensuring appropriate regulatory controls aimed at preventing pollution and ensuring high standards of environmental protection are in place within England and Wales. If DECC's call for evidence had focused on a wider set of issues relating to unconventional gas, then it would have been appropriate to approach a wider group of individuals or organisations.

The Committee also asked why Cuadrilla were not asked to provide evidence. As indicated, the DECC consultation was on the global role of unconventional gas and was limited to the biggest multi-national companies with a global view. Cuadrilla do not fall into that category. However as far as UK shale gas activity is concerned DECC has of course had a number of meetings with Cuadrilla.

2. *How many responses to the inquiry did DECC receive in total and how will these feed into DECC's policy on unconventional gas?*

Ten of the organisations and experts approached provided some kind of response. Some of these responses answered the specific questions put to them, some responses provided reports relating to unconventional gas (many of which were already in the public domain) and others provided comments or contextual information.

The information collected is intended to be used as contextual information for policy making. For example, had responses indicated that it was likely that a rapid development of large volumes of shale gas would be produced in Europe then this would have had implications for European gas prices, European energy security and other impacts which in turn might have had implications for the UK.

3. *In evidence to the Committee, Simon Toole referred to an implementation group of DECC, HSE and EA officials which met to discuss unconventional gas issues. How often does this group meet and what are the job titles of the officials attending. Does this group have contacts with equivalent regulatory bodies in the US and Europe?*

Officials from DECC, HSE, EA & SEPA have been meeting (via telephone conference) fairly regularly since 11 February. There have been three strategy meetings and three meetings at working level. Officials who have attended some or all of these sessions are as follows:

DECC:	— Director—Licensing, Exploration & Development
	— Deputy Director Licensing Strategy
	— Head of Oil and Gas Licensing
	— Senior Geoscientist
	— Head, Environmental Management Team
	— Environmental Manager
	— Manager, LED Briefing Co-ordination
HSE:	— Head, Offshore and Diving Policy

[4] http://www.decc.gov.uk/en/content/cms/what_we_do/change_energy/int_energy/policy/gas_markets/gas_markets.aspx

Defra:	—	WFD implementation
	—	Water Quality
	—	Water Availability & Quality
	—	Water Availability & Quality
Environment	—	Head of Waste & Resource Management
Agency:	—	Area Environment Manager—Northwest
	—	Groundwater Manager
	—	Climate Change Advisor
	—	Senior Government Relations Advisor
	—	Climate Change Advisor
	—	Parliamentary Co-ordination
SEPA:	—	Senior Policy Officer—National Operations Water Unit

In addition to these meetings, there continues to be an ongoing dialogue amongst these regulatory bodies via e-mail and telephone regarding specific issues and activities as they arise. Some of these officials, from Environment Agency, have had contact with counterparts in the EU and US. For example the EA has had informal discussions with the US EPA to understand the statutory framework in place in the US, and to establish key points of contact if required in the future.

4. *Does UK oil and gas legislation need to specifically refer to unconventional gas or will existing legislation provide the appropriate regulatory framework to deal with the potential hazards?*

Government does not believe there is a requirement for UK oil and gas legislation to specifically refer to unconventional gas. The technologies being used for shale gas and coal bed methane are not new. However more widespread use of hydraulic fracturing does potentially pose additional challenges for regulators, local authorities, water providers and waste management organisations. For this reason DECC has an ongoing dialogue with Defra, HSE, EA, and SEPA to ensure that exploration and drilling operations are know by all relevant parties and ensure a joined up approach.

We believe that the UK has a robust regime which is fit for purpose and will ensure that shale gas and coalbed methane operations are carried out in a safe and environmentally sound manner. We are still considering whether or not there is a need to amend any regulatory provisions to give us the same level of assurance about Underground Coal Gasification.

There are a range of regulatory requirements. It is the responsibility of each particular company to identify and comply with all legal and regulatory provisions that apply to the activities they proposes. It is not possible to list every such provision that might arise, but in a typical case of a company seeking to explore for or produce hydrocarbons onshore in the UK, all the following bodies and provisions will have to be considered:

— Department of Energy and Climate Change, which administers a licensing system under the Petroleum Act 1998, and which authorises drilling, appraisal and development activities case by case;

— The planning authority (generally the local authority), from which the company has to obtain planning permission;

— The relevant environmental agency (in England and Wales, the Environment Agency, and in Scotland, the Scottish Environment Protection Agency) which regulates discharges to the environment, and is a statutory consultee in the planning process;

— The Health and Safety Executive which regulates the process safety aspects of the activities, which contributes to mitigating the risk of environmental risks; and

— The Coal Authority (in the case of coalbed methane) which regulates access to the nation's coal.

5. *How is DECC ensuring that the UK learns from the regulatory mistakes of the US in relation to shale gas exploration over the last decade?*

When looking at shale gas prospectivity and development, we think it would be wrong to draw any strong parallel with the US for a number of reasons:

Prospectivity

Different shale plays have different prospectivity and production characteristics, so we cannot assume that UK shales will perform in the same way as some of those large producing shales in the US. Shale gas activity is only just starting here, whereas there is a well established industry in the US—with around 30,000 producing shale gas wells. With so little known as yet about UK prospectivity, it seems premature to expect any sudden surge of activity. But if it is commercially proven here, we could well imagine a steady increase in shale gas operations.

Land / Population

Land issues and population density are very different here from those in the US, with its large tracts of sparsely-inhabited land. Constraints on land access in the UK require our industry to be smarter in its planning; drilling multiple wells from one pad can be one part of a solution.

Also, the rights to oil and gas remain with landowners in the US, whereas in the UK they are granted to companies by DECC in the form of Petroleum Act licences. The UK approach allows DECC to assess the basic competence of an operator, so that there is little or no risk in the UK of damage caused by small scale amateur operations.

In the UK, the issue of a Petroleum Act licence does not remove landowner rights over access to the land, so the onus is on the licensee to negotiate access with the landowner. A recent legal case before the Supreme Court provided clarification of the issue of subterranean access. Where a landowner unreasonably refuses to agree access, where he demands unreasonable terms, or where the fragmentation of landownership means that a licensee cannot agree terms with everyone, the Mines (Working Facilities and Support) Act 1966 as applied and modified by the Petroleum Act 1998 provides a method by which a licensee can seek ancillary rights through the courts, though this is far from a common procedure.

We are aware of the reports of shale gas polluting water sources in the US, and understand investigations are going on at various levels over there to determine whether this is the case. We will of course look at all information as it becomes available, but on the evidence available and in light of thorough discussion with Environment Agency, the Scottish Environmental Protection Agency and others, Government is satisfied that our regulation is robust and there is no justification for an indefinite delay while we wait for all overseas investigations to complete.

Regulation

We have to be cautious in talking about US regulation as it does seem to be the case that regulatory responsibilities are much more widely distributed in the States.

In the UK regulation is well-designed with clear lines of responsibility among several different bodies including DECC, the HSE, the respective Environment Agency, and Local Planning Authority.

The Environment Agency has had informal discussions with the US EPA to understand the statutory framework in place in the US, and to establish key points of contact if required in the future.

In the US there do seem to be differing approaches according to where you are. For example operators would not be able in the UK to keep waste water in open pits if there is risk of overflow, or dispose of waste products without them being sent to a suitable waste treatment plant. Cuadrilla for example is storing all of its water in metal storage tanks and any waste product will be taken off site to a treatment plant.

Well Casing

We gather that there have been questions raised relating to well casings on some US shale wells. The integrity of the well casing is considered key in relation to protecting any potential contamination to the water aquifer.

We do not believe that such a situation would occur in the UK—there is an obligation on the operator to ensure that the well design is safe and fit for purpose and this is checked very carefully by the Health and Safety Executive.

In Cuadrilla's operations multiple layers of protective steel casing are being placed around the drill shaft, which in turn are surrounded by cement. This casing can reach depths of at least 10,000 feet. For the wells in the Bowland Basin, near Blackpool, the intermediate casing extends to over 1,000 feet below the level of the aquifer, with the sole aim of ensuring environmental protection.

We will be closely monitoring any results coming out of the US investigations so that we can learn any lessons which go beyond our current regulatory / industry practices and which might be applicable to UK shale gas operations.

6. *What will DECC do to ensure shale gas exploration does not de-incentivise investment in lower carbon technologies?*

As UK shale gas has not yet been commercially proven analysis of the potential effects of extraction on UK energy policy objectives and development of renewable energy would be subject to large uncertainties.

However, in general terms, if commercially extractable, we would expect the main effect of shale gas to be to reduce our dependence on imported gas, rather than displacing renewables. This is because indigenous production of shale gas is unlikely to have any significant impact on the marginal price of gas into the GB market.

But if we step back and look at the big picture, the UK faces a major issue, which is that of making the transition to a future energy economy which has much lower emissions of carbon. This Government has an ambitious programme to deliver that transition. It certainly calls for a major contribution from renewables. But we also hope to see a substantial contribution from other sources, and we are investing in carbon capture and storage. Equally, we have ambitious programmes addressing the ways in which energy is used—in our homes, in industry, in transport, in agriculture.

This transition is a massive change, and it won't all be delivered next year or even next decade. And at the moment, our energy supplies come principally from oil and gas—they supply about three-quarters of our needs. We have to start where we are, and the plain fact is that we will still be using a lot of oil of gas in five or 10 years' time. And because our own supplies, particularly of gas, are declining, the current outlook is that we will be increasingly dependent on imports.

So if shale gas does prove to be economically producible in the UK, the initial effects would all be in the area of reducing our need for imports. That does not seem a bad thing.

In the longer term, the overall role of gas in our energy supplies will be a function of its price. Prices for oil and gas are set by an global market in which UK supplies have no significant influence. We do not believe that shale gas in the UK will change that reality.

So we do not believe that shale gas activity conflicts with our overall policy on energy and climate change.

7. *How do you see shale gas affecting energy investments (and hence emissions) in developing economies?*

How shale gas production in developing countries might affect energy investments will depend on a number of factors specific to each country, such as:

- the amount of recoverable shale gas resources;
- how much it might cost to produce any shale gas;
- the cost of alternative forms of energy (including conventional gas which is still abundant in many regions) or the cost of importing gas from other countries;
- the overall level and structure of energy demand and usage; and
- whether the necessary factors to develop shale gas are in place (availability of the rigs and technological know-how, access to the land and the necessary consents, availability of water, etc).

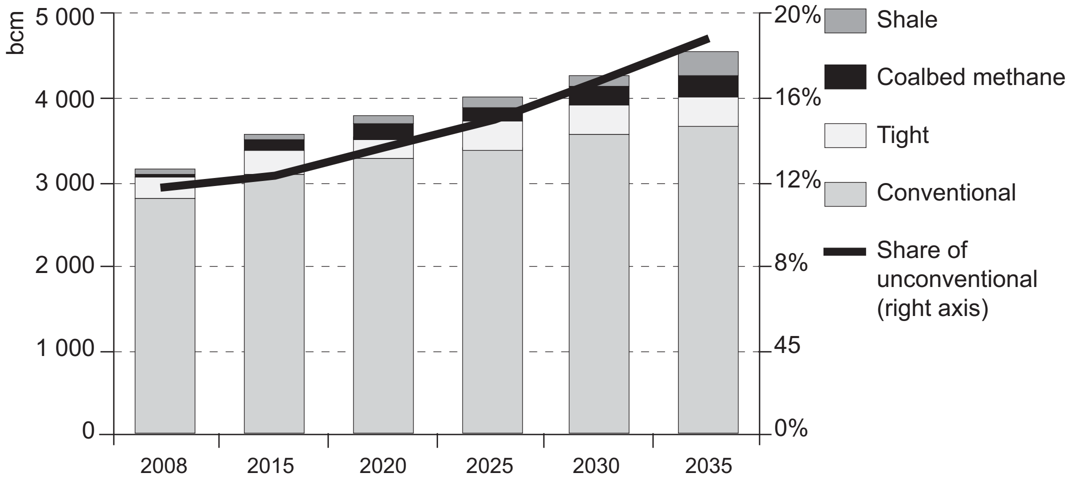
It may be more difficult and more costly to produce shale gas in many developing countries than it has been in the US. Other forms of gas—eg coal-bed methane, tight gas and also conventional gas—may in many circumstances prove to be easier and more cost-effective to extract. For example, in order to give some quantitative indication of the amount of shale gas that might be produced, the figure below shows the IEA's recent assessment of the potential production of unconventional gas (that is, shale, coal-bed methane and tight gas) to 2035 in the "New Policies"[5] scenario.

In this scenario the IEA estimate that around 35% of the increase in global gas production comes from unconventional sources and the remaining 65% of the increase coming from production of conventional gas. DECC is not aware of a specific IEA estimate for shale gas production for developing countries as a group, but based on the data provided within the WEO 2010, DECC estimates that unconventional gas production outside of the US and Canada would seem to be projected to grow by around 360bcm until 2035 in the "New Policies" scenario[6] of which some part will be shale gas.

[5] The IEA's "New Policies" scenario takes account of broad policy commitments that have already been announced, in addition to policies that had been formally adopted by mid-2010, and assumes cautious implementation of national pledges to reduce greenhouse-gas emissions by 2020 and to reform fossil-fuel subsidies.

[6] Based on the statement that around one-quarter of the increase in unconventional production is expected to come from the US and Canada. Page 188, World Energy Outlook.

WORLD NATURAL GAS PRODUCTION BY TYPE IN THE NEW POLICIES SCENARIO



Note: Tight gas production is defined and reported in different ways across regions, so the data and projections shown here are subject to considerable uncertainty, indicated by the shading.

Source: Figure 5.4 from the World Energy Outlook 2010 (source IEA).

The impact on other energy investments and emissions is complex. The cost and availability of gas in developing countries will depend on a range of factors such as the regulatory regime, levels of energy subsidies and the cost of other parts of the supply chain.

However, all other things being equal, we would expect that shale gas offers the potential to increase the availability and potentially reduce the cost of gas in some regions; where this is the case then it might lead to a) an increase in overall energy demand to some degree, and b) substitution away from other forms of energy. The impact on emissions will depend on the extent of any shale gas production and whether any shale gas use substitutes for energy source with higher average emissions per unit of energy used than gas, or sources with typically lower emissions.

April 2011

Memorandum submitted by British Geological Survey

Unconventional hydrocarbon exploration can be defined as obtaining fossil fuel energy directly from hydrocarbon source rocks, whereas conventional exploration targets hydrocarbons that have migrated to a reservoir, mainly sandstones and limestones. Organic-rich shale contains significant amounts of gas held within fractures and micro-pores and adsorbed onto organic matter. Shale gas prospectivity is controlled by the amount and type of organic matter held in the shale, thermal maturity, burial history, micro-porosity and fracture spacing and orientation. In the UK licences have already been taken up by forward-thinking companies and the interest will be high for the next licensing round.

The initial success has been exploring for gas but in a few US basins oil is being targeted. Four different types of exploration are possible:

1. Gas window source rock maturity areas.
2. Biogenic gas in source rocks immature for oil.
3. Biogenic gas in older source rocks which have been rejuvenated by bacteria-laden freshwater flushes.
4. Oil window source rock maturity areas.

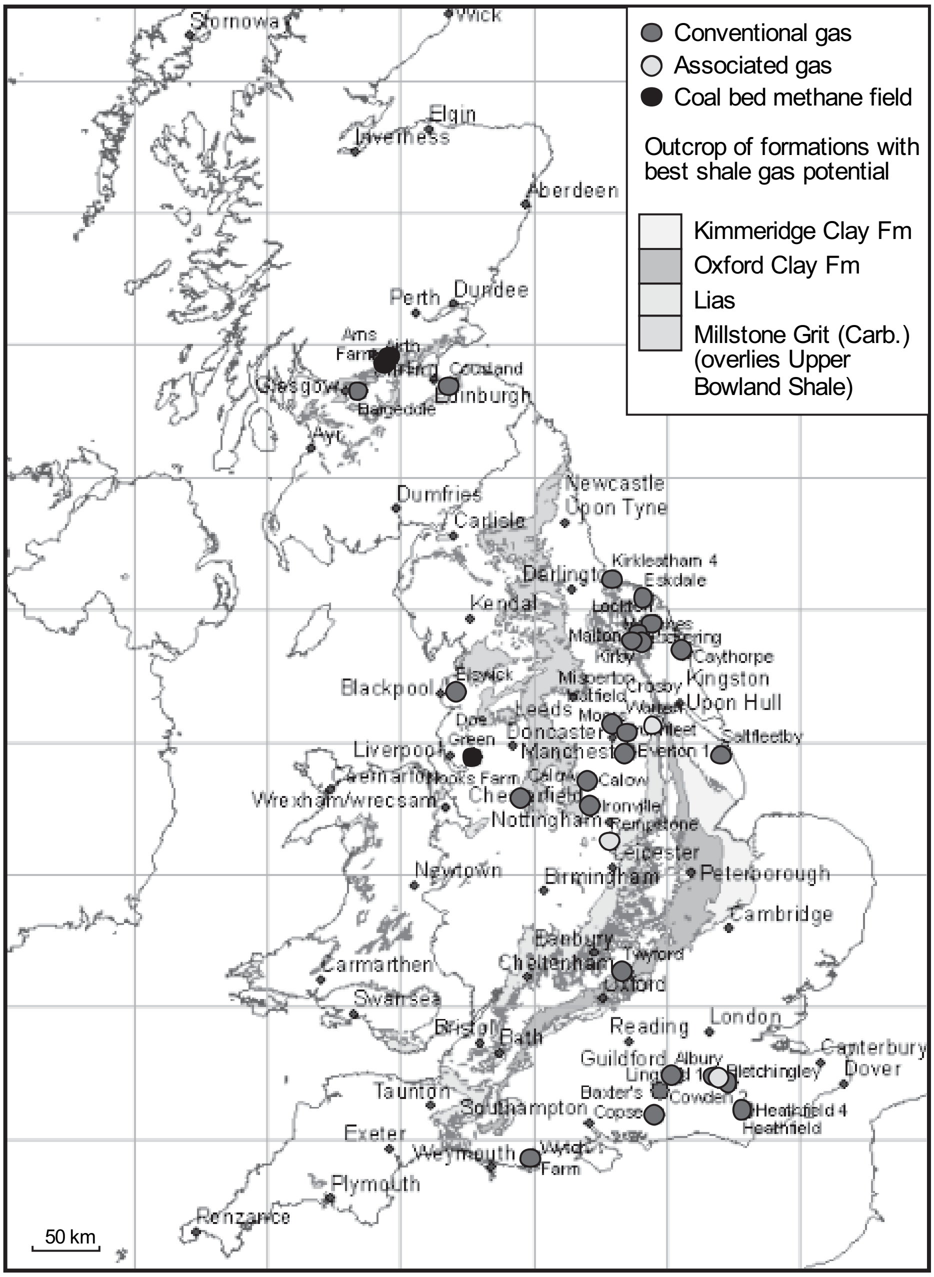
1. *What are the prospects for shale gas in the UK?*

It is too early in exploration of UK shales to be certain about the contribution which shale gas production could make. In the US shale gas extracted from regionally extensive units such as the Barnett Shale currently accounts for ~6% of gas production. Comparisons with the US suggest that there will be some production in the UK and all organic-rich shales in the UK are likely to be tested for their resource potential. Company exploration information will be confidential for several more years because the license holdings are not yet resolved and information on new hydrocarbon plays is always tightly controlled.

The lowest risk exploration is where source rocks have accompanying conventional hydrocarbon fields, which in the UK include the Upper Bowland Shale of the Pennine Basin, the Kimmeridge Clay of the Weald Basin and possibly the Lias of the Weald Basin. Deeper Dinantian shales should also be tested in the Pennine Basin and possibly in the Oil-Shale Group of the Midland Valley. Higher risk is attached to the Upper Cambrian source rock on the Midland Microcraton, which although it has not been severely tectonised, has not sourced conventional fields that have been preserved. The highest level of risk is attached to black shales within the Caledonian and Variscan fold belts, which have high organic carbon but are tectonised (affected by thrusts, intruded by igneous intrusions and converted to slates) and also have no overlying fields.

The BGS have written reports on Worldwide Shale Gas and UK prospectivity for DECC, parts of which have been included in their Promote website prior to the 14th Round of Onshore Hydrocarbon Licensing. https://www.og.decc.gov.uk/upstream/licensing/shalegas.pdf

These reports contain a fuller analysis of the prospects, data and risks. Key data relating to shale porosity, permeability and gas content has not been acquired in the past because conventional hydrocarbon exploration has concentrated on sandstones and limestones. The properties of shales have been largely ignored. The BGS also have a paper, based on our work up to March 2009, just published in the 7th Petroleum Conference proceedings.



Map showing some of the main potential source rocks at outcrop, in relation to the conventional gasfields and gas discoveries. Larger subsurface extents of the source rocks are excluded from this simplified map. Lower Palaeozoic, higher risk prospects not all shown and partly underlie Mesozoic formations.

2. W*hat are the risks of rapid depletion of shale gas resources?*

For a number of reasons exploration in the UK is likely to be slow at first. Only three licences in the 13th Round of Onshore Hydrocarbon Licensing in 2008 were targeted on shale gas. On one of these the first exploration well has been drilled (Preese Hall by Cuadrilla Resources). Hydraulic fracturing will commence in January 2011 according to their website. It is unlikely that existing licence holders on acreage taken for other (Coalbed methane or conventional hydrocarbons) targets or new awards in the 14th Round could achieve a faster completion than that of Cuadrilla, in view of the planning laws, lack of benefit to locals (in contrast to US) and the technological advances (not all applicable to conventional exploration) that need to be applied. The relatively densely populated state of the UK is also a hindrance to development.

If only small quantities of gas can be produced from the shale horizons then it is inevitable that there will be a rapid depletion. If there is success in any of the plays then large parts of the country will be opened up, but it will be a slower process than in the US.

"It is estimated that the UK could be producing 10% of its current gas needs from shale if it can be extracted at a commercial rate"

This statement from the call for written evidence is based on the position reached in the US about a year ago, and reported in the press, when US shale gas contributed about 10% of their needs. This needs several qualifications to be applicable to the UK. Firstly in 10 years time the figure will be 30% or more in the US because nearly all the discoveries there are now in "unconventionals". Secondly in the US there is no significant offshore gas production. Thirdly, assuming near complete discovery of conventional fields, there is likely to be a relationship between conventional and unconventional production in any basin because they both derive from the same hydrocarbon source rocks. Therefore in the UK, dominated by (current) large offshore gas production and large offshore basins, it is not realistic to compare these figures with the UK's likely onshore unconventional production. UK onshore basins are small in comparison with UK offshore and US onshore basins.

Offshore shale gas would have the size to affect the figures more dramatically. The US has no need to look offshore and no plans as yet, so we would have to lead the way (very difficult from our level of ignorance so far) but a lot of the existing infrastructure in the North Sea could be used. BGS unconventional hydrocarbon resource reports have not looked at the offshore.

3. *What are the implications of large discoveries of shale gas for UK energy?*

If shale gas can be produced in the rest of the world this will temporarily reduce the importance of the large LNG exporters. The US has mothballed some of its projected terminals and the tankers are being diverted to Europe. The security of supply both for domestic and imported gas will improve because producers will need to sell and prices are likely to fall, perhaps marginalising the more difficult shale gas exploration.

January 2011

Supplementary memorandum submitted by British Geological Survey in answer to Q57

Q57 Dr Lee: *Geologically, is there a concern? Are we sure about where the aquifers are for sure, 100%? Are we sure? Without wanting to suggest for a second that it necessarily contaminates water, my point is the level of uncertainty that I am trying to get down to from a geological perspective*

There is massive uncertainty. We don't know anything about the variability of gas contents and permeability of our UK shales, so all the estimates on the DECC website are based on US data. I am certain there will be a new round of UK onshore licensing. I expect this to be very popular with companies. Therefore it is likely that within about five years we could have test wells in large areas of the country. Given the relative new techniques required this may be slower for some operators. If production cannot be achieved there will be no more exploration until something changes (probably a new technological breakthrough). I am using the model of past conventional and coalbed methane exploration here. In particular I mentioned the success of coalbed methane in US and its relative failure in the UK and Europe (so far) as a pessimistic comparison.

There is also a theoretical possibility of shale gas production from offshore. The current economics rule this out as a stand-alone exploration strategy.

The Geological Society's graph (in paragraph 15 of their written submission) is very revealing. Shale gas is our last chance at fossil fuels. If we begin exploiting those resources (as we are in some parts of the world) in the top right part of the graph without carbon sequestration we will be seriously overstepping the environmental threshold and with ever-increasing energy input.

February 2011

Memorandum submitted by Professor Richard Selley, Imperial College London

EXECUTIVE SUMMARY

- There is nothing new in shale gas. It has been produced in the USA for nearly 200 years.
- Over 25 years ago research at Imperial College identified the UK's considerable shale gas resources. UK shale gas was not economic to produce at that time.
- Recent estimates of US gas reserves have increased by 35% due to shale gas exploration. US gas prices have crashed. The boom in shale gas exploration in the USA has been due to improvements in technology (seismic imaging, drilling and artificially fracturing wells to increase production).
- There is nothing new in artificially fracturing wells. The technology has been used for decades. The environmental risks of shale gas extraction are miniscule when set against benefit to the UK of such a major indigenous secure source of clean energy.
- UK shale gas production may now be economic due to rising energy prices, the repeal of Petroleum Revenue Tax in 2003, and improved technology.

The submission addresses the issues requested by the inquiry in the order in which they were listed in the terms of reference:

1. *What are the prospects for sale gas in the UK, and what are the risks of rapid depletion of shale gas resources?*

1.1 Prospects:

Gas has been produced in the USA from naturally fractured shale since 1821. In the past the artificial fracturing now used in the shale gas renaissance was too expensive. Wells flowed gas from naturally fractured shale for several decades. A single well could produce enough gas to supply a school, hospital or shopping mall indefinitely. Production rates and profit margins were too low for major companies to be interested. For some 175 years shale US gas production was a local "cottage industry" run by small operators.

In the early 1980's Imperial College used the US paradigm to study the feasibility of UK shale gas production. The research concluded that the UK had considerable potential for shale gas exploitation. The Carboniferous rocks of the West Midlands in particular were identified as highly prospective. This is, of course, the area where IGas and Cuadrilla are now operating.

The Imperial College study also concluded that exploration was not economically viable under the then prevailing tax regime (Corporation Tax + Petroleum Revenue Tax).

These conclusions were conveyed to the Department of Energy at a meeting on 8 January 1985.

1.2 Risks of rapid depletion:

The shale gas renaissance of the last decade results from four factors:

1.2.1 Increasing energy prices.

1.2.2 The ability to drill wells horizontally.

1.2.3 The ability to image the shape & volume of shale gas reservoirs seismically.

1.2.4 Artificial fracturing, which increases the permeability of rocks and hence fluid flow rate. This technique, as old as Moses, has been used in the petroleum industry for decades. There are question marks, however over long term flow rates over years or decades. Until recently artificial fracturing has been too costly to use in shale gas wells. There are plenty of data showing the cumulative shale gas production of wells, fields and basins. There are few data available for the long term production rates of recently drilled and fractured individual US shale gas wells. Most published data, and most simulations carried out by independent researchers (Eg the United States Geological Survey), only model depletion curves for two or three years.

2. *What are the implications of large discoveries of shale gas around the world for UK energy and climate change policy?*

The shale gas renaissance began in the USA in the 1980's with the application of artificial fracturing and horizontal drilling. There are currently over 900 rigs drilling for shale gas across the USA. The Colorado School of Mines has recently raised its assessment of US gas reserves by 35%. US gas prices have declined from a peak of 7$US per MBTU (Million British Thermal Unit) in 2005 to some 4$US per MBTU today, bringing the price down to pre-1980 levels. Many countries around the world (Including Argentina, Canada, China, the Ukraine, Poland, France, Sweden & India) are beginning to develop their shale gas resources. In Europe the "land grab" for prospective shale gas acreage is now over. The geopolitical importance of the UK developing its own shale gas resources is axiomatic.

The combustion of shale gas contributes to global warming, obviously. Shale gas may however be a temporary stop gap, providing energy while the combustion of other fossil fuels declines, until replaced by nuclear or renewable energy sources.

3. *What are the risks and hazards associated with drilling for shale gas?*

The artificial fracturing of shale gas wells has been blamed for contaminating aquifers with petroleum (A common phenomenon in petroliferous areas), for what Americans call "temblors"—micro-seisms in English, and for flocks of dead black birds falling from the sky. British TV audiences will have been amazed at film showing flammable gas emerging from a bathroom tap, and its attribution to adjacent shale gas extraction. The media has not been so fast to report that the preliminary results of an independent enquiry reveal that this phenomenon had been ongoing before drilling commenced. The committee could usefully enquire as to how many of the thousands of shale gas wells drilled in the USA in recent years have caused environmental damage. It is the squeaky wheel that gets the oil.

4. *How Does the Carbon Footprint of Shale Gas Compare with Other Fossil Fuels?*

Gas in general, and shale gas in particular, produces some 45% less carbon greenhouse gases and fewer particulates than oil or coal fired power stations.

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January 2011

Memorandum submitted by IGas Energy

Executive Summary

- IGas Energy believes that shale gas could make a valuable contribution to the UK energy mix, assuming it can be shown to be commercially viable in the UK. The full extent of shale gas resources in the UK is currently unknown;
- Together with Coal Bed Methane (CBM), shale gas could have clear positive implications for UK energy security. The potential supply of hitherto untapped unconventional sources of gas (both CBM and shale) mean that the UK could be significantly more self-sufficient in terms of gas supply for longer than previously expected;
- Compared to other countries, the UK has the advantage of a clearer framework for the licensing and permitting of drilling for unconventional gas, both at the surface and sub-surface. Operators have a number of clear and well-understood obligations within a consistent and predictable regulatory framework. This requires operators to communicate their intentions early, to identify all HSE hazards and explain how these will be managed, and to obtain pre-approval for all significant activities;
- IGas Energy believes that the UK's system of regulation governing unconventional gas exploration and extraction is more rigorous and effective than in many other countries; in particular because of the separation of responsibilities between the licensing authorities and the HSE, which occurred post Piper Alpha. There is also an added element of transparent control provided by the planning process;
- Shale gas (as distinct from CBM, which can be extracted without hydraulic fracturing) can only be extracted using complicated and extensive hydraulic fracturing techniques which use a mix of chemicals and which carry a degree of environmental risk. However, these risks are required to be identified and mitigated to the satisfaction of the Health and Safety Executive and, where appropriate, various Environmental agencies; and
- Onshore unconventional gas supplies offer potential carbon savings relative to gas sourced offshore or from overseas. This is due to closer proximity to customers and distribution networks and a less carbon intensive extraction process. In particular, shipping gas over distance consumes significant energy and thereby has an environmental impact of its own; Russian gas, even on conservative estimates, has a carbon footprint which is 30% greater than domestically produced gas.

1. IGas Company Profile

1.1. IGas Energy (IGas) was set up in its current form in 2003 to produce and market domestic sourced gas from unconventional reservoirs, particularly coal bed methane (CBM). IGas is now producing gas from its pilot production site at Doe Green in Warrington and selling electricity through its on-site generation. This is a UK, and potentially European, first in terms of unconventional gas.

Coal Bed Methane

1.2. IGas is the largest independent CBM producer in the UK. Extraction of CBM involves drilling into virgin coal seams and removing the gas trapped therein. Like other forms of natural gas, this gas is used to provide both industrial and domestic power. IGas has ownership interests of between 20 and 100 per cent in eleven Petroleum Exploration Development Licences (PEDLs) in the UK, wholly owns two methane drainage licences and has a 75% interest in three offshore blocks under one Seaward Petroleum Production Licence. These licences cover a gross area of approximately 1,756 km² across Cheshire, Yorkshire, Staffordshire and the North Wales coast. The mid-case estimate for gas initially in place (GIIP) in these holdings is 3,823 billion standard cubic feet of gas (bcf) (source: Equipoise Solutions Ltd), excluding any shale potential. Based on the contingent recoverable resource estimates prepared by DeGolyer and McNaughton, IGas has enough gas to supply electricity to over 7% of UK households for 15 years.

1.3. IGas Energy remains on track to establish the UK's first CBM commercial production site in 2011.

Shale Gas

1.4. Whilst IGas is currently focusing on developing its CBM resources, the company has identified a significant potential shale resource within its acreage which is estimated (on an unrisked basis) to comprise up to 1.9 trillion cubic feet of gas initially in place. IGas intends to conduct further work to better understand the potential of this shale resource.

1.5. That said, IGas is currently concentrating on extracting its CBM resource. Extraction of CBM is less complicated, less impactful on the local environment, more targeted and, currently, more commercially viable than shale extraction. It is therefore IGas' priority at this point in time.

2. *What are the prospects for shale gas in the UK, and what are the risks of rapid depletion of shale gas rResources?*

2.1. IGas Energy believes that shale gas could make a valuable contribution to the UK energy mix, assuming it can be shown to be commercially viable in the UK. DECC has identified the Upper Bowland Shale of the Pennine Basin, the Kimmeridge Clay of the Weald Basin and the Lias of the Weald Basin as offering the best shale gas potential onshore in the UK.[7] IGas Energy's shale acreage lies within its Point of Ayr license in the Cheshire Basin and consists of Holywell Shale (Upper Bowland Shale equivalent). This acreage extends over 1,195km², has an average thickness of 250m and has a high potential to be hydrocarbon bearing. These findings have led IGas Energy to retain independent consultants to evaluate the potential of these shales.

2.2. In 2010, Equipoise Solutions Ltd (acting on behalf of IGas Energy) undertook an independent review of the shale gas potential of Holywell shale within the Point of Ayr license. This is spread across the North West of England (predominantly Cheshire) and North Wales (off the coast to the north of Rhyl and Prestatyn). Estimates of GIIP aggregated over all of these interests indicate a low net total of 31 bcf shale gas, a middle net total of 412 bcf shale gas and a high net total of 1,945 bcf shale gas. These values assume that the Holywell shale is normally pressured. There is a possibility that part of the Holywell shale is actually over-pressured (although the company currently has no evidence of this). This would mean much higher gas content and higher initial production rates in those areas.

2.3. IGas intends to conduct a focussed programme of activity which will enable the Company to understand better the shale potential that is both contained within its acreage and complementary to its primary objective of commercial CBM delivery. The shale related activity would include 1) data acquisition (core/log data etc.); 2) core analysis (geochemistry/geomechanical); and 3) sponsorship of an M.Sc at a major UK University to further study the Holywell shale. The feasibility of further development of the shale potential in IGas' acreage will depend on the outcome of these studies and experience elsewhere within the UK and Europe.

3. *What are the Implications of Large Discoveries of Shale Gas Around the World for UK Energy and Climate Change Policy?*

3.1. It is broadly acknowledged that the discovery and subsequent extraction of unconventional gas in the United States played a major role in significantly reducing that country's imports of liquefied natural gas and increasing its security of supply. Whilst we do not know the full extent of shale gas resources in the UK, it is likely that there is sufficient quantity to make a significant and substantive contribution to the UK energy mix. Uncovering such a sizeable untapped domestic resource could have clear positive implications for UK energy security.

3.2. Within the broader context of UK energy and climate change policy, the UK's commitment to long-term development of renewable energy resources will demand new, low-carbon, flexible gas-fired power plants to compensate for the intermittency of wind generation. The potential supply of hitherto untapped unconventional sources of gas (including shale gas) mean that the UK could be more self-sufficient in terms of its gas supply for longer than previously expected. Given that the Government's proposals for Electricity Market Reform are already geared towards meeting the UK's EU emissions targets and managing the transition

[7] DECC, 2010—"The Unconventional Hydrocarbon Resources of Britain's Onshore Basins—Shale Gas".

to renewable energy sources, there is arguably little impact on UK energy policy beyond the assurance and reduced cost of domestic energy security. Given that domestically sourced gas is generally cheaper than gas sourced overseas, it is reasonable to assume a positive impact in terms of the cost of energy to the consumer, which may have an impact on the necessity or otherwise of fuel poverty measures.

3.3. In order to encourage the investigation of the potential of this resource, there is a need to ensure a robust licensing and regulatory system that protects the public while maximising the rate of extraction. We believe that the system as it stands provides both sufficient oversight and sufficient incentive for the potential of the UK shale resource to be properly assessed in a safe and responsible manner.

3.4. Compared to other countries, the UK has the advantage of a clearer framework for the licensing and permitting of drilling for unconventional gas, both at the surface and sub-surface. DECC awards licences based on work programmes and competency to search for hydrocarbons. Well programmes are independently reviewed by HSE-approved third party well examiners and the HSE approves well programmes in line with their own health, safety and environmental requirements. For onshore wells, various approvals are required from a number of agencies specific to the chosen site. These include (but are not restricted to) local authorities, the Environment Agency, various conservation agencies, utility bodies, Network Rail and the Highways Agency. Operators have a number of clear and well-understood obligations within a consistent and predictable regulatory framework that assists both operators and interested parties to communicate their intentions and concerns in a constructive manner.

4. *What are the Risks and Hazards Associated with Drilling for Shale Gas?*

4.1. Shale gas (as distinct from CBM, which can be extracted without hydraulic fracturing) can only be extracted using complicated and extensive hydraulic fracturing techniques which use a mix of chemicals and which carry a degree of environmental risk. However, these risks are required to be identified and mitigated to the satisfaction of the independent HSE and, where appropriate, various environmental agencies.

4.2. Unlike other forms of gas extraction, the main safety issue associated with unconventional gas is not the risk of explosion—it is the protection of aquifers in proximity to the area of operation. Where an aquifer lies in close proximity to a well, the relevant sections of the well would be encased in steel and cement in order to reinforce its integrity and to protect the aquifer completely. As it is, shale in the UK typically lies significantly deeper than nearby aquifers, so any contamination risk in this respect is substantially reduced.

4.3. Whilst there have been claims of contamination of drinking water in the United States in recent months, these have been comprehensively rebutted by US natural gas producers.[8] In fact, there has never been a documented instance of water contamination caused by hydraulic fracturing. In 2010, the US Environmental Protection Agency announced that it was undertaking a new study[9] into the potential impact of hydraulic fracturing on drinking water, human health and the environment. It is due to report in 2012.

4.4. Safety and protection of the local environment remain the primary concerns of any responsible operator. In all drilling operations in the UK, operators are required to demonstrate their suitability to operate and their ability and commitment to give due regard to the safety of workers, communities and the local environment. Community relations in particular are a vital component of onshore activity, including in relation to the environment. IGas is committed to working broadly and closely with members of the public and community leaders in all of its areas of operation. Indeed, the well-developed nature of the planning process in the UK means that such relations are absolutely essential to operate effectively.

4.5. IGas Energy believes that the system of regulation governing unconventional gas exploration and extraction in the UK is more rigorous and effective than in many other countries. The UK system of regulation benefits greatly from its origins in the North Sea and the considerable experience of the UK authorities (particularly the independent HSE) in other industries. The onshore industry has also inherited the culture of safety that has pervaded the UK offshore oil and gas industry since the Piper Alpha disaster and the Cullen Report, whilst the separation of responsibilities between the licensing authorities and the HSE allows for more effective oversight than in other jurisdictions. There is an added element of transparent control provided by the planning process.

5. *How does the carbon footprint of shale gas compare to other fossil fuels?*

5.1. Onshore unconventional gas supplies, such as shale gas and coal based methane (CBM), offer potential carbon savings relative to gas sourced offshore or from overseas. This is due to closer proximity of supplies to customers and distribution networks and a less carbon intensive extraction process. There will also be a subsequent carbon saving with respect to domestic gas as large volumes will not have to be transported through the transmission systems of Russia and Europe. Shipping gas over distance consumes significant energy and thereby has an environmental impact of its own; Russian gas, even on conservative estimates, has a carbon footprint which is 30% greater than domestically produced gas.

[8] http://www.energyindepth.org/wp-content/uploads/2009/03/faq_hf_sdwa_fluids_degettecasey.pdf
[9] http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm

5.2. Compared to other forms of unconventional gas, shale drilling is deeper and more complex than CBM and therefore imposes a heavier carbon footprint. CBM has the potential added benefit of future CCS application.

January 2011

Memorandum submitted by Cuadrilla Resources Holdings Ltd

1. Executive Summary

1.1 Cuadrilla Resources Holdings Limited ("Cuadrilla") is an English independent oil and gas company based in Lichfield, Staffordshire, pursuing an unconventional hydrocarbon exploration programme in selected European geological formations. The company's most advanced activities are located in the Bowland Shale in Lancashire, in the north-west of England.

1.2 Cuadrilla welcomes the opportunity to discuss prospects for European shale gas, our own operations, and the potential risks associated with shale gas exploration. We commend the Energy and Climate Change Committee for embracing this important topic.

1.3 Cuadrilla believes that prospects for shale gas in the UK and parts of continental Europe are promising. This assessment is based on the presence of a number of geological formations that are similar in several important respects to geological formations located in the United States and Canada, where significant deposits of natural gas have been discovered.

1.4 Natural gas produced from shale is commonly referred to as "unconventional". **It is critical to highlight that the only unconventional aspect of shale gas is the reservoir or rock type in which it is found. Shale gas exploration techniques, including directional drilling and hydraulic fracture stimulation ("fracing"),[10] are conventional and have been used across the oil and gas industry (including previously in the UK) for many decades.** What has changed is that these techniques have become progressively more technologically advanced and lower cost over time, allowing exploitation of shale gas at scale to become increasingly economically viable.

1.5 Cuadrilla believes that shale gas can offer a "triple win" for governments, including the UK government, contributing to the three key policy objectives of (1) enhancing energy security, (2) lowering the cost and price volatility of energy to consumers and (3) reducing greenhouse gas emissions.

1.6 Cuadrilla also recognises the potential for an emerging shale gas industry to create new jobs and inject investment into local economies, for example in the north-west of England, thereby helping governments pursue broader economic growth and industrial rebalancing objectives. By being a first mover in shale gas, the UK could be at the forefront of a potentially significant new European energy industry, bringing multiple economic benefits for the north-west of England and for UK Plc.

1.7 Shale gas has low carbon content compared with several other fossil fuels. Carbon dioxide emissions can be further mitigated by adopting certain production processes, such as drilling multiple wells from the same "pad".

1.8 Shale gas exploration and production sites typically occupy a small geographical footprint and their visual impact can easily be minimised.

1.9 All hydrocarbon exploration, including shale gas exploration, involves potential health, safety and environmental risks. However, these potential risks, **which are not unique to shale gas and are common to all hydrocarbon exploration**, are mitigated through stringent regulatory requirements and through established operating processes, procedures and controls. With around 200 years of cumulative experience, including involvement in the drilling and/or fracing of more than 3,000 wells, Cuadrilla's management team is implementing industry leading health, safety and environmental risk mitigation practices across all its activities.

1.10 We would be happy to provide further information to the Energy and Climate Change Committee should this be requested.

2. About Cuadrilla Resources

2.1 Cuadrilla Resources Holdings Limited ("Cuadrilla") is an English independent oil and gas company based at Lichfield in Staffordshire, formed in 2008 by a group of veteran unconventional gas explorers from the US and the UK with the support of specialist energy investors. The company is currently assembling an extensive exploration portfolio of shale gas, tight gas sand and oil-from-shale plays in established hydrocarbon provinces located in several European countries including the UK, Poland and The Netherlands. The company's most advanced activities are located in the Bowland Shale in Lancashire, in the north-west of England.

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[10] "First hydraulic fracturing treatment was pumped in 1947 on a gas well operated by Pan American Petroleum Corporation in the Hugoton Field"; Gidley, *SPE Monograph 12*, 1989; further quoted in Department of Energy, *EPA 816-R-04–003—Hydraulic Fracturing White Paper*, June 2004.

2.2 Cuadrilla employs 14 people full time: nine based in the UK, three in the US and two in Poland. In addition, the company currently uses 19 consultants and seven contractors, employing roughly 40 people who regularly work on Cuadrilla projects. The company considers its investment in local services to be of significant economic benefit to the local communities where it operates, in turn underpinning further employment.

2.3 The majority of Cuadrilla's shares are owned by two energy specialist investors, Riverstone and A.J. Lucas, which each hold a 41% stake in the company. The remainder of the equity is held by the senior management team. More information on the two main investors is available at www.riverstonellc.com and www.lucas.com.au.

2.4 With deep technical expertise and an extensive and proven track record, Cuadrilla is poised to become a leading European unconventional hydrocarbon explorer. The company also owns and operates the only integrated drilling, cementing, fracing and well testing equipment currently available in Europe. This equipment includes the latest technology from North America.

2.5 Cumulatively, Cuadrilla's six-person senior management team, led by Mark Miller and Dennis Carlton, have nearly 200 years of natural gas exploration experience and have played leadership roles in the drilling and/or fracing of more than 3,000 natural gas and oil wells. Members of the senior management team previously led Evergreen Resources Inc., a US-based company which has drilled and/or fraced more than 1,500 unconventional gas wells in the US, Canada and Europe. Fourteen of these wells were drilled in the UK. Based on this extensive experience, Cuadrilla is implementing industry leading drilling, fracing and health, safety and environmental practices throughout its exploration programme (discussed further in Section 5 below).

2.6 In the United Kingdom, Cuadrilla has received full local and national regulatory approvals, including planning permissions, environmental authorisations and health and safety approvals, to explore for natural gas at five onshore locations in Lancashire. We maintain active and positive relationships with the Department for Energy and Climate Change, the Health and Safety Executive and other UK regulatory bodies.

2.7 Cuadrilla began drilling at its first location, Preese Hall 1, located approximately five miles east of Blackpool, in August 2010. The company completed its first phase of exploration at the Preese Hall 1 site, which involved drilling a vertical exploratory well with total depth of around 9,000 feet, in December 2010. During the drilling process Cuadrilla encountered indications that natural gas is present in the rocks through which the well has been drilled.

2.8 Phase two of the Preese Hall 1 exploration programme, which the company expects to commence in the first three months of 2011 and to last three to six months, involves stimulating rocks surrounding parts of the vertical well at depths greater than 5,000 feet. Cuadrilla is using fracing techniques which have an extensive, safe and proven track record in the North America, as discussed further in Section 5 below. Only after this second phase is complete will Cuadrilla be able to determine with confidence whether commercial quantities of natural gas are present at its first drilling site.

2.9 Once drilling and fracing activities are completed at the Preese Hall 1 site, Cuadrilla intends to redeploy its drilling equipment to commence drilling at one of the other four sites in Lancashire where it has received full local and national regulatory approvals.

3. *What are the Prospects for Shale Gas in the UK & what are the Risks of Rapid Depletion of Shale Gas Resources?*

3.1 Cuadrilla believes that prospects for shale gas in the UK and parts of continental Europe are promising. This assessment is based on the presence of a number of geological formations in Europe that are similar in several important respects to geological formations located in the North America where significant deposits of unconventional gas have been discovered.

3.2 The most important variables in determining where unconventional natural gas is present and the scale of the resource are as follows:

- *Thickness.* In general, a thicker section of shale is preferred as it provides more potential gas bearing zones, increased gas storage and greater recoverable reserves.
- *Natural Fracture Intensity.* Because shale typically has very low permeability and porosity, natural fractures are important in providing a route for the natural gas from the shale rock to the well shaft. In addition, natural fracture intensity aids the fracing process, which works most effectively when the artificial fractures created intersect with existing natural fractures in the shale. Of particular importance in estimating natural fracture intensity are the width of the natural fractures (ranging from micro-fractures thinner than a grain of sand to wider fractures of approximately 1mm width), their length, and the number of connections between them. High fracture intensity allows for increased production rates and recoverable reserves.

— *"Frac-ability"*. In general, the fracing process generates more artificial fractures in more brittle shales, allowing a larger proportion of the gas reserve to be recovered. The degree of brittleness is determined by the chemical composition of the shale, for example silica and carbonates make it more brittle. Laboratory measurements on shale material collected during drilling operations are used to determine the natural stresses in the shale and how easily it will crack during the fracing process.

— *Present Day Structural Setting.* Shales can be found either in an extensional setting, in which they are being geologically "stretched" apart, or a compressional setting, in which they are being geologically "pushed" together. Those in an extensional setting exhibit more open natural fractures, allowing more natural gas to migrate from the rock to the well shaft, and increasing the amount of recoverable reserves. The Bowland Basin's present day structural setting is extensional.

— *Gas Content.* The gas content of a particular shale is the amount of gas stored within the shale pore spaces and the naturally occurring fractures. Measured in cubic feet of gas per ton of shale, it is crucial in estimating the likely scale of a particular reserve. This measurement is conducted at the well site through laboratory analysis of the rocks.

— *Total Organic Content (TOC).* The TOC of a shale is the amount of carbon material remaining in the rock and indicates its potential to have generated hydrocarbons in the past. There is a range of TOC values which are optimal and determine how prospective the shale is for a given geologic basin.

— *Maturity Level ("Ro value").* The hydrocarbon bearing potential of a shale depends on the temperature and depth at which it has spent its history. If it has been too cool then few hydrocarbons will have been generated; if it has been too hot then they will have been degraded or destroyed. A key tool for assessing a shale gas reserve is thus the determination of the "Ro" value.

— *Reservoir Pressure.* Under a higher natural reservoir pressure more gas molecules can be stored and therefore ultimately recovered. Doubling reservoir pressure approximately doubles gas reserves. Study of surrounding wells to identify reservoir pressure is also important in preventing well control concerns, as described in Section 5.

3.3 Natural gas produced from shale is commonly referred to as "unconventional". It is critical to highlight that the only unconventional aspect of shale gas is the reservoir or rock type in which it is found. Shale gas exploration techniques, including directional drilling and fracing, are conventional and have been used across the oil and gas industry (including previously in the UK) for many decades. What has changed is that these techniques have become progressively more technologically advanced and lower cost over time, allowing exploitation of shale gas at scale to become increasingly economically viable.

3.4 In both conventional and unconventional oil and gas exploration and development around the world, it is very common to drill a number of wells in different directions from a single drill pad to target specific positions in the subsurface. Directional drilling uses "off-the-shelf", proven and safe technologies. A good example in the UK is Wytch Farm near Poole in Dorset, where wells were drilled significant distances (in excess of 10km) from an onshore location to hydrocarbon deposits located offshore in order to minimise visual impacts along the coastline.

3.5 Cuadrilla's exploratory well programme at the Preese Hall 1 site employs vertical rather than directional drilling. However, Cuadrilla expects to use directional drilling in the future as its exploration programme develops. This technology will be used to minimise surface disturbance during drilling, fracing and production operations as well as to reduce the overall cost of exploration and development activities.

3.6 Fracing involves pumping fluid, more than 99% (in Cuadrilla's case 99.85%) composed of water and sand, under high pressure to open up millimeter sized gaps or cracks in shale rock formations typically found at depths greater than 5,000 feet.[11] We discuss the composition of fracing fluid in greater detail in paragraph 5.6.1 below. The cracks are held open by the particles of sand (as a "proppant") contained in the fluid. Fracing increases the number of pathways a well bore has to the surrounding natural gas-bearing rock formation and thereby provides numerous channels through which natural gas can flow into the well. As discussed in greater depth in Section 5 below, fracing takes place thousands of feet below the shallow water table. As of 2009, out of hundreds of thousands of fracing operations that have taken place in the United States, US regulators have confirmed no cases of hydrocarbons or fracing fluid leaking into shallow water aquifers as a result of fracing.[12] Cuadrilla is not aware of any incidents since 2009.

[11] "Water typically makes up 99% of the liquid phase of fracturing fluids"; American Petroleum Institute, *Hydraulic Fracturing at a Glance*, 2008.

[12] "Of the responses received, no state has reported verified instances of harm to groundwater as a result of hydraulic fracturing. Responses were crafted by the state oil and gas regulatory official in each state."; Interstate Oil & Gas Compact Commission, *IOGCC Hydraulic Fracturing Survey Facts 2002 and 2009,* June 2009. A similar conclusion was included in an earlier report by the Environmental Protection Agency on the impact of coal bed methane exploration and production, which uses similar fracing techniques but normally at shallower depths; "In its review of incidents of drinking water well contamination believed to be associated with hydraulic fracturing, EPA found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids."; *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, June 2004.

3.7 Cuadrilla does not have a detailed proprietary view of the full potential of shale gas outside North America. The shale gas industry in Europe and Asia is at a very early stage with a small number of exploration projects currently taking place. As well as Cuadrilla's exploration activities in the UK, The Netherlands and Poland we are aware of other companies exploring for shale gas in Poland, Sweden, Australia and China.[13]

3.8 Cuadrilla has undertaken its own analysis of the UK's onshore shale gas resource potential. It is worth noting that these same shales are the source of hydrocarbons found in most of the UK's conventional oil and gas fields. As a result of its analysis, Cuadrilla has targeted the Bowland Basin in the north-west of England (which is also the source of the natural gas currently being produced from beneath the Irish Sea) for its first European drilling programme. Cuadrilla believes gas-in-place volumes in the Bowland Shale could be substantial. However the volume of this resource that could be recovered economically has not yet been established and will not be known until further exploration and testing is complete.

3.9 In terms of depletion of shale gas resources over time, there are two key factors: production rates and recovery factors. The only scientific method currently available to estimate these factors for UK shale formations is by analogy to commercial North American shale plays.

3.10 Given the relative immaturity of even shale plays with the longest production record, such as the Barnett Shale, long-term shale gas production decline rates remain projections rather than based on scientific facts. These projections depend on a number of assumptions such as well operating costs and natural gas price forecasts.

3.11 Cuadrilla's expectation, informed by experience in North America, is that a typical shale gas well, in common with other unconventional gas wells, will witness steep early production decline rates—typically of around 30% to 40% for one to two years—followed by up to 50 years of commercial life at low decline rates—typically 5% to 7%. It is possible that UK shales may have a steeper decline rate than this, which would reduce their production rates and economically recoverable reserves. However it is also possible that UK shales may have lower decline rates and thus better economic recovery factors. This will become clearer over time after further exploration activity and geological testing in UK shale formations is completed.

4. *What are the implications of large discoveries of shale gas around the World for UK energy and climate change policy? How does the carbon footprint of shale gas compare to other fossil fuels?*

4.1 Cuadrilla believes increased penetration of shale gas in the energy mix increases energy options, thereby improving energy security, has the potential to lower natural gas prices (tending to reduce electricity prices), and reduces carbon dioxide emissions compared with other types of fossil fuel based power generation. Shale gas can therefore offer a "triple win" for governments pursuing the three key policy objectives of enhancing energy security, lowering the cost and price volatility of energy to consumers and reducing greenhouse gas emissions.

4.2 In addition, Cuadrilla recognises the potential for an emerging shale gas industry to create new jobs and inject investment into local economies, for example in the north-west of England, thereby helping governments pursue broader economic growth and industrial rebalancing objectives. By being a first mover in shale gas, the UK could be at the forefront of a potentially significant new European energy industry, bringing multiple economic benefits for the north-west of England and for UK Plc.

4.3 The shale gas revolution in the US in recent years has probably already had a positive impact on the UK energy system. With the US now self-sufficient in natural gas, more liquefied natural gas (LNG) has become available on world markets.[14] This has offered consuming countries such as the UK more options to source natural gas, enhancing energy security, while at the same time reducing global natural gas prices from highs of around $12/mmbtu in 2008 to around $4 more recently. Since natural gas fired power plants tend to set electricity prices in the UK, this in turn has reduced wholesale electricity prices compared with previous levels. Further discoveries of shale gas outside the US would enhance these trends.

[13] The relative immaturity of detailed scientific knowledge on the extent and location of European shale gas reserves is discussed in a recent study by the The Oxford Institute for Energy Studies; e.g. "Europe has little knowledge about the potential, quality, precise location, and location of sweet spots of its unconventional gas resources."; Florence Gény, *Can Unconventional Gas be a Game Changer in European Gas Markets*, December 2010.

[14] IHS CERA, *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda*, 2010.

4.4 Shale gas, like all natural gas, has a significantly lower carbon content per unit of energy generated compared with other fossil fuels such as coal. This is shown in the table below:

Fossil Fuel Emission Levels
- Pounds per Billion Btu of Energy Input

Pollutant	Natural Gas	Oil	Coal
Carbon dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur dioxide	1	1,122	2,591
Particulates	7	84	2,744
Mercury	0.000	0.007	0.016

Source: EIA - Natural Gas Issues and Trends 1998

4.5 As with all hydrocarbon production there are some additional carbon dioxide emissions associated with processing at the surface. However these relatively low emissions can be minimised through production efficiencies. Pad drilling is very common in the development of a multi-well shale gas field. In some cases up to 16 shale gas wells can be drilled from a common well pad. Multi-pad drilling increases the efficiency of gas gathering and production facilities compared with drilling a large number of single-well pad gas fields individually, reducing carbon dioxide emissions.

4.6 Multi-well pad drilling also significantly reduces the visual impact of shale gas production at the surface. Shale gas exploration and production sites typically occupy a small footprint and any visual impact can be minimised relatively easily.

5. *What are the risks and hazards associated with drilling for shale gas?*

5.1 As with all hydrocarbon exploration programmes, there are potential health, safety and environmental risks associated with shale gas exploration. However these potential risks, **which are not unique to shale gas and are common to all hydrocarbon exploration**, are mitigated through stringent regulatory requirements and strict operating processes, procedures and controls.

5.2 We discuss three potential risks from hydrocarbon exploration, including shale gas exploration, below: 1) leakage of hydrocarbons or, where it is used, fracing fluid into shallow water aquifers, 2) well control failure, and 3) personal injury. Although these potential risks are relatively low, and no greater for shale gas than for other forms of hydrocarbon extraction,[15] we consider them to be significant enough to deserve discussion in this submission. These three potential risks, and their mitigations, are discussed in detail in paragraphs 5.6.1, 5.6.2 and 5.6.3 respectively below.

5.3 Cuadrilla's exploration activities in the Bowland Shale have received all necessary planning, environmental and health and safety permits from the competent local and national authorities.

5.4 The UK possesses a strict regulatory framework governing onshore oil and gas exploration, including unconventional gas exploration. All UK hydrocarbon exploration projects require planning permission from the local planning authority, e.g. Lancashire County Council in the case of the Bowland Basin. Local planning permission comes with a number of project-specific requirements including ecology studies, and transportation, lighting and noise surveys. The planning permission process also requires approval from the UK Environment Agency affirming that the impact of the project on the local environment is minimal and that any environmental risks have been minimised. In addition to the local planning process, approval to drill for natural gas requires an exploration license from the UK Department of Energy and Climate Change and permission from the UK Health and Safety Executive.

5.5 As well as strict regulatory requirements, effective day-to-day operating processes, procedures and controls are critical to ensuring a safe and incident-free shale gas exploration project. As detailed in paragraphs 5.6.1, 5.6.2 and 5.6.3 below, Cuadrilla uses robust risk mitigation approaches throughout its activities, implementing industry leading practices which the management team has acquired from more than 120 years of cumulative unconventional gas exploration experience around the world (200 years of total oil and gas exploration experience, including leadership roles in the drilling and/or fracing of more than 3,000 wells).

[15] "[The main sets of issues] are risks also embedded in conventional onshore gas activities" ; Florence Gény, The Oxford Institute for Energy Studies, *Can Unconventional Gas be a Game Changer in European Gas Markets*, December 2010.

5.6.1 *Leakage of hydrocarbons or fracing fluid into shallow water aquifers*. All hydrocarbon exploration, including shale gas exploration, carries the potential risk that hydrocarbons or, in cases where it is used, fracing fluid leak into shallow water aquifers. Although facts from extensive shale gas exploration experience in North America suggest that such leakage is highly improbable,[16] Cuadrilla is nonetheless implementing a number of precautionary steps to manage this potential risk.

Fracing fluids are more than 99% composed of fresh water and sand (in Cuadrilla's case 99.85%—further details set out in the Annex). This water and sand is supplemented with a mixture of everyday chemicals typically found in people's homes, including: friction reducers (polyacrylamides) used as absorbent material in disposable nappies; surfactants (isopropanol) found in glass cleaner; clay stabilizer (potassium chloride) found in low sodium table salt; dilute acid found in cleaning products and in anti-bacterial agents such as bleach; and viscosity agent (guar gum extract) typically found in food products such as ice cream and salad dressing.

There are two possible routes by which hydrocarbons or fracing fluid could potentially leak into shallow water aquifers as an unintended consequence of hydrocarbon exploration, including shale gas exploration: 1) through leaks in the walls of the drill shaft; or 2) through spilled fluid on the surface that seeps into groundwater. Mitigations to these potential risks are discussed in paragraphs 5.6.1.2 and 5.6.1.3, respectively, below.

5.6.1.1 We do not consider there to be a risk that hydrocarbons or fracing fluid leak into shallow water aquifers as a result of the fracing process.[17] We note there is no officially documented case of fracing causing leakage of hydrocarbons or fracing fluid into shallow water aquifers in the history of US shale gas extraction.[18] This is because shallow water aquifers—including shallow water aquifers at Cuadrilla's exploration sites in Lancashire—tend to be located at depths no greater than 1,000 feet below the surface, whereas the shale geological formations where fracing takes place tend to be located at depths of at least 5,000 feet below the surface—as is also the case at Cuadrilla's Lancashire sites. Fractures caused by the fracing process never exceed 200–300 feet upwards in the vertical plane. Thus there are thousands of feet of impenetrable rock between shallow water aquifers and the upper-most point of fractures created by the fracing process.[19]

[16] "Oil and gas operations are widespread throughout North America, and drinking water supplies have been appropriately safeguarded from contamination from these activities for many years. This suggests that the risks can be managed and that shale gas development can proceed safely, with proper industry management and regulatory safeguards in place."; IHS CERA, *Environmental Issues Associated with Shale Gas Development*, September 2010.

[17] "The consensus among geologists, petroleum engineers, and government reports is that such an event [the hydraulic fracturing process contaminating drinking water aquifers] is highly improbable."; "At present there is no evidence that liquids used for hydraulic fracturing of deep shales can migrate upward to contaminate drinking water aquifers, and there are strong geological arguments to the contrary"; IHS CERA, *Environmental Issues Associated with Shale Gas Development*, September 2010.

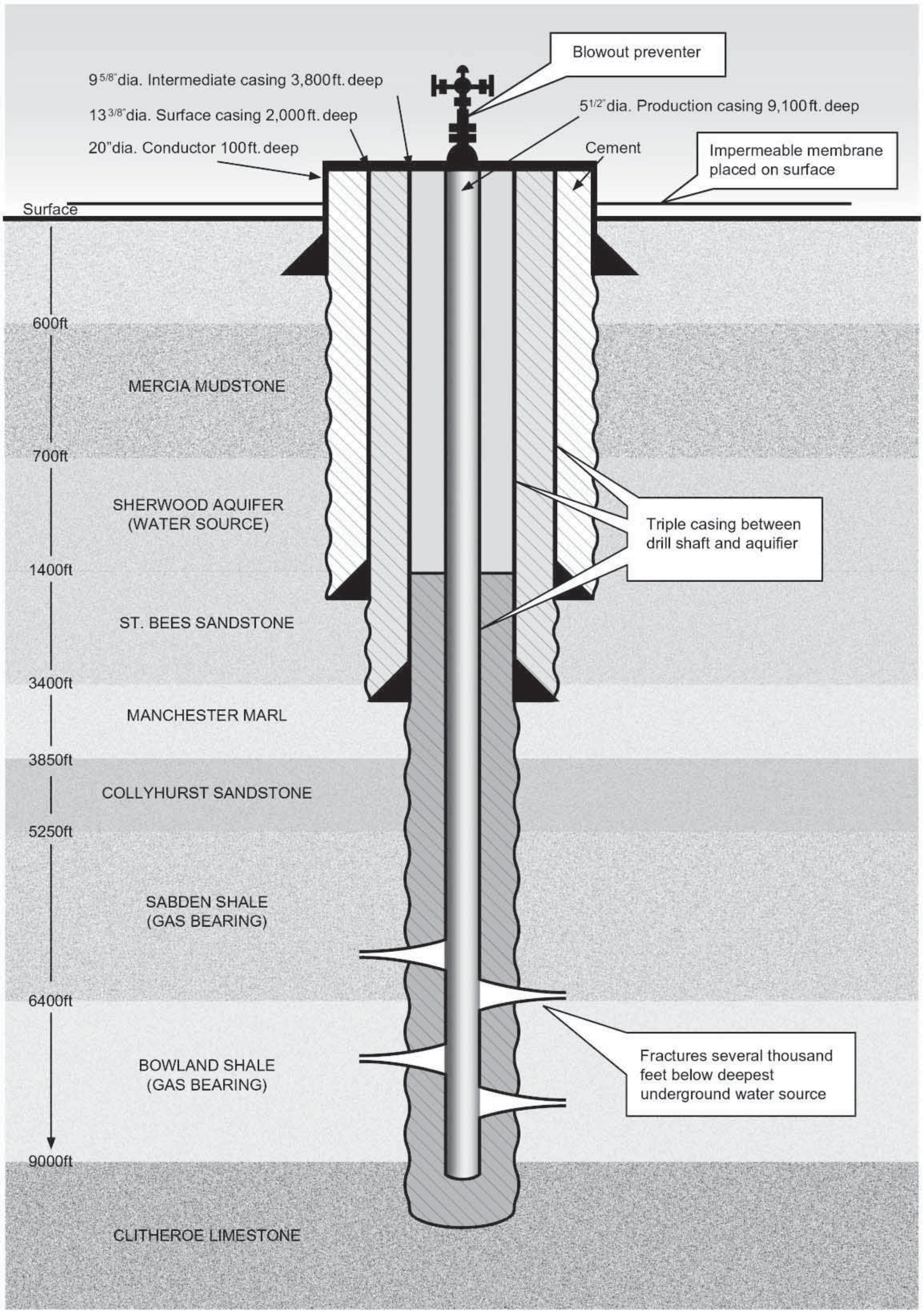
[18] "Of the responses received, no state has reported verified instances of harm to groundwater as a result of hydraulic fracturing. Responses were crafted by the state oil and gas regulatory official in each state."; Interstate Oil & Gas Compact Commission, *IOGCC Hydraulic Fracturing Survey Facts 2002 and 2009,* June 2009. A similar conclusion was included in an earlier report by the Environmental Protection Agency on the impact of coal bed methane exploration and production, which uses similar fracing techniques but normally at shallower depths; "In its review of incidents of drinking water well contamination believed to be associated with hydraulic fracturing, EPA found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids."; EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, June 2004.

[19] "From a geological point of view, such contamination is very unlikely to occur in deep shale formations, as several thousands of feet of rock separate most gasbearing formations from the base of aquifers"; Florence Gény, The Oxford Institute for Energy Studies, *Can Unconventional Gas be a Game Changer in European Gas Markets*, December 2010.

This is shown in the Bowland Shale Well Schematic (Diagram 1) on the following page:

Diagram 1

BOWLAND SHALE WELL SCHEMATIC



Note: Not to scale

5.6.1.2 Leakage of hydrocarbons or fracing fluid into shallow water aquifers through the walls of the drill shaft is prevented by the installation of three steel casings, each of which is cemented in place, in the zone of the shaft adjacent to and surrounding the shallow water aquifer. The integrity of the bond between the rock formations and casings is ensured by pressure testing and other verification techniques prior to any fracing operations.

5.6.1.3 In the unlikely event of a spillage on the surface, seepage of hydrocarbons or fracing fluid into shallow water aquifers through the ground is prevented by the installation of an impermeable membrane on land at and surrounding the well site. Surface level drainage is designed such that any spillage will be collected in a sealed pond from which it can be safely removed. Water returned to the surface during the fracing process is stored in steel tanks or sealed ponds and never touches the ground. Some of this water is recycled.

5.6.2 *Well control failure*. During all hydrocarbon exploration, including shale gas exploration, potential high pressures associated with hydrocarbon extraction must be managed and controlled. In highly rare and extreme cases, improper management and poor well construction may result in loss of well control, with the risk that a potentially explosive and damaging release of fluids occurs. Again, Cuadrilla follows industry leading procedures to manage this potential risk.

Before a drilling operation begins, Cuadrilla undertakes a comprehensive evaluation of geological and drilling records for the local area to determine if a high pressure environment may exist. If this possibility is present, the well is designed and constructed accordingly.

During drilling operations, drilling fluid is used to provide a hydrostatic head on the rocks being penetrated and to constantly monitor temperature, pressure, volume, chemical constituents, geological rock properties, gas liberated during the drilling process and other well characteristics, alerting drilling engineers to any potential problems.

A blowout preventer is installed at the top of the well. It is operated according to strict procedures which include a safety and performance check once every seven days and a major inspection every 21 days.

5.6.3 *Personal injury.* Drilling for hydrocarbons and fracing involve high pressures and high liquid flow rates, which could potentially enhance the risk of equipment failure at the surface and resulting personal injury. These potential health and safety risks are mitigated by a number of preventative measures.

Cuadrilla uses state-of-the-art equipment with automatic pressure and temperature shutdown systems to mitigate the potential risk of mechanical malfunction. Required personal protection safety gear is inspected daily.

There is an overriding safety management plan covering all Cuadrilla's operations. Under this plan, all site-based Cuadrilla personnel must undertake rigorous safety training. Detailed risk assessment and safety meetings are held daily for drill rig and well service personnel. Safety meetings are also held before and after every fracing operation. All visitors to the site must undergo a 30 minute training programme in safety.

All fracing operations are controlled and monitored remotely, at a safe distance from the wellhead. The number of personnel near the wellhead and adjacent to the equipment is restricted to the minimum necessary.

Although the chance of encountering dangerous gas compounds during drilling for hydrocarbons is very remote, hydrogen sulphide detectors are located around the site as well as in the mudflow monitoring unit.

5.7 In summary, potential health, safety and environmental risks associated with hydrocarbon exploration, including shale gas exploration, are mitigated through stringent regulatory requirements and the implementation of established industry safety processes, procedures and controls. Cuadrilla is a highly experienced unconventional gas explorer and the company adopts a robust approach to mitigating potential health, safety and environmental risks based on this experience.

6. Conclusions & Recommendations

6.1 The prospects for shale gas in Europe in general and the UK in particular are promising by analogy to similar geological formations found in North America that have proven to hold commercially productive quantities of gas.

6.2 However it is still early days for the European shale gas industry, in which Cuadrilla considers itself to be a pioneer.

6.3 Shale gas exploration techniques, including directional drilling and fracing, are conventional and have been used across the wider oil and gas industry (including previously in the UK) for many decades.

6.4 Shale gas offers the potential to be a "triple win" for the UK, helping to enhance energy security, tending to lower the cost and price volatility of energy to consumers and reducing greenhouse gas emissions, while also promising to be a significant source of new economic activity for the north-west of England and for UK Plc.

6.5 The carbon footprint of shale gas is low relative to several other fossil fuels.

6.6 Shale gas operations have a small geographical footprint and their visual impact can be minimised relatively easily.

6.7 There are strict regulatory requirements in place for shale gas exploration in the UK, to which all Cuadrilla's operations adhere.

6.8 Cuadrilla is a highly experienced shale gas explorer. The company adopts a robust approach to mitigating potential health, safety and environmental risks based on this experience, implementing industry leading processes, procedures and controls. The potential risks associated with shale gas exploration are not unique and are common to all hydrocarbon exploration.

6.8 Cuadrilla believes 1) science-backed education and 2) supportive fiscal and regulatory frameworks will be critical to the success of the UK shale gas sector. We would welcome the opportunity to discuss both areas further with the Energy and Climate Change Committee.

6.9 We are grateful to the Energy and Climate Change Committee for considering Cuadrilla's responses to the questions posed in its shale gas enquiry. We would be happy to provide further information if requested.

Annex

Note on the specific composition of Cuadrilla's fracing fluid

Cuadrilla's fracing fluid is a minimum of 99.75% water and sand.

The remaining 0.20%—0.25% is comprised of three additional ingredients:

- Around 0.075% is a friction reducer called Polycrylamide. Polycrylamide is found in facial creams (available on the High Street and produced by major brand names), soil sealants and contact lenses.

Two other chemicals may be used:

- Around 0.005% is a biocide used at this very low concentration. This will be used if and only if the domestic water from United Utilities is not pure enough. But if it is sufficiently pure the biocide will not be used.
- Around 0.125% is a weak hydrochloric acid to help open the perforations to initiate frac fluid injection and again will only be used if needed. This is the same acid that can be used in "drinking" water wells to stimulate water production, and in some cases used in swimming pools. It is also the food additive E507 that is commonly used in UK food products.

Memorandum submitted by the Tyndall Centre Manchester

Executive Summary

This report outlines both local pollution-related and global climate-related issues that collectively raise serious concerns about the use of shale gas in the UK. The former leaves little doubt that in the absence of a much improved understanding of the extraction process shale gas should not be exploited within the UK. The later suggests a more categorical conclusion that in an energy hungry world another fossil fuel will only lead to additional emissions and consequently must not be exploited if we are to meet existing climate change commitments.

- Shale gas exploitation gives rise to a range of environmental risks and hazards that have led New York State to impose a moratorium on hydraulic fracturing whilst it awaits the findings of a US EPA investigation. The main issues being considered by the EPA, and which will be equally if not more, important in the UK, are:
  - High levels of water consumption necessary for hydraulic fracturing operations.
  - Groundwater pollution following catastrophic failure or loss of integrity of the wellbore, or if contaminants travel from the target fracture through subsurface pathways.
  - Surface pollution via leaks and spills of various contaminants held on a site.
  - Noise from drilling.
  - Traffic associated with construction.
  - Landscape impacts of individual sites and the combined impact of sites across the country.
- The exploitation of shale gas will, in an energy hungry world, lead to an increase in carbon emissions at a time when a rapid reduction is required. There is little evidence that shale gas has played or will play a role as a transition fuel in the move to a low carbon economy and its development seriously risks directing investment away from genuine low carbon technologies. While shale gas use in the UK may not increase overall UK emissions it must be viewed in relation to impacts on global energy use and emissions. In this regard, if the UK Government is serious about avoiding dangerous climate change, the only safe place for shale gas remains in the ground.
- The extraction of shale gas is likely to release higher levels of greenhouse gases per unit of gas produced than does the extraction of conventional gas. These additional emissions are relatively small compared to overall emissions associated with combustion, however additional fugitive emissions may arise but these cannot be quantified at this time.

Introduction

1. With conventional natural gas reserves declining globally shale gas is increasingly portrayed as a potentially significant and beneficial new source of "unconventional gas2. In the United States production of shale gas has expanded from around 7.6billion cubic metres (bcm) in 1990 (or 1.4% of total US gas supply) to around 93bcm (14.3% of total US gas supply) in 2009 (EIA, 2010b).

2. This new availability of shale gas in the US (and potentially elsewhere) has led to huge interest in its potential. Arguments have been made about the impact on energy security and the potential for shale gas could, in principle, be used to substitute more carbon intensive fuels such as coal in electricity generation.

3. Whether shale gas is able to provide such benefits depends on a number of factors including: the greenhouse gas (GHG) intensity of the novel extraction process required in the production of shale gas: the potential impact of shale gas exploitation on carbon emissions; and the environmental risks and hazards associated with drilling and production. It is these three areas that are the focus of this submission,

What are the prospects for shale gas in the UK?

4. Prospects of shale gas in the UK will depend on the right combination of shale type, total organic content (TOC), maturity, permeability, porosity, gas saturation and formation fracturing and in addition, the right market conditions and economic incentives. Shale deposits on a global level are not a new source of gas and have been evaluated since the early 1980's and produced with commercial viability in North America since the 1990's (Verma et al, 2001). To assess the prospects for shale gas in the UK it will be necessary to understand what factors have a role in developing sustainable reservoirs internationally and indeed if the same resources and conditions are present in the UK. Prospects will require the right combination of "shale type, total organic content (TOC), maturity, permeability, porosity, gas saturation and formation fracturing" (Boyer et al, 2006). Equally important will be the right market conditions and economic incentives for commercial viability. Security of supply and the impact on the environment should be an integral part of any cost-benefit analysis and the latter will be the focus of this report.

5. The shale potential in the UK is not known and the only way to quantify the potential of a shale gas reservoir in terms of its producibility is to drill, core, fracture and then test the "play". According to the British Geological Survey (BGS, 2011), the UK has abundant shales at depth but their distribution and gas potential is not well known. The methodologies employed in assessing deposits such as shale gas are very different to those currently used for conventional accumulations. Traditional petrophysical well evaluation can only provide a limited means of making an assessment of the accumulations (Geny, 2010) and it is widely recognised that there is currently no way of quantifying the potential of a shale gas reservoir in terms of its producibility other than to drill, core, fracture and then test the "play".

6. The success of the Bowland shale near Blackpool will not be openly available for another four years. The first well drilled specifically to assess shale gas in the UK by Cuadrilla Resources, in the Bowland shale near Blackpool, is only due to be tested in January 2011, the results of which will not be openly available for another four years due to licensing agreements. Further ongoing preliminary exploration of deposits with a view to further development and known activity in the UK are summarised in Appendix 1.

7. The onshore shale gas potential of 150bcm stated in the DECC report could over-predict reserves due to the Barnett shale in the US (which was used for the analogy) being an above-average producer due to its low clay content facilitating fracture stimulation important to the producibility of a shale reservoir. Equally, it may underestimate the true reserves and more shale gas accumulations may be discovered in time. Attempts have been made at producing theoretical estimates of the shale rock volume across the UK to provide an indicator of the potential resources. According to the December 2010 report by BGS on behalf of the UK Department of Energy and Climate Change (DECC, 2010a), "*the UK shale gas industry is in its infancy, and ahead of drilling, fracture stimulation and testing there are no reliable indicators of potential productivity*". Applying some assumptions and applying analogies with similar producing shale gas plays in America, however, BGS estimates that UK shale gas reserve potential could be as large as 150 billion cubic meters (bcm). BGS acknowledge that the figure may be inaccurate due to the Barnett shale in the US (which was used for the analogy) being an above-average producer due to its low clay content facilitating fracture stimulation important to the producibility of a shale reservoir (Leonard et al, 2007). Equally, it may underestimate the true reserves and more shale gas accumulations may be discovered in time, as well as the techniques for making estimates developing through experience as has happened with oil & gas reserves in the UK since exploration began.

8. The UK onshore shale gas potential of 150bcm would increase proven reserve levels by just over 50%. However, at the current levels of UK consumption this represents only 2.5 years of current supply production as a standalone resource. Taking the DECC estimates of 150 bcm and putting them into the context of current UK gas supply (BP, 2010) provides a general picture of the limited impact on supply that shale gas might have. There has been a decline in conventional gas production in the last decade in the UK, with only 59.6 BCM being produced in 2009 in comparison to 102.9 bcm in 2003. Additionally, with only a marginal decrease in demand, this has resulted in an increase in imports over the same period. The UK has proven gas reserves of 290 bcm which has also declined from 910 bcm in 2003 (BP, 2010). On a national level the DECC estimate of 150 bcm of shale gas reserves would increase the proven reserves level by just over 50%, but at current levels of UK consumption this represents only 2.5 years of supply as a standalone resource. As the 6th largest

consumer of gas in the world, the UK has a clearly unsustainable demand without assistance from imported supplies, or supplies from alternative sources. Onshore shale gas would only provide a short-term supplementary supply using current estimates of resources.

9. In terms of UK offshore potential, the costs associated with drilling a high density of directional wells and subsequent well stimulations would make such projects economically unviable at current market prices. There is little coverage within the current literature or the DECC (2010a) report discussing the prospects for offshore shale gas in the UK, although its existence is recognised by the DECC stating "Much larger areas are prospective offshore for shale gas, and some of these might be accessible by extended reach drilling" in reference to the US. The costs associated with drilling a high density of directional wells offshore and subsequent well stimulations would make such projects economically unviable at current market prices. Additionally, there could be more potential environmental impacts associated with such exploration. However, in relation to the UK it should be noted that over the last 10 years 99.8% of all gas production has come from offshore wells and of the 3314 wells drilled, only 299 of these were on land[20] (DECC, 2009). It is highly probable that large volumes of shale gas exist in these generally deeper accumulations.

What are the implications of large discoveries of shale gas around the world for UK energy and climate change policy?

10. As efforts begin to exploit shale gas outside of the US it is important to better understand impacts this may have on CO_2 emissions and efforts to minimise impacts of climate change. To do this we have developed two sets of scenarios, one for the UK and one for the World.

11. **There is little to suggest that shale gas will play a key role as a transition fuel in the move to a low carbon economy.** There is little evidence from data on the US that shale gas is currently, or expected to, substitute, at any significant level for coal. Projections suggest it will continue to be used in addition to coal in order to satisfy increasing energy demand. The importance of transitional fuels is often overstated, for example, in the International Energy Agency Blue Map scenario (50% reduction in global emissions by 2050), power generation efficiency and fuel switching accounts for only 5% of required emission reductions (IEA, 2010). If carbon emissions are to reduce in line with the Copenhagen Accord's commitment to 2°C, urgent decarbonisation of electricity supply is required. Given shale gas is yet to be exploited commercially outside the US, it is unlikely to have a major role to play even with respect to national emission reductions. If reserves were exploited in time, shale gas would still only be a low-carbon fuel source if allied with, as yet unproven, carbon capture and storage technologies. If a meaningful global carbon cap was established then the impact of a price of carbon could facilitate some substitution of coal for shale gas in industrialising (non-Annex 1) countries.

12. **Without a meaningful cap on emissions of global GHGs, the exploitation of shale gas is likely to increase net carbon emissions.** In an energy-hungry world, where GDP growth continues to dominate political agendas and no effective and stringent constraint on total global carbon emissions is in place, the exploitation of an additional fossil fuel resource will likely increase energy use and associated emissions. Possible implications were examined through three global scenarios for shale gas exploitation. The starting point was an estimate for the global reserves of shale gas provided by the US National Petroleum Council (NPC, 2007). Three scenarios were developed assuming differing proportions of the total resource are exploited (10, 20 and 40%). Making a further assumption that 50% of this available resource was exploited by 2050, these scenarios give additional cumulative emissions associated with the shale gas of 46–183$GTCO_2$, resulting in an additional atmospheric concentration of CO_2 of 3–11ppmv by 2050. Given current growth in energy use it is very possible that exploitation could be more rapid and that these figures would increase accordingly. This will further reduce any slim possibility of maintaining global temperature changes at or below 2°C and thereby increase the risk of entering a period of "dangerous climate change".

13. **Carbon budgets should ensure that shale gas use in the UK should not add to UK emissions, however, it may put pressure on efforts to stick to these budgets and could have implications for global emissions.** To better understand the potential implications of shale gas production in the UK, four scenarios were developed. Two assumed the amount of shale gas produced correlates with the figure provided in DECC (2010a)—150bcm; and two assumed an amount double this. For both the 150 and 300 bcm scenarios two different rates of extraction were used; one based on a Hubbert type curve (a bell curve) that is often used as an approximation for resource extraction; the other based on the (highly uncertain) growth rates that are predicted for the US by the EIA (eg EIA, 2010). All four scenarios see the majority of shale gas being exploited before 2050 and the cumulative emissions associated with the use of this shale gas ranged from 284–609 $MTCO_2$. To give this some context this amounts to between ~2–4.3% of the total emissions for the UK under the UK Domestic Action budget outlined in CCC (2010). Assuming that the carbon budget is adhered to then this should not result in additional emissions in the UK. For example, it is possible that UK produced shale gas could substitute for some imported gas. However, it is also possible that extracting additional fossil fuel resources could put pressure in efforts to adhere to our carbon budget by reducing gas process and directing investment away from renewable energy. It is also important to note that in a market led global energy system where energy demand worldwide is growing rapidly, even if shale gas were to substitute for imported gas in

[20] 3,314 wells were drilled in total offshore, of those 402 were in the southern North Sea, the largest contributing region of gas in the UK. (DEC, 2009).

the UK, leading to no rise in emissions, it is likely that this gas would just be used elsewhere, resulting in a global increase in emissions.

14. **Rapid carbon reductions require major investment in zero-carbon technologies and this could be delayed by exploitation of shale gas.** The investment required to exploit shale gas will be substantial. In relation to reducing carbon emissions this investment would be much more effective if targeted at genuinely zero- (or very low) carbon technologies. If money is invested in shale gas then there is a real risk that this could delay the development and deployment of such technologies.

What are the risks and hazards associated with drilling for shale gas?

15. The processes and operations involved in the extraction of shale gas from wells are not without their human health and environmental implications and these have risen in prominence in the US and are now the subject of USEPA investigations.

16. **When considering densely populated countries such as the UK, potential risks and hazards of drilling shale gas cover a wide range of environmental impacts including groundwater pollution, surface pollution, water consumption, noise pollution, traffic and landscape impacts.** The "novel" risks associated with hydraulic fracturing of wells are not the only potential drawback of shale exploration, particularly when considering relatively highly populated countries such as the UK. More "run of the mill" impacts such as vehicle movements, landscape, noise and water consumption may also be of significant concern locally and more generally, especially, when one considers the scale of development required to deliver significant supplies to the UK.

17. **To sustain production levels equivalent to 10% of UK gas consumption in 2008 would require around 2,500–3,000 horizontal wells spread over some 140–400km^2 and some 27 to 113million tonnes of water.** To set the cumulative nature of impacts in context, Table 1 provides estimates of the resources required to deliver shale gas production at a rate of 9bcm/year (equivalent to 10% of UK gas consumption in 2008).

Table 1

RESOURCE REQUIREMENTS TO DELIVER 9BCM (10% OF UK GAS CONSUMPTION IN 2008)

	Assuming No Re-fracturing		*Assuming a Single Re-fracturing on 50% of Wells (delivering an assumed 25% increase in productivity for those wells)*	
Area -km2	141	396	123	346
Well pad area—ha	743	990	648	864
Wells		2,970		2,592
Well pads		495		432
Cuttings volume—m3		409,365		357,264
Water volume—m3	26,730,000	86,130,000	34,992,000	112,752,000
Fracturing chemicals volume (@2%)—m3	534,600	1,722,600	699,840	2,255,040
Flowback water volume—m3	3,920,400	67,953,600	5,132,160	88,957,440
Flowback water chemical waste content (@2%)—m3	78,210	1,359,270	102,384	1,779,408
Total duration of surface activities pre production—days	247,500	742,500	302,400	859,680
Total truck visits—Number	2,135,925	3,262,050	2,732,400	4,132,080

18. Risks and impacts of shale gas and shale gas processes and development have been assessed as part of a study by the Tyndall Centre for the Co-operative Group. Key risks and impacts identified in that study are summarised below.

19. **Groundwater pollution:** The potential for contamination of groundwater is a key risk associated with shale gas extraction. A screening of the identity of 260 substances listed in a database of fracturing fluid additives suggests that 58 of the 260 substances have one or more properties that may give rise to concern owing to toxic, carcinogenic, mutagenic and/or reproductive effects.

20. Groundwater pollution can occur if there is a catastrophic failure or loss of integrity of the wellbore, or if contaminants can travel from the target fracture through subsurface pathways. There are a number of documented incidents in the US with principal causes being improper construction and/or operator error. Amoung these incidents are consequences including high levels of pollutants (such as benzene, iron and manganese) in groundwater, and a number of explosions resulting from accumulation of gas in groundwater.

21. **Surface pollution:** There are a number of potential sources of pollution including: well cuttings and drilling mud; chemical additives for the fracturing liquid; and flowback fluid—the liquid containing toxic chemicals that returns to the surface after fracturing. There numerous routes by which these potential sources

can cause pollution incidents including failure of equipment and operator error. Unsurprisingly, a number of incidents have been reported in the US.

22. **Water consumption:** Shale gas extraction requires very significant amounts of water. To carry out all fracturing operations on a six well pad takes between 54–174million litres of water, which is equivalent to about 22–69 Olympic size swimming pools.

23. **Noise pollution:** Given the high population density and the likelihood that any shale gas extraction may be located relatively close to population centres, noise pollution may be an important consideration. Activities such as drilling mean that each well pad requires around 500–1500days (and nights) of noisy surface activity.

24. **Traffic:** It is estimated that the construction of each well head would require between 4300–6500 truck visits. This could have a local impact on roads and traffic in the locality of shale gas well heads. Damage to roads not suited to the levels of truck traffic associated with gas drilling has been an issue in the US.

25. **Landscape impacts:** The construction of well pads is an industrial activity and requires access roads, storage pits, tanks, drilling equipment, trucks etc. Well pads take up around 1.5–2ha and the well pads will be spaced between 1.25–3/km^2. To produce 9bcm of gas annually in the UK over 20 years would require 430–500 well pads and would need to cover an area of 140–400km^2. For comparison 400km^2 is about equivalent to the Isle of Wight.

How does the carbon footprint of shale gas compare to other fossil fuels?

26. **The key difference between the footprint for shale gas and conventional natural gas is the extraction process.**[21] These additional sources include: horizontal drilling; hydraulic fracturing; the transportation of fracturing fluids; and waste treatment of the fracturing fluids after use.

27. **There is limited data available with which to estimate the carbon impact of shale gas extraction in the UK. Using limited data from non-peer reviewed US reports CO_2 emissions associated with shale gas extraction could account for an additional 0.14–1.63tonnes CO_2/TJ of gas energy extracted.** The combination of emissions from these processes based on data from US Shale sites and UK transportation and waste disposal provides an estimate per well for a fracturing process of 348–438tonnes CO_2 (using data sourced from: ALL, 2008; New York State 2009; Water UK 2006; DECC, 2010b); DECC's recent report suggests that refracturing could happen every four to five years for successful wells. Using examples of expected total production for shale basins in the US we estimate that, on average, the additional CO_2 emissions associated with the additional extraction processes associated with fracturing account for between 0.14–1.63tonnes CO_2/TJ of gas energy extracted assuming two fracturing processes during the lifetime of the well (using assumptions on production rate per well from Wagman (2006). However, it should be noted that the estimates presented here are not based on fully peer reviewed emissions data.

28. **The larger the amount of natural gas that can be extracted from a shale well, the lower the contribution the fracturing process makes to the emissions/TJ of extracted energy.** DECC's reserve potential for the UK of 150 bcm is based on analogy with shale gas plays of similar geology in the US. The rate of return per well is not available for UK basins, the rate will determine the relative carbon intensity per unit of energy extracted per well associated with the additional emissions from fracturing etc.

29. **Further emissions may arise from differences in shale gas composition and leaking of fugitive methane emissions during extraction. These will not be quantifiable until sites have been drilled and levels could vary between sites.** Additional differences may occur due to the difference in the composition of gas extracted from shale sources which may potentially require further processing and clean up before the source is suitable for entry to the gas distribution network. This is well dependent and it should be noted that conventionally sourced gas will also vary in its processing requirements. Further emissions may arise from methane leakage during extraction; we have found no evidence to indicate whether shale and conventional sites differ in this aspect.

30. **These relatively low levels of additional emissions suggest that there would be benefits in terms of reduced carbon emissions if shale gas were to substitute for coal. However, rapid carbon reductions require major investment in zero-carbon technologies and this could be delayed by exploitation of shale gas.** Combustion of coal produces around 93tonnes CO_2/TJ compared to 57tonnes CO_2/TJ for gas. Clearly even with additional emissions associated with the extraction of shale gas, the emissions from gas would be considerably lower. The benefits increase when the higher efficiencies of gas fired power stations compared to coal fired power stations are considered.

[21] We assume the emissions from the combustion of gas from shale sources are the same as from conventional sources. In considering the UK, the distribution of shale gas would be the same as conventional gas and therefore subject to the same losses. The limited verifiable data available makes assessment of the additional extraction emissions problematic. However, the figures above use data on expected emissions from the Marcellus Shale in the US to determine the likely emissions associated with the different processes. The processes included in the assessment were: horizontal drilling; hydraulic fracturing; the transportation of fracturing fluids; and waste treatment of the used fracturing fluids.

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January 2011

APPENDIX 1

Cuadrilla Resources	In November 2009 planning permission for an exploratory drill site at Preese Hall Farm, Weeton, Preston Lancashire was granted by Fylde Borough Council (with no requirement for environmental assessment or application for a decision as to whether one was required). According to the planning application and other documentation, the purpose of the exploratory drill is to identify whether the formation can produce gas at economic levels and, if the results prove positive, any further development will be subject to a further planning application. Drilling at Preese Hall was completed on 8 December 2010 and the rig is to be located a second drilling site at Grange Hill (some 15km from Preese Hall) where drilling will commence in January 2011. A full hydraulic fracturing of Preese Hall is expected to commence in January 2011. Preparations for a third exploratory well at Anna's Road are underway and a planning permit was approved on 17 November 2010.

Island Gas Limited	On 15 February 2010 Island Gas Limited (IGL) announced that it had identified a significant shale resource within its acreage. The reserves identified (using existing borehole logs in the locality) potentially extend over 1,195km^2 with an expected average thickness of 250m. These shales are understood to be hydrocarbon bearing as they have been locally demonstrated to be the source rock for hydrocarbons in the Liverpool Bay area.
Composite Energy	Composite Energy was initially focused solely on Coalbed Methane (CBM) but also has shale resources and conventional oil and gas within its current license portfolio and expects to add to that potential in 2010–11. Composite reports that it has identified shale potential within its licenses and is working to establish approaches to shale operations in a UK and European context (Composite Energy, 2010).

Memorandum submitted by the Geological Society of London

1. The Geological Society is the national learned and professional body for Earth sciences, with 10,000 Fellows (members) worldwide. The Fellowship encompasses those working in industry, academia and government, with a wide range of perspectives and views on policy-relevant science, and the Society is a leading communicator of this science to government bodies and other non-technical audiences.

2. The Geological Society is notable for its track record of seamless association between theory and practice, and routinely brings together the best from across academia, industry and government (particularly the British Geological Survey (BGS)), to exchange views and research findings through its scientific meetings and publications. This is especially true in the area of hydrocarbons, where there is a well developed community of Earth scientists spanning these sectors—they routinely collaborate on research, and there is considerable mobility of individuals between the sectors. This group has strong links with the engineering community, also active in the Society, including (but not limited to) petroleum engineers. Fellows from industry, academia and government have contributed to this submission. Notably, there is no evident divergence between the collective views of these groups. Rather, shale gas (and unconventional hydrocarbons more generally) is an area of active research and debate, with a variety of views being expressed across the community.

What are the prospects for shale gas in the UK, and what are the risks of rapid depletion of shale gas resources?

3. While there are large sedimentary basins in the UK which contain significant shale sections, and there are known to be some shale gas resources present, there is currently no clear consensus within the Earth science community regarding the quantity of these resources in the ground (either in the UK or more widely in Europe), and the prospects for extracting these economically. Exploration of these resources is at an early stage, but considerable effort is now being devoted to clarifying the extent and nature of the physical resources, across government (BGS), industry and academia. This work includes identification and characterisation of potential resources, and research to improve our understanding of the geology, which in turn promises better characterisation, and hence improved resource estimates and productivity (for instance by helping identify "sweet spots" in gas plays). While some industry players are actively involved in this work, suggesting a degree of optimism about prospects for economic exploration and production of UK shale gas, others have no such plans and consider it unlikely that this resource will play any significant part in meeting UK gas needs.

4. Notwithstanding this diversity of views, it seems likely that there are reasonably significant onshore physical resources present in the UK. However, there are geological, economic and regulatory constraints (see below) which will determine the extent to which these can be exploited, so in practice the contribution of domestic shale gas resources to the UK energy mix is likely to be modest. The suggestion that 10% of current UK gas needs could be met from domestic shale gas seems entirely speculative, and it appears unlikely that this will be achieved at least in the short to medium term, given the constraints (in particular, differences from the US, where shale gas has been extensively developed), and the fact that there is no UK production at present.

5. We note that BGS has also made a submission to the present inquiry, which includes a description of current UK shale gas prospects. Industry focus is currently on the onshore Carboniferous and especially the Pennine Basin Lower Carboniferous Bowland Shales, which are thought to be most likely to yield significant resources capable of exploitation. BGS has also produced more substantial reports for DECC on UK and worldwide shale gas prospectivity, and further work is reported in Smith et al, 2010. Offshore, there are likely to be substantial North Sea resources. But while some of the constraints which apply to onshore shale gas exploration and production will not apply offshore, this is not close to being economic given current costs and gas prices. It is rarely discussed in the hydrocarbons industry, as it is viewed as such a distant prospect. Furthermore, although the existing North Sea infrastructure for conventional hydrocarbons would confer some advantage, the UK would have to pioneer offshore shale gas exploration and production, particularly as the US has no need to look to offshore resources.

6. Besides the physical resources present in the UK, key constraints on discovery and exploitation are:

(a) Geological: Shale gas plays vary enormously. In particular, the favourable geology characterising the major US plays—such as thick, high TOC (total organic content) oil prone source rocks with low clay contents, deposited in large, relatively unstructured basins—are not generally found elsewhere. European plays are smaller and more complex. There is often also a high level of heterogeneity within plays—on a scale of metres to hundreds of metres horizontally, and down to centimetres vertically. These challenges are not intractable, and drive research and data gathering, but act as a limiting factor.

(b) Economic: The costs of extraction (which depend *inter alia* on the nature of the deposit and the state of technology), the price of gas, carbon costs (shaped by the regulatory environment) and potential synergies with other elements of the energy system, will determine whether the resource can be exploited economically.

(c) Regulatory/legal: Environmental standards, policy with regard to carbon pricing and the tax regime will directly influence whether companies decide to invest in new hydrocarbon developments, including shale gas—so government has considerable capacity to shape such developments. Given the political will, it might in time even make offshore shale gas production a more realistic prospect—an indication on the part of government of the will to make this happen would stimulate creative thinking in the industry. Conversely, uncertainty about regulatory plans and future carbon prices is a strong disincentive to investment in new business lines. A fundamental difference between the UK and the US is the ownership of mineral rights. In the UK, these are held by government, whereas in the US they are owned by the landowner, who can therefore expect a share of revenues—a financial incentive which is absent in the UK. The size of individual land holdings in the UK (and other European countries) is smaller too. The complexity of the planning process, the possible need to seek compulsory purchase from many landowners, etc, has historically been a major obstacle to onshore hydrocarbon development in the UK.

7. Shale gas should be seen in its context as one of a range of types of unconventional gas (and other hydrocarbons), including tight gas and coal bed methane (CBM) (there are some prospects for the latter in the UK). Internationally, shale gas plays tend to have high breakeven prices relative to tight gas and CBM. There is no agreed meaning of "unconventional", though it now usually refers to resources which unlike classical reservoirs are not confined by geological boundaries. Greater effort is usually required to extract them compared to "conventionals". (At one time, reservoirs under deep water were referred to as unconventional, but deep water drilling has become conventional.) Although many hydrocarbons companies still have separate teams for unconventionals, there is a healthy trend away from regarding these as a distinct well-defined category, and towards considering a range of hydrocarbon resources, with many varying characteristics (some of which will affect ease of extraction and economic viability), affected by common factors (regulatory frameworks, technologies, carbon price, energy prices) in the context of holistic global and local energy systems. A single field may have the potential to deliver some combination of conventional and unconventional hydrocarbons, hot water, and sequestration of CO_2 (possibly with enhanced oil recovery). The economics of such a holistic view may be very different to considering each resource alone. In Saudi Arabia, for instance, it is thought unlikely that shale gas could be generated at a profit, but it might be used to generate sufficient energy to drive secondary oil recovery on the same site. There are synergies too with regard to research and data collection. For instance, past exploration of conventional reservoirs may provide a source of useful baseline data about shale gas lying above or below—though this is unlikely to be a substitute for purposeful shale gas exploration given the different information needs and geological factors involved.

8. Compared to conventional gas, shale gas is produced at higher levels initially, which decline rapidly, with a very long "tail" of low production rates. So physical depletion of any given shale gas play is not likely to happen quickly. However, as noted above, physical depletion of the total resource in the ground is not the primary constraint on production. It is important to draw a distinction between resources (the total amount in the ground) and reserves (the amount of a resource which can economically be extracted with current technology). As with other mineral resources, reserve levels will increase with rising prices and with technological improvements (and conversely, will reduce if prices fall).

What are the implications of large discoveries of shale gas around the world for UK energy and climate change policy?

9. The primary motivations for examining UK prospects in shale gas are economic benefit and security of supply. In both instances, the focus should not just be on domestic resources. There are major opportunities for the development and application of UK research and technology, and for UK-based industry, irrespective of the location of resources. A number of UK research institutions are internationally respected in conventional hydrocarbons, and some (including UCL and the Durham Energy Centre) are establishing themselves as world leaders in alternative energies. These opportunities can only be taken with government support. Furthermore, improved security of supply may be achieved by means other than moving towards self-sufficiency based on domestic resources. Developments elsewhere may decrease the market power of particular countries which are currently dominant, reducing international dependence on their supplies. Moreover, security of UK supply would be helped in particular by the realisation of prospects in the EU.

10. Shale gas production in the US has grown dramatically in only a few years, from 1% of US gas supply in 2000 to 20% in 2009 (projected to rise to 50% by 2035) according to one estimate from CERA, and this has stimulated widespread attention to shale gas elsewhere. (See the Chatham House report on shale gas (Stevens, 2010) for further detail). A key driver of this "revolution" has been technological development,

especially of hydraulic fracturing and horizontal drilling. But it has also depended on advantageous geology of North American shale gas plays which is not replicated elsewhere, and a distinctive regulatory environment, including with regard to planning and land/mineral rights ownership as outlined above. (The Chatham House report is right to point out that the US experience will therefore not directly translate to other national settings, but it is unduly pessimistic regarding the scope for international learning. Research and the development of new technologies and business models have been hugely stimulated. Notably, many European, Indian and Chinese companies have acquired small percentages of US shale gas plays, to build their knowledge, technology base and human capital.) The impact of US shale gas on global markets is often overstated. In feeding the domestic market, it has indeed reduced US dependence on liquefied natural gas (LNG) imports—but this has been largely offset by rapidly increasing demand in the Middle East, Latin America and South and East Asia, which have all emerged as material LNG importers. US shale gas is not expected to impact directly on UK energy policy unless it starts to be liquefied and exported, which is considered unlikely.

11. Large shale gas discoveries in mainland Europe could contribute to European (including UK) energy security. However, opinion differs regarding the prospects for discovering and exploiting such resources. There are technical, commercial and regulatory hurdles. BP's view, for instance, is that usable shale gas resource in Europe is limited, and that any impact is likely to be local rather than pan-European. Shell, meanwhile, sees the possibility of a positive impact on security of gas supply, but not before 2020. (In addition to the long lead time for exploration and development, they note that regulation and permitting are not yet in place, and that economic assessment will also take time.) European prospects will not be comparable to those in North America. Nonetheless, active exploration is underway in many European countries. Among collaborative projects tackling associated research challenges and addressing the need for a systematic database of prospects, the most significant is the "Gas Shales in Europe" (GASH) project, sponsored by industry and run by a multinational expert task force drawn from universities, other research institutions, geological surveys and consultants. (See, for example, Schulz et al, 2010.)

12. Outside Europe, only North Africa and Russia are likely to have shale gas resources which might impact UK energy policy if they were exploited. Algeria and Tunisia, with possible large unconventional resources, constructive established commercial relationships and existing export infrastructure to Europe, are well positioned to continue to be important suppliers of gas. (Libya may have similar physical resources, but lacks the other advantages.) However, there is little economic incentive at present to address issues which would need to be tackled to allow development at scale. In Russia, significant untapped conventional resources remain, so shale gas is unlikely to be an attractive prospect in the near future. (Notably, though, Russia appears to be scaling back conventional gas exploration in the Arctic, which was expected to supply Europe in future decades, at least partly in reaction to possible shale gas development in Europe.) There is also considerable shale gas exploration in China and India, both by multinationals and local companies, and government enthusiasm in the context of dependence on domestic coal and imported oil and gas, and the need to manage CO_2 emissions.

What are the risks and hazards associated with drilling for shale gas?

13. All those who have contributed to this response are cognisant of potential environmental and social risks, and recognise the responsibility on industry to act responsibly and sensitively. Indeed, the move towards thinking of integrated energy systems outlined above brings environmental impacts centre stage, particularly as the regulatory system increasingly ensures that environmental costs (including those of carbon emissions) are captured. Some of the environmental risks which have been posited include:

(a) Water sourcing and subsequent disposal: Hydraulic fracturing requires a great deal of water to be injected (perhaps 100,000 barrels of fresh water per multi-stage fracture per well), much of which is then forced to the surface (now salinated) and has to be managed. There is the potential for competition, for example with agriculture, over water resources. This is certainly a legitimate constraint on shale gas development in some areas, for instance in parts of India, whose government is generally keen to see such development, but will rightly not allow it in areas where agriculture already contends with water shortages, despite the presence of promising shales. It has also been suggested that water supplies near to hydraulic fracturing operations may become contaminated, typically by added chemicals with which the hydrocarbons industry is very familiar from conventional drilling, or by the presence of hydrocarbons, heavy metals and organic compounds. There is no recorded evidence of this, and good reason to think it untrue, since the process takes place at depths of many hundreds of metres below the aquifer. Although the public debate about this in the US is not well informed, sensitive and responsible behaviour by industry is key to avoiding over-bureaucratic regulation.

(b) Air quality: As with conventional drilling, this can and must be appropriately managed.

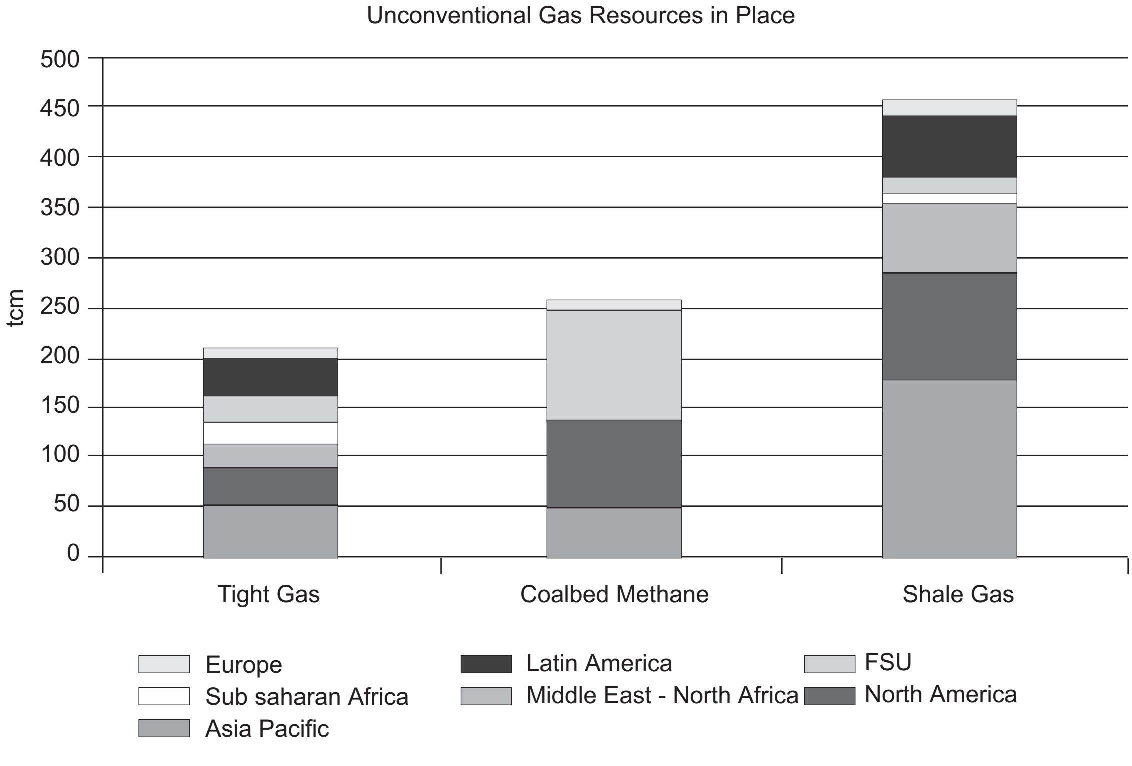
(c) Release of radioactive material: Recent research has raised the risk of mobilisation of natural uranium from source rocks. Again, US public debate about this is not well informed, and there is no evidence of harm.

(d) Induced seismicity: This is not thought to be a significant risk in the UK, but may be more of a concern where there is already earthquake risk (eg parts of India). The same risk applies to other processes which involve the injection of large volumes of fluid into rock (CCS, geothermal energy, etc), and this is an area of active research.

14. Both the number of wells required to extract shale gas and the size of each well site (to accommodate fracturing), and therefore the physical footprint associated with onshore exploitation, are very large compared to conventional hydrocarbons. A typical full field development using 850 wells might occupy 110 square miles, over a period of 40 years. Noise, access and visual impact are associated factors. In countries such as the UK, which is much more densely populated than the US, and where landowners does not own the associated mineral rights, this is likely to be a major obstacle to development. Technological approaches to reduce land use requirement, developed in the US, include "superpads"—rather than drill evenly spaced vertical wells, a group of wellheads is clustered together, and the well shafts "splay out" into the gas field below. This is more expensive, but the additional cost may be offset by the reduced economic and social costs associated with land use.

How does the carbon footprint of shale gas compare to other fossil fuels?

15. The carbon footprint associated with shale gas production is essentially the same as for other types of natural gas production. CO_2 emissions are dominated by end use, the energy used in producing and transporting the gas generally being small in comparison, despite the considerable work done in horizontal drilling and fracturing. This is illustrated in the chart below, showing Net Energy Ratio (NER) and technological maturity for various hydrocarbons including unconventional types. (The exception is when natural gas is converted to LNG, where typically 10–15% of the produced gas can be consumed in liquefaction and transportation of the product.) In comparison to other fossil fuels, natural gas results in up to 50% less CO_2 emissions than coal when used to generate electricity. Emissions of other pollutants (sulphur dioxide, nitrogen oxides, mercury and particulate emissions) are also substantially less or negligible. In the US there is an emerging public debate, which is not well founded, about greenhouse gas emissions directly to the atmosphere as a result of "methane leakage" associated with shale gas development. This is very unlikely to be due to hydraulic fracturing, since this occurs at depths of several thousand metres beneath the surface.



Concluding Remarks

16. We would be pleased to discuss further any of the points raised in this submission, to provide more detailed information, or to suggest oral witnesses and other specialist contacts.

January 2011

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Memorandum submitted by Nick Grealy, No Hot Air

- My name is Nick Grealy. I have had almost 20 years experience in the UK Gas Industry dealing with all levels of Industrial and Commercial Gas Customer.
- My employers have been London Total Gas, a JV between London Electricity and Total Gas Marketing, EnergyQuote a commercial consultancy and as Gas Buyer for the NHS Purchasing and Supply Agency, an agency of the Department of Health, responsible for purchasing gas for approximately 5,000 sites of the National Health Service in England.
- Since 2008 I have published a web site No Hot Air, originally aimed at advising I+C End Users on how to reduce energy costs.
- In that capacity, at a time when Oil and Gas prices were at their peak, I first became aware in mid-2008 of the sudden emergence of the shale gas phenomenon in North America. I immediately saw the potential impact of shale gas in creating a paradigm shift for energy globally.
- I would define myself as an eco-pragmatist. I do not deny climate change science but feel that any hoax lies in how much we ask end-users to pay for it.
- I come from an initial view that since energy use is unavoidable, it has an economic impact akin to taxes. At the same time, the cost of not acting on carbon reduction has potential for longer term costs that need also to be considered.
- Although there are minimal differences between supplier rates, I strongly believe that the idea that competition between energy suppliers is pointless in a commodity based market. I advocate transparent solutions based directly on wholesale market indices that nudge end-users to act in their own best interests.
- As such I believe that end-users should not have to struggle to get the best rate as in the current market structure which is based on confusing customers far more than helping them.
- A key part of consumer confusion arises from the popular mis-conception that gas, and by extension power, is insecure as defined by volumes of actual supply and potential price volatility.
- The sudden emergence, and what I and many other commentators call the future permanence of abundant natural gas via the shale revolution will be beneficial for almost everyone, while causing massive disruption to current UK energy policy. This disruption is likely to be overwhelmingly positive.
- I have always approached the shale phenomenon from the viewpoint that it can be environmentally acceptable and affordable. There are no perfect magic bullet solutions to energy security and that includes natural gas. Gas is not a perfect low carbon solution. But shale promises to provided energy security as defined by both physical supply and affordability.
- UK energy policy, built as it is on the Energy White Paper of 2007, has an a priori assumption that natural gas is an insecure fuel as measured by the risk of finite supply and the connected implications for price volatility.
- I strongly believe that emergence of shale gas means that fear of gas supplies not reaching the UK is groundless.
- There are three basic reasons for this view:
  1. shale gas causing a new reality in LNG supply;
  2. the potential for shale gas development in our near-neighbours; and
  3. potential for development of substantial shale gas supplies on-shore UK.

LNG

- The development of a global LNG market ran in parallel to the emergence of shale gas. But the long lead times involved in engineering and capex of LNG led to a distortion when initial USA shales were able to ramp up production in short periods and rapidly declining costs of exploiting it.
- The LNG market was built on the expectation that the United States would join existing markets in Japan, Korea and Taiwan and an expansion in European, especially UK import capacity.
- But the sudden wave of US and Canadian shale gas has meant that apart from arbitrage plays into the US North Eastern states during the winter peak, there is no longer any fundamental need for US imports.
- Despite a recovery in Korean demand, and new supplies to Chinese, Indian and Brazilian markets, Asia is already very well supplied from existing suppliers in Indonesia, Australia, Malaysia and Brunei.

— Qatar based it's strategy of a massive run up to over 70 million tons of LNG capacity on filling the US and UK markets. The evaporation of US demand means that those supplies will have little option but to go to Europe.

— Existing or proposed suppliers of LNG to the US also include Trinidad and Tobago, Nigeria, Equatorial Guinea and Egypt.

— Those nations, along with Qatari cargoes, are now effectively cut out of the US market. The UK has imported very large volumes of LNG both for domestic use and for re-export to Europe. During winter 2009, Centrica shut in production at it's Morecambe Bay field as it found spot imports were more competitively priced, even during the severe winter period of January 2010.

— Spot LNG trade has led to a fraying of the oil/gas pricing link that many observers see as permanent and unavoidable going forward. The severe winter at both ends of 2010 saw this trend moderate slightly, as European buyers were still buying spot gas at rates closer to oil indexed prices from Russia and Algeria. There are also short term issues surrounding LNG shipping capacity which are unlikely be permanent going forward.

— *The essential point is that even without any physical UK or European gas production, the UK's energy security is positively affected by the revolution in LNG, which in turn is strongly influenced in the short term by shale resources.*

— Observers who note that LNG makes the UK open to gyrations in global markets are technically correct, but not in practice. There is literally nowhere else for LNG to flow to except Europe.

— Asian demand is mostly met by existing suppliers, and there is developing, but as yet insignificant Asian spot demand.

— Asian demand is dominated by the mature markets of Japan, Korea and Taiwan. All three markets have limited potential to expand import needs so that new import sources from Australia, Qatar, Peru, Sakhalin (Russia) are already sufficient to satisfy import needs.

— The common view in commodities that Chinese and Indian demand is pushing up prices does not appear to be happening in LNG. Import capacity in both countries, while growing is still far less than the export capacity of Qatar and planned Australian LNG projects.

— China will be the first market in Asia to have multiple sources of gas supply from domestic conventional and coal bed methane supply, LNG imports and pipeline imports from Turkmenistan today, Myanmar from 2012 and proposed Russian (Siberian) fields. LNG imports will therefore be just one part of the Chinese natural gas mix. It is unrealistic to assume that Chinese and Indian demand will have anything except short duration impacts on European imports and prices.

— What is especially significant is how both China and India threaten to leapfrog Europe on shale gas production. Both countries are said to have massive shale resources and the political will to access them. The US State Department has been engaging countries worldwide with it's Global Shale Gas Initiative.

— The initiative is open to all countries and it would be useful if the Committee could ask the FCO how they have responded to the US initiative.

— Shale gas development in China and India is already at least as advanced, if not further, than in Europe. The implications are that shale will at a minimum lessen their need for LNG imports, placing further pressure on prices and displacing LNG to other markets.

— Schlumberger announced in January 2011 that their estimate of Indian shale resources stood at 300/2100 TCF, compared to the largest existing Indian gas resource of 8 TCF in an off shore field.

— Despite projected increases in LNG imports to Brazil and Argentina in 2010, the total volumes involved are still relatively small compared. Additionally, Argentina recently announced shale gas deposits officially put at 257 TCF or over 8 Trillion Cubic Meters. For comparison a find of that size is 100 years of present UK consumption. I am told off the record that the actual discovery is at least three times higher and it is instructive that Exxon Mobil announced exploration in an area next to the initial discovery.

— Significantly, it now appears that North American shale production will be exported from 2014 onwards, providing perhaps a stronger link in the Atlantic Basin between Henry Hub and NBP prices. There have already been two cargoes re-exported from Louisiana to Texas during winter 2010/2011.

— Naturally, to ensure European and UK energy security we must study the prospects for shale gas reserves in the European continent and the UK.

— Such estimates are problematic at present. But it is reasonable to consider much of North America's experience as at least analogous to Europe. Similarly, geologist estimates have been consistently cautious in the United States. The Marcellus Shale was estimated at being 15 TCF as recently as 2006, but present estimates point to over 500 TCF.

— **The best approach therefore for UK energy policy going forward would be one of wait and see. The speed at which shale is developing should mean that even a delay of little as one to two years is a far more prudent option that provides little risk.**

— **The larger risk is of the UK locking itself into structures based on out-dated realities.**

— The sudden emergence of super giant gas fields in several North American locations has led to a true paradigm shift in that the key issue in North America is not supply but the creation of new demand to soak up the increased production.

— North America uses coal as the dominant form of generation, but gas is now the cheaper option in many markets.

Many NA observers also point to the potential for creating demand by replacing diesel with natural gas in the transportation sector. The freight sector is responsible for up to 40% of transportation related CO_2. It is not unreasonable to expect that natural gas either in LNG or Compressed Natural Gas form can remove 10% of total transportation CO_2. The associated costs will be far lower than those for the development of electric vehicles and the time frame would be far shorter. NGV use will also lead to lower transportation costs and significant improvements in air quality as LNG emissions contain no particulates or SO_2 as contained in oil.

— The immense size of the US gas resource is leading many observers to feel that even if with increased generation and transportation demand, there will still be very large quantities remaining for export. The case of Canada is instructive as almost 60% of natural gas production is exported to the USA. The emergence of US shale plays means that the US no longer needs Canadian imports to meet demand. Canada is already advanced in planning exports from Horn River and Montney Shales of Alberta and British Columbia to Asian markets via a terminal at Kitimat BC originally intended to import LNG.

— The key issue going forward for natural gas is not managing supply, but creating demand.

— Using clean-burning natural gas as partial, but immediate, solution to contemporary energy problems, is a forward step, not a retrograde move. The substantial difference in fossil fuels between natural gas, coal and oil needs to be better communicated.

— Natural gas can provide currently viable, scalable, affordable and significant but *partial* decarbonization of the electric generation sector.

— We must be realistic: Other technologies aim for a *full* decarbonization at some point several decades away. Is it wise to bet on technology today for 2050?

— The greater environmental risks are likely to be those associated with *not* developing shale resources.

— Similarly, the greater economic risks of shale increasingly appear those associated with *not* developing shale resources.

— Shale gas has the potential to reduce energy costs during a time when global stimulus is again becoming necessary.

— Lower energy costs reach consumers and industry far quicker than tax or regulatory changes can.

— Lower energy costs serve the same purpose in stimulating economic growth or consumer demand as direct government expenditure or quantitative easing. They do so at no cost to taxpayers while reducing government expenditure through lower energy costs in government energy estate.

— Europe in general and the UK in particular risk being marginalised as China and India embrace shale gas potential as other nations deny it.

— Regulation is to be welcomed and will not add any significant costs to shale extraction. It ultimately helps the shale process by encouraging innovation and removes both risk and bad actors from the industry.

— Full decarbonization technologies are either unproven or expensive. They all have significant externalities. Do they work? Are they affordable? Do they provide a permanent fix for the problem? Do they simply grandfather waste and storage issues onto future generations? We risk making an expensive bet today on technology that might well be the electric typewriter, fax machine or videocassette of the future.

— It will be an expensive assumption that the oil/price link will continue simply because of history. Shale gas changes history.

— Should future hopes ignore currently available and cheaper options that, while they do not offer permanent solutions, will deliver partial solutions in much shorter time frames? Delaying partial decarbonization also makes the cumulative impact of carbon more problematic still in 2050.

— Environmental challenges should not be confused with obstacles. We think that the natural gas industry can meet the environmental challenges introduced by shale gas. It has considerable incentive to do so.

— Community engagement will be key, as it is in any business. Fears have to be allayed for as large a part of the populace as possible, but community engagement means starting at the top and influencing government policy at the highest levels.

— Shale is a lot bigger than a narrow energy issue, it is a macro economic issue with significant government revenue and job creation potential.

— Gas is now a global market. Local issues in the UK or any other market are mostly irrelevant or short lived structural matters that cannot distract from the overall influence of global drivers.

— In the longer term, the influence of world markets may even fade as both natural gas and renewable energy become localised.

— The new method of natural gas extraction, can, with sufficient oversight, be replicated globally.

— In a global market, it is of declining relevance where natural gas comes from.
— A new paradigm is being simultaneously created: Local energy is by definition sustainable energy.
— Diversity of supply is security of supply. A diverse supply gives no one supplier a dominant position that can be abused.
— Much initial exploration is, and has been, going on under the radar. That shouldn't be confused with inaction.
— Security of supply issues have evaporated in North America, and the potential exists for similar affects globally in as little as five to 15 years.
— Today, I think we see a moderate risk of price spikes for the period 2014 onwards, but feel optimistic that even a year from now some of the issues will have been resolved positively. Absolutely no one yet knows with any certainty what will happen in 2014–20. One thing we feel fairly sure about is that long term investment based on negative sentiment over rising power or gas prices is to be avoided. Paybacks should be calculated on a combination of rising network costs but lower commodity costs framed within a matrix of efficiently managed demand.
— The post 2020 era promises to be one of the most transformative energy events since the initial major oil discoveries in Texas and the Middle East a hundred years ago. Natural gas can provide valuable breathing space as a bridge fuel to a low/no carbon future.
— I would summarise my views as we must have an energy policy based on the facts, and as Keynes noted, when the facts change, we must change our minds.
— Finally, natural gas cannot provide a perfect solution. But we cannot currently afford to make the perfect solution of no carbon at all the enemy of the good solution of secure, significant, affordable and scalable carbon reductions through increased use of natural gas.

January 2011

Supplementary memorandum by Nick Grealy, No Hot Air in response to follow-up questions

Thank you for your letter of 16 March and for the opportunity to give evidence. My responses to your further questions are as follows:

1. *Is shale gas more likely to a regional rather than a national phenomenon in the UK ie is shale gas more likely to be locally distributed that transmitted nationally?*

Any UK shale gas depends of course on how large the resource actually is, but one could anticipate that any gas will be put into the National Transmission System, where it will balance the system nationally, much as any gas today from the various input points does. Shale gas could have significant local impact nevertheless if large generation or major end-users could have direct connections independent of the NTS.

2. *How difficult is it in the UK for new entrants to contribute gas to the grid?*

I am not an expert on the transmission system, but the general rule is that access to the net-work is open to all who have resources to contribute to it. National Grid would have commercial considerations as to how the capacity needed would be paid for, but in principle I don't see any problems in inputting gas to the system.

3. *Is the higher population density in the UK, compared to the US, a barrier to shale gas exploration?*

The higher population density issue is a bit of a red herring. Europe's population development means that while urban areas have high population densities, rural areas often have relatively low density. The original Barnett Shale development took place in Fort Worth, one of the largest US urban areas. Advances in pad spacing since then mean that one pad with multiple wells could serve an area of up to 5 square miles or more. The fact that UK PEDI's are far larger in area than those in the US, primarily due to the fact that the Crown owns all resources would actually make well pad spacing inherently more efficient, with associated cost implications in the UK than the US.

4. *In the US, the private owners of the shale gas receive royalties—in the UK, where the state owns oil and gas rights, how can the public be convinced to accept the impacts of onshore shale gas exploration and production? What more should the Government do if it wanted to support unconventional gas?*

Similarly, one must consider that well pad spacing and construction would make actual disruption to communities a short term phenomenon. Even a multi pad well could have a total construction time of less than a year, after which the actual footprint needed would be quite small. The physical and visual impact could be mitigated and minimised to the point of near invisibility long-term. I note that Charles Hendry recently posited that communities could be compensated in some way for the impact of wind turbine development, which would obviously lead to long term visual disruption. The long term implications of shale development would be far smaller and shorter. This would mean that any long term financial compensation to communities for shale gas would be unfair. Short term compensation is to be considered, but this could be in the same way that housing or commercial development is often tied to upgrading roads or other infrastructure. The community engagement plans of some shale gas developers propose that the community would be compensated in some way financially for disruption, but again this has to weigh that short term disruption can be minimised and longer term the community would gain at the national level in lower prices, increased energy security and higher national tax revenues.

5. *The US stimulated the shale gas industry with tax breaks from 1980 until 2002—are tax breaks necessary to stimulate the shale gas industry in the UK?*

I don't think that tax breaks are necessary, on the contary as I pointed out, tax revenues would be impacted positively at the national level. The main help government could provide would be to ensure that local planning restrictions take into account the over-riding national interest of energy security. Even there, I believe that existing planning law already has provision for this.

6. *Will the lack of an onshore service industry hinder development of unconventional gas in the UK and Europe?*

The lack of an onshore service sector reflects the lack of a historical need for those services. One would expect as the market for services develops that the world service sector will meet the needs. I think it is important to consider the attractiveness of the UK and Europe compared to many of the more exotic international locations where the service sector operates. I feel that both the UK and Europe should not sell themselves short in realizing how attractive a location they could be for services compared to any number of similar international areas where the sector currently operates. The service sector internationally has been able to quickly ramp up capacity in far more problematic locations and would be eager to invest in Europe for any variety of reasons.

March 2011

Memorandum submitted by WWF-UK

Executive Summary

WWF-UK welcomes the opportunity to respond to the Energy and Climate Change Committee's enquiry into shale gas.

There is evidence that there are a number of serious environmental and health risks associated with shale gas production the most serious of which is the potential for contamination of groundwater sources, currently the subject of a US Environmental Protection Agency enquiry. Other notable environmental concerns include air pollution, spillage of hazardous substances, treatment and disposal of waste water, water consumption, well blowouts, noise and traffic.

For these reasons **WWF-UK is opposed to the production of shale gas in the UK**. At the very least, given the current lack of understanding of the environmental risks and hazards associated with shale gas, WWF considers that **no shale gas related activity should be undertaken until there is a robust scientific consensus demonstrating exactly what the risks are and what, if any, practices may be adopted to minimise hazards associated with shale gas, drilling and hydraulic fracturing.**

Climate change targets

To stand a chance of reducing global greenhouse gas emissions to a level which is likely to limit global climate change to 2ºC or below, and retain some possibility of limiting temperature increases to 1.5 ºC, global emissions must be reduced by 80% compared to 1990 levels by 2050. To have any chance of achieving this goal, the majority of the world's fossil fuel reserves need to stay in the ground. From a climate change perspective, whilst it makes sense to burn lower carbon fuels such as gas, rather than coal, this argument is only valid where there is evidence that gas is being used as a direct substitution, not in addition, to coal.

At the UK level, we have a climate change act which commits us to at least an 80% reduction of greenhouse gas emissions by 2050. The Committee on Climate Change recently recommended that the UK's power generation should be largely decarbonised by 2030.[22] Any new "dash for gas" driven by the shale gas boom could seriously undermine the UK's ability to meet these targets and risks undermining investment in renewable energy both for power generation and heat.

Gas and affordability

Several analysts have demonstrated that the reason that gas prices are currently low is that the increase in shale gas production has surprised investors and led to an oversupply of gas. There is strong evidence that although gas prices are currently low they are unlikely to remain at their present levels and that far from representing "a new era of cheap gas" the impact of shale gas on global markets is one of uncertainty. With this in mind future gas prices may damage, as opposed to enhance, affordability for UK energy consumers.

[22] http://www.theccc.org.uk/reports/fourth-carbon-budget

Prospects for shale gas in the UK and Europe

A recent paper by Florence Gény of the Oxford Institute for Energy Studies analyses the market conditions in the US and Europe and concludes that there are limited prospects for significant production of shale gas in the UK or Europe, given the very different conditions to those prevailing in the United States. These differences include geological differences between US and European shales, water supply constraints and protection, spatial constraints linked to population density and site protection.[23] Environmental concerns are also having serious impacts on shale gas in the US with a moratorium on gas drilling currently in force in New York State. Risks of uncertainty in gas markets driven by the shale boom, coupled with Gény's assessment that there are limited prospects for shale gas in the UK or Europe, particularly in the short term, call into question arguments that shale gas can enhance UK security of supply.

Additional greenhouse gas emissions

Finally, although the recent Tyndall Centre report[24] is a significant contribution to the debate on greenhouse gas emissions resulting from shale gas, more research, including the issue of methane leakage from wells is required.

Question 1: *What are the prospects for shale gas in the UK, and what are the risks of rapid depletion of shale gas resources?*

A recently published in depth analysis by Florence Gény[25] of the Oxford Institute for Energy Studies, which was published in December 2010, looks specifically at the potential for unconventional sources of gas, particularly shale gas, in the US and Europe. The report suggests that the numerous conditions that have allowed shale gas production in the US to prosper are not present in Europe or the UK. Even in the event of significant legislative changes in favour of shale gas, a move which WWF would oppose, Gény does not believe that any "game changing" quantity of shale gas will be produced in Europe before 2020.

Gény states that: "Each of the conditions behind the success of unconventional gas in the US, encounters different conditions in Europe...geological differences between US and European shales, water supply constraints and protection, spatial constraints linked to population density and site protection".[26]

Furthermore, Gény estimates that finding and development costs in Europe are in the region of 2–3 times higher than the US.[27] The UK has a population density which is eight times that of the US[28] and limited land availability which combined with the differences described above indicate that domestic shale gas is unlikely to be able to compete with imports in the foreseeable future.

There has been very limited geological investigation of the UK's shale gas resources. Where shale exists there is significant uncertainty relating to its suitability for the hydraulic fracturing process due to wide variations in the geological properties of the rock. We examine some of these constraints in more detail below.

Environmental impacts, regulation and costs

The environmental impact of shale gas exploitation is subject to increasing scrutiny from the public, regulators and academics in the US and Canada (a development which WWF welcomes) where the industry has up until now been subject to very limited environmental regulation. Gény's report estimates that the cost of environmental compliance in the US, even without stricter environmental regulations, is set to increase production costs by 5–7%.[29] Any shale gas production in Europe will be subject to Europe's environmental and health and safety regulations which are more advanced than those in the US and compliance will therefore mean that production costs are higher than those in the US.

The shale gas production process is also very water intensive. According to Gény, the cost of water in Europe is ten times higher than in the US and on a per capita basis, the US has 3 times more fresh water resources than in Europe. We discuss environmental concerns in more depth in our response to the question about environmental risks and hazards.

[23] http://www.theccc.org.uk/reports/fourth-carbon-budget

[24] Tyndall Centre. Wood, R. Gilbert, P. Sharmina, M. Anderson, K. Footitt, Glynn, S. Nicholls, F. A. Shale Gas: A provisional assessment of climate change and environmental impacts. Commissioned by the Co-operative Group. http://www.tyndall.ac.uk/shalegasreport

[25] Geny, F. 2010 Can Unconventional Gas be a Game Changer in European Gas Markets? http://www.oxfordenergy.org/pdfs/NG46.pdf,

[26] Geny, F. 2010 Can Unconventional Gas be a Game Changer in European Gas Markets? http://www.oxfordenergy.org/pdfs/NG46.pdf, page 100

[27] Ibid,

[28] US average population density according to Wikipedia (see link below) is 32 persons per km2 whilst UK average population density is 255 persons per km2. http://en.wikipedia.org/wiki/List_of_sovereign_states_and_dependent_territories_by_population_density

[29] Geny, F. 2010 Can Unconventional Gas be a Game Changer in European Gas Markets? http://www.oxfordenergy.org/pdfs/NG46.pdf, page 44

Land use and population density

Shale gas requires relatively large amounts of land with spacing of approximately 3.1 wells per km².[30] Concentrations of shale gas are far lower at around 0.2–3.2 billion cubic metres per km² compared to conventional gas with a concentration of 2–5 bcm per km² requiring more wells to be drilled.[31] A recently published report by the Tyndall Centre estimates that 2,580–3,000 wells would be required to produce 9bcm (billion cubic metres) per year of gas from shale.[32] Shale wells peak early and then deplete more rapidly than conventional gas wells.[33] Therefore **maintaining a significant volume of production would require regular drilling of new wells spaced over large areas of land**.

For each well drilled it would be necessary to build appropriate transport infrastructure and storage pits (discussed in our response to question 3). Whilst the US has vast amounts of sparsely populated land, the UK by contrast is small, densely populated and has many areas of protected land. Given the many potential negative environmental effects of shale gas, which are of concern to WWF, it would be reasonable to anticipate significant resistance from local communities.

Supply chain

According to Gény there is "currently close to no fracking expertise nor manufacturing capacity in Europe...relying on international service providers will likely be the solution of choice".[34] Therefore, it seems likely that any shale gas production in the UK will rely on importing both labour and equipment from overseas, probably the US, given its position as market leader. This is in stark contrast with the potential economic and job creation benefits, which low-carbon technologies such as marine renewables could bring to the UK as highlighted by the Committee on Climate Change (CCC) in its Building a Low Carbon Economy report.[35] We discuss this point further in our response to question 1 of the ECC enquiry on the Electricity market reform.

To conclude, as the CEO of Cuadrilla Resources admitted in a recent ENDs report[36] article "there is no chance of a shale gas rush in Europe over the next few years". Gény adds in the conclusion to her report that "Europe cannot replicate much of the American model".[37] This casts strong doubt on any speculation that shale gas may increase UK energy security or may play a "bridging" role as the in the decarbonisation of the UK and EU power sectors.

Question 2: *What are the implications of large discoveries of shale gas around the world for UK energy and climate change policy?*

Overview

For there to be a reasonable chance of global temperature increases not exceeding two degrees Celsius and some possibility that they may remain below 1.5 degrees, global greenhouse gas (GHG) emissions need to fall by 80% relative to 1990 levels by 2050. From a climate change perspective whilst it makes sense to burn lower carbon fuels such as gas, rather than coal, this argument is only valid where there is evidence that gas is being used as a direct substitution, not in addition, to coal and also as part of a clear plan to substantially reduce the power sector's overall dependence on fossil fuels. There is a risk that the lower emissions argument is used to mask the fact that increased supplies of gas from shale result in a net increase in global emissions and serve to undermine the much needed transition to renewables. The majority of the world's fossil fuel reserves need to stay in the ground if we are to avoid catastrophic climate change.

In the UK context, the 2008 Climate Change Act commits the UK to at least an 80% reduction in domestic GHG emissions by 2050. The CCC, tasked with setting out recommendations on carbon budgets, recommends in its 4th budget report that the UK power sector should be close to decarbonised by 2030 with an average carbon intensity of $50gCO_2$/kWh compared to approximately $500gCO_2$/kwh today.[38] The same report also advises that to be on track to meet the 2050 target, GHG emissions should be 60% below 1990 levels by 2030. To achieve its targets, the UK needs to reduce its dependence on both gas and coal and move towards rapid decarbonisation of the power sector.

Shale gas, prices and global markets

A key focus for UK energy policy should be to deliver a near-decarbonised power sector over the next 20 years, whilst ensuring continued security of supply in a way that minimises increases to consumer bills. **There is strong evidence, which we outline below, that uncertainty over the future contribution of shale to**

[30] Ibid p66
[31] IEA, 2009, World Energy Outlook (Paris:International Energy Agency)
[32] http://www.tyndall.ac.uk/shalegasreport p70 430–500 well pads would be required to deliver 9bcm per year of shale gas. We have assumed 6 wells per pad—the figure used in the report.
[33] Stevens, P. 2010. The 'Shale Gas Revolution' Hype and Reality. Chatham House.
[34] Geny see 6 p96
[35] http://hmccc.s3.amazonaws.com/CCC_Low-Carbon_web_August%202010.pdf page 15
[36] http://www.endsreport.com/26207
[37] Geny, F. 2010 Can Unconventional Gas be a Game Changer in European Gas Markets?
[38] http://www.theccc.org.uk/reports/fourth-carbon-budget different figures exist for the current carbon intensity of UK electricity generation. This is a mid point of the various estimates.

global gas supplies may threaten UK security of supply and lead to significantly higher and fluctuating gas prices.

There has recently been speculation that the world may be entering a new era of cheap gas due to the US "shale" revolution. We have seen a delinking of oil and gas prices for the first time in decades. Gas prices are therefore currently relatively low due to a combination of unforeseen rapid expansion in US shale gas production and overinvestment in Liquid Natural Gas (LNG) and other conventional gas capacity.

There is however, strong evidence that current low gas prices may be temporary and therefore any second "dash for gas" could harm not only the UK's prospects for meeting climate change targets but also affordability and potentially security of supply. For example, in a 2010 Chatham House report, Paul Stevens notes that "given investor uncertainty, investment in future gas supplies will be lower than would have been required had the shale gas revolution not happened…if it fails to deliver on current expectations…in ten years or so gas supplies will face serious constraints".[39] Stevens then expresses doubt over whether the shale gas "revolution" can spread beyond the US, or even be maintained within it.

Furthermore, even if shale gas production does expand it is highly unlikely that gas prices will remain low. Frank Harris of Wood Mackenzie is recently quoted in The Economist[40] saying that some of the downward pressure on price will ease. "Despite sedate growth, the LNG glut should dissipate, probably by 2014, says Mr Harris; and low prices will kill more projects, clearing the inventory". This is echoed in Gény's report where she says that "we believe it is only a question of time before costs drive up prices or drilling slows down significantly and production falls".[41] Gas prices therefore appear to be low, because the increase in shale gas production has surprised investors and led to an oversupply of gas. Therefore as the market corrects itself prices are likely to rise, possibly leading to a shortage of gas.

Policy implications and recommendations

Given the impacts of shale on gas markets described above, and the doubts raised in our response to the previous question regarding limited prospects for shale gas in the UK, it **is clear that any expectation that shale gas will necessarily enhance UK security of gas supply or guarantee lower prices for consumers is seriously flawed.**

As highlighted throughout this paper any change to UK energy policy due to either temporary low gas prices or future shale gas production in the UK would be extremely risky and probably delay investment in low carbon technologies. This could risk damaging the UK's ability to meet its climate change and energy security targets. The UK government has recognised that the current structure of the UK's energy market is not fit for purpose if the UK is to substantially decarbonise its power sector, which has led to the current Electricity Market Reform (EMR) consultation. WWF-UK is strongly of the view that the principal purpose of the EMR should be to deliver a near-decarbonised power sector by 2030. The EMR should aim to deliver this objective in the most environmentally sustainable way possible, by relying as much as possible on sources of energy that have the fewest environmental side effects, such as renewables.

Whilst the CO_2 emissions from burning natural gas from shale are almost certainly[42] lower than those from coal, the average emissions from a new gas CCGT power station are around eight times higher than the CCC's recommended target of 50gCO_2/kWh by 2030.[43] Any new gas power stations built today will continue to run for around 25–30 years. **Whilst WWF accepts that some gas generation will be required as flexible back up to the UK's power system in the future and that some gas with CCS may be part of the supply mix,** we are concerned that future large discoveries of shale gas could have the impact of delaying investment in areas where it is really needed, in particular marine renewables, co-ordinated grid, energy efficiency and interconnection infrastructure.

Question 3: *What are the risks and hazards associated with drilling for shale gas?*

There are many negative environmental impacts and serious health and safety concerns associated with shale gas production. Due to the rapid expansion of the shale gas industry in the US and Canada, against a backdrop of weak environmental regulation, many implications are currently poorly understood, carry huge risk and require significant further investigation.

Contamination

There is strong evidence that shale gas production can cause contamination of water sources such as aquifers. Aquifers provide 30% of the UK's water and significantly more than this in the south east.[44] This contamination is mainly from methane but there are also serious concerns about the other substances and

[39] http://www.chathamhouse.org.uk/files/17317_r_0910stevens.pdf
[40] http://www.economist.com/node/15661889
[41] Geny, F. 2010 Can Unconventional Gas be a Game Changer in European Gas Markets? http://www.oxfordenergy.org/pdfs/NG46.pdf,
[42] we have addressed this point more thoroughly below
[43] http://www.theccc.org.uk/reports/fourth-carbon-budget
[44] http://www.waterbank.com/Newsletters/nws17.html

chemicals (including known carcinogens such as benzene)[45] used in the fracking process. Some in industry claim that contamination is not possible because shale gas drilling takes place beneath the deepest fresh water zones and special casing in the drill hole is used to isolate fresh water zones from contamination.[46] However, there is a substantial and growing body of evidence to indicate that contamination is occurring and that it is caused by the drilling and fracking processes. According to Abrahm Lustgarten of ProPublica "more than 1,000 cases of contamination have been documented by courts and state and local governments in Colorado, New Mexico, Alabama, Ohio and Pennsylvania".[47] These are only five of the many states where shale gas production is currently underway.

There are several ways in which it is thought that contamination may occur. Whilst it is not possible to go into much detail here, there is evidence that the drilling process itself, inadequate casing of drill holes, unintended "communication" between separate wells (where fracking fluids from one well have shown up in another up to 715m away)[48] and pathways opened up through the fracking process which join up with natural cracks in the rock are all potential sources of contamination. Anthony Ingraffea, a professor of civil and environmental engineering at Cornell University and a member of the Cornell Fracture Group, is quoted in a paper by Ben Parfitt saying that "it is possible that the fracking process could open up a pathway upwards to freshwater...it is not right to say that thousands of feet of impermeable rock between where the shale formation is fracked and points higher up prevents such an occurrence".[49]

As a result of growing concern about contamination and public opposition to shale gas, the US Environmental Protection Agency is currently investigating the links between hydraulic fracturing, drinking water quality and potential impacts on public health to inform potential new regulations. The results of this study are due in 2012. In addition, draft legislation called the FRAC act has been proposed to congress.

Well Blowouts

According to Gény,[50] there have been two recent consecutive well blowouts in the Marcellus shale area in the US. One such incident occurred in Clearfield County, Pennsylvania at a well operated by EOG Resources Inc where natural gas and drilling fluids were shot 23 metres into the air.[51]

Water Consumption

Shale gas production is known to be very water intensive. Estimates for the volume of water required from start to finish of the fracking operation vary significantly probably due to lack of reliable data and differences in depth and geology of shale plays. For example an estimate in Parfitt's paper states that hydraulic fracturing of 10 shale gas wells requires circa 910,000 cubic metres of water which equates to 91,000m^3 per well.[52] However, according to the recent Tyndall Centre report "the entire multi-stage fracturing operation for a single well requires around 9,000–29,000m^3".[53] More research is needed on the actual quantities required and the impact of site specific variables on final water requirement.

According to the Environment Agency's Catchment Abstraction Management Strategies (CAMS) "there are considerable pressures on water resources throughout England and Wales".[54]

Disposal and Treatment of fracture fluids

Of the large volume of water used in the fracking process around 60% "flows-back" (although flow back rates appear to vary significantly) as contaminated wastewater which must be disposed of. This wastewater is highly saline with a high mineral content and is contaminated with chemicals used in the fracking process, including known carcinogens in the US context, and heavy metals.[55] Assuming Gény's figure that c91,000 cubic metres of water are required for each well this equates to around 54,600 cubic metres of wastewater per well. It is possible to recycle wastewater and should shale gas production take place in the UK this should be mandatory.

45 Parfitt, B. 2010. Fracture Lines: Will Canada's water be protected in the rush to develop shale gas?

46 Ibid

47 Lustgarten, Abrahm. November 13, 2008. "Buried Sectrits: Is Natural Gas Drilling Endangering U.S. Water Supplies?" ProPublica..

48 http://www.ogc.gov.bc.ca/document.aspx?documentID=808&type=.pdf

49 Parfitt, B. 2010. Fracture Lines: Will Canada's water be protected in the rush to develop shale gas?

50 Geny, F. 2010 Can Unconventional Gas be a Game Changer in European Gas Markets? http://www.oxfordenergy.org/pdfs/NG46.pdf,

51 http://www.businessweek.com/news/2010–06–07/shale-gas-well-blowout-raises-specter-of-new-bp-energy-markets.html

52 Parfitt, B. 2010. Fracture Lines: Will Canada's water be protected in the rush to develop shale gas? http://www.powi.ca/pdfs/groundwater/Fracture%20Lines_English_Oct14Release.pdf quoting a presentation to the sixth annual shale gas conference in Calgary, Alberta in January 2010, by Ken Campbell, a professional geologist and senior hydrologist with Schlumberger Water Services.

53 http://www.tyndall.ac.uk/shalegasreport p21

54 http://publications.environment-agency.gov.uk/pdf/GEHO1208BPAS-e-e.pdf

55 Parfitt, B. 2010. Fracture Lines: Will Canada's water be protected in the rush to develop shale gas? http://www.powi.ca/pdfs/groundwater/Fracture%20Lines_English_Oct14Release.pdf quoting Lee Shanks of the British Columbia Oil and Gas Commission.

Like the actual drilling and fracking process, wastewater has been linked to incidents of water contamination.[56] The treatment and disposal of this contaminated wastewater is a contentious issue. Wastewater is usually stored in open pits or tanks prior to treatment. Gény states that "Because of the large quantities of waste to be handled, the risks of contaminating surface water and soil during storage, transport and disposal are very high".[57] Concerns have also been expressed in the US over contaminated wastewater being sent to municipal facilities.

According to the website for the shale gas documentary Gaslands, whilst the wastewater is being stored in pits or tanks, Volatile Organic Compounds (VOCs), a known health risk, are "evaporated". "As the VOCs are evaporated and come into contact with diesel exhaust from trucks and generators at the well site, ground level ozone is produced. Ozone plumes can travel up to 250 miles".[58] The transportation of such large volumes of water requiring treatment also puts additional strain on local infrastructure.

Infrastructure and impacts on local communities

The drilling process requires large volumes of water, sand and chemicals as well as heavy industrial equipment to be transported to the site. Waste products such as drilling mud and wastewater much of which is likely to be classed as hazardous waste[59] will then need to be removed. Wells are often arranged in "pads" of 6 wells grouped together. Each well will therefore require access roads to be built placing unforeseen demands on local transport infrastructure. The Tyndall Centre's report demonstrates that 4,315–6,590 truck journeys to each well pad will be required in the pre-production phase, of which 90% are associated with the fracking process.[60]

Noise pollution is also likely to be an issue both from trucks travelling to and from the site and pre-production activities, which the Tyndall Centre report indicates could be expected to last 500–1500 days, including several weeks of 24 hour drilling per well, for each 6 well pad.[61]

The UK is far more densely populated than North America. Even without taking into account possible contamination issues, shale gas production is clearly likely to be highly disruptive to local communities and have a negative impact on local roads, buildings adjacent to access roads, noise levels and air quality.

Regulation

UK and EU regulation of the oil and gas industries is more stringent than that of the US. However, according to a recent ENDS report article fracking is not mentioned in UK regulations. A spokesperson from the Environment Agency told WWF that "the Environment Agency is currently developing policy at the national level on shale gas permitting" and that "fracking" will probably not be able to go ahead without a permit.

It is clear that there are significant risks associated with allowing any shale gas production to take place in the UK. Large scale shale gas production has been allowed to take place in the US prior to any impartial research over its impacts on human health and the surrounding environment being conducted. New York State has recently imposed a moratorium on any new drilling of shale gas wells pending the outcome of the current US EPA investigation. There is therefore considerable uncertainty as to the full extent of the environmental impact of shale gas exploration in the US.

Conclusion

Taking into account all the environmental impacts described above WWF does not believe that shale gas production should be allowed to take place in the UK. At the very least, WWF considers that no permits should be granted for shale gas activity in the UK until there is a robust scientific consensus demonstrating exactly what the risks are and what, if any, practices may be adopted to minimise hazards associated with shale gas, drilling and hydraulic fracturing.

Question 4: *How does the carbon footprint of shale gas compare to other fossil fuels?*

There is very limited publicly available information on the carbon footprint of shale gas in relation to other fossil fuels. Emissions may be higher than those associated with conventional gas due to methane leakage or the additional energy requirements of unconventional sources of gas such as shale. It is therefore important to take into account the full lifecycle emissions of the use of shale gas before drawing any conclusions as to its carbon intensity.

The Tyndall report estimates additional carbon footprint of shale gas and production and draws the conclusion that additional emissions would be around 0.2–2.9% higher than those associated with gas from conventional sources. However, it is highlighted that the impact of fugitive emissions, for example leakage of

[56] Parfitt, B. 2010. Fracture Lines: Will Canada's water be protected in the rush to develop shale gas?
[57] Geny, F. 2010 Can Unconventional Gas be a Game Changer in European Gas Markets? http://www.oxfordenergy.org/pdfs/NG46.pdf,
[58] http://www.gaslandthemovie.com/whats-fracking/
[59] http://www.tyndall.ac.uk/shalegasreport P58
[60] Ibid p24 and p70
[61] Ibid p23 and 70

methane gas during production, were not taken into account in this estimate.[62] This is significant because these emissions are cited in a preliminary review paper by Robert Howarth which suggests that there is approximately a 1.5% methane leakage rate for the oil and gas industry and that therefore emissions from coal may be similar to those from natural gas.[63]

Howarth's is only a preliminary paper which has not been peer reviewed but it highlights the **urgent need for a comprehensive assessment of the full range of emissions of greenhouse gases from using natural gas obtained by "hydrofracking"**. Clearly, this information must be independent and subject to unbiased peer review.

January 2011

Memorandum submitted by the Environment Agency

Summary

The Environment Agency welcomes the opportunity to provide evidence to the Energy and Climate Change Select Committee's inquiry into shale gas.

We believe that there is a robust regulatory regime in place to ensure any environmental impacts from unconventional gas exploration are minimised. Environmental concerns are addressed by our staff on a site by site basis as we assess the need for, and respond to, applications for environmental permits.

1.0 Introduction

The Environment Agency is responsible for granting environmental permits and has powers to serve notices where required to protect the environment. We are a statutory consultee in the planning process and will provide advice to Local Authorities on individual shale gas extraction sites. We apply a proportionate and risk-based approach to preventing pollution and protecting the environment

2.0 Environmental Permitting of Unconventional Gas Exploration

A permit under the Environmental Permitting Regulations 2010 (EPR) is required where fluids containing pollutants (substances liable to cause pollution) are injected into rock formations that contain groundwater (a "groundwater activity" under EPR). An environmental permit may also be needed if the activity poses a risk of mobilising natural substances that could then cause pollution. The permit, if granted, will specify limits on the activity and any requirements for monitoring. All Environment Agency environmental permits are placed on the public register.

If we decide that the activity poses an unacceptable risk to the environment, we will not issue a permit and if necessary we may issue a notice under EPR to prohibit it. If we decide that the activity cannot affect groundwater, a permit will not be necessary. The Water Framework Directive and EPR defines groundwater as all water which is below the surface of the ground in the saturation zone and in direct contact with the ground or subsoil. Under statutory guidance it is for the Environment Agency to decide whether groundwater is present and whether a groundwater activity is taking or will take place. Each proposal will be assessed on a site by site basis.

The environmental permit will also place a general management condition on the operator to provide a written management system that identifies and minimises risks of pollution. This will include activities at the surface, such as the storage and disposal of chemicals.

We may also:

- Issue a permit for activities associated with the surface works, or with the final production of gas/oil, if these involve emissions to surface or groundwater.
- Serve notices for aspects of the operation that would not normally be subject to EPR, such as the drilling of the borehole. This would require the operator to cease an activity or apply for a permit if we consider it warranted.
- Advise on any requirement for controls needed where the operation has the potential to impact water resources, for example, due to the effect on groundwater levels and flows. We expect operators to notify us of their intention to carry out drilling, at which time we will advise on any requirement for control under the Water Resources Act 1991.
- Consider any application for a water abstraction licence should a direct supply of water be needed by the operator. This would only be granted where sustainable water resources are available.

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62 http://www.tyndall.ac.uk/shalegasreport P73

63 Howarth, Robert W. 2010. Preliminary Assessment of the Greenhouse Gas Emissions from Natural Gas obtained by Hydraulic Fracturing.

3.0 Environment Agency Involvement at Existing Operations

The Environment Agency has assessed the permitting requirements for one exploratory shale gas activity operated by Cuadrilla Resources in North West England. Local Environment Agency staff have assessed the potential impact of Cuadrilla's operations on the water environment and have decided that, at present, it does not require permitting under the EPR. This is a site specific decision. Our local staff have determined that the activity currently planned does not require a permit because:

- There is no groundwater in or around the deep shale formation. The formation has a very low permeability and therefore is not considered part of the saturation zone so will not contain "groundwater", as defined by the Water Framework Directive and EPR.
- There are no vulnerable near-surface aquifers.
- There are no nearby surface water features such as streams, rivers or lakes.

If Cuadrilla's operation changes they will need further planning permission and we will review whether it needs a permit under EPR.

Local Environment Agency staff have been consulted on several proposals for coal bed methane exploration, including the joint venture by Nexen and Island Gas near Warrington. At present, we have decided that the exploration boreholes do not require a permit because there is no groundwater activity taking place. We obtain detailed information from the operators to satisfy ourselves that any sensitive aquifers are adequately protected.

4.0 Chemical Composition of Fracturing Fluid and Risk to the Environment

Where there is insufficient natural permeability in the shale or coal for the extraction of gas, this can be enhanced by pumping a fluid into the borehole at pressure. Typically, the injected fluid contains sand which is used to prop open the fractures to maintain the enhanced permeability. The fluid is mainly water but small amounts of other substances may be added. Overall, the process can involve the injection and return of significant volumes of fluid.

We require operators to tell us about any activities that potentially involve the discharge of pollutants into the ground and the nature of those pollutants so that we are able to make informed decisions about whether the activity permit. We have powers if necessary under EPR to require such information.

Cuadrilla are intending to use mains drinking water supplied by United Utilities. As part of hydraulic fracturing they may add glutaraldehyde, FR-40 (a polyacrylamide blend) and dilute hydrochloric acid. The fluid will be pumped three kilometres below the ground into a low permeability shale formation. At the current Cuadrilla site our staff consider that there is a very low risk from these chemicals because there is no groundwater in or around the deep shale formation and there is a low risk of the chemicals migrating upwards and having an adverse impact on the environment.

The Water Framework Directive (WFD) aims to protect and improve the water environment. The Environment Agency is the competent authority for implementing the WFD in England & Wales. The Directive allows some direct discharges of pollutants into groundwater with conditions (Article 11(3)j). Cuadrilla's operations will not be affected by this because there will be no discharge of pollutants into groundwater, as noted earlier. Dependent on what is proposed, other shale gas sites and proposals for Coal Bed Methane exploitation may involve the direct discharge of pollutants into groundwater and Article 11(3)j may then apply. A permit under EPR will be required for these activities to meet WFD objectives and to protect the water environment.

5.0 Conclusions

The Environment Agency considers that the current regulatory framework is sufficiently robust to minimise any risks to the environment that may arise from shale gas and coal bed methane operations. We are also in dialogue with other regulatory bodies on these matters.

March 2011

Supplementary memorandum submitted by the Environment Agency

Q1 *How will the Environment Agency monitor emissions from shale gas exploration and production including NOx, volatile organic compounds, particulate matter, SO_2, and methane?*

The Environment Agency will not normally monitor emissions to air from shale gas exploration and production activities because the activities will not normally require a permit issued by the Agency under the Environmental Permitting Regulations (EPR) 2010 for emissions to air.

Such a permit will only be required if the activities involve the refining or large scale combustion of gas as described below:

> **Refining of gas:** We expect that shale gas will normally be pure enough not to need refining. However if it is refined then an EPR permit will be required for emissions to air. The Environment Agency will be the regulator if the quantity refined exceeds 1,000 tonnes per year and the local authority will be the regulator if it is less than 1,000 tonnes per year.
>
> **Combustion of gas:** We expect that shale gas will only be burned on a small scale (less than 20 megawatts (MW) thermal input). However if it is burned on a large scale then an EPR permit will be required for emissions to air. The Environment Agency will be the regulator if the combustion plant has a thermal input greater than 50 MW and the local authority will be the regulator if it is between 20 and 50 MW.

If the activities did require an EPR permit for emissions to air the operator would be required to monitor emissions of oxides of nitrogen, volatile organic compounds, sulphur dioxide and methane. The permit issued to the activity would have due regard to the Government's Air Quality Strategy. Monitoring results would be reported to the regulator. In addition the regulator could carry out its own monitoring.

Where there is no requirement for a permit, there will be controls under Part III of the Environmental Protection Act 1990 in relation to statutory nuisances, and under health and safety legislation as regards safeguarding the workforce from emissions. Local authorities are responsible under the 1990 Act for inspecting their areas for nuisance—including odour and noise associated with the venting or flaring of gas. The Health and Safety Executive will ensure safe operation at both exploration and production phases (eg by minimising releases and the flaring of vented gases) and these controls may also have an environmental benefit.

Q2 *Is the Environment Agency concerned by the production and storage of volatile "wet gas" or "gas condensates" produced along with shale gas?*

No. We expect most shale gas wells to produce a high quality gas that will not need refining so there will be no gas condensates produced.

However, the composition of Shale Gas varies on a site by site basis depending on the underlying geology, with some being "wetter" than others. If the shale formation produces a "wet gas" operators will need to refine gas before injecting it into a natural gas pipeline. If "wet gas" is combusted on-site, it will require a permit as described in the answer to Question 1.

Q3 *How will gases and waste water produced during well completion (when the well bore is made free of debris, gas, and water prior to production) be dealt with?*

Operators will require a permit from the Environment Agency under EPR 2010 in advance of beginning the production phase where:

- drilling activities may have an impact on a groundwater resource;
- certain onsite activities (eg refining and/or large scale combustion of gas) are taking place; and
- operators wish to discharge waste or waste water to the environment.

The Environment Agency will not normally regulate the emissions of gases produced during well completion. However we can make recommendations during the planning application process to ensure the well design and construction minimises any environmental impacts.

Waste water treatment and disposal options will vary depending on the nature of the waste and local environmental conditions. The Environment Agency will assess this on a case by case basis and in accordance with the EPR 2010.

- An environmental permit would be required for a discharge into a surface environment, for example to a local watercourse. Pre-treatment is likely to be needed to ensure the discharge can meet environmental standards.
- Operators may be allowed to dispose of waste water back into the strata from which it has been extracted, subject to environmental safeguards and providing only waste directly from the shale gas extraction operation is involved.
- If groundwater is present in the strata then the disposal would become a groundwater activity under EPR 2010 and a permit would be required.
- Where an operator needs to transfer waste fracking water offsite for treatment, they will need to satisfy any conditions required by the waste receiver/treatment facility, who in turn will be operating under an environmental permit. It will be necessary for the waste receiver to ensure that the waste is suitable for treatment at their facility and that they can continue to meet their own responsibilities under the legislation.

Q4 *Is the Environment Agency aware of "green completion" technology and equipment developed in the US that allows such emissions to be captured (and then sold)?*

The Environment Agency has not yet encountered "green completion" technology since there has not yet been any commercial development of shale gas in the UK. In the event that an operator would need a permit under EPR 2010 from the Environment Agency, we would require operators to use Best Available Techniques for the management of shale gas emissions and/or the disposal of waste fracking water. The operator wants to sell the natural gas so it will be in their commercial interests to minimise gas releases into the air, and to maximise the reuse of water.

April 2011

Supplementary memorandum submitted by the Geological Society of London in response to follow-up questions

Further to the written submission of the Geological Society to the Committee's inquiry into Shale Gas, Dr Jonathan Craig appeared at the oral evidence session on 1 March, in his capacity as chair of the Petroleum Group of the Society. Subsequently, the chair of the Committee wrote to him with further questions. The responses below have been prepared in discussion with Dr Craig, and are presented on behalf of the Geological Society.

1. *Is shale gas more likely to be a regional rather than a national phenomenon in the UK, ie is shale gas more likely to be locally distributed than transmitted nationally?*

Two distinct considerations should be taken into account: geology (regionality of occurrence of the resource) and distribution (regionality of use).

First, the size and geographical location of shale gas resources in the ground is dependent on the geology, which varies from area to area. So the physical occurrence of shale gas in the ground is by its nature a regional phenomenon. In particular, some UK hydrocarbon basins are more likely to yield shale gas than others. The Midland Valley of Scotland, for instance, is more promising than the Grampian Highlands in this regard, as the rocks in the latter do not have the characteristics necessary to produce shale gas. The essential conditions for the occurrence of shale gas are relatively unstructured sedimentary basins which include a shale section of sufficient thickness (10s to 100s of metres) and thermal maturity, with high TOC (Total Organic Content) (>1%), preferably liquid-prone and overpressured, typically at depths of less than 3,500 metres. More is known about the geology of the UK than that of almost anywhere else in the world—but while we know that there is potential for shale gas, and we have a great deal of background data, we do not know whether it is economically viable, because past exploration has not been carried out with the objective of identifying shale gas resources. Exploration for this specific purpose remains in its early stages.

Second, once shale gas is extracted from the ground, its means and ease of distribution is a matter of the technology, engineering and economics of the gas grid. Shale gas and other forms of "unconventional" gas, once they have been extracted from the ground, are no different from "conventional" natural gas, and hence the factors affecting its distribution are the same. (It is the location, the nature of the reservoir rocks, and the concomitant means of extraction of gas which cause it to be considered "conventional" or "unconventional"—though as pointed out in our previous written evidence, these terms are not clearly defined.) The technical and economic factors affecting operation of the gas grid are outside our area of expertise, and we offer no comment on them, but assuming that these do not present a barrier there is no reason that the use of gas need be regionally restricted. However, as noted below, there may be benefits in using locally produced gas to supply local needs (see question 4).

2. *How difficult is it in the UK for new entrants to contribute gas to the grid?*

The relevant factors regarding grid technology, engineering and economics (including system pressures, spare capacity, market structures and regulation) are outside our area of expertise, and we cannot comment.

3. *Is the higher population density in the UK, compared to the US, a barrier to shale gas exploration?*

We take this question to refer to both exploration and production of shale gas. It is important to consider both physical and social/psychological potential barriers.

To some extent, there is greater physical restriction on the development of shale gas resources in the UK compared to the US, because of greater competition for land use in many areas, and the greater likelihood of proximity of a gas field to population centres. These restrictions can be mitigated to some degree by the use of horizontal well drilling and "superpads" (also known as "multipads"—rather than drill evenly spaced vertical wells, a group of wellheads is clustered together, and the well shafts "splay out" into the gas field below). This is more expensive, but the additional cost may be offset by the reduced economic and social costs associated with land use. Such methods have been used in the US, in some instances allowing drilling to take place under populated or build up areas, such as Dallas/Fort worth airport.

There is also likely to be a greater social and psychological barrier to the development of shale gas in the UK. Open spaces may be more highly valued in light of their relative scarcity, bringing a greater public and regulatory determination to protect them. Significant parts of sparsely populated land are protected as National Parks, Areas of Outstanding Natural Beauty, etc. However, the UK hydrocarbons industry has demonstrated that it can successfully exploit resources in such areas while meeting the highest environmental and social standards. Wytch Farm, the largest onshore oil field in Western Europe, discovered by British Gas in the 1970s and operated by BP since 1984, is located in one of the world's most famous and sensitive regions of outstanding beauty and natural interest (not least because of its geology and geological heritage), which includes the Jurassic Coast World Heritage Site, designated wetlands of international importance, and national nature reserves. BP has set world standards in environmental protection and community engagement, using horizontal drilling at distances of more than 10km, keeping the size of well sites and other facilities to a minimum, using innovative design, and screening them with trees, for instance, in order to minimise environmental and visual impacts.

As identified in our earlier written evidence, the difference between the UK and US planning regimes is also a significant factor.

4. *How can the UK public be convinced to accept the impacts of onshore shale gas exploration and production?*

Historically, the hydrocarbons industry has often not done as good a job as it could in communicating with the public and decision makers the benefits and the challenges of unconventional gas exploitation, and of building confidence and trust. Decision makers have frequently found themselves in the position of making judgments on the basis of poor knowledge, and sometimes inaccurate or misleading information from a variety of different sources. Responsible and forward looking oil and gas companies recognise the onus on them to behave accountably and transparently, and to provide evidence about their exploration and production plans and their likely impacts to the public and to policy makers. Given the current poor public perception of industry credibility in this regard, there is the potential for learned and professional bodies and academia to play a role in building trust and brokering dialogue.

The industry also faces some challenges in communicating with the public which are beyond its control. In particular, inaccurate assertions made by some environmental campaigning groups may not be subject to the same levels of scrutiny and testing as the public statements of oil and gas companies, and the dissemination of such assertions through the media stands in contrast to the high levels of rigour and quality control achieved through the application of peer review to the pronouncements of professional scientists. It is incumbent on policy makers, responsible media organisations and scientific bodies such as learned societies to encourage open and balanced public debate about how we are to meet our energy needs in the context of affordability, security and environmental change, and to hold to account those on all sides of this debate.

Public concern over such matters might helpfully be addressed by challenging the implicit assumption that the extraction and use of resources are aimed at providing "somebody else's energy". There is often a disconnect between local infrastructure projects, which may arouse opposition, and the provision of one's own services. This perception is less likely to arise where installations predominantly meet local needs. For example, in countries where CHP (Combined Heat and Power) plants are common, these are often located near to population centres, the energy needs of which are met in part by the heat generated, lending to a higher level of public acceptance of such plants. If shale gas were to be used to supply local energy needs (eg if the Bowland Trough or Fylde area were seen to be providing a service to Blackpool and the surrounding conurbations), such development might be regarded more positively. This is consistent with a holistic system approach to energy resources, as outlined in our previous written evidence.

5. *What more should the Government do if it wanted to support unconventional gas?*

The fundamental driver for exploitation of hydrocarbon resources, conventional or otherwise, is price. If such activity is profitable, or has sufficient potential to be so, companies will make the necessary investment—and at present, a number of companies are demonstrating their willingness to invest in UK exploration for unconventional gas. If Government should wish to influence resource prices in order to stimulate investment, several policy instruments are available to it, including subsidies for particular resources or technologies, feed-in tariffs, tax breaks, regulation, and carbon pricing. Policy with respect to unconventional gas should be seen in this context, as one aspect of energy policy and macroeconomic policy more generally. It is beyond the scope of this document for the Society to comment on such matters (and largely outside our area of competence, although many of our Fellows in industry will have informed views on issues such as the likely efficacy and unintended consequences of particular policy measures). Factors which might lead Government to favour one resource type over another might include energy security—for example, if growing domestic shale gas production were seen as likely to reduce dependence on gas imports (conventional or otherwise) from particular countries. Intervention to stimulate investment might also be prompted by considerations outside energy policy, as usually understood, including employment and training.

To ensure that best use is made of domestic resources and that the UK shares in the economic and service value of global resources, it is vital to ensure the continued excellence of the UK's world-leading Earth science research base and the supply of high-quality trained personnel.

Other issues such as the planning regime (which can also be regarded as being a cost factor) and ensuring balanced and open public debate have been addressed elsewhere.

6. *Are tax breaks necessary to stimulate the shale gas industry, as in the US?*

As noted above, tax breaks are one of the policy instruments available to government to influence price.

7. *Will the lack of an onshore service industry hinder development of unconventional gas in the UK and Europe?*

The phrase "service industry" is broad and rather vague. The Earth science community tends rather to think of what might be termed the "geoscientific service industry" which supplies geological consultancy and expertise to hydrocarbons companies with regard to exploration and production. (Such expertise and services derive from academia and government, specifically through the activities of the British Geological Survey, as well as from industry *sensu stricto*.)

Although there is little history of unconventional gas exploration and production in the UK, there is no reason to think that the requisite service industry is a limiting factor. UK service industry geologists are among the best in the world. As noted above, there is no intrinsic difference between conventional and unconventional gas, and the geological understanding required in each case is shared. It is true that the service industry required to support the particular technologies of horizontal drilling and hydraulic fracturing of wells is less developed in Europe in comparison to the US, but this is unsurprising given the immaturity of the unconventional gas industry in Europe. The determining factor here is not whether development takes place onshore or offshore, but what activity is required to enable it to happen. The service industry supporting these technologies in Europe is sufficient for the current testing phase. The expertise for this industry to develop is not likely to be a limiting factor, and if they perceive that they can derive value from a growing onshore unconventional gas industry in Europe, companies will position themselves accordingly.

The successful operation of Wytch Farm, referred to above, which set new records for horizontal directional drilling distances, both demonstrates the fitness for purpose of the UK service industry for horizontal drilling (and for onshore development), and constitutes a site for learning from best practice.

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