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Electricity Costs: The folly of wind-power

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January 2012

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Executive summary

- Britain's energy policies are heavily influenced by the Climate Change Act (2008) and the EU's Renewables Directive (2009). Under the Climate Change Act Greenhouse Gas (GHG) emissions are to be cut by 34% by 2018-22 and by 80% by 2050 compared with the 1990 level. These are draconian cuts. Under the Renewables Directive Britain is committed to sourcing 15% of final energy consumption from renewables by 2020. (Chapter 1)

- These commitments add to energy costs and undermine business competitiveness. (Chapter 1)

- Britain's zeal in cutting carbon emissions should be seen in a global context. Britain's CO_2 emissions are about 1.5% of the world total and even the EU27's share is only 12% of the world total. No other major emitters have binding policies to cut back their emissions. China's emissions are, for example, rising quickly. (Chapter 1)

- Using estimates on the costs of electricity generation compiled by engineering consultants Mott MacDonald (MM) (chapter 2):
    - Excluding carbon costs, coal-fired power stations are the least expensive technology for generating electricity for both near-term and medium-term projects.
    - Including carbon costs, gas-fired power stations are the cheapest option for near-term projects, but nuclear power is the least expensive in the medium-term. Other things being equal this would suggest that investment should be concentrated in gas and nuclear technologies. A mix of technologies is preferable for operational reasons. Coal-fired power stations become relatively uneconomic, reflecting the heavy carbon costs, especially in the medium-term.
    - Onshore wind looks relatively competitive on the MM data. But MM exclude the additional costs associated with wind-power. When allowance is made for these additional costs, the technology ceases to be competitive for both near-term and medium-term projects.
    - Offshore wind (even before allowing for additional costs) and Carbon Capture and Storage (CCS) technologies are inordinately expensive.
- Nuclear power and gas-fired CCGT are therefore the preferred technologies for generating reliable and affordable electricity. There is no economic case for wind-power. (Chapter 2).

- Wind-power is also an inefficient way of cutting CO_2 emissions, once allowance is made for the CO_2 emissions involved in the construction of the turbines and the deployment of conventional back-up generation. Nuclear power and gas-fired CCGT, replacing coal-fired plant, are the preferred technologies for reducing CO_2 emissions. (Chapter 3)
- Wind-power is therefore expensive (chapter 2) and ineffective in cutting CO_2 emissions (chapter 3). If it were not for the renewables targets set by the Renewables Directive, wind-power would not even be entertained as a cost-effective way of generating electricity and/or cutting emissions. The renewables targets should be renegotiated with the EU.

Chapter 1:
Energy policy and climate change

Introduction

Economic growth, or the lack of it, is now central to any economic debate. On a related issue, Britain has lost competitiveness since the late 1990s. One of the most authoritative sources of comparative material on competitiveness is the World Economic Forum (WEF), which compiles an index of competitiveness, a weighted average of a large range of relevant social and economic indicators. The WEF's *The Global Competitiveness Report for 2011-12* showed the UK in 10th position, well down on the UK's ranking in 1998, when it was fourth.[1]

The British economy needs a really radical growth strategy in order to reverse the lost competitiveness experienced since 1998 and stimulate the economy.[2] One area which should be tackled is energy policy, where "green policies" are adding to business's costs, especially manufacturing.[3] The Autumn Statement included some growth measures, including some help on energy costs for energy intensive industries, but they were far too modest.[4]

Energy policy and climate change: CO_2 emissions

The latest DECC estimates for the costs of "green policies" are shown in table 1. They show, for example, that such policies could be adding 45% to electricity costs by 2030 for medium-sized business users, on DECC's central case.[5,6] In 2009 the estimates of the green "add-ons" were, if anything, higher.[7]

Table 1: Estimated impacts of energy & climate change policies on average electricity prices, 3 scenarios

	2011	2020	2030
Household:			
Low fossil fuel prices	15%	41%	37%
Central case	15%	27%	28%
High fossil fuel prices	15%	21%	17%
Medium-sized business users:			
Low prices	22%	51%	58%
Central case	22%	34%	45%
High prices	22%	26%	29%
Large energy intensive users:			
Low prices	11 to 16%	14 to 44%	27 to 53%
Central case	11 to 16%	8 to 28%	27 to 41%
High prices	11 to 16%	5 to 21%	19 to 25%

Source: DECC, "Estimated impacts of energy and climate change policies on energy prices and bills", November 2011. The 3 scenarios are:

- Low fossil fuel prices: gas prices 35p/therm, oil $79pb, coal $79/tonne in 2020.
- Central fossil fuel prices: gas prices 68p/therm, oil $118pb, coal $109/tonne in 2020.
- High fossil fuel prices: gas prices 92p/therm, oil $134pb, coal $150/tonne in 2020.

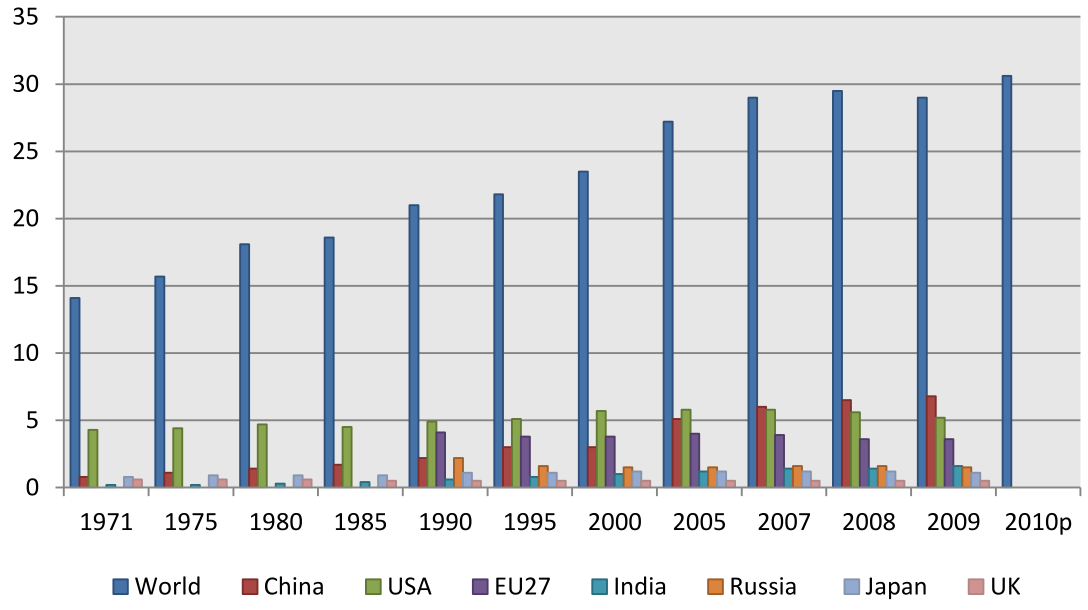
These extra costs damage competitiveness and undermine viability, especially high energy users. They risk driving industry to migrate overseas, along with their CO_2 emissions, thus having zero net impact on global emissions totals. Indeed such migration could increase global CO_2 emissions if the recipient country is less energy efficient than the UK. Suffice to say the supply of competitively-priced, secure and reliable sources of electricity is vital to modern industry.

The Government's energy policy is inextricably tied up with its climate change policy, which is principally concerned with cutting greenhouse gas emissions, especially CO_2, in order to "mitigate dangerous manmade global warming". We will not discuss the scientific evidence for or against this phenomenon in this paper, but will note that the UK was responsible for just 1.7% of total global emissions in 2008 and 1.6% in 2009.[8] The direct impact of the UK's decarbonising "green" credentials on world emissions should therefore be kept in perspective. We are shrinking into irrelevance as a carbon-emitting nation. Even if Britain's economy were to be completely decarbonised the saving in global emissions, other things being equal, would be less than 0.5bn metric tonnes. In 2009 China's CO_2 emissions increased by over 0.3bn metric tonnes, to 6.8bn metric tonnes. Between 2007 and 2009 the increase in China's emissions was 0.8bn metric tonnes, over one and half times Britain's total emissions.

Chart 1 shows the CO_2 emissions from fuel combustion for the world, China, the USA, the EU27, India, Russia, Japan and the UK for selected years. Between 1971 and 2009, world emissions more than doubled, even though they fell back slightly in 2009, to around 29 billion metric tonnes, reflecting the "great recession". Early data from the International Energy Agency (IEA) suggest that emissions in 2010 were around a record 30.5 billion metric tonnes as the western economies partly recovered and growth in the emerging economies forged ahead.[9]

The change in country composition over the period 1971-2009 is startling. The USA was by far the largest emitter in 1971, followed by the USSR and Germany. But by 2009 China was the greatest emitter (accounting for 23.6% of total emissions), followed by the USA (17.9%) and India (5.5%). Taking the EU27 in total, the bloc accounted for 12.3% of emissions, approximately half of China's. Given the EU's current strategy of leading the fight against manmade global warming, these basic data put the EU's ambitions into perspective.[10] The EU is, in reality, quite a minor player.

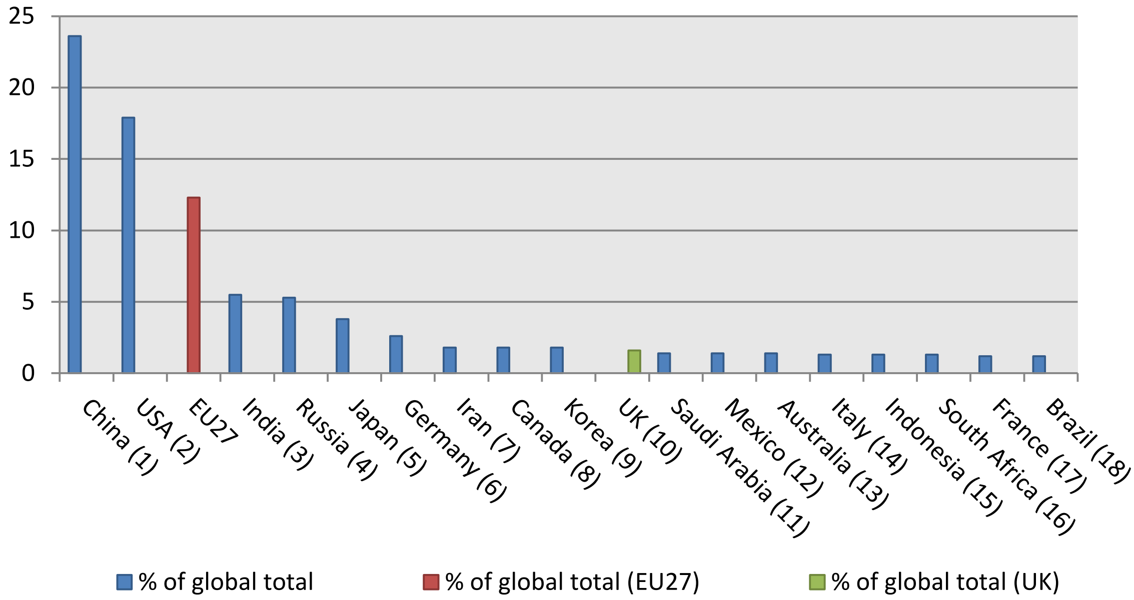
Chart 1: CO2 emissions from fuel combustion, billion metric tonnes (Mt), selected years



Sources: (i) International Energy Agency (IEA), *CO_2 emissions from fuel combustion, highlights*, 2011 edition, www.iea.org. Data for the EU27 and the Russian Federation are only available from 1990; (ii) the provisional 2010 figure is from IEA, "CO_2 emissions reach record high in 2010", May 2011.

Chart 2 shows the shares of the global emissions by the top 18 emitters in 2009. In total they accounted for over 75% of the world total. The chart highlights the huge gulf in emissions between China and the US, on the one hand, and the other largest emitters, on the other.

Chart 2: CO2 emissions from fuel combustion, top 18 emitters, % of global total, 2009



Source: International Energy Agency (IEA), *CO_2 emissions from fuel combustion, highlights*, 2011 edition.

Legislation affecting the UK energy policy

There are two crucial pieces of climate change legislation that affect energy policy:

- The Climate Change Act (2008), which is driving the draconian reduction in greenhouse gas (GHG) emissions. Under this Act GHG emissions are to be cut by 34% by 2018-22 and by 80% by 2050 compared with the 1990 level. This represents the near-decarbonisation of the economy and has huge implications for the energy sector, in particular, and the economy, more generally. As the consultants Redpoint Energy point out "…meeting these targets will mean a radical change in the way the UK produces and consumes energy over the coming decades."[11] The EU's target is for a less draconian 20% reduction in GHG emissions by 2020, compared with the 1990 level.

- The EU's Renewables Directive (2009) whereby the UK is committed to sourcing 15% of final energy consumption (f.e.c.) from renewables by 2020. Renewable energy sources include wind, hydro and biomass, but not nuclear power. Given the very low renewables base from which Britain has to meet this target, the challenge is very great indeed.[12] There is, arguably, little chance that Britain will be able to meet the renewables target. Note that the Renewables Directive does not add to the pressures on Britain to cut GHG emissions further, it merely insists that renewables must contribute to the overall emissions cuts dictated by the climate change legislation.

In order to reach the 80% cut by 2050, the Government has set the first four 5-year Carbon Budgets as steps to the overall target. The first three budgets were set in May 2009, the fourth in May 2011. Table 2 shows the prescribed cuts in greenhouse gases under these budgets.

Table 2: Greenhouse gas (GHG) emissions, metric tonnes carbon dioxide equivalent (MtCO2e)

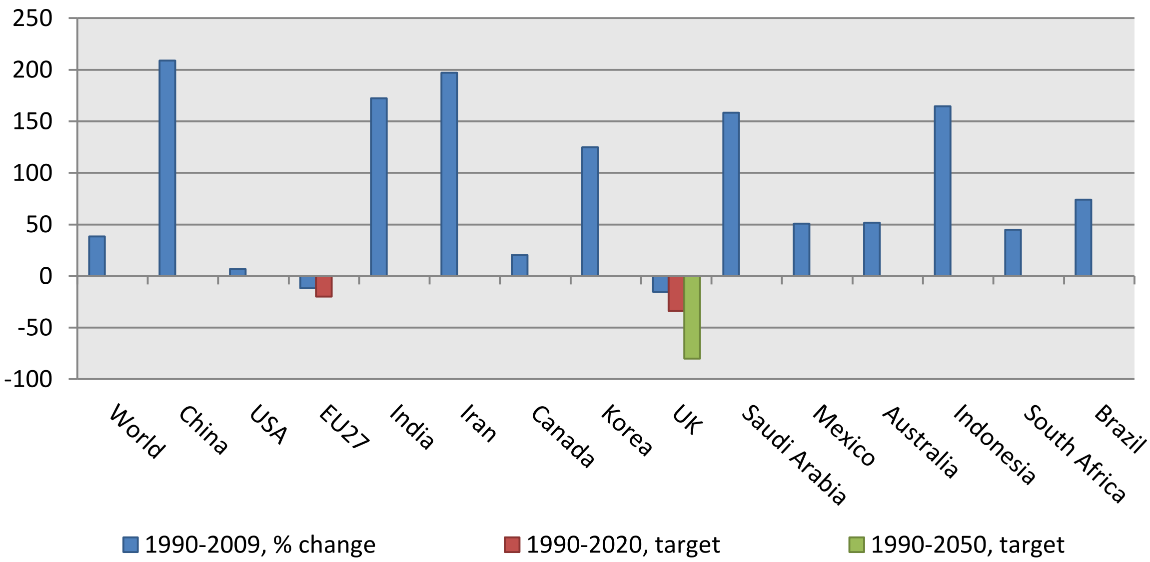
Years	Carbon Budget	$MtCO_2e$, million	Compared with 1990 level
5-year periods:			
2008-12	First	3018	-22%
2013-17	Second	2782	-28%
2018-22	Third	2544	-34%
2023-27	Fourth	1950	-50%
2050	Target		-80%

Source: DECC website, www.decc.gov.uk

Chris Huhne, Secretary of State for Energy and Climate Change, announced that there would be a review of policy "in early 2014 to ensure our own carbon targets are in line with the EU's" when he released the details of the Fourth Carbon Budget.[13] This is a sensible development. But he should also be considering developments in the rest of the world as well. Many nations regard the EU's decisions as of little consequence.

Chart 3 shows the change in CO_2 emissions between 1990 and 2009 for selected key economies, alongside the EU's and Britain's targets. It is highly unlikely the emerging economies will risk damaging their growth by curbing their use of fossil fuels as Britain plans to do. And the outcome of the latest climate change talks in Durban (December 2011) will almost certainly do nothing to change this situation. It was agreed that talks would start on a new deal in 2012 and end by 2015, coming into effect in 2020 – nearly a decade away.[14] Britain's draconian decarbonising policies, indeed the EU's, are arguably futile.

Chart 3: CO2 emissions, % changes compared with 1990



Source of back data: International Energy Agency (IEA), *CO_2 emissions from fuel combustion, highlights*, 2011 edition.

Carrots and sticks

As part of its decarbonising strategy, the Government is incentivising investment in low-carbon technologies in general and renewables technologies in particular by an assortment of carrots and sticks, some of which serve to increase the relative price of fossil fuels vis-à-vis other fuels. These carrots and sticks mainly comprise:

- The Climate Change Levy (CCL), introduced in April 2001, is a tax on the use of energy in industry, commerce and the public sector (i.e. all non-domestic sectors). The CCL is intended to encourage energy efficiency and reduce carbon emissions. There are exemptions but, notably, nuclear generated electricity is not one of them - despite the fact such generation has no carbon emissions.

- The Renewables Obligation (RO), introduced in 2002, is the obligation placed on licensed electricity suppliers to deliver a specified amount of their electricity from eligible renewable sources. The costs associated with the RO are rising reflecting increasing obligation levels. The RO is currently the primary mechanism to support deployment of large-scale renewable electricity generation.

- Compliance with the EU's Emissions Trading System (ETS). The ETS is the EU-wide "cap and trade" scheme which started in 2005. Phase I ran from 2005 to 2007, phase II is currently operative (2008 to 2012). The allocation of free permits (or carbon credits) will be substantially reduced under phase III (2013-2020) and there will be no free allowances whatsoever for the power sector. Carbon costs associated with the ETS can be expected to rise significantly.

- The Feed-in Tariffs (FiTs) scheme was introduced in April 2010. The scheme provides a fixed payment for the electricity generated privately from renewable or low-carbon sources called the "generation tariff". Any unused electricity can be exported to the grid. FiTs work alongside the Renewables Obligation (RO). They will also work alongside the Renewable Heat Incentive (RHI) which, when implemented, will support the generation of heat from renewable sources.

In addition, the Carbon Price Floor (CPF) due to start in April 2013, will raise the carbon costs of fossil fuel energy sources further.[15,16,17] The CPF is intended to "provide greater support and certainty to the price of carbon in the power sector to encourage investment in low-carbon electricity generation".

References

1. WEF's *The Global Competitiveness Report for 2011-12*, 2011.

2. Ruth Lea, "Britain needs a really radical growth programme", in *The Future of Conservatism*, editors David Davis, Brian Binley and John Baron, ConservativeHome, 2011.

3. Ruth Lea and Jeremy Nicholson, *British Energy Policy and the Threat to Manufacturing Industry*, Civitas, July 2010.

4. DECC, *Estimated impacts of energy and climate change policies on energy prices and bills*, November 2011. The energy division of BERR and the climate change responsibilities of DEFRA were transferred to the new Department of Energy and Climate Change (DECC) in October 2008. Website: www.decc.gov.uk. These costs mainly comprise Feed-in Tariffs, the Climate Change Levy (CCL), Carbon Price Floor (CPF, from 2013), Renewables Obligation (RO) and the EU Emissions Trading System (ETS). The data were released before the Autumn Statement.

5. HM Treasury, Autumn Statement 2011, Cm8231, November 2011. The Autumn Statement announced that "…the Government intends to implement measures to reduce the impact of policy on the costs of electricity for the most electricity-intensive industries, beginning in 2013 and worth around £250m over the Spending Review period. As part of this the Government will: (i) compensate key electricity-intensive businesses to help offset the indirect cost of the carbon price floor and the EU Emissions Trading System, subject to state aid guidelines; and (ii) increase the level of relief from the climate change levy on electricity for Climate Change Agreement participants to 90%." The Treasury's measures are unlikely to offset the extra costs arising from "green energy" policies.

6. Previous estimates were released in DECC, *Provisional estimates of the impacts of energy and climate change policies on prices and bills of large energy users*, July 2011.

7. HM Government, *The UK Renewable Energy Strategy*, July 2009.

8. International Energy Agency (IEA), *CO_2 emissions from fuel combustion, highlights*, 2011 edition, www.iea.org. CO_2 emission sources include emissions from the energy industry,

from transport, from fuel combustion in industry, services, households, etc. and industrial processes, such as the production of cement.

9. IEA, "Prospect of limiting the global increase in temperature to 2^{o}C is getting bleaker", May 2011, www.iea.org. The IEA wrote "…while the IEA estimates that 40% of global emissions came from OECD countries in 2010, these countries only accounted for 25% of emissions growth compared to 2009. Non-OECD countries – led by China and India - saw much stronger increases in emissions as their economic growth accelerated."

10. Under the Kyoto Protocol (1997) the EU15 agreed to cut GHG emissions by 8% by 2008-12 compared with 1990 levels. Under the "burden sharing" scheme of 2002, different member states were allocated different emissions targets. Germany, for example, agreed to a cut of 21% (possible because of the collapse of much of eastern Germany's industry) whilst the UK agreed to a cut of 12.5%. Spain, on the other hand, was permitted an increase of 15% and Greece an increase of 25%. The planned cut in the UK's first Carbon Budget (2008-12) is 22%. Kyoto's GHG comprise: CO_2, methane, nitrous oxide, hydrofluorocarbons, perflurocarbons & sulphur hexafluoride, converted into CO_2 equivalent units.

11. Redpoint Energy, *Electricity market reforms: an analysis of policy options*, December 2010.

12. Ruth Lea and Jeremy Nicholson, *British Energy Policy and the Threat to Manufacturing Industry*, Civitas, July 2010, discusses the challenges presented by the Renewables Directive.

13. DECC, "Fourth Carbon Budget: oral ministerial statement by Chris Huhne", 17 May 2011.

14. BBC, "Climate talks end with late deal", 11 December 2011.

15. HM Treasury and HMRC, "Carbon price floor: support and certainty for low-carbon investment", consultation document, December 2010.

16. The Government announced in the March 2011 Budget that the carbon price support would be introduced via the Climate Change Levy and fuel duty with a target price of £30 per tonne of carbon dioxide (£30/tCO_2) in 2020. See House of Commons Library,

"Carbon Price Support", October 2011.

17. DECC, "Planning our electric future: a White Paper for secure, affordable and low-carbon electricity: Electricity Market Reform (EMR) White Paper 2011", July 2011.

Chapter 2:
Electricity generation costs

Preliminary remarks

Electricity generation is a major contributor to Britain's CO_2 emissions. In 2010 it accounted for nearly a third of total emissions.[1] The sector is significantly affected by the Government's climate change and renewables policies. And the carrots and sticks listed at the end of chapter 1 are very relevant to electricity generation, adding to costs.

Britain's technology of choice in order to meet the twin targets of cutting CO_2 emissions and boosting renewables is wind power, which is very costly. The Government is also pressing for new nuclear build in order to reduce CO_2 emissions.

Estimates of electricity generation costs: Mott MacDonald

The engineering consultancy Mott MacDonald was commissioned by DECC to update UK electricity generation costs in 2009 and its report was released in June 2010.[2] They calculated the "levelised generation costs" for several technologies, which can be defined as "the lifetime discounted costs of ownership of using a generation asset, converted into an equivalent unit cost of generation in £/MWh or p/kWh". These costs are sometimes called the "life cycle costs", emphasising the "cradle to grave" aspect of the definition.

Mott MacDonald emphasised that estimating such costs was far from straightforward, there were great uncertainties and that many assumptions about fuel prices and the maturity of technology have to be made (for example). They costed both major and minor electricity generating technologies including biomass and hydro, see annex table 1 for details.

The major technologies included the following:

- Gas-fired combined-cycle gas turbines (CCGT).
- Advanced supercritical (ASC) coal-fired power plants.
- Gas CCGT with carbon capture and storage (CCS).
- Coal (ASC) with CCS.

- Onshore wind.
- Offshore wind.
- Nuclear pressurised water reactors (PWR).

For the major technologies Mott MacDonald considered ten different cases, using different assumptions about the timing of the project, the discount rate used, the maturity of certain technologies, and fuel and carbon prices. The maturities of the technologies were assigned as either "first of a kind" (FOAK) for new, immature technologies and "nth of a kind" (NOAK) for mature technologies.

The ten cases are listed in annex table 2. For this paper just two have been chosen:

- Case 2, a near-term project: taking 2009 for the start date, with a 10% discount rate, mixed maturity of technologies and using DECC's central fuel and carbon prices projections (annex table 3 lists the detailed projections). CCGT, ASC coal and onshore wind were regarded as mature (NOAK) technologies. The other technologies were not (i.e. they were FOAK).

- Case 5, a medium-term project: taking 2017 for the start date, with a 10% discount rate, all mature (NOAK) technologies and using DECC's central fuel and carbon prices projections.

Mott MacDonald: chosen near-term project

Charts 1a and 1b show the levelised generation costs (LGC) of electricity for the chosen near-term project (2009, case 2), in terms of £/MWh.[3]

Chart 1a omits the carbon costs. Under these circumstances the ASC coal-fired plants and the unabated gas CCGTs are clearly the lowest cost generators. Offshore wind and gas and coal with CCS are the most costly. Integrating CCS into coal or gas-fired plant substantially raises the capital costs.

If the carbon costs are taken into account (chart 1b) the gas CCGT is the least costly, with onshore wind in second place. Coal-fired plants without CCS especially suffer from the imposition of carbon costs. But, as we discuss below, the costs of wind generation as calculated by Mott MacDonald significantly underestimate the true costs. The discussion below shows that the inclusion of the additional costs associated with wind generation radically undermines wind's relatively favourable cost position.

Chart 1a: MM case 2, 2009 project start, levelised generation costs excluding carbon costs, £/MWh

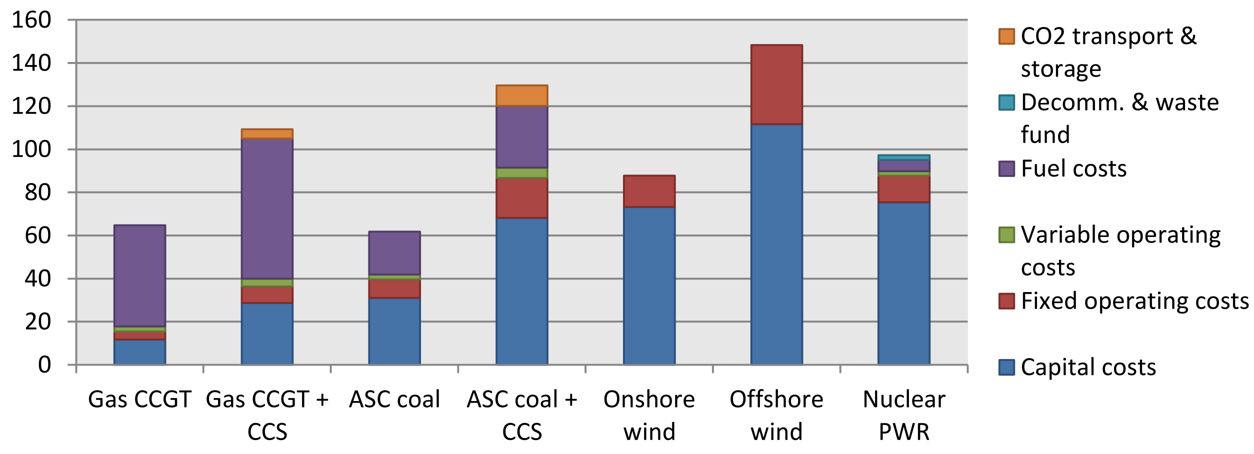
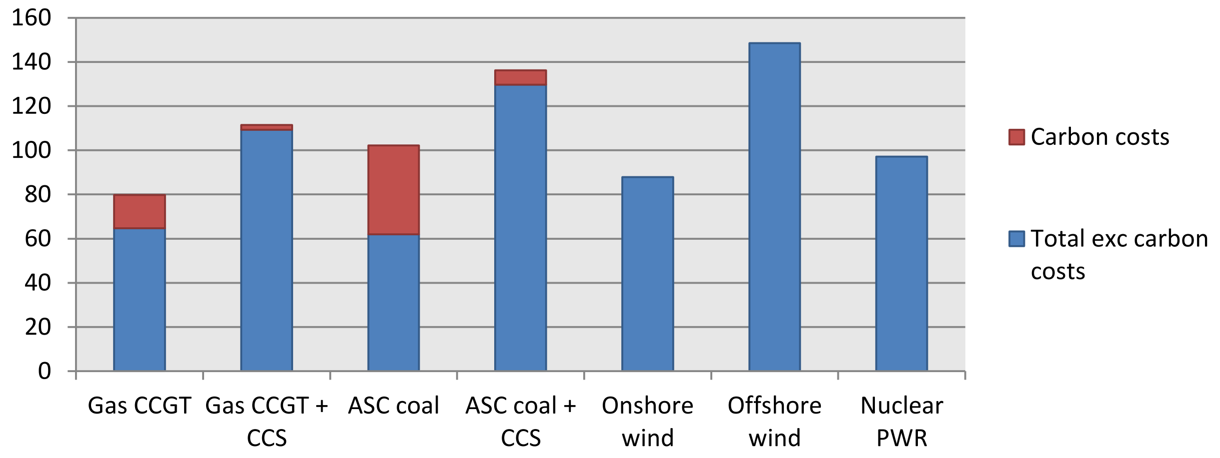


Chart 1b: MM case 2, 2009 project start, levelised generation costs including carbon costs, £/MWh



Source: Mott MacDonald, *UK electricity generation costs update*, June 2010.

Mott MacDonald: chosen medium-term project

Charts 2a and 2b show Mott MacDonald's cost estimates for the chosen medium-term project, with a project start-date of 2017 (case 5).

Before the additions of the carbon costs (chart 2a), coal and gas remain the cheapest technologies, with nuclear a close third. After taking carbon costs (chart 2b) into account nuclear is the most cost-effective, with gas and especially coal significantly more expensive because of the high (and increasing) carbon costs. Onshore and offshore wind as calculated by Mott MacDonald are more expensive than nuclear, even before taking into account the very significant additional costs.

Chart 2a: MM case 5, 2017 project start, levelised generation costs excluding carbon costs, £/MWh

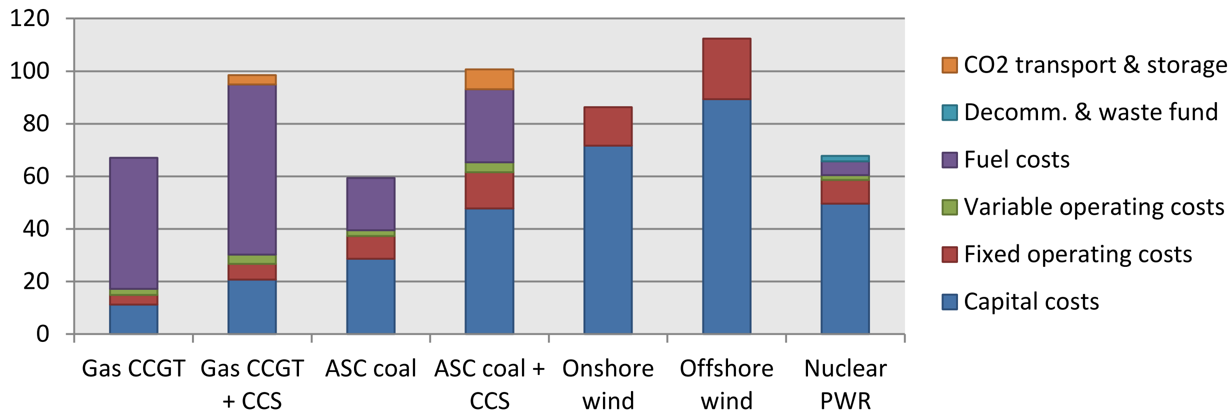
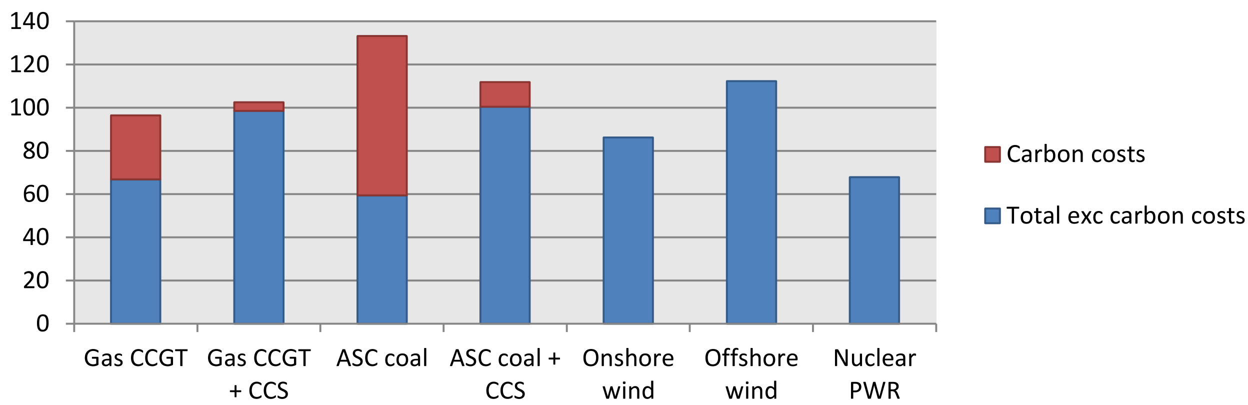


Chart 2b: MM case 5, 2017 project start, levelised generation costs including carbon costs, £/MWh



Source: Mott MacDonald, *UK electricity generation costs update*, June 2010.

Wind: a special case

As we have already pointed out the estimates by Mott MacDonald flatter wind-power as they made no allowance for any add-on costs. One of the main reasons is that wind-power is unreliable and requires conventional back-up generating capacity when wind speeds are, for example, very low or rapidly varying, which increases the overall costs of wind-power. Mott

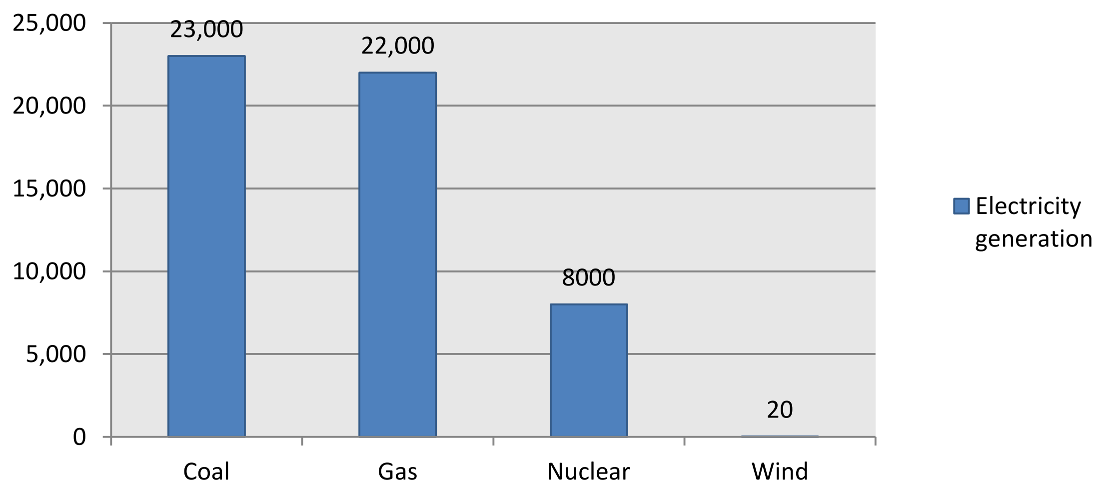
MacDonald assumed load factors of just 25-31% for onshore wind and 35-45% for offshore wind.[4]

However it should be noted that even these figures for load factors can give an impression of greater reliability than is actually the case. In spells of very cold weather associated with high pressure areas, when there is enhanced demand for electricity, there tends to be very little wind. This analysis was confirmed by BBC weatherman Paul Hudson, who wrote in January 2011:[5]

> "...during the recent intense cold weather, it's been our traditional coal and gas fired power stations that have been working flat out to keep our homes and businesses warm. And for the third winter running, the intense cold has gone hand in hand with periods of little or no wind. This should come as no surprise since prolonged cold is invariably associated with areas of high pressure".

The following chart (chart 3) was included in this BBC report. Wind's contribution to total electricity output (53,020 Megawatts) on 21 December 2010 was, according to the BBC, 0.04%. This insight is a useful answer to those who say "the wind is always blowing somewhere" in defence of wind-power. In Britain on very cold days it effectively is not. Twenty Megawatts of generation should also be seen in the context of the estimates for plant capacity. Plant capacity has been calculated to be over 5½ thousand Megawatts, see annex table 4b.

Chart 3: Electricity generation, 21 December 2010, Megawatts



Source: Paul Hudson, "Coal takes the strain...again", *BBC website*, 10 January 2011.

There are several estimates of the additional costs associated with wind-power. For example Parsons Brinckerhoff (PB) Power, in a report for the Royal Academy of Engineering (RAE), estimated in 2004 that stand-by costs could add around 45% to the costs for onshore wind and 30% to the costs for offshore wind.[6]

More recent and detailed estimates are provided in a paper by Colin Gibson, Power Network Director at the National Grid Group (1993-97),[7] which are quoted in a recent paper by the Renewable Energy Foundation.[8] Gibson's cost estimates, the caveats on the accuracy of which are discussed in his paper, are shown in table 1 below.

Gibson identifies three separate additional costs:[9]

- The Extra System Costs, which refer to the costs of fast response plant to address the intermittency, the uncontrolled variability, of wind in the operational timescale, i.e. in the very short term, or minutes or hours.[10]
- The Planning Reserve, which refers to the need to maintain an under-utilized conventional fleet equivalent to peak load (plus a margin) to cover periods when output from the wind fleet falls to extremely low levels – in common parlance "when there's little or no wind". Gibson assumes a level of 8% of installed wind capacity.
- Required Transmission, which describes the cost of grid needed to transport energy from wind sites to consumers. Wind farms tend to be situated in the north of the country in order to exploit higher wind speeds to improve load factors. But demand is weighted towards the south of the country. This exacerbates the existing north to south flow of power and brings forward requirements to reinforce the system.

Table 1: Additional system costs for onshore and offshore wind, £/MWh of wind-power generated

Technology	Extra system operation costs	Capital charges for extra planning reserve	Total capital charges for required transmission	Total
Onshore	16	24	20	60
Offshore	16	28	23	67

Source: Renewable Energy Foundation, *Energy policy and consumer hardship*, 2011.

Incorporating the additional costs, and taking our two chosen Mott MacDonald cases as illustrations, the cost of onshore wind would become quite uneconomic and offshore wind even more absurdly expensive. Charts 4a and 4b show the effective generating costs including the additional costs.

Chart 4a: MM case 2, 2009 project start, including additional costs, £/MWh

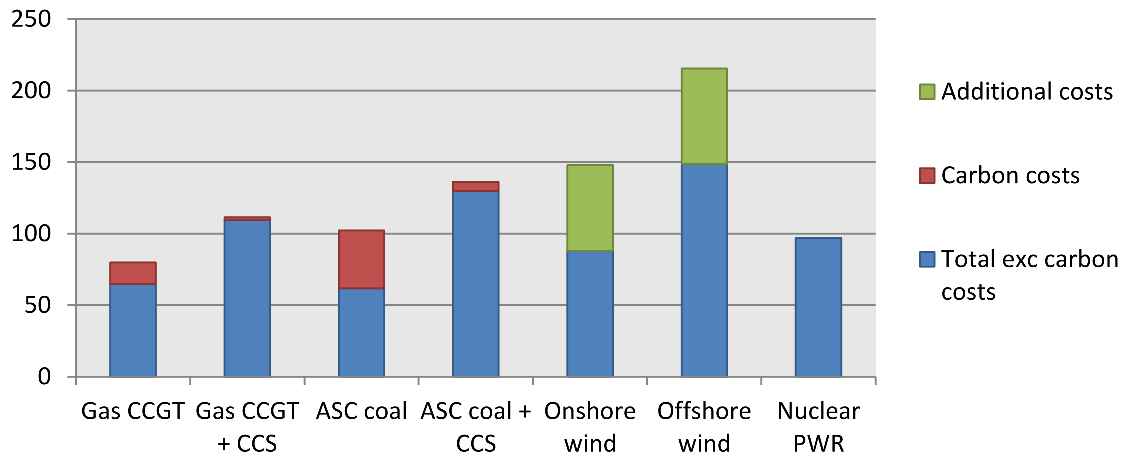
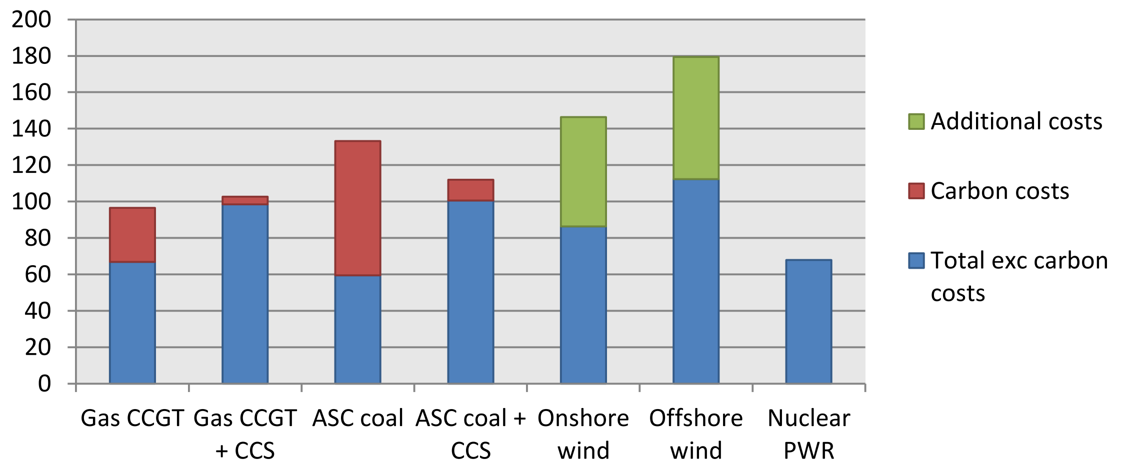


Chart 4b: MM case 5, 2017 project start, including additional costs, £/MWh



Main source: Mott MacDonald, *UK electricity generation costs update*, June 2010.

The costing of wind-power electricity generation is clearly very complex. But one conclusion can safely be drawn and that is that wind-power is expensive – especially offshore. Under these circumstances it seems unwise to be embarking on a huge programme of investment in wind generated electricity, especially when the country is facing grave economic challenges. This analysis also ignores the perceived environmental costs of wind-power, especially onshore wind turbines.

Conclusions from the Mott MacDonald report: levelised costs

Tables 2a and 2b below rank the levelised costs, as calculated by Mott MacDonald, of the seven technologies chosen for this paper. They are ranked in order from the least costly to the most costly.

Table 2a: MM case 2, 2009 project start, levelised generation costs ranked

	Excluding carbon costs	**Including carbon costs**	**Also including additional costs**
Least expensive	ASC coal	Gas CCGT	Gas CCGT
2nd	Gas CCGT	Onshore wind	Nuclear
3rd	Onshore wind	Nuclear	ASC coal
4th	Nuclear	ASC coal	Gas + CCS
5th	Gas + CCS	Gas + CCS	Coal + CCS
6th	Coal + CCS	Coal + CCS	Onshore wind
Most expensive	Offshore wind	Offshore wind	Offshore wind

Table 2b: MM case 5, 2017 project start, levelised generation costs ranked

	Excluding carbon costs	**Including carbon costs**	**Also including additional costs**
Least expensive	ASC coal	Nuclear	Nuclear
2nd	Gas CCGT	Onshore wind	Gas CCGT
3rd	Nuclear	Gas CCGT	Gas + CCS
4th	Onshore wind	Gas + CCS	Coal + CCS
5th	Gas + CCS	Coal + CCS	ASC coal
6th	Coal + CCS	Offshore wind	Onshore wind
Most expensive	Offshore wind	ASC coal	Offshore wind

Main source: Mott MacDonald, *UK electricity generation costs update*, June 2010.

The main conclusions may be drawn for the MM data are:

- Excluding carbon costs, coal-fired power stations would be the cheapest form of generation for both the near-term and medium-term projects.
- Including carbon costs, gas-fired power stations are the cheapest option for the near-term projects, but nuclear power is the least expensive in the medium-term. Other things being equal this would suggest that investment should be concentrated in gas and nuclear technologies. A mix of technologies is preferable for operational reasons. Coal-fired power stations become relatively uneconomic, reflecting the heavy carbon costs, especially in the medium-term.
- Onshore wind looks a relatively attractive proposition on the MM data, but once allowance is made for the additional costs associated with wind-power, the attraction fades. For both near-term and medium-term projects, onshore wind ceases to be a competitive technology. The only rationale for Britain's current "rush for wind" is the Government's attempt to meet its renewables target under the EU's Renewables Directive. There is no economic case for wind-power. Moreover, there is not even a CO_2-cutting case for wind-power, as is discussed in chapter 3.
- Offshore wind, even before allowing for additional costs, and CCS technologies are inordinately expensive.

Levelised generation costs: further reports

Since the release of the Mott MacDonald report DECC has commissioned two updates, see annex table 6 for details:

- For conventional electricity generation by Parsons Brinckerhoff (PB).[11]
- For renewables by Ove Arup.[12]

Both PB and Arup considered two cases:

- Case 1: near-term project, 2011 project start, FOAK/NOAK mix, an approximate update of Mott MacDonald's case 2 (2009 start data).
- Case 2: medium-term project, 2017 project start, all NOAK, an approximate update of Mott MacDonald's case 5.

Charts 5a and 5b show the comparative estimates by PB and MM for conventional technologies and by Arup and MM for renewables.[13] We have included Round 3 (R3) of offshore wind, as an eighth technology, in the charts below. The detailed calculations are shown in annex table 7.

Chart 5a: Comparison of MM (case 2) and PB & Arup (case 1), levelised costs, £/MWh: near-term project

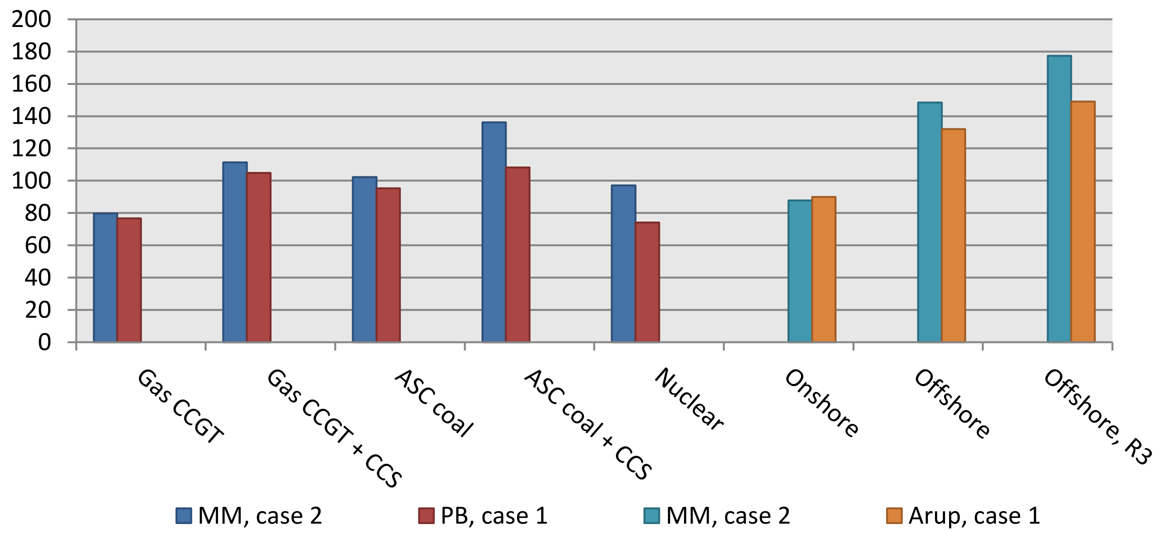
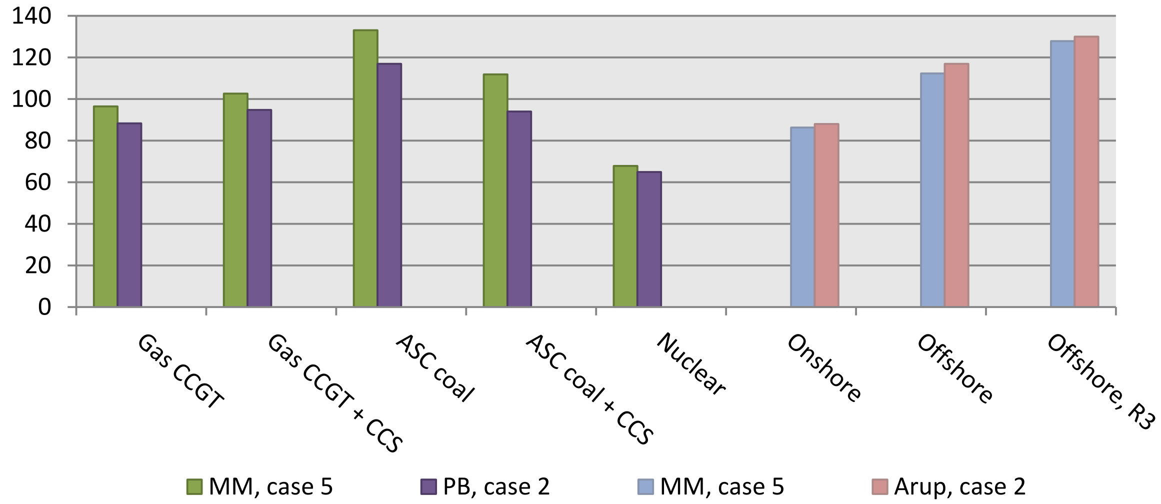


Chart 5b: Comparison of PB & Arup (case 2) and MM (case 5) levelised costs, £/MWh: medium-term project



Sources: Parsons Brinckerhoff, *Electricity Generation Cost Model – 2011 update revision 1*, for DECC, August 2011; Mott MacDonald, *UK electricity generation costs update*, June 2010; Ove Arup & Partners, *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*, for DECC, June 2011. The onshore wind figures refer to capacity greater than 5MW.

The final set of charts, 6a and 6b, make allowance for the additional costs of wind-power. As with the calculations above, we have assumed additional costs of £60MWh for onshore wind and £67MWh for offshore wind.

Chart 6a: Comparison of MM (case 2) and PB & Arup (case 1), levelised costs, £/MWh: near-term project, including additional costs (wind)

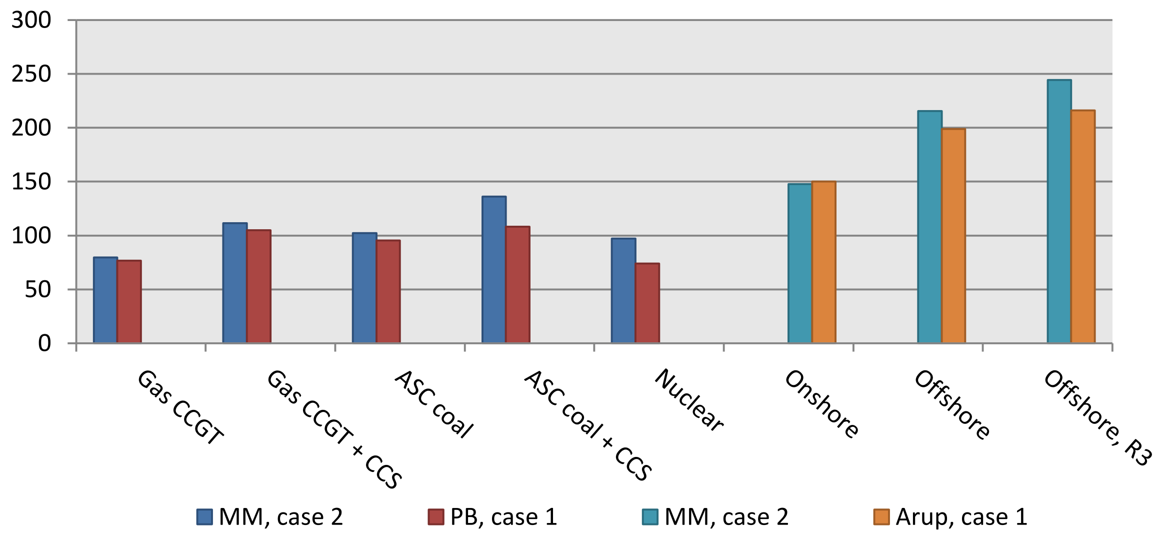
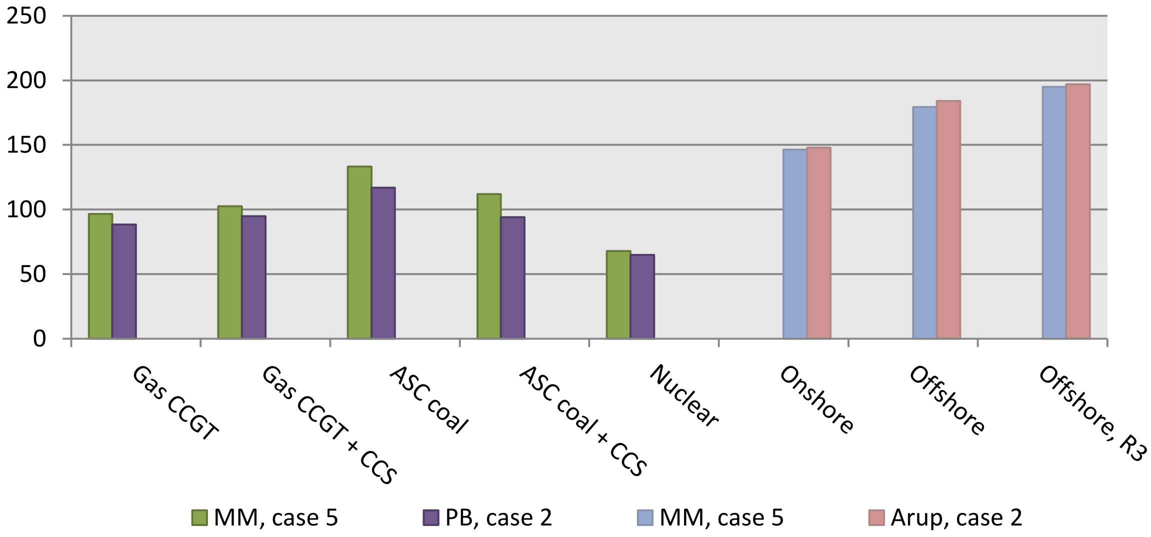


Chart 6b: Comparison of PB & Arup (case 2) and MM (case 5) levelised costs, £/MWh: medium-term project, including additional costs (wind)



Finally, tables 3a and 3b rank the levelised costs, as calculated by Parsons Brinckerhoff and Arup, of the eight technologies chosen for this paper. They are ranked in order from the least costly to the most costly. The main conclusions from the MM study of the comparative costs of the different technologies are not fundamentally changed by the PB and Arup analysis. Nuclear and gas remain the most competitive conventional technologies, given the high carbon costs factored in, whilst onshore wind gives the superficial appearance of being competitive but when allowance is made for the substantial add-on costs it loses its appeal. Offshore wind, even without any add-on costs, remains expensive, especially R3. Specifically, PB costings show that nuclear has an advantage over gas both for the near-term and the medium-term projects.

Table 3a: PB/Arup case 1, 2011 project start, levelised generation costs ranked

	Including carbon costs	**Also including additional costs**
Least expensive	Nuclear	Nuclear
2nd	Gas CCGT	Gas CCGT
3rd	Onshore wind	ASC coal
4th	ASC coal	Gas + CCS
5th	Gas + CCS	Coal + CCS
6th	Coal + CCS	Onshore wind
7th	Offshore wind	Offshore wind
Most expensive	Offshore wind, R3	Offshore wind, R3

Table 3b: PB/Arup case 2, 2017 project start, levelised generation costs ranked

	Including carbon costs	**Also including additional costs**
Least expensive	Nuclear	Nuclear
2nd	Onshore wind	Gas CCGT
3rd	Gas CCGT	Coal + CCS
4th	Coal + CCS	Gas + CCS
5th	Gas + CCS	ASC coal
6th	ASC coal	Onshore wind
7th	Offshore wind	Offshore wind
Most expensive	Offshore wind, R3	Offshore wind, R3

References

1. DECC, "UK climate change sustainable development indicator: 2010 greenhouse gas emissions, provisional figures", March 2011. See also table 1, chapter 3.

2. Mott MacDonald, *UK electricity generation costs update*, June 2010.

3. Kilowatt hour (kWh) = 10^3 watt hours; Megawatt hour (MWh) = 10^6 watt hours; Gigawatt hour (GWh) = 10^9 watt hours; Terawatt hour (TWh) = 10^{12} watt hours.

4. The load factor (or capacity factor) is the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full "nameplate capacity" the entire time.

5. Paul Hudson, "Coal takes the strain...again", BBC website, www.bbc.co.uk, 10 January 2011.

6. RAE, "The cost of generating electricity", Parsons Brinckerhoff (BP) Power, 2004.

7. Colin Gibson, "A Probabilistic Approach to Levelised Cost Calculations For Various Types of Electricity Generation", the Institution of Engineers and Shipbuilders in Scotland, Energy Strategy Group, October 2011, www.iesisenergy.org/lcost. Gibson places caveats on the accuracy of his cost estimates, which should be noted.

8. Renewable Energy Foundation, *Energy policy and consumer hardship*, 2011.

9. In addition, there are constraint costs. Congestion or constraint is the name given to the access rights that cannot be used due to insufficient network capacity. Generators who have paid for their access rights are entitled to compensation, constraint payments, if their rights cannot be honoured. They are paid not to produce. Constraint payments are higher for wind power generators than for fossil fuel generators. For example, BBC Scotland, "Scots windfarms paid cash to stop producing energy", 1 May 2011, reported that 6 Scottish windfarms had been paid up to £300,000 to stop producing energy. The details emerged following research by the Renewable Energy Foundation (REF).

10. UKERC defined the "system reliability costs of intermittency" as the difference between the contributions to reliability made by intermittent generation plant, on the one hand, and by conventional generation plant, on the other. See UKERC, "The costs and impacts

of intermittency: an assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network", March 2006.

11. Parsons Brinckerhoff, *Electricity Generation Cost Model – 2011 update revision 1*, for DECC, August 2011, available from www.pbworld.co.uk

12. Ove Arup & Partners, *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*, for DECC, June 2011, available from www.arup.com

13. The Renewable Energy Foundation (REF), *Renewable energy in the countryside: rewards and risks: a study for CPRE Devon*, September 2011, discusses both the PB and the Arup reports.

Chapter 3:
Cutting greenhouse gas emissions

Britain's greenhouse gas emissions

The UK's greenhouse gas emissions are shown in table 1. They totalled 492MtCO_2e in 2010, over 16% lower than in 1990. The Energy sector emitted nearly 40% of these greenhouse gases (191MtCO_2e) in 2010, with power stations contributing nearly a third of the total (156MtCO_2e).[1]

Table 1: Sources of greenhouse gas emissions, 1990, 2009, 2010, MtCO2e

	1990	2009	2010	2010 (% share)	Change (%) 1990-2010
Energy supply	241	185	191	38.8%	-20.8%
Of which:					
Power stations	203	150	156	31.7%	-23.1%
Transport	120	121	121	24.6%	+0.8%
Residential	79	75	85	17.3%	+13.3%
Business	110	76	78	15.9%	-29.1%
Other	40	17	17	3.5%	-57.5%
Total	590	474	492	100.0%	-16.6%

Source: DECC, "UK climate change sustainable development indicator: 2010 greenhouse gas emissions, provisional figures", March 2011. Emissions related to the use of electricity generation are attributed to power stations, the source of these emissions, rather than homes and businesses where the electricity is used. There are rounding errors in the table.

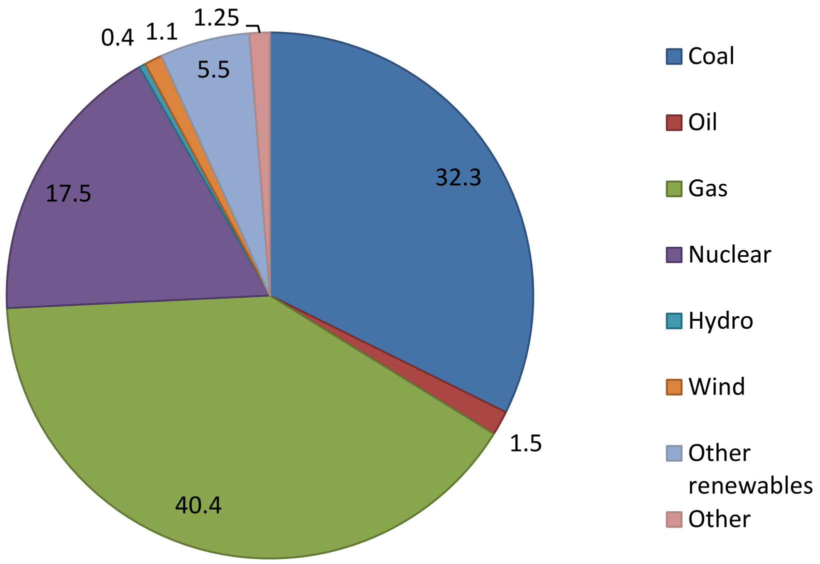
Even though there was an increase in overall energy consumption between 1990 and 2010, emissions from the energy sector fell by around 21%. Concerning power stations only, the final consumption of electricity was around 18% higher in 2010 than in 1990 according to DECC, with domestic electricity consumption almost 27% higher. However, emissions from electricity generation decreased by 23% over the same period. The main reasons were: firstly, improvements in the efficiency of electricity generation; and secondly, switching from coal to less carbon intensive fuels such as gas. Clearly, the more efficient the plant, the lower the emissions per unit of output will be, other things being equal. And, equally clearly, switching from high carbon intensive coal to lower carbon intensive gas, the lower the emissions per unit of output will be, other things being equal.

In 2010, gas usage for generation was at historically high levels, whilst use of coal in generation had roughly halved since 1990. Gas-fired combined-cycle gas turbines (CCGTs) represented around 37% of the total plant capacity (see table 6 in the annex), the majority of which has been brought on-stream since 1990. Coal's share of plant capacity is around 32%, although a significant proportion of this is scheduled to close over the next one to two decades in response to EU Directives on emissions.[2] Nuclear and wind currently account for around 12% and 5-6% of plant capacity respectively.

The energy sector's emissions rose by 3% in the year 2010. The increase can almost entirely be attributed to power stations. Part of the increase was explained by higher demand for electricity. But because of technical problems at some nuclear power stations, there was less nuclear power available for electricity generation than in 2009, and more coal and gas were used instead. This resulted in an increase of around 4% in emissions from electricity generation.

Overall CO_2 emissions reflect, of course, the mix of fuels used to generate electricity. The proportions of coal (32.3%), gas (40.4%), nuclear (17.5%) and other fuels used for electricity generation in 2010 are shown in chart 1. Note that the use of coal was roughly in proportion to its share of plant capacity, whilst the deployment of gas and especially nuclear power was higher than their share of plant capacity. Wind-power was significantly lower by a factor of about five. Its contribution to Britain's electricity demands was almost risible.

Chart 1: Fuel used for generation, all generating companies, share (%), in 2010



Source: DECC, "Digest of UK energy statistics" (DUKES), annual tables, www.decc.gov.uk. The basic data are in million tonnes of oil equivalent (Mtoe).

The challenge: draconian cuts in CO2 emissions

As discussed in chapter 1, the Government has set draconian emissions cutting targets. Planned cuts are 28% (for 2012-17), 34% (2018-22) and 50% (2023-27) compared with the 1990 level. The overall target is to reduce emissions by 80% by 2050. Putting aside doubts over the strategy, of which there are many, the key issue then becomes the most effective way in which the cuts may be achieved.

As mentioned already a switch from coal-fired to gas-fired power stations reduces CO_2 emissions. Redpoint Energy recently provided some calculations which suggested that, by continuing with this policy, there could be a potential further 30% of CO_2 emissions savings.[3]

Redpoint's main conclusions were:

- On a unit output basis, emissions averaged 452g/kWh of all electricity generated in 2009, down from 496g/kWh in 2008. Fossil fuel plants were responsible for the majority of the emissions in 2009. On a unit output basis, these plants emitted 573g CO_2/kWh of electricity generated.[4]

- However, there was a significant difference between the average CO_2 emissions per unit of output of a coal-fired generation plant (882g/kWh) and a gas-fired generation plant

(376g/kWh). The emissions per unit of output of a coal-fired plant were effectively over twice that of a gas-fired plant. Total emissions were, therefore, very sensitive to the relative balance of coal versus gas in the generation mix.

- Redpoint calculated that if all of the electricity output produced by CCGT plant in 2009 had been generated from coal instead, there would have been an increase of around 75Mt in total CO_2 emissions (40% above the actual 2009 level). Conversely, if all of the output produced by coal plant in 2009 had instead been generated from CCGTs, there would have been a reduction in CO_2 of around 55Mt (30% below the actual 2009 level).

Continuing the switch from coal to gas is, therefore, an efficient way of cutting CO_2 emissions. And as discussed in chapter 2, gas is one of the most cost-effective ways of generating electricity. Policy-makers are of course also looking to other technologies to reduce emissions, especially wind-power and nuclear power and also carbon capture and storage (CCS). Again as discussed in chapter 2, nuclear power is cost effective, whilst wind-power and CCS are not.

Wind-power is not effective in cutting CO_2 emissions

At first glance it could be assumed that wind-power could play a major part in cutting CO_2 emissions. Once the turbines are manufactured (an energy-intensive business in itself) and installed then emissions associated with the electricity could be expected to be zero - as indeed for nuclear power.

But, as pointed out in chapter 2, wind-power is unreliable and intermittent and requires conventional back-up plant to provide electricity when the wind is either blowing at very low speeds (or not at all) or with uncontrolled variability (intermittency). Clearly the CO_2 emissions associated with using back-up capacity must be regarded as an intrinsic aspect of deploying wind turbines. This is all the more relevant given the relatively high CO_2 emissions from conventional plants when they are used in a back-up capacity.

As energy consultant David White has written: [5]

- "… (fossil-fuelled) capacity is placed under particular strains when working in this supporting role because it is being used to balance a reasonably predictable but fluctuating demand with a variable and largely unpredictable output from wind turbines.

Consequently, operating fossil capacity in this mode generates more CO_2 per kWh generated than if operating normally."

- "…it seems reasonable to ask why wind-power is the beneficiary of such extensive support if it not only fails to achieve the CO_2 reductions required, but also causes cost increases in back-up, maintenance and transmission, while at the same time discouraging investment in clean, firm generation."[6]

In a comprehensive quantitative analysis of CO_2 emissions and wind-power, Dutch physicist C. le Pair has recently shown that deploying wind turbines on "normal windy days" in the Netherlands actually increased fuel (gas) consumption, rather than saving it, when compared to electricity generation with modern high-efficiency gas turbines.[7,8] Ironically and paradoxically the use of wind farms therefore actually increased CO_2 emissions, compared with using efficient gas-fired combined cycle gas turbines (CCGTs) at full power.

Conclusions

Britain has committed itself to draconian cuts in CO_2 emissions. On the basis of the costings discussed in chapter 2, nuclear power and gas-fired CCGT were the preferred technologies for generating reliable and affordable electricity. On the basis of the evidence presented above, these two technologies are also the preferred technologies for reducing CO_2 emissions.

Wind-power fails the test on both counts. It is expensive and yet it is not effective in cutting CO_2 emissions. If it were not for the renewables targets set by the Renewables Directive, wind-power would not even be entertained as a cost-effective way of generating electricity or cutting emissions. The renewables targets should be renegotiated with the EU.

References

1. DECC, "UK climate change sustainable development indicator: 2010 greenhouse gas emissions, provisional figures", March 2011. Emissions related to the use of electricity generation are attributed to power stations, the source of these emissions, rather than homes and businesses where the electricity is used.

2. Redpoint Energy, *Electricity market reforms: an analysis of policy options*, December 2010. See also table 6a in the annex.

3. Redpoint Energy, *Electricity market reforms: an analysis of policy options*, December 2010.

4. The "emission factor" of a fuel is conventionally expressed in terms of the mass of CO_2, for example, emitted for every unit of energy delivered (gCO_2/kWh).

5. David White, *Reducing carbon dioxide emissions: estimating the potential contribution from wind-power,* Renewables Energy Foundation, December 2004. The author has held a range of senior management posts with Esso Petroleum Co. and the Exxon Group.

6. Clean generation includes gas-fired CCGT generation, clean coal and nuclear. The answer to David White's wholly sensible point is that Britain has draconian renewables targets.

7. C (Kees) le Pair, "Electricity in the Netherlands: wind turbines increase fossil fuel consumption & CO_2 emissions", October 2011. This paper is a short version of the Dutch report "Gas, wind en CO_2 op Schipol, de crash van de windmolens", available from www.clepair.net.

8. In his analysis Le Pair included the following factors: the energy needed to build and to install wind turbines; the energy needed for cabling and net adaptation; and the increased fuel consumption through partial replacement of efficient generators by low-efficiency, fast reacting open cycle gas turbines (OCGTs).

Annex

Table 1: Mott MacDonald analysis: technologies considered

Major technologies	Minor technologies
Gas-fired combined-cycle gas turbines (CCGT)*	Biomass
Gas CCGT with carbon capture and storage (CCS)*	Open Cycle Gas Turbine (OCGT)
Advanced supercritical (ASC) coal-fired power plants*	Anaerobic digestion (AD) on agricultural wastes
Coal (ASC) with CCS*	Landfill gas, sewage gas
Coal integrated gasification combined cycle (IGCC)	Biomass, combined heat and power (CHP)
Coal IGCC with CCS	Gas fired CHP
Onshore wind*	Reservoir hydro, hydro-pumped storage schemes
Offshore wind* & offshore wind R3 (round 3)	
Nuclear pressurised water reactors* (PWR)	

Note: chapter 2 includes discussion of the levelised generation costs (LGC) for the starred technologies.

Table 2: Mott MacDonald analysis: 10 case studies

Case	Start-date	Discount rate	NOAK technologies	FOAK technologies	Prices of fuel, carbon
1	2009, based on early 2010 EPC prices	10%	Gas-fired CCGT; ASC coal; onshore wind	Other	DECC's central fuel & carbon prices assumptions
2*	2009, projected EPC prices	As case 1	As case 1	As case 1	As case 1
3	2013, projected EPC prices	As case 1	As case 1	As case 1	As case 1
4	2017, projected EPC prices	10%	As case 1	As case 1	As case 1
5*	2017, projected EPC prices	10%	All	None	As case 1
6	2023, projected EPC prices	10%	All	None	As case 1
7	As case 1	7.5%	As case 1	As case 1	As case 1
8	As case 6	7.5%	As case 6	As case 6	As case 1
9	2017, projected EPC prices	10%	All	None	High fuel prices
10	As case 9	As case 9	As case 9	As case 9	Low fuel prices, flat £20/tCO_2 carbon price

Source: Mott MacDonald, *UK electricity generation costs update*, June 2010.

EPC prices = Engineering, procurement and construction prices.
NOAK = Nth of a kind (as opposed to the first), i.e. mature technologies.
FOAK = First of a kind, i.e. immature technologies.
Note: chapter 2 includes discussion of the levelised generation costs (LGC) for the starred cases.

Table 3a: DECC's projections of real energy prices

	Mid case, January 2009, 2008 prices			Central prices scenario, October 2011, 2011 prices		
	Gas (p/therm)	Coal ($/tonne)	Coal (£/tonne)	Gas (p/therm)	Coal ($/tonne)	Coal (£/tonne)
2008	58	147	92	Na	Na	Na
2010	58	110	69	44	93	60
2011				63	130	84
2012				69	130	84
2013				74	130	84
2014				80	127	82
2015	63	80	50	81	124	80
2016				81	121	78
2017				76	119	77
2018				70	116	75
2019				70	113	73
2020	67	80	50	70	110	71
2025	71	80	50	70	110	71
2030	74	80	50	70	110	71

Sources: (i) DECC, "Communication on DECC fossil fuel price assumptions", January 2009 review of 2008 estimates, coal prices converted to sterling using $1.60 to the £. There were 4 scenarios: low global energy demand; timely investment & moderate demand (mid case); high demand & producers' market power; high demand & significant supply constraints. Mott MacDonald used the mid case for 8 of its 10 cases and Parsons Brinckerhoff used the mid case for both of its cases. Mott MacDonald added a delivery charge of £6/tonne for coal and 2p/therm for gas to give a "burner tip" price. (ii) DECC, "DECC fossil fuel price projections: summary", October 2011, coal prices converted to sterling using $1.546 to the £, central prices scenario. This document covers 3 scenarios (low, central, high for oil, gas and coal prices) and gives the latest figures.

Table 3b: DECC's projections of carbon prices, real terms, £/tCO2e

	Central case, traded carbon values, June 2010, 2009 prices	Central case, total carbon price, October 2011, 2011 prices
2008	Na	19
2009	Na	12
2010	14.1	13
2011	14.3	13
2012	14.5	14
2013	14.7	16
2014	14.9	17
2015	15.1	19
2016	15.4	21
2017	15.6	22
2018	15.8	24
2019	16.1	26
2020	**16.3**	**29**
2021	21.7	33
2022	27.1	38
2023	32.4	42
2024	37.8	47
2025	43.2	51
2026	48.5	56
2027	53.9	61
2028	59.3	65
2029	64.6	70
2030	**70**	**74**
2040	135	143

Sources:
(i) DECC, "Updated short term traded carbon values for UK public policy appraisal", June 2010. These values refer to the EU Allowances (EUA), under the EU's Emissions Trading System (ETS). Mott MacDonald used these central case traded carbon values for their 2010 analysis (cases 1-9). The average annual carbon price from 2010 to 2040 works out as £54.3/t.

(ii) DECC, "Carbon values used in DECC's energy modelling", October 2011. The total carbon price = the EUA price + the carbon price support rates (carbon price support (CPS) rates), reflecting the introduction of the Carbon Price Floor (CPF) in 2013. Total carbon prices have been calculated as follows:

- For 2011 and 2012: the carbon price is in line with the projected EUA.
- For 2013, the announced level of CPS (£4.71/tCO_2, in 2011 prices) has been added to the projected EUA.
- For 2014 onwards, the price level is the higher of either the trajectory of the carbon price floor or the EUA price.

(iii) See also DECC, "A brief guide to the carbon valuation methodology for UK policy appraisal", October 2011.

Table 4a: Plant capacity (UK), Megawatts

End December	2006	2007	2008	2009	2010
Major power producers:					
Conventional steam stations:	33,608	33,734	32,423	32,431	32,439
• **Coal fired**	22,882	23,008	23,069	23,077	23,085 (27.7%)
• **Oil fired**	3,778	3,778	3,778	3,778	3,778 (4.5%)
• **Mixed or dual fired**	6,948	6,948	5,576	5,576	5,576 (6.7%)
Combined cycle gas turbine stations	24,859	24,854	26,578	27,269	32,209 (38.7%)
Nuclear stations	10,969	10,979	10,979	10,858	10,865 (13.1%)
Gas turbines and oil engines	1,444	1,445	1,456	1,560	1,560 (1.9%)
Hydro-electric stations:					
• **Natural flow**	1,294	1,293	1,392	1,395	1,391
• **Pumped storage**	2,726	2,744	2,744	2,744	2,744
Total hydro	4,020	4,037	4,136	4,139	4,135 (5.0%)
Wind	Na	795	997	1,205	1,776 (2.1%)
Renewables other than hydro & wind	96	134	213	213	213 (0.3%)
Total transmission entry capacity	74,996	75,979	76,782	77,675	83,197 (100.0%)
Other generators:					
• **Conventional steam stations**	3,059	2,924	2,722	2,813	2,757
• **Combined cycle gas turbine stations**	2,106	2,076	2,015	1,945	1,890
• **Hydro-electric stations (natural flow)**	123	126	127	131	133

• **Wind**	822	246	435	656	484
• **Renewables other than hydro & wind**	1,296	1,391	1,365	1,547	1,747
Total capacity of own generating plant	7,407	6,763	6,664	7,091	7,011
All generating companies:					
Conventional steam stations	36,667	36,658	35,145	35,244	35,196 (39.0%)
Combined cycle gas turbine stations	26,965	26,930	28,593	29,214	34,099 (37.8%)
Nuclear stations	10,969	10,979	10,979	10,858	10,865 (12.0%)
Gas turbines and oil engines	1,444	1,445	1,456	1,560	1,560 (1.7%)
Hydro-electric stations:					
• **Natural flow**	1,417	1,419	1,519	1,526	1,524 (1.7%)
• **Pumped storage**	2,726	2,744	2,744	2,744	2,744 (3.0%)
Wind	822	1,042	1,432	1,860	2,260 (2.5%)
Renewables other than hydro & wind	1,392	1,525	1,578	1,760	1,960 (2.2%)
Total capacity	82,403	82,742	83,446	84,766	90,208

Source: DECC, *Digest of UK Energy Statistics (DUKES)*, table 5.7, updated, July 2011, www.decc.gov.uk.

Notes: (i) major wind farms have been included in major power producers since 2007; (ii) small-scale hydro and wind capacity are shown on declared net capability basis and are de-rated to account for this by factors of 0.365 and 0.43 respectively.

Table 4b Plant capacity for all generating companies (UK), with wind power not de-rated, Megawatts

End December	2006	2007	2008	2009	2010
All generating companies:					
Conventional steam stations	36,667	36,658	35,145	35,244	35,196 (37.8%)
Combined cycle gas turbine stations	26,965	26,930	28,593	29,214	34,099 (36.6%)
Nuclear stations	10,969	10,979	10,979	10,858	10,865 (11.7%)
Gas turbines and oil engines	1,444	1,445	1,456	1,560	1,560 (1.7%)
Hydro-electric stations:					
• **Natural flow**	1,417	1,419	1,519	1,526	1,524 (1.6%)
• **Pumped storage**	2,726	2,744	2,744	2,744	2,744 (2.9%)
Wind, adjusted (not de-rated) figures	1,912	2,423	3,330	4,326	5,256 (5.6%)
Renewables other than hydro & wind	1,392	1,525	1,578	1,760	1,960 (2.1%)
Total capacity, wind adjusted	83,493	84,123	85,344	87,232	93,204

Notes: (i) no adjustment has been made to small-scale hydro; (ii) coal-fired plants account for about 32% of plant capacity.

Table 4c: Wind-power capacity (Megawatts), operational wind farms

	Onshore		Offshore		Total	
	Capacity (MW)	Operational wind farms	Capacity (MW)	Operational wind farms	Capacity (MW)	Operational wind farms
England	842.5	109	1,364.6	11	2,207.1	120
Northern Ireland	359.7	30	0	0	359.7	30
Scotland	2,628.1	122	10.0	1	2,638.1	123
Wales	411.9	35	150.0	2	561.9	37
UK	4,242.3	296	1,524.6	14	5,766.9	310

Source: *UK Wind Energy Database – UKWED*, RenewableUK (formerly BWEA, British Wind Energy Association), www.bwea.com, October 2011.

Table 5: Fuel used for generation, Million tonnes of oil equivalent (Mtoe)

	2006	2009	2010
Major power producers:			
Coal	35.0	23.8	24.8 (40.0%)
Oil	1.0	1.0	0.6 (0.8%)
Gas	23.9	28.2	29.4 (41.5%)
Nuclear	17.1	15.2	13.9 (19.6%)
Hydro (natural flow)	0.3	0.4	0.2 (0.3%)
Wind	Na	0.6	0.7 (1.0%)
Other renewables	0.7	0.7	1.0 (1.4%)
Net imports	0.6	0.2	0.2 (0.3%)
Total major power producers	78.7	70.2	70.9 (100.0%)
Of which:			
Conventional thermal & other stations +	38.4	26.5	27.5
CCGT	22.2	27.9	29.0
Other generators:			
Transport undertakings:			
Gas	0	0	0
Undertakings in industrial & commercial sectors:			
Coal	0.9	0.9	0.8
Oil	0.5	0.5	0.5
Gas	1.8	2.7	2.5
Hydro (natural flow)	0.1	0.1	0.1
Wind	0.4	0.2	0.2
Other renewables	1.7	3.3	3.4
Other fuels	1.6	1.0	0.8
Total other generators	9.0	8.6	8.4
All generating companies:			

Coal	35.9	24.7	25.6 (32.3%)
Oil	1.4	1.5	1.2 (1.5%)
Gas	26.8	30.9	32.0 (40.4%)
Nuclear	17.1	15.2	13.9 (17.5%)
Hydro (natural flow)	0.4	0.5	0.3 (0.4%)
Wind	0.4	0.8	0.9 (1.1%)
Other renewables	3.5	4.0	4.4 (5.5%)
Other fuels	1.6	1.0	0.8 (1.0%)
Net imports	0.6	0.2	0.2 (0.25%)
Total all generating companies	87.7	78.8	79.3 (100.0%)

Source: DECC, "Digest of UK energy statistics" (DUKES), annual tables, www.decc.gov.uk
+ Mainly coal, but includes gas turbines, oil engines & plants using thermal renewable sources.

Table 6a: Parsons Brinckerhoff updates, Arup updates: technologies considered

Major technologies, non-renewable (PB)	**Renewable technologies (Arup)**
Gas-fired combined-cycle gas turbines (CCGT)	Onshore wind
Gas CCGT with carbon capture and storage (CCS)	Offshore wind
Advanced supercritical (ASC) coal-fired power plants	Hydro
Coal (ASC) with CCS	Marine
Coal integrated gasification combined cycle (IGCC)	Geothermal
Coal IGCC with CCS	Solar PV (photovoltaic)
Nuclear pressurised water reactors (PWR)	Dedicated biomass (solid), biomass co-firing, biomass conversion, bioliquids
	Energy from waste, Anaerobic digestion
	Landfill gas, sewage gas
	Renewable combined heat and power (CHP)

Table 6b: Comparison of case studies by PB, Arup and Mott MacDonald

Parsons Brinckerhoff, conventional					
Case	**Start-date**	**Discount rate**	**NOAK technologies**	**FOAK technologies**	**Prices**
1	2011, projected EPC prices	10%	Including gas-fired CCGT; ASC coal	Other	DECC's central fuel and carbon prices assumptions
2	2017, projected EPC prices	10%	All	None	As case 1
Arup, renewables					
Case	**Start-date**	**Discount rate**	**NOAK technologies**	**FOAK technologies**	**Prices**
1	2011, projected EPC prices	10%	FOAK-NOAK mix	FOAK-NOAK mix	Na
2	2017, projected EPC prices	10%	All NOAK	None	Na
Mott MacDonald					
Case	**Start-date**	**Discount rate**	**NOAK technologies**	**FOAK technologies**	**Prices**
1	2009, based on early 2010 EPC prices	10%	Gas-fired CCGT; ASC coal; onshore wind	Other	DECC's central fuel and carbon prices assumptions
2*	2009, projected EPC prices	As case 1	As case 1	As case 1	As case 1
5*	2017, projected EPC prices	10%	All	None	As case 1

Sources: (i) Parsons Brinckerhoff, *Electricity Generation Cost Model – 2011 update revision 1*, for DECC, August 2011; (ii) Ove Arup & Partners, *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*, for DECC, June 2011

Table 7a: Comparison of PB case 1 with MM case 2, levelised costs, £/MWh

	Gas CCGT	Gas CCGT + CCS	ASC coal	ASC coal + CCS	Nuclear PWR
PB case 1:					
Costs excluding carbon costs	58.5	102.4	47.6	102.6	74.1
Carbon costs	18.1	2.4	47.8	5.7	0
Total	76.6	104.8	95.4	108.3	74.1
MM case 2:					
Costs excluding carbon costs	64.6	109.2	61.9	129.7	97.1
Carbon costs	15.1	2.1	40.3	6.5	0
Total	79.7	111.4	102.2	136.2	97.1
Differences between PB (case 1) & MM (case 2):					
Costs excluding carbon costs	-6.1	-6.8	-14.3	-27.1	-23.0
Carbon costs	3.0	0.3	7.5	-0.8	0
Total	-3.1	-6.6	-6.8	-27.9	-23.0

Table 7b: Comparison of PB case 2 with MM case 5, levelised costs, £/MWh

	Gas CCGT	Gas CCGT + CCS	ASC coal	ASC coal + CCS	Nuclear PWR
PB case 2:					
Costs excluding carbon costs	60.6	90.7	47.6	85.5	64.9
Carbon costs	27.8	4.1	69.3	8.6	0
Total	88.4	94.8	116.9	94.1	64.9
MM case 5:					
Costs excluding carbon costs	66.6	98.5	59.4	100.5	67.8
Carbon costs	29.6	4.1	73.8	11.4	0
Total	96.5	102.6	133.2	111.9	67.8
Differences between PB (case 2) & MM (case 5):					
Costs excluding carbon costs	-6.0	-7.8	-11.8	-15.0	-2.9
Carbon costs	1.8	0	-4.5	-2.8	0
Total	-4.2	-7.8	-16.3	-17.8	-2.9

Table 7c: Comparison of Arup analysis with MM, levelised costs, £/MWh

	Onshore	Offshore	Offshore round 3
Arup case 1:			
Total costs	90 (>5MW)	132 (>100MW)	149
MM case 2:			
Total costs	87.8	148.5	177.4
Differences between Arup (case 1) & MM (case 2):			
Total costs	2.2	-16.5	-28.4
Arup case 2:			
Total costs	88 (>5MW)	117 (>100MW)	130
MM case 5:			
Total costs	86.3	112.4	127.9
Differences between Arup (case 2) & MM (case 5):			
Total costs	1.7	4.6	2.1

Source: (i) Parsons Brinckerhoff, *Electricity Generation Cost Model – 2011 update revision 1*, for DECC, August 2011; (ii) Mott MacDonald, *UK electricity generation costs update*, June 2010; (iii) Ove Arup & Partners, *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*, for DECC, June 2011.