A Green Alliance briefing

November 2012

The future of gas power

Critical market and technology issues

by Rachel Cary

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Green Alliance
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Green Alliance
36 Buckingham Palace Road, London, SW1W 0RE
020 7233 7433
ga@green-alliance.org.uk
www.green-alliance.org.uk

The Green Alliance Trust
Registered charity no. 1045395
Company limited by guarantee
(England and Wales) no. 3037633
Registered at the above address.

Introduction

The future role of gas in the UK power sector has become an increasingly controversial issue. Some worry that too high an investment in new gas power stations will jeopardise our ability to meet carbon budgets as it could delay or prevent electricity sector decarbonisation. Others worry that without significant investment in flexible new gas power stations over the next decade, we may risk maintaining security of supply. The government is to publish a strategy that will set out the role that gas generation will play in the future and what government will do to enable this.

Currently, capacity margins (the difference between the amount of electricity that generators on the system could produce and the maximum demand) are generous at around 20 per cent.[1] The recession has dampened demand and looks likely to continue to do so for the foreseeable future. The closure of many of the existing fleet of fossil and nuclear electricity plants, due to environmental legislation and old age means that future capacity margins may fall over the coming decade. The Department of Energy and Climate Change (DECC) estimates that capacity margins could fall to under five per cent by the late 2020s or earlier, if there is higher demand for electricity.[2] Others, however, suggest that capacity may not be an issue over the next two decades as new low carbon sources of supply come onto the electricity system and existing power stations are given life extensions.

Looking at capacity margins alone won't be enough to ensure security of supply in the future because flexibility will be needed. As we move to increasing amounts of intermittent renewables, such as wind, we need to be able to cover reductions in output over hours or even days. Resources that are flexible, ie can increase or reduce electricity production and demand within a relatively short period and other long, more sustained periods, will become increasingly important.

Building new gas power stations isn't the only option for ensuring security of supply; interconnection, demand reduction, demand side response and storage will all need to play an important role. But how much are they likely to contribute and over what timescales?

If new gas power stations do need to be built what sort of plant is best? Will efficient Combined Cycle Gas Turbines (CCGT), or less efficient but less capital intensive Open Cycle Gas Turbines (OCGT), be the right technology for our future needs? What about Combined Heat and Power (CHP) that is both flexible and efficient? If large CCGTs are built what options do we have for abating carbon emissions through carbon capture and storage (CCS)?

This discussion paper aims to explore some of these issues and map different stakeholder views of the future role of gas in our electricity mix. It outlines some of the issues to be considered further by a gas dialogue event involving a specialist group from industry, NGOs and academia.

Does closure of existing power stations lead to capacity crunch?

So, what is our current electricity generation mix and how will this change? According to DECC in 2010 the total capacity on the transmission system was 83GW to meet a peak demand of around 61GW. [3] Of this 28GW was coal-fired and 30GW gas-fired. The large combustion plant directive (LCPD) will lead to the closure of around 12GW of coal and oil-fired generation by the end of 2015 at the latest. Ofgem's latest capacity assessment highlights that some coal plants will close before this date as the relatively low price of coal, the desire to minimise fixed costs and exposure to higher carbon prices[4] have meant that operators have run these plants at full load for extended periods, quickly running through the operational hours allotted to them under the LCPD[5] However, Ofgem's paper does highlight that, even at this reduced level of capacity, the UK's system security level in 2015-16 (in terms of loss of load expectation) will still be higher than in many other member states.

The industrial emissions directive (IED) could also lead to further closures by 2023 although the exact impact of the IED on existing gas is unknown. Many of the older gas power stations may choose to close rather than fit expensive selective catalytic reduction (SCR) equipment to reduce their NOx emissions to a level that would comply with the legislation. In addition, up to around 6GW of existing nuclear generating capacity is reaching the end of its regulated life by 2020. In total this means that up to around 18GW of capacity might close by 2020, with potential further closures by the end of 2023.

However, the capacity situation may not be as bleak for a number of reasons:

- demand may stay flat due to the continuation of recession;
- many of the existing nuclear plants are expected to get life extensions;
- mothballed or 'preserved' gas plants could be brought back on-line; and
- around 30GW of new capacity is due to come on line, two thirds of which is renewable.[6]

National Grid suggest that only one new CCGT may be needed by 2015 to ensure system security if Teesside is brought back online, lifetime extensions are given to existing nuclear and that only two more may be needed by 2019-20.[7]

Bloomberg New Energy Finance (BNEF) suggests that "although supply and demand balance will tighten following plant closures mid-decade, capacity margins discounted for the intermittency of renewables should remain at a comfortable level through 2020". [8]

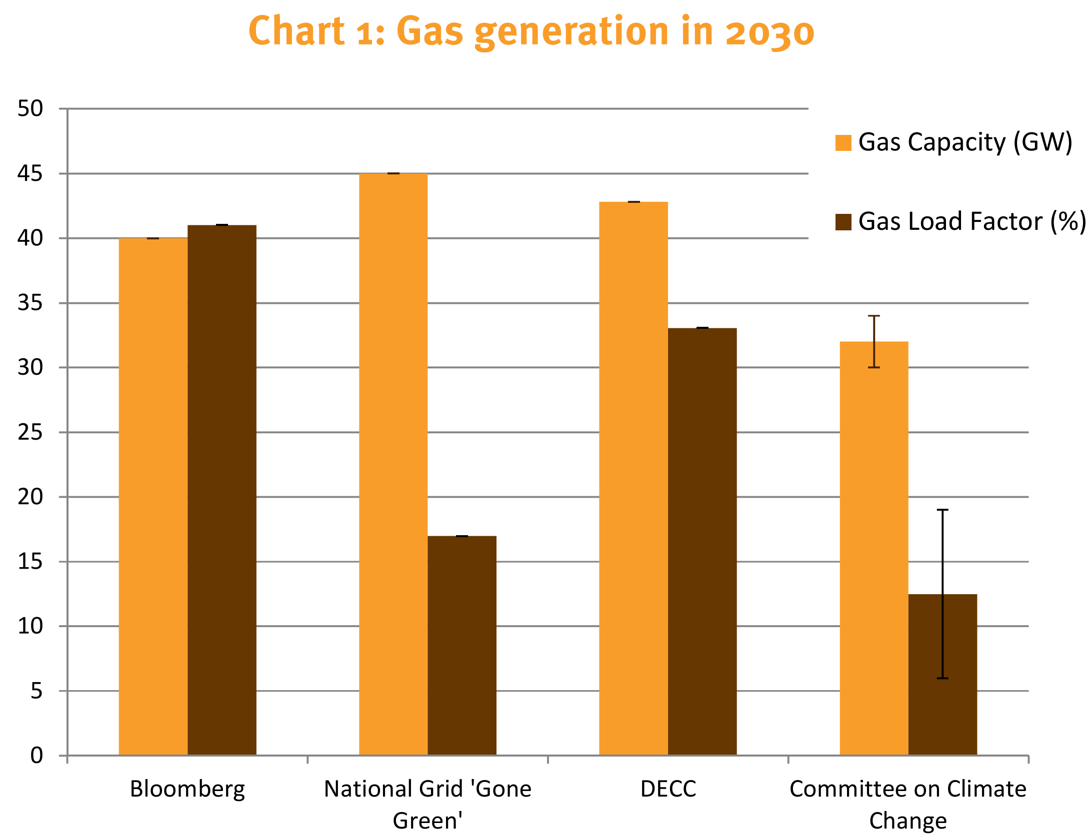
A 'dash for gas' is unlikely in recession but a risk in upturn

Only 9GW of unabated gas plant can be run at typical load factors, to meet an electricity demand of 450TWh, if we are to meet the carbon intensity target for the electricity sector of 50gCO_2/kWh in 2030.[9] This figure may be even lower as the actual carbon intensity of the power sector in the Committee on Climate Change (CCC) budgets is only 38gCO_2/kWh.

The amount of existing gas still left on the system (and therefore the need for new plants) is very dependent on lifetime assumptions which depend on both technical and economic factors. If we assume existing gas power stations typically have a lifetime of 25 years (as older plant become less economic), there will still be 2GW of existing power stations on the system in 2030.[10] If, however, their lifetime is longer at 30 years which is technically possible, there will still be 10GW of existing power stations ie more than could run at high load factors whilst meeting the electricity sector decarbonisation target.

Predictions of the amount of new gas likely to be built over the next decade vary widely. National Grid projected in 2011 that there will be 12GW of new CCGT by the end of 2015.[11] It predicts there will be around 44GW of gas power stations on the system in 2018. Bloomberg anticipates 11GW of new gas will be built by 2016, with a further 2GW built between 2016 and 2030. Redpoint's modelling for DECC for the impact assessment of their emissions performance standard (EPS) suggests that there will be some 12GW of new CCGT gas plants by 2030.[12] There are also significant differences in the assumed average load factor ie how much the fleet will be used. (Note that average load factors may be low but will vary significantly across different gas power plants, as new plant is more efficient and will be run at higher load factors than older plant).

The different capacity of gas plant on the system in 2030 envisaged by these different organisations and their average load factor is shown below.[13]



Of the 12GW of plant expected by National Grid to come online by 2016, 2.5GW has been completed[14], 1.3GW is under construction[15] and a further 6.8GW has been given planning permission [16]. The remaining 1.5GW of plant has been delayed till 2016[17]. If the number in the pipeline are built and run at high load factors we will exceed our carbon targets.

Some suggest that few if any of these plants will be built for a number of reasons:

- **Weak economic case**
  The difference between the gas price and electricity price, the 'spark spread' has been low for a number of years and a number of gas power stations have been mothballed, such as the CCGT at Teesside. This is due to an excess of generation compared to demand, which has been weak due to recession.
- **Waiting for contracts**
  Through its electricity market reform (EMR) the government is introducing a capacity market which will give generators and demand side services capacity payments rather than relying on the current energy-only market to give sufficient price signals (ie high prices when capacity margins are tight). The promise of future capacity payments creates a 'wait and see' situation preventing investment.
- **Unknown future market share and average load factors**
  There is also uncertainty around the future volumes of low carbon generation being brought on through the new feed-in tariff with contracts for difference (FiT CfD) and,

therefore, what size of market will be left for gas power to fill. There is uncertainty around the average load factor new gas plants will run at in the medium to long-term as it will depend on both the profile of future electricity demand, the availability of other flexibility resources and the nature of new low carbon supply. In the short term, the main sources of finance for new plant will be based on the ability for gas plants to make money from participating in the wholesale market, which will be heavily dependent on expected load factors. In the medium to long term as the penetration of low carbon power increases, gas will increasingly play a peaking role and developers will need to estimate how much additional money they require to operate and bid this into the capacity market.

There is concern that a return to strong economic growth could change this situation. Either way, the introduction of capacity payments means that new gas power stations may be built even if private sector investment isn't currently forthcoming in an energy-only market. It will be important to consider how much and what sort of gas plant will be needed to best suit our future needs.

Even if a significant number of gas power stations are built, it is envisaged that the low carbon generation coming on will displace gas (as they have low or no running costs so can bid into the electricity market at very low prices). This displacement will be helped by the carbon floor price (CFP) which will make the cost of gas power increasingly expensive if it heads up to £70tCO_2 in 2030. There is however a risk that insufficient contracts are given out to low carbon generators, if the pot of funding available is insufficient, and that government may fail to stick to its carbon floor trajectory. In this case, new gas plants paid for through the capacity market may not be run as peaking plant to complement renewables as intended, but may be run at high load factors, putting electricity sector decarbonisation in jeopardy.

Different views on the role of gas in 2030

The Committee on Climate Change (CCC) has warned that 'the role for unabated gas fired power generation should be limited to balancing the system in 2030, by which time the share of unabated gas generation in the total should be no more than ten per cent, compared to 40 per cent today." [18] To get to 50gCO_2/kWh in 2030 the CCC envisages there being "investment in around 10GW of unabated gas-fired power capacity over the next two decades, resulting in total gas-fired capacity of around 30GW in 2030. This would play an important role generating at low annual load factors (eg less than ten per cent on average in 2030) to balance intermittent renewable generation."[19] The CCC suggests that investment in conventional gas after 2020 should be ruled out. [20] It warns that "if the 30GW of gas-fired capacity were to generate as baseload plant in 2030, this would raise average emissions to 200gCO_2/kWh (ie beyond the limits implied by carbon budgets)."[21]

This view that, beyond 2030, gas should only play a peaking role is supported by other commentators. In its response to the government's call for evidence on its gas strategy, WWF-UK says that "whilst WWF-UK recognises that unabated gas-fired power stations will have a useful role to play as a bridging and system balancing fuel in a power sector that is near-decarbonised by 2030, we are strongly of the view that the role of gas needs to be carefully monitored from both an environmental and system security perspective." WWF's *Positive energy* report found that "in a scenario with 24GW of installed gas capacity, only 5GW of gas is unabated CCGT working at baseload with 17GW fitted with CCS and the remaining 2GW being OCGT peaking plant. Any significant increase in baseload unabated CCGT plant will lead to the decarbonisation target being missed." [22,23]

Others however are optimistic about the possibility of a future cheap gas world, and think that gas should continue to play an important role in the coming decades. In his negotiations with the DECC Secretary of State Ed Davey around the renewables obligation banding review, Chancellor George Osborne revealed his wish to see a continued heavy reliance on gas running at high load factors rather than as a back-up to renewables. [24]

Policy Exchange suggests that although the electricity sector is likely to need to be virtually carbon free by 2050, there may be benefits in investing in new unabated gas power as a transition fuel, if gas prices are low.[25] It argues that if CCS proves not to be technically or economically viable, new gas power stations can be retired ahead of their natural economic or technical lifetime. It suggests that, due to the relatively low capital cost of gas power stations, it is likely to be "much cheaper in the next decade to build gas generation and retire it well ahead of its full lifetime than to build R3 offshore wind."

DECC is keen to stress that we can both meet our carbon targets whilst using gas power stations at high load factors. In July 2012, Lord Marland's written statement on the renewables obligation said "We see gas continuing to play an important part in the energy mix well into and beyond 2030, while meeting our carbon budgets. We do not expect the role of gas to be restricted to providing back up to renewables, and in the longer term we see an important role for gas with CCS."[26] The government's Carbon Plan predicts that between 10GW and 20GW of new gas capacity can come online in the next 20 years without jeopardising carbon targets.[27] DECC Secretary of State Ed Davey has recently announced his expectation that 20GW of new gas plant capacity will be built by 2030.[28]

Need for CCS if gas is run at high load factors

If gas power plants are to run at high load factors 2030 it will need to be fitted with CCS to be compatible with a 50gCO_2/kWh target. Fitting CCS to gas plants will be expensive. Element Energy estimates that "the capital cost for the addition of post-combustion capture equipment to a CCGT facility whether capture ready or not, nearly doubles the total capital cost of the plant." It is also important to consider whether gas plants with CCS can provide flexibility services. Insights from current R&D suggest that gas plants with CCS could potentially be flexible (although capture rates may be slightly lowered if plants are ramped up and down a lot) but the high costs associated with CCS may mean that gas plants with CCS would need to run flat out to recover these additional costs.

Element Energy estimates that "over 85 per cent of the existing CCGT fleet is technically capable of accepting CCS".[29] New power stations are required to be 'CCS ready' but there is concern that many of the proposed gas plants are in the wrong location for CCS, making it impossible or overly expensive to fit the technology at a later date. CCS remains an unproven technology at scale and across the full supply chain from generation to storage. However, there are plans for a gas CCS demonstration project at Peterhead, and its developers SSE and Shell are currently bidding for European and UK government funding. [30]

If gas CCS is proven through the demonstration programme, ensuring widespread take up of the technology will require a combination of carrots and sticks. Existing regulation is unlikely to drive the deployment of CCS on gas even if it is shown to be technically and economically viable. The Energy Bill sets an EPS of 450gCO_2/kWh for new plant until 2045. As gas power stations typically emit between 365-488gCO_2/kWh[31], plants that come through the planning system under the current EPS will not face any restrictions (either in terms of limited running hours or CCS retrofit) during their lifetime.

If such weak regulation is used, it means the incentives have to be high to ensure take up. It is unclear whether the new low carbon contracts will be a sufficient carrot as there is currently very little detail on the design of the CfDs for CCS nor is there any clarity on the strike price. It is also unclear as to what the CfD will cover. A number of important questions remain such as:

- If CCS is retrofitted onto an existing plant, the capital cost for the base plant is sunk, so will the CfD only pay for the CCS costs?
- For a new plant fitted with CCS will the CfD cover the whole plant?

Alternatively, by the time of deployment the carbon price could be high enough to drive take up, although this requires the government to stick to a high carbon price trajectory and for the costs of CCS to be sufficiently low enough to make it economic.

In the medium to long term, as the proportion of plant with CfDs increases, the energy price will be reduced. This could make any unabated proportion of the gas plant uneconomic without significant support through the capacity market. The government, therefore, needs to provide further clarity about the interaction between the CfD and capacity mechanism as they will both have a significant impact on the economics of a gas CCS plant.

Flexibility options

By 2030, the electricity system will look very different, with a significant proportion of electricity coming from intermittent renewables like wind. Demand profiles will also change significantly as a growing proportion of heat and transport is electrified. Various options will be needed to enable the production of electricity, or demand, to be increased or decreased on relatively short timescales. Gas is likely to play a role as a flexible back-up to renewables alongside storage, greater interconnection and demand side response.

Will alternatives to gas deliver?

In its renewable energy review, the CCC sets out an illustrative scenario in 2030 with renewables accounting for 40 per cent of electricity generation, nuclear 40 per cent, CCS 15 per cent and unabated gas ten per cent. It also considered a higher renewables scenario where renewables account for 50 per cent of generation and CCS is neither technically feasible or economically viable. Under this scenario there is 30GW of CCGT running at a 19 per cent load factor. This scenario also assumes significant levels of demand side response, interconnection and bulk storage. In the table below we consider whether the flexibility options in this high renewable scenario are likely to deliver.

It is worth noting that the scenario includes a significant reduction in electricity use for existing services. It assumes demand in 2030 is 409TWh/year including 120TWh for heat and transport. As current demand is 350TWh this represents a reduction of 17 per cent in electricity used for existing services. This is possible, but as shown by a recent DECC report, existing policy will only deliver around 13 per cent at best. [32] There is therefore a need to introduce new policy such as an electricity efficiency feed-in tariff through EMR.[33]

Will flexibility options required under the CCC's 50 per cent renewable scenario deliver?

Flexibility option	Level under CCC 50 per cent renewable scenario	Description	Deliverable and reliable?
Demand side response (DSR)	~20GW	Equal to 15 per cent of total demand	DSR could play a significant role if adequately incentivised through the capacity market. In forward capacity markets in the USA, demand side resources clear around ten per cent of the auction volume term. In future some domestic load shifting will be enabled through smart meter roll-out. A significant amount of DSR in 2030 comes from domestic electric heating with storage and electric cars.
Interconnection	16GW	From current levels of 3.5GW	Greater interconnection will help smooth both demand and supply and should reduce the amount of spare generating capacity required. There may be financing issues as load factor drops significantly above 7GW.[34] In addition the carbon floor price may result in electricity prices being higher than elsewhere in Europe in which case interconnectors may be full importing electricity.
Bulk and distributed storage	4GW	Currently, 2.7GW of pumped hydro storage connected to the transmission network.	DECC estimates that most additional storage will be in the distribution network and that total storage of anything between 1GW-29GW could be achieved by 2050.[35] A study by Imperial College for the Carbon Trust found that energy storage technologies could potentially generate total system savings of £10 billion per year and storage deployment of 25 GW.[36] Heat pumps and CHP will need to be flexible and come with heat storage.
Balancing generation	30GW	Unabated gas running at a load factor of 19 per cent	As outlined above we will have between 2-9GW of existing gas power stations in 2030 depending on lifetime assumptions. New build will be required but may be hard to finance given low load factors. It may be difficult to ensure the gas plants built are run at such low load factors without some form of policy backstop eg reduced running hours.
	4GW	Coal CCS	Dependent on successful outcome of CCS demo. In addition coal CCS is unlikely to be run as flexible generation, as it suffers from similar economic barriers to nuclear.

It is not just the potential capacity of these resources that is important, it is also worth considering when the alternatives to gas will be available and, therefore, whether they will displace the need for new CCGTs in the short to medium term. It will also be important to consider over what timescale they can provide services as ensuring security of supply during periods of low wind that can last for several hours and even days.

How useful will non-gas flexibility options be in dealing with wind?

	Timing compatible?	Deal with periods of low wind?
Demand side response (DSR)	Partly – scope to shift existing demand especially in non-domestic sector. The uptake of both electric cars and heat pumps may not be significant until the late 2020s however, yet the penetration of wind will reach significant levels at the beginning of the 2020s.	Yes – some DSR services eg turning off or lowering input of commercial refrigeration could be staggered eg each participant provides service for one hour, so it only takes 24 participants to provide services for full day.
Interconnection	Yes - new interconnectors can take between four to six years to construct. The East-West Interconnector with Ireland was announced in 2006, and became operational earlier this year. BritNed, connecting the UK and the Netherlands, was announced in 2007 and completed in 2011.	Partly - anticyclones may result in low wind speeds across large areas of Europe. However, even if renewable output is low across connected areas, greater interconnection should smooth demand profiles. Greater interconnection could provide access to geothermal and significant pumped hydro resources such as in Norway.[37]
Storage	May not be - much of new storage will be in distributed networks, it will depend on the uptake of heat pumps and CHP connected to heat networks. Uptake may be low until the late 2020s.	May not - the energy that can be produced from pumped storage is proportional to the size of the reservoir. Current UK facilities are only large enough to provide hourly storage. Meeting demand over longer periods would require facilities of a substantial size. It may be difficult to coordinate and guarantee the output from lots of distributed storage over sustained periods. Large heat storage could provide a way of reducing demand for electricity over long periods of time.

What sort of gas stations will be best?

As the CCC's analysis suggests that some unabated gas will be needed in 2030, it is important to consider what sort of gas power would be best so that policy can be designed to deliver the capacity best suited to our future needs.

Given that wind speeds tend to fall over hours rather than seconds there may not be a need for additional OCGTs in a non-peaking capacity, as CCGTs could ramp up quickly enough and are significantly more efficient.[38]

However, CCGTs run at high load factors – typically over 60 per cent - and their performance may be reduced if they are turned on and off many times a day. In addition, CCGTs tend to be around twice as expensive so, although fuel costs are lower (typically they are a third more efficient) this may not justify the higher capital costs involved. Some existing CCGTs can be converted to run as OCGTs.[39] This reduces their efficiency and capacity but means they can run for shorter periods, making them more flexible.

Combined heat and power (CHP) plants and other distribution connected generators, eg onshore wind, don't currently play a role in balancing the transmission system for two reasons:[40]

- They are still relatively small in total capacity compared with other forms of generation so do not have a large impact on overall capacity.
- Distribution networks are not smart enough to monitor these generation sources and feed information back to the system operator.

Given their high efficiency compared to generating heat and electricity separately, and the potential contribution they could make to managing demand on the electricity distribution networks, which will become increasing important as demand for heat pumps and electric vehicles increases, they should play an increasing balancing role in future.

If CHP units are slightly oversized and fitted with a hot water storage system, then they could export excess electricity to the grid at peak times whilst storing the heat produced for use at times of low electrical demand.[41] Recent policy changes such as the removal of Levy Exemption Certificates (LECs) make it significantly less economic for CHP systems to export electricity however and systems will be increasingly designed only to meet onsite demand. Unless the full value of flexibility is reflected in mechanisms such as the capacity market, CHP operators are unlikely to oversize plant to offer export services, and will size their plant according to their contracted heat loads.

Summary of technical features of different types of gas plant

	CCGT	OCGT	CHP
Best practice emissions per kWh electricity	350gCO_2/kWh	700gCO_2/kWh	280-290gCO_2/kWh
Efficiency	58 per cent	39 per cent	Depends on how it is run ~ 70 per cent +
Able to ramp up and down?	Yes	Yes	Yes, but only if connected to heat storage or if there is a mix of heat supply (so you can run part of plant just to produce electricity to meet peak demand).
Able to contribute to system balancing?	Yes	Yes	Yes, depending on whether heat supply and/or demand is flexible. Large-scale CHP connected to industrial heat demand, such as the Isle of Grain, can provide flexible output as heat output can be varied. Smaller CHP embedded in the distribution network may be able to flex its output if oversized for on-site demand, but may need to participate through an aggregator to access the balancing market. There also needs to be more sophisticated flow between transmission and distribution networks.

[1] De-rated capacity margins have increased from around eight per cent in 2007 to 20 per cent in 2011. Source: DECC, 2011, *Planning our electric future: technical update*, www.decc.gov.uk/assets/decc/11/meeting-energy-demand/energy-markets/3884-planning-electric-future-technical-update.pdf

[2] Ibid

[3] Ibid

[4] From 2013 fossil fuel power stations will be exposed to the Carbon Floor Price.

[5] Ofgem, 2012, *Electricity Capacity Assessment*. Online: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/

[6] Bloomberg New Energy Finance, 2012, *White paper – UK power forecasts, weak demand takes the bite out of the British capacity crunch*, http://bnef.com/WhitePapers/download/64

[7] Mark Ripley, National Grid, slides from Cornwall energy presentation, 17 April 2012

[8] Bloomberg New Energy Finance, 2012, *White paper – UK power forecasts, weak demand takes the bite out of the British capacity crunch*

[9] Assuming load factor of 64 per cent based on DUKEs 2010 data. Using an emissions factor of 0.44kgCO_2/kWh for CCGT. Source: Oxford University, 2005, emissions factors and the future use of fuel, www.eci.ox.ac.uk/research/energy/downloads/40house/background_doc_m.pdf

[10] Based on DUKEs 2010 Table 5.11.

[11] National Grid, 'National Electricity Transmission System Seven Year Statement', 2011. This document outlines the new CCGT expected to come onto the system in 2015 (those under construction, consented and in planning), but works on the assumption that all coal plant shutting down under the LCPD will close in 2016. Because of the lower price of coal relative to gas, many of these older plant are running through the 20,000 operational hours the LCPD permits faster than expected and will close earlier than this date. For example, EON have stated that Ironbridge will close in 2013, while Kingsnorth and Cockenzie have approximately 25% of their allotted hours remaining (DECC & Ofgem, 'Statutory Security of Supply Report', 2011.

[12] DECC, 2011, *Emissions performance standard impact assessment*, www.decc.gov.uk/assets/decc/11/policy-legislation/emr/2179-eps-impact-assessment-emr-wp.pdf

[13] Sources: Bloomberg New Energy Finance, 2012, *White paper – UK power forecasts, weak demand takes the bite out of the British capacity crunch*, National Grid, 2012, *Future Energy Scenarios*; DECC, 2011, *Emissions performance standard impact assessment*; Poyry for Committee on Climate Change, 2011, *Analysing technical constraints on renewable generation to 2050*; Redpoint for Committee on Climate Change, 2012, *Modelling the trajectory of the UK power sector to 2030 under alternative assumptions*

[14] This covers the Isle of Grain, and Pembroke plants

[15] This is the West Burton CCGT.

[16] National Grid, 'National Electricity Transmission System Seven Year Statement', 2011. This document lists the following plants as having consent to build and a predicted completion date before 2016: Abernedd Stage 1 (435MW), Partington Power Station (910MW), Brine Field (1020MW), South Holland Stage 1(390MW & 450MW), Barking C (470MW), Drakelow D(1320MW), Thames Haven(840MW), and Kings Lynn B(981MW). Several of these plants are on hold and it is presently unclear which projects will be taken forward.

[17] This is the proposed new Carrington II power station.

[18] CCC, Statement by David Kennedy on unabated gas-fired generation, 24 May 2012: www.theccc.org.uk/news

[19] Adair Turner letter to Ed Davey on emissions performance standard (EPS) for gas-fired power generation: 27 March 2012 http://downloads.theccc.org.uk.s3.amazonaws.com/Letters/EdwardDaveyMP_Letter270312.pdf

[20] Committee advises government to consider extending CCS demos and emissions performance standard to cover gas generation, www.theccc.org.uk/news/latest-newsletter/newsletter-articles/710-committee-advises-government-to-consider-extending-ccs-demos-and-emissions-performance-standard-to-cover-gas-generation

[21] Adair Turner letter to Ed Davey on Emissions Performance Standard (EPS) for gas-fired power generation - 27 March 2012

[22] The scenario assumes that 62 per cent of power would come from renewables and that system balancing is partially provided through interconnection with demand side response also playing a role.

[23] WWF, 2011, *Positive energy*, http://assets.wwf.org.uk/downloads/positive_energy_final_designed.pdf

[24] www.guardian.co.uk/environment/2012/jul/23/george-osborne-letter-ed-davey-gas-

[25] Policy Exchange, 2012, *Fuelling transition - prioritising resources for carbon emissions reduction*, www.policyexchange.org.uk/images/publications/fuelling%20transition.pdf

[26] www.decc.gov.uk/en/content/cms/news/wms_ro_lm/wms_ro_lm.aspx

[27] HM Government, 2011, *The carbon plan*, www.decc.gov.uk/assets/decc/11/tackling-climate-change/carbon-plan/3702-the-carbon-plan-delivering-our-low-carbon-future.pdf.

[28] DECC, speech by Ed Davey to GasTech Conference, 8 October 2012, www.decc.gov.uk/en/content/cms/news/gastech_ed/gastech_ed.aspx.

[29] Element Energy, 2010, *Potential for the application of CCS to UK industry and natural gas power generation*, http://downloads.theccc.org.uk.s3.amazonaws.com/0610/pr_supporting_research_element_Energy_CCS_on_gas_and_industry.pdf

[30] The Peterhead CCS project will capture CO_2 from SSE's Peterhead Power Station in Aberdeenshire, transporting and storing it in Shell's Goldeneye offshore geological facility in the North Sea.

[31] Houses of Parliament, 2011, *Carbon footprint of electricity generation*, www.parliament.uk/documents/post/postpn_383-carbon-footprint-electricity-generation.pdf.

[32] McKinsey for DECC, 2012, *Capturing the full electricity efficiency potential of the UK*, www.decc.gov.uk/assets/decc/11/cutting-emissions/5776-capturing-the-full-electricity-efficiency-potential.pdf.

[33] Green Alliance and WWF, 2012, *Creating a market for electricity savings*, http://www.green-alliance.org.uk/grea_p.aspx?id=6665

[34] Energy Research Partnership, 2012, *Delivering flexibility options for the energy system: priorities for innovation*, www.energyresearchpartnership.org.uk/dl395

[35] DECC, 2012, *Electricity system: assessment of future challenges – annex*, www.decc.gov.uk/assets/decc/11/meeting-energy-demand/future-elec-network/6099-elec-system-assess-future-chall-full.pdf

[36] www.carbontrust.com/media/129310/energy-storage-systems-role-value-strategic-assessment.pdf

[37] Poyry for Committee on Climate Change, 2010, *Options for low carbon power sector flexibility to 2050*, http://downloads.theccc.org.uk.s3.amazonaws.com/4th%20Budget/fourthbudget_supportingresearch__Poyry_%20power%20sector% per cent20flexibility%20to%202050.pdf.

[38] According to a report by NERA for Scottish Power, we are unlikely to need more fast response (flexible) plant as total wind output seems to change relatively slowly in aggregate, so that the variation over an hour (or even over four hours) can be met by varying the output of ordinary capacity, both by changing the output of plant that is already

running and by starting or stopping whole plants. Instead NERA suggests there is a need to ensure there is sufficient peaking capacity (at times of high demand) and of mid-merit capacity (at times of low demand) to deal with periods of low wind over hours or days. Source: NERA, 2011, Electricity Market Reform: assessment of a capacity payment mechanism, www.nera.com/nera-files/PUB_ScottishPower_0311.pdf

[39] By fitting bypass stacks for the hot exhaust gases so the steam turbine is effectively closed down.

[40] DECC, 2012, *Electricity system: assessment of future challenges – annex*

[41] Ibid