UK Gas Generation Strategy – BG Group submission

Introduction

BG Group is an international natural gas company, active in more than 25 countries around the world. BG Group produces more than 6% of total UKCS gas annually. In recent months, the company has begun to produce its first gas molecules from Norwegian waters – gas which is imported into the UK. BG Group owns 50% of the Dragon LNG import terminal in Milford Haven and is a Belgium-UK Interconnector 'shipper'. The company has been a constant fixture in the FTSE100's top 10 for several years.

BG Group has been involved in discussions with HM Government on how best to reform the UK's gas and power markets for more than two years. We agree with the Government that the UK's energy – and power - supply security is best based on a range of diverse fuel types. Our principal concerns have been that:

- Policy-makers may underestimate how much gas will be needed in the fuel-mix - particularly to the middle of the next decade;
- Policy-makers may assume that the necessary investments in new gas production and gas infrastructure will emerge naturally and in a timely fashion; and
- Capacity payment models that are more sharply targeted than the models currently under discussion may be required to avoid tightness in the middle and towards the end of this decade.

Response to 'call for evidence' questions

1. **What are the main strengths and weaknesses of gas generation in helping deliver a secure, affordable route to decarbonisation through to 2020 and then by 2050?**

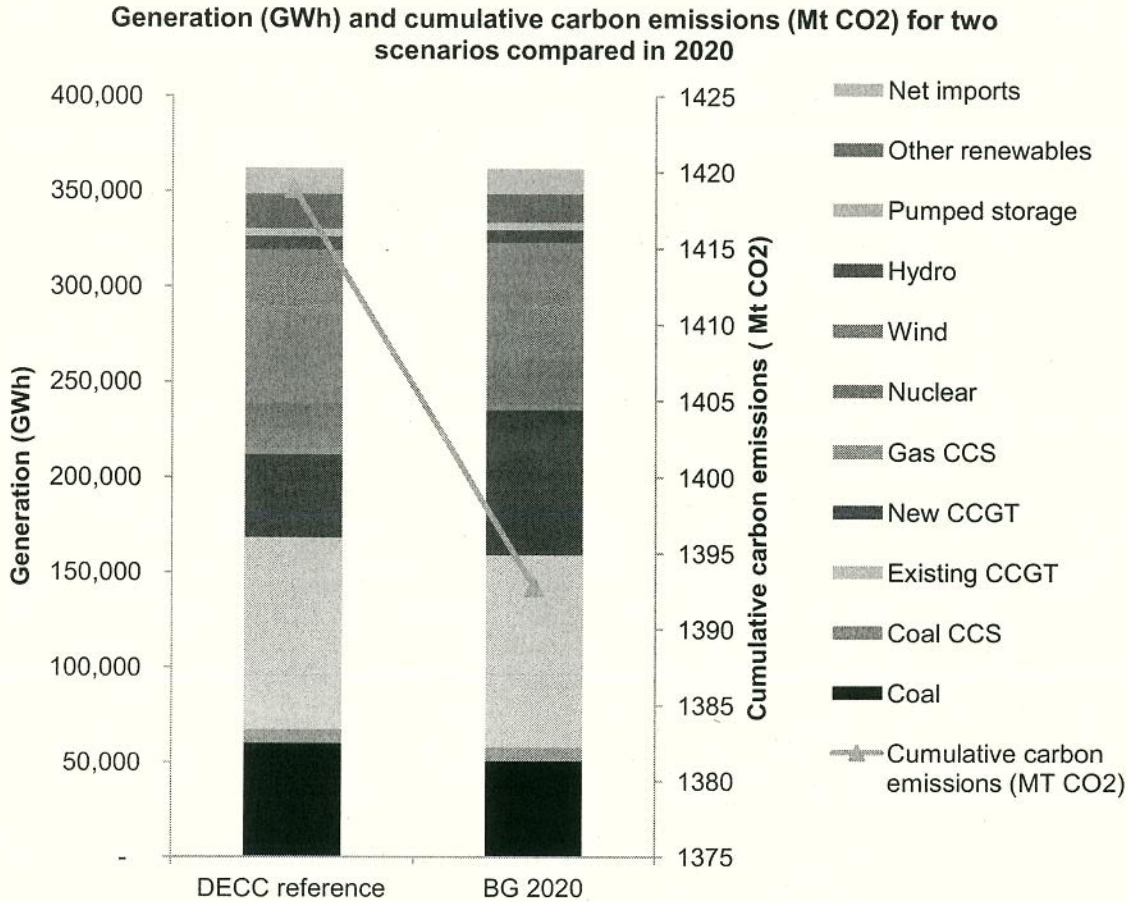
If the incentives to natural gas investments are sufficiently well targeted, natural gas will perform a critical and central role in guaranteeing security of power supply until 2030 at least. It can also play a major role in helping the UK government achieve its 2020 decarbonisation targets.

Natural gas will do this by providing some baseload generation but also – and as importantly - by plugging gaps left either by a slower than expected development of renewables and new nuclear capacity or by the intermittency that will result as renewable generation's share of the fuel-mix increases. Unless some coal-fired plant are granted derogations from the LCPD, no other fuel will be available to fill these gaps. Of course, any coal derogations would make achieving our 2020 decarbonisation target difficult or impossible.

BG Group's analysis suggests that, as a result of coal-to-gas switching, the UK can meet its 2020 decarbonisation target even in the event of renewables developing more slowly than the UK Government hopes may be the case. We have modelled a 'BG 2020' scenario, which assumes the pace of renewable growth to be three years slower than in the DECC Reference Central scenario. This has some coal-to-gas switching, and assumes 4.4GW more new CCGT build than in the same scenario.

By 2020 the 'BG 2020' scenario, compared to the DECC Reference scenario, demonstrates:

- Carbon savings: achievement of the 2020 carbon intensity target of 300g/kWh, and further CO_2 emissions savings of 4 million tonnes
- Cost savings: £18,016 million saved in new build capital expenditure
- Energy security: capacity margin increased from 18% to 20%



For the UK to meet its 2050 decarbonisation target, there is likely to be a requirement for the introduction of large scale Carbon Capture and Storage. While it looks challenging for the UK to be in a position to introduce extensive, commercially viable CCS by 2030, it may well be feasible by 2050. We believe that the scale of global gas reserves means that natural gas will be a destination fuel – not simply a bridging fuel. However, that outcome is likely to be dependent on CCS or other as yet unidentified technologies.

The main strengths of natural gas are the fuel's availability, its flexibility and its position as the fossil fuel with the lowest carbon content on combustion. In terms of availability, with or without unconventional resources, there is sufficient natural gas located in every region of the world to meet demand at current levels for in excess of 100 years. The

IEA's *Are We Entering A Golden Age of Gas?*[1] is a recent piece of analysis that reinforces what has long been acknowledged to be the case.

In terms of flexibility, the ability to put CCGT on line quickly (in 24-26 months after FID) is highly valuable, given the unpredictability of commodity prices, the absence of technology risk and the possible delays to new nuclear. There is around 10GW of consented CCGT capacity awaiting development.

There have been suggestions that the weakness implicit in a further round of investments in natural gas infrastructure in the UK is that gas-fired generation will be "locked in" for another 25-30 years, potentially undercutting renewables and making it difficult for the UK's power system to decarbonise. However, we do not agree with this because we are looking at a future in the UK in which CCGTs will tend to run on load factors significantly lower than has been the case historically in this country. This is the very reason the UK Government is contemplating introducing a Capacity Payments Mechanism: so that investors can be confident that they will get steady returns on their investments, even when their plant is running only part of the time.

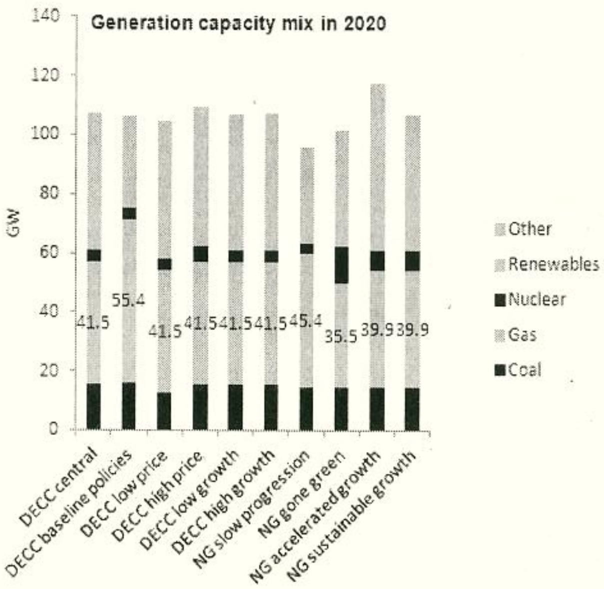
Of course, gas is the lowest-cost form of new generation – acknowledged in DECC's own figures for levelised costs. There have been suggestions that the price of gas will inevitably and inexorably rise in forthcoming years and that price-volatility will inevitably be a problem. Our own analysis of the supply-demand picture to the middle of the next decade suggests that NBP prices will be affordable between now and 2025 – analysis that is shared by two separate external consultancies from whom we have commissioned price forecasts.

While there will always be some volatility in commodity prices, we believe that, given the significant increase in import capacity in the first part of the 2000s, we will not see a return to the kind of volatility that occurred in the UK market in the 2004-06 period. Demand Side Response (DSR) initiatives and new storage capacity – perhaps stimulated by supplier stockholding obligations – can further diminish price volatility risk.

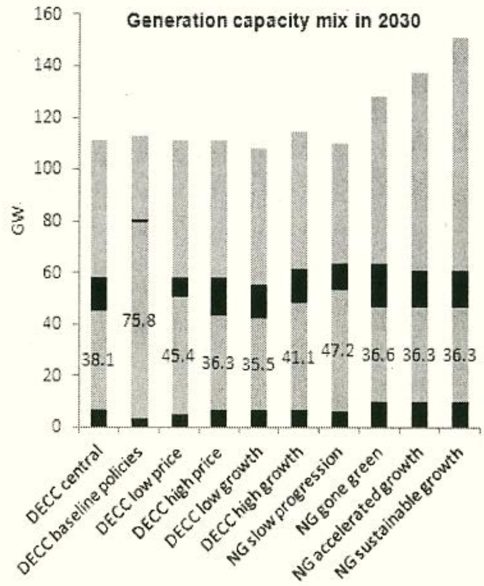
2. **What role can gas-fired generation play in the future and what level of gas generation capacity is desirable?**

The slide below shows that, in all recent DECC and National Grid scenarios, the share of power generation that will be provided by gas plant is around 40% on average to 2020 but still in excess of 35% by 2030.

[1] World Energy Outlook, 2011.
http://www.iea.org/weo/docs/weo2011/WEO2011_GoldenAgeofGasReport.pdf



The average percentage of gas across ALL scenarios at 39.9% is greater than other fuel types averages



On average gas features as 36% of the generation capacity mix across ALL scenarios, therefore has a significant role to play in 2030 supporting renewables

We believe that these are realistic figures for gas generation but that the share of generation to be provided by natural gas may have to be higher in both 2020 and 2030 in the event of the development of renewable – and particularly offshore wind – capacity failing to reach the levels forecast by DECC. The pace of development of new nuclear capacity will also be an important factor. Although most of the scenarios outlined in the table envisage limited nuclear capacity in 2020, it is not possible at this juncture to forecast whether nuclear will return to levels of generation historically enjoyed in the UK by 2030, given uncertainties about the investment climate for the technology at present. In the cases of limited renewable capacity and modest new nuclear growth, natural gas will again be required to pick up the slack with the result that these 40%/35% figures for 2020 and 2030 may be somewhat on the low side.

We are also persuaded by analysis which suggests that, above a given level of generation, wind can introduce dangerous instabilities into the system. Howard Rogers, in his publication, *The Impact of Import Dependency and Wind Generation on UK Gas Demand and Security to 2025*[2], suggests that wind generation in excess of 28GW represents a tipping point beyond which it is difficult to guarantee security of power supply not only on occasions when the wind does not blow but also on occasions when surges of wind power take place[3].

"It would appear that the more ambitious targets for wind generation in the UK have been formulated without a full appreciation of the costs and complexities caused by intermittency of very substantial levels of wind generation. [Our] analysis...concludes that the maximum feasible limit of 'unconstrained' wind generating capacity for the UK is around 28GW. At

[2] Oxford Institute of Energy Studies, NG 54, August 2011, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/08/NG-54.pdf
[3] As above, 71-72

higher levels than this, the country faces the prospect of short notice intervention to reduce turbine output with the added complication that forecasts of wind speed (and hence generation output) beyond six hours into the future are inherently uncertain," writes Rogers[4].

Some of the scenarios featured in the slide above foresee wind generation in excess of 28GW. We are not convinced that that level of capacity will create a benign and secure power generation environment. Ironically, the higher the level of wind capacity, the more natural gas and natural gas capacity will be required to be on standby.

3. **What are the key factors driving the economics of investing in new gas-fired power generation and how are these factors likely to change?**

4. **What barriers to investors face in building new gas generation plants in the UK? What are the key regulatory uncertainties that may prevent debt and equity investors making a final investment decision in gas generation and supply infrastructure?**

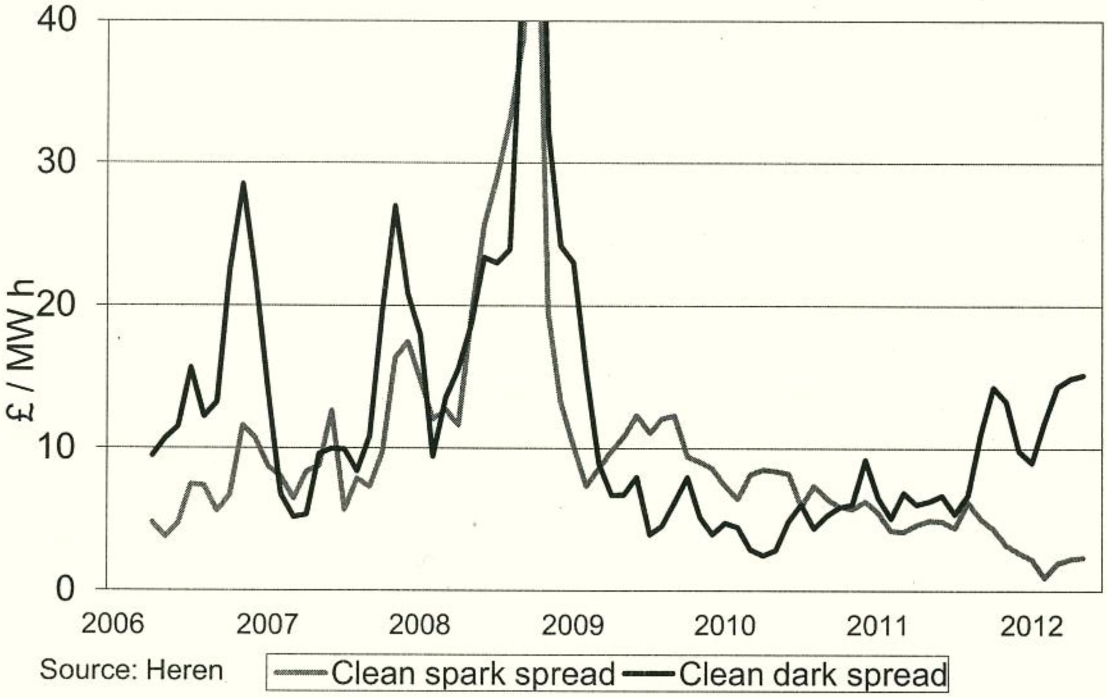
There are several factors that are contributing to the fact that, while there may be CCGT capacity permitted or *en route* to permitting, there is unlikely to be new construction in the short term. These include:

- Low spark spreads and more attractive dark spreads
- Low levels of gas and power demand due to the economic downturn
- Significant mothballed gas-fired capacity
- A promise of a Capacity Payments Mechanism but a lack of clarity as to what it might look like, what kind of capacity might attract capacity payments and whether they will be available broadly or only as a last resort
- Uncertainty around load factors and increasingly irregular running regimes for CCGTs going forward

The slide below spells out the current, unattractive situation for gas-fired generators.

[4] As above, pp83-84

UK Month Ahead Clean Spark and Clean Dark Spreads Jan 2006 - May 2012



Source: Heren

The situation has been exacerbated by the recent low European carbon price. This has given coal the edge and has seen a significant gas-to-coal shift in recent months. Official DECC figures showed the amount of electricity produced from coal in the UK rose by more than one-fifth in Q1 2012 compared with a year earlier, representing a six-year high for coal.

Coal accounted for 46% of all power generated in Q1 with gas falling to a 14-year low, as CO2 prices fell 50% year-on-year.

Recent figures[5] suggested that, despite having to buy carbon allowances, coal-fired power generators were netting close to £17MW/h, while 1MW/h of gas-fired generation would produce just £3.25 of profit.

In terms of overall demand, power was down 4.6% and natural gas's share of the mix fell to just 27% in Q1 compared to a range of 40%-55% over the past four years. It is true that opted out coal plant will begin to be retired as of 2013 but it is clear that there are few incentives to take permitted CCGTs from the drawing board to actual construction at present. A recent Energy and Climate Change Select Committee report[6] suggested that the 2015 deadline for new CCGTs to claim 'grandfathered' status - and, hence, protection from retrospective CCS requirements – could be a key factor in producing a 'dash-for-gas'. However, this was based on the assumption that new capacity had to be built by 2015. The

[5] Reuters Point Carbon, May 31, 2012

[6] The UK's Energy Supply: Security or Independence? http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/1065/1065.pdf

requirement is simply for permitting to be granted by 2015 so the risk is more of a 'dash-for-CCGT-permitting' than of an actual 'dash-for-gas'.

In terms of plant mothballed, the table below shows our understanding of the amount of capacity that has been switched off during 2011 and 2012.

Build year	Plant mothballed in 2011/12	Owner	MW
2000	Fife	SSE	123
2005	Peterhead units 2, 3 & 4	SSE	810
1997	King's Lynn	Centrica	340
1993	Peterborough	Centrica	405
1993	Teesside Units 1 & 2	GDF Suez	1800 (but now running at 200MW)
1995	Keadby & Medway	SSE	1358
TOTAL mothballed			**4636**

Although this may give a sense of a comfortable cushion of capacity existing to meet any abrupt switch from coal or pick-up in demand, the 4.6GW of mothballed capacity needs to be set against a total of 19GW of nuclear and coal plant forecast to be retired between now and the end of the decade. It is highly likely that the UK will need three or four new CCGTs before the end of the decade on top of the return of some or all of its mothballed capacity. Policy-makers also need to take account of the fact that it may take up to six months to return mothballed plant to operational readiness, should major maintenance and/or staff recruitment and training be required.

The situation clearly calls for some targeted incentives for CCGT investments but the irony is that the Government's signal that it is preparing a Capacity Payments Mechanism has introduced another kind of paralysis to the system. As one financier said at a recent EMR discussion in London: "The fact that the Government has said there is going to be a Capacity Payments Mechanism means that nothing is getting built."

This is not to say that a CPM is a bad thing; it does mean that the Government needs to clarify as soon as possible the kind of mechanism that it has in mind, based on the Capacity Market and the Reliability Market models contained in last year's White Paper. We note that DECC is promising to publish more detailed design choices by the end of 2012, to complete the design by March 2013 and consult on the details later that year. We outline below an alternative that could be introduced swiftly and without the need for primary legislation. The need for primary legislation to introduce the Capacity Market and Reliability Market options risks creating a very tight timetable, given that we may be looking to Capacity Payment Mechanism auctions as early as 2014.

Potentially more serious than timetabling concerns are concerns that the Capacity Market and the Reliability Market models are relatively untried in real power markets and, though conceptually sound, may be complex and prove to be unfit for purpose.

We are particularly concerned that the potential impact that the introduction of such mechanisms could have on the smooth functioning of the UK's gas market have not been taken into consideration in their design. For example, under the terms of the Reliability Market option, there would be a cap on electricity prices at times of system stress. If this coincided with a spike in gas-prices, during a cold snap or a supply outage, generators would not be able to pay those higher gas-prices without being out of pocket, placing further stress on the security of electricity supplies. Of further concern would be the resultant damping down of signals to the gas market of the need for storage or other sources of flexible supply to meet more volatile load profiles of gas-fired generation.

We at BG Group have developed an alternative Capacity Payments model, which we believe would be simpler and more sharply targeted at bringing about the availability of the CCGT capacity required in a world with less predictable load factors. It could be introduced without the need for primary legislation (ie: quickly). We would envisage this model as being one of a range of tools that National Grid would be able to call upon but, in our view, this model could address most of the central uncertainties that currently hang over the aspects of the proposed electricity market that are not addressed by Contracts for Difference.

We enclose with our consultation response a slide-pack outlining our proposal in greater detail but, essentially, the UK Government could guarantee availability of the right kind of flexible capacity by handing National Grid powers to offer long term ancillary services contracts for reserve with plant which would be available to deliver the contracted volume of incremental power. This would not require primary legislation and could be achieved through a variation to National Grid's existing System Operator Incentives (as set out in the Special Conditions of its Transmission Licence) and *via* a modification to the existing Balancing and Settlement Code.

The amount of capacity required to be contracted under these arrangements could be calculated on the basis of factors such as anticipated cumulative periods of stress caused by peaks, historical utilisation and anticipated changes to forecast error across the system as a whole, as a result of changes in the generation mix over the contractual period. The methodology would be set out in National Grid's Procurement Guidelines (which are subject to annual review and industry consultation).

Annual capacity/availability payments would be made and adjusted according to the achieved availability of the plant. Costs could either be recovered from customers through the ancillary services component of settlement prices or through Balancing Services Use of System (BSUoS) Charges. As today, participants would place offers into the Balancing Mechanism to cover variable costs of delivering such flexibility (eg: fuel, carbon and other operational costs).

Investors who bid successfully in such an auction would be able to operate their plant at other times (ie:.outside the contractual window or when they have been notified by National Grid that their services are not required). They would continue to do so on the basis of existing bilateral contractual agreements with their customers or by trading within the wholesale market.

The critical distinction between this proposal and how we read the existing proposal is that National Grid would be tendering for capacity on the basis of an extended operating regime and not just availability at peak. This would incentivise generators to reinstate previously mothballed capacity or to retain lower load factor capacity and to make it available to National Grid for energy (and system) balancing purposes.

We accept that this would not be the only Capacity Payment tool. National Grid would not want to commit solely to long term contracts but to use them in addition to its existing suite of system and energy balancing tools, as well as developing other options such as Demand Side Response (DSR) initiatives and storage options. It is important also to leave scope for new, innovative solutions in future years. However, our proposal represents a simple, easy-to-implement method of helping meet our security of supply requirements.

We will leave comment on the regulatory uncertainties that may prevent debt and equity investors from making FID on gas generation and supply infrastructure to those in financial markets; but our experience, from a range of EMR discussions with representatives from our sector and the world of finance, has been of repeated warnings that a lack of clarity around the shape of the support mechanisms to the electricity market is blocking investment.

5. **Are there any other policy issues that need to be addressed beyond the Government's proposals for the capacity mechanism and the EPS?**

It will be important that the structure of the Contracts for Difference element of the market is compatible with the Capacity Payments Mechanism. We would also underline the point we make above: that DECC needs to be careful that its reformed electricity market reforms do not have unintended consequences for the smooth operation of the gas market.

We would urge the UK Government not to relent in its efforts to drive forward the liberalisation agenda in Europe. The creation of a fully effective, single gas market in Europe and increased gas-to-gas competition is among the best ways to diminish the risk of price volatility.

We would also urge DECC to continue to work with HM Treasury with a view to supporting UK Upstream activity. It is important that our sector is able to maximise the amount of gas that can be produced from the UK Continental Shelf. It is estimated that around 40% of 'yet-to-find' oil and gas in the North Sea is likely to be in High Pressure High Temperature (HPHT) reservoirs. Drilling these prospects and producing from HPHT discoveries is extremely challenging and expensive and there is a need for HM Government to share some of that risk.

We have been working with HM Treasury and DECC to try to design tax-reliefs or other support mechanisms that will enable us to find and develop what can be huge discoveries. We failed to land a proposal that the sector and HM Government could both support in time for Budget 2012 but we continue to work with HM Treasury to find a way through. It would be deeply regrettable, were significant quantities of gas to remain in place so we would urge DECC to continue its work with HM Treasury and industry to find a solution.

6. **Given a continuing role for gas and the potential for increased volatility in gas demand, to what extent is gas supply and related infrastructure a barrier to investment in gas-fired generation? What impact will unconventional gas have on the case for investing in gas generation and the supporting infrastructure?**

On gas security of supply, we have concerns about the reforms to the emergency cash-out price mechanism currently being proposed by Ofgem *via* a Significant Code Review (SCR). SCR reform alone does little to address the prevention of future gas supply emergencies. Further measures will probably be necessary and desirable but perhaps not immediately. Studies consistently identify demand-side response and additional underground stockholding *via* a supplier obligation as the lowest cost routes to improving security of supply.

We recommend strongly integrating possible SCR reform into a wider review of gas supply security. However, we will be lobbying DECC and Ofgem separately on this issue, given its importance and the scale of our concerns about the proposed SCR.

We have in place already the pipeline and LNG import infrastructure required to meet the UK's gas supply needs for many years to come but the key issues affecting security of supply going forward are likely to be the decline in term supply cover, as UKCS output falls, and daily and within-day supply flexibility.

As wind generation rises, the issues of flexibility in both gas transmission network and in physical gas supply (*via* underground storage, LNG send-out or pipeline interconnectors) may become a matter of concern for National Grid, policy-makers and consumers. The system balancing role played by Grid, which ensures supply security, may become more difficult, onerous and costly with much more intermittent generation.

We do not believe that gas infrastructure or supply issues are a barrier to new CCGT investment but, were new CCGT investment seen to be providing essentially back-up capacity, there may be important implications for other gas users and for wholesale gas price-formation.

The decisions that have to be made about the future shape of the UK's electricity market will have to be reached well before the potential impact of shale developments in the UK become clear. Should shale gas become a significant factor in years to come, it will enhance the attractiveness of gas, lowering prices and adding to supply security but this is not a development that we can factor in at this stage and we do not expect a significant impact on European supply or price-formation pre-2025.

The impact upon the requirements for supporting infrastructure would be dependent upon both the location and volumes of resources discovered. However, the density of the UK pipeline infrastructure (NTS and distribution networks) would suggest that minimal investment in new pipeline capacity would be required.

The impact of low US gas-prices on UK and European gas-prices is by no means certain and would depend both upon the volumes of export projects approved by US regulators, keen to preserve the benefits of low gas-prices on domestic industrial growth, and upon the demand for gas from premium Asian markets. Our expectation is that US regulators and law-makers will limit shale-to-LNG exports with a view to ensuring their own domestic gas prices do not rise significantly.

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