centrica

Centrica response to DECC Gas Generation Strategy Call for Evidence

1. Introduction & Summary

Gas power plants are likely to be a necessary component of the future energy mix. In the transition to a low carbon generation fleet, gas has significant potential to provide relatively low carbon, affordable and reliable power. In the longer term, in the context of a largely decarbonised power system, gas generation is still likely to be needed as it provides flexible generation to 'back-up' more intermittent forms.

However, the current market environment for gas generation is challenging. As a result of policy and market factors, the economics of gas plants have been significantly eroded, making investments in maintaining existing plant, let alone in building new plant, challenging. Looking to the longer term, as the UK moves to greater gas import dependence, there is greater uncertainty in the commodity outlook both in terms of the availability of the commodity and its price. In addition, as the UK continues to reform the electricity market and support investments in low carbon generation, which will displace gas generation in the merit order, the contribution of gas is increasingly uncertain; while it is clear gas will have a role, it is not clear what that role will be. Both these uncertainties significantly deter investment.

It is therefore essential that the gas generation strategy takes a holistic view of the policy and commodity context within which investment decisions are taken. In terms of the policy context, this means taking into account both the specifics around EMR such as the design of the capacity mechanism as well as the longer-term pathway towards 2050, and the anticipated role for gas generation within that. In terms of the commodity context this means an active strategy to ensure gas security of supply, taking into account uncertainties in global gas markets, the role for new storage, pipeline gas, LNG and prospects from the UKCS.

2. Centrica Overview

Centrica is a leading UK energy company that secures gas and electricity to supply over half of Britain's homes. From owning no power generation assets in 2000 we are now a major player in the UK power market with significant existing assets and investment options including:

a) Seven gas-fired power stations including Langage, one of the most modern and efficient gas plants on the system;
b) A leading position in offshore wind with 280MW generating capacity, a further 270MW in construction; we also own the rights to develop over 4GW of Round 3 offshore wind in the Irish sea in a joint venture with Dong Energy;
c) Through our joint venture with EDF Energy we have a 20% stake in the former British Energy nuclear fleet, and we also have the option to participate in the nuclear new build programme with EDF Energy; and
d) We are currently exploring opportunities to develop two biomass plants between 80 and 140MW.
e) Centrica Group also owns and operates the Rough storage facility through its wholly owned subsidiary, Centrica Storage. It is the UK's only long range storage (LRS) facility and can deliver approximately 10% of peak day demand on a day. Rough can store approximately 118bcf of gas which is injected in the summer months, and produced at approximately 1.6bcf of gas per day in around 74 days (over the winter months).Centrica has plans to develop the Baird LRS facility which is similar to the

Rough LRS facility with 108bcf of space which can be produced, on average, at a rate of 1bcf over a 90 day period.

f) In addition, on the demand-side, British Gas is pioneering the development of 'smart homes' combining energy efficiency, microgeneration and smart meters. This is in recognition of the importance of putting customers in control of their energy use and the potential contribution of the demand side to energy system security.

Centrica aims to have a diverse generation portfolio, excluding coal. Any investment in new gas plants, or in the maintenance and upgrade of our existing fleet will need to compete with other investments in other technologies across the power sector. Indeed power sector investments will also need to compete with all the opportunities available to our Board such as the oil and gas sector, storage, the downstream retail business and even opportunities in North America. Any investment case must therefore provide our Board with reassurances that the rewards are commensurate with the risks, that the returns are sufficiently attractive and visible over the lifetime of the investment, and that the external environment is sufficiently well understood.

3. Gas Power is likely to be needed into the future

Gas fired power generation currently makes an important contribution to UK energy security. It makes up roughly a third of installed capacity and generates roughly 40% of UK power.

Gas plants are relatively clean and efficient, with low capital costs and short construction times. Most modern gas plants use 'Combined Cycle Gas Turbine' technology (CCGT), a highly efficient energy generation technology that combines a gas-fired turbine with a steam turbine. Modern CCGTs can achieve efficiencies of as much as 60%. Centrica's Langage power station is one of the most modern and efficient stations operating in the UK. It features the largest ever-installed heat recovery steam generators in the UK, and has emissions levels among the lowest in the world for this type of facility. It is also highly flexible and can go from 0 to 900 MW in less than an hour.

The average time taken to build a CCGT is short, and once planning permission has been consented it can take as little as 3-4 years. They are also relatively low cost. According to Mott Macdonald, the economic consultants, CCGTs have both a lower capex and lower levelised cost than any other baseload generation alternatives.[1]

In terms of carbon emissions, gas power has roughly half the carbon intensity of coal. If all the UK's coal power generation was switched to gas overnight, UK power sector emissions would reduce by as much as a third.

CCGTs therefore have significant advantages in terms of their contribution to the power mix. However, in order to meet the UK's 2050 climate change target, it is likely that emissions from the power sector will need to be very substantially reduced. This is in order to both reduce direct emissions and pave the way for the electrification of transport and heating. The Government believes that this 'decarbonisation' of the power sector is likely to need to take place in the 2030s. In this context, CCGTs cannot be providing significant amounts of baseload power. However, given the probable technology mix of the UK power fleet, there is likely to still be an important role for CCGT capacity to ensure security of supply.

Lower carbon power generation sources are likely to comprise nuclear, CCS and renewables providing baseload, complemented by significant amounts of intermittent renewables such as on- and off-shore wind. There will be circumstances when power

[1] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf

demand is high, but output from intermittent generation is low, for example on days of low wind. It is therefore important to have significant amounts of flexible 'back-up' generation available for these circumstances to ensure security of supply. Currently only gas-fired plant can play this role. It has estimated that wind capacity has a firm contribution to security of supply of only 5-10% - thus for every 1000MW of wind, 900-950MW of reliable capacity would be needed to back it up. Until CCS is developed and has the flexible capabilties currently provided by CCGTS, or some other technology on the demand or supply side is developed, significant back-up CCGTs will be needed even in the context of a largely decarbonised power sector to support wind.

The DECC 2050 Pathways work demonstrated that there are a range of trajectories to 2050 with different timings and scales for decarbonisation of the power sector within the 2030s. Rapid deployment of low carbon generation is likely to be more cost-effective for the UK in the context of high commodity prices. However, it is also conceivable that a lower cost trajectory to meeting the UK carbon budgets involves decarbonising the power sector later on. This might occur if there is a global gas glut, for example, as a result of significant shale being recovered in a range of markets and exported to the UK.

In both scenarios however, CCGTs are likely to continue to play a role in the future power generation mix, albeit that the role may be very different depending on the scenario. The need for significant gas generating capacity is clear in any event, but its future utilisation is highly uncertain.

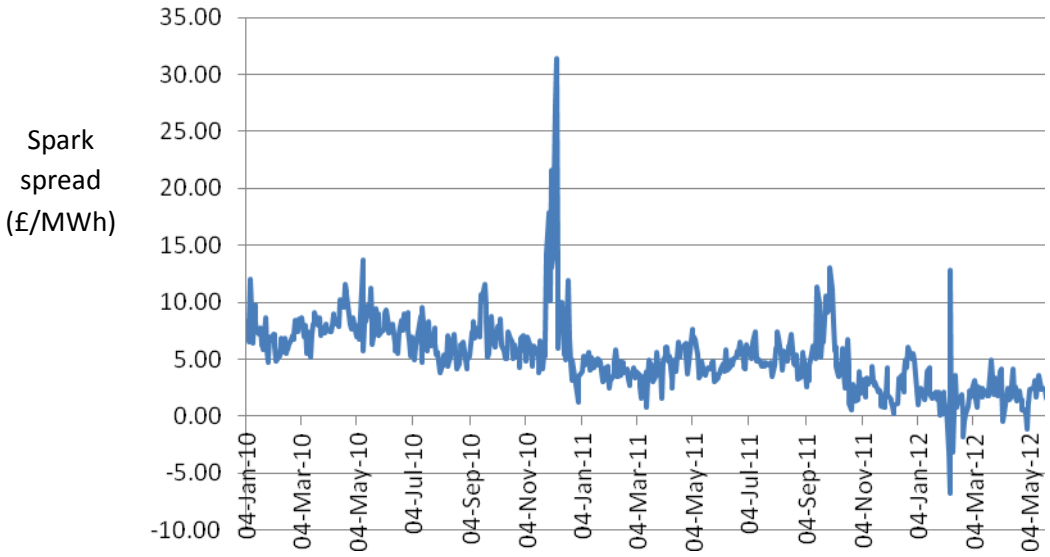
4. The current outlook for gas is challenging.

Despite the long-term requirements for CCGTs on the system, in the short term the outlook for gas plant is extremely challenging. The economics of CCGTs are hugely dependent on the level of the 'clean spark spread'. This is the difference between the gas price and carbon costs, as the input costs, and the power price, as the revenue stream.

Over the past few years, spark spreads have been substantially below long run marginal costs due to a combination of factors; these include: high gas prices and weaker coal and carbon prices which have pushed gas CCGTs to the margin; falling demand due to the economic downturn, continued renewable build and the recent completion of a number of new build CCGTs that were invested in before 2008.

As a result, a number of older existing CCGTs – including one of our own power stations – have already announced closure decisions – and the future of others is hanging in the balance. Taken together with the closure of older coal and oil stations unable to meet tighter emissions standards, one can expect a material deterioration in current comfortable capacity margins for GB power generation over the next few years.

The chart below shows the steadily declining spark spreads* over the past two years.



Source: Centrica; Heren

* Spark spreads are usually calculated on a hypothetical "baseload" assumption (i.e. across all the hours in the day or year). In reality, gas plant will typically operate in some periods only and may earn a higher spark spread in those hours when they are actually running

It is likely that margins will recover in the medium term as some coal and oil plant goes offline due to environmental regulations resulting in a tighter supply/demand balance. However, this may not be enough, or in sufficient time, to keep some gas plant online now that could be necessary later to ensure security of supply. Many CCGTs have challenging economic cases, and many require significant ongoing investments to remain operable. Centrica recently closed a 325MW power station in Kings Lynn and we are consulting on converting two of our other gas-fired power stations to biomass.

Profitability analysis carried out for Centrica and internal analysis also point to the risk that there could be further substantial closures of CCGT and coal plant on economic grounds over the next few years. This is supported by a number of recent announcements about plant closures and temporary withdrawals.

5. The long-term outlook for gas fired power generation is even more uncertain.

However, the short-term economic challenges for CCGTs are compounded by longer-term uncertainties that significantly impact on the investment case. These can be grouped into two categories: policy uncertainty and commodity uncertainty.

Policy Uncertainty

It is important to recall that a CCGT plant investment committed in the next few years will normally have an economic life running through to the mid 2030s. As mentioned previously, while it is clear that as it currently stands CCGTs are likely be required in any future power generation mix, what is not clear is what role they will take, for example simply as capacity back-up or as a major power contribution into the 2030s, and within that, how much capacity is likely to be required. The answers to this will be as much a result of policy decisions as they will be of market developments. While this uncertainty exists, any business case for a new CCGT is challenged and lacking sufficient robustness for Boards to make investment decisions.

Previously the majority of investment decisions took place within the market framework, so investors could model and attempt to predict the likely overall generation mix, and therefore the possible running patterns of any plant they invested in and its financial performance. However, the future generation mix will largely be determined by Government through the Renewable Obligation in the shorter term and then the allocation of CfDs. This will be very dependent upon the level of support that the Government offers to low carbon investors (via the level of banding per technology in the RO and then on the strike price set per technology for CFDs) and the number of contracts the Government chooses to award. Because these decisions are outside the energy market they will be very hard for generators to predict. This makes developing an investment case for a non-supported technology such as CCGT even more challenging.

The capacity mechanism envisaged under EMR will be a crucial factor in addressing these risks and uncertainty, and its design will be an important factor in ensuring the viability of new CCGTs and/or other peaking units. We are engaging separately with DECC on the detailed design issues, including through our participation in the expert working group.

With increasing uncertainty in the generation mix and more risk over security of supply, we believe that it is important now that the Secretary of State specifies, on behalf of customers, what be believes is the appropriate generation security of supply standard for the UK. This then becomes the foundation for the Capacity Mechanism design. In order to work properly, it is important that the capacity mechanism produces stable and predictable payment streams for both new and existing generators.

We are working with DECC on the design but are concerned about maintaining momentum on policy development. There will inevitably be teething issues, so it is important to establish the mechanism as soon as possible and work through these issues rather then keep it on drawing board. In addition, this is a 'no-lose' option since if it is not needed, the capacity payments will be zero or low. However, if the mechanism is needed then that justifies its early introduction. We would welcome a firm commitment as to when the first auction will be held, as a deadline investors can work to.

Commodity uncertainty

The other key uncertainty facing CCGT investors is related to commodity risk.

Two decades ago CCGTs were typically supplied with gas on a long term delivered, take-or-pay contract basis. However, as the NBP became more liquid, generators began to feel that they were being driven to burn gas at times when it was not economic to do so, since they could not easily sell gas back onto the wholesale market. Over time, therefore, some of these contracts were renegotiated and most of those that were not have now expired.

Nowadays, CCGT gas procurement, certainly in Centrica's case and most likely across the industry, is mainly or entirely done via traded markets rather than by contract. Gas is bought on the prompt or forward markets when there is a sufficiently positive clean spark spread to lock in, and at the same time the carbon is bought and the electricity sold.

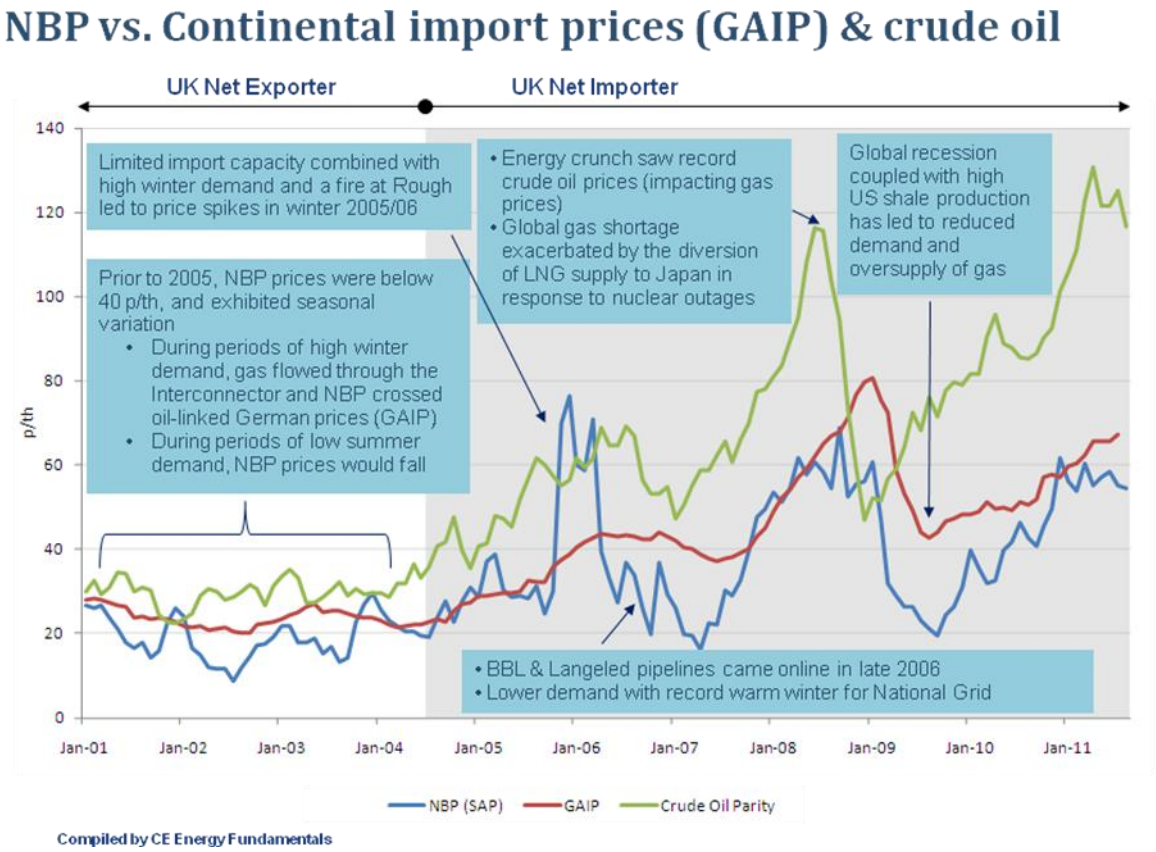
As wind generation increases, the predictability of CCGT load factors and running will reduce further, so generators are even more likely to either want to lock in positive clean spark spread by buying power and gas 'back to back', or to keep themselves available for very short term despatch when wind drops and back-up plant is required. There seems little likelihood therefore of a return to long-term contracts.

The position might be different for project-financed generation projects, for example if they can buy gas under contract at a price that is linked (in whole or in part) to wholesale electricity prices, and thus pass some of the merchant risk back on to their gas supplier. However, this is likely to be a minority case as the recent precedents are tolling contracts which put the onus on the offtaker (i.e. the utility) to purchase the gas.

A liquid and effective gas market (as well as a sufficiently liquid power market) is therefore crucial to the economics of gas power generation, and developments in this market have a clear knock-on impact on CCGTs.

When the UK still had plentiful reserves in the North Sea, gas prices were relatively stable and predictable. As the UK has becomes increasingly reliant on international energy markets to secure gas supplies, this has brought volatility and uncertainties about price and availability.

As you can see in the chart below, whereas continental prices have (for the time being) largely remained linked to the oil price, as the UK became a net importer, NBP has become more unpredictable and volatile.

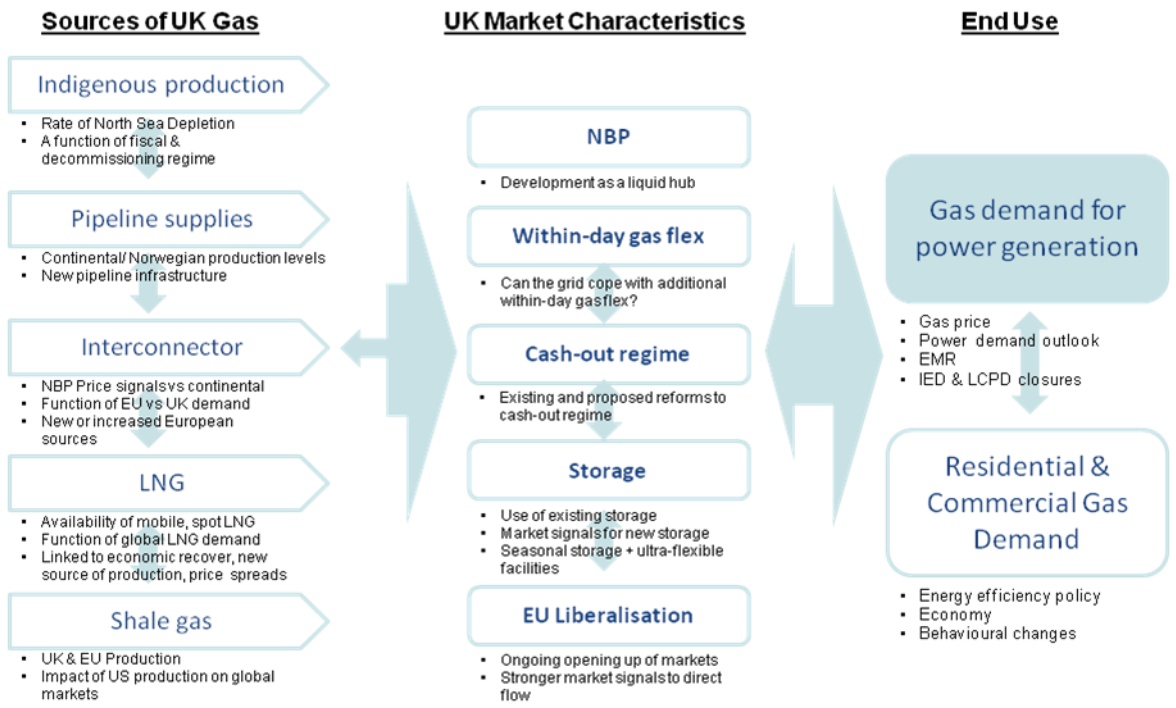


Investors are not looking for Government to manage commodity risks. However, CCGT investors need to be confident that gas will be available when it is needed it in order to sell power and lock-in the spark spread. In addition to availability, the UK needs to ensure it is attracting gas at competitive prices in order to support broader UK competitiveness.

What is required, therefore, is an acceptance from Government that with import dependence comes a need for a more holistic approach to gas security of supply. This will reassure

CCGT investors that the Government is doing as much as possible to maximise appropriate gas supply in order to meet demand.

The below schematic demonstrates that CCGT gas demand is a function of a much broader chain of variables, each with their own uncertainties.



Areas throughout the gas value chain where there is scope for a more holistic view include:

The UKCS
Although there is still significant gas and oil resource still available within the UK's territorial waters, projects are becoming increasingly marginal given the current tax regime. The Government's use of tax allowances is therefore increasingly important to determining whether new investment takes place.

The current approach of the UK Government is to test the appetite for investment through a series of licensing rounds and field allowance regimes. There is no holistic strategy for maximising the economic reserves in the UK. We are not necessarily advocating that there be one, but flagging that this absence has not been a conscious decision but instead simply the default option.

Pipeline Supplies
Developments in Norway and continental Europe are raising questions about whether the UK is currently well-served with existing pipeline infrastructure or whether there is scope for more.

Norwegian pipelines currently make up biggest source of gas supply to the UK and Norway is looking for routes to grow its market. The UK could be an attractive destination for this new supply.

Within continental Europe the gas market is changing. Market liberalisation has led to more liquid and accessible continental markets, the European demand profile is changing and the

potential of exports from Russian and central Asian to Europe could create surplus resource for the UK, or at the very least change they regional gas market dynamics.

All these factors raise questions about appropriateness of current UK import infrastructure either through pipeline, or through the other growing contributor to UK and European gas demand - LNG.

Liquified Natural Gas

Through LNG, the UK has access to the global gas supplies. However, access to these markets does not necessarily mean the gas will come to the UK, or that it will be at the price we want.

The global gas market is characterised by too many variables to provide any confident prediction of impacts on UK energy supply and certainly not to provide any reassurance that the outlook is benign.

There is no doubt US Shale has been a game-changer. In that market, shale now makes up 20% of natural gas production and it is likely that unconventional resources will make up over 60% of North American production by 2030. As a result, Henry Hub gas prices are at a 10-year low. However, the impact globally is less clear and there is no guarantee the molecules will be exported, will come to the UK or will do so at the right price.

Federal Approval has been given to the Sabine Pass LNG facility for export of 1.2bcf per day from 2015. However, there remains a political debate around potential impact on domestic prices which will impact future licence approvals. Any exports will go to the highest prices, and looking at current markets this is likely to mean primarily the higher priced Asian market, supported by planned widening of Panama Canal.

Within Europe, UK shale production is likely to be limited and long-term in its recovery. Usable shale gas resource in Europe may be more significant by the 2020s, but the impact is still likely to be local. For example production in Poland is likely to offset imports. Overall European potential should not be overstated given population densities, economics and regulatory barriers all constraining production. Moreover, European shale gas production costs seem likely to be well above those in North America.

On the demand side there is a little more confidence that Asian and global demand is set to continue to rise, and potentially to absorb any supply side increases. However, the pace of demand growth is unknown and how each market develops is unpredictable.

In addition to these uncertainties, recent years have demonstrated potential for a number of ‘shocks’ to further impact on the market. On the supply-side these include the ‘game-changing’ nature of shale gas in North America and geopolitical events impacting on the Straits of Hormuz. On the demand-side, examples include the closures of the Japanese nuclear fleet following Fukushima on LNG demand, the uncertain rate of growth in emerging LNG markets such as China or India and the impact of the recession on global demand.

While it is clear that LNG will play a crucial role in the future energy mix, the global LNG market is hugely uncertain. The UK track record in securing LNG has improved, and Centrica signed a £2bn, 3-year deal with Qatargas in February 2011. However, the UK will need to compete internationally to secure global LNG, and given that many exporters are state-owned, this will require Government involvement.

6. UK Market Resilience – the role for more storage

Centrica endorses DECC's view that gas plays a vital role in the GB energy mix. Further, we agree that gas, and electricity generated from gas will continue to be fundamentally important for supplying GB's energy and heat requirements for at least the next two decades. We also agree that maintaining a flexible and diverse supply of gas will be essential if the risks of supply and price shocks are to be managed.

Despite the gas market showing resilience to date, the GB gas market is likely to move into a period of increasing price risk, as UKCS production continues to decline through to 2020 and beyond. Whilst investment in GB gas market import infrastructure means that the risk of physical supply disruption is unlikely there is an increasing risk of high prices and un-served demand (through 'price' disconnection).

Centrica has commissioned an independent study from Eclipse Energy to review price security in the UK. Eclipse constructed a base case built on its fundamental assumptions, Centrica's assumption on storage and DECC's assumptions on input commodities. In the base case, winter gas prices are forecast to increase to £1.40/therm by 2026 driven by a rise in coal and oil commodity prices and greater reliance on imported gas. Eclipse then constructed two 'stress' scenarios; one driven by demand (cold weather) and one driven by Continental European supply or demand issues requiring flows from the UK to balance the European market.

Both 'stresses' lead to price spikes as more expensive gas is needed to be attracted to the market

- Under the demand stress winter 2025 prices reach £2.54/therm (£1.97/therm real 2012)
- Under the supply stress winter 2025 prices reach £2.83/therm (£2.20/therm real 2012).

Both scenarios lead to unserved demand among large industrial consumers.

Eclipse found that the addition of new seasonal storage capacity (of c. 3bcm) would reduce the total annual cost of gas in the case of their winter stress scenarios by £1.2bn in the demand case and £1.6bn in the supply case.
From a policy makers perspective, whilst the Eclipse study provides a convincing case for more seasonal storage capacity (certainly by 2020) the market at present is not delivering new seasonal storage, and, Centrica believes, nor will it.

It is important to distinguish between seasonal storage that will provide significant volumes of gas over a period of weeks to address risks associated with major infrastructure failure or weather related demand increases from short duration storage that addresses price spikes related to short term demand variations such as intermittent generation. All storage capacity added since 1985 has been short to medium duration, which has significantly increased UK storage deliverability but not capacity. It should be noted that there are a number of short/medium duration storage facilities currently under construction, this is not the case with seasonal storage.

Investment, including that of new gas storage, will be made on economic grounds and the current market signals do not support the investment case for new seasonal storage in particular.

In the short term, current seasonal spreads (the difference between summer and winter prices which are main driver of storage revenues) are low and forward seasonality remains depressed, mainly as a result of summer prices remaining high due to the carbon tax

increasing the coal switching price, the limited availability of LNG over summer and the interaction with Continental oil-linked contract prices. Long-term uncertainty persists over the seasonal spreads due to short-term market signals, Government policy, e.g. green agenda and future role of gas and supply uncertainty, e.g. potential for shale gas in UK, Far East demand and US LNG exports.

These factors have contributed to the fact that, as noted previously, despite a number of projects being developed to the pre Final Investment Decision stage no new seasonal storage has been built since Rough became operational in 1985 and the mid range storage which has been developed does not materially add to storage capacity..

Centrica believes that to mitigate against the increasing price spike risk resulting from exposure to the global gas market the GB market needs to replace 'locally sourced' flexible gas as the UKCS declines; import dependency reduces the certainty that physical gas will be available when it is required. Gas storage is the obvious substitute for several compelling reasons:

- It delivers physical gas
- Is locationally close to the market
- Is subject to third party access arrangements and is more open than other GB markets
- Is transparent: usage and availability is monitored and publicly available
- Provides delivery support for other source of supply
- Works with market signals (i.e. strategic withholding/reserving not required for security of supply)
- Is available to be called upon by NGG in a Gas Emergency

Further import capacity would not provide equivalent benefit in terms of GB gas supply security, since capacity does not equal gas and the UK would still be exposed to winter spot price risk.

Centrica therefore recommends that as part of this strategic review DECC should include the need case to introduce a mechanism to overcome the current barriers to investment in seasonal storage. The UK gas market has worked well to date in allocating storage usage so any support needs to be: direct, targeted, and should work with the grain of the market.

Centrica believes that a capacity payment in the form of a storage revenue top-up, providing direct financial support to storage capacity providers by (in effect) putting a floor under the level of return, would be the most effective way of ensuring security of supply while minimising the risks of unintended consequences.

It is also worth noting that whilst seasonal storage provides the obvious substitute for the decline in the UKCS these investments are not quick to develop; Centrica's view is that if the Government wants to encourage more seasonal storage by 2020 then the market will need to be certain of the policy arrangements within the next 12 months.

7. Conclusion

On a stand-alone basis, CCGTs have a number of attractions for investors. The technology is mature, proven and understood. The construction time is relatively short and planning risks are manageable.

The current economics for CCGTs are extremely challenging which is having an impact on plant decisions. These conditions are largely due to market fundamentals, specifically a high gas price combined with a low power price. However, policy and regulation are to some

degree the cause for this situation, with accelerated coal burn ahead of forced closures, the allocation of free carbon allowances, and the increasing build out of renewables.

In the longer-term however, uncertainties in the policy outlook will dominate investment decisions and largely skew market fundamentals. This is compounded by a more complex commodity environment adding to the risks associated with a project.

It is essential therefore that the Government's Gas Generation Strategy be set within a more holistic energy security strategy looking at providing a stable policy environment through EMR, and an active gas security strategy as import dependence grows.

Key policy elements are likely to include:

- Early introduction of a capacity mechanism
- A gas strategy that ensures the UK is taking necessary steps to secure supplies for the UK through pipeline, LNG and other forms
- A mechanism to ensure the UK supports investment in new seasonal storage capacity
- A supportive field allowance regime in North Sea as part of a broader strategy to maximise economic production.