DRAFT RESPONSE TO GAS GENERATION STRATEGY CALL FOR EVIDENCE

We welcome the opportunity to respond to DECC's call for evidence on the role of gas in the electricity market. Gas plant will continue to play a key strategic role in the generation mix, both contributing to electricity security of supply and helping to move to a decarbonised electricity system in the short to medium term (to 2020) and beyond.

As noted in the call for evidence, the market has delivered significant new investment over the last 20 years on the basis of market signals alone. For example, in recent years there have been significant commitments to new CCGT's by many of the major players and independents (i.e. Centrica, SSE, ESBI, ConnocoPhilips, DONG, RWE npower, E.ON and EdF) commissioning over 9GW of new gas-fired generation since 2009 in response to these signals. RWE npower has been the single biggest investor in the GB electricity sector since 2006, and has committed approximately £1.8bn on two new highly-efficient CCGTs at Staythorpe and Pembroke as well as other gas plant upgrades in the last three years.

Government must be careful not to undermine the value of these projects if it is to sustain the investor confidence required to enable future generation investments in the UK. The introduction of a separate capacity market will reduce the wholesale electricity price by separating the existing wholesale electricity revenue into two components (electricity price and capacity price). Government must ensure that existing investments in CCGTs and renewables are able either to participate in the new capacity market on an equitable basis with new plant or receive appropriate compensation for their reduction in income. We acknowledge that investment in new plant may require a longer capacity contract duration, however all capacity needs to be priced at the same level in order to avoid distortions in the market.

Furthermore, at Pembroke and Staythorpe we have specified in the technology design some additional capability to operate flexibly in response to future capacity needs; and are concerned that these investments should not be undermined by Government's capacity mechanism proposals. Efficient and flexible capacity would, in particular, expect to earn the majority of its revenues from the energy (MWh) market. Introducing a mechanism that rewards 'capacity' under a crude nameplate definition would inevitably erode energy prices. This could mean a transfer of value from newly constructed plant to significant less efficient, older assets, often assets with higher carbon emissions.

If a capacity mechanism is introduced (and we do not believe that the case has been proven), it should be introduced in a way which seeks to reflect the true cost of capacity currently within the energy price such that clear price signals continue to incentivise efficient use of the electricity system. This will also complement the efficient features of the current market design as far as possible, and will not devalue other pre-existing policy objectives (e.g. smart meter programme and incentivising demand side response). Focusing the capacity mechanism on efficient and reliable plant will also ensure the capacity mechanism can be delivered at lowest cost to the consumer.

We support Ofgem's cash-out review if it results in more cost-reflective prices. This will lead to increased liquidity delivered by market solutions and improved price signals, which will, in turn, lead to an improved response from demand and generation. Unfortunately, the introduction of a capacity market, if poorly designed and implemented, could undermine energy prices and lead to further uncertainty.

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Further policy/regulatory interventions (beyond the EMR) are neither desirable nor necessary in either the electricity generation market or the ancillary gas storage and import infrastructure markets.

Some market participants argue that Ofgem needs to intervene to improve liquidity in the wholesale market. This is not the case, current liquidity levels, whilst lower than we would like, are still sufficient for market participants to manage their volume and price risks effectively within an already very competitive market. We continue to work hard with our counterparties on market solutions to improve liquidity and are seeing increased day ahead volumes, producing robust reference prices, against which trading in financial futures is taking off. We expect this trend to continue and become self-sustaining.

a) 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?

Gas plant has a key strategic role to play in the generation mix, both in ensuring electricity security of supply and in terms of helping to decarbonise the electricity system at least cost to consumers.

In the period leading into the mid-2020s, investment in gas generation is essential to replace coal-fired generation plant due to close as a result of the Large Combustion Plant Directive and in later years, Industrial Emission Directive requirements. This switching from coal-fired generation to gas-fired generation will help to reduce the overall carbon intensity of the generation fleet at a lower cost to the consumer.

From a security of supply perspective, gas generation plant is a proven technology, which is well understood and one with which the industry has extensive experience operating at various capabilities. Gas generation plant has a lower levelised unit cost of electricity (Mott MacDonald & Parsons Brinkerhoff Electricity Generation Cost studies, 2010 & 2011) than other large scale proven power generation technologies. Once consented, a new CCGT can be procured and constructed from a competitive global supply base and reliably delivered to time and budget. CCGT is the default investment decision for new plant, with a project construction timescale of about 36 months from final investment decision (FID) to commercial operation (COD).

In the medium to longer term (by 2030), as the amount of intermittent and inflexible generation on the system increases, gas-fired generation can continue to play a key role in the generation mix as a flexible and controllable generation technology that is capable of operating at all points throughout the merit order.

Both open- and combined-cycle gas-fired plants already play an important part in providing the ancillary services, such as frequency response, STOR and black start capability, that are required to balance the system and maintain system security. This role in balancing the system is likely to expand considerably in future years.

Some commentators argue that a lack of regulatory control (e.g. limits on the amount of gas generation built or constraints on its operation through a tight Emissions Performance Standard) will potentially lock in unabated gas generation and make it more challenging to decarbonise electricity generation. However, this argument overstates the risks as CCGTs have a maximum of a 20 year economic life and do not operate at base load for their full economic life – a fact that is already taken into account in the investment case for any new gas plant by a prudent operator. This is driven by a continual evolution and improvement of the CCGT power plant technology. New CCGT plant are larger and more efficient than previous generations of technology meaning that older CCGTs are displaced in the merit order and move from base load to mid merit and then peaking plant operation over their 20 year economic life.

b) What role can gas fired generation play in the future and what level of gas generation capacity is desirable?

In the longer term, as we progress towards 2050 goals, CCS could be a feature of gas or other fossil fuelled plant. However at present CCS remains an unproven technology at scale. Until further information is known on the technical performance, energy consumption, reliability, grid support capabilities and cost of a CCS plant, the scale of likely deployment of CCS plant is unknown. Whilst all new CCGTs are built as CCS ready, it is unlikely to be cost effective for all gas generation to install CCS. Therefore, a considerable proportion of gas investment through to 2050 is more likely to be unabated gas generation. The permitting regime, including the EPS should allow this investment, noting that there is the prospect of an investment hiatus in the investment lead times to 2045 (i.e. from 2030). However, the electricity sector in 2050 is likely to be very different from the one we are used to today (e.g. scenarios could include increased electricity demand with significant uptake of electric vehicles and heating, increased penetration of distributed technologies, greater use of demand side management to coincide with smart meter roll out or other unknown technological changes).

Gas generation will continue to play a significant role in the future – including (as outlined above) providing both the crucial flexibility required in the national electricity generation portfolio and grid ancillary services as more intermittent and inflexible generation comes onto the system.

As noted in the call for evidence, the future is dynamic and it is difficult to predict the levels of investment required at any given time. If left to the market, investment in gas generation will be determined by the price and associated market signals with shareholders bearing the associated risks rather than Government.

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

The key criteria that factor into gas power project economics and influence investment decisions are:

- Site economics, influenced by for example scale, cooling technology choice, gas exit charges and electricity transmissions charges;
- Consenting and permitting regimes;
- Upstream capital costs and construction contract framework;
- Long term view on market outlook and predictability of regulatory regime over the investment period, rather than current market fundamentals (the forward curve does not provide visibility far enough out to be of relevance to any investment decision today);
- Revenue forecasts, influenced by for example predicted load factors and projected view of clean spark spreads over the economic life of the plant;
- The level of support provided to other low carbon or renewable technologies, together with advancements in the efficiency of these technologies;
- Availability of (and competition for) capital; and
- Comparison with other investment opportunities in European utility portfolios.

In recent years there have been significant commitments to new gas-fired generation plant by many major players and independents (see table below), who have delivered over 9GW of gas-fired generation since 2009 in response to efficient market signals, without the need for any capacity payment and in full knowledge of the government's renewables and carbon targets. This is despite the challenging economic conditions in the UK.

Plant	Owner	Output	Commissioned
Langage	Centrica	885MW	2009
Marchwood	SSE/ESBI (50:50)	840MW	2009
Immingham extension	ConnocoPhilips	450MW	2009
Severn Power	DONG	850MW	2010
Staythorpe	RWE	1,650MW	2010
Grain CHP	E.ON	1,275MW	2011
Pembroke	RWE	2,100MW	2012 (commissioning)
West Burton	EdF	1,270MW	2012 (commissioning)

Table: Investment in gas-fired generation since 2009

As DECC note, the GB electricity market is currently over-supplied and the market is not signalling that it needs investment in the short term. However, DECC conclude that in the medium term the outlook appears more favourable and the case for investment will improve. In the interim, companies continue to develop options to invest for when it once again makes sense (with over 16,500 MW CCGT capacity already consented).

Key cost elements, such as gas entry and TNUoS charges, have significant impact on CCGT project economics. The ability to fix these cost elements over the long term could help to improve the economics of these projects.

Some commentators have suggested that the economics of new CCGT plant have been eroded by uncertainty over load factors over the life of the plant as a result of significant low carbon deployment to meet UK carbon budgets and renewable targets. We agree that as new low carbon generation plant with low operating costs comes onto the system, CCGT plant will be displaced in the merit order and be required to operate more flexibly and at lower load factors. However, the impact of this on the investment case for new gas plant is significantly overstated. We would expect that any prudent operator looking to investment in new gas plant would have taken account of the government's renewable and carbon targets in their investment case. In the case of our own recent investments at Staythorpe and Pembroke, we specified that their design include a higher degree of flexibility to ensure the stations have increased capability to meet a future need for increased two-shifting and to maximise the future incomes from short term optimisation.

d) What barriers do 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?

As DECC conclude in the call for evidence, the market signals for investment in new gas plant are not currently there given an over-supplied market. However, in the medium term the outlook is more favourable and the investment case is expected to strengthen as existing coal and nuclear plants retire later in the decade, margins consequently tighten and baseload wholesale prices are expected to increase. We do not believe that this analysis leads to a conclusion that intervention is needed, so the introduction of either a capacity mechanism or an EPS by government is at this point in time unnecessary.

Indeed, it is uncertainty around the EMR package (in particular the proposed capacity mechanism) and other regulatory interventions in the wholesale market (e.g. Ofgem's liquidity review, Project TransmiT) that are currently the most significant barriers to investment in generation. There is considerable uncertainty about the scale and extent of the intervention through the EMR package and there is a clear risk that parties will not invest until the details of the scheme have been determined and are clearly understood by investors. Given the state of discussions, there is concern that a workable capacity mechanism within the current market framework may be difficult to design and deliver in the timescale required.

A further disincentive for investment is uncertainty about the start date of the capacity mechanism and the absence of clarity on the problem that Government is trying to address. Some suggest an early intervention to encourage new CCGT capacity, despite DECC originally indicating that part of their concern surrounded the increasing penetration of wind in the late 2020s. It is still unclear what problem the mechanism is trying to solve and the very nature of the intervention is exacerbating concerns about security of supply problem from 2014 onwards.

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

We believe that further policy intervention in the electricity market to support gas fired generation is neither desirable nor necessary. As we note above, uncertainty around the EMR package and other regulatory interventions in the wholesale market are the most significant barriers to investment in generation. Any further policy interventions will merely serve to add to the uncertainty in the market, potentially prolonging the current investment hiatus and exacerbating concerns over security of electricity supply towards the end of this decade.

We still do not believe that the case has been made for the introduction of a capacity mechanism. In particular we do not believe is it possible to define a separate homogenous 'capacity' (MW) product when, in the end, what customers actually need is 'energy' (MWh). The advantage of a pure energy price over a capacity price is that both sides of the market can react to an energy price, whereas only the supply-side can react directly to a capacity price. Furthermore, there is no point subsidising capacity that is not actually producing when needed for whatever reason. The current market design already strongly encourages companies to balance supply and demand of energy. It also rewards companies who offer the necessary additional balancing and flexibility services (i.e. spare capacity) to the system operator. The proposals being made to change the existing arrangements will result in less efficient outcomes and higher bills to consumers (our modelling estimates the incremental cost of a market-wide mechanism as £7.5bn[1]).

However, given the Government's intentions to introduce a capacity mechanism, we, as both an operator and an investor, require clarity on the design and implementation date of such a mechanism as soon as possible to enable investment decisions to be taken at the right time whilst minimising the risks inherent in these decisions. We also wish to ensure that the efficient features of the current market design are retained as far as possible; and that any capacity mechanism both takes account of the cost to the consumer and supports and enhances other policy objectives (e.g. the delivery of

[1] Present Value 2015 to 2025, real 2010.

the smart meter programme and demand side response) rather than undermining and devaluing them.

As noted above, since 2009 there have been significant commitments to new gas fired investments by both existing players and new entrants to the GB generation market. Government must be careful not to undermine the value of these recent investments if it is to sustain the investor confidence that will be required to deliver future generation investments in the UK, both conventional and low carbon.

Under the current market the key determinant of capacity delivery is a future energy price that includes an appropriate scarcity premium. We note concerns about peaky and volatile prices, but we believe that volatility is an inherent component of any market, including an energy market with a capacity mechanism, as the value of capacity should also vary through time. Price volatility, both in energy and capacity, is the signal to which market participants on both the supply and demand side react to ensure that the market is functioning appropriately.

Whichever capacity model DECC ultimately choose, it needs to be priced into and compatible with the existing bilaterally traded market to ensure economic and efficient market signals. In addition, such an approach would ensure that recent investments, made under the prevailing market framework, are not unduly penalised or undermined. Consequently, all capacity – both existing and new – needs to be priced at the same level in order to avoid unwarranted distortions in the market.

Freely determined imbalance prices (reflective of the full costs providing these services) for individual settlement periods must remain an inherent and essential component of the GB electricity market. This was recognised in the old GB pool (with capacity payments) through the administrative arrangements that enabled power prices to increase at times of system stress through uplift payments. It is also worth recalling again that end-users are not exposed to these volatile prices unless they chose to be and that both suppliers and generation businesses are free to sell energy in forwards markets for any time period. This hedging process usually means that short-term price spikes are, in the end, less relevant to consumers than might be expected from crude modelling exercises since well-run businesses will protect their customers against such exposure. This already encourages the development of spare generation capacity.

RWE remains sceptical about the value of introducing an Emissions Performance Standard (EPS). It introduces further uncertainty into investment decisions and it duplicates policy already enacted. However, we welcome the application of the EPS to new plant only, the enshrining in primary legislation of the EPS level and the grandfathering for power stations consented under the 450g/kWh-based level until 2045. It is crucial that these elements are retained as the Electricity Bill moves through the legislative process, as they help to reduce the regulatory risk associated with the introduction of the EPS.

We also welcome the provisions to exclude emissions associated with the supply of heat to customers from combined heat and power (CHP) plants. This removes any perverse incentives for new Good Quality CHP plant to maximise its electrical efficiency potentially to the detriment of overall plant efficiency (i.e. electricity and heat), which would have acted as a further deterrent to investment in new high efficient gas CHP.

However, the proposed 3-yearly review of the EPS level from 2015 increases risks for investors in new highly efficient CCGT plant. The process and criteria for review of the EPS level and grandfathering arrangements are critical in implementing the EPS appropriately and should be set out in primary legislation.

f) 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?

Global gas supply and role of unconventional gas

There is no shortage of gas globally, we benefit from full liquid global gas markets with gas moving to areas of demand in response to price signals and we already have import infrastructure in place to bring that gas to the UK. DECC's risk assessment for the EU Regulation 994/2010 on security of gas supply showed that supply infrastructure was adequate to meet peak demand even with the loss of major infrastructure. We do not believe that there is the case for intervention in this market.

At the moment it is still too early to predict what long term effect shale gas will have on UK or European energy markets. The situation in Europe is very different from that in the US where shale gas has so far made a significant impact. Development here is likely to be slower with stronger environmental consenting regimes and more complex land and mineral rights. The development of unconventional gas is unlikely to be a key factor in CCGT investment decisions.

The majority of reserves appear to be located in Poland and eastern Europe, and the general view is that there is unlikely to be any significant volumes before 2015. European conventional gas production is expected to continue to decline, and new supplies will therefore simply help to balance the expected down turn in conventional gas.

In the UK, development of shale gas potential might be important locally, but the UK is likely to continue to be increasingly dependent on imports in the future. The main impact on UK prices is therefore likely to be via the LNG networks which will allow non-European shale producers access to European gas markets and therefore be able to arbitrage value between European gas and their home markets. It is therefore likely that Europe will be exposed to shale gas economics without ever producing meaningful quantities of shale gas itself.

Impact on investment in supporting gas infrastructure

We do not believe that there is a case for any intervention in the existing commercial gas storage and import infrastructure market. There has been significant investment in gas storage and import infrastructure over the past decade, which we expect to continue:

- The market has delivered a 500% increase in GB gas import capacity during the last decade, with LNG import capacity now equivalent to 150% of annual consumption. This is at diverse locations around GB and with different equity owners and processes in place to release unused berthing slots, giving confidence that the capacity will be utilised when required.

- Over the same time period, the market has delivered a 30% increase in storage capacity. National Grid expects storage deliverability to increase almost twofold by 2020 due to the completion of new storage facilities. There are also a number of gas storage projects at various stages of development.

- The UK also has 3 interconnectors with other Member States – IUK, Moffat and BBL. IUK can offer physical reverse flow, while BBL and Moffat can offer virtual reverse flow.

Some commentators argue that the UK has proportionally less storage capacity than a number of other EU member states principally because of its past reliance on indigenous UKCS gas. However, storage projects reported by National Grid show an increase in capacity and deliverability in the future. When added to our other supplies from UKCS (including its implicit storage capacity), LNG, Norway, Interconnector, the demand side and a liquid traded market, we have a flexibility and diversity of supply that very few, if any other EU country can match.
Winter/summer gas spreads do not justify building commercial long-range storage (like Rough). The market has also brought forward several short/medium range storage projects in response to signals. Any form of mandated storage (whether new build of a regulated or semi-regulated storage facility, a storage obligation or strategic storage) may jeopardise the commercial market response to storage investment that we have historically seen and continue to see. A storage obligation would also remove the opportunity for suppliers to meet the requirement in alternative ways. This would lead to increased costs to consumers and may result in stranded assets as gas demand reduces as a result of decarbonising our energy needs.

We support policy options:

- Promoting more active participation by the demand side in balancing supply and demand. Smart meters and settlement will facilitate the introduction of new tariff structures, which will in turn encourage customers to smooth or avoid consumption, thereby reducing peak flows and prices.

- Actively promoting liberalisation of and access to transportation and storage capacity across EU member states.

Proposed additional interventions in the gas market

Gas Security of Supply Significant Code Review

The current cash-out arrangements are uncapped and provide strong incentives on shippers/suppliers to balance supply and demand. We support the objective of sharpening gas cash out prices, but do not believe that the current Ofgem proposal to strengthen incentives on market participants to deliver gas supplies by introducing the Value of Lost Load (VoLL) into cash-out during emergencies will produce the desired effect.

We believe that the current arrangements are already leading to investment in LNG import terminals, increased interconnection and storage projects and are not convinced that changes would necessarily enhance security of supply. In particular, we remain to be convinced that sufficient Demand Side Response contracts will be struck, with customer holding out for compensation at VoLL.

The interaction between the electricity and gas market (and the cause and effect of any shortage) needs to be correctly reflected when considering who pays for the added security requirements given greater reliance on imported gas. Arguably, declaration of an emergency is recognition of market failure and resolution is about safety rather than commercial requirements.

Gas network flexibility

We understand the issue that has been outlined by National Grid, but to-date there have been no problems with National Grid refusing flexibility and we have yet to see a clear forward view from National Grid as to when the pinch points will materialise.

We support Ofgem's requirement on National Grid to continue to monitor the use of network flexibility and to report back annually. We believe that National Grid need to produce a forward looking view, including developing a methodology that demonstrates when the pinch points will materialise and undertaking cost benefit analysis to identify what National Grid will need to do to make the system more flexible (e.g. investment in compressors, better control centre) and by when.