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Project Discovery
Options for delivering secure and sustainable energy supplies

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Target audience: Consumers, industry, government and other interested parties.

Overview:

This document presents the conclusions from Project Discovery, Ofgem's year-long study of whether the current arrangements in GB are adequate for delivering secure and sustainable electricity and gas supplies over the next 10-15 years.

We have identified a number of concerns with the current arrangements and have concluded that significant action will be called for given the unprecedented challenges facing the electricity and gas industries. We are keen to work with consumers, industry and government to find the best way forward. Prompt action will reduce the risk to energy supplies and environmental objectives, and can help reduce costs to consumers.

We have put forward for consultation a wide range of possible policy measures, ranging from improvements in pricing and/or obligations on suppliers to deliver specific levels of supply security, through to models that mandate or secure specific investments in new generating capacity and gas infrastructure.

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Associated Documents

- Project Discovery - Energy Market Scenarios. October 2009. Reference number 122/09
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=Discovery_Scenarios_ConDoc_FINAL.pdf&refer=Markets/WhlMkts/Discovery

- Project Discovery – Updated Energy Market Scenarios. February 2010. Ref 16a/10
http://www.ofgem.gov.uk/

- Energy Markets Outlook Report. December 2009.
http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/markets/outlook/outlook.aspx

- Gas Transportation Ten Year Statement. December 2009.
http://www.nationalgrid.com/uk/Gas/TYS/current/TYS2009.htm

- Meeting Carbon Budgets – the need for a step change. Progress report to Parliament. October 2009.
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http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx

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- Energy Security: A national challenge in a changing world. July 2009.
http://www.decc.gov.uk/en/content/cms/what_we_do/change_energy/int_energy/security/security.aspx

- Decision time - Driving the UK towards a sustainable energy future. July 2009.
http://climatechange.cbi.org.uk/uploaded/CBI_DecisionTime_WEB.pdf

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Summary

Over the two decades since privatisation and liberalisation, the electricity and gas markets in Great Britain (GB) have delivered secure supplies and substantial investment. Significantly, during the last few months, the gas market has coped well with material supply losses on days of record demand. However, the decline in our indigenous gas supplies and the need to make demanding cuts in carbon emission levels, represent unprecedented challenges, which will grow over the next two decades. Large parts of our ageing energy infrastructure will need replacement and, at the same time, we must make rapid progress towards the substantial decarbonisation of our economy. We estimate that up to £200 billion of investment might be required by 2020 alone, in the face of huge global demand for investment in energy infrastructure; volatile commodities prices; and the ongoing effects of the financial crisis.

Scale of the challenge

In October, we set out the risks and challenges facing gas and electricity industries in GB over the next 10-15 years in our Energy Market Scenarios document. Our analysis drew considerable support from consultees, although many thought that we had understated some of the risks. We have updated this work in the light of this consultation. We assess, after these updates, that risks to gas security of supply remain high in the latter half of this decade, and risks to electricity security of supply at that time are now greater in some of our scenarios.

The responses to the consultation have proved extremely valuable and we are grateful to those organisations and individuals that have contributed thus far to Project Discovery. We are now in a position to consult on our appraisal of the current arrangements and on possible policy measures (including whether any early actions should be considered), to address the risks and issues we have identified.

Key issues

Consistent with the analysis in the recent Energy Markets Outlook (EMO) report, published jointly by the Department of Energy and Climate Change (DECC) and Ofgem, our scenarios show supply to be relatively secure until around 2015. However, in light of the consultation and our further analysis we conclude, and so report to consumers, industry and government, that significant action will be called for to deliver both security of supply and environmental objectives at affordable prices longer term, given the nature and scale of challenges facing the GB market.

We have identified five key issues. Although each is of real significance, it is their combination that causes us the greatest concern. The key issues are:

- There is a need for unprecedented levels of investment to be sustained over many years in difficult financial conditions and against a background of increased risk and uncertainty.
- The uncertainty in future carbon prices is likely to delay or deter investment in low carbon technology and lead to greater decarbonisation costs in the future.

- Short term price signals at times of system stress do not fully reflect the value that customers place on supply security which may mean that the incentives to make additional peak energy supplies available and to invest in peaking capacity are not strong enough.
- Interdependence with international markets exposes GB to a range of additional risks that may undermine GB security of supply.
- The higher cost of gas and electricity may mean that increasing numbers of consumers are not able to afford adequate levels of energy to meet their requirements and that the competitiveness of industry and business is affected.

Policy measures

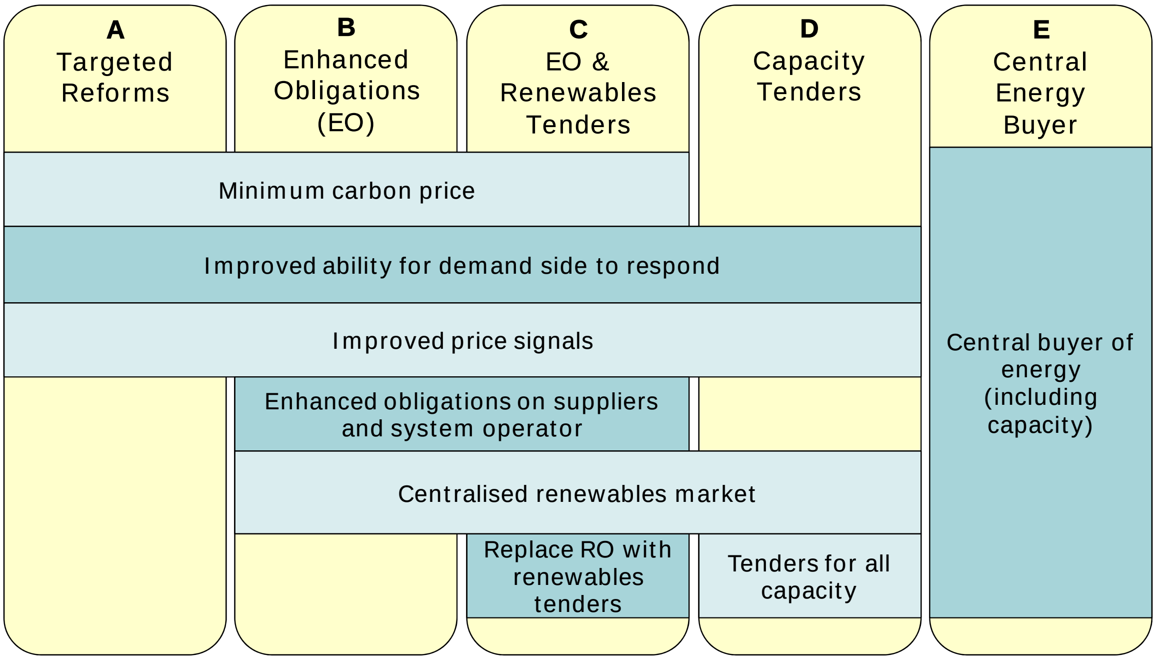
Ofgem does not consider that leaving the current arrangements unaltered is in the interests of consumers, given the risks and issues identified. However, we recognise the need for a stable environment for investment, and do not advocate change lightly. We are therefore looking for solutions that make the GB energy markets more capable of attracting finance over the medium to longer term, whilst at the same time being mindful to ensure that existing and on-going investments are not compromised.

To meet the challenges identified and ensure the arrangements are resilient to a number of possible future outcomes, we have examined a range of policy measures. They include measures to address risks which are internal to the GB market (for example strengthening price signals within industry codes), and measures to mitigate the impact of external risks, principally at international level (for example measures to increase GB storage capacity to help manage future gas supply shocks).

We have combined the different policy measures into five possible policy 'packages' to be considered in consultation with consumers, industry and government. The figure below summarises the packages starting with those involving the least reform and intervention in the market on the left (although even this package involves significant changes) and moving to the most dramatic move away from competitive markets on the right.

In developing these policy packages we have referred to recommendations from the Wicks Review, the Committee on Climate Change reports, leading industry commentators and investment banks. At the same time, we recognise that there may be other policy measures and other combinations that could address the risks and issues identified.

Figure i – Possible policy packages



A minimum carbon price, which would provide long term certainty for investors and should bring forward low carbon investment, features in three of the packages. Improved price signals coupled with measures to promote demand side response, should improve security of supply by increasing the incentives to make peak energy supplies available and invest in peaking capacity including storage. In two of the packages, we include enhanced obligations on industry players to deliver a specific level of supply security. In some packages, we include the concept of a centralised renewables market designed to help manage the variability of some forms of renewable energy sources for both the generator and the system operator. Long term capacity tenders covering renewables, low carbon generation and/or gas storage feature in some packages to facilitate financing, and in one case these are coupled with short term capacity tenders for all generation and demand side response. The Central Energy Buyer package envisages a single entity responsible for coordinating the procurement of new energy supplies, or at least certain forms of energy supplies or infrastructure such as strategic gas storage.

This document does not consider explicitly further measures to deal with the ability of some consumers to afford adequate levels of heat and power. All the measures we have considered are designed to deliver secure and sustainable energy supplies without incurring more costs for consumers than are necessary. The key policy drivers to address affordability issues, such as the structure of environmental incentives and social tariffs arrangements, and further initiatives to tackle fuel poverty, largely rest with government. We will be publishing a document which looks at the implications of Project Discovery for different types of consumer in the coming months.

Assessment of policy packages

Inevitably there are trade-offs among the packages. Those that target specific volumes and types of investment, such as the Central Energy Buyer and Capacity Tenders, would in theory be expected to increase the probability of delivering security of supply and environmental objectives. However, there are risks associated with leaving a central entity to make all the key decisions, which could turn out to be wrong. There is also a risk that large scale, centralised supply side solutions will dominate at the expense of small scale, local solutions and demand side response. These packages are also likely to be more difficult and time consuming to implement, and importantly there may be significant legal issues, particularly with the Central Energy Buyer where the existing European legal framework would limit what is possible.

The less interventionist Targeted Reforms or Enhanced Obligations package are conceptually easier to design but continue to leave key decisions about supply security to individual market participants, which may provide less confidence of achieving specified levels of supply security and carbon reduction. We also need to recognise that there are legal issues and complexities around the design and implementation of a minimum carbon price that could impact the timing and effectiveness of these packages.

Our scenario analysis indicates that prices to consumers are likely to rise under most cases, in large part due to the levels of investment required. The question is which of the policy packages is most likely to deliver the desired outcome for secure and sustainable energy supplies at lowest cost to customers. More mandated outcomes could reduce the cost of finance (by reducing investor risk), reduce the risk of high prices resulting from under-investment, and remove some of the inefficiencies in current mechanisms such as the Renewables Obligation (RO). However, such approaches may expose customers to risks of over-investment, and deprive them of some of the benefits of innovation and cost reductions driven by more effective competitive markets. For these reasons, we present a full range of policy measures for consideration by government.

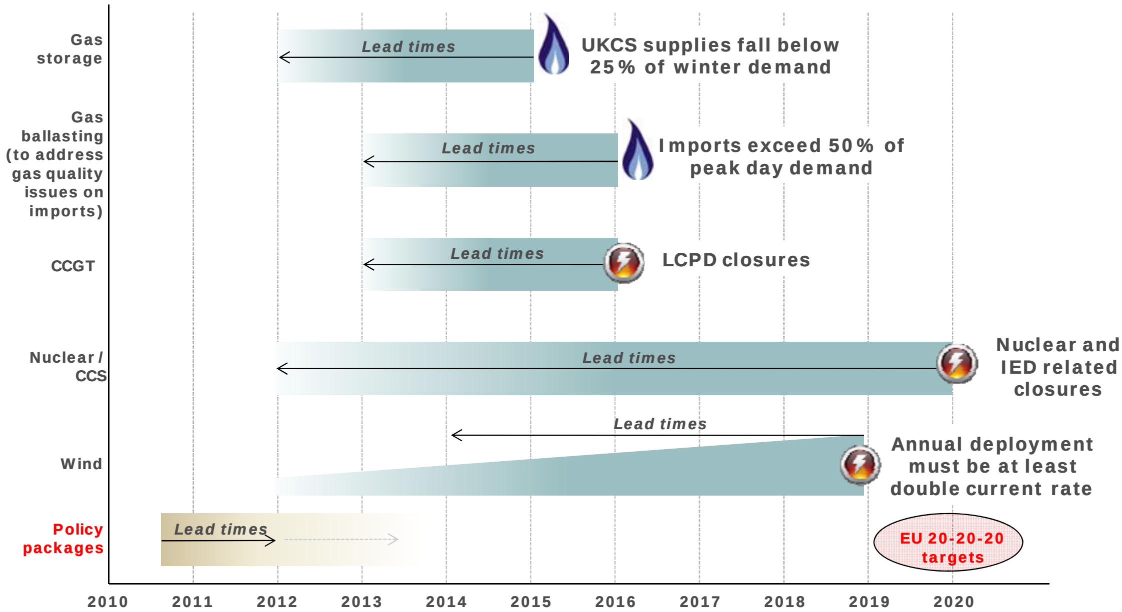
Figure ii – Key benefits and key risks of the five packages

	Key benefits	Key risks
Targeted Reforms	Increases incentives to invest whilst retaining the benefits of competitive markets	May not be sufficient to address the financing challenges and therefore deliver secure and sustainable supplies
Enhanced Obligations	Puts onus on industry players to deliver a specified level of security of supply	May not be sufficient to address the financing challenges and achieve renewables and climate change goals
Enhanced Obligations and Renewables Tenders	Puts onus on industry players to deliver a specified level of security of supply and enhances probability of efficiently meeting renewables targets	May not be sufficient to address all the financing challenges and achieve longer term climate change goals
Capacity Tenders	Facilitates raising finance thus accelerating investment in pre-determined levels and types of low carbon generation and storage	Customers exposed to risk of any poor decisions surrounding the type and scale of capacity required. Small-scale options and supply side may be overlooked
Central Energy Buyer	Underwrites long term contracts giving increased confidence of specific outcomes and access to lower cost finance	May stifle innovation and customers exposed to the risk of any poor contracting decisions Existing European legal framework would limit what is possible under this approach

Timing

Although our scenarios do not indicate concerns over supply security until beyond the middle of the current decade, the timescales required to secure finance, mobilise supply chains and deliver the infrastructure needed suggests that the period around 2012 and 2013 could be important for investment decisions critical to future secure and sustainable energy supplies. Hence, there is a window of opportunity between now and then to implement any policy measures that may be necessary to make sure that investment takes place in a timely fashion.

Figure iii – Key timings



We have highlighted in the figure:

- The potential need for additional gas storage and gas ballasting facilities (to address gas quality issues) around the middle of the next decade as our import dependence passes significant milestones (as based on our Dash for Energy scenario);
- The possibility that additional combined cycle gas turbines (CCGTs) will be needed before 2016 to offset plant closures associated with the Large Combustion Plant Directive (LCPD);
- The need for low carbon alternatives, such as new nuclear or plant fitted with carbon capture and storage (CCS), to be deployable at scale to replace closing nuclear plant and large volumes of fossil fuel plant expected to close from 2020 under the terms of the Industrial Emissions Directive (IED); and
- The (at least) doubling of our wind deployment rate by the end of this decade that will be needed if the 2020 renewables targets are to be met.

The earlier action is taken, the more options there are available and the more cost effective that investment is likely to be. Some of the reforms we have outlined are suitable for early action, whilst others will take longer. However, the key concern is to provide clarity of direction against which investors will have the confidence to make decisions.

Next steps

Some of the measures outlined above could be taken forward by Ofgem and industry; others would require government to take the lead. We are, however, currently considering whether it is necessary to pursue certain measures immediately (informed by experience in the gas market this winter). What is of particular importance is the need to develop a coherent package rather than implementing them in a piecemeal fashion. The findings of this project may provide useful input to the Government's coming Energy Market Assessment.

Nonetheless we confirm our commitment to work with government in delivering what is required to ensure secure and sustainable supplies for consumers.

We welcome responses to this consultation by 31 March 2010. In particular, we are seeking respondents’ views on our appraisal of current arrangements; our policy packages and assessment of them; whether other policy measures should be considered; and the extent to which early actions should be considered.

1. Introduction

1.1. The interest in the ability of energy markets to deliver secure and affordable energy and at the same time meet environmental objectives is intense. In July 2009 the Government's Low Carbon Transition Plan and the Renewable Energy Strategy set out how the Government expects the supply of energy from renewables and other low carbon sources to develop over the next decade. Also in July the Prime Minister's special representative on international energy, Malcolm Wicks, reported on International Energy Security and the Confederation of British Industry published its report on energy security this summer. In October, the Committee on Climate Change also published its first statutory progress report assessing the progress made in reducing emissions against carbon budgets. The Government announced in its Pre-Budget Report that it would publish an Energy Market Assessment at the time of the Budget, and is about to publish the results of its 2050 work.

1.2. Significant developments are also taking place in European policy, notably implementation of the Third Package of liberalisation legislation, together with the establishment of the Agency for the Cooperation of Energy Regulators (ACER) and the proposed Regulation for security of gas supply.

1.3. In the 2008 Energy Act, Ofgem’s statutory duties were extended to put greater emphasis on the achievement of sustainable development. New social and environmental guidance came into force on 18 January 2010. The Government’s Low Carbon Transition Plan emphasised that Ofgem's duties to protect current and future customers should include tackling climate change and ensuring security of supply and that measures other than competition should be considered.

1.4. Project Discovery was begun in early 2009 to explore whether the current arrangements are capable of delivering both security of supply and environmental objectives at affordable prices, given the nature and scale of challenges facing the British market. It comprises three stages:

- First, identifying the scale of the challenge and risks facing the GB and wider European and global energy markets over the next two decades through scenario and stress test analysis. The October consultation document sought views on the results of that analysis;
- Second, appraising the current arrangements to see if they are appropriate for this challenge; and
- Third, if there are areas that need changing, identifying possible policy measures.

1.5. Our October consultation document covered the first stage of the project and set out the context for Project Discovery and described the most significant challenges. In the present consultation document, we are reporting the results of our work under the second and third of these three stages.

2. The Challenge

Chapter Summary

This chapter summarises the key messages from our October Energy Scenarios document, the responses received to the consultation and subsequent updates made to the analysis.

2.1. Over the two decades since privatisation and liberalisation, the electricity and gas markets in Great Britain (GB) have delivered secure supplies and substantial investment. Significantly, during the last few months, the gas market has coped well with material supply losses on days of record demand. However, the decline in our indigenous gas supplies and the need to make demanding cuts in carbon emission levels, represent unprecedented challenges, which will grow over the next two decades. Large parts of our ageing energy infrastructure will need replacement and, at the same time, we must make rapid progress towards the substantial decarbonisation of our economy. We estimate that up to £200 billion of investment might be required by 2020 alone, in the face of huge global demand for investment in energy infrastructure; volatile commodities prices; and the ongoing effects of the financial crisis.

2.2. In October we presented for consultation our energy market scenarios[1], which we used to assess the scale of the challenge facing energy markets, inform our appraisal of the current arrangements and help us in developing possible policy measures if necessary. Four scenarios were used to illustrate diverse, yet plausible and internally consistent, visions of the future. Stress tests were used to demonstrate how the resilience of the market may evolve over time and differ between scenarios.

2.3. Consistent with the analysis in the recent Energy Markets Outlook (EMO[2]) report, published jointly by the Department of Energy and Climate Change (DECC) and Ofgem, our scenarios show supply to be relatively secure until around 2015.

2.4. However, our Discovery analysis led us to conclude that the current arrangements for delivering secure and sustainable energy supplies are likely to be tested to an unprecedented extent over the next decade or so. This

[1] http://www.ofgem.gov.uk/Markets/WhlMkts/Discovery/Documents1/Discovery_Scenarios_ConDoc_FINAL.pdf

[2] The 2009 Energy Markets Outlook (EMO) report, published jointly by the Department of Energy and Climate Change (DECC) and Ofgem (http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/markets/outlook/outlook.aspx), is not a forecast but it explores the drivers affecting demand and supply for key fuels, drawing on analysis by Government, Ofgem, National Grid and others. In summary, the EMO analysis showed that the recession-driven reduction in demand has resulted in an increase in security of supply in the near term.

conclusion informed our approach to the subsequent appraisal of the current arrangements and assessment of possible policy packages.

2.5. Following the October consultation, our working hypothesis for the definition of secure and sustainable energy supplies is as follows:

- No customer loses supply of gas or electricity if they would have been willing to pay more for a more reliable supply (or is adequately compensated if they do lose supply);
- Environmental objectives to tackle climate change and air pollution are broadly adhered to; and
- All consumers have access to adequate supplies of gas and electricity at prices they can afford and pay no more than they need to in the achievement of these objectives, whilst prices are consistent with the need to finance future investments.

Scenario analysis - our approach to risk and uncertainty

2.6. In order to understand the range of possible outcomes and in particular the risks to security of supply, meeting our environmental objectives and costs to consumers, we adopted the widely used approach of scenario analysis. The Discovery scenarios represent a series of diverse, but plausible and internally consistent, futures that have helped us to test current arrangements and possible future policy responses. The scenarios are not intended to represent forecasts and many other possible outcomes can be envisaged.

2.7. In developing our scenarios we selected the two key global drivers which we believe will most likely shape different outcomes for the GB energy markets over the next decade or so. They were first the speed of global economic recovery, and second the extent of globally co-ordinated environmental action. These global drivers will affect the supply and demand for energy, and influence policy decisions, at the EU and national levels. The combination of the two drivers yielded four scenarios as set out in Figure 1 below.

Figure 1: Global drivers and scenarios

		Economic recovery	
		Rapid	**Slow**
Environmental action	**Rapid**	Green Transition	Green Stimulus
	Slow	Dash for Energy	Slow Growth

2.8. To capture those risks that could be best described as shocks, such as major infrastructure failures, and which could occur in any scenario in any year, we designed a number of stress tests. The stress tests were used to demonstrate how the resilience of the market may evolve over time and differ between scenarios.

Key messages

2.9. Under each of our scenarios presented in our October consultation, gas and electricity supplies can be maintained to businesses and households provided the market participants respond adequately to market signals broadly as they have in the past - but each scenario comes with real risks, potential price rises and varying carbon impacts. Britain's ability to meet its demand for gas and electricity is therefore poised to be tested over the next decade or so. Growing exposure to a volatile global gas market and ageing power plant nearing the end of its life, along with the need to tackle climate change, are the central energy challenges the country faces.

2.10. High levels of investment are likely to be needed – up to £200 billion may be required by 2020. This would imply more than doubling the rate of investment spending compared to the last 10 years.

2.11. Consumer bills rise in all scenarios due to the levels of new investment required and increasing costs of carbon, and especially so if oil and gas spot prices spike sharply or continue their underlying rise since 2003.

2.12. The key results reported in our October document are summarised in Figure 2 below.

Figure 2 - Key results from October scenario and stress test work

	Green Transition	Green Stimulus
Key supply risk:	Generation intermittency	Generation intermittency
CO2 impact:	Down 33% by 2020	Down 43% by 2020
Impact on bills:	Up by 23% by 2020	Up 14% by 2020
Invt required:	£200bn	£190bn
	Dash for Energy	**Slow Growth**
Key supply risk:	Gas import dependency	Deferred investment
CO2 impact:	Down 12% by 2020	Down 18% by 2020
Impact on bills:	Up 60% by 2016	Up 22% by 2020
Invt required:	£110bn	£95bn

Stress test	Period	Today	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
Re-direction of LNG supplies	1-in-20 severe winter	Low impact	Moderate impact	Moderate impact	High impact	High impact
Russia-Ukraine dispute	1-in-20 severe winter	Moderate impact	Moderate impact	Moderate impact	High impact	High impact
Bacton outage	1-in-20 peak day	Moderate impact	Moderate impact	Moderate impact	Moderate impact	Moderate impact
No wind output	1-in-20 peak day	Low impact	Moderate impact	High impact	Low impact	Low impact
Electricity interconnectors fully exporting	1-in-20 peak day	Low impact	High impact	High impact	Moderate impact	Moderate impact

Low impact Moderate impact High impact

2.13. The scenario and stress test analysis presented in our October consultation suggests that the current arrangements may well be tested severely over the next two decades.

Consultation responses and subsequent changes

2.14. We published our October consultation in order to subject our scenario analysis and stress tests to wider scrutiny, so as to ensure it was robust before we assessed possible policy measures. We have also engaged with consumers to incorporate their perspective as we consider possible policy measures.

2.15. In total we received responses from 55 organisations to our consultation. The majority of respondents were supportive of the project and the general approach we have taken. In particular, we received very positive feedback on our use of scenario analysis and stress tests for assessing uncertainty. Many respondents thought that we had understated the risks and had been too optimistic, giving us further evidence that our concerns are warranted.

2.16. We received very useful feedback on specific assumptions and have made a number of updates to our Discovery model, including adding some additional stress tests covering gas quality, oil price shocks and possible investment delays. These changes have not, however, materially affected our conclusions presented in the October document, although we now assess that risks to gas security of supply remain high in the latter half of this decade, and risks to electricity security of supply at that time are now greater in some of our scenarios. Increases in bills are marginally lower than previously, mainly as a result of a downward revision to gas demand in our scenarios, informed by National Grid's latest Ten Year Statement (December 2009)[3].

[3] http://www.nationalgrid.com/uk/Gas/TYS/current/TYS2009.htm

2.17. The key results of the revised analysis are summarised in Figure 3 below, and set out in more detail in the separate paper, "Energy Market Scenarios Update", published in parallel with this document.

Figure 3 - Key results of revised scenario and stress test work

	Green Transition	Green Stimulus
Key supply risk:	Generation variability	Generation variability
CO2 impact:	Down 33% by 2020	Down 46% by 2020
Impact on bills:	Up by 23% by 2020	Up 13% by 2020
Invt required:	£194bn	£190bn

	Dash for Energy	Slow Growth
Key supply risk:	Gas import dependency	Deferred investment
CO2 impact:	Down 14% by 2020	Down 19% by 2020
Impact on bills:	Up 52% by 2016	Up 19% by 2020
Invt required:	£110bn	£95bn

Stress test	Period	Today	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
Re-direction of LNG supplies	1-in-20 severe winter	🟢	🟡	🟡	🔴	🔴
Russia-Ukraine dispute	1-in-20 severe winter	🟢	🟡	🟡	🔴	🔴
Bacton outage	1-in-20 peak day	🟡	🟢	🟡	🟡	🟡
No wind output	1-in-20 peak day	🟢	🟡	🟡	🟡	🟡
Electricity interconnectors fully exporting	1-in-20 peak day	🟢	🔴	🔴	🔴	🔴

Low impact 🟢 Moderate impact 🟡 High impact 🔴

3. Appraisal of current arrangements

Chapter Summary

This chapter describes the initial conclusions from our appraisal of the current arrangements under a number of key themes. From this we draw out five key issues. Finally, in this chapter we consider what might happen if no further action is taken to enhance the prospect of future secure and sustainable energy supplies.

Question 1: Do you agree with our assessment of the current arrangements?
Question 2: Are there other aspects of the current arrangements which could have a negative impact on secure and sustainable energy supplies, or costs to customers?
Question 3: Do you agree that the five issues we have highlighted are the most important?
Question 4: Do you have any comments on our description of what might happen if no changes are made to the current arrangements?

Introduction

3.1. The first stage of Project Discovery identified the scale of the challenge and risks facing the GB and wider European and global energy markets to 2020 (and beyond) through scenario and stress test analysis. We have conducted an appraisal of the current arrangements, in order to understand whether the existing framework is likely to be sufficient to mitigate those risks and meet those challenges and, if not, what type of changes may be needed.

3.2. From this wide-ranging appraisal, we have identified a number of specific concerns, and from those concerns five key issues. These issues lead us to conclude that there are reasonable doubts as to whether the current arrangements will deliver security of supply and environmental objectives, at least not without consumers paying substantially more than they would otherwise need to. For this reason, Ofgem does not consider that leaving the current arrangements unaltered is in the interests of consumers.

Background

3.3. There are two main objectives of the current arrangements in GB:

- First, at the day-to-day operational level - they should incentivise efficient use of the currently available assets, infrastructure and supply sources.
- Second, they should secure the efficient, cost-effective and timely provision (or extension) of assets, infrastructure and supply sources to deliver acceptable supply security in the face of uncertainty while meeting other policy objectives such as the drive to reduce carbon dioxide emissions.

3.4. A critique of past performance would suggest that the arrangements have performed reasonably well against both objectives, particularly the first. There have been lower costs and better service for consumers through the successful introduction of supply competition, large sums of external investment and secure supplies. One area where the arrangements appear to have performed less well is in bringing forward investment in low carbon generation, at least in comparison with Government targets.

3.5. Critics of the current arrangements suggest that the markets have benefited from being until now largely self-sufficient in gas and inheriting large capacity margins in electricity at the time of privatisation. The "dash for gas" in the late 1990s, stimulated by a combination of cheap North Sea gas and expensive domestic coal, provided additional capacity before the advent of the New Electricity Trading Arrangements (NETA) in 2001. They also argue the arrangements have been effective in sweating existing assets, and bringing forward relatively low capital cost investments such as combined cycle gas turbine (CCGT) plant, but are not yet proven in bringing forward large scale ‘lumpy’ investments such as nuclear plant.

3.6. On the other hand the markets have delivered 30 GW of new generation capacity (around 40% of the total installed capacity) and 125 bcm/yr of new gas import capacity and storage (equivalent to around 125% of annual demand) over the past 20 years. However, the current arrangements have not been tested to the extent illustrated by our scenario and stress test analysis. Certainly investments to date have been against the background of future expectations of growing demand, which may no longer be the case. Furthermore, much of the generation investment occurred pre-NETA.

3.7. While the current arrangements have largely delivered, our assessment recognises that conditions have significantly changed. The need to take action to drive decarbonisation of the energy sector; the large investment required to replace aging generation plant; and rapidly declining indigenous gas supplies (all three of these in the context of a global financial crisis) are all features of the markets that have grown significantly in importance in recent years.

3.8. In arriving at our conclusions, we have assessed a wide range of potential issues. These issues were identified in previous Ofgem work; discussions with stakeholders as part of Project Discovery; published views of leading commentators; and additional Ofgem assessment work.

Specific concerns

3.9. We have organised our findings from the appraisal under a number of specific concerns:

- costs and availability of finance;
- market structure;
- uncertain price of carbon;
- investment signals in generation;
- issues with current market rules;
- enabling demand side response and distributed generation;
- risk management;
- costs to consumers;
- interaction with interconnected markets;

- interaction with networks; and
- non-financial barriers.

3.10. We set out below a summary of the specific concerns identified.

Cost and availability of finance

3.11. Although investor confidence appears to be recovering from the global financial crisis, there is still a question as to whether the high levels of investment needed in the GB energy sector over the next decade will be available at a reasonable cost given the riskiness of the investment environment. The markets' willingness to lend or invest and the associated cost of funding will be determined by the perceived risks in the GB energy sector relative to other sectors and markets. Our assessment suggests that low forward liquidity in power markets and uncertainty surrounding future carbon prices and subsidy levels are key risk factors facing investors. A perception of heightened policy and regulatory uncertainty, particularly given the long term nature of the investments required, may also push up the costs of financing them.

3.12. The scale and relative riskiness of the investment required within such a short timescale may push up the cost of capital to the industry. For this not to lead to a reduction in security of supply, prices will need to rise. Furthermore, in general terms, higher costs of capital will disadvantage low carbon technologies since a greater proportion of their costs is related to the capital investment. For those technologies that receive subsidies this may mean that subsidies have to increase in order that environmental objectives can be met. As a consequence, consumers will need to pay more for their energy.

3.13. The bulk of the investment required in the GB market is likely to be focussed on riskier activities such as generation (including renewable energy), gas storage and smart meters. Raising debt at the project level for these types of investment remains challenging, which implies that a higher degree of equity finance will be required to meet funding requirements. Currently the primary sources of such funding remain pension and infrastructure funds, other private sources of equity and sovereign wealth funds. Companies can expand their balance sheets to fund new investment through borrowing, equity and bond issuances, but may start to face the constraint of limited market demand for further issuances should the companies become over-borrowed. In any event, management teams are likely to proceed cautiously. Multi-national players may seek to prioritise investments in markets where there is a higher degree of confidence in achieving good returns.

3.14. Liberalisation attracted a substantial wave of external investment in the GB energy market, which could be largely attributed to the high degree of transparency in the GB market and the perception that the risks of government and regulatory intervention were low. However, we are entering a phase of substantial new investment in energy markets globally, to replace retiring assets and to increase the penetration of low carbon technologies. If the GB market is perceived as higher risk than those overseas, returns will need to be higher in order to attract sufficient investment. Furthermore, international competition for constrained skills, equipment and other resources could push up costs.

Market structure

3.15. The gas and electricity supply markets and electricity generation market are currently dominated by the 'Big 6' vertically integrated players. With their relatively secure customer bases and strong balance sheets these players would under many circumstances be well placed to make the large investments required, although the scale and risk of some investments, such as nuclear, are such that these companies have formed joint ventures with each other for certain projects.

3.16. Based on recent evidence, a significant proportion of the investment required is likely to come from these players, and we believe that the markets are sufficiently competitive such that strategic withholding of investment to exploit positions of market power is a low risk at present. However, some of the investments required in the future can only be made by a relatively small number of players, and the field may contract further where joint ventures have formed. This issue must be carefully considered in the context of how the current arrangements, or any future alternative policy measures, deliver the investment required at a reasonable cost for customers.

3.17. Although these larger companies are likely to play an important part in delivering secure and sustainable energy supplies, their balance sheets and management are constrained and there are competing calls on their capital. Therefore, in order to raise all the finance required, particularly in renewables and low carbon technologies, it is likely that new investors will need to be attracted to the market. It is important that there are no material obstacles to this happening.

3.18. Ofgem's energy supply Probe into retail gas and electricity markets noted that companies sought to benchmark their procurement and hedging strategies against each-other in order to minimise the risk of their energy costs deviating materially from the average. Such behaviour is a consequence of the market structure and the lack of threat from new entry in supply. There is a risk that such dynamics could impact the perceived riskiness of generation investments, such that, perversely, investments with stable operating and fuel costs (such as nuclear and wind) could be viewed by the Big 6 suppliers as more risky than investments whose costs vary with volatile global fuel costs. Under the current market structure, in the absence of effective new entry, there is no obvious mechanism for consumers to express a preference for more stable energy costs.

3.19. A final issue surrounding market structure, highlighted within the Wicks report[4], is that the industry codes are 'owned' by the industry players. Wicks advocates that market participants' involvement in the governance arrangements must be limited to technical and practical issues, and where there are important issues of security of supply there must be mechanisms in place to deal with these urgently. Indeed, some of the issues we identify in relation to the current

[4]http://www.decc.gov.uk/en/content/cms/what_we_do/change_energy/int_energy/security/security.aspx

arrangements are issues we have identified in the past, but have lacked the power to resolve fully under existing governance arrangements. Nevertheless, it is important for a well-functioning market that the regulatory and market framework can adapt to changing circumstances without undue risk for investors. Our ongoing review of code governance will report in the coming months. The Third Package also appears to envisage a greater ability on the part of the National Regulatory Authorities to implement a number of policies directly. While the detail of any changes has yet to be decided, the two are at least broadly consistent with each other.

Uncertain price of carbon

3.20. Uncertainty surrounding the future price of carbon is a significant impediment to investment in low carbon technologies. Current European Union Allowances (EUA) prices are low, in part the result of recessionary effects on demand, and the absence of a globally binding deal emerging from Copenhagen has lowered expectations of higher prices in the future.

3.21. The risk is that more generous subsidies are required to overcome discounted future views of carbon prices in order to stimulate the desired low carbon investment. Should carbon prices subsequently rise, low carbon generators may enjoy super-normal profits at the expense of consumers.

3.22. The existence of subsidy schemes and separate targets for low carbon measures can themselves undermine the carbon price by reducing demand for allowances. Furthermore, the plethora of different mechanisms which implicitly place different values on carbon abatement may contribute to a complex environment, making investment decisions difficult.

Investment signals in generation

3.23. Uncertainty surrounding future carbon prices may encourage companies to invest in CCGTs since these are less exposed to carbon price uncertainty[5], have relatively low capital costs and can be built quickly. This could exacerbate gas import dependency, and make decarbonisation of the power sector over the longer term more difficult.

3.24. However, we may need this additional gas-fired capacity to maintain security of supply during the latter part of the decade. As an increasing proportion of the market receives revenues via subsidies this will place downward pressure on the profitability of gas powered generation and thermal plant will operate at lower load factors to accommodate the variable output patterns of wind and other renewables. Flexible thermal plant will increasingly rely on either high prices in periods of system tightness to make an adequate return. If prices

[5] This is because CCGTs are usually the marginal price setter of electricity and can therefore pass through their carbon costs relating to the prevailing carbon price.

do not rise sufficiently in these periods then investment in flexible capacity, either new or existing, may be insufficient to maintain security of supply.

3.25. As we discuss below, our assessment suggests that prices may indeed not rise sufficiently during periods of scarcity and we believe that this presents a material risk to security of supply. As a result, potential investors in new power stations could find it difficult to recover their investment costs and so may not build new plant. Some commentators suggest that this so called 'missing money' problem in electricity markets can only be addressed through separate mechanisms for rewarding capacity as have been implemented in the US and elsewhere. Others argue that capacity mechanisms are not necessary and lead to inefficiently high prices.

Issues with current market rules

3.26. Our assessment has raised a number of concerns surrounding the strength of short term cash-out (imbalance) price signals in both the electricity and gas markets. In both markets it is possible that firm customers could have their load curtailed before cash-out prices have reached the value of lost load of those customers. This suggests that companies do not have sufficient incentives to avoid such outcomes. Ofgem has recognised these issues for some time, but the industry has so far not proposed adequate change to address them. The problem has now become even more acute given the challenges we have identified.

3.27. In gas, the problem primarily manifests itself in the emergency cash-out arrangements. Firm load could be curtailed in an emergency with the cash-out price frozen well below the value of lost load for the customers being interrupted. If the price was able to rise in an emergency, additional supplies could be attracted from the Continent and from LNG, thus enhancing security of supply by reducing the risk of firm load curtailment.

3.28. In electricity, the problem is primarily caused by the fact that certain balancing actions undertaken by the system operator can be mispriced. For example, there is no cost reflected in the cash-out price calculation when voltage control or automatic load disconnection occur, even though these actions may be the precursor to wider spread disconnection. Similarly, the pricing of the upfront costs of reserve contracts into the cash-out price does not reflect how these contracts have actually been used.

3.29. As we move to a system with a growing penetration of renewables, it will become increasingly important that the short term price signals lead to the most efficient dispatch of the market and elicit the necessary responses on both the supply and demand sides when periods of low renewables output coincide with periods of high demand, or when the supply/demand balance shifts rapidly and perhaps unexpectedly.

Enabling demand side response and distributed generation

3.30. One of the consequences of insufficient short term signals is that the incentives to develop demand side response are reduced. Demand side response can play a vital role in maintaining security of supply, by allowing those consumers with a lower value of lost load to reduce load first, thus enhancing security of supply for those customers willing to pay more for a continuous supply of energy. A more responsive demand side would allow a greater amount of variable renewables to be connected to the system, without the need for additional flexible generating capacity (which is often highly carbon emitting). It may also reduce the need for network reinforcements.

3.31. Whilst there is an active demand side response in the industrial and commercial (I&C) sector (albeit with potential for more if, for example, price incentives can be improved), in the mass market there are a number of barriers to enabling demand side response which our assessment has identified. These include deficiencies in the settlement arrangements which limit the options for introducing time of use tariffs, deficiencies in metering technology (which will now be addressed through the mandated roll-out of smart and advanced meters by 2020), and the need for consumers to respond to price signals (which may only be achieved via automation provided by smart appliances controlled by in-home devices).

3.32. In the future new electrical loads such as heat pumps and electric vehicles will be connected to the system, although the extent of this remains uncertain. These new loads present additional opportunities for demand side response, but may place constraints on distribution networks which will need to be managed, potentially through smart grid technology. Through Ofgem's recent review of distribution prices and the RPI-X@20 project, we are ensuring that distribution network operators face the correct incentives to make the correct choices between network reinforcements and constraint management.

3.33. Smart grid and smart meter technologies may also be an enabler of distributed generation (DG)[6], including micro-generation, the penetration of which in GB is very low compared to some other European countries. DG can provide benefits to both security of supply and emissions reduction, directly where it is low carbon and indirectly through greater energy conversion efficiency and the reduction of losses. There are a number of barriers to DG that were identified in our joint review with Government in 2007:

- Cost – firstly, the true cost of carbon is not yet fully incorporated in electricity prices and this disadvantages lower carbon technologies. Secondly, DG technologies tend to have higher capital costs. Finally, the rewards for exporting
  excess electricity produced by distributed generators were seen as small and difficult to access.
- Lack of reliable information – there was a low awareness of DG options amongst potential users; grants and financial incentives such as Renewables

[6] DG is small-scale generation which is directly connected to the distribution networks and offsets demand for centrally supplied electricity, with benefits including reduced requirement for network capacity and reduced transmission losses.

Obligation Certificates (ROCs) were perceived as being hard to access, and the lack of an accreditation scheme for suppliers and installers put people off untried technologies[7].

- Electricity industry issues – due to the nature of the existing industry structure, it could be hard for small generators to connect to and operate in the centralised system. Network operators could do more to accommodate the connection of distributed generators. The cost to suppliers of rewarding small generators for exporting their excess electricity was a disincentive.
- Regulatory barriers – the difficulties of getting planning permission for DG technologies was raised, especially in the context of community developments and new housing, where the associated costs and delays acted as a disincentive[8].

Risk management

3.34. The GB markets rely on price signals and the companies' response to these to deliver the desired level of supply security. Even with the appropriate price signals, it is not clear what level of collective cover companies will provide, and yet security of supply is of critical importance to the economy and society as a whole. Recent experience of the financial crisis has exposed the limitations of risk measurement techniques, such as value-at-risk and earnings-at-risk, which are also widely used in energy markets. These measures may be adequate under 'normal' market conditions but can be exposed during major market dislocations, of which the Discovery stress tests could be examples.

3.35. Possible failings in risk governance with incomplete separation of risk management from commercial decision making may contribute to less exacting risk standards. Another factor may be the ‘moral hazard’ provided by common supply to customers since it is not just the customers of a company that has failed to provide sufficient cover that could be interrupted, and indeed its own customers could be totally unaffected. Thus the reputational risk driver, which might otherwise help to compensate for a lack of sufficiently strong short term price signals, is diluted. In many ways this is analogous to the ‘too big to fail’ issue exposed by the financial crisis – if events become extreme, individual companies assume that the situation is beyond their control and as an issue of national importance the government will intervene, not necessarily to rescue individual companies but to manage the physical supply situation as best it can, and deal with the fall-out from widespread loss of supply to customers.

[7] Since this study was completed, the Government has announced a new feed-in tariff regime for sub-5 MW generation plant, which should address some of these concerns.
[8] The new National Planning Statements, which are currently under consultation by the Government, may address some of these issues.

Costs to consumers

3.36. We noted in the Project Discovery scenarios that consumer bills are likely to increase in the future in response to increasing wholesale energy costs and to fund new investment. This may impact on the international competitiveness of GB's energy intensive industries (although this will depend on the extent to which GB companies are exposed to these factors compared to their international competitors) and particularly affect those on low incomes and in fuel poverty.

3.37. In appraising the arrangements and considering policy measures, our objective has been to ensure that customers pay no more than they need to for secure and sustainable energy supplies whilst at the same time ensuring investors are able to make adequate returns. As well as being concerned with overall price levels, we also recognise that different policies could have different distributional effects, which can have important implications for fuel poverty, for example.

3.38. Our assessment has raised three key concerns in relation to consumer bills. First, if the arrangements are perceived to be unduly risky in GB, this will push up the cost of financing the large investments required which, unless the additional risk yields other benefits in terms of price discovery and market efficiency, customers will need to pay for. Second, if in order to overcome discounted future expectations of carbon prices, subsidies for renewables and other low carbon technologies are utilised, these may end up being too generous should a robust carbon price subsequently transpire. Third, if we have sustained periods of high prices as a result of, for example, capacity shortages or volatile supplies, costs to consumers will be impacted. Larger I&C customers are likely to be directly exposed to short term movements in wholesale prices and would therefore experience these higher prices immediately. Suppliers to domestic and small/medium enterprise (SME) customers purchase a large proportion of their electricity and gas requirements in advance in order to hedge against short term price spikes, so one-off or occasional spikes will have a minimal effect on their costs (and consequently on consumer bills) and indeed provide the appropriate incentives to hedge forward. But if spikes occur regularly for a period of weeks or months and the market does not respond with additional supplies, they will have a more significant direct effect on costs and will also start materially to affect forward prices, so a larger proportion of suppliers' cost base will be affected. These costs will then need to be passed on to consumers.

3.39. There are a number of Ofgem and Government initiatives underway to improve energy efficiency and facilitate increased demand side response capability as discussed in the next chapter. These should to some extent mitigate the expected increases in customer bills.

Interaction with interconnected markets

3.40. GB is becoming increasingly reliant on imports of gas, either via interconnectors or as liquefied natural gas (LNG), to meet its gas demand.

3.41. Some steps have been taken to increase harmonisation of gas and electricity markets across Europe and recently Ofgem has led efforts which bring improved transparency of gas transmission and storage. However, there are a number of differences between the way that the markets operate in GB compared with markets with which we are interconnected, and there is a danger that change will not occur on a sufficient scale and/or sufficiently quickly to mitigate the security of supply risks caused by heterogeneous arrangements. In particular, whereas in GB we rely on price signals to provide security of supply, in other European markets public service obligations (PSOs) and strategic provision are the norm. Due to the existence of longer-term contracts, third party access to pipelines and storage can also be more difficult in other European gas markets than in GB.

3.42. Divergence in the arrangements for delivering security of supply in interconnected markets can exacerbate the risks in GB. Where the security standards provided by the PSOs create stronger incentives than the price signals provided by the GB arrangements, gas will flow to continental markets rather than GB, and in extremis flow out of GB. While gas markets have generally worked well both this winter and last, there were concerns that gas was withdrawn from GB storage ahead of continental storage during the Russia-Ukraine gas crisis in January 2009.

3.43. The availability of uncontracted LNG cargoes, and the physical limitations imposed by transporting over large distances, may similarly limit LNG responsiveness to short term price signals in GB. Furthermore, GB companies may be thwarted from making forward arrangements to cover peak positions through contractual congestion of pipeline and storage capacity in continental markets, and remaining limitations on transparency. This will mean either a lower level of supply security in GB markets or an inefficient duplication of assets (for example, more storage facilities) which will ultimately cost consumers more.

3.44. We have also appraised the issue surrounding the difference in gas quality standards between GB and other markets. GB has a tighter range covering the typical specification of UKCS gas, and any "out of spec" gas would damage consumer appliances thus being a safety risk and is therefore not permitted to flow on the GB transmission network[9]. The difference in gas specification creates a risk that gas cannot flow via the IUK interconnector to the GB market. Up until now, Fluxys, the Belgian SO, has been able to manage this risk to imports via the IUK by swapping higher calorific sources with lower calorific sources or by using linepack to keep gas within the GB specification. However, there is a risk that the high specification of new sources of Russian gas and the increasing specification of Norwegian gas arriving at Zeebrugge may make it more difficult for Fluxys to provide these services. This means that there is an increasing risk that flows could be curtailed on certain days to stop "out of spec" gas from entering GB. To prevent this, processing facilities at Zeebrugge or Bacton may be required in the future. However, since shippers of non-UK specification gas can currently benefit from effectively a free ‘processing’ service, there are currently few economic signals for shippers to invest in such facilities.

[9] The Government has ruled out proposing any change to the GB regulated gas specification to take effect before 2020.

Interactions with networks

3.45. Securing connection access has proved a major hold up in the expansion of renewables particularly in constrained parts of the electricity system. Non-renewables projects are also experiencing long delays for connection agreements.

3.46. The Transmission Access Review was set up to explore options for speeding up connections and the implications for constraint costs and how these are recovered. The Government recently announced that its preferred option is the "connect and manage socialised" model whereby renewables can be connected to the system in advance of network reinforcements and the costs of managing the associated constraints are shared between network users.

3.47. Ofgem's RPI-X@20, the fundamental review of how we will regulate energy networks in the future, is considering how the regulatory framework can encourage networks to contribute proactively to the changes needed to achieve a sustainable energy sector including encouraging networks to work effectively with others and to face signals that encourage effective investment and improvements in the use of existing network assets.

3.48. Meeting the 2020 renewables targets will in part depend on successful outcomes across these two initiatives.

Non-financial barriers

3.49. Our assessment highlights the problems that delays in the planning process have caused in bringing forward new investment, particularly in renewables. Changes to planning policy are designed to overcome these barriers.

3.50. It needs to be recognised that GB is gearing up for an unprecedented deployment of new technologies within a very short space of time. Additional barriers to rapid deployment of low carbon technologies are availability of skills and the establishment of supply chains.

Key conclusions from the appraisal

3.51. From the specific concerns above, five key issues emerge. They lead us to conclude that, in the context of the risks identified in our scenario work, there are reasonable doubts as to whether the current arrangements will deliver security of supply and environmental objectives at affordable prices. These are:

1. **There is a need for unprecedented levels of investment to be sustained over many years in difficult financial conditions and against a background of increased risk and uncertainty**. In an environment of heightened, or heightened perception of, risk the cost of raising the necessary finance could become very high if the investment is to be delivered in a timely fashion, requiring prices to rise correspondingly. There are also practical limitations on deployment of new infrastructure at this rate including planning, connections, technical barriers and constraints in the supply chain.

2. **The uncertainty in future carbon prices is likely to delay or deter investment in low carbon technology and lead to greater decarbonisation costs in the future**. Ongoing uncertainty is likely to lead to fewer or deferred low carbon investments and/or push up the cost of capital, necessitating further interventions which could prove costly or further undermine the market.

3. **Short term price signals at times of system stress do not fully reflect the value that customers place on supply security which may mean that the incentives to make additional peak energy supplies available and to invest in peaking capacity are not strong enough**. Whilst the signals have worked well to date in incentivising short term response and long term investment, we identified a number of reasons why we believe that, given the challenges of the coming decade, short term price signals as currently designed are not likely to react sufficiently to periods of market tightness in both gas and electricity. The risk is that prices do not rise high enough under stress conditions (for example during periods of low variable generation output coinciding with high demand) to attract energy supplies or for price responsive consumers to reduce demand. As a result the longer term signals to contract forward or invest to avoid future price spikes are undermined, with the risk of much higher and enduring high prices in the future.

4. **Interdependence with international markets exposes GB to a range of additional risks that may undermine GB security of supply**. There is a risk that political considerations may override the economic decisions impacting on the production of gas and the free flow of energy from international markets. Furthermore, we assessed that the current arrangements could exacerbate our increasing dependence on imported gas by not bringing forward sufficient low carbon generation, leading to increased gas consumption in the power sector, and not bringing forward sufficient new gas storage to increase our resilience to future gas supply shocks. As a result future gas prices could be more volatile, and the GB market more exposed to them.

5. **The higher cost of gas and electricity may mean that increasing numbers of consumers are not able to afford adequate levels of energy to meet their requirements and that the competitiveness of industry and business is affected**. We have concerns about the affordability of energy in light of the need for increased investment, and whether the customers most benefiting from this investment are the ones that are paying for it.

3.52. In isolation these five issues need not necessarily be an insurmountable problem: it is the conflation of them that causes the greatest concern. The combination of lower or uncertain revenue expectations (particularly for low carbon assets) and higher costs of capital may lead to lower investment and hence lower security of supply and/or failure to meet sustainability goals. For these reasons, Ofgem does not consider that leaving the current arrangements unaltered is in the interests of consumers.

Possible implications of our findings if no changes are made

3.53. Given our findings, we describe below what might happen if no changes were made to the current arrangements.

3.54. Regarding electricity, we consider one possible outcome is that investment in renewables continues at the current or a somewhat increased pace but is insufficient to meet the 2020 targets. The capacity gap which emerges after 2015 is likely to be filled by new CCGTs. Such an outcome would increase the dependence on imported gas (which was identified as a key risk in our Dash for Energy and Slow Growth scenarios given the low installed storage capacity), and risks increasing the costs of future decarbonisation of the power sector as these plants may have to be written off well before the end of their useful working lives.

3.55. An alternative outcome is that CCGT investment may not be forthcoming because investors become concerned about the risk of future government intervention to address these issues (e.g. promotion of CCS and nuclear) and thus of stranding assets in the future. In this case, the system would experience a reduced level of security of supply in the 2016-2020 period before new CCS/nuclear plant comes on stream. This period could be extended if the large capital investment required for new nuclear plant and/or investment in CCS are also seen as too risky. The result could be large variations in the electricity capacity margin with resulting swings in prices. This may in turn lead to some short term interventions to boost security of supply such as expensive contingency contracts with generating units that might otherwise be closing, investment in short lead-time peaking plant (such as Open Cycle Gas Turbines (OCGTs)), or otherwise avoidable demand reduction.

3.56. In the case of gas, it seems likely that there will be some investment in fast cycling storage, but investment in seasonal storage may not be forthcoming. In the scenario work, we identified the lack of seasonal storage to supply gas through a severe winter as one of the biggest risks. The business case for seasonal storage is currently challenging for four key reasons.

3.57. First, the differential between summer and winter prices is currently quite low (largely as the result of a short term glut of LNG), possibly suggesting the market is not fully pricing in the risk of future supply shocks, which is when our stress test analysis suggests storage would be needed. Second, future gas demand, and by extension demand for storage, is very uncertain as illustrated by the difference in gas demand between our Dash for Energy and Green Transition scenarios. Third, the upfront investment costs are large, particularly when the requirement for large volumes of cushion gas are factored in, and as a risky investment the cost of capital is likely to be high. Finally, given the size of each facility, and the long payback period, investors appear to be nervous about the possibility that the seasonal differential could reduce following commissioning thus eroding revenue earning potential.

3.58. If there is insufficient seasonal gas storage, there would be a risk of protracted higher prices and of demand curtailment during periods of extreme weather or following supply shocks. Further, any immediate attempt to deal with the issue through a change of policy at that stage is likely to be much more expensive. There are similar implications if investment in gas ballasting (or sufficient alternative flexibility in gas) is not secured, and a gas quality issue arises.

3.59. Developments towards greater liberalisation, transparency and harmonisation in European gas markets are likely to continue, although the pace is uncertain. Unbundling of gas (and electricity) transmission companies when implemented will reduce barriers to reform. New requirements for greater transparency are likely to be implemented in late 2010 or 2011, potentially soon followed by new congestion management procedures for gas interconnection points. From 2012, new network codes will come into effect, based on framework guidelines established by the Agency for the Cooperation of Energy Regulators (ACER) which will be established in March 2011. Over time, this will promote a more effective internal market in the EU. However, the pace of change may be restricted by the continuing role of legacy contracts and public service obligations to ensure secure supplies, and by the concentrated structure of the industry.

3.60. We have assumed that the roll-out of smart and advanced meters to all customers by 2020, as mandated by Government, would be successful. However, it is less clear whether it will be possible for the full benefits of smart meters to be realised and in particular in terms of enabling demand side response. Inadequate price signals and approximations within the current market rules may deter suppliers from offering innovative tariffs and technologies to their customers until these are addressed.

3.61. The extent to which energy efficiency measures, the sub-5MW Feed-in Tariff and the Renewable Heat Incentive (RHI) will be successful in achieving their targets is unclear. This will depend on customer awareness/uptake, fossil fuel prices, and the strategies of energy suppliers and energy services companies.

4. Possible policy responses

Chapter Summary

In this chapter we outline policy measures that could address the issues identified in our assessment of the current arrangements, illustrating them with international examples where appropriate. We describe five policy packages which combine individual measures, and we believe to represent a range of consistent approaches involving varying degrees of reform. At the end of the chapter we briefly discuss other possible measures that might be considered.

Question box

Question 5: Do you believe that our policy packages cover a sufficient range of possible policy measures?
Question 6: Do you have suggestions for variants to these policy packages?
Question 7: What other policy measures do you believe should be considered, and why?

4.1. In this chapter we examine how the challenges facing the industry and the issues identified in our appraisal could be addressed through a range of different possible policy measures. The approach we have taken is that policy measures should make sure that the arrangements are resilient to the kinds of future uncertainty illustrated by our four scenarios, such as the wide range of potential future gas demand levels. The interdependency between different policy measures also needs to be carefully considered.

4.2. We first discuss different policy measures and then describe five alternative policy packages that include different combinations of these policy measures. In the next chapter we assess each of the five policy packages.

Implementing change

4.3. Many of the key policy choices about the broad direction of GB energy markets rest with government. Whilst Ofgem (with the industry, or failing sufficient industry support, by reference to the Competition Commission) is able to oversee changes to pricing arrangements and licences, which may go a long way towards meeting those challenges, none of the packages we outline below is achievable without some government involvement. In particular, a key issue for future investment is certainty over the future carbon price, which can be addressed only through legislative measures at the EU level, or failing that (and to the extent possible without undermining the EC legislation) at the UK or GB level. With the descriptions of the individual policy measures below we have set out our initial view of how they might be implemented.

4.4. It is important to take account of the European context within which policy measures will need to function. The "Green Package" introduced targets for 20% reduction in carbon emissions and 20% of energy to be produced from renewable sources by 2020. The Industrial Emissions Directive will require plants with NOx and SOx emissions over a certain level to reduce emissions or to close.

4.5. The Third Package embeds further liberalisation requirements and creates new tools to continue to develop the internal market in electricity and gas. It ensures independent regulation, establishes a new European regulatory agency and creates a framework for new legally-binding rules and 10 year network development plans. Work is already underway to allow early implementation in some areas: new legal requirements, building on work promoted by Ofgem, are being enacted to provide greater transparency in gas and the European regulators have recently consulted on new rules to require auctioning of gas transmission capacity.

4.6. The Gas Security of Supply Regulation is currently being negotiated in the European Council and European Parliament. It is likely to set new security of supply standards and improve transparency of emergency measures and public service obligations (including obligations in relation to gas storage levels ahead of the winter). The final form of that legislation will have important implications for GB security of supply.

4.7. Ofgem has recognised a number of issues which need addressing for some time, but the industry has so far not proposed adequate change to address them. In Ofgem's code governance review we are therefore proposing a role for Ofgem to lead significant code changes.

Range of policy measures

4.8. We have examined a wide range of possible policy measures that could address the key issues raised in our appraisal. These are summarised in Figure 4 below for the first four key issues.

Figure 4: Range of possible policy measures

Scale and timing of investment • Improve price signals • Supplier obligations • Centralised renewables market • Capacity tenders • Central energy buyer	**Uncertain future carbon price** • Carbon price intervention • Tender for low carbon plant • Central energy buyer
Weakness of short term signals • Improve price signals • Supplier obligations • Improve ability for DSR • Short term capacity auctions • Liquidity measures • Central energy buyer	**Risks from inconsistencies with international arrangements** • Improve price signals • Supplier obligations • Storage capacity tenders • Central energy buyer

4.9. The fifth issue of affordability should be improved to the extent that the policy packages tackle the other four issues, and deliver secure and sustainable supplies at a lower cost. There are separately questions around the extent to which these options (and existing policy measures) require current consumers to pay more than is appropriate; for example, by paying for low carbon investment now to reduce the future costs of carbon abatement. Ofgem will publish a discussion document on these issues in the coming months.

Existing policy initiatives

4.10. In Project Discovery we have focused our analysis of possible future policy measures on addressing issues surrounding larger scale investment. There are a number of additional measures that the Government is implementing to promote energy efficiency, microgeneration and renewables heat. Delivering on all of these will also play a vital role in delivering secure and sustainable energy supplies. These policy initiatives include:

- Carbon Emissions Reduction Target (CERT)
- Carbon Reduction Commitment Energy Efficiency Scheme (CRC EES)
- Community Energy Saving Programme (CESP)
- Renewable Heat Incentive (RHI)
- Feed-in Tariff for sub-5MW generation (FIT)

4.11. These schemes are described in Appendix 4.

4.12. The Government is also implementing policies to provide the regulatory framework and financial support (via capacity tendering) for up to four CCS demonstration projects. Should it become technically and commercially proven, CCS could play a significant role in providing secure and sustainable energy supplies.

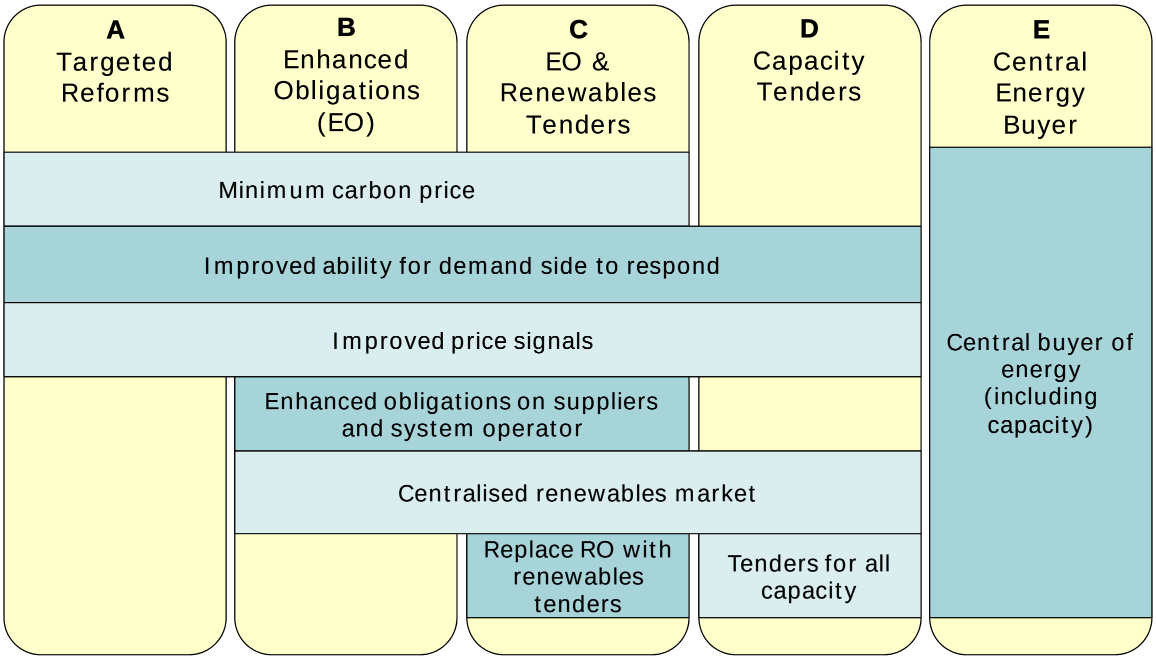
4.13. These existing policy initiatives are assumed in all five of the policy packages.

Possible policy packages

4.14. We have combined the different policy measures into five possible policy 'packages' to be considered in consultation with consumers, industry and government. All five packages have been designed to address the risks and issues identified in a consistent way. We have considered how they might be applied in the GB context, but have specified them only at a high level at this stage. Figure 5 below summarises the packages starting with those involving the least reform and intervention in the market on the left (although even this package involves significant changes) and moving to the most dramatic move away from competitive markets on the right.

4.15. In developing these policy packages we have referred to recommendations from the Wicks Review, the Committee on Climate Change reports, leading industry commentators and investment banks. At the same time, we recognise that there may be other policy measures and other combinations that could address the risks and issues identified. Some of these are set out at the end of this chapter.

Figure 5 - Possible policy packages



Package A - Targeted Reforms

Objectives and rationale

4.16. The key objectives of this package would be to promote low carbon investment by reducing carbon price uncertainty with a minimum carbon price, and to strengthen investment signals through improving short term price signals in both the gas and electricity markets.

4.17. There would be no explicit mechanisms to deliver longer term investment in generation capacity or gas storage and supplies, although the stronger price signals at times of system stress should promote demand side response and encourage players to make additional forward provisions. Hence, the package should be beneficial to security of supply but not necessarily eliminate risks associated with any under-investment. The minimum carbon price may promote further renewables investment but the Renewables Obligation would remain the primary mechanism to deliver the 2020 targets.

4.18. The package would retain market contestability with associated competitive benefits for consumers. Aspects of this package would also be relatively easy to implement compared to the other packages but would involve significant code changes. The minimum carbon price would require primary legislation and would need to be designed so as to operate alongside, and be consistent with relevant EC measures and schemes. In this regard, the EU ETS and internal market harmonisation of minimum levels of taxation of energy products would, in particular, need to be considered carefully.

4.19. The rationale for this package would be to fix 'known issues' whilst retaining the principles of the current market design, and thus minimise disturbance to current investment activity.

Key features

4.20. The Targeted Reforms package would include a minimum carbon price, and measures to improve short term price signals and the ability of the demand side to respond, as described below.

Minimum carbon price

4.21. Ideally the EUA price (and investors' expectations of it) would be sufficient to promote low carbon investment. However, there is currently significant uncertainty over the future level of the price. Action at the EU level to create a floor for the EUA price could counter this. However, if this does not happen and if reductions in carbon dioxide emissions domestically is seen as important for longer term decarbonisation, it may be necessary to consider a minimum carbon price in the UK or GB.

4.22. The minimum carbon price would reduce carbon price uncertainty and help to promote investment in low carbon technologies. Under this approach, carbon emitters (in the traded sector) would still participate in the EU ETS but where their weighted average cost of allowances (or an independently determined benchmark[10]) was less than the minimum price they would need to pay an additional “top-up carbon tax” to make up the difference.

4.23. By imposing a minimum price for carbon, investors in low carbon technologies should have greater confidence in the future carbon 'premium' in electricity prices, since fossil fuel generators, which are normally the price setting plant, would need to recover this carbon cost in their offer prices.

4.24. Since the minimum carbon price is primarily a tool for longer term investment it would not need to take effect immediately but could be set forward, for example from 2020 onwards, although investors would need to have confidence that it would come into effect should the EUA price be below this level come 2020.

4.25. However, it should be noted that the relationship between the carbon price and the carbon premium in electricity is likely to change over time. With growing amounts of renewables and other low carbon technologies, the proportion of time that fossil fuel plant are setting prices will diminish and the pass-through of the carbon price will reduce over time. Hence, there is a question over the effectiveness of a minimum carbon price as a long term investment signal

[10] An independent benchmark would have the advantage of giving companies the incentives to buy efficiently since they can beat the benchmark.

although it is unlikely the carbon premium in the electricity price would be significantly eroded before 2030.

4.26. The level for the minimum carbon price would ideally be set close to where the EUA price would outturn in the future. This would give sufficient investor certainty to allow investment decisions in low carbon technologies to proceed without leading to unnecessarily high costs for consumers which potentially would damage the international competitiveness of GB industry.

4.27. There would also be a need to consider how this would be implemented, in particular recognising the need to minimise the political uncertainty that could remain. For example, key decisions would be needed as to the length of time over which the minimum price would be set and the institutional framework by which the minimum price could be changed.

4.28. A minimum carbon price covering the traded sector could be aligned with any future carbon tax covering the non-traded sector introduced to meet domestic carbon targets.

Improved price signals

4.29. This package includes measures to sharpen short term price signals in both the gas and electricity markets through modifications to the gas and electricity trading arrangements.

4.30. In gas, sharpening price signals would primarily involve reforming the cash-out arrangements under an emergency. Currently the cash-out price is frozen during an emergency, with the risk that additional supplies (from the Continent and LNG) are not attracted into the market. Under this reform, prices would be allowed to rise during an emergency up to the value of lost load of customers who are being curtailed.

4.31. In electricity, sharpening price signals would primarily involve making the allocation of reserve costs more reflective of system tightness (currently these are allocated based on an ex-ante algorithm), and ensuring that when measures are deployed under extreme conditions, such as voltage control and firm customer disconnection, this is reflected in the price. Weighting the cash-out prices more towards the marginal cost of balancing actions undertaken by the system operator is another option.

4.32. With respect to the allocation of reserve costs, one possible mechanism would be to introduce a daily reserve market where the system operator tenders for the reserve that it forecasts that it will need each day. Under this approach, the value of reserve factored into the cash-out prices can more accurately reflect conditions on the day, and therefore be targeted at the participants causing any shortfall (thereby increasing their incentive to avoid shortfalls).

Improved ability for demand side to respond

4.33. Demand side response in the electricity market is likely to play an increasingly large role in helping to balance the system as variable renewable generation increases its share of the generation mix. Large energy users have been active in providing voluntary demand side response where there have been appropriate commercial incentives. Smaller industrial and commercial customers may provide an additional source of demand side response but thus far have been less responsive to opportunities to reduce their energy costs in exchange for interruption. This may be a consequence of the increased transaction costs caused by the relative complexity and assumed risk of interruptible contracts, and a lack of consumer awareness of the types of demand side response they may be able to offer.

4.34. Demand side response will become increasingly attractive in the mass market as smart meters and smart appliances are developed and installed. The combination of sharper short term price signals and reforms to settlements that would allow sophisticated time of use tariffs to be introduced should facilitate the development of demand side response in the electricity market.

4.35. A number of initiatives are underway to enable greater demand side response:

- DECC has recently announced that all homes will have smart meters by 2020, and Ofgem is now working with DECC to take forward the smart metering programme which will involve developing the regulatory framework and establishing the systems and processes required to support the nationwide roll-out of smart meters;
- Ofgem and DECC are jointly chairing the Energy Networks Strategy Group's Smart Grids Working Group charged with producing a high level vision of what a UK smart grid might look like, the challenges it would help address, and a route map for delivery of this vision;
- To stimulate Distribution Network Operator (DNO) innovation and trialling of the new technologies required to facilitate demand side response and energy efficiency, Ofgem introduced a new £500m Low Carbon Networks (LCN) fund for the 2010-15 control period.
- On smart metering, we are managing the Energy Demand Research Project (EDRP), which involves around 59,000 households taking part in a number of activities designed to test demand response. Early indications have shown that trial participants have responded positively to having improved information about their energy use. Our final report is due in early 2011.

4.36. To allow appropriate incentives to develop alongside new technologies, we recognise it is important to develop metering sophisticated enough to deliver changes to tariff structures and balancing and settlement practices, and flexible enough to adapt to changes in market design and challenges not currently envisaged. As part of our ongoing work we are exploring specific market design issues related to balancing and settlement, which may include:

- the potential for half-hourly (or shorter interval) settlement for residential customers to be introduced;
- the design of time of use tariffs and real-time pricing that could lead to automated load shifting via in-home devices and smart enabled technologies;
- the potential for a central information repository; and
- the role of demand-side aggregators.

4.37. Ofgem is in discussion with industry stakeholders, consumers and their representatives regarding the development of demand side response and expects to publish a discussion paper on this issue in mid 2010.

Package B - Enhanced Obligations

4.38. If the Targeted Reforms package is deemed insufficient to address the issues identified surrounding security of supply and sustainability, for example if the stronger price incentives are considered inadequate alone to induce the necessary response, the Enhanced Obligations package could be considered.

Objectives and rationale

4.39. The objectives of this package would be to implement additional measures beyond those contained within the Targeted Reforms package to promote security of supply. The principal mechanism for this would be through obligations on suppliers to demonstrate sufficient provisions against a prescribed security standard; obligations on the SO to provide, or otherwise ensure access to, back-up generation capacity and emergency gas; and obligations on gas-fired generators to have back-up fuel, provide further insurance policies.

4.40. Renewables deployment could be facilitated through a centralised renewables market, and benefit from the minimum carbon price, but as with the Targeted Reforms package, the Renewables Obligation would remain the primary mechanism to deliver the 2020 targets.

4.41. The rationale for this package would be that if the measures within the Targeted Reforms package are deemed insufficient, further measures are required to promote security of supply.

Key features

4.42. The Enhanced Obligations package would share the following features of the Targeted Reforms package described above: minimum carbon price, improved price signals and improved ability for demand side to respond.

4.43. It would also include enhanced obligations on suppliers, enhanced obligations on the SO, obligations on gas-fired generators and a centralised renewables market, as described below.

Enhanced obligations on suppliers

4.44. In addition to the stronger incentives provided by sharper short price term price signals following code reforms, under this package suppliers would also be obliged to demonstrate that they had sufficient contracted supply to cover the future energy demand of their customers against some pre-defined security standards. These would be similar to the PSOs observed in some European countries[11].

4.45. There may be benefits in having both stronger obligations and enhanced price signals. The sharper price signals may not be sufficient alone to encourage suppliers to increase their forward contract cover. Similarly, obligations alone may not encourage suitable short term responses (particularly from the demand side) at times of system tightness.

4.46. The length of the obligation is an important design consideration. The obligations could simply be on an annual basis, requiring suppliers to demonstrate that they had made provisions at the year-ahead stage, or could be for a longer duration requiring suppliers to reveal plans for future investment to meet the anticipated future demand of their customers.

4.47. Shorter term obligations would increase the level of contracting and would provide some signals for additional investment. They would not, however, guarantee investment over the longer term. Longer term obligations could provide greater confidence in this respect, but it would be difficult to verify compliance and may be detrimental to new entry and competition, since smaller players may find it more difficult to demonstrate future investment plans. This may reduce competition in the retail market.

4.48. We believe that obligations of duration between 3 and 5 years may strike the right balance between future visibility of provisions and market contestability.

Enhanced obligations on the System Operator (SO)

4.49. A further potential measure under this package would be to place enhanced obligations on the electricity and gas system operators.

4.50. The electricity SO could be required to purchase forward sufficient back-up and flexible generation to meet future requirements. The rationale for this is that industry participants, even under obligations, might not be as well positioned as the SO to anticipate future needs in a system where the capacity mix is changing

[11] In Spain, for example, security of supply considerations in the gas sector have led to obligations on minimum storage levels and maximum levels of import dependence. Gas storage obligations in Spain require year round minimum security stocks equivalent to 12 days of firm sales to final consumers, rising to 20 days in October for the start of winter. The diversification obligation places a 50% cap on the proportion of imports from Spain's largest gas source (Algeria) and applies to all parties importing over 7% of national gas supplies. Italy requires importers of non EU gas to hold strategic reserves corresponding to 10% of their annual imports.

rapidly, and that some of the additional system balancing requirements can only be met by the SO[12].

4.51. To reduce the risk and severity of gas emergencies, the National Emergency Co-ordinate (NEC), a role currently fulfilled by the gas SO, could be required to buy imported gas during in an emergency up to the point where it would be more economic to disconnect certain classes of customer. This would ensure that the price rises up to the value of lost load of the customers that are being interrupted, thus further reinforcing the incentive to make sufficient provisions[13].

4.52. Furthermore, it could be required to make certain provisions in advance. However, if it was to do so consideration would need to be given to how the costs would be recovered. The costs of the insurance policy could be levied to consumers annually, although this may undermine the incentives on suppliers to make their own arrangements to cover emergencies. Alternatively, the costs could be recovered if emergencies occur through the price charged for the contingency gas, but leaving the SO with a considerable cashflow exposure to manage.

Obligations on gas-fired power stations

4.53. Currently approximately 5 GW of the existing 26 GW CCGT stock has the ability to generate using back-up fuel (distillate). This back-up fuel effectively acts as another form of gas storage. Those CCGTs with back-up capabilities tend to be of the older generation, and the design of most new CCGTs does not include this capability.

4.54. An obligation could be introduced on all CCGTs to have the capability to run on back-up fuel for a certain number of days. This measure would need to be introduced progressively given the investment required to retrofit plant. Care would also need to be taken to avoid the unintended consequence of delaying investment in new CCGTs, or unduly deterring deployment of the highest efficiency turbines that may not be designed to switch to alternative fuels.

[12] In Sweden and Finland, the SOs have been granted powers by legislation to acquire peak load reserves. In both countries, these interventions were introduced as a temporary (~5 years) measure. In Sweden, the tendering procedure has been extended from the original 2003-08 timeframe to 2011, and the regulator has recently recommended a phased reduction in reserve capacity out to 2020 while demand side response capabilities are developed. Recognising the potential impact on price signals, new procedures were introduced in 2009 for the activation of peak reserves in the Nord Pool spot market (once all commercial offers have been activated). Nevertheless, the role of peak load reserves remains a subject of debate as the Nordic countries move towards greater harmonisation of their balancing and settlement arrangements.

[13] Code changes surrounding the emergency cash-out arrangements would need to reflect any change to the role of the NEC.

Centralised renewables market

4.55. This package would retain the current bilateral market in electricity, with self-dispatch and the SO playing the role of residual balancer, but would introduce a centralised market and dispatch function for wind (and other variable renewables). The benefit of this approach is that it would provide a market in which variable renewables generators can sell their output without the cash-out price risk and it may increase within day liquidity. Without this (or other form of differentiated cash-out for variable renewables) the sharpened price signals described above could be detrimental to renewables investment.

4.56. This approach may also allow the SO to balance the system more efficiently since it can take a holistic view of wind output, demand and demand side response, reserve requirements and managing transmission constraints. Regional wind dispatch centres have been successfully introduced in Spain.

Box 1
Case Study: Spain - Centralised dispatch of renewables

Installed wind capacity connected to the Spanish electricity system has grown rapidly, from less than 1 GW in 1996 to over 16 GW in 2009 with plans to reach 20 GW by 2010. Over the last decade, wind generation has been increasingly exposed to market signals with the vast majority of wind generation currently fully integrated into the wholesale market. A number of technical innovations have supported wind integration, including a centralised Control Centre of Renewable Energies (CECRE), which allows the SO to curtail wind power in real time if needed for system security.

The Spanish electricity market[14] is a pool-based system where all participants (conventional and renewable plant) submit bids in a 24-hour day ahead market, and then may adjust their position in six intra-day markets. Both the day ahead and intra-day markets are cleared with a single marginal price that affects all transactions in each market.

Regulation to support renewable has evolved quite substantially: In 1998, a pure Feed-in-Tariff scheme (a fixed tariff price per produced MWh) was introduced, under which all wind generators faced no market price or balancing risk.

As the wind industry matured, technical obligations (such as mandatory production forecasting) and incentives for market integration were introduced in 2005. As an alternative to the pure Feed-in Tariff, renewable generators could now participate in the wholesale markets like conventional generators. However, unlike conventional generators, on top of the market price achieved, wind generators received a fixed premium for each MWh generated.[15] While the

[14] In 2007 a single Iberian electricity market, known as MIBEL, came into force. MIBEL allows market participants to sell their electricity in either Spain or Portugal, in a system modelled on the Scandinavian Nord Pool market.
[15] In order to attract wind generators to this “more market” option, the premium was calculated so that the average renewable generator would receive slightly higher income compared to the standard Feed-in.

imbalance penalties introduced for renewables were smaller than the real costs of balancing, their introduction made wind generators aware of their impact on the system.[16]

After a period of high wholesale prices led to high revenues for wind generators, the market option was changed in 2007 to include a cap and floor on the overall income of wind generators. This change was designed to retain income stability and predictability (commonly cited as the best aspects of a Feed-in tariff), while leaving some market exposure.[17] In addition, all wind generators would be fully responsible for imbalances.

As wind reached high levels of penetration, there were concerns about the system's security of supply. In response, the Spanish SO set up the CECRE to monitor and control renewable generation in real time. The key feature of the CECRE is that it enables the SO to curtail wind generation in times of concerns about security of supply.

The SO control of renewable generation is achieved by requiring facilities bigger than 10MW (almost all of the installed Spanish wind capacity) be connected to the CECRE via a regional dispatch centre. Regional centres send real time information about their wind farms to the CECRE, and can receive real time orders to reduce wind production. Connected renewable facilities must be able to comply with CECRE's orders within 15 minutes.

Spain's balancing arrangements provide the same incentives for wind generation to balance as for other types of generation. This has led to a competitive market for forecasting tools; the market offers forecasting services by collecting weather forecasts for each wind farm and aggregating data. In addition, the SO has developed tools to predict wind generation using weather forecasts and other wind power measurements provided by wind generators to the CECRE.

Spain now has the third highest installed capacity in the world and is second in terms of wind penetration. The high penetration of wind is attributed to the success of innovations to promote market integration. Over 90% of wind generation is currently subject to the wholesale market price and therefore are no longer treated as 'negative load'. Balancing requirements on renewables has led to sophisticated forecasting tools and, via the CECRE, Spain has become the first country worldwide to have real-time control over all their wind farms over 10MW.

4.57. The key features of how a centralised renewables market could work in the GB market are described in Box 2 below.

[16] If the error (difference between generation and 1 hour forecast) was greater than 20% (in the case of wind generators), then the wind generators had to pay a penalty equivalent to 10% of the average total system costs.

[17] Renewable generators can switch between the fixed Feed-in tariff and the premium market option once every 12 months, with no limit on how many times they switch options.

Box 2
Centralised renewables market

- At some point prior to gate closure, say 4 hours out, the SO completes a forecast of variable renewables output (mainly wind) across the country.
- A position is deemed for each variable renewables plant at this point (in lieu of a Final Physical Notification).
- The SO then sells out this deemed renewables volume through a within-day auction with buyers submitting bids. (Other sellers could submit offers and demand side response could also be offered.)
- The auction will clear, generating a single market price.
- Following each auction the SO then has control of the variable renewables fleet – it would have the option of constraining back output (subject to rules governing priority dispatch for renewables) if this was the most cost effective way of providing reserve/managing transmission constraints. The SO would be incentivised (as currently) to minimise balancing costs.
- The SO would continue to use the balancing mechanism and other balancing services contracts to provide the flexibility required to balance the system, taking into account the variable generation position.
- The auction clearing price is the price paid to all variable renewables output based on their metered (not deemed) output.
- The renewable generator pays Grid a balancing fee (which could be fixed or vary depending on market conditions).
- Renewables plant would receive ROCs and LECs based on metered output as currently.
- They would receive compensation from the SO for lost output and ROCs/LECs where they have been constrained off. These costs could either by channelled into BSUoS and smeared or factored into the balancing fees charged to variable renewables plant.
- The centralised renewables market could be optional, although some of the potential efficiency benefits for the SO could then be lost.

Package C - Enhanced Obligations with Renewables Tenders

4.58. If the Enhanced Obligations package is deemed insufficient to bring forward sufficient deployment of renewables by 2020 because of the risks they are exposed to in the wholesale market, a package also including tenders for renewables capacity could be considered.

Objectives and rationale

4.59. The objectives of this package are similar to the Enhanced Obligations package, but by replacing the Renewables Obligation with Capacity Tenders for future renewables investment, it would seek to increase the likelihood of meeting the 2020 renewables target whilst providing better value for money for consumers.

4.60. This package would be more complex to implement than the Enhanced Obligations package since a new renewables financial support mechanism would need to be introduced, and the existing Renewables Obligation arrangements would need to be grandfathered.

4.61. The rationale for pursuing this package over the Enhanced Obligations package would be that if the desired outcome for renewables deployment is largely known (i.e. hitting the 2020 target), the benefits of a quota system with traded certificates are reduced, and a tender approach may yield a more efficient outcome although this requires the supply of potential renewables projects to exceed the tendered volumes.

Key features

4.62. The Enhanced Obligations with Renewables Tenders package would share the following features of the Enhanced Obligations package described above: minimum carbon price, improved price signals, improved ability for demand side to respond, enhanced obligations on suppliers, enhanced obligations on the SO, obligations on gas-fired power stations and a centralised renewables market.

4.63. In addition, it would replace the RO for new investment with tenders for renewables capacity, as described below.

Replace RO with renewables tender

4.64. Under this package the Renewables Obligation (RO) would be replaced for new large scale renewables. The sub-5MW Feed-in Tariffs as proposed could remain in place, and arrangements of existing RO-qualifying plant would need to be grandfathered (the potential for buying out these arrangements could also be considered).

4.65. The renewables capacity tenders could be technology neutral or technology specific. However, it is highly likely that the tenders for renewables would be differentiated by technology to a degree to promote investment in emerging technologies which may be higher cost (as is the case with banding in the RO currently). A central entity would need to determine the amount of capacity in each tender, and also the timing of the tenders.

4.66. Generators would bid into the tenders based on the additional revenue needed to earn an appropriate return on investment, over say a 20 year period, taking into account the impact of the minimum carbon price floor on future electricity prices. They would still be exposed to the wholesale markets for their electricity revenue. It may be necessary to include some form of carbon price indexation in the tender clearing prices such that if carbon prices were to rise above the minimum price in the future, the plant receiving the capacity subsidy would not be ‘double rewarded’. Further, more general revenue stabilisation could be included by indexing the tender prices to the wholesale electricity price (inversely i.e. if wholesale electricity prices rise the capacity subsidy falls and vice versa). This would reduce the risk to consumers of increasing electricity prices, and conversely the possibility that successful tenderers shelve their projects should electricity prices fall subsequent to the tenders taking place. Penalties for non-delivery would also mitigate this risk, but would likely push up the bids of the tenderers[18].

4.67. There is a design question whether the successful tenderers are paid-as-bid or receive the tender clearing price for their renewable technology class. The capacity revenues could be paid based on availability, or possibly a combination of output and availability. The risk with the former (also an issue with the current RO) is that renewables generators bid at up to minus their subsidy price in order to keep generating. Currently, the proportion of renewables on the system is too low to have an impact, but in the future this could start materially to distort short term prices and provide perverse incentives leading to inefficient dispatch.

4.68. The costs of the Renewables Tenders could be levied to customers via suppliers as is the case with the RO, or through some other mechanism.

4.69. Renewables plant would sell their output through the centralised renewables market as described above. The only difference being that where renewables are constrained off the system they would be compensated for any proportion of the tender revenue foregone based on output, rather than ROCs.

Package D - Capacity Tenders

4.70. If the above packages are deemed insufficient to address the challenges identified in bringing forward adequate low carbon and renewables investment whilst maintaining security of supply, the introduction of tenders for all generation capacity, new gas storage and other gas infrastructure could be considered.

Objectives and rationale

4.71. The objectives of this package would be to target prescribed outcomes for security of supply and decarbonisation by specifying the generation mix and tendering for capacity. It should provide greater certainty surrounding security of supply than the preceding three packages by providing explicit long term investment signals. It should also bring forward specific volumes of low carbon and renewables investment and, in so doing, obviate much of the case for a minimum carbon price (in the form proposed in earlier packages).

4.72. The approach risks mis-forecasting the requirements for future gas storage, particularly where substitutes are available, and generating capacity requirements. This would lead to additional costs for consumers, but conversely reduces the risk to consumers of high prices caused by insufficient investment. There is also a risk that large scale, centralised supply side solutions will dominate at the expense of small scale, local solutions and demand side response.

[18] Lessons would need to be learnt from the experience of previous tender processes. However, we believe that any issues that have arisen in the past could be avoided through careful design.

4.73. The rationale for this package is threefold. First, if the government has a particular view of the required generation mix, it may offer a more efficient route of delivering it. Second, it may offer a solution if it is believed that the market may under-deliver new capacity and that stronger price signals and obligations are insufficient to counter this. Third, that with an increasing proportion of the generation market covered by subsidies, if it is believed that the wider market becomes undermined posing significant risks to investment and security of supply, this would require a more general capacity intervention.

Key features

4.74. This package retains three features of the Enhanced Obligations package, improved price signals, improved ability for demand side to respond and the centralised renewables market. It would not include the minimum carbon price.

4.75. The Capacity Tenders package would also include capacity tenders for all generating capacity, and new gas storage and other gas infrastructure that may be deemed necessary to maintain security of supply, such as gas ballasting facilities to help manage gas quality issues[19]. These features are described below.

Tenders for generation capacity

4.76. This package would include a combination of long term tenders for low carbon generation plant, including renewables, CCS[20] and nuclear, and shorter term tenders for generation capacity more generally (and demand side response).

4.77. The longer term tenders for low carbon generation would be similar to those described for renewables in the Enhanced Obligations with Renewables Tenders package described above. They would likely be differentiated by technology (i.e. nuclear, CCS and renewables) and could be further sub-divided by type of renewables technical and by location. It would need to be recognised that the greater the sub-division, the greater would be the risks of market power.

4.78. Making the tenders locational has the advantage of allowing co-ordinated expansion of the transmission network, and in the case of CCS facilitating the development of carbon transport and storage infrastructure, but again increases the risks of market power.

4.79. The 'commitment' period of the tenders may vary depending on the technology. For example, the typical economic lifetime of a nuclear investment may be double that of an onshore wind plant.

[19] We recognise that any form of capacity tender would need to be consistent with the European third package, which does envisage the use of tenders but restricts the circumstances in which they are permitted.
[20] These tenders could follow on from those being proposed for the CCS demo plant.

4.80. As with the Renewables Tenders described above, there would be penalties for non-delivery, the cleared tendered price could be linked to the carbon price or electricity price, and the capacity revenues could be paid based on availability, or possibly a combination of output and availability. The costs would be levied to consumers.

4.81. By increasing investment, the additional financial support provided by the capacity tenders for low carbon generation could drive down electricity prices. This could undermine investment in conventional generation, and hence capacity tenders could be extended to all generation plant and demand side response in order to promote security of supply.

4.82. Under this approach, a central entity would determine the volume of capacity needed to meet the required security standard. All generation plant (existing and new) plus demand side response can offer into the auction. They are competing for the additional revenue they require above their expectation of wholesale market prices. Successful participants receive the market clearing price for capacity, but would be penalised if the capacity is not available at the required times. Generators would sell their output in the within-day market (see below) competing on energy price.

4.83. The duration of the capacity tenders is an important design consideration. They would likely be shorter than the long term tenders for low carbon investment, which reduces the risk of incorrectly forecasting the necessary volume or future patterns of demand. The 'capacity auctions' seen in US markets have generally been extended from 1 year ahead to 3 years ahead. A longer duration provides more certainty and allows new build to participate.

4.84. Consideration would need to be given as to how the capacity auctions would interact with the existing bilateral market, i.e. they should not just result in a windfall for generators, and it should be expected that wholesale prices fall correspondingly with more competition between plant as the capacity margins increase. In the US, the capacity auctions run alongside centralised dispatch mechanisms and explicit measures to limit bid and offer prices under certain circumstances have been applied to prevent undue exploitation of market power. Similar regulatory measures may be required if capacity auctions were included in this package. Consideration would need to be given as to whether short term capacity tenders can operate with the current arrangements or whether a form of “pool” would need to be reintroduced.

4.85. The interaction between the long term capacity tenders for low carbon generation and the shorter term capacity tenders would be an important design consideration. The simplest approach would be to include also the capacity from the low carbon tenders at zero cost in the short term capacity tenders. Whether or not low carbon generators would receive the clearing capacity price is an important consideration, and would influence how they bid into the long term capacity tenders. Also for consideration is what capacity 'credit' variable renewables would be attributed in the short term tenders.

Box 3
Case Study: New England, USA: Forward capacity market

New England has had an installed capacity market (ICAP) to provide a price signal for generation capacity investment since the market was opened in 1998. However, the ICAP did not reflect the locational value of capacity and cleared at a low price. An increasing number of locational "Reliability Must Run" (RMR) designated generators were choosing to opt out of the market and instead received RMR payments. The cost of these out of market payments had risen to $129M in 2008.

The Forward Capacity Market (FCM) was approved in 2006 as a replacement for the ICAP and the first auctions took place in February and December 2008 for the commitment periods 2010-11 and 2011-12 respectively. The FCM provides locational price signals by modelling as separate zones all export constrained zones and any import constrained zones where the installed capacity, less retirement and export bids for that zone, is less than the Local Sourcing Requirement (LSR).

The FCM procures the forecasted Net Installed Capacity Requirement (NICR) for the entire New England Control Area three years in advance. This is to encourage participation by new resources and so that the market can adapt to resources seeking to leave the market.

The initial Forward Capacity Auction (FCA) is structured as a descending clock auction resulting in uniform clearing prices that are used as the basis for payments to capacity suppliers. The first three auctions included a price floor, which started at $4.50/kW month and has decreased with each auction. From the fourth FCA there will be no price floor. Secondary Reconfiguration Auctions are held annually and monthly prior to the commitment period.

Existing capacity participates in the FCM annually and can only auction capacity for a one-year commitment period. Existing capacity must bid to de-list, for example to export from New England and can be refused for local reliability reasons. New resources can choose a commitment period of one to five years at the time of qualification. Both new and existing capacities are paid the same market clearing price in the first year, provided there is sufficient competition and sufficient supply. The price paid to new capacity after the first year is indexed for inflation.

In the first two rounds only 189MW of new generation was cleared through the FCA. However, as there is still excess capacity in New England, it would have been surprising if more new generation capacity had been procured. Another 489MW of capacity was treated as "existing" generation as its entry was not dependent on the outcome of the FCA. A further 1104MW of new generation which was cleared through the auction also received additional payments from Connecticut's Request for Proposals (RFP). The RFP is used in Connecticut to encourage investment to reduce Federally Mandated Congestion Charges which have raised consumer bills in the state.

In addition, 7 per cent of the 2010-11 and 9 per cent of the 2011-12 NICR were procured from demand response. Although this is a positive outcome of the auctions, the involvement of considerable demand response may be the result of differences in obligations on capacity resources. It has been proposed that obligations be equalised to balance incentives for all capacity resources. The fact that the first two auctions cleared at the price floor implies that consumers may have over paid for capacity, as there is still a surplus. The removal of the price floor from subsequent auctions will resolve this issue

The FCM has successfully reduced out of market RMR capacity payments from $129M in 2008 to $7M in 2010-11. More generation is thus participating in both the capacity market and the energy market so a more effective price signal is being created. However, the existence of other out of market payments, such as the Connecticut RFP, is still hindering effective price formation in the capacity market.

Tenders for gas storage and other gas infrastructure

4.86. It is difficult to replicate the capacity tender/capacity auction concept in the gas market since security of supply is as much about the available supplies of gas as the daily delivery capacity.

4.87. In this package, there could be a targeted intervention to expand explicitly the amount of gas storage. The central entity would determine the amount and type of new storage required several years in advance. It would then tender for the build and operation of this capacity.

4.88. Once constructed the gas storage could be operated as a strategic asset with gas stored and released into the market based on predefined rules, like strategic oil reserves, or it could be made available to the market through third party access. In the case of the former, the storage would be acting as an insurance policy and in theory it should not unduly deter private investment in storage assuming strategic gas is only released at very high prices[21]. In the case of the latter, the single entity is acting as a direct competitor to private investors.

4.89. The central entity may also have a role in providing ballasting facilities where these become necessary to keep imported gas within the GB market quality standards. It (or National Grid) could tender for one or more ballasting facility. The costs could be socialised or alternatively a ballasting service (or third party access) could be sold to shippers where they require it.

Package E - Central Energy Buyer

4.90. If the Capacity Tenders package is deemed to be insufficient to address the issues identified because the scale of investment required cannot be achieved without significantly de-risking it, the package representing the most radical departure from the current arrangements would be a Central Energy Buyer.

[21] However, it should be noted that there is evidence of strategic energy reserves being released into the market under political pressure, and this evidence itself could deter private investment.

Objectives and rationale

4.91. The objectives of this package would be to deliver prescribed outcomes for security of supply and decarbonisation by co-ordinating future investment through a single entity. In theory, it would remove much of the uncertainty surrounding future security of supply and decarbonisation, recognising that there would remain other risks and barriers (such as planning and construction risks) that may still prevent the desired outcome being achieved.

4.92. In practice there is a significant risk with this package that the Central Energy Buyer makes the wrong choices and over-contracts with consumers bearing the costs. On the converse side, the reduced risk to investors (lowering the cost of capital) and competition between them could drive down the cost of delivering certain types of investment.

4.93. Of the packages, this would be the most complex to implement and the existing European legal framework would limit what is possible under this approach.

4.94. The rationale for this package would be that if the risks to future secure and sustainable energy supplies were so high, and the challenges of raising the necessary investment capital so great, then a Central Energy Buyer could be put in place with consumers underwriting the risks.

Key features

4.95. The Central Energy Buyer package represents a very different policy measure than those considered under the other four packages. The policy measures considered in those packages, whilst in some cases quite major reforms, would be designed to work in conjunction with existing arrangements. The Central Energy Buyer would represent a significant departure from usual competitive electricity and gas markets that rely on market participants to respond to price incentives.

4.96. There are significant legal issues (including, importantly, under the EC Treaty and in respect of the implementation of internal market legislation) that would need to be considered in designing the Central Energy Buyer. Existing European legislation would limit the form and scope that this may take.

4.97. Below we describe in outline what the key features of the Central Energy Buyer package might be (subject to satisfactory resolution of the legal issues mentioned above). There would be a design question as to whether the Central Energy Buyer in electricity would be the same entity as in gas (and whether in either or both cases giving this role to the SO would be possible and/or appropriate).

Central buyer of electricity capacity and energy

4.98. The Central Energy Buyer in electricity could take many forms. One possible model would be the Central Energy Buyer acting as a type of broker, buying all the output from generators and selling it to suppliers under standard terms. By entering into long term agreements with generators it is able to determine the future generation mix.

4.99. The Central Energy Buyer would likely be implemented alongside a centralised dispatch mechanism or “pool” into which generators would compete to sell their output to the Central Energy Buyer. In addition to buying output on a short term basis, the Central Energy Buyer would look to enter into forward contracts (which could be financial swaps against the pool price) with generators. These forward contracts could be bought and sold through an extension of a pool trading platform.

4.100. Where the Central Energy Buyer is looking to bring forward new investment to deliver the required generation mix, it would separately tender for long term power purchase agreements (PPA) with developers of the required technologies. For some technologies these contracts could be for forty years or more, provided they comply with EC and domestic competition rules. The output from these plant would be sold through the pool under pricing terms determined in the PPA, split between a utilisation fee reflecting the short run costs and an availability fee which would include any premium for low carbon or renewables. The Central Energy Buyer would need to consider both the utilisation and availability fees in making its economic decisions.

4.101. The Central Energy Buyer would sell output purchased in the pool to suppliers. There is a key design question over how it does this. At one extreme, suppliers could buy physical electricity from the pool and make their own arrangements to hedge future price risk, possibly entering into financial agreements with generators who have the opposite exposure. The availability fees paid by the Central Energy Buyer would be charged through to suppliers. This would leave the role of the supplier essentially unchanged. At the other extreme, the Central Energy Buyer could enter into fixed price commitments with generators (which may be necessary to de-risk certain investments) and therefore manage some price risk on behalf of suppliers. In this case it may offer a bulk tariff to all suppliers under standard terms. The tariff would cover the availability fees and energy costs, and may include correction factors to the extent that Central Energy Buyer has not hedged all future price and volume risk in advance. In this case, suppliers would have the same wholesale input costs, and would be competing only on service and supplier costs. Which model the Central Energy Buyer follows would depend on its objectives and how it was incentivised.

4.102. Another consideration is whether suppliers and end-users can buy direct from generators thus bypassing the Central Energy Buyer and the pool. Allowing this option may make the Central Energy Buyer package more compatible with EU legislation. One possible model would be the Central Energy Buyer only covering the domestic and SME markets, with larger customers supplied the existing bilateral wholesale market. The drawback with this approach is that the Central Energy Buyer would have less influence on the future generation mix, which would weaken one of the key rationales for this package.

4.103. Finally, the role of the Central Energy Buyer alongside decentralised solutions such as distributed generation and renewables heat would need to be considered.

Central buyer of gas storage (and other gas infrastructure as deemed necessary)

4.104. The scope of a Central Energy Buyer in gas would likely be somewhat different. It would be active in tendering for new gas storage, ballasting and import capacity infrastructure. Its scope could be extended to entering into long term gas supply contracts.

4.105. For gas storage, the Central Energy Buyer would determine the amount and type of new storage required several years in advance. It would then tender for the build and operation of this capacity, and could use it as a strategic asset or offer third party access. This would be similar to the Capacity Tenders package. This model could be extended to other forms of gas infrastructure, for example ballasting facilities, LNG terminals and interconnectors where the Central Energy Buyer determines that additional capacity is required in these areas.

4.106. Where the role of the Central Energy Buyer is limited to tendering for new capacity, the role of shippers and suppliers would remain the same as under the current arrangements. They would have third party access to the assets developed by the Central Energy Buyer, as they would to privately owned assets (that do not have exemptions). The costs of the tendered capacity (to the extent that they are not recovered through usage charges) would be recovered via suppliers levying a charge to their customers. It should be noted that the activity of the Central Energy Buyer may lead to some crowding out of future private investment.

4.107. Where the role of the Central Energy Buyer is extended to entering into long term gas contracts, this would have a more fundamental impact on the role of suppliers. As with electricity, the Central Energy Buyer would then sell gas to suppliers under standard terms, diminishing their role in some market segments to one of service provider.

Summary

4.108. Figure 6 below summarises how the policy packages address the first four key issues from our appraisal. The policy measures are a combination of actions that address the issue directly, for example changes to pricing arrangements, and actions that provide insurance against the issue, for example tendering for storage to reduce exposure to international gas markets.

Figure 6 - Summary of how policy packages address key issues

	Scale of investment required	Future carbon price uncertainty	Weakness of short term price signals	Exposure to international markets
Targeted Reforms	-	Minimum carbon price should incentivise low carbon investment	Changes to pricing arrangements provide additional incentives to invest and to secure supply	Sharper emergency gas cash-out prices should encourage greater provisions (e.g. storage)

Enhanced Obligations	-	Minimum carbon price should incentivise low carbon investment	Obligations provide additional incentives to invest	Obligations encourage players to make greater provisions (e.g. storage, back-up generation)
Enhanced Obligations and Renewables Tenders	Greater revenue certainty for renewables facilitates financing	Minimum carbon price should incentivise low carbon investment	Obligations provide additional incentives to invest	Obligations encourage players to make greater provisions (e.g. storage, back-up generation)
Capacity Tenders	Greater revenue certainty for generation and gas storage facilitates financing	Tendering for specific quantities of low carbon generation	Explicit capacity revenues reduce reliance on short term price signals to stimulate investment	Capacity tenders deliver additional storage
Central Energy Buyer	Investment underwritten by customers	Generation mix chosen by Central Energy Buyer	Price signals no longer required to stimulate new investment	Risk can be managed through storage tenders and long term contracts

Other policy measures

4.109. In developing our five policy packages we recognise that many other packages are possible, including different combinations of the policy measures within them. We also recognise that there may be other policy measures that we have not considered and we would welcome consultees' views on these.

4.110. Some select examples, many of which have been employed in other gas and/or electricity markets around the world are summarised in Figure 7 below. We have mapped these against our first four key issues.

Figure 7 – Possible alternative or additional measures

Key issue	Possible measure
The need to sustain unprecedented levels of investment	▪ **Regulated returns/prices**: regulated returns or prices for certain types of (capital intensive) investment particularly where number of potential players is limited. ▪ **Government loans**: low cost finance for certain 'strategic' projects, e.g. required for security of supply or

	major low carbon projects. ▪ **Customer funded investments**: a levy on consumers could be used to raise finance for investment rather than subsidising revenues; financial support schemes such as the RO and proposed CCS levy could be incorporated in such an approach. ▪ **Action to promote liquidity:** Requirement for vertically integrated companies to trade more externally, for example through trading platforms or auctions.
Market's reaction to uncertainty in future carbon prices	▪ **Low carbon obligations**: extension of Renewables Obligation to all low carbon plant. ▪ **Emissions performance standards**: progressively tightening restrictions on carbon dioxide emissions from generating plant making low carbon investment more attractive. ▪ **Feed-In Tariffs**: extension of sub-5MW Feed-in Tariffs to all renewable plant.
Insufficient short term price signals	▪ **Capacity payments**: administered capacity payment mechanism (potentially with capacity payments differentiated by location). ▪ **Centralised dispatch**: re-introduction of an electricity pool with revised price setting algorithms. ▪ **Locational signals**: market splitting (Nordpool style) or full locational pricing (North-Eastern US style) possibly coupled with centralised dispatch.
Interdependence with international markets	▪ **Diversity obligations**. Limitations on the amount of gas supplied from any one source.

5. Assessment of the five packages

Chapter Summary

In this chapter we present our initial assessment of the policy packages outlined in Chapter 4.

Question 8: Do you agree with the assessment criteria that we have used to evaluate the policy packages?
Question 9: Do you have any comments on our initial assessment of each of the packages?
Question 10: Do you agree with our summary of the key benefits and key risks of each policy package?
Question 11: Do you have a view on which package is preferable, or alternative policy measures or packages that you would advocate? We are particularly interested any analysis you may have to support your views.

5.1. In the preceding chapter we described each of our five policy packages in outline. In this chapter we present our initial high level assessment of these packages. This is not intended to be a full impact assessment at this stage but rather to highlight qualitatively how the different packages may influence outcomes for secure and sustainable energy supplies.

5.2. Figure 8 below summarises our initial assessment of what we believe are the key benefits and key risks of each of the five packages that have emerged from our assessment.

Figure 8 – Key benefits and key risks of the five packages

	Key benefits	Key risks
Targeted Reforms	Increases incentives to invest whilst retaining the benefits of competitive markets	May not be sufficient to address the financing challenges and therefore deliver secure and sustainable supplies
Enhanced Obligations	Puts onus on industry players to deliver a specified level of security of supply	May not be sufficient to address the financing challenges and achieve renewables and climate change goals
Enhanced Obligations and Renewables Tenders	Puts onus on industry players to deliver a specified level of security of supply and enhances probability of efficiently meeting renewables targets	May not be sufficient to address all the financing challenges and achieve longer term climate change goals
Capacity Tenders	Facilitates raising finance thus accelerating investment in pre-determined levels and types of low carbon generation and storage	Customers exposed to risk of any poor decisions surrounding the type and scale of capacity required. Small-scale options and supply side may be overlooked

Central Energy Buyer	Underwrites long term contracts giving increased confidence of specific outcomes and access to lower cost finance	May stifle innovation and customers exposed to the risk of any poor contracting decisions Existing European legal framework would limit what is possible under this approach

5.3. Inevitably there are trade-offs among the packages. Those that target specific volumes and types of investment, such as the Central Energy Buyer and Capacity Tenders, would in theory be expected to increase the probability of delivering security of supply and environmental objectives. However, there are risks associated with leaving a central entity to make all the key decisions, which could turn out to be wrong. There is also a risk that large scale, centralised supply side solutions will dominate at the expense of small scale, local solutions and demand side response. These packages are also likely to be more difficult and time consuming to implement, and importantly there may be significant legal issues, particularly with the Central Energy Buyer where the existing European legal framework would limit what is possible.

5.4. The less interventionist Targeted Reforms or Enhanced Obligations package are conceptually easier to design but continue to leave key decisions about supply security to individual market participants, which may provide less confidence of achieving specified levels of supply security and carbon reduction. We also need to recognise that there are legal issues and complexities around the design and implementation of a minimum carbon price that could impact the timing and effectiveness of these packages.

5.5. Our scenario analysis indicates that prices to consumers are likely to rise under most cases, in large part due to the levels of investment required. The question is which of the policy packages is most likely to deliver the desired outcome for secure and sustainable energy supplies at lowest cost to customers. More mandated outcomes could reduce the cost of finance (by reducing investor risk), reduce the risk of high prices resulting from under-investment, and remove some of the inefficiencies in current mechanisms such as the Renewables Obligation (RO). However, such approaches may expose customers to risks of over-investment, and deprive them of some of the benefits of innovation and cost reductions driven by more effective competitive markets.

5.6. We now describe in more detail our initial assessment of each package against our assessment criteria. We then discuss the issue of timing and how investment lead times must be considered in the context of the time it may take to implement different packages.

Assessment criteria

5.7. We have developed seven assessment criteria recognising that there are trade-offs between the packages and no one package is likely to score highly against all criteria. They are as follows:

i. Confidence of achieving supply security
ii. Confidence of achieving 2020 carbon targets through domestic reductions
iii. Confidence of achieving 2020 renewables targets
iv. Risk of prices being greater than necessary
v. Risk of dampening of innovation
vi. Implementation issues
vii. Legal issues

5.8. We have assessed each policy package against each criterion in turn relative to leaving the current arrangements unaltered. We have not attempted a detailed cost/benefit analysis but in some cases use results from the Discovery Model to illustrate certain points against our assessment criteria. Should any of the packages be considered for implementation, more detailed assessment and analysis would clearly be needed.

i. Confidence of achieving supply security

5.9. This criterion considers the likelihood of there being sufficient capacity and available supplies of energy to meet firm demand, whilst avoiding high prices associated with protracted periods of scarcity.

Targeted Reforms

5.10. There are three features of the Targeted Reforms package that may impact on security of supply, namely the minimum carbon price, improved price signals and demand side response measures.

5.11. By reducing uncertainty, the minimum carbon price should bring forward low carbon investment. This could increase capacity on the system and also have the effect of improving the diversity of the generation mix by reducing reliance on gas-fired generation. Conversely, the higher carbon price may lead to earlier closures of coal plant whose margins would be squeezed.

5.12. The improved price signals in this package should mean that prices give a stronger incentive to attract gas imports at times of system stress and incentivise suppliers to increase their forward contract cover. This should in turn provide stronger investment signals. The further demand side response measures should benefit security of supply by identifying customers willing to reduce demand thus reducing the risk of curtailment for other customers who place a higher value on an unbroken supply of energy. We have attempted to quantify the potential price impact of improved price signals on security of supply in the electricity market using some high level analysis presented in Box 4.

Box 4
Relationship between short term price signals and electricity capacity margins

To explore the relationship between short term price signals and electricity capacity margins, we have developed the concept of an "economic capacity margin". This is the de-rated capacity margin at which the cheapest generation technology[22] (in our examples, CCGT) could just cover its fuel, operating and capital costs (or "levelised costs"). If the de-rated capacity margin is higher than this, electricity prices would be too low to cover the levelised costs of a new CCGT. If the de-rated capacity margin was lower than this, prices would be higher and further investment should be attracted into the market.

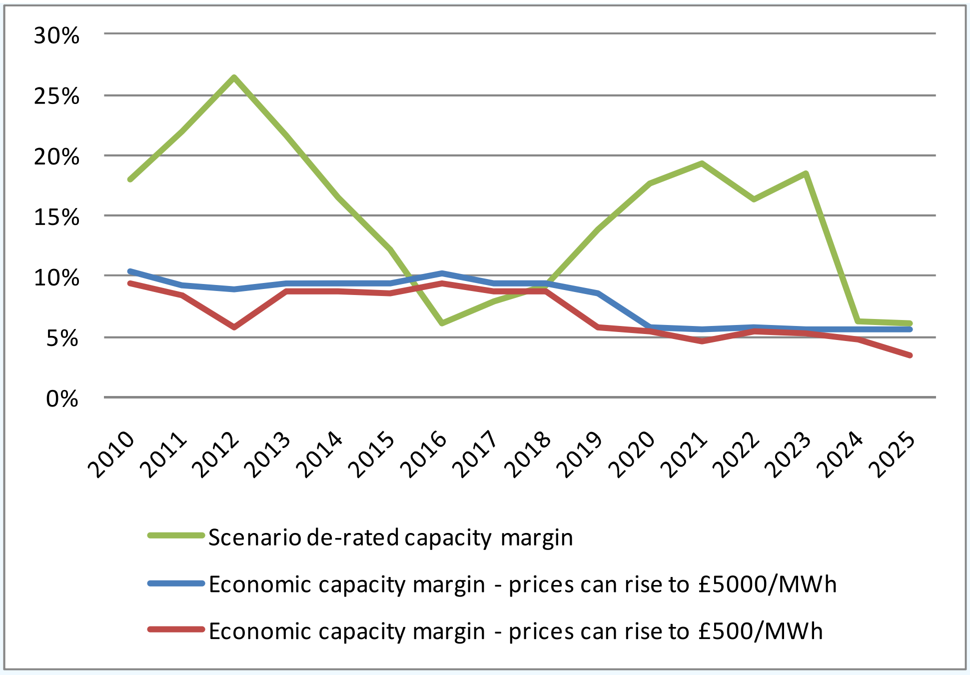
We have examined 'economic capacity margins' under two theoretical cases. One where cash-out prices only rise to £500/MWh, and one where cash-out prices can rise up to £5,000/MWh (which is closer to some assumptions of the value of lost load for domestic customers).

Figure 9 below shows the economic capacity margins for these two cases under the Green Transition scenario, and compares them to the scenario de-rated capacity margin. The theoretical economic capacity margins are very different to the scenario de-rated capacity margins, the latter reflecting expected cycles in demand and investment patterns and the potential effect of subsidies for renewables in boosting overall investment.

What the analysis demonstrates is that (all other things being equal) a de-rated capacity margin in the region of 10% might be expected if prices are able to rise to £5,000/MWh, but a de-rated capacity margin of 1-2% lower could be expected if prices can only rise to £500/MWh. The analysis also suggests that the economic capacity margin starts to fall from 2020. This reflects the fact that CCGTs are running at lower load factors due to the high penetration of renewables and hence need prices to rise higher (which will only happen with lower capacity margins) in order to cover their fixed cost and remunerate capital. This further highlights the importance of the correct short term price signals as the proportion of renewables on the system increases.

[22] Which can be built in relatively short timeframes. In some instances nuclear may be cheaper on a levelised cost basis but development timeframes are currently too long for it to be able to respond to short term capacity shortages.

Figure 9 - Illustration of economic capacity margins under Green Transition scenario



Enhanced Obligations

5.13. The Enhanced Obligations package includes additional policy measures that are likely to have an impact against the security of supply assessment criteria. These are supplier obligations, SO obligations and gas-fired generator back-up fuel obligations.

5.14. The supplier obligations should further encourage players to increase their contract cover over a longer period, for example by signing long term gas supply contracts with suitably flexible volume terms. By moving beyond simply strengthening short term price signals, the obligations make individual players more accountable for delivering a specific level of security of supply.

5.15. The obligations on the SO actively to source gas imports during an emergency should reduce the severity and duration of any such event. Likewise, placing obligations on it to insure there is sufficient flexible generation capacity (and demand side response) several years forward to manage anticipated future requirements, should mitigate the impact of renewables variability on the system. The risk with these additional obligations on the SO is that it reduces the incentives on industry participants to make their own arrangements, thus lessening the potential benefit of this policy measure for security of supply.

5.16. Placing obligations on gas-fired generators to be able to generate on back-up fuel over a certain period could enhance gas supply security since gas could be released from the power sector at times of system stress. The risk with this policy measure is that it may negatively impact on electricity security of supply where plant find it difficult to comply without expensive investments, forcing some plant to close early and possibly deterring new investment in CCGTs. This could result in higher costs for consumers.

Enhanced Obligations and Renewables Tenders

5.17. This package may have some additional benefits for security of supply since it will increase confidence surrounding the amount of renewables that will be built. This also allows investors in other technologies to have increased confidence of the requirement for further capacity.

Capacity Tenders

5.18. The Capacity Tenders package shares the improved price signals and demand side response measures with the Targeted Reforms package. By targeting a particular level of capacity margin in electricity and a particular amount of storage capacity in gas it should improve security of supply, although there remains a risk that the required volume is under-forecasted or mis-specified (e.g. if tenders are highly specified in terms of technology, the benefits of diversity on security of supply may be undervalued). There is also the risk of the unintended consequence of there being an investment hiatus whilst the new policy is being implemented, increasing the scale of any future security of supply problem.

5.19. In electricity, the capacity tenders can provide no absolute guarantee of the levels of future investment and hence capacity margins. However, by providing an additional capacity revenue stream this may reduce the investment risk and lower the cost of capital[23]. In Box 5 we present some high level analysis to demonstrate the possible relationship between cost of capital and security of supply.

Box 5
Relationship between cost of capital and electricity capacity margins

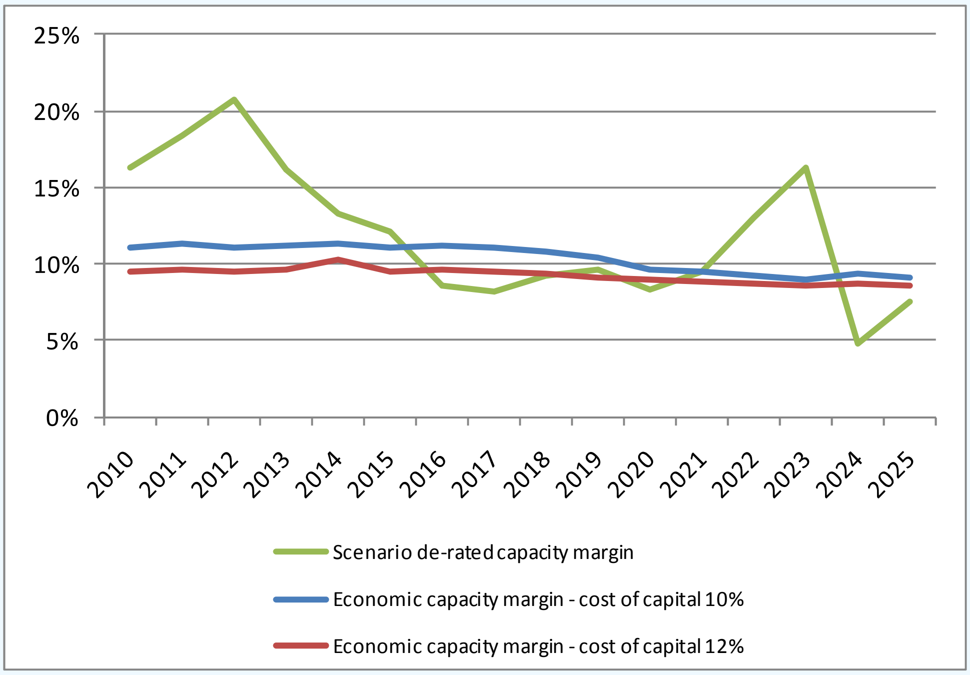
We have used the economic capacity margin concept described in Box 4 to assess the approximate impact of cost of capital on security of supply. For this analysis we hold electricity prices constant but change the cost of capital for CCGT investment by 2%. With a higher cost of capital, electricity prices need to be higher to cover the levelised costs of the plant and hence the economic capacity margin falls, and vice versa.

We have illustrated this effect on the Dash for Energy scenario shown in Figure 10 below. Again we show the scenario de-rated capacity margin for comparison. This analysis suggests that if the Capacity Tenders package were to reduce the

[23] This may be the case even if the result of this policy was to reduce the wholesale electricity price resulting from higher capacity margins.

cost of capital by 2% (from 12% to 10%) for CCGTs this could increase de-rated capacity margins in the region of 0.8%-1.7% (all other things being equal).

Figure 10 - Illustration of economic capacity margins under Dash for Energy scenario



5.20. In gas, the capacity tenders target specific investments. We have analysed how much additional storage capacity would be required to avoid any firm curtailment under our stress tests in each of the four scenarios. This ranges from 0bcm in the Green Transition and Green Stimulus scenarios to 3.3bcm in the Slow Growth scenario. These volumes assume that the tendering does not displace private investment. If it did volumes would need to be greater. In Box 6 below we compare the cost of this additional storage to the impact on prices.

Central Energy Buyer

5.21. The Central Energy Buyer is the package with the most direct intervention to promote security of supply. By offering long term power purchase agreements there is a high probability that the required investment will materialise (although still subject to rise of delays, technical failures or contractual defaults), and as with the Capacity Tenders package the tendering for specific gas storage facilities (and other types of gas infrastructure where required) suggests a high probability that they will be built.

5.22. The Central Energy Buyer package does however carry some risks for security of supply. There is a risk that the Central Energy Buyer under-forecasts the future requirements, notwithstanding the fact that previous experience with single buyers suggests the opposite risk is greater. Further, the Central Energy Buyer may undervalue the diversity that a more competitive market may deliver.

Finally, the Central Energy Buyer may undermine the existing market and lead to earlier exit and closure of assets.

ii. Confidence of achieving 2020 carbon targets through domestic reductions

5.23. Our next criterion considers the likelihood that the 2020 carbon targets would be met from domestic carbon emissions reductions. It should be noted that for the traded sector (power generation, industrial gas use) the target could be met by buying allowances under the EU ETS. Nevertheless, we are conscious that the UK Government has committed under the Climate Change Act 2008 to reduce greenhouse gas emissions by 80% (against 1990 levels) by 2050. Given the long-term nature of investments, any investment framework for the energy sector will need to balance short and medium term needs to 2020 against this long-term commitment. In setting and agreeing to the 2020 targets, European and UK Governments considered that the 2020 targets were not inconsistent with a long-term commitment to decarbonise the energy sector. Hence, we have assumed that meeting carbon targets from domestic reductions, and minimising the buying in of allowances in the future, is an appropriate assessment criterion for our packages.

Targeted Reforms

5.24. The minimum carbon price within this package increases the chances of meeting the 2020 carbon targets from domestic reductions. The demand side response measures may also provide a benefit by reducing the reliance on high carbon emitting thermal plant to provide the flexibility that the system will increasingly need to accommodate greater proportions of variable renewables.

5.25. The minimum carbon price should reduce the risk of low carbon investments and make them more attractive to investors. To what extent is uncertain; even with a minimum carbon price in place investors may perceive ongoing political risk associated with the possibility that future governments repeal it (the lower the political risk, the higher the attractiveness of low carbon investments to investors). Furthermore, for the reasons discussed above, the impact of carbon prices on electricity prices is likely to change as the sector becomes increasingly decarbonised.

5.26. We have not attempted to assess the likely impact of the minimum carbon price on investment in our four scenarios. However, just as an illustration, if we were to say that the effect of the minimum price were to reduce the cost of capital for low carbon investment, by say 1% for nuclear and 0.5% for renewables (for whom electricity revenues make up 50% or less of their total revenues), this would have the effect of reducing the levelised costs of nuclear and offshore wind by approximately £4/MWh and £5/MWh respectively.

5.27. This would make these low carbon investments look more attractive and in the case of renewables may allow a reduction in subsidy (lower RO band for future projects) to maintain the same expectation of future margins and achieve the same level of deployment. We discuss the possible impact on customers in paragraph 5.43 below.

5.28. A further impact of the minimum carbon price (assuming it was higher than the outturn EUA price, which it might be, particularly in relation to our non-Green scenarios) would be to encourage switching from coal to gas generation. This would serve to reduce domestic carbon dioxide emissions, but would have no overall impact on EU emissions since these are covered by the overall trading caps.

Enhanced Obligations

5.29. The Enhanced Obligations package shares the minimum carbon price and demand side response measures with the Targeted Reforms package. Hence, our assessment against this criterion is broadly the same.

Enhanced Obligations and Renewables Tenders

5.30. This package includes the replacement of the Renewables Obligation with Renewables Tenders for new plant and may increase the confidence of hitting the 2020 renewables targets and consequently be beneficial to the 2020 carbon targets criterion. However, there are some risks associated with this policy measure. First, the change in policy could lead to an investment hiatus. Second, there is no guarantee that successful tenderers will develop all projects, particularly where wholesale electricity prices subsequently fall (although this risk could be mitigated with some form of revenue stabilisation applied to the tender price).

Capacity Tenders

5.31. By long-term tendering for all forms of low carbon investment, and not just renewables, this policy package should further increase confidence in achieving the 2020 carbon targets via domestic reductions. The caveats noted above surrounding a potential investment hiatus and the risk of successful tenderers failing to deliver also need to be considered.

Central Energy Buyer

5.32. By coordinating investment, the Central Energy Buyer can to a large extent control the future generation mix (at the large scale) and bring down emissions intensity to be consistent with achieving the 2020 targets through domestic reductions.

iii. Confidence of achieving 2020 renewables targets

5.33. We next consider the likelihood that the required contribution of the power sector to the 2020 renewables targets would be achieved[24]. This criterion is

[24] Note that there are no explicit targets by sector under the Renewables Directive. However, the Government in its Renewable Energy Strategy has indicated the

separate from the carbon target criterion in recognition of the explicit targets under the EU Renewables Directive. Clearly there is a strong link between these two criteria.

Targeted Reforms

5.34. The minimum carbon price which features in the Targeted Reforms package, may have a beneficial effect on renewables deployment and the confidence of achieving the 2020 target, by increasing expectations of future electricity prices. However, the impact is likely to be relatively small since the wholesale electricity price typically contributes less than 50% to the revenues of renewables plant (and zero in the case of the plant that will qualify for FITs). The level of subsidy (RO band, and level of FITs) are likely to be a more important driver of renewables investment than the carbon premium in the electricity price.

5.35. The sharper short term price signals included in this package could be detrimental to renewables deployment since it increases the balancing risk for those with variable output such as wind.

5.36. Conversely, by stimulating demand management through sharper price signals and explicit measures to promote demand side response (including electricity storage), the system should be able to accommodate greater proportions of variable renewables by matching demand more closely to variations in wind output.

Enhanced Obligations

5.37. By including a centralised market for renewables, the Enhanced Obligations package would reduce cash-out risk for variable renewables (exacerbated by the sharper price signals), and provide a liquid wholesale market to sell their output. This should reduce investment risk and facilitate deployment thus increasing the probability that the 2020 renewables target can be met.

Enhanced Obligations and Renewables Tenders

5.38. As described above under the carbon target criterion, the capacity tenders for renewables in this package should further increase the probability of meeting the 2020 renewables target. The caveats noted above surrounding a potential investment hiatus and the risk of successful tenderers failing to deliver also need to be considered.

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contributions that it is expecting from each sector. For the purposes of the policy packages, we have assumed that the Renewable Heat Incentives remains the primary mechanism for delivering the heat target and hence we have focused on the electricity sector.

Capacity Tenders

5.39. The approach for promoting renewables investment is the same in this package, and so our assessment is the same as for the Enhanced Obligations with Renewables Tenders package.

Central Energy Buyer

5.40. The required volume of renewables output is contracted by the central entity. Therefore, provided limitations in the supply chain can be addressed, planning can be expedited and timely connections secured, there is a high probability that the required contribution from the electricity sector to the 2020 renewables targets can be met.

iv. Risk of prices being greater than necessary

5.41. Our fourth criterion assesses the risk that customers are exposed to excessively high prices. Such prices could arise due to costs associated with inefficient resource allocation, excessive market risks, investors earning higher returns than required for the level of risk incurred (due to inefficient market mechanisms), or the costs of stranded assets due to poor investment decisions (to the extent that customers are exposed to this).

Targeted Reforms

5.42. The Targeted Reforms package includes a number of policy measures that are likely to impact on prices, including the minimum carbon price, improved price signals, and demand side response measures.

5.43. The impact of the minimum carbon price on customers will depend on its level relative to the EUA price. In our high level analysis we have assumed a minimum price equivalent to the assumed EUA price under the Green Transition scenario (the highest across our four scenarios) from 2020 onwards.

5.44. Hence, in the Green Transition it has no direct impact other than by reducing risk by providing future certainty. The possible lower cost of capital that we discussed above may feed through to lower prices for consumers. If all the savings were passed through this might amount to around £2 per domestic customer in 2020.

5.45. In the other three scenarios the minimum carbon price increases the cost of carbon, with the biggest effect in the Slow Growth scenario with a minimum price of €50/t compared to a scenario EUA price of €30/t in 2020. In this scenario, domestic bills would be £35 per customer higher in 2020 (far outweighing any possible benefit from a lower cost of capital for low carbon investment), and the average I&C cost would increase by £12/MWh.

5.46. Since the caps on carbon emissions in the traded sector (which includes power generation) are set at the EU level, higher bills for domestic customers and industry in GB would not immediately contribute to lower total global emissions.

However, GB customers could benefit in the longer term from a more decarbonised power sector and therefore less exposure to future carbon prices which could he higher than the minimum carbon price. There may also be further economic benefits to the UK economy where the minimum carbon price contributes to investment in low carbon manufacturing and services that can be exported.

5.47. A risk with a minimum carbon price is that it could lead to windfalls for renewable generators whose subsidy levels (RO bands) may have been set when investors' expectations of future carbon prices were much lower than the minimum price.

5.48. The sharper price signals and demand side response measures within the Targeted Reforms package should in theory lead to lower prices overall for customers. The sharper price signals should attract energy supplies and demand side response in the short term and stimulate investment where it is needed over the longer term. This should lead to a more efficient allocation of resources, and ultimately reduce the costs of delivering a certain level of supply security. There is a risk, however, that if the demand side and/or investors cannot or do not respond to these signals, prices are simply higher and customers end up paying more for the same level of security of supply.

Enhanced Obligations

5.49. The additional policy measures included within the Enhanced Obligations package would likely have further impacts on prices.

5.50. By placing additional obligations on suppliers the risk of a future security of supply problem leading to very high prices is reduced. However, there is a risk of collective overprovision of supplies and/or capacity with the increased costs being passed on to customers. Further, these obligations may disadvantage smaller players and by making new entry more difficult contribute to a less competitive market. The obligations on the SO could also result in overprovision of back-up supplies and capacity which customers would be exposed to via higher use of system charges. Finally, the requirement on gas-fired generators to have back-up fuel capability may be a more expensive option than additional storage or LNG supplies.

5.51. The centralised renewables market policy measure, contained within this package, could lead to a more efficient dispatch outcome by aggregating wind forecasting across the country and providing the SO with more control for balancing the output from variable renewables (including geographically). Conversely, there is a risk with this approach that the true cost of balancing variable renewables is not revealed, which could lead to inefficient outcomes in the long term.

Enhanced Obligations with Renewables Tenders

5.52. The capacity tenders for new renewables included in this package would introduce competition for subsidies between developers and could provide better value for customers. However, this does require the supply of renewable projects to exceed the volumes of the tenders, and for there to be sufficient competition between players. The efficiency could be further improved by reverse indexing the tender prices to wholesale electricity prices such as when electricity prices increase the subsidy falls and vice versa. This approach may also reduce investor risk and yield benefits in terms of a lower cost of capital. There may also be efficiency advantages in being able to coordinate network expansion with the renewable tenders, thus reducing the risk of constraints or stranded network investment.

5.53. The risk with the capacity tenders for renewables is that they would need to provide incentives to ensure delivery which could push up the tender prices and undermine any potential benefit in terms of lower cost of capital. A further risk is that the central entity responsible for determining the mix and location of renewables for the tenders might not make the most cost effective choices.

Capacity Tenders

5.54. The same arguments described above would also hold for the more general tenders for low carbon investment within the Capacity Tenders package. For tenders to be an effective mechanism there would need to be enough competition within each tranche of tendered capacity. For some technologies, such as nuclear and CCS, there may only be a limited number of bidders. In such cases, a regulated price may be more appropriate than one set via a tender mechanism.

5.55. This package would not need to include the minimum carbon price (in the form proposed in the packages above) since the capacity tenders would be the primary vehicles for stimulating all low carbon investment. By avoiding a minimum carbon price there is less risk to economic competitiveness and of higher customer bills, although domestic emissions may be higher since there could be more unabated coal generation at the expense of gas.

5.56. More generally the capacity tenders would likely lead to higher capacity margins and greater amounts of gas storage which should reduce the risk of price spikes caused by under-investment. However, this policy carries the risk that the requirement for additional capacity is over-estimated by the central entity or it has overlooked possibly lower cost substitutes, a risk that increases the longer the tenders and the greater difficulty in forecasting demand and its price elasticity. We attempt to illustrate these trade offs in the high level analysis presented in Box 6 below.

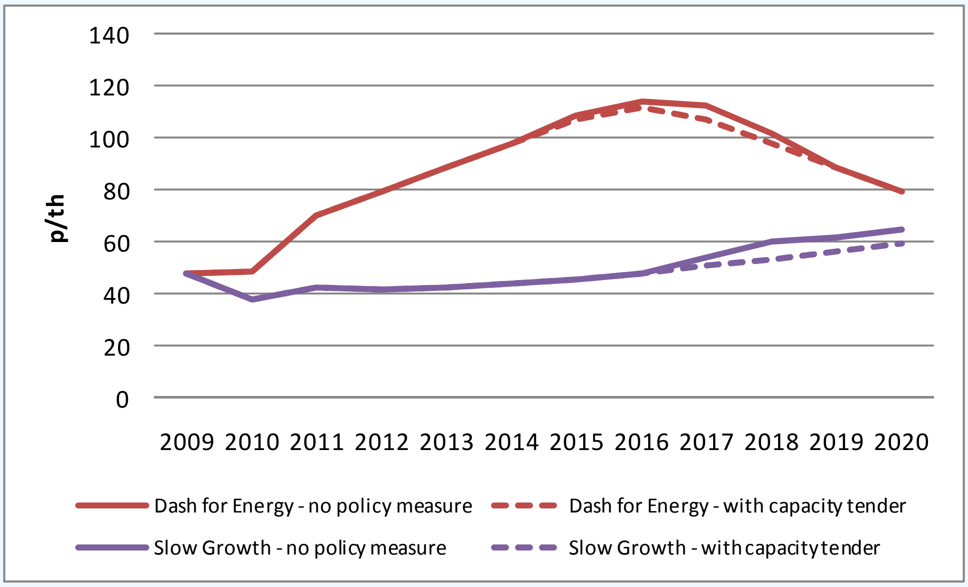
Box 6
Costs of additional gas storage versus impacts on price

As a high level example of the trade off between the costs of additional investment and the impact on wholesale prices, we have modelled the impact of increasing GB gas storage under the Capacity Tenders package to a level such that there would be no curtailment of demand for any firm gas or electricity customers under our stress tests.

The total additional investment required to put this policy in place would be equivalent to 1% of total investment by 2020 in the Dash for Energy scenario, and 3% of total investment in the Slow Growth scenario.

The analysis suggests that by reducing the risk of firm curtailment this policy could lead to lower wholesale gas prices from 2015 onwards in the Slow Growth and Dash for Energy scenarios, as illustrated in Figure 11 below.

Figure 11 - Impact of Policy on Gas Wholesale Price in Slow Growth scenario (p/therm)



The simple analysis suggests that the cost of the additional storage would be equivalent to around £7 per year on the average domestic gas bill (around 1 p/th for I&C users) if volumes were projected based on the Slow Growth scenario. If the storage was not subsequently needed (as would be the case in the Green Transition and Green Stimulus scenarios) this would represent an additional cost to consumers. However, the savings from lower wholesale gas prices could be as much as 7 p/th if the Dash for Energy or Slow Growth scenarios transpired, saving domestic customers as much as £75 per year in some years.

Central Energy Buyer

5.57. The Central Energy Buyer package could represent a significant shift of risk from investors to consumers. The long term power purchase agreements and storage tenders would provide revenue certainty for investors and lower the cost of capital. This could reduce the overall cost of bringing forward the necessary investment. However, there is a risk that the central entity makes the wrong choices or over-forecasts future requirements, requiring consumers to pay more than they should. There is also a possibility that the Central Energy Buyer is less exacting in negotiating its contracts than a private company given the fact that risks can be backed off to customers.

5.58. The Central Energy Buyer could provide greater price certainty to the market by entering into fixed price contracts for generation and gas supply. Some consumers may see advantage in greater price stability although there is a risk that the Central Energy Buyer's hedging decisions leave the economy exposed to high prices should global energy prices subsequently fall.

5.59. Also the role of supply competition may be diminished where suppliers are purchasing increasing proportions of their energy from the same entity under the same terms. Consumers could end up paying more as a result of this.

v. Risk of dampening of innovation

5.60. The next criterion considers the risk that inadequate innovation in the near term leads to higher price outcomes over the longer term. The table below presents the positives and negatives of the policy packages with respect to the potential implications for 'dynamic efficiency'.

Targeted Reforms

5.61. Arguably the current arrangements, which rely on competition in the wholesale markets to deliver energy supplies and future investment, are effective in promoting innovation. Any reform that risks undermining this competitive effect could be detrimental in this respect.

5.62. Since the Targeted Reforms package represents the least departure from the current arrangements, it is likely to be the most effective in promoting innovation of our five packages. Further, measures to promote greater demand side response and sharpen short term price signals should stimulate innovation in smart technologies and demand management.

Enhanced Obligations

5.63. There is a risk with this package that the supplier obligations are unduly onerous for smaller players and new entrants and reduce the overall competitiveness of the market. This could reduce the driver for innovation in products and services for customers.

Enhanced Obligations with Renewables Tenders

5.64. By targeting particular types of renewables, the tenders in this package risk excluding some new and emerging technologies and reduce the incentives for research and development. This would need to be carefully considered when designing the form of the tenders.

Capacity Tenders

5.65. There is a risk with the Capacity Tenders package that new and emerging technologies are not captured within the initial tenders, and then have no route to market since capacity is already contracted forward. This could be addressed by using a combination of shorter and longer term tenders, so that a certain proportion of the market remains available year on year.

Central Energy Buyer

5.66. The Central Energy Buyer package has potentially the most negative impact on innovation of our five packages, since the extent of competition in delivering energy supplies and capacity is reduced. Instead the scale and type of future investments are determined by a single entity which may not have access to the same amount of collective information that a competitive market has.

vi. Implementation issues

5.67. There would be a number of risks and issues associated with implementation of the policy packages, in terms of a) Deliverability – the processes and governance arrangements for implementing change; b) Timing – the timescale to implement the package (including legislation); c) Implementation resources – the expected costs of implementing the package. There are also a number of legal risks that we address under a separate assessment criteria in the next section. The risk of unintended consequences must also be considered, for example the possibility of an investment hiatus during the implementation period.

5.68. Timescales indicated below are broad estimates based on current governance arrangements and past experience. To implement change more rapidly some of these arrangements may need to be changed.

Targeted Reforms

5.69. A minimum carbon price could only be achieved through legislation, and there are legal issues and complexities around the design and implementation of a minimum carbon price that could impact the timing and effectiveness of this package.

5.70. Changes to pricing arrangements can be achieved within the existing industry code governance framework. This currently relies on industry members raising proposals to modify the industry codes (principally the Balancing and Settlement Code (BSC) in electricity and the Uniform Network Code (UNC) in gas). Ofgem is then the decision-making body for all proposals. Ofgem may initiate industry workgroups or seminars to explore pricing issues. Through our code governance review we are proposing a role for Ofgem to lead significant code changes.

5.71. Demand side response measures such as reforming the settlement arrangements, promoting time of use tariffs and real-time pricing, and facilitating information provision and the role of demand side aggregators could be achieved through a combination of changes to industry codes and other routes that we are exploring as part of the wider Smart Metering Roll-out Programme.

Implementation costs

5.72. Implementation costs are likely to be significant although lower in this package than the others. Government resource would be needed, particularly in the design and implementation of an appropriate minimum carbon price. Ofgem and industry resource would also be needed, particularly to design, assess and implement appropriate code modifications. System and IT changes would also be required.

Timing

5.73. Code modifications can take anything from 3 months to 18 months from proposal to implementation, depending on, for example, complexity and level of agreement and commitment within industry. Government legislation to introduce a minimum carbon price could take between 15 and 30 months.

Enhanced Obligations

5.74. As with the Targeted Reforms package the same implementation issues will exist in relation to a minimum carbon price, demand side response measures and changes to pricing arrangements.

5.75. The obligations described would all require changes to the licences of the relevant companies. Ofgem can propose licence amendments, which will be implemented if more than 80% of licensees to whom the amendments apply agree to them. If more than 20% object, Ofgem has the option to refer the proposed amendments to the Competition Commission (CC), who will then assess the case for such amendments to be made. Alternatively, Ofgem may ask the CC to consider amendments without first seeking the consent of licensees[25].

5.76. Some consequential modifications to the BSC and UNC may also be required, particularly in relation to a changed role for the SO in procuring gas (in an emergency) and back-up generation. Any changes to gas emergency arrangements must also be compatible with National Grid's Safety Case, which the Health and Safety Executive is responsible for keeping under review.

5.77. It is possible that a centralised renewables market might be achieved through a coordinated combination of changes to NG's transmission licence and BSC modifications. There would also likely be implications for existing commercial arrangements between renewable generators and suppliers which would require careful consideration.

Implementation costs

5.78. On top of the costs of the Targeted Reforms package set out above, the obligations would require careful design, and potentially a CC reference, which would increase implementation costs. The creation of a centralised renewables market would require either the creation of a new entity or an extension of the SO's role to operate the centralised market. Significant industry code and licence changes are also likely, which would take considerable industry and regulatory resource.

[25] We note that changes to licences can also be made through legislation.

Timing

5.79. Changes of this type to licences could be implemented within a minimum of around 4 months. However, if a CC reference is involved total time could be up to 18 months.

5.80. Whilst industry code modifications and licence amendments individually can be implemented within a few months, the design and implementation of a coordinated and simultaneous set of changes to create a centralised renewables market is likely to take significant planning and consultation. An initial view is that this would take 12-24 months.

Enhanced Obligations and Renewables Tenders

5.81. This package shares the implementation issues described above for the Targeted Reforms and Enhanced Obligations package. In addition, the introduction of a capacity tender for renewable generation would require the involvement of government, Ofgem and industry. Legislation would be required to replace the Renewables Obligation and to allow for a tendering body to be created. Amendments to codes and licences may be needed to allow the tender to interact effectively with the rest of the market.

5.82. Grandfathering arrangements would also need to be put in place for plant participating in the RO.

Implementation costs

5.83. In addition to the costs identified for the Enhanced Obligations package, the creation of a new entity to tender for renewable generation would require significant government, industry and potentially Ofgem resource to design and plan. There would also be costs involved for participants in the renewables market.

Timing

5.84. We estimate the planning, design and implementation of all the measure in this package, including a capacity tender for renewable generation would take up to 24 months.

Capacity Tenders

5.85. As with the tender for renewable capacity above, legislation would be required to introduce capacity tenders more broadly. Significant licence amendments (and possibly new licences), and code modifications are also likely to be required.

5.86. In implementing any capacity tenders relating to gas storage there would be a need to consider how existing storage operators would be treated.

Implementation costs

5.87. The introduction of capacity tenders for all new generation would constitute major reform and involve considerable resource from industry, Ofgem and government.

Timing

5.88. We estimate the planning, design and implementation of a capacity tender would take 18 to 30 months.

Central Energy Buyer

5.89. This package would constitute major reform, requiring significant involvement of government, Ofgem and industry. As stated above, there would need to be satisfactory resolution of the legal issues. It is likely that new licences and industry codes would be required.

5.90. Similar issues arise as for the Capacity Tenders package, but to a greater extent in relation to possible inconsistencies with interconnected markets.

Implementation costs

5.91. This package would be the most costly to implement, as it would effectively involve replacing the current market framework with a new set of arrangements.

Timing

5.92. We estimate that it would take between 24 and 36 months from deciding to adopt this option to completing implementation.

vii. Legal Issues

Targeted Reforms

5.93. Any measures aimed at ensuring long-term price signals such as a minimum carbon price (possibly operating as a “top-up carbon tax”) would need to be designed so as to operate alongside, and be consistent with, relevant EC measures and schemes. In this regard, the EU ETS and internal market harmonisation of minimum levels of taxation of energy products would, in particular, need to be considered carefully.

5.94. Ofgem is not currently able to propose modifications to the industry codes. Any modifications would have to be raised by signatories to the relevant code, though licence amendments can be proposed by Ofgem if necessary and decided by the Competition Commission on reference in the absence of industry support. However, given the need for (likely) primary legislation in respect of a minimum carbon price, it may be that enabling powers through primary legislation could be included in order to ensure delivery of the complete policy package.

Enhanced Obligations

5.95. As with the Targeted Reforms package above, there are similar legal considerations in relation to implementation.

Enhanced Obligations with Renewables Tenders

5.96. As with the Targeted Reforms package above, there are similar legal considerations in relation to implementation.

5.97. We recognise that any form of capacity tender would need to be consistent with the European third package, which does envisage the use of tenders but restricts the circumstances in which they are permitted.

5.98. The issues may differ depending on how the tender is designed (for example there are likely to be fewer legal issues with a tender that effectively acts as a top-up subsidy than one which results in full-scale government ownership and fewer issues with narrowly targeted interventions than with widespread tendering across all generation).

Capacity Tenders

5.99. We recognise that any form of capacity tender would need to be consistent with the European third package, which does envisage the use of tenders but restricts the circumstances in which they are permitted. There may be an argument that broader tenders of capacity are required in light of initial steps to ensure environmental and security of supply issues: in short, that once intervention has reached a certain level, pure market mechanisms are "crowded out" such that further tenders are required in order to achieve security of supply. This, of course, could only be determined in light of the evidence.

5.100. The issues may differ depending on how the tender is designed (for example there are likely to be less legal issues with a tender that effectively acts as a top-up subsidy than one which results in full-scale government ownership).

5.101. A tender for gas storage would need to be designed to be compliant with EC and national legal requirements relating to non-discrimination.

Central Energy Buyer

5.102. Significant legal issues would need to be resolved if this package were to be pursued. These issues would include the UK's duty under the EC Treaty not to jeopardise the attainment of EC legal measures (such as the third package, which envisages a competitive markets and requires unbundling of transmission from those competitive markets), issues arising out of Article 106 EC in conjunction with the other competition rules, as well as potential issues with procurement rules and other directly applicable principles such as Freedom of Establishment.

5.103. The legislation above would limit what is possible under this approach.

6. Timing

Chapter Summary

In this chapter we discuss the timing issues around potential reforms and when investment is required. We discuss whether early actions should be considered in advance of more wider reform. At the end of the chapter we discuss next steps.

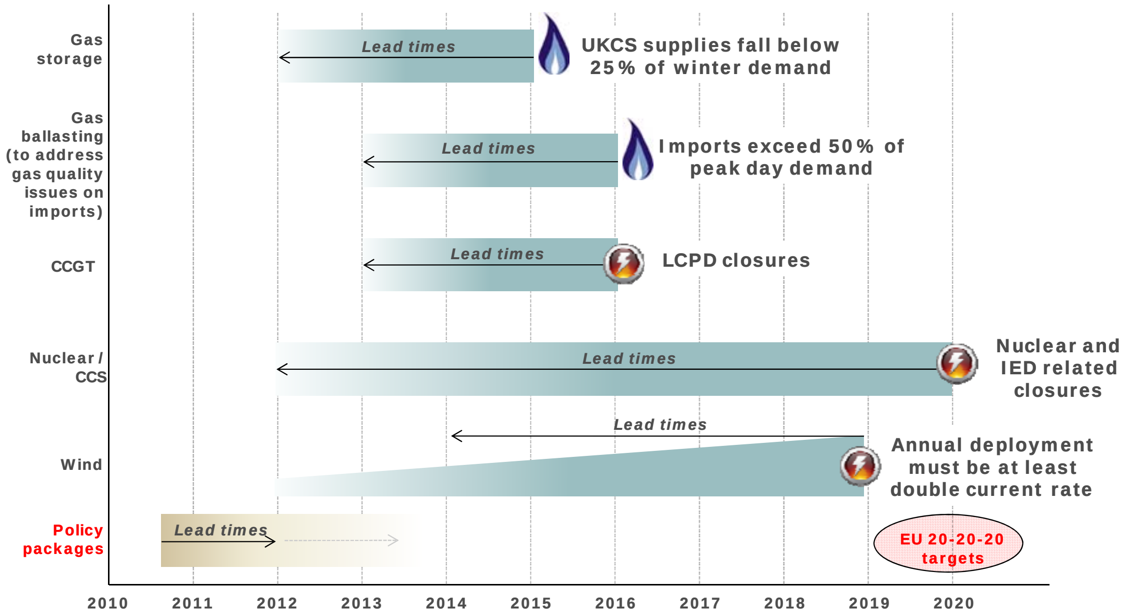
Question 12: Do you agree with our assessment of the timing for important investment decisions?
Question 13: Do you believe that early actions should be considered?
Question 14: Do you think that the issues are such that policy measures should be considered as a package or should they be considered on a case by case basis?

Timing of policies and investments

6.1. Ofgem does not consider that leaving the current arrangements unaltered is in the interests of consumers, given the risks and issues identified. However, we recognise the need for a stable environment for investment, and do not advocate change lightly. We are therefore looking for solutions that make the GB energy markets more capable of attracting finance over the medium to longer term, whilst at the same time being mindful to ensure that existing and on-going investments are not compromised.

6.2. Although our scenarios do not indicate concerns over supply security until beyond the middle of the current decade, the timescales required to secure finance, mobilise supply chains and deliver the infrastructure needed suggests that the period around 2012 and 2013 could be important for investment decisions critical to future secure and sustainable energy supplies. Hence, there is a window of opportunity between now and then to implement any policy measures that may be necessary to make sure that investment takes place in a timely fashion.

Figure 12: Summary of key timings



6.3. On gas storage, there are a number of projects currently under development which would increase present capacity from 4.4 to 5.2bcm. When additional storage is required is quite uncertain but we note that supply from UKCS is likely to fall below 25% of winter demand in 2015 (under our Dash for Energy scenario), which is also the year that our stress tests are showing increased risk of firm demand curtailment in some of our scenarios. If we assume a minimum lead time of 3 years for new storage projects, projects will need to be committed by the beginning of 2012 at the latest.

6.4. Since our October consultation we have undertaken an additional stress test looking at the impact of gas quality issues on interconnector flows. As the Wobbe index rises from high quality gas there is an increased risk that flows on the IUK could fall outside the GB specification at certain times requiring imports to be curtailed. We are undertaking further analysis of the probability of this occurring. However, we note from our scenario analysis that imports are likely to make up over 50% of peak day demand from 2016 (under our Dash for Energy scenario) highlighting the risk from any curtailment. Assuming a three year lead time to get a gas ballasting facility operational at Bacton or Zeebrugge to treat imported gas, a decision would need to be made by the beginning of 2013 should a facility be required by 2016.

6.5. The 12GW of plant that are opted out of the LCPD must close by the end of 2015, although some plant may close earlier than this date. If CCGT plant (which are likely to be the quickest to build) are required to fill any capacity gap decisions of these would also be required by early 2013.

6.6. The IED (which is still being negotiated in the European Parliament) is likely to lead to further closures of coal plant, and some gas plant, from 2020 onwards. Also, 7GW of existing nuclear plant is also likely to have closed by this point. If this plant is to be replaced by low carbon plant, the first new nuclear plant may need to be operational by then. Assuming an eight year lead time for the first plant, the project would need to be committed by early 2012. CCS plant could provide another low carbon alternative and some of the demonstration plant should be operational by then. However, it is uncertain whether CCS will be a technically and commercially proven technology by this point, and provide the scale of capacity needed to replace closing unabated thermal plant.

6.7. In order to meet the 2020 renewables targets, our scenario analysis suggests that the rate of wind deployment will need to be at least double current rates (including a large proportion of offshore) by 2019. Based on a 5 year lead time this would suggest that the pipeline of committed projects will need to double over the next four years.

Implementing change

6.8. The earlier action is taken, the more options are available and the more cost effective investment is likely to be. Some of the policy packages that we outline will have longer implementation times, and may not be viable unless decisions are taken quickly and/or the normal regulatory and policy governance arrangements can be accelerated.

6.9. Some of the measures outlined above could be taken forward by Ofgem and industry; others would require government to take the lead. We are, however, currently considering whether it is necessary to pursue certain measures immediately (informed by experience in the gas market this winter). What is of particular importance is the need to develop a coherent package rather than implementing them in a piecemeal fashion. The findings of this project may provide useful input to the Government's coming Energy Market Assessment.

6.10. The experience in the energy markets as a result of cold weather in recent weeks has provided a timely reminder of the multiple challenges that the current arrangements have to deal with. Days of record demand coincided with outages at Norwegian platforms, from where a significant proportion of our supplies come. Given the recentness of the events we have not yet conducted detailed analysis. The arrangements and the system appear to have coped well with these challenges. However, storage levels were high at the beginning of January; overall winter conditions to date have not been exceptional; and with North Sea supplies declining annually we recognise that we need to be sure that the arrangements will continue to cope in the event of similar, and more difficult, conditions in the coming years.

6.11. In Appendix 6 we set out preliminary views on our experience of winter 2010 thus far. We shall review this at the end of the winter but would welcome views as to whether early actions to put in place different arrangements for the next 2-3 winters should be considered, either as temporary solutions or as the first components of an enduring policy package.

Next Steps

6.12. We welcome responses to this consultation by 31 March 2010. In particular, we are seeking respondents' views on our appraisal of current arrangements; our policy packages and assessment of them; whether other policy measures should be considered; and the extent to which early actions should be considered.

6.13. We confirm our commitment to work with government in delivering what is required to ensure secure and sustainable gas and electricity supplies for consumers.

Appendices

Index

Appendix 1 - Consultation response and questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 31 March 2010 and should be sent to project.discovery@ofgem.gov.uk.

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Any questions on this document should, in the first instance, be directed to:

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Senior Economist, Trading Arrangements
Ofgem, 9 Millbank
020 7901 7000
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CHAPTER: One

There are no questions associated with this chapter.

CHAPTER: Two

There are no questions associated with this chapter.

CHAPTER: Three

Question 1: Do you agree with our assessment of the current arrangements?
Question 2: Are there other aspects of the current arrangements which could have a negative impact on secure and sustainable energy supplies, or costs to customers?

Question 3: Do you agree that the five issues we have highlighted are the most important?
Question 4: Do you have any comments on our description of what might happen if no changes are made to the current arrangements?

CHAPTER: Four

Question 5: Do you believe that our policy packages cover a sufficient range of possible policy measures?
Question 6: Do you have suggestions for variants to these policy packages?
Question 7: What other policy measures do you believe should be considered, and why?

CHAPTER: Five

Question 8: Do you agree with the assessment criteria that we have used to evaluate the policy packages?
Question 9: Do you have any comments on our initial assessment of each of the packages?
Question 10: Do you agree with our summary of the key benefits and key risks of each policy package?
Question 11: Do you have a view on which package is preferable, or alternative policy measures or packages that you would advocate? We are particularly interested any analysis you may have to support your views.

CHAPTER: Six

Question 12: Do you agree with our assessment of the timing for important investment decisions?
Question 13: Do you believe that early actions should be considered?
Question 14: Do you think that the issues are such that policy measures should be considered as a package or should they be considered on a case by case basis?

Appendix 2 – Summary of responses to October consultation

Summary

1.1. The responses to the Discovery Consultation offered support for the project. There was particularly positive feedback to our approach to modelling uncertainty through scenarios and stress tests. Overall, it seems that respondents felt the results of our security of supply analysis are optimistic. We received more detailed feedback for specific questions asked in the Consultation document, which suggested additional sources of uncertainty and ways of capturing information. At this stage, given the general endorsement we have received for our work to date, as well as the other work commitments for Discovery between now and the beginning of next year, we are not planning to spend significant resources on revising the Discovery model.

Background

1.2. We published 'Project Discovery Energy Market Scenarios' on 9 October 2009. The deadline for responses was 20th November. We have received responses from 55 organisations, composed of 33 companies (including all of the big 6), 2 government agencies, 14 independents (mainly academics) 3 consultants and 2 environmental groups and 1 other. All received responses are summarised here and we do not expect any further written responses.

Key Issues

1.3. The respondents are divided between whether they view our security of supply conclusions as optimistic or pessimistic. These views tend to be linked to their assessment of the market's ability to deliver desirable/efficient/economic outcomes. More respondents find our assessment to be optimistic than pessimistic.

1.4. Amongst the respondents that viewed our work as being optimistic were four of the big 6 as well as two consumer groups — Centrica, EON, SSE and EDF, Consumer Focus and Which. Their view seems based on perceptions of the challenges in investing in the energy supply chain, which have been compounded by the recent downturn. In contrast, RWE, ESBI and other respondents believe that the 'market will deliver'. This view seems partly attributable to concerns that government intervention is a worse alternative — the market is the lesser of two evils.

1.5. The responses did not focus on policy options per se, which reflects the content of the October Discovery publication and the questions posed in it — the feedback is concentrated on our modelling of energy market scenarios. Inevitably though, some respondents strayed into making comments about policy in their response. These comments tended to relate to perceptions of how well the market has delivered to date as well as how likely it is to deliver in the future. However, some feedback related to the particular issues faced by certain respondents. For example, ESBI is keen that no further subsidies be given to renewable energy while Fluxys endorses a regulated return model for investment.

1.6. While a number of respondents suggest that our modelling could benefit from extra sophistication and /or detail, other respondents view it as broadly 'fit for purpose', given the aims of this piece of Discovery work.

1.7. Going forward, respondents suggest a number of ways in which we could improve our modelling. These suggestions include modelling investment dynamically and including greater commodity price volatility as well as further analysis of regulatory uncertainty, building/planning challenges, smart metering/grids, renewable technology's characteristics, funding constraints and differential impacts on consumers. An additional scenario is the UK having a different growth and/or green target experience to the rest of the world while additional stress tests include gas quality, oil price shocks and investment delays.

Next steps

1.8. We have analysed the responses and plan to do the following to take on board feedback:

- Publishing an assumptions booklet — a number of respondents felt they could not provide complete feedback on some of our modelling as we did not include information about all of the model's assumptions in the consultation document. We have drafted an assumptions booklet and plan to publish it before the end of the year.

- Data verification – where respondents have provided specific pieces of data as potential alternative inputs to our model, we are checking them against the sources that we have used.

- Model sophistication — we are exploring how to extend the model to capture impacts on different consumers (fuel poor and I&C customers) as well as allowing costs of capital to vary across technology and time.

- Additional stress tests — we have already completed or begun work on a number of additional stress tests, including oil price shocks, investment delays and gas quality.

Issue	View	Respondents
Discovery study	Broad support for project	NHSPSA/PGEP, RWE, CoalPro, AP, Shell, INEOS, SP, EDF, EIUG, BWEA, Oil & Gas UK
	Importance acknowledged	ESBI, Which, Centrica, INEOS, MRP, CIA, Centrica, MRP, CE
	Rationale and/or purpose questioned	ESBI, SONE

Issue	View	Respondents
Uncertainty modelling	Broad support for use of scenarios and stress tests	EON, RWE and Drax, Consumer Focus, Which, Helius Energy, CoalPro, SSE, International Power, Centrica, Shell, ATCO Power, UK Coal Mining, Chris Fox, NG, MRP, UKERC, CIPS, BCC, Statoil, INEOS Prosyma Research, EMRI, SBGI, SP, EDF, BWEA, CE, SONE
	Our modelling is 'fit for purpose'	EON, Drax, CoalPro, SSE, UK Coal Mining, NG, MRP, SP
	Our modelling requires extra sophistication/detail	RWE, NHSPSA/PGEP, EMRI, International Power, Centrica, ATCO Power, ExxonMobil, CIPS, BCC, Steve Browning, UKERC, Helius Energy, EDF, EIUG, Stag Energy
Scenario feedback	Pessimistic – market will deliver	RWE, ESBI, International Power, AP
	Pessimistic – forecasts indicate demand growth lower and/or supply higher	Consumer Focus
	Optimistic – market will not deliver i.e. inadequate storage, long lead times required for investment	Which, Helius Energy, CoalPro, Gazprom, CIA, INEOS, GrowHow, Centrica, Chris Eagleton, Fells Associates, CIA, Helius Energy, EDF, SONE
	Optimistic – forecasts indicate lower supply due to investment uncertainty and recession	EON, UK Coal Mining, GrowHow, BCC, CoalPro, SSE
	Non-green scenarios unlikely – various commitments already in place	EON, AEP, BWEA
	Green scenarios unlikely – challenges of meeting targets	BCC, MRP, CIA, GrowHow, Ineos, SP,

Issue	View	Respondents
		EIUG, Oil & Gas UK, SONE
	Internal inconsistency – investment and plant closure assumptions do not fit scenarios	RWE, Fells Associates, SP, EIUG
Additional scenarios	Separation of heat and renewable targets	EON
	Slow/fast nuclear build	Prosyma Research
	Full liberalisation of European markets	Statoil
	UK/Europe situation different to rest of world – growth and/or meeting green targets	SBGI, Shell, BCC, MRP, CE
	Early government intervention to achieve energy policy goals	SP
	True green scenario – no nuclear and greater domestic renewables	WWF
Changes to modelling	Data supplied for model correction/validation	Gazprom, Helius Energy, Wind Output, EBHPD, CoalPro, EMRI, NG, UKERC, Stag Energy
	Investment outcomes should be modelled dynamically in the model i.e. respond to price	Drax, RWE, International Power, MRP, EDF
	Interconnector flows should be made a function of price	Drax, Centrica, AEP, MRP
	Commodity prices should be more volatile i.e. gas, electricity, carbon and oil	EON, NHSPSA/PGEP, SSE, DEI, Angus Bryant and John Mason, CIPS, NG, Centrica, SP
	Balancing charges should be higher	Drax, ESBI
	Capital costs should be higher (or funding challenges not adequately captured)	EON, CoalPro, Helius Energy, SSE, UK Coal Mining, CIPS, NG
	Negative impact of regulatory uncertainty and/or inappropriate market interventions on investment not adequately captured	EON, ESBI, SSE, Helius Energy, ACTO Power, MRP, CIPS, UK Coal Mining
	Building planning challenges not adequately captured	ESBI, NHSPA/PGEP, SSE, CoalPro, MRP, CIPS, UK coal mining, SP

Issue	View	Respondents
	Smart metering and grids not adequately captured (but split feedback on potential demand-side impact)	EON, NHSPA/PGEP, Consumer Focus, Which, SSE, Centrica, BCC, MRP, NG, EDF
	Longer time horizon necessary for security of supply assessment (to match investment planning)	EON, Prosyma Research, Centrica, AUP, SP, EDF
	Pipeline and stored gas should also be a source of swing gas in addition to LNG	EON, Centrica, Statoil, UKERC, Exxonmobile, EIUG, Oil & Gas UK
	Renewable energy technologies not adequately detailed i.e. insufficient back up capacity in model for intermittent characteristics, inadequate diversity in generation, not enough nuclear or too much wind	Drax, RWE, ATCO Power, CIA, INEOS, GrowHow, Centrica, International Power, MRP, Helius Energy, Exxonmobil, SP, EDF, CE, SONE
	Climate change impacts not fully captured i.e. on physical environment	Consumer Focus
	Differential impact of various consumers not adequately captured i.e. fuel poor or industrial customers	Consumer Focus, Which, CoalPro, ATCO Power, CIA, INEOS, GrowHow, BCC, CIPA, EIUG
Stress test feedback	Pessimistic – supply offered by interconnector	EON
	Optimistic – possibility of 'double whammy' concurrent adverse events, focus on short term impacts, impact of gas storage assumptions	RWE, EON, NHSPA/PGEP, CoalPro, SSE, CIA, Centrica, ATCO Power, Fells Associates, UK Coal Mining, GrowHow, International Power, INEOS, ATCO Power, NG, CIA, SBGI, Statoil, SP, EDF, EIUG
	Russia-Ukraine dispute/European supply disruption is a credible risk.	SP, EDF
	Low probability/will be low impact of Russia-Ukraine conflict	UKERC, Shell, Centrica
Additional stress tests	Oil price shock	NHSPSA/PGEP, SSE, Angus Bryant and John Mason

Issue	View	Respondents
	Government intervention in response to supply shortage	EON
	Gas quality	RWE, Fluxys consortium, SSE, Gazprom, Centrica, AEP, Statoil, Peter Taff, EDF
	Investment delays	Drax, International Power, ACTO Power, ExxonMobil, SP
	Nuclear capacity shortage – construction delay or plant fault	Consumer Focus, Helius Energy, UK Coal Mining, BWEA, WWF
	Carbon price volatile and/or uncertain	Consumer Focus, BWEA
	Coal supply disruption	Helius Energy
	High summer demand	Fells Associates
	Industrial action resulting in temporary loss of part of generation fleet	EDF
	Loss of part of transmission infrastructure – due to terrorism, weather related natural disaster	EDF, EMRI, Which, Fells Associates
Presentation of results	Consumer bills – link between investment and prices should be clearer	NHSPSA/PGEP, RWE, CIA, EIUG
	Justification of choices – for scenarios and stress tests presented	SSE
	Assumption booklet requested	Which, SSE, ExxonMobil, BCC, NG, Centrica, Helius Energy, SP, EDF

Appendix 3 - Issues with current market rules

1.1. Both the electricity and gas markets are designed around the concept of parties taking responsibility for balancing their own positions through dispatching their assets, forward contracting and prompt trading. The rationales for this approach to market design include mitigating the risks from the exercise of short term market power (which was perceived to be an issue under the England and Wales Pool) and to reduce the role of the System Operator (SO) to that of residual balancer. Incentives on parties to balance are provided by the two-part cash-out regimes. These typically offer less attractive spreads than the prompt markets, since the prices are derived from the balancing actions of the SO which can be quite expensive. The SO itself is incentivised to reduce the costs of balancing actions through the Balancing Services Incentive Scheme (BSIS) scheme.

1.2. The assessment has raised a number of concerns surrounding the strength of short term cash-out price signals in both the electricity and gas markets. In both markets it is possible that firm customers could have their load curtailed before cash-out prices have reached the value of lost load of those customers.

1.3. In electricity this occurs because the System Operator can use automatic load disconnection with no corresponding impact on cash-out prices. Likewise voltage control, which is the last stage before automatic load disconnection, is a 'free option' to the SO. The assessment also noted that the ex-ante method for allocating the availability fees for certain types of reserve into cash-out could dampen the price signal in the periods when the reserve is most actively used.

1.4. In gas the problem manifests itself in the emergency cash-out arrangements. Firm load could be curtailed in an emergency with the cash-out price frozen well below the value of lost load for the customers being interrupted. If the price was able to rise in an emergency, additional supplies could be attracted from Norway, the Continent and from LNG, thus enhancing security of supply by reducing the risk of firm load curtailment[26].

1.5. In gas the 'main' cash-out price (charged to parties who are short when the system is short and paid to parties who are long when the system is long) is based on the marginal trade conducted by the SO. In electricity, the main cash-out price is a 'chunky' marginal price calculated from the average of the highest-priced (system short) or lowest-priced (system long) 500MWh of energy balancing actions. In practice this means that the main cash-out price is normally the average of balancing actions taken since the imbalance volume is 500MWh or greater only 3% of the time.

[26] UNC modification 260, which was implemented in December 2009, increases the incentives on gas shippers to ensure they have sufficient gas to supply their customers during and in the run-up to a gas emergency, through changes to the post-emergency claims arrangements. The Joint Office of Gas Transporters (www.gasgovernance.com) website has further details.

1.6. There are some arguments that a more marginal price in electricity would be appropriate, and we have previously considered this when deciding on modifications. In making our decisions previously we have recognised that it is very difficult to derive a single half-hourly value for energy from the Balancing Mechanism which is a continuous mechanism with the SO counterparty to all deals. The SO takes actions over different lead times for different reasons (which do not necessarily map onto individual settlement periods). Hence, there is a wide range in prices of accepted bids and offers, including some very high priced short notice actions. This spread explains why paid-as-bid for balancing actions rather than a cleared price has been retained within the current electricity trading arrangements design. We have concluded previously that since it is very difficult to extract a pure energy price from the Balancing Mechanism a fully marginal price may not be appropriate, although we have indicated that this should be kept under review and that it may be appropriate to make cash-out prices more marginal in the future. In gas, the greater tolerances in the system mean that balancing actions taken by the SO tend to be less specific (other than for locational reasons), making a fully marginal cash-out price more appropriate.

1.7. Both the gas and electricity markets are based on dual price settlement, akin to the bid/offer spreads seen in financial and other commodity markets. Our assessment noted that the spread between the cash-out prices in electricity was particularly high. The dual pricing acts as an incentive to balance (and thus minimises the role of the SO as residual balancer), and an incentive to contract in advance thus lessening the risk of market power which increases closer to real-time. However, too large a spread can distort prices and unduly penalise those parties that find it difficult to balance (for example, variable renewables) or have poor access to shape and balancing products to manage their own positions. Analysis conducted for regulatory impact assessments for previous modification proposals[27] demonstrated that the monies collected from out-of-balance parties far exceeds the costs incurred by the SO in balancing the system, an effect caused almost exclusively by the large cash-out price spread.

1.8. The ‘chunky’ marginal cash-out price, pay-as-bid in the Balancing Mechanism, and dual cash-out prices are features of the NETA/BETTA approach. The arrangements have been subject to a number of modifications and could be further improved, most noticeably in the treatment of reserve costs, voltage control and automatic demand disconnection. However, to introduce a marginal cleared price for balancing actions which would then be applied as a single cash-out price for imbalances, would likely require a move away from the continuous Balancing Mechanism to a set of within-day auctions with generators and suppliers bidding standard half-hourly energy products. In the absence of unfavourable dual cash-out prices, parties are more likely to be willing to trade their power in the ‘balancing market’. This would imply a much ‘deeper’ role for the SO. This is not necessarily the wrong outcome and would certainly be more beneficial to smaller players since

[27] e.g. BSC modification proposals P211, P212 and P217

there would also be a market available to buy and sell power in the short term. A key question for any future reform to the arrangements is what is the right balance from an efficiency perspective of self-dispatch versus aggregated balancing by the SO, and whether this changes with increasing penetration of variable renewables.

1.9. In gas, the impact of the dual pricing approach is less since cash-out price spreads tend to be lower and shippers have the ability to trade after-the-day.

1.10. The actions of the SO have the potential to distort the market in both gas and electricity. In gas, an issue was recognised that the SO could avoid taking balancing actions by using linepack, the natural storage available in the pipeline system. This was leading to misallocation of balancing costs between days. To address this problem, financial incentives were placed on the SO in 2001 to minimise day-on-day linepack variations (and also to trade close to the market price to avoid taking sudden balancing actions). Although this helped to address the cost misallocation cost problem, it now means that a valuable balancing resource, linepack, may be being underutilised. Proper pricing of linepack would allow it to be utilised without distortion of cash-out prices.

1.11. In electricity, the SO is incentivised to minimise balancing costs but unlike in gas has no incentive surrounding minimising its impact on the market. There are occasions when the SO can cause an energy imbalance, for example where it has taken a forward action to resolve an anticipated transmission constraint. In this situation, it may need to take a corrective balancing action even when the rest of the market is perfectly balanced, thus potentially distorting cash-out prices.

1.12. In both markets, but particularly in electricity, our assessment noted that the market arrangements are complex. It is very difficult for large players, let alone small players, to predict accurately whether the electricity system will be short or long and hence be able to estimate their exposure to cash-out. Larger players can manage these exposures through the integrated businesses and superior risk management capabilities. Small players are at a large disadvantage in this respect, which may create a barrier to entry.

1.13. Moving forward, the rules in electricity will need to deal with an evolving generation mix with an anticipated rapid expansion of variable renewables. This is likely to lead to more volatile prices (with greater extremes of high and low prices), require greater deployment of reserve and lead to more frequent occurrence of transmission constraints. Renewables that receive subsidies based on output are likely to bid negatively to keep generating which may lead to very high constraint costs and distortions in cash-out prices, which in turn could undermine future investment in renewables. Whether the current balancing arrangements will lead to the most efficient dispatch of the system will require further investigation, and in particular whether it is right to continue to seek to minimise the role of the SO when there may be greater efficiencies in it taking more responsibility for balancing the wind portfolio.

Box 7
Case Study: The Netherlands: Single marginal cash-out

In the Netherlands, TenneT (the SO) introduced a market-based balancing mechanism for electricity in 2001, with the aim of getting the 'right' imbalance price in real-time through an open market. TenneT is responsible for balancing the system, and participants receive the marginal clearing price in the markets for both control and reserve power. This contrasts with the GB cash-out arrangements where participants are 'paid-as-bid', the imbalance price is based on a volume-weighted average of bids/offers (a 'chunky marginal price'), and there is a dual cash-out price to encourage market players to balance in advance.

In the Netherlands there is no fixed incentive component in the imbalance price. However, a weekly flexibility mechanism allows for an incentive component to be added if the pre-defined 'performance level' is not achieved, creating a dual cash-out price. The performance level defines thresholds for an acceptable level of imbalance over a weekly period, and is deemed to have been achieved if both of the following conditions are met:

1. the number of inadvertent exchanges over five minutes that are greater than 300MW and less than -300MW is less than 40; and
2. the weekly average of inadvertent exchanges over five minutes is greater than -20MW and less than 20MW.

The weekly incentive component started at maximum value or around €11/MWh in 2001, but was promptly set to zero and has generally remained there since 2003, indicating that the level of system imbalance has rarely exceeded the thresholds defined by TenneT over this period. Although generators can potentially achieve substantial premiums by 'spilling' power into the balancing market (particularly at times of system tightness), only 1.5%–3.5% of power is traded through this mechanism.

One of the key differences with the GB cash-out arrangements is that TenneT takes action at the day-ahead stage to resolve transmission constraints and offset the associated energy imbalances, and these actions are explicitly excluded from the imbalance price calculation. This allows for a marginal 'energy only' imbalance price to be calculated. For this day-ahead isolation of system actions to be effective, TenneT must be able to forecast transmission constraints accurately at the day-ahead stage and parties must seek approval to change their physical positions within-day. This may become difficult as more wind generation comes onto the system.

Having resolved constraints day-ahead, TenneT then uses both the balancing and reserve markets to resolve energy imbalances in real-time, by accepting bids and offers in price order. In each 15-minute settlement period, a System Buy Price (SBP) is set based on the marginal offer price, and/or a System Sell Price (SSP) is set based on the marginal bid price from accepted actions from both the reserve and balancing markets. It is possible for an SBP and SSP to be set in the same period if balancing actions have been taken in both directions, but in most periods there is either a single marginal SBP (when the system is short) or a single marginal SSP (when the system is long).

One of the potential drawbacks of the day-ahead approach in the Netherlands is that as participants in the reserve market do not know at the day-ahead stage whether they will be dispatched for one or multiple 15-minute periods, they must internalise all their dynamic costs (start-up, ramping, etc.) into a single 15-minute bid/offer. Relative to a more continuous within-day balancing approach such as that adopted in GB, this can create higher than necessary imbalance prices, sub-optimal dispatch, or both. TenneT is currently working on developing block-bids in the imbalance mechanism to help resolve this issue.

Although it is difficult to isolate the impact of any particular policy, the marginal approach to balancing adopted in the Netherlands may have contributed to higher forward prices. An analysis of the Dutch wholesale markets undertaken in 2008 by the Office of Energy Regulation (Energiekamer) indicated that prices in OTC forward markets between 2005 and 2007 were generally higher in the Netherlands relative to those in Germany and France (which both operate ‘paid-as-bid’ balancing mechanisms).

In 2008 Energiekamer recommended the introduction of a similar market-based balancing mechanism for gas, which it considers will allow market players to more efficiently manage their imbalances and therefore bring down gas costs for electricity producers.

Appendix 4 - Existing policy initiatives

1.1. The Government is bringing forward a range of environmental programmes to address areas such as household-scale energy efficiency, heating and generation. All of our packages assume that these schemes would remain in place. The schemes are described below.

Carbon Emissions Reduction Target (CERT)

1.2. The CERT, a Government scheme administered by Ofgem E-Serve, is an obligation on domestic energy suppliers to deliver a reduction in carbon emissions. Suppliers can deliver this through a range of energy-saving activities such as insulation, low energy lighting, advice and visual display units. This scheme levies a charge on the supplier on a per-customer basis.

1.3. The scheme, which currently runs from 2008-2011, will deliver lifetime savings of 185MtCO_2. The Government is currently consulting on extending the scheme to December 2012, increasing the lifetime savings to 293MtCO_2. The success of the scheme also implies a reduction in demand both in terms of greater efficiency and in terms of a premium on bills which should further encourage demand reduction.

1.4. The CERT is currently the Government's primary policy for delivering its 2015 target of insulating all domestic lofts and cavity walls where practicable. The successor scheme set out in the Household Energy Management Strategy is expected to be announced shortly. This will take effect from 2013, and begin to address higher-cost measures such as solid wall insulation, and renewable and low carbon heat, particularly for hard-to-treat homes.

Feed-in Tariff (FIT)

1.5. The FIT is a Government incentive, to be administered by Ofgem E-Serve from April 2010. It will apply to small-scale low-carbon electricity generation, up to a maximum limit of 5MW capacity - 50 kW in the case of fossil fuelled CHP. The FITs will be introduced through changes to electricity distribution and supply licences. The Government projects that generators supported by the FIT will deliver around 2% of UK final electricity consumption by 2020 (around 8TWh/yr). The tariff rates were published on 1 February 2010.

Renewable Heat Incentive (RHI)

1.6. The RHI, a Government scheme to be implemented by Ofgem E-Serve from April 2011, will provide an incentive payment to renewable heat generators to encourage the implementation of renewable heating schemes at domestic and community level. Eligible renewable heat will include biomass, biogas, solar thermal and heat pumps. The Government published further details on 1 February 2010. The Government projects that this will provide around 12% of UK final heat demand by 2020 (around 80TWh/year).

1.7. We expect that initial take-up of renewable heating would be greatest in off-gas areas to displace more expensive heating fuels such as electricity, oil, LPG and coal, which are also typically more carbon intensive. Therefore early take-up may reduce carbon emissions and possibly electricity usage, but have less impact on gas demand. However, the RHI could also begin to displace gas heating, both in terms of individual gas boilers and also through development of and conversion to renewable heat in district and community heat networks.

Carbon Reduction Commitment Energy Efficiency Scheme (CRC EES)

1.8. The CRC Energy Efficiency Scheme (formerly known as the Carbon Reduction Commitment) is the UK's mandatory climate change and energy saving scheme, due to start in April 2010. The Environment Agency will administer this cap-and-trade scheme for large non-energy intensive businesses not captured by the EU ETS or CCAs, whose half-hourly electricity consumption is greater than 6000MWh in the qualifying year. Following an introductory phase, a capped phase will begin in April 2013, leading to a reduction in energy demand amongst scheme participants.

Community Energy Saving Programme (CESP)

1.9. The CESP is an obligation on energy suppliers and certain power generators to deliver lifetime savings of 3.9MtCO_2. The obligated parties will deliver this reduction by installing carbon abatement measures in homes, which will be targeted at low income households. Eligible measures include insulation and other methods of improving the thermal efficiency of buildings, as well as replacement of inefficient heat sources (G-rated gas boilers, oil and coal heating, electric heating) with condensing boilers and renewable or low carbon heat devices. It is at the discretion of the obligated parties to determine how they will fulfil their obligations, so the exact effect on electricity and gas demand is not clear.

CCS demonstration projects regulatory framework and financial support

1.10. The Government consulted in June 2009 on its future policy for the development of Carbon Capture and Storage technology (CCS). It published responses in November alongside a document which set out its position following the consultation. It has committed to funds being provided to at least two and up to four demonstration projects which would allow deployment of a mixture of CCS technologies. It also made the commitment that all new coal plant must demonstrate CCS technology and that from 2020 all new coal plant must fully capture and store all carbon emissions (with existing stations to have CCS capability retro-fitted by 2025).

1.11. Funding for the demonstration projects will come from a levy on electricity suppliers, with the costs probably passed through to consumers. Arrangements for the levy form part of the current Energy Bill announced in the Queen's Speech in November. Details on the selection of plant to demonstrate the new technology and qualify for funding for the other proposed projects have yet to be fully established.

Appendix 5 - Summary of assessment of policy packages

Confidence of achieving supply security

Package	Positives	Negatives
Targeted Reforms	**Minimum carbon price** ▪ Removes key uncertainty for low carbon investment which may bring it forward (lowers cost of capital) **Improved price signals** ▪ Should encourage players to increase contract cover which should in turn strengthen investment signals ▪ Should attract gas imports at times of system stress ▪ Should encourage demand side response **DSR measures** ▪ Should benefit security of supply by identifying consumers willing to reduce demand thus reducing risk of curtailment for other customers	**Minimum carbon price** ▪ May lead to earlier closures of unabated coal plant
Enhanced Obligations	**As above plus:** **Supplier obligations** ▪ Would further encourage suppliers to increase contract cover over a longer period ▪ Would make individual players more accountable for security of supply **SO obligations** ▪ Would provide additional insurance in case of gas emergency ▪ Would provide longer term signal for flexible generation capacity **Gas-fired generator back-up fuel obligation** ▪ Would reduce power sector gas demand at times of system stress	**As above plus:** **SO obligations** ▪ May reduce incentives on suppliers to make their own arrangements to cover peaks and insure against emergencies **Gas-fired generator back-up fuel obligation** ▪ May lead to plant closures and/or deter investment where plant find it difficult to comply

Package	Positives	Negatives
Enhanced Obligations with Renewables Tenders	**As above plus:** **Capacity tenders for renewables** ▪ Increased confidence surrounding amount of renewables build which would increase confidence surrounding other generation investment decisions	**As above**
Capacity Tenders	**Improved price signals, DSR measures** ▪ As Targeted Reforms **Capacity tenders** ▪ Increased confidence around future capacity margins - possible lower cost of capital ▪ Increased confidence surrounding future storage build	**Improved price signals, DSR measures** ▪ As Targeted Reforms **Capacity tenders** ▪ Risk of under-forecasting required volumes ▪ Risk of investment hiatus while new policy is being implemented
Central Energy Buyer	**Central energy buyer** ▪ Increased confidence around future capacity margins ▪ Increased confidence surrounding future storage build ▪ Increased confidence surrounding future gas and fuel supply	**Capacity tenders** ▪ Risk of central energy buyer under-valuing diversity ▪ Risk of investment hiatus while new policy is being implemented

Confidence of achieving 2020 carbon targets

Package	Positives	Negatives
Targeted Reforms	**Minimum carbon price** ▪ Removes key uncertainty for low carbon investment which may bring it forward (lowers cost of capital): main impact on nuclear, some impact on renewables and CCS but already covered by other subsidies ▪ Encourages coal to gas switching on short run basis reducing domestic emissions although no impact on meeting overall EU emissions since covered by EU ETS **DSR measures** ▪ Encourages flexibility from the demand side reducing the requirement for high emitting thermal capacity	
Enhanced Obligations	**As above**	
Enhanced Obligations with Renewables Tenders	**As above plus:** **Capacity tenders for renewables** ▪ Increased confidence surrounding amount of renewables build	**Capacity tenders for renewables** ▪ Risk of investment hiatus while new policy being implemented ▪ Risk that successful tenderers do not develop projects, particularly where wholesale prices subsequently fall (unless some form of revenue stabilisation included)
Capacity Tenders	**As above plus:** **Capacity tenders** ▪ Increased confidence surrounding amount of low carbon build (including renewables)	**Capacity tenders** ▪ Risk of investment hiatus while new policy is being implemented ▪ Risk that successful tenderers do not develop projects, particularly where wholesale prices subsequently fall (unless

Package	Positives	Negatives
		some form of revenue stabilisation included)
Central Energy Buyer	**Central energy buyer** ▪ Increased confidence surrounding future generation mix and hence emissions intensity	

Confidence of achieving 2020 renewables targets

Package	Positives	Negatives
Targeted Reforms	**Minimum carbon price** ▪ Some impact in reducing risk for renewables but effect likely to be small given RO/FIT subsidies **DSR measures** ▪ Greater response from demand side allows more variable renewables to be accommodated on the system	**Improved price signals** ▪ Sharper price signals might be detrimental to variable renewables since they would increase balancing risk
Enhanced Obligations	**As above plus:** **Centralised renewables market** ▪ Reduces balancing risk for renewables and provides liquid market for their output – by reducing risk should bring forward investment	
Enhanced Obligations with Renewables Tenders	**As above plus:** **Capacity tenders for renewables** ▪ Increased confidence surrounding amount of renewables build	**As above plus:** **Capacity tenders for renewables** ▪ Risk of investment hiatus while new policy being implemented ▪ Risk that successful tenderers do not develop projects, particularly where wholesale prices subsequently fall (unless some form of revenue stabilisation included)
Capacity Tenders	**As above**	**As above**
Central Energy Buyer	**Central energy buyer** Required volume of renewables contracted by central entity	

Risk of prices being greater than necessary

Package	Positives	Negatives
Targeted Reforms	**Minimum carbon price** ▪ By removing carbon price uncertainty it should reduce cost of capital for low carbon technologies meaning prices can be lower to attract investment **Improved price signals/DSR measures** ▪ Should lead to more efficient outcome if market is working effectively, particularly where demand side is activated since less investment required for same level of supply security	**Minimum carbon price** ▪ May increase costs to consumers if minimum price turns out to be higher than EUA price with detrimental impacts to the economy ▪ May lead to existing renewables being over-rewarded where RO bands previously set on expectations of carbon prices lower than minimum price ▪ May lead to inefficient dispatch decisions e.g. gas displacing coal when overall impact on EU emissions remains unchanged **Improved price signals** ▪ Could lead to very high prices with impacts on consumers if investors and demand side do not or cannot react to sharper price signals
Enhanced Obligations	**As above plus:** **Centralised renewables market** ▪ May lead to more efficient dispatch outcome ▪ Possible lower subsidies required for renewables if risk materially reduced	**As above plus:** **Centralised renewables market** ▪ Risk that true cost of managing renewables variability not revealed **Supplier obligations** ▪ May lead to collective overprovision of supplies/capacity with increased costs to customers ▪ Obligations may disadvantage smaller players and reduce competition **SO obligations** ▪ SO may over provide or not procure efficiently **CCGT back-up fuel obligation** ▪ Back-up capability may be more expensive than other

Package	Positives	Negatives
		options e.g. more storage/LNG supplies
Enhanced Obligations with Renewables Tenders	**As above plus:** **Capacity tenders for renewables** ▪ Competition through tenders should reduce overall size of subsidy and provide better value for consumers (but requires supply of renewables projects to exceed tendered volumes) ▪ May reduce cost of capital (although large scale renewables still exposed to wholesale electricity revenue risk) ▪ Opportunity to include revenue stabilisation to reduce risk further and provide better value for consumers ▪ Co-ordinated network expansion may reduce risk of asset stranding	**As above plus:** **Capacity tenders for renewables** ▪ Risk that volumes and types of renewables chosen are not the most 'cost effective' ▪ Risk that penalties for non-delivery needed to ensure projects get built could drive up the tender prices reducing value for consumers
Capacity Tenders	**Capacity tenders** ▪ More confidence over capacity margins and amounts of storage reduces the risk of high prices for consumers ▪ Competition through tenders should reduce overall size of subsidy and provide better value for consumers ▪ May reduce cost of capital particularly where revenue stabilisation included ▪ Co-ordinated network expansion may reduce risk of asset stranding ▪ No minimum carbon price that might disadvantage GB customers and distort dispatch signals	**Capacity tenders** ▪ Risk that volumes and types of generation capacity and storage are not the most 'cost effective' ▪ Risk of getting volume wrong increases the longer the duration of the capacity tender ▪ Risk that penalties for non-delivery needed to ensure projects get built could drive up the tender prices reducing value for consumers
Central Energy Buyer	**Central energy buyer** ▪ Greater revenue certainty for investors reduced cost of capital	**Central energy buyer** ▪ Risk that investment choices are not the most 'cost effective'

Package	Positives	Negatives
	▪ Greater price certainty for customers depending on how price risks are managed by Central Energy Buyer	▪ Risk of getting volume wrong ▪ Risk that Central Energy Buyer's "hedging strategy" is wrong and disadvantages customers ▪ Possible negative impact on supply competition ▪ Less wholesale market competition could lead to inefficiencies

Risk of dampening innovation

Package	Positives	Negatives
Targeted Reforms	**Improved price signals/DSR measures** ▪ Would promote innovation in demand side measures including smart technologies	
Enhanced Obligations	**As above**	**Supplier obligations** ▪ Could reduce innovation in supplier offerings to the extent new entry is deterred by onerous obligations
Enhanced Obligations with Renewables Tenders	**As above**	**As above plus:** **Capacity tenders for renewables** ▪ By choosing types of renewable capacity there is a risk that development of new technologies is reduced
Capacity Tenders		**As above plus:** **Capacity tenders** ▪ Risk that new technologies (particularly on the demand side) emerge subsequent to tenders and therefore do not get developed
Central Energy Buyer		**Central Energy Buyer** ▪ Less competition to drive future innovation

Appendix 6 - Experience of winter 2010 to date

1.1. Gas demand hit unprecedented levels on two consecutive days this January, reaching 454 mcm on 7 January and 465 mcm on 8 January. The record demand coincided with a range of problems in pipeline gas supply, most notably in reduced flows through Langeled, the pipeline that connects Norwegian Gas fields with the UK, due to technical issues at some of these fields. As a result of high demand coupled with supply problems, National Grid issued 4 Gas Balancing Alerts (GBAs) between the 4 and 11 January. The market responded well, with supplies from a number of sources, including the IUK interconnector, ramping up in response to the GBAs. In the electricity market, comfortable capacity margins, despite high demand and some unplanned outages, meant no system warnings were issued.

1.2. The market's response suggests that the overall GB market has a range of flexible sources upon which to call. Figure 13 below shows the GB gas supply composition just prior to and for the week 4-10 January 2010. The chart captures the changing composition of GB gas supply and illustrates how a variety of sources increased their supply in reaction to various events and increased demand. Each GBA was met by a different set of sources responding. The high demand on 4 January was met with increased LNG as well as some short range storage (SRS) and medium range storage (MRS). The GBA on 7 January saw the biggest responses come from the interconnector and MRS, whilst on 9 January LNG and MRS provided the biggest increase in their volumes.

Figure 13 - Gas supply composition, 30 Dec 2009 - 11 Jan 2010

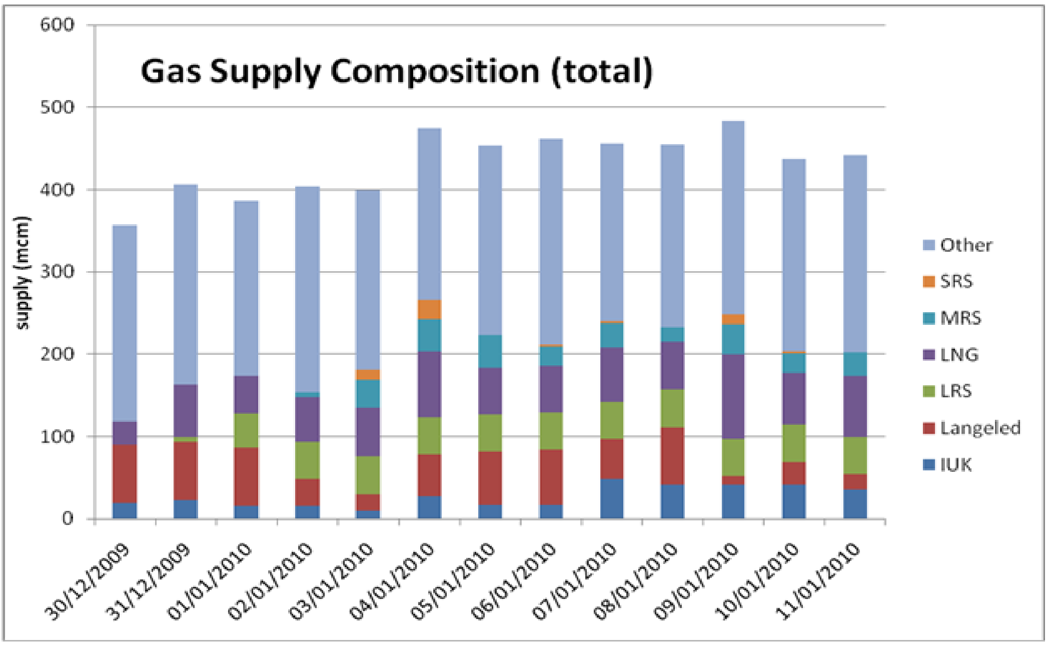
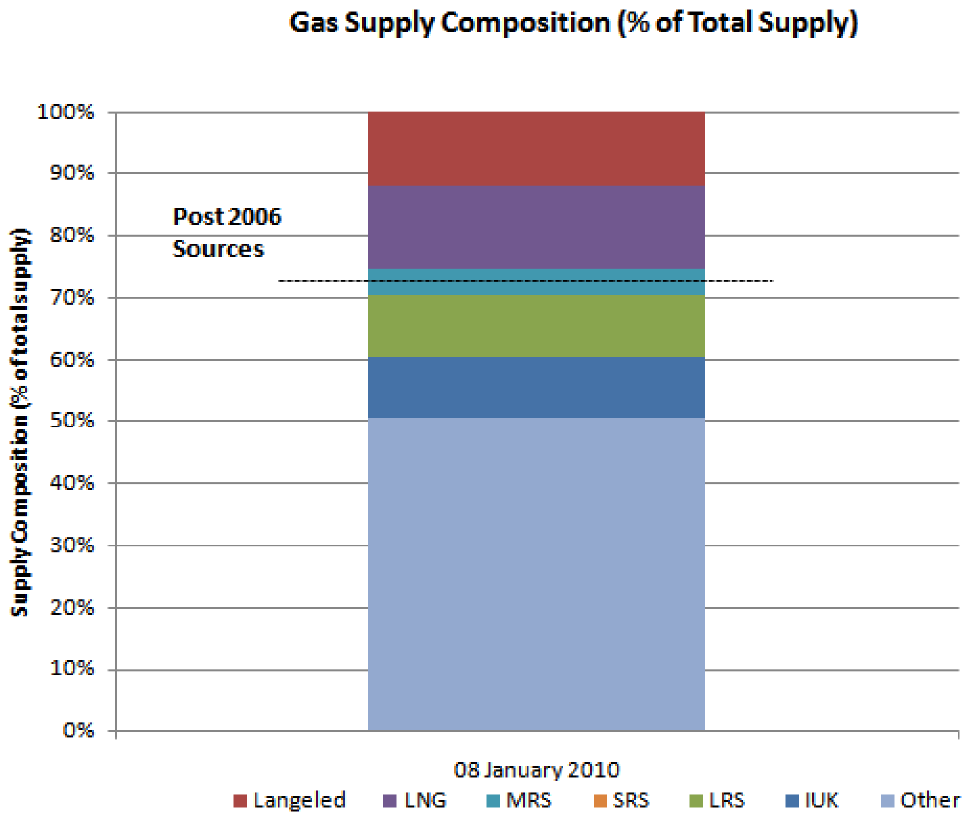


Figure 14 – Gas supply composition (% of total supply), 8 January 2010



1.3. The supply composition of gas to GB has changed markedly in just a few years as the market has responded to declining output from the UKCS. Figure 14 shows the composition of gas on the record demand day of 8 January 2010. Over 30% of this demand was served by sources of supply that were only completed in or after 2006; namely the Langeled pipeline[28] and the Milford Haven LNG facility[29] and the Aldbrough MRS facility[30]. This indicates that the current arrangements have to date delivered large scale investment.

[28] The Langeled pipeline, the largest in the world, began construction in 2003, with the first gas coming to UK In October 2006, and was fully completed in October 2007.
[29] The Dragon LNG Terminal at Milford Haven was originally conceived in 2004 and completed in 2007, with an estimated investment cost of £259 million. The second and final phase of the South Hook LNG terminal facility is due for completion in 2010.
[30] The first phase of the Aldborough gas storage facility was completed in July 2009, with capacity to hold 60 mcm. The forecasted end date for completion of the whole project is the end of 2012 when it is expected that the facility will hold 370 mcm.

1.4. The response of the current arrangements to the challenges of this winter to date needs to be seen in the context of a well supplied global gas market. Global gas demand has fallen due to the recession at the same time as supply has increased. In addition European gas stocks were high at the start of the cold spell. The within day price of UK gas only needed to rise modestly to attract flows from the IUK interconnector[31] and other sources. It should also be noted that, although we have seen days of record demand, the winter to date has not been particularly severe by historical standards. Of course several weeks of the winter remain, and the potential for more cold weather and supply shocks remain (in both gas and electricity markets). We therefore continue to monitor closely the markets, and can only make a full assessment once the winter is over.

1.5. While the global gas market is expected to remain well supplied for a few years, the Discovery scenarios highlighted the risks associated with increasing global gas demand and falling indigenous EU supply, particularly in the case of a severe winter. Previously, when GB was predominantly served by UKCS, supply problems related to a particular field and their potential impact would have generally been of a magnitude of less than 10 mcm per day. However, the experience so far this winter, and of the fire at Rough in 2006, suggests that future supply shocks could be of a significantly bigger magnitude. Individual facilities appear to have gained in strategic importance (given their large capacities) and their potential to affect total supply has thus increased.

[31] Prices reached £2 therm in March 2006 when the first ever GBA was issued. However, they struggled to hit the 70 p/th barrier during the week day GBAs, whilst NG bought at around £1 therm form the OCM for the weekend GBA.

Appendix 7 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[32]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[33].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[34];
- the need to contribute to the achievement of sustainable development; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[35]

[32] entitled "Gas Supply" and "Electricity Supply" respectively.
[33] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[34] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[35] The Authority may have regard to other descriptions of consumers.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- promote efficiency and economy on the part of those licensed[36] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- the effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[37] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[36] or persons authorised by exemptions to carry on any activity.
[37] Council Regulation (EC) 1/2003

Appendix 8 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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