Electricity System: Assessment of Future Challenges - Annex

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Executive Summary

1. The GB electricity system is facing significant challenges over the coming years and decades. The generation mix will evolve from a mix dominated by large power stations providing predictable and mostly flexible electricity to a mix with a significantly greater proportion of intermittent and less flexible generation. Demand profiles will also change. The level of electricity consumption will increase due to the expected electrification of heat and transport. Daily peaks and troughs are likely to become more extreme. The locational profile of demand will change as residential demand increases to power cars and heat homes. Increasingly, balancing technologies (electricity storage, demand side response (DSR) and interconnection) and smarter networks will be required to help match the supply and demand of electricity efficiently and cost-effectively.

2. Analysis undertaken for the Government by Imperial College and NERA Economic Consulting (NERA)[1] suggests that the value of balancing technologies starts to be realised in the 2020s and into the 2030s and beyond. The same analysis also shows that under the majority of likely generation and demand scenarios there is likely to be an important role for all balancing technologies. Making the most efficient use of these technologies will require the deployment of smarter distribution networks which allow the network companies to have more active control over power flows and act as enablers of balancing technologies like storage and DSR.

3. The need for a more flexible electricity system with more widespread deployment of balancing technologies and a smarter network appears to crystallise in the 2020s, nevertheless it is important that we ensure we are facilitating its development today. This means ensuring market arrangements are fit for purpose, supporting the development of key balancing technologies and promoting investment in smarter network infrastructure.

4. The market framework is changing as a result of the Electricity Market Reform (EMR) programme and other initiatives to improve the overall efficiency of the electricity market and it is difficult to predict accurately the strength of signals for flexibility under the new arrangements (although there is no evidence to suggest that the necessary signals will be not provided). The importance of promoting flexibility in the electricity system is explicitly recognised in the opportunity for both electricity storage and DSR to play a fair and equivalent role alongside generation in the Capacity Market proposed as part of EMR.

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[1] Imperial College and NERA Consulting, 2012, *Understanding the Balancing Challenge* , analysis commissioned by DECC to support this publication. Please see http://www.decc.gov.uk/en/content/cms/meeting_energy/network/strategy/strategy.aspx#Electricity_system_policy

5. Technology development is central to the successful evolution of a flexible electricity system - in terms of delivering key balancing activities (electricity storage and DSR in particular) and also in terms of helping new electricity infrastructure developments (such as electric vehicles) be sufficiently flexible to support DSR. There are a number of different dimensions where Government could help tackle barriers hindering technology development and deployment, ranging from standard technology development support, through understanding consumer engagement with new technologies to looking at how effective commercial arrangements could be developed.

6. There is already a considerable amount of work underway to promote the development of, and remove barriers to, smarter networks, notably in partnership with Ofgem and the Smart Grid Forum (an industry group). As well as the technical evolution of smarter networks there could be changes in the roles of, and interactions between, key players in the networks industry and it will be important to remove any barriers to the development of these new interactions and associated commercial frameworks.

7. Overall this paper demonstrates that balancing technologies, in conjunction with smarter networks, will have a key role to play in ensuring the supply of and demand for electricity match in a cost-effective way. There are multiple factors that will influence the actual trajectory of generation and demand so a full range of solutions will likely be deployed. There will continue to be a key role for Government in helping to ensure market frameworks and networks develop in a way that is fit for purpose, and in removing barriers to widespread deployment of balancing technologies.

Chapter 1: The GB Electricity System

1.1 Delivering secure energy on the way to a low carbon energy future, while minimising costs to consumers, is a key priority for the UK Government. We face unprecedented challenges to our energy system as we seek to transform the UK into a low carbon economy and meet our 15% renewable energy target by 2020 and our 80% carbon reduction target by 2050.

1.2 We expect much of this decarbonisation to come from the electrification of the heat and transport sectors coupled with a radical change in the electricity generation mix. Analysis published in the December 2011 Carbon Plan[2] suggests that the most cost effective paths to deliver the 2050 target require the electricity sector to be largely decarbonised during the 2030s. These changes will present challenges to the design and operation of the electricity system, particularly as we move into the 2020s and beyond.

1.3 The primary aim of the electricity system is to generate and transmit electricity according to where and when it is demanded. In order for the system to balance, supply of electricity must be equal to demand at all times. This is of fundamental importance to ensuring that demand can be met and the integrity of the system can be maintained. Ensuring that supply and demand are always in balance currently relies primarily on the availability of sufficient generation that is predictable, controllable and can be operated flexibly in order to react to fluctuations in demand and supply shocks. It also requires a fit for purpose network to ensure that electricity can be moved around the system efficiently and securely.

1.4 Achieving this in a cost effective and efficient way is central to the realisation of our energy, climate and growth objectives (see Box).

1.5 The major transformation to a new low carbon electricity system will also create pressures on the natural environment, land use, agriculture, landscape, water resources and quality, waste regulation and marine management. Risks from competing demand for resources, climate change, price volatility and interruptions to supply may have an effect on the on the supply of resources needed for low carbon energy technologies. It will therefore be important to ensure future energy technologies and infrastructure are deployed in a way that is resilient to environmental change and will not cause unnecessary harm to the natural environment, including the water and agricultural resources.

[2] The Carbon Plan: Delivering our low carbon future - http://www.decc.gov.uk/assets/decc/11/tackling-climate-change/carbon-plan/3702-the-carbon-plan-delivering-our-low-carbon-future.pdf

Secure energy supplies

The ability for supply to match demand at any given time is key to ensuring security of supply. Overall generation capacity is fundamental to achieving this but, given the challenge of delivering secure energy in a low carbon future, enhanced flexibility in the system that is able to react when intermittent generation is not available will increasingly be required. This means ensuring that we have the appropriate network capacity as well as other flexible solutions to enable the system to operate reliably, securely and be resilient to future climate impacts. It is also important to ensure that the system as a whole is robust to cope with large amounts of new types of generation (including wind power).

Reduce carbon emissions

Decarbonisation of the electricity system will require a large amount of new renewable or other low carbon generation technologies to be built in the coming decades so that we can reduce our carbon emissions. Renewable and low carbon generation technologies bring new challenges for balancing the electricity system. Flexibility in the system will be key to meeting the intermittency challenges associated with many renewable and low carbon generation technologies, while the network needs to ensure that all new generation can connect in line with its project timescales and be accommodated effectively within the electricity system.

Contribute to Growth and Minimise costs to the consumer

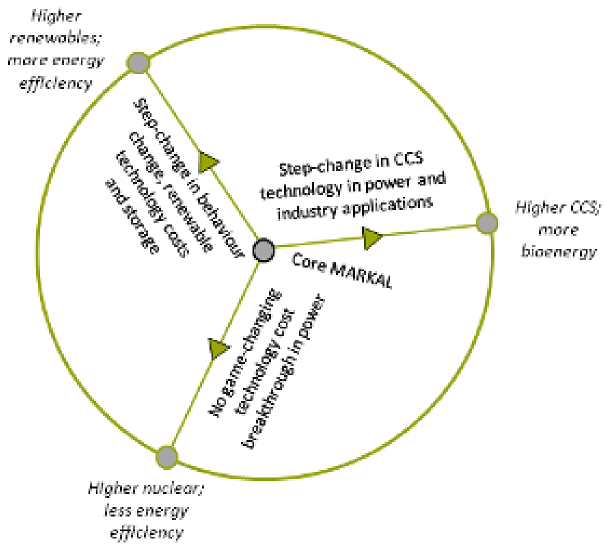
Investment certainty and costs are an important consideration in the development and operation of the electricity system. Over and under investment in generation and networks can both result in higher costs to the consumer and a negative impact on the system. It is essential that the right balance is struck between investing in generation, non-generation balancing technologies (i.e. storage, demand-side response and interconnection) and network assets. Efficient operation of the electricity system is also critical to maximising the efficient use of assets across the system. This might involve, for example, developing smarter networks to maximise their efficient use or using balancing technologies to shift peaks and reduce overall levels of generation and network investment required. Electricity consumers (individuals, businesses, the public sector) will have in the future greater opportunities to interact directly with the system through engaging in Demand Side Response (DSR) initiatives, for example Time of Use tariffs, which can both improve the efficiency of the electricity system and help minimise the impact on bills.

Electricity Supply

1.6 Whilst there is no certainty about the detail of the future electricity generation mix, the need to decarbonise whilst maintaining a diverse energy mix in the face of depleting North Sea fossil fuel resources and increasing world consumption means we can expect significant changes to the current mix. The Electricity Market Reforms being taken forward by the Government (set out in detail at Annex A) are designed to ensure that we have a framework in place that delivers sufficient levels of secure, low carbon electricity generation to meet our requirements, but will not deliver a specified generation mix.

1.7 To help with planning for the future, the Carbon Plan: Delivering our low carbon future[3] set out a number of 2050 future scenarios based on what the year 2050 might look like when the UK meets its carbon reduction targets. These include four different future generation mixes, which range from a cost-optimised 'core' scenario to three further 'futures', one with a high proportion of renewable generation, one with a high proportion of Carbon Capture and Storage and one with a high proportion of nuclear generation.

Figure 1: The Carbon Plan 2050 Futures[4]



1.8 Some elements of the future generation mix will be less predictable and less easy to flex compared to the current generation mix which relies primarily on fossil-fuelled generation that can respond relatively easily to changes in demand and supply shocks. Increasing

[3] December 2011 http://www.decc.gov.uk/en/content/cms/emissions/carbon_budgets/carbon_budgets.aspx

[4] The UK Government works in partnership with the Devolved Administrations in Northern Ireland, Scotland and Wales to deliver the targets set by the Climate Change Act 2008. While the administrations have a shared goal of reducing the impacts of climate change, policies on how to achieve this vary across the administrations – the Scottish Government, for example, is opposed to the development of new nuclear power stations in Scotland. It believes that renewables, fossil fuels with CCS and energy efficiency represent the best long-term solution to Scotland's energy security.

levels of renewables will bring a number of challenges – variability (wind, wave) and predictable but inflexible supply (tidal, solar). In addition, increasing levels of nuclear generation and fossil-fuelled generation with carbon capture and storage plants installed, means that there will be greater technical challenges to plant operating flexibly to adjust to demand fluctuations.

1.9 It is also likely that there will be more generation at the local level, which connects directly to the distribution network rather than the transmission network. This distributed generation includes microgeneration such as solar panels on people's homes, as well as larger scale projects at a community level such as combined heat & power (CHP) plants and small scale wind. From the perspective of the System Operator (SO), they will see more variable demand from the distribution network, as some local demand is serviced by local supply. This increases the potential for more frequent and/or pronounced fluctuations in demand for output from larger scale generation through the transmission network.

Electricity Demand

1.10 Electricity demand will also change in the future with, over the longer term, GDP growth, employment growth and population growth, combined with greater levels of electric vehicles and heat pumps, expected to drive increases in demand. The Carbon Plan 2050 scenarios also include possible demand futures for 2050, with varying levels of electrification of heat and transport and also of energy efficiency.

1.11 The rate and extent of uptake of heat pumps and electric vehicles will have a significant impact on overall demand levels as we move into the future. As with the future generation mix, there is a lot of uncertainty on future demand requirements and the trajectories to get that point. To help network companies with their forward planning, the Smart Grid Forum has developed indicative trajectories for the uptake of heat pumps and electric vehicles consistent with the fourth carbon budget scenarios and the strategic direction set by the Heat Strategy[5]. These trajectories suggest the annual demand from heat pumps could be between 23 TWh and 50 TWh and between 5 and 14 TWh for electric vehicles by 2030, rising to 30 to 67 TWh for electric vehicles in 2050[6]. The increase in electricity demand for heat pumps may however be mitigated through the recovery of excess and wasted heat for supply through heat networks, thereby reducing the overall demand for the electrification of heat.

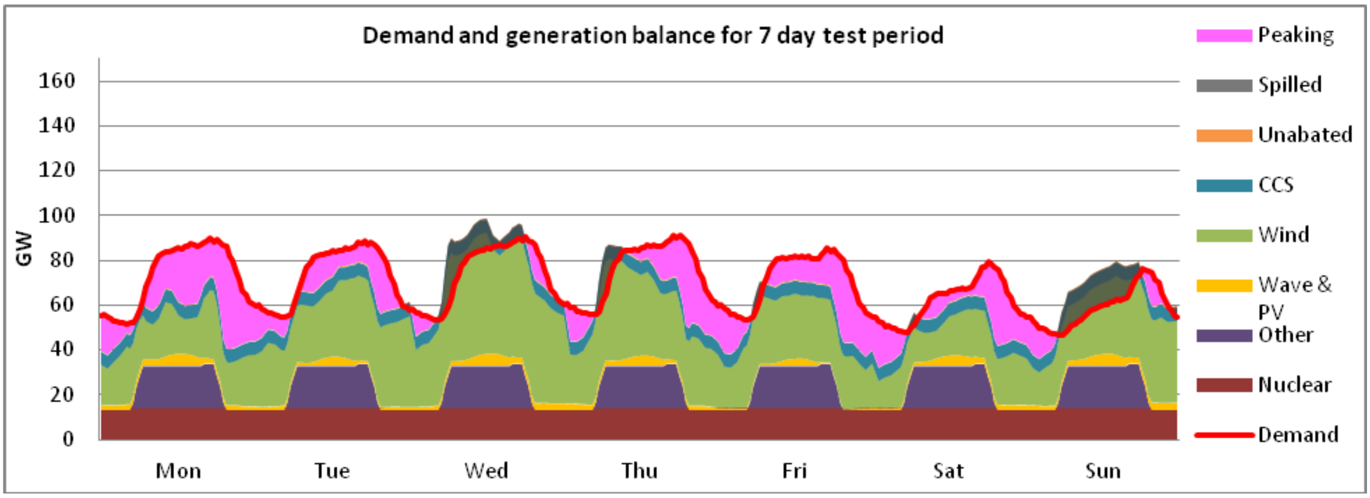
1.12 Clearly there is a lot of uncertainty about the levels of electricity demand almost 40 years away. Whilst energy efficiency measures and measures to reduce electricity use will offset some of this increase, overall levels of demand are still projected to rise 29% to 54% by 2050[7] over 2007 levels[8].

1.13 The pattern of demand will also change on both a daily and seasonal basis, with higher daily peaks and lower troughs resulting from changes to the way we use electricity (i.e. for charging cars or the widespread heating of homes). Increased electricity consumption in residential areas may also change the overall pattern of electricity demand across the

[5] The Future of Heating: A strategic framework for low carbon heat, March 2012 http://www.decc.gov.uk/en/content/cms/meeting_energy/heat_strategy/heat_strategy.aspx
[6] http://www.ofgem.gov.uk/Networks/SGF/Pages/SGF.aspx
[7] Based on scenarios used in *The Carbon Plan: Delivering our low carbon future, December 2011* http://www.decc.gov.uk/en/content/cms/emissions/carbon_budgets/carbon_budgets.aspx
[8] Noting that DECC's 2050 Pathways Analysis modelled scenarios where electricity demand in 2050 is higher and lower than this range.

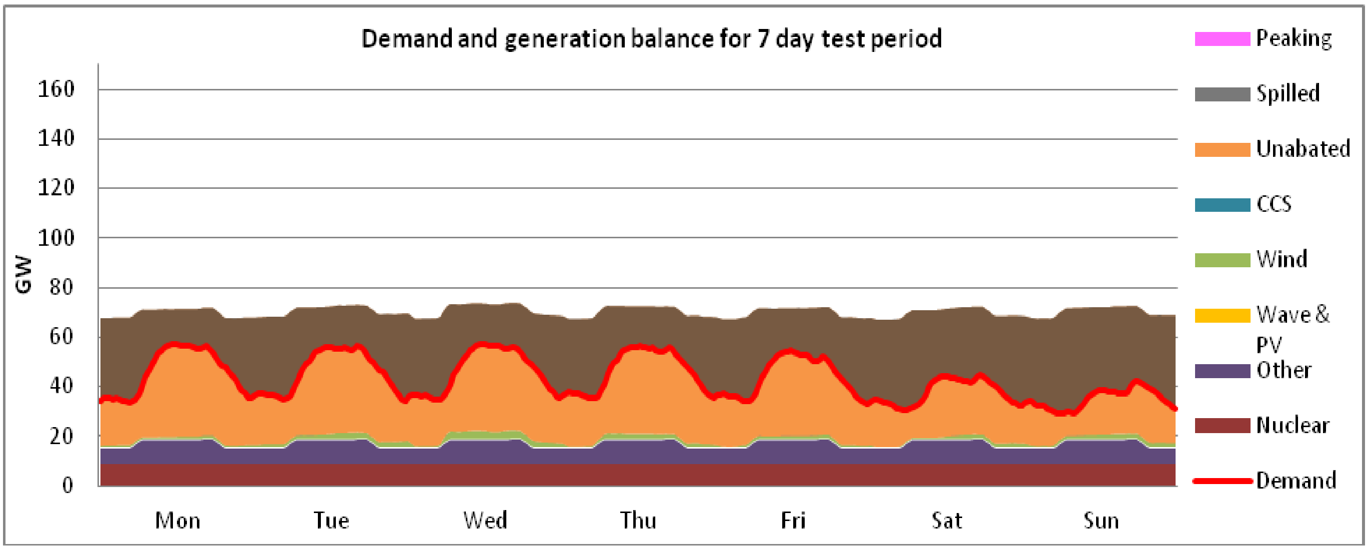
country with implications for electricity networks and levels of responsiveness required from generation.

Figure 2: An illustrative example of a potential 2050 demand profile (the red line) and generation mix, taken from the Carbon Plan 2050 future – higher renewables, more energy efficiency, on an average winter day.



This can be compared with the significantly more regular generation profile with slightly less emphasised, and lower, peaks in demand set out in the example profile below.

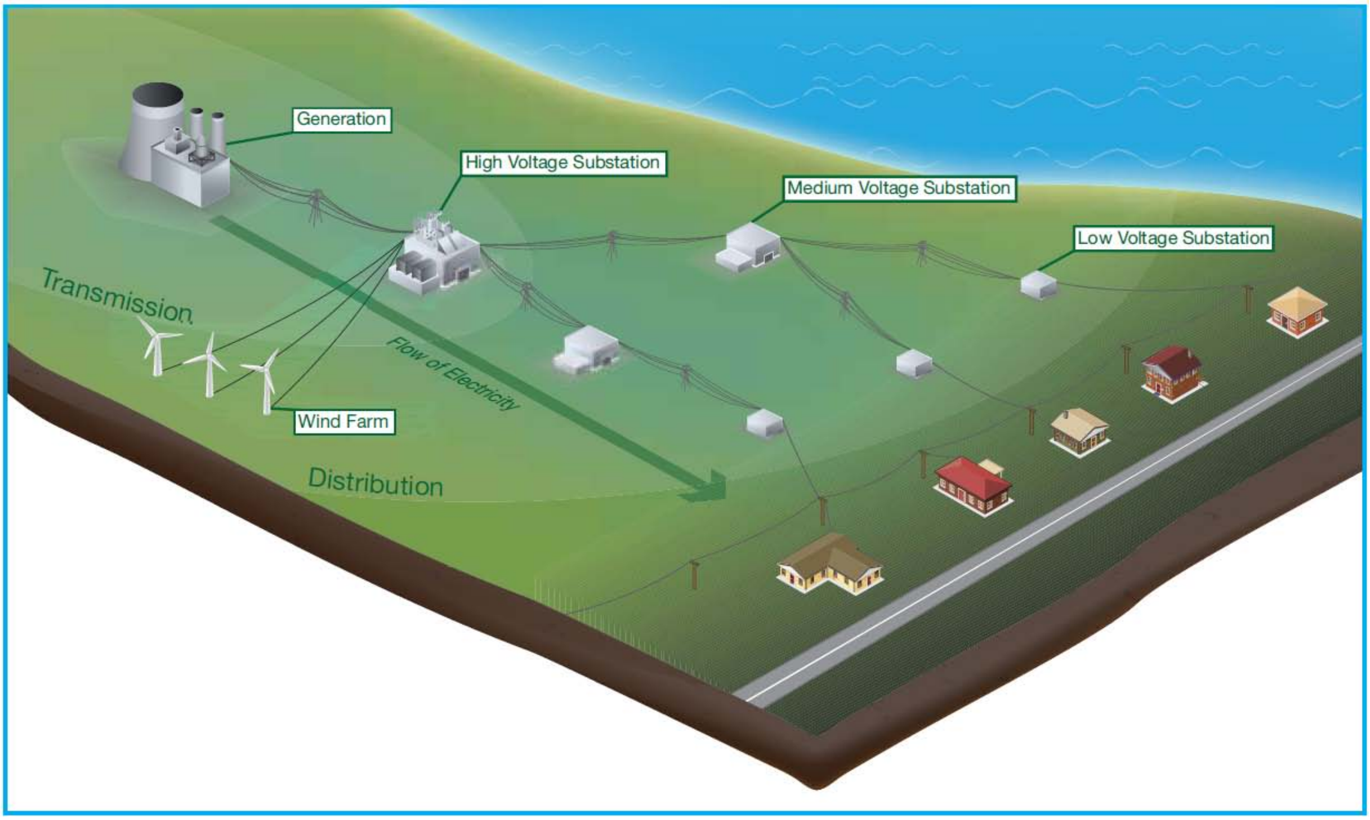
Figure 3: An example of the current demand profile (red line) and generation mix, on an average winter day.



Networks

1.14 Power stations are built by private companies under a liberal market and the electricity they produce is traded in bilateral trades or through power exchanges to energy suppliers, which are also private companies. Consumers buy their electricity from the suppliers and can also sell electricity to the suppliers in the case of surplus distributed generation. The electricity is transported via the GB electricity network, also known as the "grid".

Figure 4: electricity is mainly transported from big power stations to final users



1.15 The network we currently have has primarily evolved to channel electricity from a small number of big power stations to a large number of final users – see Figure 4 above. It has two distinct parts: the transmission network and a number of regional distribution networks.

1.16 The transmission network is the backbone of the grid and carries power at high voltages (between 275kV[9] and 400 kV) over long distances. Much of the transmission network (owned and built by National Grid Electricity Transmission in England and Wales, and Scottish Power and Scottish Hydro Electric Ltd in Scotland) is carried on the large pylons that are the most visible part of our electricity network. Over time we will have more transmission network underwater as the amount of offshore electricity generation increases. Interconnectors between GB and other countries feed into and transport from the transmission network. On a day-to-day basis, the transmission network is managed by the SO (although it contracts some of its tasks in Scotland to the Scottish Transmission Owners. Its role is to ensure the overall electricity system is secure, balanced, and efficient.

1.17 There are 14 regional distribution networks in Great Britain. In these distribution networks the voltage of electricity from the transmission network is reduced down through a series of transformers to the 230 volt supply that reaches most homes and businesses.

1.18 Changes in the generation mix and demand will provide challenges for the network infrastructure. For example, many of the new sources of electricity are further away from the existing transmission network, such as in the north of Scotland or even offshore. This will require new transmission network infrastructure to be built and existing infrastructure to be reinforced.

[9] In Scotland and offshore, voltages of 132kV and over are defined as transmission.

1.19 The expected longer term increase in electricity demand, together with an increase in distributed generation, will also impose greater demands on the distribution network (and require greater investment). As well as the need to build new networks, distribution networks will need to be smarter to make best use of assets and operate in a more complex environment including accommodating two-way flows of electricity, compared with one-way flows today.

1.20 Deciding where, when and on what scale new network infrastructure will be required is challenging given the levels of uncertainty of future generation and demand and long lead times for designing, planning and constructing network infrastructure. There will be additional complexity to the design of the network if the levels of non-generation technologies (electricity storage, DSR and interconnection) grow. The co-ordination of networks, their operation and strategic investment, will increasingly be required to ensure efficient development of onshore and offshore networks including interconnection.

Non-generation technologies in the electricity system

1.21 The expected changes in the future generation mix and level and profile of electricity demand will pose significant challenges for the electricity system as it is likely to be more difficult and expensive to match supply with demand through flexing of generation as is currently the way. This suggests that there is a greater role for non-generation solutions (more details on technical capability at Annex B) such as storage, DSR and interconnection, in combination with flexible generation plant, in order to balance the electricity system in the most cost effective, and efficient, way.

Electricity storage

1.22 Storage of electricity enables electricity which is generated at a point of low demand to be used at a time of high demand and allows the operator to capture the difference between prices at their peak and trough. Large scale storage ("bulk") is connected to the transmission system and tends to have relatively large power output and long periods over which that power can be provided. Storage systems can also operate on a smaller scale ("distributed") connected to the distribution network.

1.23 Electricity may also be turned into thermal energy and stored as heat, particularly at times when the electricity price is low or even negative.

Demand Side Response (DSR)

1.24 DSR is an active, short-term reduction/shifting in consumption of energy demand at a particular time, usually shifting demand away from periods where the cost of electricity is higher, to periods where the price is less. In this way DSR could reduce the total capacity needed on the system, reducing the need for peaking plant and network reinforcement.

Interconnection

1.25 Interconnection allows connected markets to import and export electricity according to the market prices on either side of the interconnector. This allows the GB market to connect to mainland Europe, Ireland and countries like Iceland and Norway via subsea cables. Increased amounts of interconnection have the potential to bring savings to the system where connected markets have different generation and/or demand profiles to trade. In such circumstances interconnection could result in generation capacity being dispatched more efficiently and reducing the total generation capacity required. Whether it is efficient to build a particular interconnector will depend on a number of factors, including the generation mix and demand profile on either side, length, relative costs, benefits and security implications compared with competing balancing options, and the allocation of benefits and costs to GB consumers.

The Purpose of this Paper

1.26 It is essential that the electricity system is prepared to deal with the future challenges around a more diverse, and perhaps intermittent, electricity generation portfolio combined with expected changes in demand profiles.

1.27 There are numerous scenarios for how generation will develop up to 2050, while the rate of electrification of heat, transport and industrial processes may follow a variety of different trajectories. Each combination is likely to have different implications for the levels of deployment of the generation and non-generation balancing technologies (storage, DSR, interconnection) required to match the supply of and demand for electricity.

1.28 We need to understand fully the implications of these challenges across representative scenarios and possible means of addressing them in order to determine whether there is a need for the Government to take action to ensure the electricity system can facilitate future low carbon generation and expected increases in electricity demand in the most secure and affordable way, with the most efficient use of assets.

1.29 The interaction between generation patterns, demand profiles and the balancing technologies required to match supply and demand makes it important to take a whole system approach to the issues involved. Traditional divisions between generation, demand and the networks that link them will become more blurred as the system becomes more integrated and roles and functions evolve.

1.30 This paper seeks to explore some of those challenges and set out the context within which these changes to supply and demand will be taking place. It assesses the technologies available to assist with meeting the challenge of matching the supply and demand of electricity, what role those technologies may play and whether there are any barriers that Government needs to tackle to allow them to achieve their potential.

1.31 Taking account of sustainability and climate resilience (the need to be able to cope with extreme weather conditions) requirements will also be important for the long term future of our electricity system. Government has actions in hand to address these issues (set out in Chapter 5) but they are not considered in detail in this paper.

Chapter 2: The GB Market And Networks Context

Introduction

2.1 The current electricity market has been developed to encourage the balancing of the supply and demand of electricity by providing incentives for, or requiring supportive behaviours from, participants and investment in generation capacity with the necessary characteristics.

2.2 A number of significant changes to the incentives within the GB and EU electricity markets over the course of this decade are planned, many stemming from the Government's Electricity Market Reform Programme. These are intended to drive certain necessary investment, such as decarbonisation of our electricity generation (whilst maintaining security of supply), but they may also impact on the signals in the market that encourage efficient balancing of supply and demand and investment in plant that can operate flexibly.

2.3 Alongside the market framework for electricity sits a regulatory framework (overseen by an independent regulator, Ofgem) for networks to ensure the right networks are built in the right place, at the right time, and that they provide secure, efficient transportation of electricity from where it is generated to where it is used.

2.4 This chapter sets out the current frameworks for the market and networks, together with the responsibilities of the key actors. It also looks at how the regulatory framework for networks is changing to help ensure networks continue to be secure and efficient and continue to support system balancing in the future.

The current electricity market

2.5 Balancing the electricity system is not something new. Actions have always been needed to ensure that electricity generation matches demand in real time. The markets within the electricity system have been developed to achieve this efficiently. The current market framework encourages market participants to contract sufficient generation to match their demand profile for each half hour throughout the day.

2.6 Participants are incentivised to balance their own positions by contracting to buy or sell electricity prior to gate closure (the point at which trading between generators and suppliers for a particular half hour period stops). The System Operator (SO) has responsibility for matching supply and demand in real time, after gate closure.

The role of the System Operator (SO) in balancing the system

The SO is responsible for real time balancing of supply and demand on the Great Britain electricity system (although wholesale energy market participants are incentivised to balance their own position over all half hour periods). Generators submit their final physical positions to the SO at gate closure (one hour before each half hourly settlement period) and the SO will plan for the system's balancing needs ahead of gate closure (i.e. to ensure it has a sufficient range of tools available). After gate closure, the SO takes any subsequent actions necessary to balance the system including the despatch of generation and/or demand. National Grid Electricity Transmission (NGET) is the SO for Great Britain (including offshore networks).

In its role as residual balancer, the SO procures services and takes various actions to maintain the frequency and voltage on the whole network within security and quality of supply standards. These balancing actions are taken to manage system events such as sudden generation loss; surges in demand, for example during TV commercial breaks; and network congestion (known as 'transmission constraints') where the capacity of the network between two locations can, on occasions, be insufficient to transmit electricity from where it is produced to where the demand for it is situated.

In part, the SO balances the system by accepting Bids and Offers in the Balancing Mechanism, where generators Offer to increase or Bid to reduce their output (and vice versa for demand) at prices submitted at gate closure. It also has a number of other tools in place (such as Short Term Operating Reserve (STOR) and fast reserve) in order to have sufficient reserve generation capacity and flexibility. The SO may also carry out trades in the market if it identifies a need ahead of time, or enact previously arranged bilateral deals (such as option contracts) which allow it to restrict the generator's output within an agreed notice period.

The actions the SO takes fall into two categories – system and energy balancing. In simple terms, energy imbalances result from the intended level of generation within the market being different to the forecast and actual level of demand, whereas system balancing actions (including those referred to in the previous paragraph) would be needed even if the market delivered a perfectly balanced position at gate closure. Energy balancing costs are attributed to the market participants who are out of balance through the imbalance settlement, otherwise known as "cash out", whereas the system balancing costs are shared proportionately between all market participants through SO charges.

The majority of this paper discusses a third type of balancing – market balancing. It looks at the tools and signals within the electricity market to balance supply and demand of electricity, although some of the discussion on technologies also looks at their role to provide services after gate closure to the SO.

Market Balancing

2.7 Suppliers contract in a variety of markets, ranging from forward markets a year or more ahead of need through to intra-day so that their contracted position meets projected demand. Variations in demand for electricity mean there is a requirement for a certain proportion of generation to be able to increase and decrease its output in order to meet fluctuations in demand. The market signals, set out below, have provided the system with both the necessary adequacy and flexibility to date within the framework provided by the British Electricity Trading Transmission Arrangements (BETTA).

2.8 Prices in the wholesale market serve to encourage participants to bring forward and make use of a diverse mix of generation types, with different short and long run costs and technical properties. As demand fluctuates, and pushes up the wholesale price, plants with higher short run marginal costs start to come on to the system. The same effect could be seen if demand remained static but output from lower short run marginal cost plant reduces (e.g. wind output falling). These short-term wholesale price changes encourage the availability and utilisation of plant that can operate flexibly in response to the price signals and therefore help to provide a supply and demand balance for each half hour period at gate closure.

2.9 The principal way in which participants are incentivised to balance their supply and demand position in the market is through cash out. Participants whose metered output or demand deviates from their contracted positions over a half hourly settlement period are exposed to cash out prices.

2.10 The cash out price can be volatile and has been designed in a way that puts those exposed to it at a financial disadvantage compared to contracting accurately within the market. Individual participants are charged a price for imbalances between their contracted and actual metered positions. When they contribute to the overall system imbalance they are charged in a way that reflects the costs incurred by the SO in balancing the system. When they counteract the overall system imbalance they are charged a representation of the (intraday) market price for electricity.

2.11 The wholesale price for electricity and cash out price provide longer term signals to invest in building and maintaining generation plant, electricity storage facilities and potentially Demand Side Response (DSR). In this way, cash out provides incentives for the market to determine an efficient mix between flexible and inflexible plant. The Government and Ofgem have expressed concerns with the ability of the existing arrangements to deliver secure supplies efficiently. Ofgem has announced their intention to launch a Significant Code Review (SCR) of cash out arrangements and the Government will legislate to introduce a Capacity Market in consideration of these concerns (see Annex C).

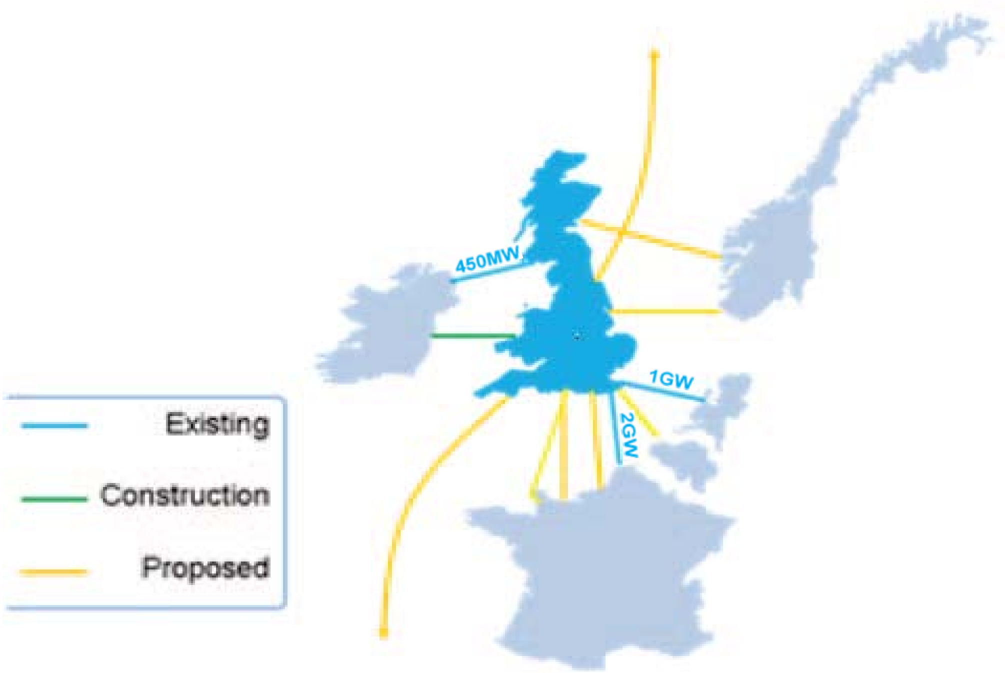
The role of interconnection in the market

2.12 Foreign parties can also participate in the GB market through interconnectors. Electricity trading across the interconnector can result in flows in either direction. Prices should reflect the underlying market conditions in the connected areas and if flows are efficient this will result in flows from low to high price areas.

2.13 Once notified of the direction and capacity of interconnector flow, the SO plans into its forecasts whether the interconnector will be acting as supply or demand and to account for any network constraints the flow may result in. Balancing with increasing amounts of interconnection is expected to be possible, although the swings in direction of flow and the speed at which that happens may bring new challenges. These challenges could be countered through existing or new commercial or regulatory arrangements, but the level of interconnection optimal for GB is likely to be influenced by a number of factors including Europe's future generation mix and level of flexibility, and decisions regarding the level of GB-located generation required to maintain security of supply. Interconnection is discussed in more detail in Chapter 3.

Case Study: Existing and Planned GB Interconnectors

Trading of energy between countries is not new. The GB electricity network is connected to the systems in France, Northern Ireland and the Netherlands through 'interconnectors', with others under construction or planned (shown in the figure below). Britain already imports and exports electricity and in 2011, exports and imports accounted for around 3-4TWh of the electricity supplied.



Balancing Services

2.14 As described in the box above, the SO has a role as a residual balancer and takes a holistic view of the network issues and most cost efficient way to balance the system in real time.

2.15 The SO has a number of balancing services on which it can draw to help keep the system in balance in real time. It maintains an operating reserve to ensure it has sufficient flexible generation or demand available to balance out any under or over supply of generation. The requirements for the provision of reserve include being able to respond within four hours and generate for two hours with STOR, through to fast reserve which needs to respond within two minutes and sustain output for 15 minutes. More detail on the range of balancing services is included in Annex B and on National Grid's website.

2.16 The SO also contracts for other system services such as Frequency Response (to manage the system frequency which is continuously changing, depending on the balance of demand and total generation in real time). The two types of Frequency Response are known as Dynamic and Non-Dynamic. Dynamic Frequency Response is where service providers continuously adapt to routine real time variations on the system by moderating output or consumption automatically, Non-Dynamic Frequency Response is usually a discrete service, triggered at a defined frequency threshold, and providers are required to either change consumption or output within seconds to address the frequency issue.

2.17 There is potential for challenges to arise in controlling frequency with the likely technical properties of future generation mixes and the SO is looking at a range of possible solutions. These include techniques to limit instantaneous frequency changes, optimising the proportion of thermal and renewable generation on the system at any one time, improving generator's frequency control capability and increasing frequency resilience.

2.18 Depending on the nature of the service provided, Balancing Service Providers receive an availability payment, which requires them to be available at specified times, or a utilisation payment, which they receive when the service is utilised and sometimes both. For example, a STOR (Short Term Operating Reserve) contract usually provides an Availability Payment for generation made available for dispatch during certain periods of time (in the case of generation, this is compensation for limiting commercial output in order to be available for the SO's balancing needs), and a Utilisation Payment for electricity (or demand reduction) despatched by National Grid during the that period.

2.19 Investment in capacity specifically to participate in balancing services is not currently being seen in significant volumes. The short term nature of the contracts is potentially a barrier to investment in new plant suitable for these services. The longer term STOR contracts of 15 years that were available for a short time were considered by some to provide enough certainty to invest in new plant to participate in these services. The long term contracts were offered to fill a projected gap in provision and were suspended once the need had been met. These longer term contracts did serve to bring forward investment in new flexible plant specifically for participation in balancing services and remain a tool for the SO should they project a gap in provision in the future. They are, however, likely to be used cautiously as the longer term contracts will foreclose the market to new, potentially more efficient, and economic, technologies.

2.20 National Grid is subject to the SO incentive scheme, which is designed to encourage effective management of the costs of operating the system. Cost targets are set out for the SO with financial incentives for achieving them and penalties for missing them (see Annex C for more detail).

The future electricity market

2.21 The Government is in the process of implementing a number of changes to the electricity market framework in order to achieve our carbon reduction and security of supply objectives which will impact on the flexibility, predictability and location of generation. The Electricity Market Reform package addresses the need to decarbonise the electricity system at a rate commensurate with achieving Government's long term carbon targets through a Carbon Price Floor (CPF), Emissions Performance Standard (EPS) and Contracts for Difference (CfD), and seeks to ensure there is enough capacity on the system to meet demand through the introduction of a Capacity Market. The sustainability of any particular technology or mix of technologies will also be a factor in setting incentives for low carbon generation as set out in the Government's Electricity Market Reform. Before taking decisions on incentives, Government will be considering the overall impacts including on decarbonisation, security of electricity supply, sustainability and consumers

2.22 These measures will impact on the type, size, amount and location of generation capacity and they will also change the signals within the market for other actions such as providing flexible capacity to balance supply and demand.

2.23 More detail on the impact of Electricity Market Reform and other market framework proposals (cash out arrangements, SO Incentive, wholesale liquidity arrangements) that will impact on the future balancing of electricity supply and demand can be found in Annexes A and C.

Potential European developments under the Third Energy Package

2.24 Measures at the EU level to be adopted under the Third Energy Package[10] are likely to result in changes to the way the GB electricity system operates and interacts with the wider EU electricity market. Member States have committed to move to a single electricity market by 2014 using common trading arrangements ("the European Target Model") which should ensure that trading electricity across borders is as easy as trading within a country.

2.25 To give practical effect to this process, the Third Package empowered the European Network of Transmission System Operators for Electricity (ENTSO-E), a cross-EU group of transmission system operators, and the Agency for the Cooperation of Energy Regulators (ACER) representing the independent regulators from Member States, to develop a series of non-binding Framework Guidelines and European Network Codes. These Codes will be directly applicable in Member States and will ensure that national arrangements are mutually compatible. DECC's aim will be to agree Network Codes that maximise benefits and minimise costs for GB.

2.26 ACER is currently consulting on the draft Framework Guideline for Balancing covering electricity balancing across the EU. The objective is to ensure the integration, coordination and harmonisation of balancing regimes in order to facilitate electricity trading within the EU. One of the main aims of the Balancing Framework Guideline is to reduce the cost of balancing services through increased competition and liquidity, and potentially reduce the level of reserve needed as a result of increased sharing. ACER also see it as essential that the guidelines anticipate future developments such as increasing levels of intermittent generation and a more active role for consumers.

2.27 This Guideline along with the code on Capacity Allocation and Congestion Management (CACM), which includes market coupling (discussed below), could have significant implications for how the SO and the GB electricity system carries out and recovers the costs of balancing, depending on the detailed design of the code.

2.28 The CACM Code will also impact the current GB regime on interconnection to support the concept of market coupling. Market coupling aims to coordinate the flows across interconnectors to optimise the use of capacity, resulting in rational electricity flows to the higher priced markets. Such trading arrangements are already being used between the French, Dutch, German and Belgian markets (the Central West Europe or CWE region) and the Nordic region.

The current electricity network framework

2.29 As well as an effective market framework, the electricity system requires robust network infrastructure to ensure that electricity is supplied securely regardless of the generation mix and / or the locations of demand. The transmission network takes electricity from where it is supplied – both onshore and offshore – to demand centres. The distribution network then takes it to individual premises, and also connects small-scale, distributed generation.

2.30 There are a number of elements to the regulatory framework governing the development of the networks ensuring they are fit for purpose, cost effective, meet the needs of all users of the system and enable the system to be balanced.

2.31 In the same way as for the market framework, Government sets the overall policy and legislative framework for the networks, and Ofgem is responsible for implementing it to ensure that network infrastructure is built and operated to support our energy goals while protecting consumers. The SO manages the transmission network, while Transmission Owners (TOs) design, finance, construct and maintain their elements of the transmission network. At a local level, Distribution Network Operators (DNOs) have a similar development and maintenance role as TOs, but they are also responsible for operating their networks, albeit in a much more passive way than the SO currently.

[10] The term "Third Package" refers to a package of EU legislation on European electricity and gas markets that entered into force on 3 September 2009, see http://ec.europa.eu/energy/gas_electricity/legislation/third_legislative_package_en.htm

Roles and responsibilities in managing electricity networks

Government generally sets the overall policy within which networks are regulated, for example the need to ensure security of supply or to meet renewable energy targets. On occasions Government takes an active role. An example of this is the enduring ‘connect and manage’ regime established in 2010 to help ensure generators could connect in a timely manner and support the achievement of renewable energy targets. The regime allows generators to connect to the transmission network once the local works are complete without having to wait for wider network reinforcements to also be completed as previously.

Ofgem

Ofgem is the independent regulator. Its priority is to protect consumers which it does by promoting competition, wherever appropriate, and regulating the onshore monopoly network companies and the SO. It regulates these companies through price controls which set limits on the revenues to be recovered from users as well incentives to be efficient and to innovate. Ofgem sets licence conditions which users of the network have to abide by, monitors compliance and enforces the conditions where there have been breaches. It also approves or rejects changes to the industry governance codes and agreements.

System Operator (SO)

The SO for the Great Britain transmission network (including offshore) is National Grid. As well as its system balancing role set out earlier, the SO is responsible for managing the transmission network for example through making connection offers to generators and ensuring an efficient and coordinated network.

Transmission Owners (TOs)

The onshore assets of the GB transmission network are owned by three companies: National Grid Electricity Transmission (England & Wales), Scottish Power Transmission (Central and Southern Scotland) and Scottish Hydro Electric Transmission Ltd (Northern Scotland). TOs are responsible for designing, financing, constructing and maintaining their part of the network in a cost effective and timely manner. Offshore, companies are granted Offshore Transmission Owner (OFTO) licences through competitive tenders run by Ofgem to build (where a generators chooses not to do so itself), own and maintain connections of 132kV and above to offshore wind farms.

Distribution Network Operators (DNOs)

There are 14 regional distribution networks owned and operated by six DNOs. They are responsible for the design, financing, construction, operation and maintenance of the regional networks. To date, operation at a distribution level has been relatively passive compared with the SO role at the transmission level.

Future network framework

2.32 The network has a critical role in balancing the future supply and demand of electricity and the framework which governs it will need to develop in a way that facilitates this. Work is already underway in a number of areas to achieve this objective.

Network Price Control Reviews

2.33 As already highlighted, balancing the electricity system efficiently requires a fit for purpose network. The main regulatory tools for ensuring this happens onshore are the network price controls.

2.34 Responding to the future challenges to the network, Ofgem recently reformed its process for carrying out Price Control Reviews. Its new framework, RIIO (Revenue=Incentives+Innovation+Outputs) aims to ensure that network companies, transmission and distribution, play a full role in the move towards a sustainable low carbon and secure energy system while providing long term value for money for existing and future consumers. The next transmission price control (RIIO-T1) period is 2013-2021 and business planning by the three TOs is well advanced. Ofgem recently launched the next distribution price control (RIIO-ED1) for 2015-2023 and draft business plans for all 14 distribution networks are expected in May 2013.

2.35 RIIO-T1 supports the overall balancing of the system in a number of ways. First, it requires TOs to present business cases for a longer time period as well as look beyond that to consider the context out to 2050. Improved strategic investment planning should help ensure that the TOs deliver a sustainable network where and when it is required (e.g. areas with increasing generation but limited existing network infrastructure). Increased transmission capacity supports efficient system operation, including reducing the level of constraints (and constraint costs) across the network. Through tools such as the uncertainty mechanisms within RIIO-T1 TOs are able to respond to changing demands on the network, for example bringing forward investment plans should generation wish to connect more quickly than anticipated.

2.36 In addition, RIIO-T1 creates incentives for TOs to support the balancing and managing of the electricity system through, for example, information sharing with the SO on planned upgrades when the network will be unavailable.

2.37 RIIO-ED1 for distribution will also support system balancing. As with transmission, it will be important that the right network is delivered in the right places, including the potential need to support non-generation balancing tools. This might be through the use of smarter network technology to provide real-time information or connecting those tools to the network. The role of smarter networks in system balancing is outlined in detail in later chapters. A new, important consideration during the RIIO-ED1 process will be the active role that DNOs can play in helping to balance the system. Traditionally, distribution networks have had a very passive role in balancing the electricity system. This is expected to change in the future as we see increased levels of distributed generation and two-way electricity flows.

Network Coordination

2.38 Coordinated onshore and offshore networks can support balancing of the electricity system. In particular, as offshore generation and interconnection increases it will be important that, where appropriate, offshore transmission and interconnection assets can integrate effectively with the onshore network (and each other) to deliver a consolidated network that can balance generation with demand efficiently.

2.39 Currently the main role of the offshore network in balancing the system is ensuring that new offshore generation connects in a timely, well integrated and secure manner so the electricity supplied can contribute to meeting demand. The extension of the SO onshore role to the offshore network supports this.

2.40 Government and Ofgem have undertaken a joint Offshore Transmission Coordination Project, to consider whether additional measures are needed to maximise the opportunities for coordinated offshore networks development. This project, which concluded in March 2012, found that savings of £0.5bn-£3bn could potentially be realised from coordinated grid configurations. This is driven mainly from potential savings from offshore projects sharing larger but fewer transmission assets, but also includes the potential use of offshore assets to avoid the need for onshore network reinforcements. The project identified a number of potential barriers to the development of appropriate coordinated configurations, and has set in motion a number of measures to address them[11].

2.41 System planning arrangements and regulatory interfaces need to be sufficient to deliver an integrated transmission network across onshore, offshore and international boundaries. These are two of the six potential barriers to coordination identified by the Offshore Transmission Coordination Project. Ofgem's Integrated Transmission Planning and Regulation (ITPR)[12] project, initiated in March 2012, is currently evaluating these areas. It will explore what is needed with respect to system planning to deliver the future integrated transmission system onshore, offshore and cross-border, and will review how the relevant institutions and the incentives around them should evolve to support the new activity. The ITPR project will also consider how the onshore, offshore and interconnector regulatory regimes interact in the delivery of multiple-purpose transmission projects that could be a feature of the future energy system. This work is timely given recent project proposals to link offshore transmission into onshore reinforcements, link offshore transmission into interconnectors and potentially to import electricity from projects outside of UK waters.

2.42 National Grid has also identified the need for a consolidated view of longer term potential onshore and offshore network investment set against consistent scenarios. It is therefore undertaking a consultation on a new annual Electricity Ten Year Statement which would present potential onshore and offshore network reinforcements to meet a range of future energy scenarios[13].

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[11] http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/2012/Documents1/20120103_OTCP%20Conclusions%20Report.pdf

[12] http://www.ofgem.gov.uk/Europe/Documents1/ITPR%20Open%20Letter%20-%20Final%20version%20-%2023%20March%202012.pdf

[13] http://www.nationalgrid.com/NR/rdonlyres/1D781F6A-1E62-4744-BE73-B82D8CB0E3E3/52997/ETYSConsultationdocument.pdf

Network Connections

2.43 The connection of new generation capacity to the network is essential to ensure the system remains balanced and secure. The SO is obliged to provide a connection offer to any prospective generator seeking a connection to the network. Since the introduction of the enduring 'connect and manage' regime in 2010, 107 large generation projects – representing a total capacity of 29.7GW – have advanced their connection dates by an average of six years. This should provide further options for the SO to balance the system but will also require further network build. These revised connection dates are factored into the TO RIIO-T1 business plans for new investment referred to in the Network Price Controls section of this chapter. The need to reduce constraint costs is an important driver for new network investment, although, in the short term, such investment will increase constraint costs. This is due to generators being able to connect to the network before wider network reinforcements to accommodate them are completed and also the need for some outages on the existing network (to maintain network safety and security) while new reinforcements are integrated to it.

2.44 Distribution networks were designed to accommodate electricity flows in one direction - from centralised power stations to people's homes and businesses. The increased connection of decentralised (distributed) sources of energy such as solar, wind and electric vehicles to distribution networks will result in two way flows of electricity which pose new and significant challenges to networks. The scale and the nature of the challenge will vary according to location and type of connection involved. Smarter distribution networks will enable network operators to monitor the condition of distribution networks to assist with the timely the connection of distributed energy sources and the electrical impacts that will arise.

Network Charges

2.45 The costs of building and managing the networks are recovered through a series of charges applied to suppliers and generators and, ultimately, consumers. These charges are designed to provide incentives for efficient network design and management which can influence the scale and location of generation projects which in turn has implications for the electricity system, including balancing. For example, the clustering of generation in a particular area can lead to an increase/decrease in the cost of transmitting electricity from where it is produced to where it is consumed and/or lead to a reduction/increase in constraints on the network and the cost of balancing the system. Further detail can be found at Annex C.

2.46 Locational and time-of-use tariffs have recently been introduced for larger users of the distribution network, and further work is underway by the Smart Grid Forum (see chapter 4) to assess charging models that better reflect the impact users have on the distribution network. Smart meters and the smart monitoring of the condition of distribution networks, could be important in effectively targeting tariffs and location charges.

Network Innovation

2.47 Innovative solutions deployed on the networks can help balance the electricity system. For example, by increasing capacity from existing network assets or by exploring how the networks can facilitate DSR. A prime example of existing funding for network innovation is the £500m Low Carbon Networks Fund (LCNF) established by Ofgem. The Fund supports projects (details at Annex D) sponsored by the DNOs to try out new technology, operating and commercial arrangements. Under RIIO this fund under a new name (Network Innovation Competition) will also cover Electricity Transmission and Gas Transmission and Distribution. Eight different projects (details at Annex G) are also being funded under DECC's Low Carbon Investment Fund (£2.5 million) including storage and demand side management projects.

2.48 Under the RIIO-T1 framework Ofgem is also developing an Environmental Discretionary Reward (EDR) for the TOs. The EDR proposals contain mechanisms for measuring TO performance in deploying innovative solutions, including those relating to storage and DSR both of which have the potential to make a significant contribution to balancing the system.

Conclusion

Market framework

2.49 The physical system and wholesale market arrangements were designed when the market was dominated by flexible, predictable generation and low levels of interconnection. More intermittent generation, increased interconnection and a more integrated way to trade across borders with neighbouring countries will put stress on existing market arrangements and system operation unless they adapt.

2.50 The current market and regulatory framework contains a number of mechanisms to incentivise the secure and efficient running of the electricity system incorporating signals and incentives for where generation is built, how it operates and how it is transmitted and distributed to demand. Reviews are currently taking place on some of these, such as the intended Significant Code Review (SCR) of cash out arrangements, to result in their more efficient operation.

2.51 The signals within the system to invest and operate are changing as a result of new policies introduced to help meet carbon reduction commitments and ensure secure electricity supplies. These will also combine with changes as a result of increased interconnection and moves towards a more harmonised European electricity market. It is currently unclear whether or not the requirement for flexibility will continue to be communicated strongly enough in the market through price signals, or whether the signals for flexibility will be substantively dampened, or changed, by other interventions in the market.

2.52 As a result, the possible impacts of market developments on signals for the electricity system to bring forward sufficient flexibility in future and to develop in a way that allows the most cost effective and sustainable balancing of supply and demand will need to be kept under review.

Networks

2.53 The electricity networks and the regulatory frameworks that support them will need to adapt to support the electricity system of the future. Ofgem's new price control framework is an important early step. As well as providing the incentives to plan ahead and consider context out to 2050, it recognises the need for some degree of flexibility in the light of uncertainty, allowing network companies to review investment needs over time and more effective TO/DNO/SO interactions.

2.54 Other areas of work, such as that of Ofgem's ITPR project, the innovation schemes and National Grid's work on the new Electricity Ten Year Statement will also help ensure networks are ready to adapt to future challenges such as greater network integration and accommodation of new technologies.

Chapter 3: Impact Of The Generation Mix On Balancing The Electricity System

Introduction

3.1 The overall generation mix and the characteristics of the generation technologies involved have a significant impact on the functioning of the electricity system. As set out earlier, the generation mix will change radically over time – whilst fossil fuel generation currently plays the primary role in balancing the electricity system, low carbon generation technologies will increasingly play a larger role in meeting demand and will need to act as flexibly as possible.

3.2 In order for the electricity system to continue to match the supply of, and demand for, electricity as effectively as possible, balancing technologies (such as demand side response (DSR), storage and interconnection) are likely to play an increasingly important role over the longer term.

3.3 Analysis undertaken by Imperial College on behalf of the Government demonstrates that differences in the generation mix can have implications for the overall contribution of balancing technologies in order to balance the system cost effectively, with a continued role for gas in providing backup in 2050. The same analysis suggests that changes in the generation mix and changing demand profiles start to benefit from significant deployment of balancing technologies towards 2030 and beyond[14].

Current Flexibility

3.4 Currently flexibility in the system comes largely from the ramping up and down of core gas and other fossil fuel generation (‘thermal peaking plant’).

3.5 These sorts of thermal plants are capable of increasing and decreasing their output relatively easily and quickly, meaning that they can react promptly to fluctuations in demand. In addition, some smaller gas plants (Open Cycle Gas Turbines - OCGTs), oil and diesel generators are available to run more infrequently and ensure that there is enough capacity which can react at short notice to meet demand and ensure system stability. This makes up much of what the System Operator (SO) contracts as reserve services.

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[14] Imperial College and NERA Consulting , 2012, *Understanding the Balancing Challenge'* , analysis commissioned by DECC to support this publication. Please see http://www.decc.gov.uk/en/content/cms/meeting_energy/network/strategy/strategy.aspx#Electricity_system_policy

3.6 In 2010, installed transmission connected generation in GB was approximately 28GW of coal-only burning plant and over 30GW of gas-burning plant, out of a total capacity of about 83GW available to meet a peak demand in the region of 61GW. This generation mix will change in the future as a number of coal and oil fired plant, and nuclear plants are scheduled to come to the end of their working lives.

3.7 The Large Plant Combustion Directive[15] will lead to the closure of around 12GW of coal and oil-fired generation by the end of 2015 at the latest. The Industrial Emissions Directive[16] could also lead to further closures by 2023. In addition, according to current timetables, up to around 6GW of existing nuclear generating capacity is reaching the end of its regulated life by 2020 (although much of this nuclear capacity may be granted life extensions by the regulator if the economic and safety case is made). In total this means that up to around 18GW of capacity might close by 2020, with potential further closures by the end of 2023.

3.8 The Government expects to see a continued role for unabated gas. Over the next two decades, gas will continue to play a key role in our energy mix alongside other lower carbon electricity sources. We will need new gas generation capacity to ensure security of supply, and to balance the electricity system as more low carbon technology become available. In the longer-term the share of different electricity sources in our electricity mix is inevitably less certain. Dependent upon the pace of development and deployment of other generation technologies and the rate at which their costs reduce, gas generation may continue to play a crucial role in the provision of baseload capacity in the coming decades also acting as an effective policy ‘hedge’. It could play a significant ongoing role in a decarbonised electricity system with Carbon Capture and Storage (CCS).

3.9 By 2050, we may still need unabated gas for back-up and to meet some peak demand, while still meeting our carbon emission targets. The analysis estimates that some gas would be needed for all scenarios to balance supply and demand, in the range of 50 – 400 TWh in 2050 (including gas CCS), depending on the core generation mix. In the scenario with high gas generation (up to 400TWh), the majority is abated gas from CCS plant.

3.10 The Government is taking steps to ensure that gas generation continues to be built in the UK and has recently published a Call for Evidence on Gas Generation[17], with a Gas Generation Strategy to be published in the Autumn. The strategy will focus on the role of gas in the electricity market with the aim of ensuring that the UK continues to attract investment in gas generation in order to ensure energy security, meet the UK’s carbon reduction targets, and make the best use of the UK’s natural resources.

3.11 The gas network faces a number of major challenges in the coming years, particularly the transmission system which may need a significant upgrade in order to support a greater number of flexible gas supply contracts and maintain gas pressure in the network. Therefore we actively want to encourage investment in new gas infrastructure.

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[15] LCPD 2001/80/EC
http://eur-lex.europa.eu/LexUriServ/site/en/oj/2001/l_309/l_30920011127en00010021.pdf
[16] IED 2010/75/EU
http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:334:0017:0119:EN:PDF
[17] http://www.decc.gov.uk/en/content/cms/consultations/gas_elec_mkt/gas_elec_mkt.aspx

3.12 Investments in the gas network are regulated by Ofgem. Ofgem are currently reviewing business plans for investment in gas network upgrades, submitted by network operators for the next price control period (RIIO) which will run from April 2013-2021. In their plans National Grid have proposed uncertainty mechanisms to release increased investment for network flexibility. Ofgem are due to make their final decisions on allowed network expenditure in December 2012.

Low carbon generation (CCS, renewables and nuclear)

3.13 Low carbon technologies have considerable capacity to provide valuable services to the electricity system and the potential to operate flexibly within certain constraints.

3.14 Carbon capture and storage (CCS) although not yet commercially proven, has the technical potential to run flexibly whatever the fuel type (coal, gas or biomass). Based on existing knowledge, post-combustion CCS has good flexibility potential as the carbon capture plant could be added to existing fossil fuel generation plant (which provides the majority of system flexibility today). Other types of CCS design (such as those using pre-combustion capture or oxyfuel combustion) or those which involve new build generation plant might have the ability to offer some flexibility depending on possible design specifications. There is likely to be some additional cost in operating and designing a CCS plant to run flexibly. Research into the capability for CCS plant to run flexibly and overcome technical barriers such as flow rates of CO_2 is underway, as well as research to understand better the sustainability of CCS including issues such as water requirements. Government is also supporting a CCS Commercialisation Programme which will improve our understanding of the ability of generation plant with CCS to operate flexibly. There are also opportunities to understand how certain climate risks can be addressed with CCS (including water abstraction) through technology and spatial and catchment wide planning.

3.15 Renewable generation technologies could be operated more flexibly in the future, as long as the resource (e.g. wind, tide) is available. Excluding hydro and biomass, most renewable technologies have a different, natural supply profile dependent on the weather, time of day or season: For example, solar PV supply peaks at midday during the summer months, whereas tidal range power will peak at varying times according to the tides. Biomass is one renewable technology that can be operated independently of weather, season and time, both in dedicated plant and co-fired with fossil fuels, as long as sufficient fuel is stored.

3.16 Wind power is more difficult to predict, although there are some seasonal and daily trends and each wind farm will have a well understood speed profile based on location and anemometer readings. A study of on-shore UK wind characteristics[18] showed the highest wind generally occurs from December to February with the lowest between June and August. The study also found a clear pattern of higher wind power output during daylight hours than overnight. Generally wind offshore is stronger than onshore and less turbulent[19]. This, coupled with the larger wind turbines that are planned and being built off shore, will mean that off-shore wind farms will have higher load factors than present onshore farms, with a more steady output. As the UK continues to build a geographically diverse portfolio of wind farms, on- and offshore, total wind power output should also become much more stable.

3.17 At critical mass, the different generation profiles and locations of renewable generators may offset each other, but once renewables become a greater proportion of the generation mix by 2050, they may need to be operated more flexibly. Wind, for example, has the technical capability to feather its blades in order to keep the rotational speed of its blades constant as wind speed varies - this is already used for gearbox efficiency and to ensure safety in high wind conditions, but could be used to moderate electrical output if necessary. In countries with high wind penetration (such as Denmark, Ireland and Spain) Transmission System Operators have imposed requirements for any new installation to be capable of power tracking and frequency regulation services when there is enough wind resource available[20]. Wind turbine manufacturers are therefore designing all new turbines with this capability, so new wind farms in the UK will also have the capability to provide frequency services should they be needed.

3.18 With a high proportion of wind energy, wind turbines could also be used in the operating reserve - by running at lower than potential (e.g. 80% of output) there would be scope to flex generation output up or down depending on the balancing need. Any tidal flow turbines should also have similar technical capabilities as they are based, similarly to wind, on turbine, generator and power electronics.

3.19 Biomass is a different type of renewable resource that has similar flexing capabilities to fossil fuel generation. Currently the majority of biomass electricity is generated through co-firing with coal, although smaller dedicated biomass boilers and biomass CHP are also being built. The co-firing of biomass and coal takes place in specially converted coal-fired power stations and has the same technical capability to provide flexible generation as conventional coal. The smaller dedicated biomass boilers also could provide flexibility as they are based on conventional boiler technologies. As with other renewables the extent to which they will flex will depend on market signals.

3.20 Biomass can also be gasified or fed through an anaerobic digestor to produce biogas or syngas which could be burnt in dedicated combined cycle gas turbines stations. This technology has the same technical capability as conventional combined cycle gas turbines to operate flexibly.

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18 "Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand" Sinden, Graham, Energy Policy, 35 (1), p.112-127, Jan 2007

19 http://www.offshorewindenergy.org/reports/report_026.pdf

20 "Tutorial of Wind Turbine Control for Supporting Grid Frequency through Active Power Control", National Renewable Energy Laboratory, available electronically here: http://www.osti.gov/bridge

3.21 Even new nuclear plant, which is traditionally seen as baseload generation, may have the capacity to be operated more flexibly - as the French nuclear fleet is operated today. The new reactor designs can adjust supply by a small percentage once running (any load following activity would, however, have to undergo rigorous safety testing before it would be allowed in the UK).

Distributed Generation including Combined Heat and Power (CHP)

3.22 Distributed generation (DG) - such as solar panels on homes, as well as projects at a community scale such as combined heat and power (CHP) plants and small scale wind connected via the distribution network - currently does not play a role in balancing the transmission system. There are two main reasons for this. Firstly, it is still relatively small in total capacity compared with other forms of generation so does not have a large impact on overall capacity. Secondly, distribution networks are not 'smart' enough to monitor these generation sources and feed information back to the SO.

3.23 Feed-in tariffs, alongside the government-industry Microgeneration Strategy, are supporting the growth in distributed electricity generation. Analysis for DECC's latest impact assessment on feed-in tariffs[21] suggests that the uptake of DG may increase dramatically over the next 10 years. This could have significant implications for the system in the future, potentially creating unplanned imbalances. Moreover, its potential as a tool for active balancing is unharnessed. A key way to address these issues is the use of smarter networks which should enable more information and control over the generation capabilities of these assets, avoiding unplanned imbalances and allowing them to be operated flexibly and play a greater role in meeting peak demand. CHP in particular could offer rapid additional electricity generation at times of peak demand.

3.24 As well as the potential to harness DG for system balancing, we could see changes in the role of DNOs, where they take a more active role in balancing themselves. It is not clear, however, whether the current regulatory, market, commercial arrangements are sufficient to facilitate the full leveraging of these distributed energy resources and a potentially changed role for DNOs.

3.25 CHP systems are either gas turbine or engine-based. Turbine-based CHP units are used in industry where process heat is required. These types of CHP systems and are based on conventional combined-cycle gas turbine (CCGT) technology and electrical output could be increased on demand by diverting the steam used for process heat through a steam turbine to generate more electricity and running boilers to supply heat i.e. turn it back into a fully-condensing CCGT.

3.26 Engine CHP units are usually up to around 5MWe in size and tend to be used in the service industry or small commercial settings where hot water and space heating, rather than process steam, is required. If slightly oversized and fitted with a hot water storage system, then the CHP unit could export excess electricity to the grid at peak times whilst storing the heat produced for use at times of low electrical demand.

[21] Impact Assessment: Government response to consultation on Feed-in Tariffs Comprehensive Review Phase 2A and 2B

Balancing Technologies

Demand Side Response (DSR)

3.27 DSR is an active, short-term reduction or shifting in the consumption of electricity at a particular time. DSR enables this by shifting demand away from periods where the cost of electricity is higher, to periods where it costs less.

3.28 In a world where there is going to be more intermittent and inflexible generation, DSR can be used to help balance supply and demand of electricity by providing system flexibility, especially at times when customer demand and availability of intermittent renewable generation move in opposite directions (i.e. demand is increasing to system peak while availability of intermittent renewable generation is reduced to a minimum and vice versa). This could be achieved by self-supplying using local backup generation, or by not using the electricity at that time, reducing the need for peaking plant and network reinforcement. In this way, DSR can reduce the total capacity needed on the system, and reduce the need for generation capacity to meet peaks in demand.

3.29 As set out in chapter 2, the SO uses a range of contracts to help balance the system but overall DSR currently accounts for less than 1 per cent of the SO's balancing services[22].

3.30 As part of the Transmission Use of System charges and Triad[23], suppliers also offer to their customers tariffs which encourage DSR. On the distribution side, the Distribution Network Use of System (DNUoS) charges enable suppliers to charge their customers different prices for use of the network, incentivising them to avoid peak times. In addition, following changes to the current methodology, all half-hourly customers will face higher DNUos charges at times of system peak, to reflect the cost of capacity at these times and encourage customers to avoid them where efficient.

Storage

3.31 Storage has the technical ability to provide a number of benefits to the electricity system for example, by regulating output by smoothing supply profiles from intermittent generation (capturing price arbitrage) and potentially allowing generation to be run with less constraint as opposed to being curtailed in periods of low demand. It can also provide balancing services to the SO, and potentially save or defer network upgrade costs that may be required in the future to meet peak demand. In comparison to DSR and interconnection, storage provides a greater guarantee of availability that is less dependent on the response of GB consumers or the European market to price signals in the GB market.

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[22] http://www.ofgem.gov.uk/Markets/sm/strategy/Documents1/Smarter%20Markets%20Strategy%20-%20Consultation%20document.pdf.

[23] Large demand users that take power directly from the transmission network face Transmission Network of System (TNUos) charges, levied on the basis of their half-hourly metered demand during the "Triad" period. These charges can be avoided if such customers have no consumption (contribution to peak demand) during these periods.

3.32 There are two main ways to deploy storage. Bulk storage connected at transmission level (e.g. Dinorwig pumped storage) offering significant balancing services for example to respond to the variable output from intermittent renewables and to capture the benefit of extreme variations in prices. The second is 'distributed storage' built onto the distribution network, which may also avoid upgrades to the distribution network, as well as providing a service to the DNO.

3.33 A number of storage technologies are also able to provide very fast response rates to support the electricity system. For example battery storage and pumped hydro storage are able to respond almost instantaneously.

3.34 The UK currently has a number of pumped hydro facilities such as the Dinorwig facility in Wales. There are also a number of storage projects being built on the distributed network under the Low Carbon Networks Fund programme (see Annex D). In the future heat pumps, or other low carbon heat technologies such as CHP, may be built with the ability to flex electricity demand and store heat for use when needed.

3.35 Heat networks can provide seasonal as well as daily storage using large water tanks. These thermal stores can be used in conjunction with large scale heat pumps, other electrical sources of heat and recovered excess or wasted heat, enabling heat to be generated and stored at off peak periods, then used for reducing demand for electricity at peak times.

Case Study: Pumped Storage Hydroelectric Power, Dinorwig Power Station, North Wales

Dinorwig Power Station, located adjacent to the Snowdonia National Park in Gwynedd, North Wales, is Europe's largest pumped storage hydroelectric power station. It is also one of the fastest, most dynamic power plants in the world, capable of delivering its full station output of 1800MW in only 12 seconds. This rapid response is strategically important to the GB electricity system in helping National Grid maintain the balance of supply and demand on a second-by-second basis across the network. The power station complex was built deep underground, inside the Elidir Mountain and beneath the old Dinorwig slate quarry. It sits between an upper reservoir at the top of the mountain, and a lower reservoir in the valley below. Water falling from the upper reservoir is used to drive turbo-generators that supply power to the grid. The water is discharged into the lower reservoir and, during off-peak periods, pumped back into the upper reservoir for future use. It became fully operational in 1984 having taken nearly 10 years to plan and construct.

It is now owned by a joint venture of International Power plc (part of the GDF Suez group) and Mitsui & Co., Ltd. This joint venture also owns a second, smaller pumped storage station at Ffestiniog, some 30 miles from Dinorwig.

An overhead view of Dinorwig's lower reservoir, Llyn Peris

Interconnection

3.36 Network cables connecting neighbouring countries (known as interconnectors) have the potential to reduce the total cost of the GB's electricity system and increase the security of electricity supplies to GB consumers. It would do this in a future scenario of significantly expanded inflexible or intermittent generation by increasing the GB generation asset utilisation (for example, by allowing us to export wind on a windy day when the GB grid has capacity in excess of demand, instead of curtailing it) and by providing GB with access to European/international generation, allowing GB to export to countries that have a higher electricity price and import electricity from countries with a cheaper price.

3.37 Although interconnection may mean that GB consumers pay higher prices at certain points of the year, the entire system cost reductions described above should offset these occasional higher prices. Price increases might occur if there were a supply shortage (or demand spike) coinciding in both connected markets meaning that the GB had to compete for available generation. Like DSR and storage, interconnection can generate revenue from price arbitrage - forward selling capacity to energy traders who take advantage of the price differences between the two connected markets.

3.38 The extent of these benefits to consumers (both in the GB and connected markets) is dependent on a number of factors which will become easier to quantify in the future. These factors include the future generation profile of countries connected to the GB (there are higher benefits from connecting to countries with different generation profiles) and the GB's electricity demand profile as opposed to that of the connected country, particularly the timing of typical daily peaks and troughs.

3.39 From a simple balancing perspective, interconnection has both advantages and disadvantages. With much higher levels of interconnection, system operation may become more challenging as the interconnector can switch from being demand on, or a supply into, the GB system depending on price, but it can also provide access to non-UK generation if UK prices are higher than those of interconnected countries, providing a cheaper reserve and potentially reducing the overall cost of balancing the system.

3.40 Currently interconnectors in the UK are owned and operated by commercial companies and are governed by the same European legislation. There are slight differences in the access rules that regulate how each is operated and used, however the EU is working towards harmonising access rules. In addition, there is ongoing work to finalise the European target model which will allow interconnectors to trade close to real time and facilitate better coordination between European SOs. This should enable interconnectors to be used for system balancing by reflecting the respective balancing mechanism price differences after gate closure up to real time.

3.41 The ability of the SO to make changes to an interconnector's flows depends on the relationship and governing agreements with the corresponding system operator in the connected country: The EU's Third Energy Package[24] states that European SOs must co-ordinate and co-operate, but does not oblige them to offer balancing services over the interconnector. Emergency services, to be used at times of extreme system/market stress, are made available to both SOs in each connected market and SOs of two interconnected countries are able to talk directly to each other to change the interconnector flow.

Impact of future generation mixes on balancing the electricity system

3.42 In order to assess what impact future generation mixes might have on the requirements for the deployment of balancing technologies (storage, DSR, interconnection and flexible generation), we commissioned Imperial College and NERA to undertake analysis using the scenarios described by the 2050 Carbon Plan scenarios.

3.43 More detail regarding the assumptions and methodology can be found in Annex E, but the characteristics of the Pathways (in terms of generation profile, energy efficiency and levels of electrification of transport) used are set out in the Box below.

The Four Different Pathways

Pathway A

Much more of our energy comes from renewables with 80GW of wind capacity. 100% of heat and transport has been converted to electricity, with maximum energy efficiency and behavioural change. Consumers are happy to heat their homes to an average of 16 ^{o}C.

Pathway B

The majority of our electricity comes from nuclear (about 75GW of installed capacity), with some contribution from renewables. There is a medium level of electrification of heat and transport (about 50%) but there is far less energy efficiency and behavioural change. The average temperature assumed for home heating is 18 ^{o}C.

Pathway C

Carbon Capture and Storage has been deployed at commercial scale contributing about 40GW to our generation mix. There is low electrification of heat and transport and medium levels of energy efficiency. Homes are heated to 17 ^{o}C.

Pathway D

This sets out a balanced and diverse generation mix including contributions from marine and biomass, there is a lower level of electrification of heat and transport, but significant energy efficiency and behavioural change with homes heated to an average of 16^{o}C.

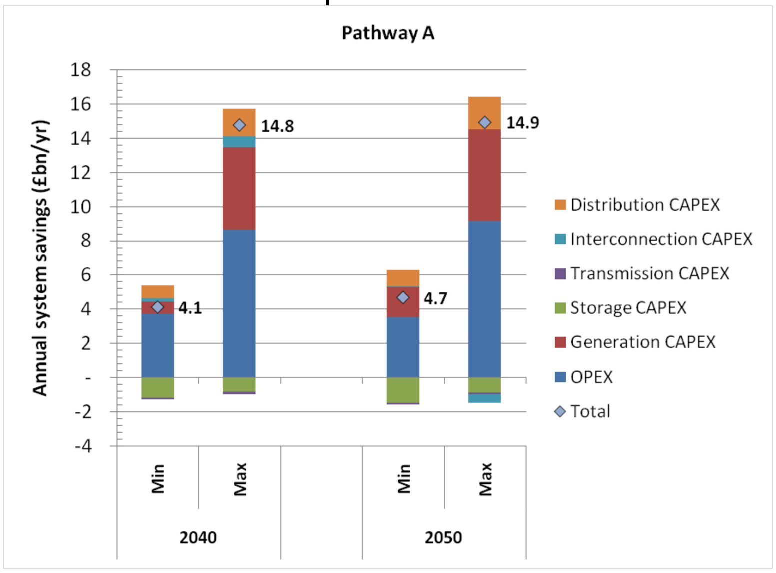
[24] http://ec.europa.eu/energy/gas_electricity/legislation/third_legislative_package_en.htm

Pathway A - High renewable generation with high electrification

3.44 This Pathway assumes a high level of wind generation on the system, so without balancing technologies there would be considerable wind curtailment. Therefore the majority of the annual savings stem from the avoided curtailment of wind (less 'back up' plant is needed and there is an improved operation of all plant and lower levels of carbon). As a result significant savings are achieved from Pathway A (see figure 5) with considerable levels of balancing technologies in place.

3.45 These results are very much dependent on the initial assumptions. For example, without high levels of energy efficiency and behavioural change to mitigate high electrification, the level of generation needed to ensure GB has sufficient generating capacity to meet peaks in demand, and consequently the value of balancing technologies would be far greater. In addition, if the level of electrification in this Pathway was lower, the savings through storage and DSR would be lower as there is less scope for shifting demand and the price difference between peak and troughs would be less.

Figure 5: Highest and lowest system savings in the Renewables with high electrification Pathway with combinations of flexible options



Pathway B - High Nuclear generation with medium electrification

3.46 Lower levels of energy efficiency and behavioural change but high levels of electrification of demand result in this Pathway having the highest demand peaks. Consequently there is considerable scope for balancing solutions. The value of the installations is lower as there is less wind generation and therefore less total curtailment[25]. The savings are more equally spread across reduced need for investment in generating capacity and reduced generation costs (which are relatively similar to Pathway A) and reduced need for investment in the distribution network, although the savings relating to the distribution network are slightly higher as a result of higher peak demand.

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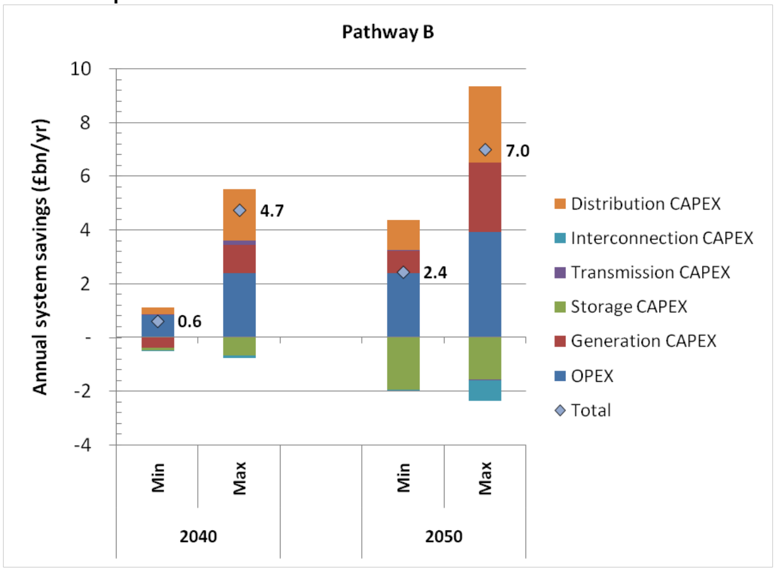
[25] A central run produced using the MARKAL cost-optimising model. This run was recreated in the 2050 calculator: http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx (as of February 2012)

3.47 There is a considerable increase in the value of balancing solutions between 2040 and 2050 as demonstrated by Figure 6. The amount of nuclear generation and the number of heat pumps increases significantly over this period. As a result the generation mix is more inflexible and there is considerably higher electricity demand through heat pumps - these changes increase the value of the balancing technologies particularly as the higher installation of heat pumps allows for greater levels of DSR and distributed storage.

Figure 6: Highest and lowest system savings in nuclear with medium electrification with combinations of flexible options



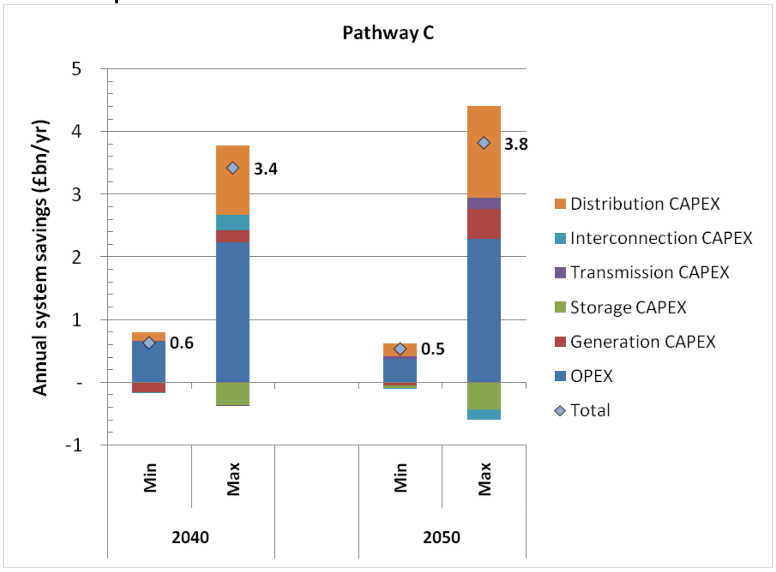
Pathway C - High Carbon Capture and Storage (CCS) generation with low electrification

3.48 The value of balancing solutions is lower under this Pathway than Pathways A and B, this is due to a more inherently flexible generation mix and less demand from the heat and transport sectors. With lower peak demand due to low electrification, the scope for peak shifting/price arbitrage and the need for additional generation capacity to cope with peaks in demand is less and the potential for reductions in investment in the distribution network is also less.

3.49 The savings in generation operating costs are also lower than in other Pathways. Base load nuclear and CCS plants have higher load factors and there is sufficient flexibility in the CCS plant to ensure that the wind on the system can maximise its output, with less curtailment. As demand in this Pathway is generally flatter, the gas power stations required to ensure security of supply have much lower load factors as they are needed less frequently. This scenario is reliant on the clean use of fossil fuels, so the values will be more sensitive to fossil fuel price changes.

3.50 The value of balancing solutions is higher in 2040 than 2050 in this Pathway. This is a result of a decrease in wind generation and an increase in gas generation with CCS over that period, consequently the savings in operational costs are reduced (as there is less curtailment).

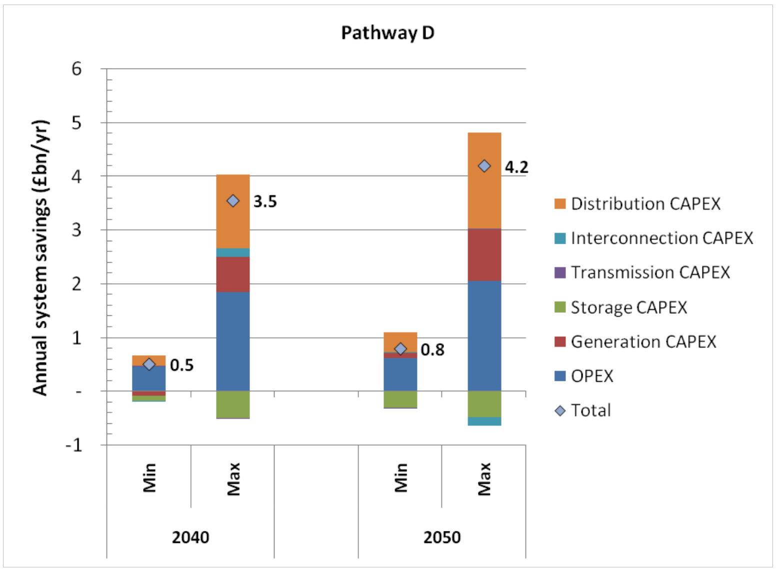
Figure 7: Highest and lowest system savings in CCS and low electrification scenario with combinations of flexible options



Pathway D - Central Markal run [26]

3.51 The level of electrification is similar to Pathway C, but there is additional energy efficiency, resulting in flatter demand and lower peaks. The value of balancing solutions is greater than in Pathway C because the generation mix includes more marine and nuclear. Marine generation will tend to be intermittent, albeit with a more predictable and different profile to wind and nuclear runs as an inflexible baseload pushing coal CCS to become a marginal plant rather than baseload – both of which mean there is additional value in the balancing solutions.

Figure 8: Highest and lowest system savings in Markal Pathway with combinations of flexible options

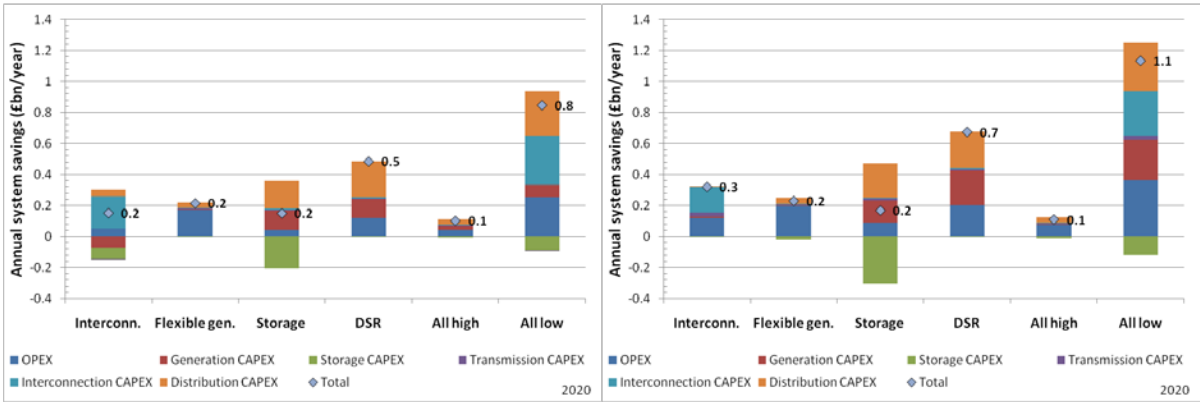


[26] A central run produced for the Carbon Plan, produced using the MARKAL cost-optimising model. This run was recreated in the 2050 calculator, and this is used here as benchmark against the other three 2050 Pathways. http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx

2020 and 2030 central scenarios from carbon plan and sensitivities of pathway A

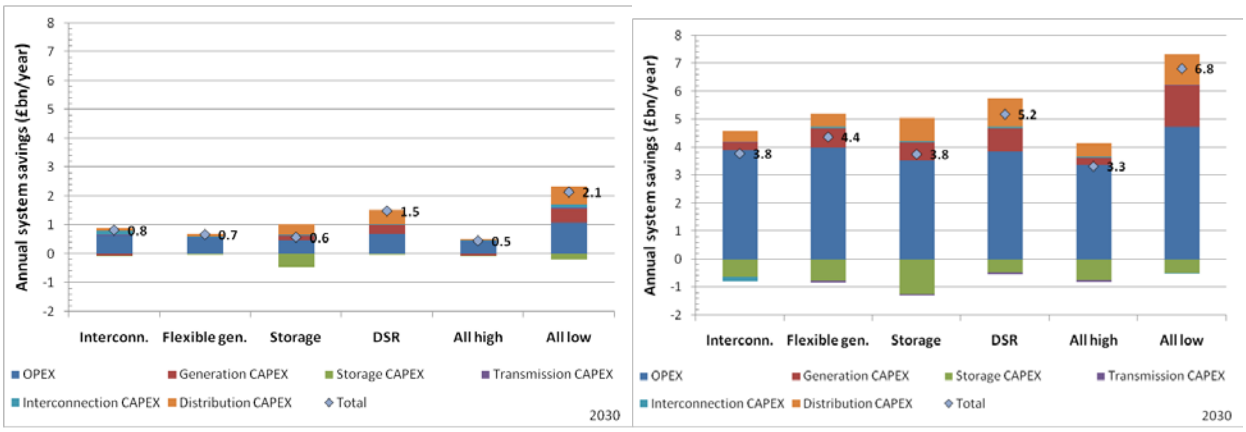
3.52 Figure 9 demonstrates the potential value from balancing technologies in 2020 for both a more central generation mix and Pathway A which has a higher level of renewables generation. This demonstrates limited value for the balancing technologies in 2020 even under the Pathway A sensitivity, as a result of the low level of electrification of heat and transport and a relatively flexible generation portfolio, resulting in a limited need for additional flexibility on the system.

Figure 9: System benefits of alternative balancing options in 2020 for a balanced generation mix scenario (left) and Pathway A (right)



3.53 By 2030 the value for balancing technologies has increased, as shown in Figure 10, as the level of electrification increases and the generation mix becomes less flexible. With all balancing technologies gaining a positive value (assuming low costs), even in the central scenario. The difference between the value of the balancing technologies for the balanced central scenario and Pathway A is greater. This is a result of much higher levels of intermittent generation (around twice as much wind capacity in Pathway A) and significantly greater levels of electrification of heat and transport.

Figure 10 System benefits of alternative balancing options in 2030 for a balanced generation mix scenario (left) and Pathway A (right)

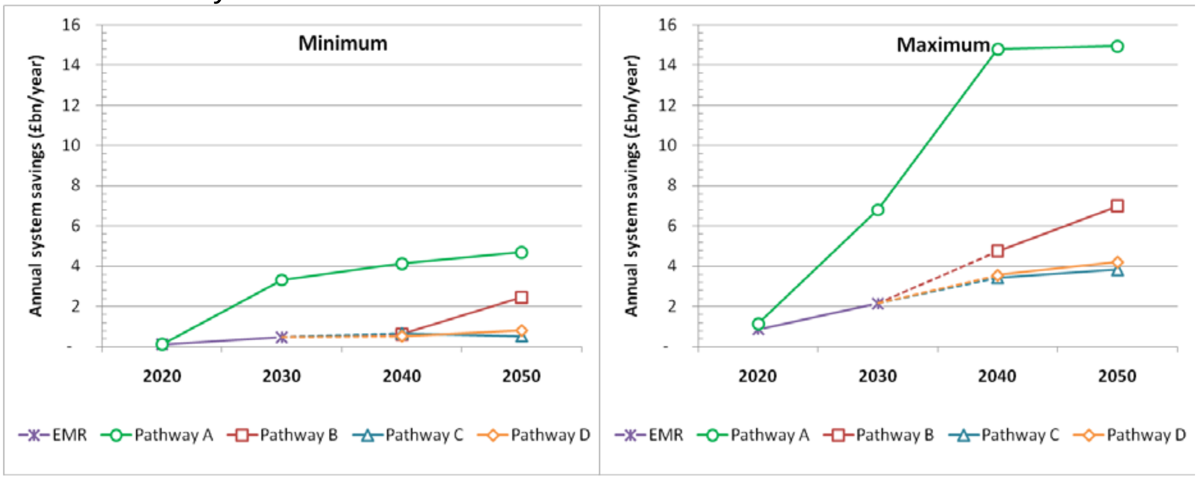


Requirements for balancing technologies over time

3.54 Figure 11 demonstrates how the value of the balancing technologies (or the balancing challenge) changes over time and across the pathways. The analysis suggests that the value of having alternative balancing solutions is lower in 2020 (although they clearly still have an important role to play) but this begins to increase towards and beyond 2030, although the scale is dependent on the Pathway. As discussed above the main variables that lead to variations in the value are the level of inflexible generation and the amount and variability of demand which is influenced by the level of electrification and the assumptions on energy efficiency and behavioural changes.

3.55 As can be seen from Figure 11 the level of flexibility of the generation mix seems to dominate the value for the balancing technologies, as demonstrated by Pathway A having a significantly higher value across all years. In contrast, the higher demand and potential for DSR in Pathway B (which comes from high levels of electrification of heat and transport but low energy efficiency) appears to only have a significant impact on the value of balancing technologies after 2040, in comparison to Pathways C and D.

Figure 11: Minimum and maximum system savings with combinations of flexible options across Pathways and time



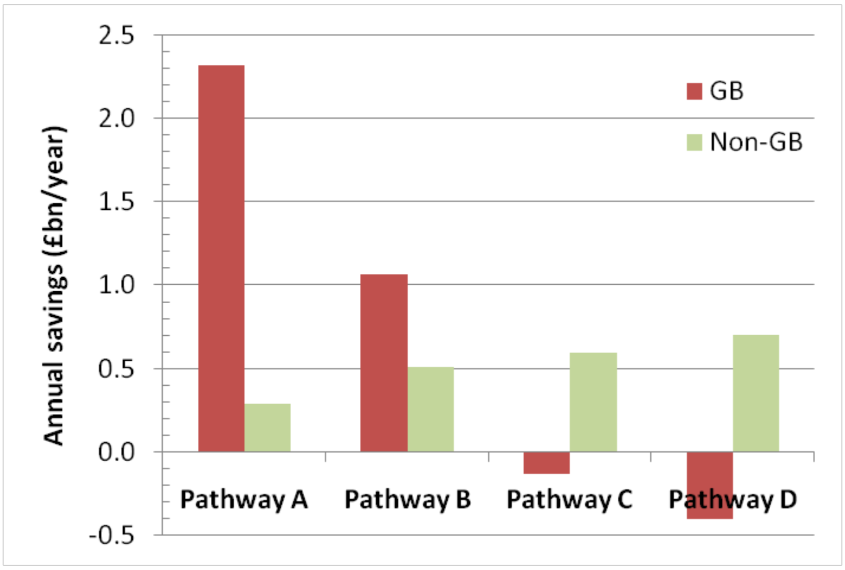
Wind generation used in the reserve and decreasing wind forecasting error

3.56 The analysis applied a sensitivity to measure the impact of increasing the reliability of wind forecasting and using wind as part of the reserve generation mix. This would enable the SO to predict more accurately how much wind would be generating at any given moment and allow the system to ramp up wind supply in response to demand, decreasing the requirements for balancing technologies.

System benefits within and outside GB

3.57 The analysis optimised benefits from a European system level, which means that benefits from reduced operating costs could fall outside GB as well within the GB system. The Pathways differed in the level of benefits seen within GB or outside. Figure 12 illustrates this using the example of benefits created by deploying interconnection as the only available flexible option. The majority of benefits fall within GB for Pathways A and B, whilst Pathways C and D actually see a reduction in savings in GB at the expense of European system benefits – mostly because GB is exporting rather than importing flexibility (so these values will change if assumptions about inherent flexibility in the future European electricity system also alter). This assumes that the appropriate market and regulatory mechanisms are in place to ensure that the total European system benefits adequately remunerate the providers of balancing technologies.

Figure 12: Comparison of benefits of interconnection generated within and outside GB in 2050 (for the case where interconnection is the only available flexible option)



Conclusions

3.58 Overall the analysis demonstrates there are likely to be significant benefits in the deployment of all balancing technologies, regardless of the future generation mix. It is therefore important that the conditions exist to facilitate the development and use of such technologies. Critically the analysis suggests that that the greater value is realised towards 2030 and beyond rather than more immediately.

3.59 The generation mix is a crucial variable in determining the overall shape of the electricity system, as demonstrated by the different levels of additional back up gas generation and the scale of balancing technologies needed in each Pathway by 2050. As expected, there is a much greater value for balancing technologies if there are high levels of variable and inflexible generation and less if the generation mix has more flexible low carbon generation (e.g. CCS and biomass). Nevertheless, there is still value from the balancing technologies across all the Pathways, just the amount and value varies.

3.60 The level and type of electrification and energy efficiency are also important to the results, impacting the total demand and the corresponding demand profile. This not only impacts the amount of generation that is needed but also flatter demand profiles improve the efficiency of generation.

3.61 Improvements in wind forecasting and the use of wind generation by the SO could decrease the need for balancing technologies particularly in pathways with higher levels of wind generation.

3.62 Benefits from balancing technologies may fall outside of the GB system. This is dependent on the need for these technologies in GB (i.e. intermittent generation and/or high increases in electricity demand) and the level of flexibility in main land Europe.

3.63 The analysis undertaken by Imperial College and NERA was a comprehensive first look at the GB electricity system which has allowed us to draw some initial high level conclusions. We need to improve our understanding of the ability of the UK system to balance electricity supply and demand in the medium to long term in the light of technological changes in key balancing technologies, additional interconnections, greater demand side response; and subject to current and future transmission and distribution constraints.

Chapter 4: Balancing Tools And Technologies

Introduction

4.1 The non-generation technologies used for balancing the electricity system (described in the first chapter) represent only a small percentage of the options currently used to balance the supply and demand of electricity. In order to understand the potential contribution each of these non-generation technologies might make to the balancing of the electricity system, the Imperial College/NERA analysis referred to in the previous chapter assessed the impact of each technology under high/low cost or penetration scenarios in each of the Pathway scenarios. Further details regarding assumptions and methodology are at Annex E.

4.2 The analysis also investigated the potential contribution of low carbon flexible generation (in the majority of the scenarios this tends to be gas and CCS plant (to keep within emissions targets)) and suggested that there will always be a role for flexible generation. A minimum of 5-10GW is built across all scenarios and Pathways by 2050, even where the model assumes that the cost of building flexibility into low carbon generation is high. Where all other technologies are assumed to be high cost/ low penetration, a considerable amount of flexible generation is installed (35-70GW).

4.3 Smarter distribution networks, utilising smart meters and other smart technologies, will have an important role to play in helping to balance the system more efficiently, including through supporting the greater use of storage and demand side response (DSR).

Demand Side Response (DSR)

Potential

4.4 Significant new load on the system as a result of electric vehicles and heat pumps will present an important opportunity to shift demand for electricity from peak to off peak times. Through innovative Time of Use Tariffs, for example, consumers could be encouraged to charge their vehicle when there is less demand for energy (provided the vehicle also had the technology to support this flexing). Smart meters, automation and smart appliances could also play an important role in supporting DSR initiatives.

4.5 Analysis undertaken by Redpoint and Element Energy (see Annex F) suggests that both static and more dynamic Time of Use Tariffs could bring significant reductions in generation investment, operation costs and distribution network investment costs. For example dynamic tariffs could create potential savings of between £170m and £500m per year in 2030, depending on the assumptions of the electrification of heat and transport and the take-up of DSR tariffs. The majority of these savings come from avoided generation build. If all system benefits were passed onto households with a dynamic DSR tariff, they could save up to £90 in electricity bills a year in 2030.

4.6 In the analysis undertaken by Imperial College, DSR tends to have the highest value and least sensitivity compared to the other balancing technologies. The benefits are also much more equally split across system operating savings and savings in investment in the distribution network. The analysis does, however, assume there are no costs associated with DSR. Although smart meters have already been mandated (and could be considered the main technology cost) in reality there are still likely to be further technology and non-technology costs associated with the deployment of DSR. These might include equipment so appliances can communicate to the smart meter, data and communications costs, system upgrades for suppliers, product changes or the need to compensate consumers or reward certain behaviours.

4.7 This means that the analysis may overestimate the value of DSR, particularly in comparison with storage. Nevertheless, even at low penetration (10%) there are considerable benefits across all Pathways, suggesting that DSR should still be pursued whatever the scenario.

4.8 Regardless of the potential of DSR, the future levels of take-up of such schemes by UK consumers is unknown. In order for the full potential to be realised, consumers would need incentives and significant engagement to make the necessary lifestyle changes. The work of the Customer Led Network Resolution undertaken under the Low Carbon Networks Fund (see Annex D for details of LCNF projects), which will trial customer-side interactions with smart meters and network technologies, will provide valuable insights about the optimal way to engage with consumers to participate in DSR following the smart meter roll-out. Preliminary results of this work are expected in the first few months of 2013.

4.9 A literature review carried out by Frontier Economics and Sustainability First for DECC[27] (more details at Annex F) looked at how domestic consumers have responded to major DSR trials internationally. Some of the main conclusions of the review were that consumers do shift their demand in response to economic and non-economic incentives, however there is a significant difference in consumer response to different tariffs, regardless of the size of the differentials.

4.10 The smart meter engagement strategy will play a critical role in helping consumers to engage more on energy issues so that they can benefit from changes to their energy use by not only reducing electricity consumption but also by making changes to their lifestyle to benefit from cheaper electricity throughout the day.

4.11 In future, aggregators could play a role in the domestic market by collecting commitments from individual households or small businesses to reduce demand. This already happens in the industrial and commercial sectors where organisations sell a service to the System Operator (SO) to be part of their balancing services either directly or through an aggregator.

[27] http://www.decc.gov.uk/en/content/cms/meeting_energy/network/strategy/strategy.aspx#Electricity_system_policy

Case Study: Low Carbon Networks Fund - DSR and Smart Networks Projects

Low Carbon London

This is a £36.1 million project, £24.3 million of which has been funded by the LCNF. The project is looking at how best to develop a smarter network. Low Carbon London is working with energy retailers to trial different tariffs for charging electric vehicles. It will also be reviewing information from 5,000 smart meters installed across 10 boroughs.

Customer Led Network Revolution – NE England

This is a £53 million project which will be assessing the potential for new network technology and flexible customer response to facilitate speedier and more economical take-up of low-carbon technologies by customers. The objective of the project will be to understand the level of DSR that should be expected in the future through a range of initiatives in the domestic, industrial and commercial sectors. The project will also provide data on the operation of low-carbon technologies including photovoltaics, heat pumps and electric vehicles, and their interactions with the networks. £27 million has been funded by the LCNF.

Capacity to Customers Project (C^2C)

This £10.7 million project is being undertaken by Electricity North West with £9.1 million funding from the LCNF. The project will develop and trial new demand-response contracts. These will allow Electricity North West to manage the demand of contracted customers if a fault or abnormal system conditions apply. Distributers currently hold 50% of network capacity in reserve. Investment in new assets will be avoided if this capacity is used for future load growth. When faults or abnormal conditions apply, contracted customers will reduce their demand back to that which the depleted system can cope with.

The contracted customers will be offered reduced connection charges in exchange for allowing Electricity North West to manage their demand in these conditions. These contracts will allow Electricity North West to restore supply to customers in as short a time as possible, without expensive reinforcement of the network.

Current support

4.12 Smart meters could provide a significant opportunity to capture the benefits from DSR, although there will be a range of other factors which will have an impact on availability and consumer take-up of DSR schemes, including whether suppliers have the right commercial incentives to offer the tariffs driving such schemes. In addition to consumer engagement, other key consumer-related factors will be what will be their risk appetite to sign up to more sophisticated Time of Use tariffs and how strongly they will be incentivised to participate. For example whether the price differential for on-peak/off-peak usage will make worthwhile any lifestyle changes which may be required to benefit from such tariffs.

4.13 More intermittent generation and a higher demand for electricity will inevitably have an impact on networks, therefore more active intelligent networks to respond to changes in demand, through technologies such as DSR, will be necessary. Smart meter functionality will also enable the DNOs to manage constraints on the network more effectively, by for example enhancing the visibility of loads.

4.14 Together with smart meters, smart appliances will also provide a significant opportunity to promote DSR. The Government commissioned a scoping study last year[28] which looked at the potential of smart appliances. The report acknowledged that smart appliances can play an important role in shifting electricity demand but also identified significant barriers to their deployment and take-up in the UK. These were technological barriers (e.g the communications requirements to link the electricity network with the appliances), market related barriers (e.g the market incentives for smart appliances to be developed and offered in mass market) and customer related barriers (e.g the consumers' willingness to buy a smart appliance given that benefits do not flow directly to them).

4.15 The availability of smart meters in homes could potentially lead to innovations in home equipment to make them more capable to respond to more dynamic tariffs and to allow the remote control of devices, in response to fluctuations in prices or because of network constraints. A number of projects have been exploring different smart technologies including the Energy Technology Institute which is looking at the requirements of a "Smart System" in 2050 from the perspective of the consumer[29] and the deployment requirements for that system, building on lessons learnt from existing trials. This work will focus on home level technologies, including heating, appliances and insulation, taking into account consumer energy behaviours and choices.

4.16 Given the expected increase in the use of heat pumps, DECC is working closely with the Energy Saving Trust on the domestic heat pump field trials, with the final report from phase II expected to be complete in March 2013. DECC is also running lab tests to investigate how domestic hot water draw off patterns and buffer tanks affect the system efficiency of heat pumps. These two studies will improve our understanding of system design for heat pumps and will inform our future work on the potential for using heat pumps to facilitate DSR.

4.17 Finally, DECC has committed that verifiable DSR should play a fair and equivalent role to generation in any Capacity Market with work ongoing to design the detail of the scheme.

Barriers

4.18 Although there are benefits associated with DSR for the society as a whole, given that utilities are not completely vertically integrated, these benefits are split across different market players. While suppliers, generators, DNOs and the SO would all accrue some benefit in the form of reduced and more efficient generation, reduced network reinforcement costs and reserve, none of these market players individually will accrue the whole benefit from investing in DSR.

[28] Delivering the benefits of Smart Appliances, a research report completed for the Department of Food and Rural Affairs, EA Technology, September 2011.
[29] www.eti.co.uk.

4.19 For suppliers, for example, it is important that when they take an action to shift their customers' demand, such action is recognised and rewarded in the settlement system[30] and savings are not socialised across all suppliers as happens currently. The availability of half-hourly data from smart meters has the potential to make imbalance charges for individual suppliers more cost-reflective.

4.20 Alongside suppliers, DNOs and the SO may require stronger incentives in order to play a more active role in facilitating DSR. Ofgem's new regulatory framework 'Revenue = Incentives + Innovation + Outputs' (RIIO), will encourage DNOs to find innovative ways to make more efficient use of their assets which could include flexible solutions such as DSR.

4.21 In addition to no single market player being able to capture the full benefits from DSR, there may be some occasions when there are conflicting incentives between the different players about how the use of DSR should be optimised. In these cases, action would need to be taken to ensure that incentives across the supply chain are aligned as closely as possible. For example there may be occasions where actions from suppliers to take advantage of high wind availability create peaks on local networks which DNOs could find difficult to manage. Such actions would need a level of co-ordination between suppliers and DNOs and also communication with the SO as they could be impacting the overall balancing of the system.

4.22 Ofgem has consulted on the scope of a strategy aiming to shape developments in the energy market to maximise the benefits consumers can get from smart metering. Its strategy for smarter markets is looking both at opportunities for innovation in retail energy markets and the potential for improvements to the processes that underpin operation of the competitive market. DSR is one of the areas which Ofgem consulted on as part of developing this strategy and they recently published a work programme[31] to take forward this strategy.

Storage

Potential

4.23 The Imperial College analysis considered both 'bulk' storage and 'distributed' storage (assumed to be at substation level and consequently its size and capacity would be constrained). The analysis concluded that the majority of value in future storage installations would be in distributed storage on the semi-urban network. The analysis chooses distributed over bulk storage in the majority of circumstances because distributed storage has the potential to avoid investment in the distribution network required by the electrification of heat and transport. The core analysis does not, however, consider alternative smart grid solutions, for instance voltage control, or installing larger wires at earlier stages which would reduce the value of distributed storage (and possibly increase the relative value of bulk storage). The efficiency of storage and the availability of DSR also had an impact on the value and level of storage installations estimated by the model in 2050.

[30] The process which ensures suppliers pay for the electricity their customers used, and generators are paid for what they produced.
[31] http://www.ofgem.gov.uk/Markets/sm/strategy/Documents1/Promoting%20smarter%20energy%20markets%20-%20a%20work%20programme.pdf

4.24 The Imperial/NERA analysis indicates that given the value to the system, additional storage could be installed in the range of 1GW - 29GW under certain future scenarios by 2050, with distribution storage dominating bulk storage, due to the savings from avoided distribution network costs. If bulk storage costs come down more rapidly than distributed storage costs, or the savings from avoided distribution network costs are less, then different results would be seen given the overall sensitivity of the results to costs[32]. In such circumstances, Imperial estimate that additional bulk storage could be installed in the range of 1GW – 18GW. Where all other technologies are assumed to be high cost/low penetration, between 10GW - 30GW of storage is installed.

Current Support

4.25 There is a wide range of potential storage technologies - some are fairly well-developed; others are at an earlier development stage and for some, further innovation may be needed to reduce costs for wider deployment.

4.26 Given the potential role for storage and the need for further innovation, DECC has identified storage as one of the specific technology areas which should be supported with energy innovation funding - from approximately £200 million allocated for the Department to support low-carbon technologies over the four financial years from April 2011.

4.27 DECC proposes to launch a scheme to support energy storage innovation in summer 2012, with a budget of up to about £10m. Details of the scheme are being developed but innovation support for storage is expected to focus on technologies which are close to market to help to secure the cost reductions necessary for technologies to be commercialised and deployed.

4.28 Ofgem's Low Carbon Networks Fund also supports investment in distributed storage with DNO's bidding for funds to undertake innovation projects and develop smart networks (see Annex D for full list).

4.29 In addition, DECC is committed to ensuring that the Capacity Market leaves opportunities open, as with DSR, for current and future storage technologies to play a fair and equivalent role alongside more conventional generation and work is ongoing to design the detail of the scheme.

[32] More detail on the relationship between bulk and distributed storage can be found in the Imperial storage project undertaken for the Carbon trust. Please see "Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future" Report by Imperial College for the Carbon Trust, 2012 http://www3.imperial.ac.uk/newsandeventspggrp/imperialcollege/administration/energyfutureslab/newssummary/news_5-7-2012-14-8-41

Barriers

4.30 A key barrier to storage deployment in the UK is that the market is not yet delivering strong enough price arbitrage signals to encourage in commercial investment in storage. While the GB electricity market has high capacity margins, cheaper fossil fuel alternatives, and relatively stable prices, it may be difficult for a potential storage operator to make a commercial case for investment in the high capital costs of storage. Some storage technologies are relatively new and quite complex to operate, which means that market players may choose technologies that they find easier to operate and where revenues are more certain.

4.31 In addition, while storage can provide benefits simultaneously to different market players across the whole value chain, as with DSR, it is difficult for a single market player to accrue the whole benefit from investing in storage because generation, transmission, distribution and supply are separated. This means that the revenue to the investor can be less than the value of the storage facility to the system, which suggests specific business models may be required to aggregate the benefits in order to make investment worthwhile.

4.32 Another barrier to storage is the fact it is a relatively new concept for the distribution network, where its value is thought to be highest. While RIIO ED1 programme and the LCNF are providing incentives for DNOs to build smarter networks, there is still some way to go before storage is considered as an alternative to a network upgrade in a significant range of circumstances.

4.33 There may also be a wider issue in that the GB's electricity market legislation and regulatory framework does not define storage as a separate category from 'generation' and provide for its unique characteristic as both a generator and customer, aligned to the price signal/system need. This inconsistency in definition means that some storage operators need to comply with network codes and hold a licence, while others do not – adding the potential for significant additional costs to a storage project.

4.34 As with low carbon power generation technologies, storage technologies such as batteries and pumped hydro storage have their own potential impacts. For example, for batteries there may be sustainability impacts from the resources used in production and disposal at the end of their lifespan and for pumped hydro, the impact on water resources and the local environment would need to be considered.

Case Study: Major Storage Projects; Innovation in the GB and abroad

In GB, Highview Power Storage has designed, built and tested the world's first **Liquid Air Energy Storage system**. The plant is connected to GB's transmission network and is hosted by SSE at their Slough Heat & Power 80MW biomass plant. The project is supported by a £1.1m grant from DECC through the Low Carbon Investment Fund (see annex G for details of other projects benefiting from this fund). The plant has successfully undergone a full testing regime, including automated performance testing for the US PJM2 electricity regulation market. This winter it was operated for seasonal TRIAD management. Highview is currently in advanced discussions with major companies from the UK and abroad to build a first multi MW commercial demonstrator.

Looking internationally, some examples of current major storage projects include:

Chile: A123 Systems, an American company, has been supplying 20MW of Advanced Energy Storage Solutions to AES Gener for Spinning Reserve Project in Chile. The project has been using A123 lithium-ion batteries to supply a flexible and scalable emissions-free reserve capacity installation.

China: Prudent Energy announced installed last year a 1MW **Vanadium Redox Battery energy storage system**, for the China Electric Power Research Institute in Zhangbei, northern China. This technology will be used alongside 30 wind turbines, 640 kW of solar photovoltaic (PV) capacity and 2.5MW of other energy storage, to enable China to develop different concepts for future grid operations.

Japan: Following the earthquake in Japan last year, Tohuku Electric Power has set up a **sodium sulphur storage system** at its fossil-fuel-burning power plant, as one measure to provide reliable power immediately. The NAS batteries will be charged when demand is low and discharged when the demand is high. The system comprises 40 2MW NaS batteries, able to continuously supply 80MW for six hours.

Interconnection

Potential

4.35 Great Britain has 3.5GW of interconnection to France, Netherlands and Northern Ireland, with an additional 0.5MW interconnection to Ireland to be added in September 2012 and other new projects that could potentially bring up to 4GW by 2020-2022. There are currently discussions for interconnection proposals to several countries, such as Belgium, France and Spain as well as Norway and Iceland who have significant hydro and geothermal generation resource. We expect the most beneficial projects to be those where the connected country benefits from low cost UK excess wind supply, while the UK will benefit from access to potentially cheaper generation and less intermittent, more diverse low carbon generation, taking account of the length, and therefore the cost, of the interconnector.

4.36 The analysis by Imperial College suggests that something in the region of 23 – 37GW (at least 10GW with mainland Europe and 11GW with Ireland) might be beneficial for the European system as a whole by 2050 if an assumption of a perfect EU market is made and on the basis of the input assumptions used for this analysis. The optimal level of interconnection as per the modelling results changes considerably if different assumptions are made and is highly sensitive to Europe's future generation mix[33], the levels of DSR and storage that are developed by neighbouring countries and the level of generation required to be located in GB.

4.37 The assumption used in all scenarios assumes that interconnection is not used to help with security of supply, i.e. there is sufficient generating capacity in GB to meet peak demand. Relaxing this assumption produces a large increase in interconnector build up to 43GW-66GW. This is because interconnection, by importing generating capacity from Europe, helps to meet peak demand in the place of some additional generating capacity, but as a consequence interconnection is underutilised over the year.

4.38 Conversely, if the assumption of no flexibility in Europe is relaxed, by assuming high levels of DSR in Europe (or any type of flexibility), the level of interconnection installed drops significantly to only 9GW (in Pathway D). Increased European flexibility will allow markets to balance internally and reduce the value of interconnection as a balancing service.

4.39 Generally interconnection is insensitive to the costs or roll out of the other balancing technologies, (within the central parameters of the modelling), with similar amounts being installed under all central scenarios with low interconnection costs. This is to be expected given that the investment incentive (price differences between countries) is not impacted by the other technologies.

4.40 Although interconnection is built in most Pathways it is difficult to interpret how much will be beneficial and what the implications might be for GB, particularly on prices. In practice, whether it is efficient to build a particular interconnector will depend on a number of factors, including the generation mix and demand profile on either side, length, relative costs, benefits and security implications compared with competing balancing options, and the allocation of benefits and costs to GB consumers.

Current Support

4.41 There are a number of policy initiatives looking at the regulatory framework and how interconnected generation is supported. The Electricity Market Reform Programme is considering how interconnected generation should be treated as part of detailed design of the proposed Capacity Market and Contract for Difference mechanisms (to be published in 2013).

[33] The input data on the generation mixes of other European countries used for this modelling exercise was derived from the European Climate Foundation 2050 Roadmap, which involved a high level of intermittent renewables and very diverse generation mixes across countries. This generation mix diversity and renewables content tends to be higher than European governments' actual forecasts which, if used, would tend to result in less interconnection to the UK being efficient from a European perspective, even assuming a perfect EU market and low levels of DSR and storage uptake.

4.42 Interconnected capacity has the potential to increase competition and to lower bills for UK consumers. A Call for Evidence[34], which closed in June, will help Government understand the potential costs and benefits of importing and exporting renewable energy, including as a contingency against the costs and delivery risks of our renewable energy and carbon targets. This is a complex issue and will require further careful consideration to ensure that we maximise the potential for interconnected capacity to provide benefits to the GB electricity market, but not pay overseas generators for services they cannot provide.

4.43 Ofgem is in the process of developing a regulated option for interconnection investment in addition to the current merchant (commercial) option. The new regime aims to overcome the challenges associated with building interconnectors on a commercial basis, which means that each project has to apply for exemptions from European legislation that requires profits to be reinvested in further interconnection[35].

4.44 The proposed regulated option aims to facilitate investment via a regulated route (where no exemption is required) and is based on a cap and floor approach. The interconnector owner would be allowed to earn returns within a pre-determined range. Returns above the cap would be passed back to the national SO and would be offset against national transmission tariffs. In times where returns are below the floor level, interconnector owners would be compensated by the SOs, who would recover the cost through national transmission tariffs and therefore ultimately by consumers. This is different to the merchant approach, where the risks are born solely by the project owner, and the exposure of consumers to risks requires a good evidence base around the costs and benefits of potential interconnection projects.

4.45 Ofgem is developing the regulated option using the interconnection project NEMO[36] as the pilot project and envisages that it will evolve into an enduring regulated regime that could be applied to other interconnector investment proposals. Ofgem is also still open to considering exemption applications, following the process set out in European legislation[37] .

Barriers

4.46 Interconnection is a proven technology and the cost of laying undersea cable is well understood by the market. The key issues for interconnection are how to ensure it adds value to the UK market and that projects help to minimise overall costs to consumers as well as offering mutual benefits to the connected markets.

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[34] Call for Evidence published at www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/5140-call-for-evidence-on-renewable-energy-trading.pdf

[35] Article 16(6) of Regulation 714/2009.

[36] 1GW proposed interconnector between GB and Belgium, expected to become operational in 2018

[37] Article 17, Regulation No 719/2009

4.47 The current regulatory framework could act as a barrier to the efficient development of interconnection. Different interconnection frameworks between European countries and different onshore and offshore regulation can create uncertainty and unnecessary complexities. Ofgem's Integrated Transmission Planning and Regulation (ITPR) project is, amongst other things, considering how the onshore, offshore and interconnector regulatory regimes might best interact to support the development of transmission projects in these areas. More broadly the North Seas Countries Offshore Grid Initiative (NSCOGI) is looking to identify the cost and benefits of, and tackle the technical, regulatory, market and planning barriers to, different approaches to co-ordinated development of offshore grids including interconnection. The ten NSCOGI nations intend to publish in December 2012 an assessment of the cost-effectiveness of more coordinated development of offshore grids and proposals for tackling regulatory, market, planning and technical barriers.

4.48 The ISLES (Irish-Scottish Links on Energy Study) project (www.islesproject.eu), jointly run between Scotland, Northern Ireland and Ireland also explored the issue of connecting networks in different markets. ISLES demonstrated that while offshore networks are technologically feasible and economically viable, there needs to be a supportive regulatory framework, both in terms of planning and the operation of the energy market. A cross-jurisdictional review of the regulatory frameworks was carried out and found that at present, they continue to form a barrier to such developments. Further work is proposed to examine market models which may be use to apportion costs and benefits across the trading countries.

4.49 A more specific possible barrier to further interconnection across the EU is the allocation of transmission charges and the cost of necessary onshore transmission reinforcements for the transit of interconnected generation. It is important that the costs of the necessary transmission network upgrades are allocated fairly to the consumers that use the generation, rather than by the transit country. For example, the UK might become transit country to export excess wind power generated in Ireland, which would require the onshore transmission network to be upgraded between the two interconnectors between GB and Ireland, and between GB and Continental Europe. Work on a methodology to allocate costs is already being undertaken by the NSCOGI, the EU Transmission System Operators and the European Commission as it is acknowledged that not allocating costs fairly will act as a barrier to further interconnection between Member States.

Smarter networks

4.50 The higher voltage transmission part of the GB electricity network is already relatively "smart". National Grid, in its role as SO, can in real-time ensure electricity demand is met (but not exceeded) by managing what electricity is put onto the networks by generators and by monitoring the system in real time.

4.51 This contrasts with the distribution networks. Their operation is mostly passive as they only manage power flows in one direction. This has worked as demand has been predictable and there has been relatively little distributed generation on the local networks. The significant new demand expected from the electrification of transport and heat together with the increased penetration of distributed generation (including from intermittent or inflexible generation) will pose new challenges for distribution networks. Smarter networks and smart meters will offer important opportunities to enable homes and communities to contribute to demand side management and energy storage as well as smart community energy schemes to optimise local energy.

4.52 Building a ‘smarter’ distribution network involves network companies applying new technologies and a communications platform to give them better information about, and more control over, the flow of power on their networks. This will allow network companies to use existing assets more efficiently by actively managing power flows, improving their ability to assess what reinforcement is needed (and therefore reduce or defer investment), fix outages more quickly, and drive up safety standards. It also has the potential to impact positively on the amount of generation and transmission investment required, particularly as more distributed generation comes online. Some of these smart technologies, such as automatic voltage control devices, are relatively simple and well understood whereas others, such as those to facilitate community level energy systems, are more sophisticated. Smarter networks are also a key enabler of balancing tools and technologies, with the suite of smart network technologies including DSR and storage solutions.

Potential

4.53 The conceptual potential of smart network technologies is widely recognised. Smart network technology and associated contractual arrangements with customers and generators will offer a more cost-effective way of providing the flexible network required. Until recently there has been little assessment of their technical capability under field conditions in the UK and little good quantitative evidence to support their claimed economic benefits, but there have been recent advances in both these areas.

4.54 Analysis undertaken by Redpoint and Element Energy suggests that both static and dynamic Time of Use tariffs could deliver significant benefits in the region of £30m to £70m per year by 2030 by providing the platform for smarter networks. Recent work by the Smart Grid Forum shows that adopting smart technologies as part of a planning and investment strategy can offer significant savings under a broad range of scenarios, including those where there is slow progress in decarbonising the economy. Savings range between £11 to £18 bn in the period to 2050 depending on the pathway to meet our carbon budgets. Recent work published by Smart Grid GB, reports there are also wider economic benefits to the UK from deploying smart grid technologies in the order of 5,000 new jobs and up to £5 bn in exports.

Barriers

4.55 There are investment, regulatory and commercial, and innovation barriers to the deployment of smart network technologies.

4.56 Network investments have a long lifespan and require detailed forward planning to ensure they are cost-effective and DNOs are used to investing in conventional technologies. There is now more uncertainty about the future structure of the energy industry, levels of electricity demand and the speed of development and location of low carbon technologies and distributed generation. This makes it more difficult to judge when to adopt smart technologies as opposed to sticking with proven conventional technologies. Furthermore, the rollout of some technologies, such as smart meters, require nationwide coordination.

4.57 The regulatory and commercial framework impacts on the investment behaviour of DNOs, and can also act as a barrier. For example, engineering recommendations which do not recognise the contribution that demand side management and storage can make offer little incentive to use it as an alternative to reinforcement. There are also legal provisions regulating ownership and control of energy storage facilities. DNOs will also need to work much more closely with the SO and suppliers to meet the challenges set out in this section.

4.58 A key aspect of many smart approaches involves consumers changing their behaviour with regard to electricity use, yet there is limited understanding of consumer willingness to take up smart approaches. The commercial relationship between DNOs and consumers has traditionally been indirect, so there has not been the need for much engagement.

4.59 Smarter networks will depend on the adoption of new technologies and associated contractual arrangements with customers, so innovation is vital. Historically the regulatory system has not necessarily recognised the long term nature of payoffs which can act as a potential barrier to the development and deployment of smart network solutions.

Current support

4.60 Overcoming these barriers requires effort by Government, Ofgem and industry, and there is a programme of work underway to do this. Key areas of support are set out below.

4.61 The RIIO-ED1 price control provides an important opportunity by incentivising and requiring DNOs to play a full role in meeting the future electricity system challenges. DECC is working with Ofgem, DNOs and other stakeholders to inform views in the development of RIIO-ED1. This work focuses on the necessary levels of cost-effective investment in distribution networks to meet the expected challenges including the use of smart network technologies.

4.62 The rollout of smart meters to all homes in the UK by 2019 will support network investment, improve coordination and interoperability, provide a platform for a smart network, and increase the capability of DNOs and other actors to improve the efficiency of existing and future networks.

4.63 DECC and Ofgem set up the Smart Grid Forum in April 2011 to develop a common understanding of challenges facing distribution networks in the transition to a low carbon economy and the contribution smart technologies might make compared to conventional network reinforcement approaches to addressing the challenges (see following Box).

4.64 There are a number of important smart grid innovation funding streams including those administered by the Technology Strategy Board, Ofgem's LCNF and the EU's Seventh Framework Programme for research and technological development. Under the LCNF (£500 million) there are currently a total of 34 projects (details at Annex D) of varying sizes and types. Projects include using smart monitoring tools to measure loads on local networks and testing smart technologies and commercial systems to support storage and DSR. Some projects involve universities, the general public and suppliers. As noted earlier, DECC has also funded 8 smart grid trials (details at Annex G) through the Low Carbon Investment Fund (£2.5m).

The Smart Grid Forum: Activities and Outputs

In its first year (2011/12), the Smart Grid Forum developed a **smart grid economic framework and modelling tool**, in order to assess the value of investing in smart technologies relative to continuing with more conventional network developments. The framework is based on shared assumptions and scenarios of future demands on electricity distribution networks necessary to meet the Government's Carbon Plan. Network companies inputted key insights on network challenges likely to be faced and potential smart technology solutions available during transition to a low carbon economy.

This work is key to fostering a common understanding of appropriate distribution network investment opportunities, and will inform Ofgem's electricity distribution price control review, RIIO-ED1. Initial results from the model suggest smart network deployment could offer net benefits of £11bn to £18bn to 2050.

Other activities included working with DECC to identify **smart meter communications requirements** to support smart network functionality.

In Year 2 (2012/13), the Smart Grid Forum will address potential **regulatory and commercial barriers** to smart grid deployment. These may include existing engineering standards, contractual arrangements and the current network charging regime. The conclusions will be published in Autumn 2012 and will inform the development of the electricity distribution price control.

It will also further refine the smart grid modelling tool and develop a **tool kit** so it can be utilised by network companies in business planning for the next price control.

Other activities include improving the **sharing of knowledge** on smart network innovation by developing a knowledge sharing platform across industry, academia and the public sector to share findings widely.

Conclusion

4.65 There are a number of different tools and technologies that can help with balancing the supply and demand of electricity, the most significant of which are storage, DSR and interconnection. Each has significant potential but, in each case, there are barriers that will need to be addressed including delivery of a smarter network if this potential is to be fully realised.

Demand Side Response (DSR)

4.66 Infrastructure being developed and invested in now can support the greater use of DSR in the future. The Government is therefore considering the business case for the functionality required to enable DSR and smart grids through smart meters. **T**he development of technology and infrastructure associated with electrified heating and transport could also present important opportunities for DSR and should similarly take account of how it can facilitate DSR further.

4.67 The plug-in vehicle manufacturers have been considering this issue but further work will need to be carried out to consider the business case for providing functionality in the vehicle to enable DSR as well as issues of functionality standards and standardisation.

4.68 Consumer engagement will be key to the take-up of DSR in households and equally it will be important that households benefit from taking actions to amend their demand to help the system. We need to investigate further how consumers can best be engaged and what may be the potential impacts of DSR on different types of consumers, in particular the more vulnerable.

Storage

4.69 The development of storage technology is encouraging and costs of storage should fall over time making it a more attractive proposition. Innovation funding will continue to support this. Given the complex impacts of storage on the system and the variety of ways it can be used, it is important that innovation also focuses on the development of commercial arrangements that allow owners and operators to capture an appropriate return for the benefits that storage can provide to different parts of the system. We will look to work further with stakeholders in the industry to understand better how this can be achieved in a robust and sustainable way.

Interconnection

4.70 Interconnection theoretically brings a positive overall benefit to the area over which it operates but we need to understand better where this benefit falls under different circumstances to ensure that GB consumers receive these. In particular we need to understand the impact for GB if we are a net exporter, both on the security of our system and on what consumers pay for their electricity. Further work also needs to be carried out in conjunction with European partners to understand the most efficient and effective way to develop interconnection in conjunction with network infrastructure. This understanding will be key to ensuring that interconnection is built to the right levels and in the right way.

4.71 There are a number of existing projects underway looking at these issues. These including Ofgem's ITPR project and the NSCOGI. We will continue to take an active interest in these projects as well as develop further our thinking in this area to ensure there is a strong evidence base and that the GB maximises the benefits of interconnection for GB consumers. This will include assessing the potential impact of significant further interconnection and the most appropriate way of developing interconnection capacity.

Smarter Networks

4.72 Smarter networks will be critical to system balancing: as a tool to enable real time information flows, as an enabler of other technologies, and to connect increasing levels of distributed generation. The effective development of smarter networks will require DNOs to operate differently particularly in the way they interact with suppliers, customers and the SO; in how they anticipate and respond to developments which affect their networks; and in how they develop and deploy innovative solutions. Work has already been undertaken to understand and overcome the barriers to delivering a smarter network including with the Smart Grid Forum (Annex H).

Chapter 5: Next Steps

5.1 Balancing the supply and demand of electricity is one of the fundamental challenges in ensuring secure energy supplies in our low carbon future. The significant changes we expect to see over the coming decades in the characteristics of the generation mix and the profiles of demand make it important to understand the system as a whole – from the individual capabilities of generation and non-generation technologies, through network capacity, to the impacts of market arrangements on overall balancing of supply and demand.

5.2 This paper has provided an overview of the operation of the system, the market arrangements and the potential value of non-generation balancing technologies and possible barriers to their widespread deployment. There remain a significant number of unknowns about the exact nature of the future generation mix, the sustainability of different technologies, demand profiles, technology and market developments which make it difficult to predict exactly what, if any, Government intervention is required to ensure the supply and demand of electricity continues to be balanced. We have, however, identified the following three key areas of focus – market arrangements, technology development and networks development.

5.3 DECC will continue to work with Scottish Government, Northern Ireland Executive and Welsh Government to ensure that, where appropriate, the actions taken reflect and facilitate the achievement of the policy aims, industry opportunity and consumer interests in their respective Devolved Administrations.

Market arrangements

5.4 The market framework is changing and flexing to address current and predicted challenges. It is difficult at this point to project the strength of the future signals for flexibility so it is important to be alive to the potential for problems to appear. There is not currently any evidence to suggest the market framework, as it adapts and develops, will not continue to provide the necessary signals but this will be kept under review.

Action: Work to ensure that demand side response (DSR) and electricity storage can play a fair and equivalent role in the Capacity Market. More generally DECC will seek to ensure that Electricity Market Reform is implemented in a way that allows the development of flexible solutions to generation challenges.

5.5 We expect the electricity system to continue to need the flexibility offered by gas generation for the next 20-30 years and a role for gas peaking plant in 2050, (in addition to demand from CCS). The UK's gas supply and gas generation infrastructure need to be able to support this role well into the future

Action: Publish a Gas Generation Strategy in autumn 2012 to ensure that the UK continues to attract investment in gas generation and infrastructure.

5.6 We need to improve our understanding of the ability of the GB system to balance electricity supply and demand in the medium to long term in the light of technological changes in key balancing technologies, additional interconnections, greater DSR; and subject to current and future transmission and distribution constraints.

Action: Revise our in-house system model to incorporate transmission and distribution constraints, and refined modelling of balancing technologies and real-time balancing activities.

Technology development

5.7 Technology has a critical role to play in ensuring that the supply and demand of electricity matches in the most cost effective way, whilst still delivering our objectives for secure and low carbon electricity. Of particular importance are new technology infrastructure developments that could significantly impact demand for electricity and therefore need to be sufficiently flexible to support the greater use of DSR technologies, i.e. electric vehicles and heat pumps, and the major balancing technologies themselves (DSR and electricity storage in particular). DECC will therefore undertake an assessment as to whether there is a need for Government to do more to support the development of key balancing technologies, areas to be considered may include:

- ***work with key organisations to support the development of the technologies likely to impact significantly and cost-effectively on the demand for electricity, and the infrastructure required for their deployment, to ensure they incorporate the functionality to support DSR initiatives.***

- ***studies to investigate further, how consumers can be best engaged to respond to demand side response initiatives, by using opportunities from other engagement initiatives, like the smart meters engagement strategy.***

- ***work, consulting with the electricity storage industry, to understand how effective commercial arrangements could be developed, and to understand the barriers to cost-effective storage options and whether there is a role for Government to remove unnecessary regulatory barriers. In parallel, we will need to consider what incentives may be required, and are appropriate, across the supply chain in order to encourage more DSR.***

- ***explore further how the recovery and distribution of excess and wasted heat through the use of heat networks might minimise the impact of decarbonising heating on the electricity sector. The potential role of heat networks is considered in the Government's strategic framework for low carbon heat, published on 29 March. Using the evidence gathered from the responses to the strategy we aim to develop policy proposals by end March 2013.***

Networks development

5.8 The changes in market arrangements, and the overall profiles of generation and demand envisaged in the future, could lead to changes in the roles of and interactions between Distribution Network Operators (DNOs), the System Operator (SO) and energy suppliers as they take new, more flexible approaches to manage their relevant parts of the system. They are likely to need to interact with each other and operate in new ways.

Action: work with Ofgem and the Smart Grid Forum to investigate in further detail what could be done to encourage, and remove any barriers to, the development of these interactions and associated development in commercial frameworks.

5.9 Investment in networks will be critical to future energy delivery and the achievement of the UK's low carbon objectives. Smart network technologies deployed in distribution networks in particular have the potential to facilitate this transition by enabling efficient system balancing and underpinning key balancing technologies. It will be critical that the right investment is made in the right places at the right time. An early opportunity to ensure appropriate investment is made is through Ofgem's RIIO-ED1 price controls process.

Action: work with stakeholders in the industry to develop a model that can be used during the RIIO-ED1 process to inform the nature and timing of distribution network investments.

5.10 Currently only a small percentage of the UK's generating capacity is delivered through Distributed Generation (DG). Analysis for DECC's latest impact assessment on feed-in tariffs suggests that the uptake of DG may increase dramatically over the next 10 years. This could have implications for the electricity system and potentially the role of DNOs.

Action: undertake further work to understand the impact of increasing levels of DG on the electricity system including the roles and responsibilities of the SO and DNO.

5.11 It is clear that transmission, as well as distribution networks, will need to change to play a full part in meeting longer term environmental and energy objectives, including balancing the system. This will require the transmission network to respond flexibly and, where appropriate, anticipate continued developments in generation, demand, storage and interconnection.

Action: work with stakeholders to analyse potential transmission network impacts of longer term developments in the electricity system and the potential network solutions.

5.12 Interconnection can enhance the overall flexibility of the system but it is important to understand the implications of a more interconnected European market and what this might mean in terms of security of supply and costs to consumers.

Action: further development of an evidence base and analysis on the impact on GB under different interconnection scenarios including further exploration of the most appropriate way of developing our interconnection capacity.

Sustainability and Climate Resilience

5.13 The sustainability of the technologies and infrastructure needed to deliver low carbon electricity is an important part of the overall picture. The Natural Environment White Paper published in 2011 contained a commitment from Government to pursue a sustainable approach to low carbon energy deployment,

Action: Government will work with industry and other stakeholders to commission analysis and research to fill evidence gaps on the impact of the new technologies and supporting infrastructure in order to identify a sustainable mix of technologies for future UK power needs. We will also continue to work with industry and civil society manage the risks around access to resources (several of which are critical to low carbon technologies) as set out in the Government's Resource Security Action Plan[38].

5.14 Over the longer term it will be important for energy infrastructure to be climate resilient to ensure it can continue to play its role in balancing the supply and demand of electricity. National Policy Statements (NPS) specify that proposals for new energy infrastructure should take account of the projected impacts of the effects of climate change, for example on flooding, water resources or coastal change. Furthermore, the Climate Change Risk Assessment[39], published in January 2012, identified that energy infrastructure is at risk of flooding, and that power stations are at risk of restrictions on water abstraction - these risks will be addressed in the National Adaptation Plan (NAP), to be published in 2013.

Action: DECC will work with Defra, the Environment Agency and energy companies under the NAP to ensure energy infrastructure is adapted to a changing climate.

[38] http://www.defra.gov.uk/publications/files/pb13719-resource-security-action-plan.pdf
[39] http://www.defra.gov.uk/publications/files/pb13698-climate-risk-assessment.pdf

Glossary

Aggregator	An organisation that collates commitments from a large number of consumers to reduce or shift consumption in return for cheaper rates for the energy they use.
Balancing Mechanism	Operated by National Grid as the System Operator (SO) to ensure the electricity system balances (i.e. supply equals demand) at any one time. Participants in the balancing mechanism can submit 'offers' (proposed trades to increase generation or decrease demand) and/or 'bids' (proposed trades to decrease generation or increase demand). National Grid then purchases offers and bids to balance the system.
Capacity Margins	The difference between peak demand and installed capacity.
Capacity Market	A type of Capacity Mechanism in which the total volume of capacity required is estimated, and providers willing to offer capacity (whether in the form of generation or non-generation technologies including storage or demand side response) can sell that capacity. There are several forms of Capacity Market, depending on the nature of the 'capacity' and how it is bought and sold.
Capex	Capital Expenditure
Carbon Capture and Storage (CCS)	CCS technology captures CO_2 from fossil fuel power stations. The CO_2 is then transported and stored safely, offshore, in deep underground structures such as depleted oil and gas reservoirs, and deep saline aquifers.
Carbon Price Floor (CPF)	A carbon price support mechanism to support investment in low carbon generation. The Government has achieved this by reforming the climate change levy (CCL) and fuel duty, to enable fossil fuels used for power generation to be taxed on the basis of their carbon content.
Cash Out	The process used to settle differences between financial contracts and physical metered volumes of electricity wholesale market participants.
Combined Cycle Gas Turbine (CCGT)	A power station that generates electricity by means of a number of gas turbines whose exhaust is used to make steam to generate additional electricity via a steam turbine, thereby increasing the efficiency of the plant above open cycle gas turbines.
Combined Heat & Power (CHP)	Generation where both heat and power is produced. This results in a more efficient use of both fossil and renewable fuels if there is a customer for the heat.

Connect and Manage	Enduring connection regime introduced by DECC in 2010 whereby generators connect to the grid once their local connection work is complete without having to wait for any wider network reinforcements to accommodate them to be completed.
Constraints	Constraints are caused by capacity bottlenecks on the electricity transmission network. They are resolved by the SO to keep the system balanced and secure.
Critical Peak Pricing (CPP)	Critical peak prices are higher prices set for only a certain number of days per year. The consumer receives notice close to the time of when a higher price will be in place.
Critical Peak Rebate	Rebates are a reimbursement to consumers for reducing consumption on a critical day, as instructed by their supplier.
Demand Side Response (DSR)	An active, short-term reduction/shifting in consumption of energy demand at a particular time.
Distributed Generation	Heat or electricity generation that is connected to a distribution network rather than the transmission network. It is typically on a small scale, such as solar panels on people's homes, and a community level, such as combined heat and power (CHP) plants and small scale wind generation.
DNO	Distribution Network Operator
Electricity Market Reform (EMR)	Government Programme to reform the electricity market to assure secure, affordable and low-carbon electricity.
Emissions Performance Standard (EPS)	A back-stop to limit how much carbon the most carbon intensive power stations - coal - can emit. An emissions performance standard will reinforce the existing requirement that no new coal is built without demonstrating carbon capture and storage technology.
EU Emissions Trading System (EU ETS)	A Europe-wide cap and trade scheme that sets an overall cap on the total emissions allowed from all the installations covered by the System. This is converted into allowances (one allowance equals 1 tonne of CO_2) that are then distributed by EU member states to installations covered by the scheme. From 2013, there will be full auctioning of allowances for the power sector in GB.
Frequency	System frequency is a continuously changing variable that is determined and controlled by the second-by-second (real time) balance between system demand and total generation. If demand is greater than generation, the frequency falls, while if generation is greater than demand, the frequency rises. The GB system frequency is 50Hz.
Gigawatt (GW)	A power measure (usually electricity) equivalent to 1,000,000 kilowatts. One gigawatt of electricity would meet the energy needs of 1million UK households, around 1.5 per cent of the UK energy demand.

Industrial Emissions Directive (IED)	EU Directive (IED, 2010/75/EU) that consolidates seven existing European Directives relating to industrial installations with the aim of providing a single clear and coherent legislative instrument for controlling pollution from industrial operations.
Interconnection	Physical linking of two electricity generation networks (usually between two countries) that allows electricity to be imported and exported in response to price signals.
Large Plant Combustion Directive	EU legislation (LCPD, 2001/80/EC) that applies to combustion plants with a thermal output of 50MW or more in order to reduce emissions.
Load Control	The process of adjusting or controlling the load on the electricity network.
Low Carbon Networks Fund (LCNF)	Fund established by Ofgem allowing up to £500m support to projects sponsored by the distribution network operators (DNOs) to try out new technology, operating and commercial arrangements. The objective of the projects is to help all DNOs understand what they need to do to provide security of supply and value for money to support the move to a low carbon economy. This will become the Network Innovation Competition under the next price control framework (RIIO) and will also cover electricity transmission and gas transmission and distribution.
Megawatt-hour (MWh)	A unit of energy equivalent to 1MW of power expended for one hour of time.
Microgeneration	Small scale generation of heat and/or electric power, typically with a capacity of less than 50kW electricity and less than 45kWth heat.
North Seas Countries Offshore Grid Initiative (NSCOGI)	Agreement by 10 European Governments to work together, with energy regulators, the European Commission and industry, to identify the cost and benefits of, and tackle the technical, regulatory, market and planning barriers to, different approaches to co-ordinated development of offshore grids in the North and Irish Seas.
OCGT	Open Cycle Gas Turbine
OFTO	Offshore Transmission Owner
Operating Reserve	The generating capacity available to the SO within a short interval of time to meet demand in case a generator goes down or there is another disruption to the supply.
Opex	Operating Expenditure
RIIO	Revenue = Incentives + Innovation + Outputs. Price control framework for Electricity and Gas network companies.
RIIO-ED1	Next price control for electricity Distribution Network Operators. Expected to run from 2015 to 23.
RIIO-T1	Next price control for electricity and gas Transmission Owners. Will run from 2013 to 2021.

Short Run Marginal Costs (SRMC)	The incremental cost of providing an additional unit of electricity in the short term. Typically this only includes variable costs (such as fuel) that are needed to provide the additional electricity.
Short Term Operating Reserve (STOR)	A service procured and used by the SO for the provision of additional power from generation or demand reduction used to balance supply and demand over critical periods in the day. Providers of STOR must be available for at least two hours within four hours notice.
Smart Appliances	An appliance that can be configured to communicate information directly to the utility operator for more efficient use of electricity.
Smart Grid	A smart grid is an electricity network that makes use of information and communications technologies (ICTs), enabling more dynamic 'real-time' flows of information on the network and more interaction between suppliers and consumers.
Smart Grid Forum	An industry group set up by DECC and Ofgem to develop a common understanding of challenges facing distribution networks in the transition to a low carbon economy and the contribution smart technologies might play to address them.
Solar PV	Photovoltaic technology that harnesses the energy of the sun to generate electricity.
Syngas	A methane rich gas made via a process called gasification. This can be renewable if biomass is used.
System Benefits	System benefits are the benefits or cost savings associated with improvements in flexibility of the system. These cost savings (benefits) include generation capital costs, transmission and distribution network capital investment costs, fuel costs, cost of carbon and constraint costs.
System Operator (SO)	The System Operator (SO) is responsible for ensuring the electricity system remains balanced within each half hour period. Generators may generate more or less energy than they have sold; customers of suppliers may consume more or less energy than the supplier has purchased. The SO must ensure that imbalances in supply and demand are addressed on a second by second basis, within the constraints of the network. National Grid Electricity Transmission (NGET) is the SO for Great Britain and offshore.
tCO_2	Tonne of CO_2.
Thermal Peaking Plant	Generating plant that can be operated at low load factors in order to ramp up or down according to demand and only tends to operate at times of peak demand.

Time-Of-Use (ToU) Tariff	Energy tariffs that charge different prices at different times of the day, week, month or year to reflect more closely the wholesale price of electricity. Tariffs that are pre-determined as to the price and when they apply, are called "static". Where the price and when they apply vary, they are called "dynamic".
Transmission Owner	Owner of the Transmission Network. Responsible for the planning, construction and maintenance of the onshore GB electricity transmission network. In GB this is National Grid Electricity Transmission, Scottish Power Transmission Limited and Scottish Hydro Electric Transmission Limited.
Triad	A short hand way to describe the three half hour settlement periods of highest transmission system demand between November and February within a financial year. They must be separated from the system peak demand and from each other by at least 10 clear days.
Wind Curtailment	When wind power is turned off due to constraints.

Annex A - Impact of Electricity Market Reform

Contracts for Difference (CfD)

A.1 The CfD will provide a mechanism for market revenues achieved by low carbon generators to be supplemented up to a pre-agreed level (the “strike price”). Conversely, when the generators’ market revenues exceed the level of the strike price, they will be required to pay back the difference. In this way investors will be able to achieve a stable price for their electricity. Low carbon generators will still need to sell their electricity in the wholesale electricity market and will be incentivised to achieve the best market price for their electricity.

A.2 The Renewables Obligation (RO) and CfD move the market away from responding just to the wholesale market price as the signal to invest and generate. Under both support schemes, low carbon plant has an incentive to maximise output to access support, which dampens the effect of the wholesale market price.

A.3 With a combination of low demand and high renewable generation levels (which may be seen overnight for example), prices can fall to very low, even to negative, levels. Negative prices primarily occur when generators are willing to pay suppliers for their electricity in the market in order to receive their RO or CfD support. In other situations generators may prefer to sell their power at a loss as it is preferable to switching off or turning down their generation. Negative prices are already being seen in Germany during the day when there are high amounts of solar electricity being produced which is in receipt of low carbon support[40].

A.4 Analysis suggests there is significant potential for negative prices if the CfD payment continues to be made once prices go below zero[41]. Steps are being taken in the design of the CfD to limit the extent to which prices drop below zero. The proposed approach is to pay CfD supported plant based on output unless the reference price drops below zero, in which case it would be paid on availability with the CfD availability payment fixed at the strike price. CfD plant would then have an incentive to stop generating once the reference price dropped below zero, amongst other things making it easier for the System Operator (SO) to balance the system and reducing distortion in the balancing mechanism. Although the steps set out above go some way to limiting the extent of negative prices, the RO will continue to be paid when prices go below zero, potentially to the negative value of the support.

A.5 Although potentially an indicator of increased challenges to the SO in managing the system, negative and low prices will also provide opportunities for storage and demand side response to respond when price differentials are higher, particularly in combination with other new market mechanisms set out here, such as the Carbon Price Floor.

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[40] http://www.epexspot.com/en/market-data/auction/chart/auction-chart/2012-04-01/DE

[41] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/energy-markets/5693-lcp-assessment-of-the-dispatch-distortions-under-t.pdf

A.6 There is the potential for an additional type of CfD to be introduced in future to encourage more flexible operation of low carbon plant. Some types of low carbon plant will have the ability to flex up and down and to turn off in response to prolonged periods where there is forecast to be either high levels of wind output (for example) or low demand. The Government acknowledged in the Electricity Market Reform (EMR) White paper that in future, a different structure of incentive may be required to bring forward investment in flexible low-carbon generation, once baseload plant has been largely decarbonised, and that one potential way to do this is through a one-way CfD. This would remove the limit on income at peak times and encourage plant to ensure they are available at these points. An option to bring in such a mechanism in future is being put in place, should it be needed, and the introduction of such an incentive will be kept under review, although the current view is that a CfD for flexible plant may not need to be issued until sometime in the 2020s.

Carbon Price Floor

A.7 The Carbon Price Floor will also have implications on the cost of flexible plant and as mentioned above may help provide opportunities for less traditional capacity such as storage and demand side response. In Budget 2011, the Government announced the introduction of a Carbon Price Floor (CPF) from April 2013. This is designed to top up the EU Emissions Trading System (EU ETS) carbon price to a target level for the electricity generation sector. The CPF as announced in the Budget begins at around £15.70/tCO_2 in 2013 and follows a straight line to £30/tCO_2 in 2020, rising to £70/tCO_2 in 2030 (real 2009 prices).

A.8 The CPF does not directly affect incentives to provide flexibility to the electricity system. It will give greater support and certainty to the price of carbon and will incentivise investment in low-carbon electricity generation more generally. It should also help storage technologies and demand side response to become more competitive as the CPF has the potential to contribute to greater price arbitrage opportunities, in combination with the effects of other market interventions, such as the CfD mentioned above.

A.9 Ultimately, it is envisaged that a strong and reliable carbon price would allow low-carbon technologies to operate in the market without any specific support, and that the wholesale electricity price and the carbon price will determine the generation mix.

Emissions Performance Standard (EPS)

A.10 The EPS aims to ensure that fossil fuel-fired electricity generation, which will continue to make an important contribution to responding flexibly in response to price signals, does so in a way that is consistent with the UK's decarbonisation objectives. It will work alongside other EMR policies and act as a backstop to limit how much carbon new fossil fuel plants can emit, through the introduction of an annual limit on the amount of CO_2 that new fossil fuel power stations are allowed to emit. This will be set at a rate equivalent to 450g CO_2/kWh at baseload, except for plant that form part of the UK's CCS programme or benefit from European funding for commercial-scale CCS.

A.11 At this level the EPS will help deliver the Government's commitment to preventing the most carbon intensive plant being built – unabated coal. It will not, however, affect new gas plant , which is expected will take over much of the flexible operation currently carried out by coal plant and an important component in enabling the transition to low carbon. Combined Cycle Gas Turbines (CCGT) will fall below the EPS level and whilst the average carbon emissions intensity of Open Cycle Gas Turbines (OCGT) – 460gCO_2/kWh – is higher than the level at which the EPS would be set, these plants operate at very low load factors therefore they will be able to comply with the EPS by running for a limited number of hours. It will not interfere with their ability to operate as peaking plant.

Capacity Market

A.12 Changes to the electricity market mean that there are risks to the future security of electricity supplies. Government will therefore legislate to introduce a Capacity Market and timing of the first capacity auction will be decided by Ministers on the basis of the security of supply outlook. The Capacity Market will provide an insurance policy against the possibility of future blackouts by providing financial incentives to ensure we have enough reliable electricity capacity to meet demand.

A.13 The Capacity Market will be focused on ensuring a required volume of capacity and placing incentives to ensure availability when needed. Providers of capacity successful in the capacity auction would enter into capacity agreements. These agreements would commit them to being available to provide capacity when needed in the delivery year, and in return receive a steady capacity payment, or face penalties. The costs of the capacity payments will be shared between electricity suppliers in the delivery year.

A.14 The guaranteed revenue provided by a capacity payment to plants that clear the capacity auction may serve to reduce the costs of finance and therefore overall costs for flexible capacity. It may also encourage the development of non-generation forms of capacity such as demand side response.

Annex B – Technical capability of balancing services and technologies

B.1 This annex aims to appraise the technical capability of the non-generation technologies, such as interconnection and electricity storage, which may need to play a larger future role in helping match supply and demand.

Balancing Services

B.2 As set out in the main document, the System Operator (SO), National Grid, procures balancing services to cater for unexpected changes in demand and generation output and differences between predicted and actual levels of demand. The balancing services which the SO requires in order for generation to meet demand and to keep the transmission system stable are summarised below[42]:

Balancing Service Definitions	Response time	Amount of power (if specified)	Length of time power needed (if specified)
Frequency Response			
Mandatory Frequency Response	<1 second		
Firm Frequency Response	<1 second	>10MW	
Frequency Control by demand management	<2 seconds	>3MW	>30 minutes
Reserve services			
Fast Reserve	2 minutes	>50MW (25MW/minute)	>15 minutes
Fast Start	5 minutes (auto) / 7 minutes manual	Full power contracted for	>4 hours
STOR (Short Term Operating Reserve)	240 minutes	>3MW	>2 hours
Demand Management	240 minutes	>25MW	Flexible
BM Start up	Hours notice as required		

[42] Taken from the balancing services contract information pack section of National Grids website, http://www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/

Frequency response

B.3 Frequency response is the service that the SO uses to balance demand and supply over sub-second to minute timescales. The fastest response to a sudden drop (or rise) in frequency caused by the mismatch of supply and demand is automatic mandatory frequency response (sometimes called inertial response). All power stations over 100MW connected to the electricity transmission system, which are covered by the grid code, have to be able to provide this service before they can connect[43].

B.4 Other frequency response is provided by certain generators pulling back from maximum output in order to create spare spinning capacity and thereby creating a safety margin. These spinning reserve generators then operate in a sensitive mode (called frequency responsive or dynamic) where they continuously monitor system frequency and respond and alter their output to correct these imbalances in supply and demand.

B.5 The SO also procures non–dynamic frequency response which is a discrete service triggered at a defined frequency deviation. Frequency Control Demand Management (FCDM) is an example of this and provides frequency response through interruption of demand customers. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting on site. Firm Frequency Response services procured by the SO can be dynamic or non-dynamic[44].

Reserve Services

B.6 The SO also contracts for a range of reserve services that can be called on over minute to hour timescales to help balance supply and demand for energy and system balancing purposes. Reserve can be provided by generators that are running part-loaded (i.e. not at their maximum output), by generators that can be called on in very short timescales, by a temporary reduction in demand (ie industrial customers who agreed to be switched off), or by generators who are waiting in a “warm” mode so they can start up in a few hours if required.

Interconnectors

B.7 Interconnectors between GB and Europe have the ability to import and export electricity. Power flows can theoretically switch direction in a few seconds but interconnectors have a ramp rate artificially limited to 100MW/min in order to help with system operation each side. Market trading decides the direction of power flows and changes in direction can only be implemented outside of these trades in emergencies. The rules which govern emergency procedures are set out in System Operator to System Operator agreements. This means that Interconnectors should be viewed either as a “generation” asset or an “end-user”.

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[43] The Grid code sets out operating procedures and principles for an efficient, co-ordinated and economical GB Transmission System. Some generating stations are exempt from having to provide frequency services, see The Grid Code on National Grid website for more details: http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/gridcodedocs/

[44] For more information on the balancing services that National Grid procures, please see their website here: http://www.nationalgrid.com/uk/Electricity/Balancing/services/

B.8 The market trading of the interconnector capacity means that it plays an important role in helping to balance the GB electricity system but it currently is not used to perform post gate closure balancing services except in emergencies as noted above.

Below is a table of existing interconnectors and those with agreements in place to be built[45]:

Name	Owner	Connects to	Capacity	Status	Date operational
IFA	NG and RTE (4)	France	2000 MW	Operational Regulated	1986
MEA HVAC Cable	Manx Electricity Authority (MEA)	Isle of Man	65MW	Operational Within the UK so not an EU law "interconnector"	2000
Moyle	NI Energy Holdings (mutualised)	Northern Ireland	450 MW to NI 80MW from NI	Operational Within the UK so not an EU law "interconnector"	2002
BritNed	NG and TenneT (5)	Netherlands	1000 MW	Operational Exemption granted 2007	2011
East West Interconnector	Eirgrid (6)	Ireland	500 MW	Construction phase Regulated	2012
East West 1 **East West 2**	Imera (7)	Ireland	2 x 350 MW	Exemption granted 2009	-
Channel Cable	Imera	France	800MW	Exemption requested in 2009	-
Nemo	NG and Elia (8)	Belgium	1000 MW	Feasibility study complete In discussions with regulators	-
IFA 2	NG and RTE	France	[1000 MW]	Feasibility stage	-
Norwegian interconnector	NG and Statnett (9)	Norway	[1000 MW]	Feasibility study	-
Belbrit	Imera	Belgium	[1000 MW]	Licence granted	-
NorthConnect	Joint Venture	Norway	[1200MW]	Feasibility stage	-
ElecLink	Groupe Eurotunnel and STAR Capital Partners	France via Channel tunnel	[500MW]	Feasibility stage	-

Storage (Transmission, Distribution and Demand connected)

B.9 Transmission connected, distribution connected and demand point storage are considered together here as some technologies are scalable and can be used at all three points. The technologies presented here are only those which are currently commercially viable or have at least been demonstrated and others may be in development. The table below demonstrates the services technically they are able to provide and a brief description of each technology follows[46].

[45] *Existing, planned and future interconnection - Electricity Interconnector Policy*, Ofgem, January 2010

[46] Information taken from: EPRI, *Electricity Energy Storage Technology Options, A White Paper Primer on Applications, Costs and Benefits;* Carbon Trust analysis and *Energy Storage Programme Planning Document*, US Department of Energy, Office of Electricity Delivery and Energy Reliability, February 2011, http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/OE_Energy_Storage_Program_Plan_Feburary_2011v3.pdf

	System level, medium-term (minutes to hours) Used for energy price arbitrage, renewables integration, system support	Short-term (<1 second to seconds) Used for fast frequency regulation, renewables integration	Transmission and distribution level, medium-term (minutes to hours) Used to postpone T&D infrastructure investment, ease congestion	End user level, medium-term (minutes to hours) Used for power quality and reliability, end user energy management, support of on-site renewables
Pumped hydro	✓	✓		
Compressed air energy storage (CAES)	✓		✓	
Cryogenic Electricity Storage	✓		✓	
Pumped Heat Electricity Storage	✓		✓	
Sodium-sulphur batteries (NaS)	✓		✓	✓
Redox flow batteries	✓		✓	✓
Lithium-ion batteries (Li-ion)		✓	✓	✓
Fuel Cells (Hydrogen / Chemical)	✓		✓	
Flywheels		✓		
Super-capacitors		✓		

Types of energy storage

Pumped Hydroelectric

B.10 Water is pumped from a lower lake or water source to a higher reservoir at times of excess electricity and then released back down through turbines which generate electricity when needed. This technology is mature and widely deployed across the world. In GB we have four large pumped hydro schemes. The largest of this is the Dinorwig facility in Wales. Although operational since the 1980s it still one of the fastest facilities in the world: it can go from shutdown to full output in 90 seconds and from spinning in air to 1320MW in 12 seconds[47]. Pumped storage generally has a round trip efficiency of ~75% with higher being possible.

Compressed Air Energy Storage (CAES)

B.11 Air is compressed and either stored underground or in storage vessels such as gasometers or expandable ‘bags’. When needed the air is pre-heated in a recuperator, mixed with a small amount of fuel before being passed through a gas turbine. Adiabatic CAES can be used without fossil fuels by storing the heat produced during compression and re-using when needed. There are two operating CAES plants in America and Germany. A third generation adiabatic CAES is planned for Germany 2013 which should see efficiency improve to around 70% (90MW power, 300MWh storage)[48]. A barrier to deployment is finding a suitable storage site. In GB we have some of the correct geology (e.g. salt caverns) but these face competition with natural gas storage.

Cryogenic Electricity Storage

B.12 Either air or nitrogen is liquefied and stored in low pressure tanks above ground. When needed the air/nitrogen is released to drive a turbine and generate electricity. The cold air product can be recycled and ambient/waste heat can be utilised in the expansion phase to improve efficiency from 50% to 70%. There is a demonstration plant hosted by Scottish and Southern Power (SSE) in Slough that was part funded by DECC and built by Highview Power (300kW power, 2.5MW hours)[49].

[47] Information taken from presentation given by Mike McWilliams (Head of Hydropower, Mott MacDonald), http://www.playitback.org/details.aspx?v=354

[48] RWE website with more information on the proposed project http://www.rwe.com/web/cms/en/365478/rwe/innovations/power-generation/energy-storage/compressed-air-energy-storage/project-adele/

[49] Highview power storage: http://www.highview-power.com/

Pumped Heat Electricity Storage

B.13 Electricity is used to pump heat from an underground vessel containing mineral particulate to another, resulting in the first container cooling to around -160°C and the second container warming to around 500°C. The heat pump machine can be thermodynamically reversed to operate as an engine and the electricity is recovered by passing the heat from the hot container back through the machine to the cold container, while the machine drives an electrical generator. The Energy Technologies institute is funding a demonstration on a primary substation owned by Western Power Distribution in the Midlands (Isentropic; 1.5MW/6MWh)[50].

Batteries

B.14 Types of batteries that are suitable include Lead-acid, Lithium-ion, Sodium-Sulphur (Na-S) and redox flow batteries; all can provide MW capacity over minutes to a few hours. Some can be portable / small and suitable for community use. Various prototypes of batteries are being tried out in America in grid support roles. One of note is a Li-ion battery backup for Tehachapi wind farm; it is 8MW with 4 hours storage[51].

Hydrogen/Chemical / Fuel Cells

B.15 Fuel cells use electricity to perform a reversible chemical reaction and can be based on various chemistries including Hydrogen and Methanol. Power can be in tens to hundreds kW depending on requirements. Fuel is stored in tanks so this will define how long the system can run for. They are in commercial use already in cars and other niche power applications such as micro-CHP. Fuels like Hydrogen can be made with excess electricity from renewable sources such as wind / Solar PV.

Flywheels

B.16 A Fly wheel is constantly spinning in a frictionless environment and uses energy to get up to speed then reverses this to produce electricity when needed. They are usually used for short/medium timescales i.e seconds to minutes and long operational lifetimes of 25+ years are possible. Flywheels have been used in lots of differing niche applications already. For example 200 were placed in parallel for a 20MW demonstration plant in US which was to perform frequency services[52].

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[50] Isentropic website: http://www.isentropic.co.uk/

[51] *Energy Storage Programme Planning Document*, US Department of Energy, Office of Electricity Delivery and Energy Reliability, February 2011, http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/OE_Energy_Storage_Program_Plan_Feburary_2011v3.pdf .

[52] *Energy Storage Programme Planning Document*, US Department of Energy, Office of Electricity Delivery and Energy Reliability, February 2011, http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/OE_Energy_Storage_Program_Plan_Feburary_2011v3.pdf.

Supercapacitors

B.17 A supercapacitor is a large storage device that can be re-charged very quickly, giving out high power but only storing a small amount. They are usually found in cars as way of recovering energy from braking and are robust with long lifetime but can be costly. Only small amounts of energy can be stored so are likely to have limited use on the electricity system apart from providing frequency services.

Annex C - Reform of Existing Market Mechanisms

C.1 The current market mechanisms will also need to continue to work effectively in the future, more challenging electricity system.

Significant Code Review of Cash Out arrangements

C.2 There are concerns that there are problems with electricity cash-out prices. These problems could harm future electricity security of supply and unnecessarily increase the costs of balancing the system, to the detriment of consumers. To address these concerns, Ofgem has announced its intention to launch a Significant Code Review (SCR) of the electricity cash out arrangements[53]. Concerns are around:

- Cash-out prices may not fully reflect scarcity at times of system stress
- Cash-out may not provide the right incentives for demand side response
- Cash-out prices suffer from a lack of transparency and predictability
- Dual cash-out prices have a large spread
- Participants are not incentivised to provide accurate Physical Notifications
- Reconciliation cashflows are large and opaque.

C.3 If reforms are made they could help provide better signals for investment and improve security of supply. They could also help improve how the market responds to signals to contract flexible generation and non-generation solutions and the costs of doing so, with the aim of minimising system costs.

C.4 While the intention to launch an SCR has been announced, the scope of the review and the impact of any changes are not yet decided. It will therefore be important to keep the strength of the signals for flexibility within the market under review.

System Operator Incentive

C.5 Meeting the future challenges of the changes to the electricity generation mix and demand profile will require the System Operator (SO) to play a full role in delivering a sustainable energy system that is robust to the challenges they face. Playing a full role will require the SO to take a proactive approach (for example in enabling new connections, encouraging demand side response) and take appropriate actions to reduce the impact of challenges on costs of performing the SO functions. It will also require them to think longer term, anticipating future challenges, such as the impact of higher levels of intermittent generation and interconnection capacity and integration with Europe, to deliver long term value for money for consumers. In doing this the SO will have to work with others and take account of the interactions with all energy market participants including in particular the Transmission Owners (TOs).

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[53] An SCR allows Ofgem and the industry to take a holistic approach to developing and making code changes in areas of complex reform of a technical nature, rather than the piecemeal reform of codes which has previously been the case. More details on the cash out SCR can be found on Ofgem's website at http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Pages/CashoutRev.aspx

C.6 Ofgem is currently reviewing the SO incentive scheme and will be publishing Initial Proposals shortly.

Wholesale market liquidity

C.7 An efficient liquid market is essential in order to avoid distortion of investment and operational signals and to allow market participants to buy and sell energy at the scale and in the timescales they need in order to manage effectively their risks, including their balancing risks. Work by Ofgem and industry to improve liquidity will play an important part in increasing competition and trading options, enabling market participants to be more in balance by facilitating easier trading out of imbalance positions before gate closure.

C.8 There have been some positive developments recently; industry-led initiatives have delivered significant improvements in day ahead trading. In addition, in order to address the problem of poor forward market liquidity Ofgem has recently consulted[54] on proposals to require the large vertically integrated companies (‘Big 6’) to sell 25% of their generation output in a range of key products in the forward market. These proposals are likely to increase overall power market trading and strengthen reference prices and transparency in the relevant parts of the market. Whilst recent developments in the day ahead market have been positive the Government believes that further measures are needed in order to enhance energy market competition and transparency. Steps to strengthen the forward markets and to sustain developments in the day ahead market are likely to be particularly important. The Government has committed to work with industry and Ofgem to ensure that liquidity strengthens.

Charging

C.9 The costs of the transmission network are paid for through two charges. Transmission Network Use of System (TNUoS) charges are administered by each of the transmission owners to recover the cost of building and maintaining the transmission network. These charges include a locational element designed to reflect costs imposed by users at different points in the network and is intended ensure the economic costs of transmission are factored into decisions about where and when to locate new generation and demand or when to close existing generation. Balancing Services Use of System (BSUoS) charges are applied by National Grid as SO, to meet the costs of network balancing as discussed elsewhere. As BSUoS is non-locational and applied equally to all liable parties, it is generally considered to be wholly factored in to market prices. Therefore it contains little or no incentive on generation to despatch or demand to balance in an efficient manner.

C.10 The costs of distribution networks are covered through the Distribution Use of System (DUoS) charge applied by each Distribution Network Operator (DNO). DNOs calculate their own charges using a methodology based on a common set of principles. The direction of travel is to ensure that DUoS charges are more cost reflective where appropriate – particularly for larger generators and users. This is leading to the development of charges that vary according to location and time of day (i.e. are greater at times of peak demand).

Annex D – Low Carbon Networks Fund Projects

Projects under LCNF Tier 1

D.1 **The 'Bidoyng' Smart Fuse (ENWLT1001)**

This project will test the feasibility of installing a sufficient number of Smart Fuses to reduce the impact of Transient Faults on Electricity's North West (ENWL's) network. If the Smart Fuse proves a reliable solution, the project will provide enough data to develop a business case for the installation of a substantial number of units.

D.2 **Voltage Management on Low Voltage Busbars (ENWLT1002)**

This project is concerned with exploring the potential for alternative technical solutions to the management of voltages on low voltage networks, in the face of increased network loads.

D.3 **Low Voltage Network Solutions (ENWLT1003)**

This project will deploy a range of distributed measurement, sensing and analogue recording instrumentation which will provide ENWL with greater understanding of the existing operating characteristics and demands of its LV networks and the tools to manage these issues.

D.4 **33kV Superconducting Fault Current Limiter (33kV SFCL) (CET1001)**

This project involves strategically placing Superconducting Fault Current Limiters (SFCLs). This could improve capability by limiting the fault current to within the rating of existing switchgear.

D.5 **Implementation of Real-Time Thermal Ratings (SPT1001)**

This project aims to unlock extra capacity in the networks thus reducing reinforcement requirements and connection costs for wind generators.

D.6 **Ashton Hayes Smart Village (SPT1002)**

The objectives of the project are to facilitate the connection of various micro generation technologies; to improve the accuracy and granularity of total electricity consumption measurement by installing additional metering on the network at secondary substation feeder level and at renewable energy source(s); providing measurement of the gross generation embedded within the community; and, to introduce innovative and new techniques to introduce demand side management capabilities aimed at assisting change in energy use related behaviours within residential homes and public properties.

[54] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=84&refer=Markets/RetMkts/rmr

D.7 **Clyde Gateway (SPT1003)**

This project will demonstrate the integration of a number of smart grid components within an established infrastructure.

D.8 **Hydro Generation and Active Network Management (ANM) (SPT1004)**

This project will deploy an ANM scheme on the network to actively manage the output of an existing hydro generator in order for it to utilise the additional generation export capability that is present during periods of higher demand. The ANM scheme will use voltage measurements to calculate in real time if the network has extra generation capacity available. This information will then be used to co-ordinate the output of the generator and other controllable devices.

D.9 **1MW Battery, Shetland (SSET1001)**

This project involves installing a 1MWe connected battery at the Lerwick Power Station on Shetland. It will provide learning regarding the operation of the battery and its integration with local Demand Side Response to remove station peaks providing additional Demand capacity (in a similar way to managing a network load constraint).

D.10 **Demonstrating the benefits of monitoring low voltage (LV) network with embedded photo-voltaic (PV) panels and electric vehicle (EV) charging points (SSET1002)**

This project will introduce 11kV LV substation monitoring to obtain directional energy usage data over a period of 12 months.

D.11 **Trial Evaluation of Domestic Demand Management Solutions (DDMS) (SSET1003)**

This project will trial a small number of DDMSs in the Shetlands.

D.12 **Demonstrating the Functionality of Automated Demand Response ADR (SSET1004)**

This project will trial the above solution on a GB high voltage (HV)/LV network to ascertain whether it can effectively help manage the constraints network operators are likely to find as they move into a low carbon economy.

D.13 **Low Voltage Network Modelling and Analysis Environment (SSET1005)**

This project will identify, test, demonstrate and evaluate a low carbon network modelling environment for a selected small sub-set of HV/LV network in the UK.

D.14 **Orkney Energy Storage Park (SSET1007)**

This project is aimed principally at demonstrating that it is possible for a DNO to create the commercial incentives and infrastructure to encourage third party energy storage providers (ESPs) to locate their storage in areas where it can be used to alleviate network constraints.

D.15 **Low Voltage Network Connected Energy Storage (SSET1008)**

This project seeks to understand the potential benefits, practicalities and costs of installing electrical energy storage (EES) connected via four quadrant power conversion systems (PCS) on the LV network. The main objective is to inform and de-risk the larger scale deployment of street batteries as detailed in the NTVV Tier 2 project.

D.16 **Demonstrating the benefits of short-term discharge energy storage on an 11kV distribution network (UKPNT1001)**

The objectives of this project are to perform validation of the storage device's capabilities with respect to data sheet performance, when installed on a real network.

D.17 **Distribution Network Visibility (UKPNT1002)**

The main objective of the project will be to demonstrate the business benefits of the smart collection, utilisation and visualisation of existing data (i.e. analogues available from RTUs). The project will establish optimum levels of distribution network monitoring and frequency of sampling for specific scenarios and applications. It will also trial various optical sensors that could potentially be used to provide detailed monitoring of sites with no RTUs.

D.18 **Validation of Photovoltaic (PV) connection assessment tool (UKPNT1004)**

This project aims to validate the assumptions within UKPN's draft guidelines and develop an approved policy and gain a detailed understanding of the impact of PV on the Low Voltage (LV) network by monitoring several PV clusters and covering different types of LV network (suburban and rural).

D.19 **Interconnection of Western Power Distribution (WPD) and National Grid Company (NGC) supervisory control and data acquisition (SCADA) systems (WPDT1001)**

This project will establish a real time link between the SCADA systems operated by NGC and Western Power Distribution (WPD) networks such that data on either system can be viewed on the other in real time.

D.20 **Network Management on the Isles of Scilly (WPDT1002)**

The project will establish real time monitoring on all of the distribution substations on the Isles of Scilly in such a way that the use of the generation facilities on the islands can be maximised to secure supplies to the islands. The control and management of the generation on the off islands will be affected using new methods that have not been used by WPD before.

D.21 **Photovoltaic (PV) impact on Suburban networks (CNT1001) - This project was registered before the networks formerly operated by Central Networks were purchased by WPD**

Through this project, WPD will explore amongst other things how to measure and capture voltage, current, harmonic, real and reactive power data on a range of distribution assets in suburban areas.

D.22 **Hook Norton Low Carbon Community Smart Grid (CNT1002) - This project was registered before the networks formerly operated by Central Networks were purchased by WPD**

This project will develop and explore customer engagement and incentive programmes. This aspect will include a small scale domestic demand response trial.

D.23 **Voltage Control System Demonstration Project (WPDT1003)**

This project aims to address the issue of fluctuations seen in long distribution lines in a rural area with DG (in the form of Wind Turbines) connected. The objective is to determine the effectiveness of D-SVCs (Static VAr Compensator for Distribution Networks) as a system to control voltage on 11kV rural networks.

D.24 **Early learning of LV network impacts from estate PV cluster (WPDT1004)**

The scheme provides a low cost opportunity for early learning of PV voltage impacts and validity of existing design assumptions. Installation of two different size LV cables in parallel to the existing cable, with linking facilities at each end, provides a real life, on load, capability to change the impedance of the feeding LV cable and measure resulting changes in voltage performance.

D.25 **Seasonal Generation Deployment (WPDT1005)**

The project will consist of two phases: phase 1 will involve the installation of a single point of generation at an 11kV substation site. Phase 2 will utilise existing network connected generation along with strategically placed generation connected to a contiguous section of 11kV network, which will be a test within a more complex network environment.

D.26 **LV Current Sensor Technology Evaluation (WPDT1006)**

DNOs will be collaborating, to evaluate a range of LV monitoring solutions under laboratory conditions at the National Physical Laboratory and in the field on their low voltage networks, equipping at total of 28 substations with sensors from 7 different manufacturers.

Projects under LCNF Tier 2

D.27 **Customer Led Network Revolution – Northern Powergrid**

This project seeks to trial how a combination of smart network technologies and flexible customer demand response can reduce the network costs associated with the mass take up of low carbon technologies. These technologies include photovoltaic (PV) solar panels, heat pumps and electric vehicle (EV) charging points in the North East of England where British Gas is rolling out 11,250 smart meters, 810 solar PV installations, 1500 heat pumps and 600 controllable white goods Northern Powergrid also proposes to deploy enhanced voltage control, dynamic thermal rating and storage.

D.28 **Low Carbon Hub - Western Power Distribution**

This is a small, discrete project which seeks to trial new technologies and operating techniques in order to connect more wind generation to a 33kV network in Lincolnshire. It is a technology-led project which seeks to utilise dynamic voltage control and a flexible AC transmission system (FACTS) device to increase the utilisation of current network assets and provide lower cost connections for DG customers.

D.29 **Low Carbon London - UK Power Networks**

This is a substantial project proposal which seeks to extract network learning from a variety of separate trials across the inner and outer London area. These trials are proposed to take place in areas designated by the Greater London Authority as low carbon zones. The trials look to monitor the impact on the LV network of PV solar panels, the extensive deployment of electric vehicle charging points, heat pumps and 5000 smart meters. Enhanced management of DG is also planned. The project includes the deployment of IT solutions to utilise smart meter data in eight Use Cases.

D.30 **LV Network Templates - Western Power Distribution**

This project focuses entirely on the performance of LV networks in a variety of areas across South Wales. WPD proposes to install monitoring equipment at over 1000 HV/LV substations and on over 7000 LV feeders. Some 7300 customers will be directly involved as monitoring equipment will be installed in their premises.

D.31 **BRISTOL – Western Power Distribution**

This is a relatively small but very innovative project that aims to address the technical constraints that the DNO expects to arise on LV networks as a result of the adoption of solar PV. It will trial the use of in-home battery storage to provide benefits to customers and aid the DNO with network management. Thirty houses, ten schools and an office will have solar PV and a battery installed.

D.32 **Capacity to Customers - Electricity North West**

This project trials techniques to avoid conventional network reinforcement for the connection of low carbon technologies and general demand growth by using the latent capacity of the high voltage (HV) and extra high voltage (EHV) networks.

D.33 **FALCON - Western Power Distribution**

This project aims to facilitate the installation of low carbon technologies by delivering faster and cheaper connections on the HV network by avoiding traditional reinforcement. The trial will provide learning on the use of real time network data to inform network planning rather than traditional indicators such as total demand and engineering guidelines.

D.34 **Flexible Networks for a Low Carbon Future - Scottish Power**

This project seeks to trial a combination of smart network interventions and customer energy efficiency measures at three network locations. The objective is to demonstrate how they can release capacity on the HV network, allowing greater take up of low carbon technologies without the need for expensive network reinforcement. These technologies include solar PV, heat pumps and EV charging points. The project also intends to encourage specific industrial and commercial customers to improve the energy efficiency of their buildings to reduce their electricity demand.

D.35 **Flexible Plug and Play – UK Power Networks**

This project seeks to achieve the cost effective connection of renewable generation to the distribution network through innovative integration of technical and commercial solutions.

D.36 **New Thames Valley Vision - Scottish & Southern Energy**

This is a large multi-faceted project which seeks, amongst other things, to develop a tool to predict the take up of low carbon technologies by consumers. The project will use retail market research techniques to do this. It will also assess the effectiveness of various interventions to manage actively the network including: automated demand response, voltage control, street level energy storage and a range of communications solutions.

Annex E – Methodology and Assumptions from Imperial/NERA analysis

Context

E.1 DECC commissioned analysis of the electricity system to 2050[55] under a range of different generation and demand scenarios[56] to attempt to quantify the potential size of the balancing challenge[57] and the value of alternative balancing technologies[58], and to understand when the electricity system might start to experience significant cost savings from widespread deployment of these alternative technologies.

E.2 The analysis used four very different potential future electricity systems, based on DECC's 2050 Pathways Analysis and considered the balancing challenge of each to understand the system benefits (and therefore economic incentive) for the different technologies. By using more 'extreme' future scenarios the analysis was able to highlight the main variants that might impact the balancing challenge and the value of alternative balancing solutions.

E.3 The 2050 Pathways Analysis scenarios were used to develop 'counterfactual' Pathways. These counterfactual Pathways artificially excluded 'balancing technologies' and assumed only existing generation would be used to ensure electricity security. The counterfactual calculated hourly peak demand profiles based on the Pathway's electrification and energy efficiency assumptions and modelled these at extreme weather situations (a severe winter coupled with a 3 day wind lull) to calculate demand profiles at the absolute peak. Additional generation was added to the Pathway to meet these absolute demand peaks to ensure that demand could be met even under extreme (1 in 10) conditions was maintained (assuming interconnection is not used).

E.4 All alternative balancing solutions assumed in the 2050 Pathways Analysis scenarios were removed to produce the counterfactual. This allowed the balancing challenge to be quantified and the value of the non-generation balancing technologies to be measured.

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[55] The focus is on snap shots in 2040 and 2050, with limited consideration of 2020 and 2030.

[56] The analytical work was undertaken by Imperial College and NERA consulting. The analytical document is published alongside this document and can be found at http://www.decc.gov.uk/en/content/cms/meeting_energy/network/strategy/strategy.aspx#Electricity_system_policy

[57] The balancing challenge is defined as the savings in UK electricity system costs that can be achieved through the adoption of alternative balancing options over the period to 2050.

[58] For more detail on the specifics of these technologies see Chapter 4

E.5 The balancing challenge is defined by the scale of cost reductions achieved by comparing the Pathways with balancing technologies against the counterfactual scenarios when the balancing technologies were removed. These cost reductions included:

- Generation capital cost reduction associated with avoiding building additional generation to meet peak demand. This cost reduction is produced by decreasing the peak demand for 1 in 10 winters or replacing the peaking generation plant to do this with an alternative.
- System operation cost reductions. This is associated with more efficient use of the existing system/generation, either through lower/more efficient use of fossil fuels and thus carbon credits or increasing the load factors of renewable generation by ensuring it can run as much as it wants – these are the costs associated with the limited ability of the system to absorb intermittent or inflexible electricity generation[59] (and therefore higher curtailment).
- Network capital investment cost reductions, split by distribution and transmission, although the majority of the potential benefits are on the distribution network. These capital savings are associated with a reduction in the need for investment to back up the network due to higher demand. Therefore they are driven by reductions in peak demand.

E.6 Using the counterfactuals as a starting point Imperial College used an electricity system model to consider the capital and operation cost of generation, the network (distribution and transmission) capacity and investment and more short term actions taken. A range of scenarios were run for different combinations of the balancing technologies under different sensitivities and the system costs from these runs were compared to the counterfactual to calculate the savings available.

[59] Generation may have to be curtailed in order to balance the system when demand is low or there are stresses on the system. The cost/ or value of this varies by form of generation.

Modelling the UK's electricity system to 2050: Assumptions, methodology and limitations

Assumptions

- The assumptions used are from a wide variety of sources, however, as far as feasibly possible all of the assumptions are the most up to date and consistent with any other analysis undertaken within and for DECC/Government.

Modelling Approach

- Snapshots of 2030, 2040 & 2050
- 4 main scenarios based on DECC's supply and demand Pathways
- Assumptions about what these mean for peak demand and supply over hourly periods, and added in a 1 in 10 winter coinciding with a 3 day wind lull
- Additional emissions are priced, but total allowances are below the cap
- A counterfactual was developed for each scenario using the level of thermal peaking plant, mainly OCGTS, required to provide security of supply, without any of the other flexibility options.
- The model then looked at the 'value' of using other flexibility options instead – both individually and as a combination with other balancing technologies
- Modelling is ambitious and detailed at a GB and European level and all hours of the year
- The model optimises everything at an EU level, and generates least cost scenarios to achieve the maximum value to the EU system
- Results are presented at an European level, not exclusively at GB level
- The focus is on pre-gate closure - market balancing

Limitations

- Sheer number of uncertainties looking nearly 40 years ahead, make the model complex and results difficult to generalise
- Demand is uncertain – GDP, efficiency, Heat Pumps and EVs
- Level of customer engagement in Demand Side Response (DSR)
- Technology – costs and performance are uncertain now, uncertainty only increases out to 2050 (particularly for new technologies)
- Market Arrangements and investment climate/decisions – difficult to predict post EMR
- Fuel Prices and Carbon Price
- Networks– what investment will actually occur, and what savings can be achieved with DSR
- Interconnection – value dependent on future EU generation mix and market arrangements
- The model assumes a perfect working market and perfect foresight of generation and demand

Balancing technologies

E.7 The analysis focussed on four balancing technologies: interconnection; demand side response (DSR); Flexible Generation and electricity storage. High and low costs or penetration assumptions were considered for each of the technologies, with the aim of providing a range of impacts. For each Pathway, 16 scenarios were considered, combining the full range of high and low for all technologies. This was used as a basis to make an assessment of the individual impact of a technology and its interaction with the other technologies. Additional sensitivities, including the input assumptions to the system model, were included to test these findings further.

Table 1: Low and high cost assumptions for the balancing technologies

Flexible option	Cost level	Value
Flexible generation	Low	10% over investment cost
	High	50% over investment cost
Storage*	Low	£75/kW/yr (B), £100/kW/yr (D)
	High	£125/kW/yr (B), £200/kW/yr (D)
Interconnection	Low	£96/MW/km/yr
	High	No new interconnections beyond 2020
Demand-side response	Low	80% penetration
	High	10% penetration

* B = Bulk, D = Distributed

E.8 A range of other sensitivities were considered in the analysis that have impacts across technologies and Pathways. These included:

- Assumptions behind heat pumps use: if heat pumps are undersized (to save installation cost or improved coefficient of performance) they will run for longer but with a lower peak level of demand to heat the home to the same level, thus flattening the demand profile. In addition the amount of energy efficiency in the home will influence how well the heat is retained and therefore how 'hard' the HP needs to work. The same can be said about whether electric vehicles are charged at home with a lower kWh demand over a longer period of time or using a higher voltage plug at street level (or installed in the home) to charge faster, but creating a greater peak in demand.
- Improved wind forecasting certainty and using wind in the reserve market. This decreases the need for and value of quick response but gives the market more certainty of what generation mix they might need. As discussed above this has varying impacts across the scenarios and Pathways; with flexible generation in Pathway A seeing the biggest impact and DSR across all Pathways hardly responding.
- There is an interaction with the value of interconnection for most of the flexible technologies under different pathways. If DSR (or other flexible solutions) is used at scale in Europe then the value of flexible solutions in GB is lower as there is less value from exporting balancing facilities.

Annex F - Additional analysis relating to electricity system balancing

F.1 The analysis by Imperial College and NERA is broadly consistent with, and builds on, a range of previous publications in this area. This includes publications by National Grid and the Committee on Climate Change.[60] The Government has also been engaged in other pieces of research related to electricity system balancing.

Benefits of household DSR

F.2 Redpoint Energy and Element Energy considered the benefits associated with different domestic demand side response (DSR) tariffs up to 2030. The analysis considered sensitivities of the level of electrification of heat and transport[61] for three DSR tariffs combined with estimates of the take up of DSR tariffs and consumer response (load shifting) as a result of the tariff. These scenarios and sensitivities were modelled to calculate the potential generation capex savings, generation operation savings (including carbon savings) and distribution network savings.

F.3 This analysis is novel in its approach to try and estimate the potential benefits of DSR under different take-up scenarios. As such the results and findings of this work should be approached with a degree of caution; however, we have aimed to present the main caveats and uncertainties.

F.4 The different DSR tariffs considered were[62]:

- Static Time of Use (STOU) tariff; different unit prices defined for different blocks of time across the day. The time and price of peak tariffs may vary seasonally, but would have to be pre-defined in advance. However, the same peak tariff window was considered for all years modelled.
- Critical Peak Pricing (CPP); a pre-specified high tariff is applied for usage during periods of stress on the system. Consumers will receive limited notice of the critical peak period e.g. one day ahead. This tariff applied for 30 days a year for a 3 hour peak on top of the STOU tariff.
- Load Control (LC); is an incentive based tariff, where consumers electrical equipment can be remotely controlled. Two variants were modelled; LC1 where load control is only available for 30 critical days and LC2 where it is available every day.

F.5 The analysis is focussed exclusively on the benefits associated with these tariffs and does not attempt to estimate the potential costs for DSR as a whole or the different tariffs. However, there will be a range of different costs associated with DSR, including the cost to consumers (in terms of the loss of utility and infrastructure needed), and costs to suppliers and other players in the market (i.e. IT systems and advertising).

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[60] Include all the references.
[61] Based on current DECC and OLEV estimates
[62] These tariffs should be considered as proxies for the potential tariffs that might be available to consumers in the future and aimed to provide a representation of the different approaches that the tariffs could take.

F.6 This work suggests that there could be significant system gross benefits from STOU tariffs (ranging from £60m to almost £200m[63] a year by 2025/30), and potentially greater savings associated with the more dynamic tariffs (up to £500m in 2030 relative to the BAU[64] from the load control tariff). The dynamic tariffs begin to show material incremental benefits over the static time of use tariff around 2025 under the central and high scenarios with the increase in the electrification of heat and transport.

F.7 The majority of benefits from domestic DSR are associated with avoiding building additional generation capacity and not reinforcing the distribution network (linked to peak reduction). The load control tariff (LC2), however, produces greater generation operational savings (£40m to £160m in 2030) as it flattens the demand load profile rather than just reducing the peak. This is potentially a more direct and real time benefit from DSR.

F.8 The analysis finds a reduction in the average wholesale price of around £1.3/MWh or 2% in 2030 for the load control tariff. The annual wholesale purchase costs savings (as seen by suppliers) ranged from £7 (STOU) to £34 (LC2) per household on the DSR tariff in 2030. These price reductions could be considered as a proxy for the incentive for suppliers to undertake DSR. If all the system savings were passed onto households they could see a benefit of up to £90 in 2030 under the high LC2 scenario.

F.9 In general the results of this work were found to be very much dependant on the level of electrification of heat and transport and the take up of the different tariffs and consumer responses to the tariffs. Further development of policies around low carbon heat and transport would reduce uncertainty around low carbon technologies projections. In addition further work is needed to consider the likely take up of DSR tariffs, consumer responses to prices, consumer acceptance of a 3rd party having more control of their electricity demand profile, and greater understanding of the costs that might be involved for all agents.

F.10 Redpoint and Element also found that there was a need for flexibility in the STOU tariff across consumers, especially as the number of heat pumps increased. Heat pump demand was being shifted forward a few hours and coinciding with the nondomestic peak and increasing the system peak. This could be resolved by varying the peak tariff window, or increasing the level of storage in heat pumps.

63 Figures not discounted

64 Business as usual – assuming no additional demand side response from status qua.

Literature Review of consumer engagement with DSR

F.11 Dynamic pricing has been in existence in the United States and some Scandinavian countries for some time. To build our understanding of how GB consumers can be best incentivised to take-up more complex tariffs, DECC commissioned a literature review[65], published alongside this document. The review has looked at how consumers have responded to major DSR trials internationally and whether there may be any lessons learnt which could apply in GB. This is a starting point, and more work is required to understand consumer responses to dynamic pricing and remote control of consumers' electricity use patterns in GB.

F.12 The main findings of the review were:

- customers do shift their demand in response to economic and non-economic incentives even if these are accompanied only by basic information, but responsiveness increases with more information;
- external automation delivers the most sustained household demand shifting;
- consumers do not necessarily respond better to tariffs with the highest differential between peak and off-peak prices. This may be related to the length of the peak periods, as longer peak periods seem to be associated with lower reductions in peak demand;
- critical peak tariffs[66] have a greater impact on peak demand in the day the response is called than Critical Peak Rebates[67] or less sophisticated Time of Use Tariffs; and
- consumers are generally positive towards DSR initiatives. They accept direct load control as long as it does not reduce their comfort and they can over-ride it.

F.13 The review also looked at other sectors such as rail, gas, water and telecoms which are subject to daily peaks and services cannot be "stored", therefore capacity needs to be in place to supply peak demand.

F.14 Some of the key findings which could be useful in how DSR initiatives are designed in the future, were:

- in line with the energy sector, there is a consistent theme across these sectors that consumers respond to economic and non-economic incentives;
- experience from the rail sector is that large price differentials for both the peak periods and the adjacent "shoulder periods" may be required to change consumer behaviour as otherwise new peaks could be created if the price in the shoulder period is too low;
- consumer sensitivity to DSR signals has varied in the telecoms sector depending on the time of the day. There could be analogies with the use of different domestic appliances in the energy sector, where consumer reaction could depend on the time of the day; and
- consumers find a large range of prices confusing; this may impact on how they respond to initiatives to shift their demand.

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[65] Demand Side Response in the domestic sector – a literature review of major trials, Frontier Economics, March 2012 is available at http://www.decc.gov.uk/en/content/cms/meeting_energy/network/strategy/strategy.aspx#Electricity_system_policy

[66] Critical peak prices are higher prices set for only a certain number of days per year where the consumer receives notice close to the time of when a higher price will be in place.

[67] Critical peak rebates are a reimbursement to consumers for reducing consumption on a critical day instead of increasing the price.

F.15 The uncertainty around the level of take-up of more dynamic Time of Use Tariffs, makes it difficult to predict at this stage how the DSR market will develop and whether the full potential value to the system will be realised. It is important that consumers are engaged and incentivised in order for this potential to be unlocked.

Analytical framework for smart grids

F.16 The Smart Grids Forum (SGF)[68] has developed a practical analytical framework which can help improve understanding of the likely value of smarter distribution network investment compared to conventional alternatives under different scenarios, and which can be updated as new information arises.

F.17 Initial analysis undertaken by the developers of the framework (Frontier Economics and GSK)[69] suggest that:

- Smart grid technologies (including DSR, storage, enhanced automatic voltage control, dynamic thermal ratings and active network management) can deliver significant savings over the period to 2050 relative to using only conventional alternatives. This is because including smart solutions in a strategy widens the set of options available to DNOs, and allows them to choose less costly solutions and defer conventional investment where appropriate.
- Savings are highest where low-carbon technologies have the greatest penetration, and where customer engagement with DSR is highest, but there are benefits even where customers' willingness or ability to be flexible with demand lower
- There is no significant cost saving in deploying smart technologies before 2023 (due to limited penetration of low-carbon technologies). Equally, nor is there a penalty in doing so. Where regional levels of low carbon technology penetration are above the national projections earlier investment in these regions will capture benefits.
- The use of smart meter dynamic DSR before 2028 provides little additional benefit to networks. It is dynamic DSR (not STOU) that provides the mechanism to manage peaks arising from wind intermittency and wind generated electricity will not be prevalent until then.
- Savings are small from grid based dynamic DSR to manage local network peaks. This is because peaks are already significantly reduced when smart meters deliver STOU and dynamic DSR.
- Most of the benefits of smart grid strategies fall to distribution networks. The costs and benefits of smart grid strategies are therefore likely to be reasonably aligned.

F.18 The results of the analysis provide a first step to understanding what drives the value of smart grids rather than a definitive assessment of their value. But the conclusion that can be drawn is that smarter networks are expected to deliver benefits in the coming decades but more analysis is required to decide at what point their deployment should commence in a significant way.

[68] The terms of reference for the SGF are available here: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=7&refer=Networks/SGF

[69] http://www.ofgem.gov.uk/Networks/SGF/Publications/Documents1/RPT-SGCBA%20%20STC%20Final%20-160312.pdf

Further electricity storage analysis

F.19 Imperial College has recently published a detailed analysis of the role and value of electricity storage for the Carbon Trust. They undertook a very similar methodology and approach as the analysis undertaken for the Electricity System analysis project. The key interesting points that come out of this work as a result of its exclusive focus on storage are:

- The difference between distribution and bulk storage – the benefits from distributed storage are generally lower than bulk for transmission and operating cost savings. Distributed storage can access distribution network cost savings. Thus there are trade-offs between the three benefits when trying to maximise the system benefits. The analysis demonstrated that with low levels of storage (2GW) bulk maximises the system benefits, but with higher levels distributed storage produces larger system benefits; i.e. the distribution network cost savings outweigh the reduction in operation and transmission network savings.
- The efficiency of storage does not impact its value significantly until high levels of deployment are reached. This fact may be hidden in the Electricity System analysis, but demonstrates that the efficiency of initial storage units may not be crucial until greater numbers are deployed.
- All the scenarios considered show considerable reductions in the value from storage per MW with greater deployment. In general the value drops significantly until 5GW in 2030 and 10GW in 2050 is installed before levelling out.

Annex G - Projects supported under DECC's Low Carbon Investment Fund

Energy Optimisers and Gaz de France

G.1 This project is a small scale demonstration of automated, aggregated demand response to provide system balancing services. It will involve a field trial to meter and control 40 air source heat pumps (4-10kw) in commercial installations using smart metering and load control devices connected to a local gateway, connected to an existing balancing services system providing demand response services to National Grid. The novelty of the project is derived from the development of an interface to link the two components. The project has two partners, Energy Optimisers and the licensed business electricity supplier Gaz de France, providing the smart metering and load control technology and balancing service provision expertise respectively. The project will conclude in April 2013.

Arqiva Ltd and E.ON

G.2 This project saw Arqiva build a Smart Grid demonstration system at its Brookman's Park facility near Potters Bar in Hertfordshire. It has been able to demonstrate the remote monitoring and automatic control of various active generation and distribution elements and is a showcase of significant importance to DNOs, equipment vendors and any other stakeholders with an interest in Smart Grid technology. Furthermore, the demonstration system has enabled utilities to perform their own Smart Grid trials and demonstrations in a prime 80 square kilometre area just north of the M25 due north of London.

Highview Power Storage and Scottish and Southern Energy

G.3 This project was led by Highview Power Storage and was concerned with the construction and deployment of a grid-connected energy storage demonstration project. The energy storage system is rated at 500kW and has a capacity of 4MWh. The project is in collaboration with the Scottish and Southern Energy and is located next to a 80MW biomass plant in south east England. The storage technology makes use of liquefied air or liquid nitrogen as the working fluid and storage medium. The proposal focuses on phase 2 of the project which relates to the charging system. The project successfully completed TRIAD arrangements with the National Grid, and the next step will be for the company to find funding to develop a commercial scale trial for a system rated at 5MW.

RLtec

G.4 This project demonstrated the potential of "dynamic demand" technology to enhance the operation of the electricity system by reducing the need for operational reserves to be held on conventional plant and hence reduce carbon emissions. The proposer supplied response services to National Grid and had agreement from Sainsbury's to install dynamic demand technology at 200 sites to deliver 3MW of demand response. The project was successful in supplying demand response services to National Grid and could be replicated across GB. This project built on experience from a CERT project approved by Ofgem to demonstrate dynamic demand from 300 and later 3,000 domestic refrigerators and extended dynamic demand into the industrial and commercial energy supply and demand sectors.

Smart Grid Solutions and Scottish Hydro Electric Power Distribution

G.5 The project will progress the understanding and operation of IT and communications technologies by applying lessons learned from the deployment of an Active Network Management (ANM) scheme on Orkney. The project will deploy an entirely new communications and IT and Communications hub environment and make the ANM scheme fully IEC61850 compliant. The project will bring the following benefits:

- progress the ANM technology trialled on the Orkney Islands
- demonstrate ANM technology on a different IT platform
- demonstrate a fully IEC61850 compliant ANM scheme
- be capable of integrating other Smart Grid technologies
- add to the UK industry knowledge of Smart Grid deployment

This project will conclude in December 2013.

Scottish Hydro and Smart Grid Solutions

G.6 This project seeks to implement an Active Network Management (ANM) scheme incorporating the integration of demand side management with an energy storage device. The primary objective is to use the energy storage device to manage demand and hence remove the need for traditional plant upgrades. It will build on three areas of development that have previously been successfully deployed:

- Progress the successful ANM technology trialled on the Orkney Islands
- Add UK learning on grid scale battery storage technology to add to the current body of knowledge on energy storage
- Extend current large industrial customer demand side management to smaller industrial & commercial customers

The generation of the battery has been delayed but the proposers hope to conclude the project in December 2013.

Scottish Power Distribution

G.7 This project is an upgrade to a distribution network in the Glasgow Clyde Gateway regeneration area, and applies automated elements to the network which includes 2MW of business demand and various sources of generation. Tools to automate re-configuration of the network and improve fault localisation will be deployed. Learning is expected in: Smart Grid technology integration into an existing network; real time monitoring and measurement of load; automation to optimise losses and utilisation; remote fault location; accommodation of various generation sources. This project is being further developed under a Low Carbon Networks Fund Tier 1 project.

National Grid

G.8 This project will assess the requirements for, and demonstrate the viability of, enhanced data exchange between the System Operator, Transmission Network Operators (TNO) and Distribution Network Operators (DNOs) to facilitate secure and effective operation of the Electricity Network following Smart Grid introduction. The project links the control centres of TNO/DNO to enable automated alerting of generating capacity change events through measurement of actual generating capacity on line rather than the "nameplate" capacity theoretically available.

G.9 The innovation is that this is the first practical data exchange deployment of this type in the UK. It will enable more effective planning in the future and potentially reduce operational costs and ensure grid operational security. This project will conclude in December 2013.

Annex H - Smarter Networks: Actions to overcome current and future barriers to smart network deployment

Summary

H.1 The low carbon transition presents new challenges for electricity networks. At the transmission level new and less flexible generation sources in new locations will need to be connected. At the distribution level, there will be greater demands on networks, driven by a shift towards electric vehicles and heating and distributed generation. Smart network (or "smart grid") solutions will help network companies manage these challenges, allowing them to offer greater value for money and enabling consumers to play an active role in managing their energy use.

H.2 Network companies will play the primary role in delivering smart network solutions, alongside suppliers and consumers. Government and the regulator also have an important role to play, and must create the right environment to support a smart future. In particular, DECC and Ofgem have been working to identify and implement actions to overcome barriers to deployment of smart network solutions. This has involved close working with industry through the Smart Grid Forum in particular.

H.3 This Annex report sets out four main barriers: *(1) uncertain investment profiles*; *(2) regulatory and commercial frameworks that are designed for more conventional approaches*; *(3) consumer engagement;* and *(4) the need for significant technical innovation*.

H.4 The report also sets out the actions we are taking to overcome the barriers:

- Through the Smart Grid Forum we developed shared assumptions and scenarios of future demands on electricity distribution networks. We used this to create an economic model to assess what smart investments will offer value to the consumer. DECC's roll out of smart meters will create a platform to support smarter networks. These actions will inform investment decisions during the electricity distribution price control period ("RIIO ED1").
- We have established a workstream within the Smart Grid Forum to assess the commercial and regulatory barriers to smart approaches, and this will produce a report in the Autumn, and will also inform Ofgem's price control review.
- Stakeholder engagement has a central focus in RIIO ED1 which will help ensure DNOs understand what their customers want. Smart meters will improve the ability of DNOs to communicate directly with their customers.
- We are supporting innovation and smart technology. Crucially, Ofgem's Low Carbon Network Fund has made £500m available to network companies over five years to trial new technologies and approaches. This will be continued under RIIO-ED1 through the Innovation Stimulus.

H.5 Smart Grid Forum published its latest report[70] in August 2012, describing its smart grid evaluation tool to assist network companies and Ofgem in business planning for the next distribution price control, RIIO ED1. Looking ahead, there is still more to do. Key milestones include the refinement of the economic model to assess smart investments so that it can assist network companies and Ofgem in business planning for the next price control, the launch by the Smart Grid Forum of a Smart Grid Knowledge Portal later this year, the roll-out of smart meters from 2014, and the implementation of the RIIO ED1 price control framework in 2015.

Introduction

Electricity networks are a crucial part of GB's energy infrastructure

H.6 The electricity network (or electricity grid) is the nation-wide infrastructure that allows us to transport power from where it is generated to the end user. The electricity network has two distinct parts. The transmission network carries power at high voltages (between 132kV[71] and 400 kV) over long distances. There are three regional owners[72] of the different parts of the onshore transmission network and they are responsible for investing in and maintaining it. On a day-to-day basis, the transmission system is managed by the System Operator (National Grid).

H.7 The other part of the network comprises the regional distribution networks, of which there are 14 in GB, owned by a variety of companies, some of whom own more than one network. In these networks the voltage of electricity from the transmission network is reduced down through a series of transformers to the 230 volt supply that reaches most homes and businesses.

H.8 The system we currently have has evolved to channel electricity from a small number of big power stations to a large number of final users, and the distribution networks in particular have been designed for a one-way flow of electricity. Electricity networks are natural monopolies and the companies running them operate within a regulatory framework set up by Ofgem, the electricity and gas industry regulator.

Low carbon and security of supply objectives will lead to major changes in the future generation and demand

H.9 We need to ensure secure energy supplies and make the transition to low carbon in a way that minimises costs and maximises the benefits to society and the consumer.

H.10 A fifth of our domestic electricity generating capacity is set to close over the next decade, and the low carbon transition will require new forms of electricity generation in new locations including at local level. Electrification of heat and transport will increase electricity demand and by 2050, and we may need as much as double today's electricity capacity to deal with peak demand[73], and bring different load patterns.

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[70] http://www.ofgem.gov.uk/NETWORKS/SGF/PUBLICATIONS/Pages/index.aspx
[71] 132Kv is used on the transmission network in Scotland
[72] They are: National Grid, Scottish Power Transmission Limited and Scottish Hydro Electric Transmission Limited
[73] http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx

H.11 Clearly, this will have significant implications for electricity networks and the wider electricity system. Today's electricity generation has the capability to vary its output to meet changes in demand. More use of intermittent renewables and other low carbon energy sources will make electricity generation less flexible, making it harder and more expensive to match supply with demand through traditional control of generation. New expected sources of demand such as electric vehicles or heat pumps and greater use of distributed generation will bring new demands on networks, including the need for two-way local power flows.

Defining the "smart grid"

H.12 Building a "smart network" (or "smart grid") is expected to be an essentially incremental process, so it is sensible to talk about "smart*er* networks". It involves the deployment of technologies and approaches that give network companies a better understanding of how their assets are used, and more control over this use. This will support greater interaction between suppliers, network companies and consumers, allowing electricity assets to be used more efficiently.

H.13 There is scope for the entire electricity system – across transmission and distribution –to become smarter. However, the focus of this paper is the distribution system, given the challenges they face, as set out below. Smarter distribution networks will help DNOs to respond to different load patterns, manage two way electricity flows and participate more actively in system operation. This will make good financial sense, and will enable network companies to use existing and new assets more efficiently and technologies innovatively to manage uncertainty and defer or avoid major capital investment keeping overall costs down.

H.14 They will also play a key role in enabling behaviour change. The transition to low carbon is not simply about connecting more wind or nuclear: it requires consumers to play their part, helping to reduce and / or shift their electricity demand.

Current state of play in GB

H.15 The transmission network already has a significant level of intelligence embedded in its systems. In real-time, the System Operator (National Grid) can monitor the generation connected, and can reduce or increase it as necessary to meet electricity demand. Use of transmission assets is optimised through two-way flows of power. Further improvements are needed, though, including to introduce greater automation to ensure the smooth operation of the system.

H.16 In contrast, distribution network companies have limited visibility of load on their networks, especially at low voltage, and limited ability to control it. Some smart technologies, such as automatic voltage control devices, are relatively simple and well understood whereas others, such as those to facilitate community level energy systems, are more sophisticated. A certain degree of smart functionality is already in place in the GB system in a few locations. For example:

- Due to the connection of both onshore and offshore wind, Skegness generates more electricity than it requires. Exporting the power to the local town of Boston would, using traditional solutions, require reinforcement of the existing lines. Instead, dynamic line rating technology monitors the weather conditions in real time and dynamically assesses the line rating, increasing the capacity of the existing lines for most of the year without the need for physical reinforcement.
- In the Orkney Islands, an innovative Active Network Management (ANM) scheme has provided the basis for the connection of multiple new renewable generators, which are managed to meet network constraints at several monitoring locations on the Orkney network in real time. The deployment of ANM and the accompanying commercial arrangements are a quicker and cheaper alternative to network reinforcement to connect more renewable generation to the Orkney network.
- In central London there is 11MW of contracted responsive demand which will enable major substations to serve higher levels of demand without resorting to major reinforcement. The contracts enable the network operator to call for immediate demand reduction in the event of an unplanned (fault) outage at times when peak demand exceed capacity.

Actions to overcome barriers to the deployment of smarter networks

H.17 In 2009 the Electricity Networks Strategy Group (ENSG) published a Smart Grid Vision for GB, followed by a roadmap (in 2010) describing the challenges to realising the vision. Drawing from this we have summarised the major barriers to the deployment of smart networks in GB:

- Investment barriers: network investment is needed ahead of demand, but future demand is increasingly uncertain as we move towards a low carbon economy;
- Regulatory and commercial barriers: existing regulation, commercial incentives and the structure of the market suit conventional technologies and approaches and may be insufficient to incentivise smarter network development;
- Consumer acceptance barriers: smart technologies and approaches often rely on consumers changing their behaviour, but the extent to which consumers will be willing to do this is still relatively untested;
- Technological barriers: new and potentially disruptive technologies will be needed, and network companies will need the right incentives to reward innovation.

H.18 Addressing these barriers requires acknowledgement of the different roles and responsibilities of DECC, the regulator and energy companies: Government sets the policy framework (including low carbon policy); Ofgem develops the regulatory framework and network companies deliver the policies through building and operating the networks. There are also significant interdependencies with other parts of industry, including supply companies, technology companies and consumers.

H.19 Recognising that this is a cross-industry challenge, in 2011, DECC and Ofgem set up the Smart Grid Forum (SGF). This is a key initiative, co-chaired by DECC and Ofgem and drawing together expertise and views from across industry, including representatives from network, supplier, generator, customer and manufacturer communities. More details about the SGF can be found on Ofgem's website including a full list of members[74].

H.20 The following sets out the major initiatives underway and planned, by the Smart Grid Forum and more broadly, to address barriers to the implementation of smarter networks in GB.

Actions to address investment barriers

H.21 Networks provide a facilitative service in transferring electricity from where it is produced to where it is used. Network assets are typically long-term investments which last many years. Network investments therefore need to be made before demand can be realised. In order to avoid building "stranded assets" and to avoid not building enough network capacity, assessment must be made of future electricity demand and the best technological solution to facilitate that demand.

H.22 Up until recently, demand has been relatively predictable and there has been little distributed generation. However, going forward there is less certainly. Furthermore, the delivery of some technological solutions (e.g. smart meters) will major undertakings, requiring cross industry coordination and will be led by suppliers.

H.23 Through the Smart Grid Forum, we are creating consensus on what the future might look like through shared assumptions and scenarios on future demands on electricity distribution networks, based on the Government's Carbon Plan. This workstream, led by DECC, has provided a vital link between Government policy and the regulatory and planning processes led by Ofgem and network companies. It has helped to define boundaries of expectation in terms of possible future uptake of low carbon technologies (e.g. heat pumps and electric vehicles) at the national level, and in doing so is assisting network companies and the regulator in designing an appropriate regulatory framework to inform investment decisions.

H.24 Based on these assumptions and scenarios, in March 2012, the Smart Grid Forum developed a smart grid economic modelling tool to assess smart investment opportunities relative to more conventional network development in the period from now until 2050. Led by Ofgem, this workstream has developed an economic framework to gain a common understanding of what drives smart investment opportunities at national scale under a range of scenarios and network types with inputs from DECC, network companies and Ofgem[75]. Subsequently, the Smart Grid Forum developed the model to assess the business case for utilising smart solutions and to assist network companies and Ofgem in business planning for the next price control. This work is being led by the network companies in conjunction with Smart Grid Forum stakeholder representatives and is due for completion in July 2012.

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[74] http://www.ofgem.gov.uk/Networks/SGF/Pages/SGF.aspx

[75] The Smart Grid Evaluation report can be found at : http://www.ofgem.gov.uk/Networks/SGF/Pages/SGF.aspx

H.25 DECC's roll-out of smart meters will provide a platform to support smarter network development, by allowing network operators to collect real world data and giving them more control over their networks. Smart meters will support more efficient use of electricity infrastructure by providing better information and improving communication between consumers, electricity suppliers and network companies. Alongside the Green Deal, smart meters will give consumers choice and the opportunity to take an active role in energy efficiency and demand side management. DECC is currently working to procure the Data and Communications services to support smart meters.

H.26 Ofgem's new price control framework – "RIIO[76]" – is designed to better incentivise network companies to make the right investments to support the future demand profiles. It extends the length of the price control period, introduces an explicit focus on delivery of outputs (including timely connections) and requires network companies to fully engage stakeholders. The electricity distribution network price control review (RIIO ED1) was launched in February of this year, and will set the investment profile for the period from 2015 to 2023. Working groups have been established to review and develop outputs, incentives and uncertainty mechanisms.

Actions to address regulatory and commercial barriers

H.27 The existing commercial and regulatory frameworks have been designed in the context of a relatively stable power system in terms of both the demand to be supplied and the technology employed. As a result, there are various ways in which they can act as impediments to the deployment of smarter network solutions.

H.28 Engineering standards govern what network is needed and how it is operated to ensure a minimum level of network reliability. Smart approaches, such as storage or demand side response, may provide alternatives to conventional network investment to meet these standards without compromising reliability. On the other hand, greater penetration of low carbon technologies may make the energy system more susceptible to malfunction (accidental or malicious) because of the increased complexity and greater reliance on electricity, so new standards may be required.

H.29 There are no formal regulatory or commercial frameworks for DNOs to reward consumers for relinquishing some control of how they use electricity, such as electric vehicle charging. At community level, there is no formalised framework for trading between community members or for DNO to invest in/reward schemes which reduce network constraints, or to engage and invest in design of holistic community energy schemes in new developments (which might reduce the need for network upstream asset capacity).

H.30 The successful alignment of the commercial, technical and regulatory structures to support smart technology deployment is a challenging area involving a number of interconnected initiatives.

[76] RIIO stands for Revenue equals Incentives plus Innovation plus Outputs

H.31 The Smart Grid Forum's Regulatory and Commercial Issues workstream was set up in May 2012. It will consider the smart solutions which might be implemented in the next price control period, identify potential regulatory and commercial barriers to implementing these and propose options to remove barriers. Areas under consideration include assessment of engineering standards and contractual arrangements between customers, DNOs, suppliers, transmission companies, the system operator and other industry parties. It will also assess regulatory options that balance objectives related to cost reflectivity of network charges and equitable treatment of network customers. It will publish a report in Autumn 2012 and will inform the development of the electricity distribution price control.

H32 In 2011 Energy Networks Association (ENA) commissioned a report to consider cyber security challenges faced nationally and by distribution network organisations as networks become smarter. It made a number of recommendations. The ENA, SGGB, DECC, Ofgem, IBM and CPNI[77] are establishing a new group to consider these recommendations and undertake a nation-wide risk assessment.

Actions to address consumer acceptance barriers

H.33 A key aspect of many smart approaches involves consumers changing their behaviour with regard to electricity use. For example, if consumers can be persuaded to shift away from peak periods of electricity use, it may be possible to reduce or defer expensive network reinforcements.

H.34 However, there is a limited understanding of consumer willingness to take up smart approaches. Although some smart approaches, such as Economy 7, which offers cheaper tariffs during off-peak times, are already accepted by some consumers, there is less understanding of how they would respond to more complicated offers, such as numerous price changes throughout the day, or direct control of appliances by network companies.

H.35 The commercial relationship between DNOs and customers has traditionally been indirect, so there has not been the need for much engagement.

H.36 As discussed above, the rollout of smart meters will put in place the platform to allow greater interaction between consumers and suppliers and DNOs. Work is being undertaken by the Smart Meters Implementation Programme to understand how consumers will change their behaviour as a result of having a smart meter.

H.37 A key aspect of RIIO ED1 – Ofgem's distribution price control review – is a requirement on DNOs to undertake greater stakeholder engagement and understand the needs of their customers.

H.38 The Regulatory and Commercial Issues workstream of the Smart Grid Forum will also address this issue.

[77] Centre for the Protection of National Infrastructure

Actions to promote smart network innovation

H.39 New smart technologies are needed to ensure that the electricity assets are used intelligently and network companies will need the right incentives to reward innovation.

H.40 We are supporting innovation in utilisation and integration of new smart technologies and commercial arrangements through a number of funding streams. In particular, Ofgem's Low Carbon Network Fund has made £500m available to networks companies over five years to trial new technologies and approaches. This will be continued by the Innovation Stimulus under the new RIIO-ED1 price control. DECC also made £2.5m available between 2009-2011 through its Low Carbon Investment Fund.

H.41 Furthermore, the Smart Grid Forum is working to improve the sharing of knowledge on smart network innovation. It is developing a knowledge sharing portal across industry, academia and the public sector to share findings widely. This will be launched later this year.

H.42 We are also working with international partners to share information through the International Smart Grid Action Network (ISGAN) and with the EU, which has made €100m available through its European Electricity Grids Initiative[78].

Next steps

H.43 There are a number of key milestones going forward, including:

- Smart Grid Forum will publish a report on the Commercial & Regulatory issues associated with smart technology deployment in Autumn 2012
- Ofgem will publish a consultation document on the proposed structure of the electricity distribution price control, RIIO ED1, in Autumn 2012 and publish its decision in February 2013
- Smart Grid Forum will launch a Smart Grids knowledge sharing platform at the ENA Low Carbon Network Conference in Autumn 2012
- DNOs will submit business plans by May 2013 and electricity distribution price control starts in 2015 and ends in 2023
- DECC will announce contract award decision for the communications service provider for the smart metering programme in Spring 2013
- Rollout of smart electricity and gas meters to all domestic properties in GB, will start in 2014, and complete by 2019

[78] This is part of the "Framework 7" Programme

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