Response from the UK Energy Research Centre (UKERC) to the House of Lords Science and Technology Committee Inquiry into the resilience of electricity infrastructure

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Introduction

Ways of viewing electricity system resilience

One way of viewing the different influences on reliability of supply of power to electricity users is in terms of three 'hierarchical levels': 1. generation (simply, is there enough generation available on the system as a whole to meet total demand); 2. transmission (is the capacity of the transmission network sufficient to allow transfers of power from generation to demand); 3. distribution (are network connections in operation from power sources to each electricity user)[1].

Electricity transmission in Great Britain is operated as a single, integrated system, with distribution networks connected directly to it. This allows a sharing of reserve generation across the country in both short (seconds to hours) and long (days to years) timescales, the only limitations being: the scheduling of sufficient 'headroom' on 'spinning reserve', the availability of sufficient short-term 'standing reserve', the sufficiency of generation capacity relative to peaks of demand that might be encountered, the location of generation relative to demand and the capacity of the network to permit surpluses of available power in some areas to be used to meet deficits in others.

Power network resilience

The various network licensees (the transmission owners and the Distribution Networks Operators, DNOs) have licence obligations towards the planning and operation of economic, efficient and secure networks. In particular, rules are defined – 'security standards', which the network licensees are obliged to follow – that outline the required level of resilience to disturbances. At a transmission level, this typically (though with some detailed variations) means that the network can still meet all demand for power even if a primary element of the system, such as an overhead line, cable, transformer or generating unit, is suddenly lost from service. Moreover, this should be possible even when other elements of the system are already out of service for maintenance. At a distribution level, the level of resilience provided against unplanned outages is lower due to the very large number of circuit km and their cost, and the lower impact of an outage. However, a significant and growing emphasis is placed on rapid restoration of supply following any disturbance that disconnects it (such disturbances on distribution network generally affect only a limited number of consumers).

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[1] Allan, RN and Billinton, R (1996). Reliability Evaluation of Power Systems. Springer, New York, US.

Generation and demand on a network

While security standards have been in place for many years and have been applied by the network licensees, achievement of secure supply of electricity depends not only on the network licensees but also owners and operators of generation. Power can only be exported to an importing area if generators are available to produce it. However, the network licensees currently have only a limited influence on the availability of generation or the level of demand that generation should meet. In the longer term, the network licensees have an obligation to make offers of connection to new generators and, if an offer is accepted, to provide and maintain it. In short-term, the National Electricity Transmission System Operator (NETSO, a role filled in Britain by National Grid) can procure, on a commercial basis, availability of generators in critical locations at critical times, provided the generator is not on a forced outage and that sufficient notice has been given. In the longer term, risks associated with prolonged unavailability of key generators must be assessed by the network planner and investments made to increase the network's power transfer capability, if the risks associated with higher imports to a particular area are judged to be excessive.

Similar risks to those associated with unavailability of generation might be linked to higher than expected levels of demand, either in a particular area or on the system as a whole. From year to year and from day to day, the level of demand is affected by the weather. Transmission system operators have generally become good at short-term demand forecasting, but the presence of generation embedded within the distribution networks and not visible to the transmission system operator is making it harder to characterise and forecast the net transfer of power from transmission to distribution. Furthermore, it seems to be the experience in many industrialised countries that longer term (year to year) levels of demand are becoming harder to predict[2].

Lessons learnt from Ireland

The answers provided below concern the electricity system in Great Britain. The system in Northern Ireland is part of a separate electrical 'synchronous area' and a separate electricity market – the Single Electricity Market on the island of Ireland. The standards and regulatory arrangements, within which the system in Northern Ireland is planned and operated, are different from those in the rest of the UK and are not discussed in detail below. However, it may be noted that Northern Ireland, while having a significant wind energy potential, has very few schedulable thermal generating units and is

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[2] CIGRE Working Group C1.32 (2014), "Establishing best practice approaches for developing credible electricity demand and energy forecasts for network planning", Terms of Reference, CIGRE, Paris.

therefore more vulnerable, to failure of one or more of those units, than a larger system would be. In order improve security of supply in Northern Ireland, a new 400kV interconnection to the Republic of Ireland has long been planned and would allow sharing of generation capacity[3]. However, delivery of the line is conditional upon planning approvals both north and south of the border, a process that is made more complicated by the need to satisfy not only both jurisdictions on the island of Ireland, but also European Commission rules on projects of common interest across national borders. This is giving rise to increasing nervousness in Northern Ireland. Meanwhile, as noted, the island of Ireland is operated as one system. It already has, relative to the demand for electricity, a much higher penetration of renewable energy than Britain. As a consequence, the system operator on the island of Ireland arguably has more experience than its equivalent in Britain of the issues associated with, in particular, the variability and low inertia of wind generation.

[3] See, for example, www.eirgridprojects.com/projects/northsouth400kvinterconnectiondevelopment/overview [accessed 19 September 2014].

Questions

Short term (to 2020)

Question 1. How resilient is the UK's electricity system to peaks in consumer demand and sudden shocks? How well developed is the underpinning evidence base?

Generation capacity

Experience over a number of decades suggests that the electricity system in GB is highly successful at delivering a reliable supply of electricity. There have been very few instances of significant failures at 'hierarchical level 1', i.e. there simply not being enough generation to meet demand. The UK has a peak winter demand of around 60 GW and meets this with around 86 GW generation capacity, plus up to 4 GW from interconnectors to foreign electricity systems. The peak load reserve has eroded in recent years due to the coal and oil thermal generation closure programme mandated by the EU Large Combustion Plant Directive. At the same time, the proportion of renewables in the system has increased and these are less likely to contribute to the peak demand than thermal plants; for example, at the peak time on the peak day in winter 2010, there was virtually no contribution to generation by wind. Yet at present, there is still sufficient thermal and hydro capacity to cover the peak (65 GW) if all of these plants are available. By 2020, as older gas-fired plants are retired as well, the reserve will be further eroded and the contribution of intermittent renewables to meeting peak loads could become increasingly important if new gas-fired plants are not commissioned.

In the event of an apparent insufficiency, the system operator does have a number of measures available to them before it becomes necessary to disconnect demand. These include interruption of demand on interruptible demand-side contracts; 'maxgen' (thermal generators, in particular, have some capability to operate at a higher than normal output for some period of time); emergency measures on interconnectors to other countries (to reduce export or, if imports are not already at their maximum level, to increase imports); and voltage reduction. Because a power system is both dynamic and highly complex, the timing of responses can be critical and, under particular circumstances, the system can be on the threshold of complete collapse without rapid intervention. As a result, we believe that 'defence plans' should be put in place that, while they might not prevent disconnection of some demand, will limit the amount that is disconnected and enable a much faster restoration of whatever demand was disconnected. These include automatic 'low frequency demand disconnection', also called 'under frequency load shedding', such as operated during one disturbance in

Britain on May 2008[4]. Although these measures are called upon only rarely, we believe that network planners and system operator should continually ensure that they are available and fit for purpose as the nature of the system develops[5]. Although it is not strictly part of the 'defence plan', one example of the need for periodic review is the performance of voltage reduction. Despite a number of engineers having noted that the nature of electrical loads has significantly changed since the 1980s, when a study of the effectiveness of voltage reduction was last performed in Britain, a new review was only initiated after the May 2008 low frequency disturbance when it was realised that voltage reduction was less effective than assumed.

It has been widely observed that much of Britain's generation fleet is already old and, hence, may be expected to be increasingly unreliable or to require replacement. In the case of nuclear power stations, closure or life extension is the product of judgments made by both the generation owner and the nuclear authorities. For many power stations of different types, the original date of commissioning is not necessarily a good guide to its condition as much of equipment within the station may already have been replaced.

Role of gas generation to 2020 for meeting demand peaks

The UK is legally committed to delivering 15 per cent of its energy from renewable sources by 2020. To reach this figure it is anticipated that renewables will need to generate at least 30 per cent of the UK's electricity by 2020[6]. Wind turbines are likely to play a significant role in achieving these targets but wind is an intermittent source of energy, hence the amount of electricity generated by wind farms is volatile. As cloud cover comes and goes, solar power during the hours of daylight is similarly variable. Such volatility requires other generation to ramp up and down to balance the electricity demand.

A future system with much higher wind capacity might be expected to rely heavily on Combined Cycle Gas Turbine (CCGT) power plants to meet the 'net demand' not met by renewables. CCGT power plants currently make up a large portion of the total generation capacity in GB at 29 GW in 2013 but this is expected to increase to roughly

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[4] National Grid (2009). Report of the National Grid Investigation into the Frequency Deviation and Automatic Demand Disconnection that occurred on the 27 May 2008. www.nationalgrid.com/NR/rdonlyres/E19B4740-C056-4795-A567-91725ECF799B/32165/PublicFrequencyDeviationReport.pdf [accessed 27 August 2014].
[5] CIGRE WG C1.17 (2010). Planning to Manager Power Interruption Events, Technical Brochure 433, CIGRE, Paris.
[6] HMSO (2010). National Renewable Energy Action Plan for the United Kingdom. Article 4 of the Renewable Energy Directive 2009/28/EC.

35 GW by 2020[7]. On occasions when wind output is dropping rapidly and demand is increasing, or is constant and high, total CCGT output should ramp up significantly; if sufficient gas storage capacity is not provided near to power stations this, in turn, implies a need for high volumes of gas to flow through the network in quite a short space of time.

Given that gas supplies from the UK continental shelf have been declining for the past few years, other sources of gas such as liquefied natural gas (LNG), Norwegian and continental gas supplies have been brought online. More storage facilities and linepack (volume of gas in pipelines) management should mollify the actuality of physical gas supply shortages. However, price shock issues are another matter entirely and can be, to a degree, addressed with greater storage capacity, alternatively fuelled power plants, interruptible power contracts and gas demand side management provided interactions with the electricity system are adequately managed[8].

Quantifying generation capacity resilience

Characterisation of the resilience of Britain's power system depends on computer modelling. This, in turn, depends on appropriate modelling of relevant mechanisms and on suitable input data. In respect of hierarchical level 1 (the kind of analysis reported by Ofgem in its annual assessment of capacity margins), the key inputs are 1. availability of conventional generators; 2. availability of power from wind farms; 3. level of demand peaks; and 4. patterns of flow on interconnectors.

There are numerous quantitative measures of electricity resilience. The main purpose of such numerical values is best thought of as helping develop insights into the drivers of

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[7] UKERC (2013). The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios. UKERC, London, UK.

[8] The PJM electricity system in North America experienced severe challenges in the winter of 2013/14 as a result of the 'polar vortex' that brought much colder weather than normal for an extended period of time. One result was that electricity demand on some days was around 33% higher than on a typical winter day. The challenge was compounded by gas demand for heating being much higher than normal and the gas system operator responding by interrupting gas demand on interruptible contracts. This included CCGT power stations. In combination with forced outages of generating plant influenced by the extreme cold weather, this resulted in a combined generation forced outage rate on January 7, 2014 of 22% compared with the historical winter average of 7%. See Keech, Adam (2014), 2014 Winter Conditions and Impacts on Electricity Markets in the PJM Region presented at CIGRE 2014, Paris, www.cigre.org/Events/Session/Session-2014/Documents-download-for-Delegates [accessed 05 September 2014].

energy security rather than to give a prediction of absolute security and reliability in, for example, the coming year. Metrics used to quantify reliability of supply at 'hierarchical level 1' use probabilistic techniques and include Loss of Lost Load Probability (LOLP) and the Expected Energy Unserved (EEU):

- The conventional meaning of LOLP is a probabilistic weighted average value that measures the likelihood of loss of load[9]. It does not capture the amount of load that will need to be shed. During the operation of the CEGB (the former nationalised owner and operator of the England and Wales electricity network and generation), a LOLP of 0.09 was considered the standard[10], i.e. the probability of peak load not being supplied was 9%. A complementary metric is Loss of Load Expectation (LOLE) which quantifies the expected number of hours per year in which supply does not meet demand. However, both DECC[11] and Ofgem[12] qualify this by referring to failure to meet demand *in the absence of intervention from the System Operator* where the interventions include controlled voltage reduction, 'maxgen' by generators, emergency services from interconnectors and controlled disconnections. In other words, LOLE is regarded by Ofgem as the number of hours in which these interventions may be expected to be required; in general this will be greater than the number of hours in which uncontracted customer disconnections will occur.

- The EEU for any particular period (day, week, year etc.) gives the probability weighted magnitude of interruption to energy supplies (loss of load). A cost of EEU can be estimated by multiplying the EEU with a given value of lost load (VOLL).

Monte Carlo modelling techniques can be used to calculate the reliability (LOLP, LOLE, EEU) of the electricity supply system. A model built specifically for this purpose has been commissioned by UKERC and will be used to quantify the impact on the reliability of the

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[9] Allan, RN and Billinton, R (1996). Reliability Evaluation of Power Systems. Springer, New York, US.

[10] Strbac, G, Pudjia, D, Castro, M, Djapic, P, Stojkovska, B, Ramsay, C, and Allan, R (2007). Transmission Investment, Access and Pricing in Systems with Wind Generation: Summary Report www.ofgem.gov.uk/ofgem-publications/55765/dti-centre-dg-and-sustainable-electrical-energy-paper.pdf [accessed 19 September 2014].

[11] DECC (2014), The Electricity Capacity Regulations 2014, www.gov.uk/government/uploads/system/uploads/attachment_data/file/249564/electricity_capacity_regulations_2014_si.pdf [accessed 05 September 2014]

[12] Ofgem (2014). Electricity Capacity Assessment 2014: Consultation on Methodology. www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-2014-consultation-methodology [accessed 27 August 2014].

GB gas and electricity infrastructure due to energy uncertainties such as wind variability, gas supply availability and outages to network assets (generation plants and transmission network).[13]

Doubts have been expressed in respect of the quality of data for all of the inputs to a reliability quantification outlined above[14]. Estimates of peak demand in recent years have tended to exceed those experienced in reality, and future estimates are made more difficult by uncertainties in the extent of demand side response (load shifting in time) as smart metering and time of use tariffs become prevalent. Particular concerns have been raised in some quarters that the potential contributions of interconnector imports are being under-represented in analyses being undertaken by National Grid as part of the process for determining requirements in the future GB capacity mechanism[15]. The claimed result of this is that the cost of generation capacity will be excessive. As minimum, we would argue here that what is required is a clear understanding on all sides of what the reliability standard represents against which generation capacity is being procured. For example, is it the likelihood of disconnection of demand that does not have a contract in place allowing it or some part of it to be disconnected? Or does it represent the likelihood of system operator action being required to manage the shortage of generation relative to demand where such actions include emergency re-dispatch of flows on interconnectors?

Transmission and distribution networks

Electricity demand interruptions experienced in Britain over the last few decades have generally been associated with network outages. Single circuit outages are not uncommon at a distribution level but, as noted above, their impact is generally limited[16]. Because of the design of the transmission network, disconnections of demand originating at a transmission level are relatively rare[17] even though 100 single circuit

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[13] Chaudry, M, Wu, J and Jenkins, N (2013) A sequential Monte Carlo model of the combined GB gas and electricity network, Energy Policy 62:473-483.

[14] Ofgem (2014). Electricity Capacity Assessment 2014: Consultation on Methodology. www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-2014-consultation-methodology [accessed 27 August 2014].

[15] Newbery, D and Grubb, M (2014), The Final Hurdle? Security of supply, the Capacity Market and the role of interconnectors. University of Cambridge.

[16] See www.ofgem.gov.uk/electricity/distribution-networks/network-price-controls/quality-service/quality-service-incentives for DNO performance in respect of 'customer minutes lost' and 'customer interruptions' [accessed 19 September 2014].

[17] See www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Report-explorer/Performance-Reports/ for reports of performance on the GB electricity transmission system [accessed 19 September 2014].

faults might occur in a typical year on the GB transmission system; around half of them due to adverse weather[18], such as lightning, very high winds or sleet, snow icing or blizzards. The most significant events are generally associated with storms that lead to multiple outages in a short space of time, and often to damage of equipment that takes time to repair. Trees and other debris falling on roads, so hindering access to key locations and faults on communications networks, often compound the difficulty of achieving safe and rapid restoration of supply. Issues around recovery from major electricity system disturbances are receiving increasing attention worldwide not least in view of the need to coordinate the responses of multiple parties[19].

The underlying resilience of the power system to adverse or extreme weather is very difficult to determine. While past experience suggests that conventional 'N-1' transmission design and operation rules do deliver a resilient system[20], extreme weather is, by definition, rare and any conclusions relative to past performance cannot be regarded as completely robust. Of particular concern should be relatively rare 'common mode' failures, such as very high winds that cause large numbers of wind turbines to shut down, 'type faults' on generators, i.e. those consequential to the design and may, as a result, be expected to affect other generators of the same type, or double circuit or substation faults on the transmission network. Particularly severe examples of the last of these started to receive increased attention in recent years following the floods in Gloucestershire during 2007.

As already noted, the most severe network disturbances occur either when there are multiple faults within a short space of time, such that earlier outages have not yet been restored before further outages occur, or that a single, very rare event leads to the loss of multiple system elements. The net result is that the system's state is worse than the 'N-1' under which it was designed to still have acceptable operation. Hence, while both cases have quite low probability of occurrence, they have quite high impact. Analysis of such situations is difficult and not helped by wide variability in the quality of outage statistics. This includes generator availabilities mentioned above but also statistics on fault rates and outage durations for network components such as overhead lines, underground cables, transformers, circuit breakers and bus sections. To be of greatest

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[18] Murray, K & Bell, KRW (2014). Wind Related Faults on the GB Transmission Network. Proceedings of the 13th International Conference on Probabilistic Methods Applied to Power Systems, Durham, 07-10 July 2014.
[19] Southwell, P (2014). On behalf of the CIGRE Technical Committee, Disaster Recovery within a Cigre Strategic Framework: Network, Resilience, Trends and Areas of Future Work. CIGRE, Paris.
[20] 'N-1' refers to the state of the system in which one element is out of service, 'N-2' when two elements are out and so on. Alternatively, in some countries, the '1' in 'N-1' refers' to an outage event that might actually cause the loss of more than one element.

value to modelling of system performance, outage causes and restoration times should be consistently noted. As reported in Murray & Bell (2014), some transmission network licensees in Britain do better than others in this respect.

A high proportion of Britain's power network assets are already more than 40 years old, sometimes more than 60 years old. Much of it may therefore require investment in replacements. Since the associated outages are longer than for routine maintenance, depleting the network's capacity in the meantime, this requires careful planning. However, in many cases it is found that assets older than their planned life are still in reasonable condition and it is not necessarily the case that new assets will more reliable or have similar longevity.

The relationship between generators and network operators

One thing noted by CIGRE WG C1.17 was the dependency on multiple actors to deliver a resilient power system. As well as providing active power, generators are critical to the regulation of system frequency and the provision of reactive power to support voltage. In a liberalised electricity supply industry such as that in Britain, generators are owned and operated independently of the system operator. In many countries, experience shows that grid codes that define generators' responsibilities towards the system and, in some countries such as Britain, markets for system balancing services, succeed in ensuring that the system as a whole can be operated reliably. However, on occasions, it is found that not all equipment performs as it should. Network licensees are responsible for the performance of network equipment and can intervene directly to maintain adequate performance. However, the system operator responsible for system performance is not responsible for whether generation equipment performs correctly, and failures of generator systems have sometimes been implicated in major system disturbances around the world[21].

The network licensees in Britain have a number of incentives to improve performance in respect to reliability of supply. The main incentive for generators is to be available to generate in order to gain revenues from the sale of energy. Under the proposed capacity mechanism, generators would not only receive an income from actual operation and production but also from being ready to operate. In some categories of short-term reserve, a similar arrangement already exists. For DNOs, there is an incentive to reduce 'customer interruptions' and 'customer minutes lost'. For the transmission owners, the average annual availability of circuits is reported along with the estimated energy not supplied as a consequence of transmission faults. A major, but not the only, influence on these indices comes from the management of the various assets, where benefits of

[21] CIGRE WG C1.17 (2010). Planning to Manager Power Interruption Events, Technical Brochure 433, CIGRE, Paris.

maintenance must be balanced with the cost of maintenance and the impact on the system of an asset being out of service while it is maintained. For older assets, where maintenance is increasingly difficult (perhaps because of the obsolescence of components) or expensive and the asset is still required on the system, replacement of asset becomes necessary.

Question 2. What measures are being taken to improve the resilience of the UK's electricity system until 2020? Will this be sufficient to 'keep the lights on'?

The main challenges identified by the Committee on Science and Technology Committee's Call for Evidence on the Resilience of Electricity Infrastructure are the:

- Closure of ageing power stations;
- Decarbonisation of electricity, largely by means of renewables and nuclear power which the Committee says will be less flexible than fossil fuelled plant.

The inability to schedule wind or solar power, their variability, the low inertia of sources of power that use power electronic interfaces and the relative inflexibility of some of the leading designs of nuclear power stations means that: (a) renewables cannot be depended on to meet peak demand; (b) the 'net demand' not met by renewables and nuclear power will be highly variable and requires some very flexible means of meeting it; and, (c) losses of power infeed (i.e. supply of power to the system, under high wind, solar or import conditions) would lead to rapid changes of system frequency and, without adequate countermeasures, risk of frequency instability.

The measures being taken that can contribute to resilience of the power system include:

- Introduction of a capacity mechanism.
- Interest by investors in development of new interconnectors.
- Development of balancing service arrangements to encourage demand side response.
- Expansion of the number of aggregators offering demand side services.
- Continued incentivisation by Ofgem of distribution network operators (DNOs) to maintain quality of service as measured in terms 'customer interruptions' (CI) and 'customer minutes lost' (CML).
- Securing of 'Network Innovation Competition' (NIC) funding by Scottish Power Energy Networks for the 'Visualisation of Real Time System Dynamics using Enhanced Monitoring' (VISOR) project.
- Proposed NIC project on the management of system stability on a system with greatly increased production of power from wind energy, from National Grid Electricity Transmission and partners.

While the above initiatives are welcome, we believe there are some open questions, among which are the following:

1. Is the reference reliability level proposed for use in the capacity market set appropriately given different stakeholders' interpretation of it and the likely costs of procuring the requisite volume of capacity[22]?
2. Will the mechanism by which capacity is planned to be procured in the capacity market both deliver sufficient capacity and be cost-effective?
3. How should potential contributions to long-term security of supply from international interconnectors be treated in the capacity market?
4. Is it appropriate that development of international interconnectors to and from Britain is left solely to private 'merchant' investors when most other European countries see it as a responsibility of the regulated transmission system operator (TSO)?
5. What more can be done to deliver the large potential for Electricity Demand Reduction already identified by DECC?[23]
6. What are the main blocks to development of demand side response that can help with electricity system in real-time and how can they be overcome?
7. Does National Grid Electricity Transmission as operator of the GB electricity system have sufficient expertise to manage a system with very high penetrations of low carbon in the most economic manner possible?

In respect of question 3 above, it may be noted that some academic studies have estimated that electricity consumers in Northern Europe could save around €50 million per annum if reserve generation is allocated optimally across the region and has access to interconnection capacity[24]. Issues around the potential value of such provision to the UK and market delivery mechanisms are currently being investigated by UKERC.

Questions 5 and 6 arise from many years of academic assertion of the value of energy efficiency and demand side response. Efforts in the former area have declined since the exclusion of lighting and appliances programmes from supplier obligations. There has been slow development of demand side response in Britain which may be speculated to be due to failure of the big retailers to offer products that include it, the relatively small financial gains for many consumers or the inconvenience it might entail.

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[22] See the discussion of reliability metrics under Question 1.

[23] www.gov.uk/government/uploads/system/uploads/attachment_data/file/66564/7035-capturing-full-elec-eff-potential-edr.pdf [accessed 19 September 2014].

[24] See, for example, Gebrekiros, Y and Doorman, G (2014). Optimal Transmission Capacity Allocation for Cross-border Exchange of Frequency Restoration Reserves (FRR), Proc. 18th Power Systems Computation Conference, Wroclaw, August 18-22, 2014.

In respect of question 7, it may be noted that while the capacity market is designed to ensure that sufficient generation is available, its utilisation depends on the system operator[25]. Although, fortunately, its occurrence is rare, the scope for human or equipment errors on the transmission system to turn a minor disturbance into a system blackout has been well-established[26].

National Grid Electricity Transmission (NGET) is obliged to comply with the Security and Quality of Supply Standard (SQSS) when operating the system and is also incentivised to keep the costs of doing so at a minimum. NGET's general success to date in 'keeping the lights on' has been discussed above. It has a well-developed set of procedures and analysis facilities to support this. However, the nature of the system with more wind and solar power than at present will be quite different and established tools and procedures may prove insufficient. Although we understand NGET to be investing in new software for the implementation of balancing services, we are not aware of the company having undertaken a systematic study of future system operation in a manner similar to that of Eirgrid on the island of Ireland which faces comparable challenges of operating an island system with high penetration of wind, and note the challenges faced by the industry in the recruitment and retention of leading engineering expertise[27].

While NGET might reasonably look to UK academics to help inform it, independent researchers are hindered in being able to make material observations on the GB system through lack of access to realistic data in practice[28]. Moreover, some funding sources such as the Network Innovation Competition require a cost-benefit analysis as part of a research proposal and this can impede novel and radical research into electricity system resilience in which such cost-benefits cannot credibly be justified at the outset. We question whether research funding from the various sources could be more holistically coordinated to encourage better and more fruitful collaborations between industry and academics, for finding better solutions to resilience issues on shorter and longer timescales.

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[25] Some issues around scheduling and utilisation of reserve are discussed in Bell, KRW (2014). Response to Electricity Capacity Assessment 2014: Consultation on methodology, available www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-2014-consultation-methodology [accessed 08 September 2014].
[26] See, for example, CIGRE WG C1.17 (2010). Planning to Manager Power Interruption Events, Technical Brochure 433, CIGRE, Paris.
[27] Bell, KRW, Fenton, W, Griffiths, H, Pal, BC and McDonald, JR (2012). Attracting Graduates to Power Engineering: Successful Industrial Engagement and Collaboration in the UK, IEEE Trans on Power Systems, vol. 27, no. 1, February 2012.
[28] Bell, KRW and Tleis, AND (2010). Test system requirements for modelling future power systems, IEEE Power & Energy Society General Meeting, Minneapolis, July 2010.

Question 3. How are the costs and benefits of investing in electricity resilience assessed and how are decisions made?

It has been noted above that debate about the costs and benefits of the proposed capacity market continues.

For transmission network investments that facilitate access to available generation in different locations, contributing to security of supply, some long-established rules written in the SQSS determine what level of transmission capacity should be provided. However, as far as we are aware, the last time the costs and benefits associated with these rules was assessed in the Review of Security Standards conducted in the 1990s. Our opinion is that, when applied for a given background of operational generation and forecast demand, the rules that there should not be under-investment though whether the associated level of network capacity is economically optimal is open to question. However, the SQSS as currently written provides little guidance on the risks associated with uncertain generation background though it may also be argued that the introduction of the capacity market will reduce the level of uncertainty. In addition, the rules provide little guidance on high impact events such as flooding.

In respect of local network resilience at a distribution level, Engineering Recommendation P2/6 (ER P2/6) defines the minimum requirement to be satisfied by DNOs. We understand it to have been based on a cost-benefit analysis undertaken in the 1970s. In light of changes to the use of electrical energy since then, this may be judged to be due for review and, indeed, a review of ER P2/6 has been initiated by the Energy Networks Association. However, our understanding is that DNOs are against wholesale changes. Nonetheless, the CI and CML incentives may be argued to provide a sufficient backstop provided the DNOs are capable of undertaking the associated analyses. In addition, while the CI and CML incentives should help manage long-term expectations of reliability of supply, appropriate measures to manage the impact of relatively rare events such as severe storms are harder to evaluate and Ofgem has recently called into question some DNOs' performance in restoring supply lost in storms in the winter of 2013/14[29].

[29] Ofgem (2014). December 2013 storms review – impact on electricity distribution customers, available www.ofgem.gov.uk/ofgem-publications/86460/finaldecember2013stormsreview.pdf [accessed 10 September 2014].

Question 4. What steps need to be taken by 2020 to ensure that the UK's electricity system is resilient, affordable and on a trajectory to decarbonisation in the following decade? How effective will the Government's current policies be in achieving this?

As indicated under Question 2, the steps outlined, in particular the introduction of a capacity market and incentives on distribution network operators (DNOs) in respect of customer interruptions (CI) and customer minutes lost (CML), promise to make significant contributions to electricity users' reliability of supply but, as also outlined above, there are some key related questions that are yet to be fully answered not least in respect of the cost of the capacity market. Other aspects of Electricity Market Reform are intended not only to facilitate investment necessary to achieve further decarbonisation but to do so cost-effectively, although UKERC research shows that EMR has not been designed adequately to incentivise electricity demand reduction[30]. It remains to be seen whether an adequate balance will be struck between facilitation of investment and management of the cost to consumers, with doubt having been cast over the contract signed for the development of Hinkley Point C[31] and the proposed contracts for difference for offshore wind[32].

One of the features of the UK's energy system that makes the achievement of the objective of a resilient, affordable and progressively decarbonised energy system a particular challenge relative to that in some other countries is the fragmentation of the industry, largely as a consequence of the introduction of competition in energy wholesale and retail. This means that as well as the market and policy initiatives outlined above, the Government has a key role to play in coordinating responses to emergencies among many different parties – system operators, generators, network owners and emergency services[33]. It always has been and remains imperative that this takes a whole energy system perspective. For example, as noted above, the gas and electricity system are already inter-related and will become more so. In addition and as was observed at Fukushima, the safe operation of nuclear power stations depends on

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[30] Eyre, N (2013). Energy Saving in Energy Market Reform – The Feed-in Tariffs Option. Energy Policy 52 190-198.

[31] European Commission (2013). State aid: Commission opens in-depth investigation into UK measures supporting nuclear energy http://europa.eu/rapid/press-release_IP-13-1277_en.htm [accessed 19 September 2014].

[32] MaCaffrey, M (2014). Allocation, allocation, allocation www.renewableuk.com/en/blog/index.cfm/id/01112537-6D02-420D-95B513F2F9958AE0 [accessed 19 September 2014].

[33] See DECC (2014). Preparing for and responding to energy emergencies, www.gov.uk/preparing-for-and-responding-to-energy-emergencies [accessed 14 September 2014].

the integrity of its power supplies which normally come from the transmission system with back-up from on-site generation[34].

Among private sector actors in the energy system in Britain, National Grid is arguably the single most important player in respect of system resilience. It is responsible for operation of the gas and electricity transmission systems, planning and development of National Transmission System for gas and planning and development of the onshore electricity transmission system in England and Wales. The Government has also given it responsibility for implementation of key aspects of Electricity Market Reform including the capacity market.

National Grid was given a highly challenging settlement by Ofgem in the most recent transmission price control[35]. According to Ofgem, "New price controls for transmission and gas distribution networks took effect in April 2013 and are designed to keep the pressure on the network companies to deliver value for money"[36]. Faced with the need to maintain its profitability, not least in order that it can raise adequate funds on capital markets to support future network investment sufficiently cheaply, we understand that National Grid has responded by conducting a fundamental review of its structure and has dispensed with a substantial number of management and engineering posts. Given the company's central role in administering so much of Britain's energy system at a time of considerable economic and technical challenges, it may be reasonable for the Committee to seek reassurance and evidence from National Grid that key expertise and experience have not been lost. Moreover, Ofgem might also be asked if particularly challenging settlements entail any medium-term risks to delivery of a secure, affordable and decarbonised energy system.

[34] At Fukushima, the same disturbance that broke the connection with the transmission network also rendered standby diesel generators unusable. See, for example, Strickland, E (2011), 24 hours at Fukushima, IEEE Spectrum, vol. 48, issue 11.
[35] Ofgem (2012), RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas - Overview, www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-national-grid-electricity-transmission-and-national-grid-gas-%E2%80%93-overview [accessed 14 September 2014].
[36] www.ofgem.gov.uk/about-us/how-we-work/promoting-value-money [accessed 14 September 2014].

Question 5. Will the next six years provide any insights which will help inform future decisions on investment in electricity infrastructure?

The next six years promise to provide important insights in respect of the following:

- Operation of the GB capacity market;
- Take-up and cost of contracts for difference for low carbon generation;
- Impact of the EU's Industrial Emissions Directive (IED)[37];
- Government policy, including targets, for decarbonisation post-2020;
- Increasing intermittent renewable capacity, forecast by National Grid to be 20 GW by 2020, which are likely to lead to more periods of excess supply and greater supply variations, and well as more volatile electricity market prices.

We do not attach a very high probability to the development of significant levels of active demand side participation in energy markets, the purchase and use of numerous electric vehicles or a significant increase in electric heating in the next six years. However, those things may ramp up in the period after 2020.

A development on which Ofgem has been working in the last few years, which may be expected to result in some concrete recommendations in the next year or two and which will affect the way in which investment in the electricity infrastructure is carried out is "Integrated Transmission Planning and Regulation" (ITPR)[38]. Among other things, this might force a separation of electricity network operation, planning, and asset procurement, construction and maintenance activities across the whole of Britain. (Electricity system operation (SO) is currently separated from the other activities in Scotland and offshore, those other activities being generally integrated within a single 'transmission owner' (TO) in a particular geographical area).

A potentially important new initiative originating within the UK's engineering community is the idea of a 'system architect'[39]. This has been motivated by recognition of the interconnectedness of the energy system and the fragmentation and complexity not only of the industry's commercial structures but also of its technical standards. As we understand it, the intended role of the 'system architect' is not one of central planner or 'chief engineer' but one of a panel that reviews industry and system developments to ensure that they work successfully in a complementary manner.

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[37] www.defra.gov.uk/industrial-emissions/eu-international/industrial-emissions-directive/ [accessed 14 September 2014].

[38] www.ofgem.gov.uk/electricity/transmission-networks/integrated-transmission-planning-and-regulation [accessed 14 September 2014].

[39] IET Power Network Joint Vision (2013), Electricity Networks: Handling a Shock to the System.

Medium term (to 2030)

Question 6. What will affect the resilience of the UK's electricity infrastructure in the 2020s? Will new risks to resilience emerge? How will factors such as intermittency and localised generation of electricity affect resilience?

Evolving electricity demands

Current electricity consumption is unlikely to reduce significantly. In the medium term, climate change is likely to increase the air conditioning load; cooling is responsible for 4 per cent of the total UK electricity demand and in London alone demand for cooling is expected to double by 2030, to nearly 3 TWh per year.[40] In the longer term, decarbonisation of heat and transport must greatly accelerate, and one strategy would be by electrification of large parts of the energy used for heating or transport. This would significantly increase the demand for electricity and would change its time-of-use profile, placing ever increasing pressures on the electricity system. For example, UKERC research shows that complete decarbonisation of heat might add 40 GW to peak demand, even using efficient heat pumps.[41]

Impact of localised and intermittent electricity generation on networks

By 2030, there could be more than 40 GW of intermittent renewables, primarily wind generation, in the UK. National Grid forecast that the proportion of generation connected to the distribution networks could almost double to 20 GW in this time.[42]

If generation is located close to demand or even on the same site as demand, e.g. domestic solar panels, it might simplistically be assumed that this reduces the need for the network. However, much of this generation capacity is expected to be based on intermittent renewables; reliable access to electric power therefore depends on either the network or storage. Other generation capacity might come from combined heat and power, the operation of which is largely heat-led and which might have a large surplus of electric power at times that are, from the perspective of power system operation and local network capacity, inconvenient. Moreover, if current institutional arrangements

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[40] Day, AR, Jones, PG & Maidment, GG (2009). Forecasting future cooling demand in London. Energy and Buildings, 41, 942-948.
[41] Eyre, N. and Baruah, P. (2014) Uncertainties in Energy Demand in Residential Heating. UK Energy Research Centre Working Paper.
[42] National Grid (2013) Electricity Ten Year Statement, http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-ten-year-statement/Current-statement [accessed 19 September 2014].

continue: (a) much of this generation capacity, embedded within the distribution network, will be visible to the transmission system operator only to the extent that it reduces that net demand; and, (b) the Distribution Network Operator (DNO) will have little or no influence over its output and its effect on the rest of the system.

It has been widely supposed that 'smart' measures will, relative to conventional means, prove more cost-effective in meeting the challenges of providing a reliable supply of electricity on a future power system, which has high demand and large quantities of highly variable renewable generation alongside what may be expected to be relatively inflexible nuclear power.[43] This effectively means that the need for primary network capacity[44] or reserve generation can be reduced by greater use of 'post-fault actions', which correct the consequences of faults instead of providing such margin on the system, preventing adverse consequences of disturbances; in so doing, better use is made of the available primary capacity. These post-fault actions include rapid re-dispatching of generation and, in particular, demand-side responses.

Given that most demand is connected on distribution networks and with the expected growth of generation embedded within the distribution system (sometimes called 'distributed generation'), if investment in primary assets is to be minimised and elements of the distribution network are not to be overloaded and voltages are to be kept within acceptable limits, DNOs will need to become more active operators of their networks, essentially becoming Distribution System Operators (DSOs). This will require more network monitoring, greater volumes of data and more involved decision making. If this and the interactions with transmission are not adequately managed, all these factors could make the uncertainties experienced by the transmission system operator worse.

Medium-term network system stability

Increasing reliance on post-fault, corrective actions makes a system operator's job more complex. While transmission system operation, in particular, already makes use of extensive automation and decision support software systems, new systems will need to be introduced. Moreover, with such dependence on corrective actions, monitoring and actuation should be extremely reliable which is likely to require redundancy to improve performance but which would not guarantee success.

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[43] UKERC (2014). Scenarios for the Development of Smart Grids in the UK. UKERC: London, UK.

[44] By 'primary network capacity', we mean that provided by high voltage assets rather than 'secondary' assets that provide monitoring and control.

Power systems are large, dynamic and complex. The benefits of networks in allowing local surpluses or deficits of power to be balanced out[45] also permit disturbances to be propagated widely and very rapidly (on a scale of milliseconds). The system operator therefore also needs to be cognisant of the state of the system as a whole. Automated protection systems have, for many years, helped to manage the propagation of disturbances. Major regional or system blackouts around the world have often associated with failures of protection or of system monitoring and decision making; reduction of system margins and greater reliance on corrective actions arguably make such events more likely in future and make the 'defence plans' mentioned earlier more important.

The risk of cascading outages has received some attention from electricity regulators in the US and from academics, but there remain significant challenges in reliably quantifying the risk[46].

Longer-term impacts of climate change

It has been shown that climate change is already leading to changed weather patterns and that power system design standards might not be sufficient to continue to deliver the levels of reliability of supply of electricity to which society has become accustomed. The ways in which changed weather might impact on the power system include the following:

- Increased ambient temperatures in summer leading to:
    - De-rating of transformers and cables, which has been predicted to increase by up to 12 per cent by the 2080s[47].
    - Lower efficiency of gas turbines as a consequence of reduced air mass flow, resulting in a loss in power output of up to 0.5 per cent for every 1°C increase in ambient air temperature.[48]
    - Potential for increased air conditioning load[49].

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[45] For the most part, storage still does not compete with network capacity economically as an alternative way of smoothing out imbalances.

[46] Vaiman, M, Bell, KRW, Chen, Y, Chowdhury, B, Dobson, I, Hines, P, Papic, M, Miller, S, and Zhang, P (2012). Risk Assessment Methodologies for Cascading Outages. IEEE Trans on Power Systems, vol. 27, issue 2, 2012.

[47] McColl, L, Angelini, T & Betts, R (2012). Climate Change Risk Assessment for the Energy Sector: Technical Report. London: Department for Environment, Food and Rural Affairs (Defra).

[48] Kakaras, E (2006). Inlet Air Cooling Methods for Gas Turbine Based Power Plant. ASME, 128, 312-327.

- Increased concentrated rainfall leading to increased risk of flooding; estimates suggest a 79% increase in the number of power stations at risk and a 21% increase in the number of substations at risk by 2050[50].
- More severe winters with increased risk of 'wet snow' or icing of overhead lines and insulators and, hence, increased likelihood of electrical faults; icing of overhead line conductors leading to risk of mechanical failure; increased snowfall coinciding with high winds and causing electrical faults.
- More frequent occurrence of electrical storms and hence of lightning causing fault outages.
- More frequently occurring or more severe high wind events with increased likelihood of short-circuit faults and, if the highest wind speeds are very high, mechanical failure of overhead lines or wind turbines.
- Colder winters leading to higher heating demand.

The Climate Change Act 2008 and the Climate Change (Scotland) Act specified that a UK-wide Climate Change Risk Assessment (CCRA) be carried out every five years. The first of these were published in 2013 and looked at 11 key sectors including energy (McColl et al., 2012). The report recognised that much of the methodology was top-down, impacts led and reductionist and did not fully develop socio-economic scenarios, behavioural aspects of change, complex systems, non-linear changes and systemic risks, but was the first major attempt to rigorously quantify the risks posed by climate change to energy infrastructure.

In July 2013, the UK Government published its first National Adaptation Programme (NAP), which was developed as a response to the CCRA and will also be produced every five years. The NAP is the Government's long-term strategy to address the main risks and opportunities identified in the CCRA. The programme focuses on the following key areas: raising awareness of the need for climate change adaptation, increasing resilience to current climate extremes, taking timely action for long-lead time measures, and addressing major evidence gaps. The Adaptation Sub-Committee of the Committee on Climate Change is due to report to Parliament on the progress made in the implementation of this programme in 2015. On infrastructure, the ASC will cover energy, ICT, transport and water, and will report on the level of exposure to a range of climate hazards, as well as the level of resilience action occurring in each sector.

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[49] UK Power Networks (2014). Business Plan (2015 to 2023) http://library.ukpowernetworks.co.uk/library/en/RIIO/Main_Business_Plan_Documents_and_Annexes/UKPN_Climate_Change_Adaptation.pdf [accessed 19 September 2014].

[50] Byers, EA, Hall, JW, and Amezaga, JM (2014). Electricity generation and cooling water use: UK pathways to 2050. Global Environmental Change, 25, pp16-30.

Further to this, the network licensees in Britain commissioned two studies from the UK Meteorological Office that have explored temperature rise and the possibility of increased occurrence of faults. However, the latter, in particular, gave little clear insight because: (a) there are limitations in the modelling of future weather; and, (b) the correlation between fault rates and demand interruption on a transmission network is not linear. Some academic studies have been commissioned more recently to look at the possible effects of climate change on power network assets, such as RESNET, ITRC and PURE, and on reliability of supply[51]. However, the complex system of governance, acting at a number of scales, in the UK still poses a significant challenge to the response of the energy industry to the impacts of climate change – especially in the long term. Changes in political priorities for different sectors can lead to conflicting demands on infrastructure providers. Addressing these conflicts will be of critical importance in the future and needs integration into national adaptation strategies.

Question 7. What does modelling tell us about how to achieve resilient, affordable and low carbon electricity infrastructure by 2030? How reliable are current models and what information is needed to improve models?

See discussion under question 1 in respect of models and information and Question 6 on quantification of the risk of cascading outages. In addition to what was mentioned above, it may be noted that there is currently no robust information on how reliable 'smart grids' and demand side management (DSM) might be.

UKERC is undertaking various studies as part of its future research activities. This will include energy system modelling, assessments of the energy, material and water resources required for energy systems, and their ecosystem impacts, research on the political economy of international resource flows and economic, engineering and policy assessments of the interactions, synergies and trade-offs between the large-scale deployment of electricity, hydrogen and heat. Explicit attention will also be paid to the social and environmental dimensions and implications of different energy system configurations.

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[51] Murray, K & Bell, KRW (2014). Wind Related Faults on the GB Transmission Network. Proceedings of the 13th International Conference on Probabilistic Methods Applied to Power Systems, Durham, 7-10 July 2014

Question 8. What steps need to be taken to ensure that the UK's electricity system is resilient as well as competitively priced and decarbonised by 2030? How effective would current policies be in achieving this?

We identify some of the important technologies that could improve the resilience of the electricity system in Question 9.

The electricity system does not operate independently of other parts of the energy system and is likely to become increasingly integrated in the future. There is very little energy storage in the current system; precursors to electricity generation are stored, such as natural gas, and generation is continuously modified to meet electricity demand. In the future, there could be much higher demand peaks and much more inflexible generation, including periods with supply exceeding demand. These changes would necessitate either the use of energy storage technologies, deployment of DSM or a great increase in generation capacity, and all of these options are potentially very expensive. Electricity storage technologies are prohibitively expensive at present and other storage options have been suggested, for example power-to-gas or heat storage. The potential for such technologies to contribute to system management will depend on how the rest of the energy system evolves (e.g. whether we use electric, hydrogen or oil-powered vehicles). We do not have a good understanding at present of how the electricity system investments could be optimised to best support the development of a low-carbon energy system, at low cost, while maintaining a resilient supply.

This is an issue now because generation and network assets have long lifetimes and investments now are likely to lock-in electricity system infrastructures for decades. This means that it is important to consider the longer-term implications of investments that are made to support the system in the 2020s and 2030s, and in particular how they are likely to affect the evolving UK energy system more widely. We believe that planning horizons for the electricity system need to be much longer in the future than they have needed to be in the past. They should account for the greater uncertainty in demand going forward, for a more inflexible supply and for a greater integration of the electricity system with other parts of the energy system.

Question 9. Is the technology for achieving this market ready? How are further developments in science and technology expected to help reduce the cost of maintaining resilience, whilst addressing greenhouse gas emissions? Are there any game changing technologies which could have a revolutionary impact on electricity infrastructure and its resilience?

The main network technologies that are seeing steady improvement in capacity and control capability are in HVDC. Cheaper superconductors would promise significant benefits.

On the demand side, the estimated potential for efficiency improvement of ~100TWh/year is with existing technology. Future technical change is likely to increase this potential. Demand-side response promises to be significant. As yet, the incentives to DSM seem not to be strong enough and, for many users, the enabling infrastructure is not present. However, the roll out of smart grids will address the latter and incentives will rise if and when system balancing problems become more acute. Energy storage is potential game-changing, in terms of enabling the use of high levels of variable renewables without large scale back-up generation capacity. However, at present, electrical energy storage remains too expensive relative to the main alternative of higher network capacity to share surpluses or deficits with other areas except where network options are particularly expensive, e.g. in connecting islands. If the cost of storage comes down, storage bought for other reasons can be exploited, e.g. electric vehicle (EV) batteries, or the difficulty of increasing network capacity goes up, e.g. because of increasing difficulty in gaining approvals for overhead lines such that much more expensive undergrounding options are required or even that the environmental impacts of undergrounding are deemed unacceptable, then the situation changes. However, a scenario in which the total cost of reliability becomes lower than at present is not impossible but unlikely.

In respect of storage, currently the cheapest form is storage of heat. When space, water or process heating uses electricity, heat storage capacity allows some scheduling/time-shifting of electricity demand and this can help to smooth out surpluses or deficits of power even though, depending on the nature of the storage, at some cost in terms of efficiency. In general, storage of heat in low cost devices (e.g. water tanks and storage radiators) and buildings themselves is already cost effective for diurnal and other short term fluctuations. However, inter-seasonal heat storage remains costly and therefore would needs further development to become a solution to the problem of electrifying heating. This highlights a key issue for the period out to 2030: how will demand for heat be met, and how do the different energy systems – electricity, gas and heat – interact?

One alternative vector often discussed for moving energy from one place to another also promises easier storage than electricity. This is hydrogen, though whether the cost trajectory and the infrastructure investment associated are such that it represents a realistic option in the next 15 years is a subject of some discussion.

Question 10. Is UK industry in a position to lead in any, or all, technology areas, driving economic growth? Should the UK favour particular technology approaches to maintaining a resilient low carbon energy system?

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Question 11. Are effective measures in place to enable Government and industry to learn from the outputs of current research and development and demonstration projects?

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Question 12. Is the current regulatory and policy context in the UK enabling? Will a market-led approach be sufficient to deliver resilience or is greater coordination required and what form would this take?

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