House of Commons

Energy and Climate Change Committee

Low carbon network infrastructure

First Report of Session 2016–17

HC 267

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The Energy and Climate Change Committee

The Energy and Climate Change Committee is appointed by the House of Commons to examine the expenditure, administration, and policy of the Department of Energy and Climate Change and associated public bodies.

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Summary

Networks are at the heart of the UK's low carbon ambition. Our inquiry into low carbon network infrastructure has identified that they face three interwoven challenges. Firstly, new energy sources—in electricity, gas, and heat—need connections to, and consequent reinforcement of, the grid. Secondly, some of these sources are variable in output, such as wind and solar electricity: system operators must therefore employ new tools to balance supply and demand. And thirdly, networks' efforts to overcome these obstacles must not be impeded by outdated and inflexible regulation and governance. Significant infrastructural development is needed, but incurs considerable expense of both time and money. Deployment of new technologies is crucial to achieving these goals while controlling cost.

The recent rise of new connection requests is astounding. For example, the UK's installed solar capacity is approaching levels previously expected by 2030, stacking pressure on regional distribution networks. There is a need for better integration of connection and planning-consent processes. More forward-looking investment by network companies may also be helpful in reversing the slowdown in connections, but Ofgem must assess the best way of recovering costs for such investment.

Connection costs remain geographically skewed. Ofgem should assess the costs and benefits of levelling connection costs across Great Britain. Network charges incurred by consumers also vary considerably by location. Moreover, transmission charges for generators in the UK remain high by EU standards. The Government must investigate the disadvantage UK generators may consequently face against other European generators as Great Britain becomes more interconnected.

The UK's gas grid must adjust to unorthodox cleaner fuels. To assist this transition, Ofgem should assess safe levels for injection of green gases into the current network and the Government should set targets for their deployment. We welcome the Government's ambitious target for district-heating networks, which are an alternative approach to the electricity and gas networks in providing heat. However, district heating needs a regulatory framework to encourage investment and complement existing voluntary schemes in safeguarding consumers.

Networks have a number of tools to balance variable energy sources:

- Storage technologies, from enormous hydroelectric reservoirs to household batteries, can store electricity at times of peak for use at times of need. However, the deployment of storage is obstructed by archaic regulation and unfair 'double-charging', both of which the Government must address urgently.

- Demand Side Response could empower consumers large and small to manage their energy use in line with system-wide need, but a more detailed Government strategy is needed to help this solution reach its full potential.

- Greater interconnection with European neighbours will improve the UK's ability to meet peak demand, though we note that Great Britain is likely to remain a net importer of electricity.

These challenges can only be met within an appropriate governance, regulatory and operational framework. Network companies have generous allowances for early-stage testing of the technological solutions they need, but the UK struggles to bring these innovations into commercial reality. More and more electricity generation occurs at the regional distribution, rather than national transmission level, but Distribution Network Operators remain somewhat blind to their energy flows and passive in managing them. There must be a transition to fully-functional Distribution System Operators which balance and control their local grids. At transmission level, we recommend creating an Independent System Operator (ISO). The Government must set out its intentions regarding an ISO, and consult on a detailed, staged plan for their implementation.

Networks are transforming. We recognise that this presents challenges for the Government but it has been slow to present a clear, holistic plan for the evolution networks need. It seems instead to have disconnected policy ideas at various stages of implementation. We are concerned that the roll-out of smart meters is not progressing quickly enough to achieve the necessary mass to truly create a smart energy network.

Our central message to the Government is that it must address the network system as a whole, learn lessons from policy lags in the key areas we outline, and develop its change readiness so as to meet the ambition of low carbon network infrastructure.

1 Introduction

1. By 2050, the UK must reduce its carbon dioxide (CO_2) emissions by at least 80% from their 1990 baseline.[1] The need for decarbonisation is clear, and it must be met—and is beginning to be met—with cleaner energy sources. Network infrastructure encompasses the pipes and pylons that carry electricity, gas and heat, the control centres and ancillary services that match supply and demand, and the public- and private-sector organisations responsible for the operation and maintenance of these. If both the production and the use of energy must change, then the networks joining them must adapt.

2. Some transformations are already occurring. Electricity generators used to be predominantly large, centralised plant connected to the high-voltage, long-range transmission network. Now, significant quantities of generation—mostly small-scale solar and wind—are connecting to the low-voltage, short-range distribution networks. Larger renewable developments must be sited where the resource is best: this is not always close to demand. Discussions with stakeholders about our priorities highlighted a need to investigate strain on the distribution networks, cost concerns for generators and consumers alike, and new challenges in balancing supply and demand.[2]

3. We launched our *Low carbon network infrastructure* inquiry on 15 September 2015. We received 53 written submissions and held six oral evidence sessions between December 2015 and April 2016. A full list of witnesses can be found at the back of this report. In addition, we visited Copenhagen in February 2016, and a note of this visit can also be found at the back of this report. We are grateful to all those who contributed to this inquiry.

4. In chapter 2 of this report, we consider connections in energy networks, analysing immediate challenges in terms of connection queues, network costs, and physical infrastructure. In chapter 3, we address the issue of managing electricity networks with more variable energy flows. In chapter 4, we discuss wider topics of regulation and governance, covering innovation funding and system operation at both transmission and distribution levels. Chapter 5 sets out what we think the Government's overarching approach to low carbon network infrastructure should be. We focus primarily on electricity networks throughout, but also consider gas and heat networks infrastructure in chapter 2, and a whole-systems approach to energy in chapter 5.

1 Climate Change Act 2008, section 1

2 Energy and Climate Change Committee, First Report of Session 2015–16, Our priorities for Parliament 2015–20, HC 368, paras 11, 14, 26

Box 1: Working towards our goals

At the start of the 2015 Parliament we set out three goals for our scrutiny work:

- Holding the Government to account on achieving a balanced energy policy;
- Setting the agenda on an innovative future energy system; and
- Influencing the long-term approach to climate targets.*

Our work on low carbon network infrastructure cuts across our goals to hold the Government to account on achieving a balanced energy policy and to set the agenda on an innovative future energy system. The UK's networks are central to an affordable, secure and low-carbon supply of energy, and the challenges they face today will require innovative techniques and technologies to overcome. Throughout the course of this Parliament, we welcome feedback on our work towards our goals.

*Energy and Climate Change Committee, First Report of Session 2015–16, Our priorities for Parliament 2015–20, HC 368, para 11

2 Connecting new energy sources

5. Electricity and gas networks are divided into transmission and distribution. Transmission networks are long-range and high-voltage (electricity) or high-pressure (gas); distribution networks are short-range and low-voltage or low-pressure (relative to transmission). National Grid Electricity Transmission (NGET) owns and maintains the electricity transmission network in England and Wales,[3] while National Grid Gas Transmission (NGGT) owns and maintains the GB-wide gas transmission network. As Transmission System Operator (TSO), National Grid operates and balances both transmission networks. Six companies own the 14 Distribution Network Operators (DNOs) responsible for electricity distribution; the eight Gas Distribution Networks (GDNs) are owned by four companies.

6. Network companies recover their costs from users—households, businesses, suppliers and generators—through various network charges. British Gas informed us that "network costs typically account for £270 of a £1,150 dual fuel residential bill (£134 for electricity network costs), and have risen by around 30% over the last 4 years".[4] As networks form natural monopolies, they are not given free rein to determine their revenues: these, and certain other restrictions and obligations to protect users, are specified in licence conditions and price controls. The current price controls are known as 'RIIO' (Revenue = Incentives + Innovation + Outputs): these are set by Ofgem, the electricity and gas regulator, and run for eight years—known as the 'price control period'.

7. Network companies have a range of obligations, some enshrined in legislation, and others encouraged by RIIO. They must offer a connection to any user requesting one. They need to ensure a safe and reliable supply of energy for households and industry. Finally, the system operators—NGET and NGGT—have responsibilities to ensure supply and demand are balanced in real time. The networks do not actually generate electricity, or sell electricity or gas to consumers; indeed, they are legally precluded from doing so. Their job is to act as conduits for power generated, supplied and consumed by other parties.

Distributed generation

8. Smaller electricity generators tend to connect to the regional, low-voltage distribution network, rather than the national, high-voltage transmission network: this is known as 'distributed' (or 'embedded') generation. Historically, the UK's electricity has been generated by relatively-few large power plants connected to the transmission system. Recently, however, the UK's distributed-generation capacity has grown explosively, rising by 54% between 2011 and 2014.[5] Currently 19.1 gigawatts (GW),[6] it could reach between 31 GW and 57 GW by 2036.[7] Most distributed generation is onshore wind or solar PV:[8] the Energy Networks Association (ENA) observed that solar PV is now connected to

3 Scottish Power and SSE own and maintain the electricity transmission network in Scotland.

4 British Gas (LCN0015)

5 Department of Energy and Climate Change (DECC), Digest of UK Energy Statistics (DUKES), Plant installed capacity, by connection - United Kingdom (DUKES 5.12) (MS Excel spreadsheet), July 2015

6 DECC, DUKES, Plant installed capacity, by connection - United Kingdom (DUKES 5.12) (MS Excel spreadsheet), July 2015

7 National Grid, Future Energy Scenarios, July 2015, p134

8 DECC, DUKES, Plant installed capacity, by connection - United Kingdom (DUKES 5.12) (MS Excel spreadsheet), July 2015

distribution networks "already close to the levels previously expected by 2030".[9] Andrea Leadsom MP, Minister of State for Energy and Climate Change, declared that "energy is undergoing a genuinely radical transformation. We have seen a massive increase in the number of local connection requests and in the type of power generation".[10]

9. This has strained DNOs' ability to connect distributed generation. Smarter Grid Solutions claimed "connection moratoria, long queues, unrealistic connection dates, high costs and lapsing connection offers are very common in the grid connection process".[11] TGE Group, a solar PV installer, outlined the challenges in connecting to the grid:

> Low voltage applications can take up to 45 days to process whilst high voltage applications take up to 65 days. Our fastest approval came in five hours whilst others have arrived at the last hour on the last day. This uncertain processing time makes scheduling work impossible, for a start, it can take the full 45 days before you know whether the customer can have, for example, a 50kWp[12] system or a 100kWp system and it is not commercially viable to do the full design work until DNO approval has been received. It's hard to accurately predict the outcome of an application, as every customer is different depending on location.[13]

We heard that one DNO's projections for distributed solar connections by 2023, the end of the current price-control period, was reached before the revenue control started in 2015:[14] the system for connecting distributed generation has been overwhelmed by its unprecedented growth. Furthermore, DNOs in different regions are distinct companies and deal with distributed generation in their own ways. Tony Glover, Director of Policy at the ENA, claimed the organisation "is looking at how we can standardise, where appropriate and where practicable".[15] However, standardisation can be difficult as "you are looking at different distribution network operators operating in different types of locations—some of them, in fact, with differently configured networks, technically speaking".[16] Technical homogeneity may be impossible, but we should expect every DNO to provide a timely and reliable connection service. That service has been widely absent.

10. Ofgem's response to the scale and urgency of this problem is its *Quicker and more efficient distribution connections* project. This project has "improved visibility and availability of flexible connections, flexible payment terms and consortia for connecting customers" and led to "an action plan for industry to progress more effective queue management".[17] Further plans in this project include:

i) 'Milestones in connection offers', which would allow DNOs to make connection offers contingent on generators meeting targets for planning consent and construction in a timely fashion.[18]

9 Energy Networks Association (LCN0018)
10 Q297
11 Smarter Grid Solutions (LCN0032) para 3.4
12 Kilowatt peak, a measure of maximum power output
13 TGE Group (LCN0003)
14 Q108 [Dr Gordon Edge]
15 Q221
16 Q221
17 Ofgem, Quicker and more efficient connections - an update on industry progress, January 2016, p4
18 Ofgem, Quicker and more efficient connections - an update on industry progress, January 2016, pp9–10, 20–24

ii) Allowing 'anticipatory investment', where DNOs reinforce the existing network in advance of expected connection requests; this is currently being trialled in a handful of areas.[19]

iii) Using existing network more efficiently, perhaps through better network management.

Active management of distribution networks is a central theme of this inquiry, and is addressed more fully in chapters 3 (at a technical level) and 4 (at an institutional level). We turn now to review points (i) and (ii) in greater detail.

Planning issues

11. Generators and their connections are often significant physical structures with potential impacts on their local environments, and as such planning consent is far from a foregone conclusion. Planning consent for connections lies with local and national authorities, whereas grid-connection processes are in the hands of the network companies.

12. DNOs are required to offer a grid connection to any generator (or other party) who requests one on a 'first-come-first-served' basis; there are currently no up-front application fees. It is therefore problematic if connection requests without meaningful prospect of fruition create blockages in the queue. Tony Glover suggested "about 70% of applications to connect are in fact speculative".[20] The Minister noted that one DNO "received 241 connection applications from one customer and none of the connection offers were taken up".[21] She cited arguments that upfront assessment and design fees for distributed connections would discourage speculative applications.[22] We agree with this logic. However, excessive fees may shut out *bona fide* developers. The objective should be to find a 'sweet spot' between the minimum fee required to discourage speculative applications, and a level that would be a significant disincentive to the development of new generation.

13. The Renewable Energy Association (REA) argued "a new system of handing out grid offers is required which incorporates project milestones and ties developers to reasonable progression".[23] Ofgem's *Quicker and more efficient distribution connections* project proposes 'milestones in connection offers' as a solution; a draft version of these rules indicates that connecting parties would lose their place in the queue if, for example, they failed to acquire planning permission or land rights by a certain date.[24] Maxine Frerk, Acting Senior Partner in Networks at Ofgem, described this as "a form of 'use it or lose it' applied to connection queues".[25] Milestones in connection offers are a sensible and proportionate response to speculative and spurious connection requests, and we support their implementation.

14. Disjoint between connection and planning-consent processes impacts more widely than the distributed-generation connection queue, and we received many calls for these

19 Ofgem, Quicker and more efficient connections - an update on industry progress, January 2016, pp13–18
20 Q213
21 Q291
22 Q291
23 REA (LCN0033)
24 Ofgem, Quicker and more efficient connections - an update on industry progress, January 2016, p21–4
25 Q280

systems to be better integrated.[26] The UK Energy Research Centre (UKERC) claimed that planning-consent problems can delay transmission connections.[27] LDA Design, a spatial design consultancy, argued:

> Network operators and energy developers need to engage with the plan-making process in much the same way as property developers do today. Local enterprise partnerships, local authorities and neighbourhood forums need to be given responsibility for planning for the growth and evolution of the network. This will allow wider spatial and growth decisions to be based as much around available energy and grid capacity as they are about housing need, jobs and transport today.[28]

15. The more information developers have on network capacity, the more efficiently they can site new generation. Scottish Power Energy Networks (SPEN) publishes 'heat maps' indicating areas of spare capacity for connections;[29] this is a useful development, and one we encourage. Tempus Energy, an energy technology and supply company, called for a single common application portal for all connection requests.[30] Tony Glover cautioned that this "could well be quite a distraction at this time" and was "a bit of a challenge at the moment", given "the tsunami of applications we currently have to deal with".[31] Nevertheless, we believe that any serious suggestion to simplify the connection process and centralise information about it is worth considering.

16. We asked John Fiennes, Director of Energy Strategy, Networks and Markets at the Department of Energy and Climate Change (DECC), about integration of the connection and planning-consent processes. He noted:

> The national planning statements encourage people to put in their connection and their generation requests at the same time. However, the timeframes for the two elements of networks and generation can be quite different so it does not absolutely insist that the connection appear at the same time because you would lose the critical path, in effect, at that stage.[32]

There is evident value in further integration of the connection and planning-consent processes, which could accelerate connections. Moreover, heat maps and possibly a centralised, standardised application procedure could improve information—and thus decisions—before those processes are even begun.

17. ***We call on the Government to establish a cross-departmental working group to investigate and report on improving the integration of the connection and planning-consent processes in England. This investigation should include an assessment of mechanisms—such as heat maps and centralised, standardised connection applications—that could simplify these processes and better inform generators about them.***

26 RSPB (LCN0009), RWE (LCN0017) para 1.3, ETI (LCN0022) para 32, LDA Design (LCN0025)
27 UKERC (LCN0016)
28 LDA Design (LCN0025)
29 Q15 [Scott Mathieson]
30 Tempus Energy Supply (LCN0056)
31 Q221
32 Q357

Anticipatory investment

18. Several written submissions called for anticipatory investment, or investment ahead of need, so that networks could develop infrastructure in expectation of future connection requests.[33] 'Anticipatory investment' is variously used to describe either maintenance and upgrade work to meet general future capacity needs, or development targeted at expected (but not certain) future connection requests. The former is standard practice and uncontroversial. This section considers the latter.

19. Tempus Energy claimed that existing rules disadvantage "unfortunate customers who trigger a major reinforcement scheme".[34] The Sussex Energy Group at Sussex University suggested that anticipatory investment could reduce costs for developers, and also discourage 'smearing' (construction of longer-than-necessary lines to reach areas of spare capacity).[35] It further contended that anticipatory investment may encourage non-traditional business models to emerge.[36] UK Power Networks (UKPN), a DNO company, observed that "investing ahead of need will also help us to deliver a smarter grid at lower cost".[37] The Minister confirmed that DECC are "encouraging greater anticipatory connections".[38]

20. Cost recovery is the major problem for anticipatory investment: if not an actual, presently-connecting customer, who pays for the infrastructure? DNOs' costs fall ultimately on their customers through network charges, and generators who take advantage of DNOs' anticipatory investment should pay their fair share. The ENA contended that "without proper rules [anticipatory investment] could also reduce the important incentive for connections customers to ask for connection in areas where reinforcement isn't required".[39] Anticipatory investment rules must also be designed to discourage DNOs from developing too many assets that end up unused or 'stranded': such misadventures are a necessary risk, but must be controlled. Andy Burgess, Associate Partner in Energy Systems at Ofgem, noted "if the network company invests and the investment is not needed, then consumers ultimately pay, so we want to get the right balance."[40]

21. Ofgem's *Quicker and more efficient connections* project is supporting trials of anticipatory investment, including two (Western Power Distribution's Grendon and Spalding) responding to distributed-generation applications.[41] It is considering three systems of cost recovery:

(1) Costs are socialised across all network users;

(2) Costs are covered by the DNOs upfront, then recovered from subsequent users; or

(3) Costs are covered by the initial connector upfront, then recovered from subsequent users.[42]

33 ENA (LCN0018), Sussex Energy Group (LCN0039) paras 11, 25, UK Power Networks (UKPN) (LCN0049) para 1.15, Tempus Energy Supply (LCN0056)
34 Tempus Energy Supply (LCN0056)
35 Sussex Energy Group (LCN0039) para 11
36 Sussex Energy Group (LCN0039) para 25
37 UKPN (LCN0049) para 2.4
38 Q358
39 ENA (LCN0018)
40 Q280
41 Ofgem, Quicker and more efficient connections - an update on industry progress, January 2016, p13
42 Ofgem, Quicker and more efficient distribution connections, February 2015, pp5–10

22. **We support anticipatory investment in principle: it is likely to improve networks' speed at connecting distributed generation. However, it also bears the risk of creating stranded assets at bill-payer expense. Anticipatory investment must therefore be accompanied by up-to-date modelling to minimise this risk.**

23. ***Ofgem should carry out further impact assessment on systems of cost recovery for anticipatory investment; this should include analysis of who bears the costs of stranded assets, so that relevant decision-makers are properly incentivised to avoid them.***

Network charges and connection costs

24. Building, maintaining and operating network infrastructure carries costs, and these are borne by bill-payers. This does not mean that networks must avoid necessary expense, but we cannot scrutinise network infrastructure without considering its price. Network charges form an increasing proportion of consumer bills; networks and their regulators must do more to achieve efficient outcomes. Moreover, network costs and connection costs are asymmetric both geographically and between transmission and distribution, and the Government must continue to consider the justifications for these disparities. Transmission tariffs for generators are also higher in GB than in the rest of the EU.

25. Network charges primarily comprise the following:

- Transmission Network Use of System (TNUoS) charges for use of the transmission network, paid by suppliers and transmission-connected generators;
- Distribution Use of System (DUoS) charges for use of the distribution network, paid by suppliers and distributed generators; and
- Balancing Services Use of System (BSUoS) charges for National Grid's roles in balancing the system, paid by suppliers and transmission-connected generators.

26. Suppliers recover network charges from consumers, who therefore contribute to all the above. Network charges on a typical dual-fuel consumer bill have risen approximately 30% in the last 4 years:[43] Ofgem claims they account for approximately 24% of such bills;[44] Scott Mathieson, Director of Network Planning and Regulation at SPEN, offered a more conservative estimate of 19–20%.[45] Network companies universally outperformed Ofgem's target rates of return under the previous price control[46] and our predecessor Committee concluded as recently as February 2015 that the RIIO settlements "are too generous and the targets are too low".[47] We reprise their complaint that despite the introduction of RIIO, network charges are rising and networks and the regulator must do more to reduce them.

27. The Association for Decentralised Energy (ADE), the REA, RenewableUK, and the Solar Trade Association wrote to us about embedded benefits, which Ofgem and National Grid are separately reviewing.[48] 'Embedded benefits' are distributed generators' exemptions from BSUoS and TNUoS charges. Distributed generation directly affects

43 British Gas (LCN0015)
44 Ofgem, Understanding energy bills, Data Table, accessed 13 June 2016
45 Q27
46 Citizens Advice, Many Happy Returns?, May 2015, pp19–22
47 Energy and Climate Change Committee, Sixth Report of Session 2014–15, Energy network costs: transparent and fair?, HC 386, para 19
48 Tim Rotheray *et al*, Correspondence regarding embedded benefits, April 2016

system balancing—it is often variable—and the transmission network: National Grid informed us that "with an increasing penetration of distributed generation we are finding that the need for transmission development is growing".[49] However, distributed generation does not affect the transmission network as much as transmission-connected generation. Cornwall Energy, a consultancy, warns of higher wholesale electricity prices among other drawbacks if embedded benefits are removed.[50] We will continue to follow the progress of these reviews and may return to this issue to scrutinise their conclusions.

28. Network charges also vary considerably according to location. Ofgem notes:

> Electricity distribution charges are higher than average in North Scotland, Merseyside & North Wales and South West of England and lower in London and Eastern England. In contrast, electricity and gas transmission charges are higher in the south of England and lower in Scotland while gas distribution charges are higher in London and the south of England and lower in Scotland and the north east of England.[51]

29. Our predecessors recommended "that the Government and Ofgem publish an evidence-based analysis of the advantages and disadvantages of introducing national tariffs for transmission and distribution network charges".[52] 'National tariffs' would standardise network costs, eliminating regional differences. Ofgem consequently produced a document, *Regional differences in network charges*, in October 2015; this concluded that national network charging would raise bills for 16 million households while lowering them for 11 million, though "in most cases the increase or decrease would be small".[53] The Minister told us national network charging "would risk an overall increase in network costs".[54]

30. Regarding generation, the ADE argued "the [current] cost reflective approach promotes efficient use of the network by larger users, for example, by providing a signal to generators that locating close to their customers requires less transmission network to be built".[55] However, among EU member states, the UK is one of only three with locational transmission tariffs.[56] Indeed, transmission costs borne by generation are higher in GB than elsewhere in the EU.[57] Haven Power, a supplier, observed TNUoS charges rising 16% in the past year alone.[58] RenewableUK "support the principle of locational and cost-reflective charging, but this should be applied in a way that recognises that renewable resources are often location-specific and therefore projects exploiting them cannot respond to locational incentives".[59] A wind or solar PV installation should be sited where the resource is best, and this may not be near demand centres. This combination of high and regionally variable connection and transmission costs may disadvantage renewable generation in the UK which is distant from demand centres: Renewable UK further noted

49 National Grid (LCN0047) para 22
50 Cornwall Energy, What next for embedded benefits?, accessed 13 June 2016
51 Ofgem, Regional differences in network charges, October 2015, p5
52 Energy and Climate Change Committee, Sixth Report of Session 2014–15, Energy network costs: transparent and fair?, HC 386, para 25
53 Ofgem, Regional differences in network charges, October 2015, p5
54 Q360
55 ADE (LCN0046)
56 Scottish Renewables (LCN0035)
57 ENTSO-E, Overview of Transmission Tariffs in Europe: Synthesis 2015, June 2015, p13
58 Haven Power (LCN0008)
59 RenewableUK (LCN0055)

"GB is unusual in the EU in charging generators at all for the use of the system, and that this could lead to unfair competition as this country becomes more interconnected with others".[60]

31. ***Cost-reflective charging should account for the reality that many renewable-energy sources are location-specific and distant from demand sources, particularly as UK transmission charges remain high by EU standards. DECC should investigate the disadvantage UK generators may consequently face against other European generators as Great Britain becomes more interconnected, and the impact this may have on development of domestic renewable generation.***

32. In addition to the general network charges described above, generators pay costs for connecting to the network; these costs vary with location and whether a distribution or transmission connection is sought. At transmission level, there are application fees ranging from £15,000 to £480,000[61] and the generator then covers National Grid's costs in installing and maintaining the asset over its lifetime by an annual Connection Charge, which—depending on the specifics of agreements between the parties—totals approximately 10% of the connection's Gross Asset Value.[62] At distribution level, there are currently no up-front application fees (see paragraph 12) and generators are charged asset costs for network extension and a portion of reinforcement costs, though methodologies differ from DNO to DNO;[63] payments can be staged but are usually upfront for smaller works.[64] Locational connection-cost differences tend to be higher for distribution than transmission connections.[65]

33. ***Ofgem should analyse the costs and benefits of levelling connection costs across Great Britain.***

Electricity network reinforcement

34. New connections are not the only infrastructure requirement that networks need to meet. Some physical assets are approaching the end of their expected lives and require replacement. In addition to reinforcing existing network infrastructure, it is increasingly becoming important to manage networks more flexibly in order to wring extra capacity from existing infrastructure with smart grid technologies. Though one approach may reduce need for the other, they are by no means mutually exclusive.

Physical network reinforcement

35. Some written evidence identified ageing network assets as problematic. RWE, a major supplier, told us:

> The lack of sufficient network investment in the post-privatisation era is a well recognised limitation of our electricity system today. The recent significant

60 RenewableUK (LCN0055)
61 National Grid, The Statement of Use of System Charges, Draft Issue 12 Revision 0—1 April 2016 (PDF download), p23
62 National Grid, Guide to Connection Charging (PDF download), October 2013
63 ENA, Distributed Generation Connection Guide: A Guide for Connecting Generation to the Distribution Network that Falls Under G59/3, June 2014, p47
64 ENA, Distributed Generation Connection Guide: A Guide for Connecting Generation to the Distribution Network that Falls Under G59/3, June 2014, p50
65 Q283 [Andy Burgess]

> surge in investment via increased revenue allowances under the RIIO regime is helping to ready the systems, but the impacts of chronic historic underinvestment will persist for some time. There is a need to replace aging infrastructure that is no longer fit for its current purpose as well as adapting and extending networks to serve an evolving low carbon economy.[66]

36. UKERC pointed to "ageing generation and network assets which are reaching or have already gone beyond their expected lives" and argued that "whatever the benefits of a 'smarter' grid, progressive decarbonisation of the electricity system will still require significant investment in primary assets".[67] This challenge is not limited to the UK: we learned in Copenhagen that ENTSO-E (the European Network of Transmission System Operators for Electricity) has identified a need for 50,000km of electricity transmission line across Europe by 2030, costing up to €150 billion.[68] The scale of the challenge to reinforce the UK's networks is considerable. RenewableUK called for investment in new HVDC capacity to reinforce the network.[69] National Grid are about to commission an HVDC link between Scotland and England which "provides a large step change in capacity".[70]

37. Phil Jones, CEO of Northern Powergrid, a DNO company, responded by noting that not all physical infrastructure will reach the end of its expected life simultaneously;[71] he further indicated that RIIO-ED1 allocates "sufficient funds to replace and upgrade the ageing assets".[72] DECC agreed that "our electricity system will need to evolve […] this will require ageing assets to be replaced and upgraded".[73]

Smart grids

38. DECC and Ofgem define a smart grid as "a modernised electricity grid that uses information and communications technology to monitor and actively control generation and demand in near real-time".[74] Smart grids optimise electricity networks, particularly at distribution level, by providing them with better information on energy flows and giving them automated and discretionary tools to manage these flows. Stephen Goldspink, Director of Strategy and Business Development at Siemens Energy Management, an engineering firm, illustrated the problem that smart grids aim to solve:

> We have to understand that our distribution networks in its truest sense are largely blind to the distribution network operators. We do not have automation right through the networks, we do not have sensors that can detect faults and give very rapid indication of where those faults are. We do not have the communications infrastructure right the way through the network, which enables things like demand response right across the distribution networks. So that automation, that monitoring, that real-time communications across the networks are just the fundamentals of smart grids.[75]

66 RWE (LCN0017) para 1.2
67 UKERC (LCN0016)
68 ENTSO-E, ENTSO-E recommendations to help achieve Europe's energy and climate policy objectives, October 2014, p4
69 RenewableUK (LCN0055)
70 Q202 [Phil Sheppard]
71 Q186
72 Q188
73 DECC (LCN0041) para 8
74 DECC and Ofgem, Smart Grid Vision and Routemap, February 2014, para 3
75 Q94

Technologies enabling smart grids include "real-time equipment ratings and associated forecasting techniques", "phase shifting transformers, series compensation and their co-ordinated use" and "integrated monitoring, protection, remote control and data collection for distribution networks".[76] Storage and Demand Side Response (DSR) can be thought of as components of smart grids, but we consider these separately in the next chapter.

39. Smart grids can enable networks to use their existing physical infrastructure more efficiently, allowing quicker connections for new generation and reducing reinforcement needs. 'Active network management' refers to networks controlling their energy flows rather than passively letting them occur, and 'connect and manage' denotes using these techniques to connect generators. Scott Mathieson drew our attention to SPEN's Accelerating Renewable Connections (ARC) project:

> We have our grid supply point at Dunbar that was potentially triggering a major reinforcement on the transmission system and through active network management, Accelerating Renewables was able to connect about 60 megawatts to that area. We were also able to connect and facilitate about 2.2 megawatts of photovoltaics, equivalent to about 750 homes in the Berwickshire area, through effectively investing in protection and control equipment that gave us in real time more information about how the assets were performing and the generation was operating within that area.[77]

Mr Mathieson claimed this project had saved £6.2 million for a cost of £800,000, and avoided a further £20 million worth of reinforcement.[78] Tony Glover observed that the Orkney Smart Grid has averted £30 million in network reinforcement at a cost of only £500,000.[79] Phil Sheppard, Director of SO[80] Operations at National Grid, emphasised "connect and manage" as the main mechanism to connect more renewables.[81] He claimed that "actively managing voltage in the network, or at the connection point, or the interface between the transmission and distribution network, or automatic network management systems" had enabled an extra 5.7 GW of renewable connections in the previous 12 months, as opposed to "the old, traditional way of doing things".[82] Active network management has great potential to address the challenges in connecting new generation, reducing network costs and (virtually) reinforcing the network. Its rollout may require DNOs to acquire more power as Distribution System Operators; we return to this question in chapter 4.

40. DECC and Ofgem state that "smart meters are a key enabler of a smart grid".[83] A smart meter "is a gas or electricity meter that is capable of two-way communication […] that allows data to be read remotely and displayed on a device within the home, or transmitted securely externally".[84] These may contribute to DSR by encouraging consumers to respond to dynamic prices, as we discuss in the next chapter. In the context of smart grids, quicker and more accurate information from smart meters may help networks use infrastructure more efficiently. Phil Jones brought up Northern Powergrid's

76 UKERC (LCN0016)
77 Q11
78 Q12
79 Qq222, 255
80 System Operator
81 Q202
82 Q224
83 DECC and Ofgem, Smart Grid Vision and Routemap, February 2014, para 3
84 Ofgem, Smart metering - what it means for Britain's homes, March 2011, p1

Consumer-Led Network Revolution (CLNR) project with British Gas. CLNR analysed smart-meter benefits, and discovered that "the diversity in people's behaviours [relating to time of electricity consumption] is much wider than was ever assumed", and consequently that the maximum network demand "is about half of what was being assumed when networks were built".[85] Smart meters may thus reduce the need for physical infrastructure development, saving money. DECC estimates that smart meters will provide £1 billion worth of benefits to networks, among approximately £18 billion of wider benefits against the cost (approximately £12 billion) of their roll-out.[86] The Minister reaffirmed that DECC is "absolutely committed to ensuring that everyone has been offered a smart meter by 2020".[87] However, our recent pre-legislative scrutiny of the Government's draft legislation on energy highlighted "legitimate questions about whether the smart meter roll-out programme is on track to meet its 2020 targets".[88] We will continue to scrutinise the Government's progress on the smart meter roll-out throughout our inquiry work.

41. **We are concerned that the roll-out of smart meters is not progressing quickly enough to achieve the necessary mass to truly create a smart energy network.**

Gas and heat networks

42. Electricity is carried in the same form regardless of how it is generated, whereas heat can reach the home through different media, each of which requires its own network infrastructure. At present, the majority of UK heating is provided through natural gas piped directly into homes and businesses. Three approaches to decarbonising the heat sector have stood out in evidence: one is to electrify heating; another is to replace methane with 'green gases' such as biomethane and hydrogen; the third is to develop heat networks, or 'district heating'.

Electrification of heat

43. Electrification of heat would increase the UK's requirements of electricity network infrastructure. Several commentators suggested that electrifying heat completely would add 300 GW to peak electricity demand,[89] a roughly five-fold increase from current levels.[90] Dr David Clarke, Chief Executive of the Energy Technologies Institute (ETI), noted "the ramp rate that we have all got used to through gas central heating: the ability to turn the thermostat up and get an instantaneous response".[91] He told us that "it is inconceivable to deliver that ramp rate from electricity".[92] Electrifying heat immediately would be overwhelming, but remains a gradual, long-term prospect; Scott Mathieson illustrated this point:

> From 2009, the collapse of the Lehmans Bank, right up to date there has been about a 1% to 2% reduction in demand. The work that we have done with the

85 Q179 [Phil Jones]

86 DECC, Impact Assessment: Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB), January 2013, p3

87 Q320

88 Energy and Climate Change Committee, Sixth Report of Session 2015–16, Pre-legislative scrutiny of the Government's draft legislation on energy, HC 776, para 12

89 Qq39 [Stephen Goldspink], 115 [Chris Clarke]

90 National Grid, Winter Outlook Report 2015/16 (PDF download), October 2015, p15

91 Q117

92 Q117

> future energy scenarios shows that that begins to flatten out over the period between now and 2023 and gradually, with the switch towards potential electric vehicles or electric heating, demand begins to increase by about 1% to 2% per annum. With scenarios there is always a high, low or medium, but whichever of those scenarios you look at they all show a trend towards increasing electricity demand.[93]

A long-term policy to electrify heat and transport will significantly impact networks. We will return to this issue in our ongoing inquiry into 2020 renewable heat and transport targets.

Green gases

44. The Government's most recent major strategy publication on low-carbon heat—2013's *The Future of Heating: Meeting the challenge*—identifies biomethane and hydrogen as compliments or alternatives to natural gas. Biomethane is produced by extracting CO_2 and other impurities from biogas, which is a mixture of methane and CO_2 created by anaerobic digestion of organic material. As biomethane is chemically similar to natural gas, it can be used with or instead of natural gas in the gas grid without pipeline modification. However, its CO_2 emissions are approximately 90% lower than natural gas,[94] as the process of anaerobic digestion used to generate it absorbs CO_2 from the atmosphere. Chris Clarke, Director of Asset Management at Wales and West Utilities, a GDN company, noted biomethane "is in its infancy"[95] and that green gases in general are "perhaps like solar was 10 to 15 years ago […] at that stage of development".[96]

45. Unlike biomethane, hydrogen is insufficiently similar to natural gas to be injected into the current gas grid at high quantities. It may make steel pipes brittle (thus more vulnerable to cracks) especially at high pressures.[97] It also has a lower calorific value than natural gas—it produces less energy per volume.[98] Chris Clarke stated that hydrogen can be blended with natural gas up to 20%.[99] Burning hydrogen does not itself emit CO_2 (though producing the hydrogen may do).[100] There is also a natural synergy with renewable electricity, where spare generating capacity could create hydrogen through electrolysis.[101] Maxine Frerk noted "in the last year, we have seen a twelvefold increase in biomethane being connected to the network" and network innovation funding (examined in chapter 4) has been used for several biomethane and hydrogen projects.[102]

46. ***Ofgem should build on the promise of green gases by continuing to investigate and clarify safe levels for their injection. Both the Government and Ofgem should set indicative targets for biomethane and hydrogen deployment, and consider what support might be needed to deliver consequential changes to network infrastructure.***

93 Q2
94 *Future of Natural Gas in the UK*, POSTnote 513, Parliamentary Office of Science and Technology (POST), November 2015, p3
95 Q121
96 Q126
97 Paul E. Dodds and Stéphanie Demoullin, Conversion of the UK gas system to transport hydrogen, International Journal of Hydrogen Energy, vol 38 (2013), pp7189–7200
98 Q125 [Dr David Clarke]
99 Q123
100 *Carbon Footprint of Heat Generation*, POSTnote 523, POST, May 2016, p2
101 Q230 [Tony Glover]
102 Q274

District heating

47. Most homes in the UK are heated by an on-site water boiler powered by gas from the distribution system. District heating systems, also known as heat networks, use a large shared boiler to distribute hot water or steam to a number of homes. DECC provides the following summary of district-heating penetration in the UK:

> There are thought to be over 2,000 heat networks and communal heating schemes of various sizes in the UK serving 200,000 dwellings and 2,000 commercial and public buildings. The largest heat network schemes are predominantly found in cities and on university campuses. There are also a large number of smaller schemes in the domestic sector, often linking communally heated blocks of flats. This extent of heat networks represents around 2% of the domestic, public sector, and commercial buildings heat demand. Benefits from the increased use of heat networks could include energy cost and Carbon Dioxide (CO_2) emissions reductions for the UK, through allowing the exploitation of lower CO_2 and higher efficiency forms of generation. These could include the use of CHP,[103] biomass, heat pumps, waste heat and low grade heat sources.[104]

48. Dr David Clarke suggested that power plants be sited with a view to utilising waste heat.[105] Such synergies between electricity and heat development exemplify the benefits of a whole-systems approach, as we discuss in chapter 4. Dr Tim Rotheray, Director of the ADE, noted that district heating provides in-built thermal storage.[106] The Government observed in 2013 that "up to 20% of UK domestic heat demand might be served by heat networks by 2030"[107] and the Minister reaffirmed DECC's commitment to this target.[108] This would be a tenfold increase, in proportional terms, in uptake in less than a decade-and-a-half—an ambitious goal. The 2015 Spending Review and Autumn Statement announced £300 million of funding for district heating, "expected to support construction of up to 200 large heat networks in towns, cities and communities across England and Wales, and also to leverage up to £2 billion of private and local investment".[109] When asked in April how this money would be spent, the Minister noted that DECC would soon consult on this,[110] though we are still waiting for this consultation to open. Wales and West Utilities observed commercial barriers to district heating in a study conducted in Bridgend: it found a payback period of 35 years, and that "80% of the consumers either could not or would not pay".[111] Drs Clarke and Rotheray argued, however, that a low-carbon network would require significant infrastructural investment regardless of the mix of technologies chosen.[112]

49. We heard that district heating remains under-regulated: this could harm both existing customers, who are insufficiently protected, and future customers, if returns on investment are uncertain. The ADE has co-created a voluntary code of practice for district-heating providers. In November 2015, the ADE also launched Heat Trust, an independent

103 Combined Heat and Power (CHP) plants are thermal power stations which supply both electricity and hot water.
104 DECC, Assessment of the Costs, Performance, and Characteristics of UK Heat Networks, 2015, p6
105 Q139
106 Q155
107 DECC, The Future of Heating: Meeting the challenge, March 2013, p45
108 Qq381–4 [Andrea Leadsom MP]
109 Q379 [Andrea Leadsom MP]
110 Qq379–80
111 Q135 [Chris Clarke]
112 Qq136–7

customer protection scheme for district heating customers. This works with the Energy Ombudsman to manage complaints, and mandates audits for member providers every five years. While both of these are positive steps, and in no need of reversal, we would prefer that such self-regulation co-exists with independent regulation to ensure consumer protection. Furthermore, we heard it is unclear whether local authorities have the power to require district heat networks as part of local planning.[113] Regulation could also stimulate investment in district heating. Dr Rotheray told us "the Government need to develop a regulatory investment framework, like the one we have for gas, water and other infrastructure […] so that if you are an investor like an institutional investor, you will be able to look at different options and evaluate them on a similar playing field".[114] As noted earlier, the Government's plan to meet its 20% target for district heating relies, at this stage, on leveraging £2 billion of private investment; thus any measure that encourages such investment, while protecting consumers, must be looked on favourably. District heating currently has no independent regulation: Maxine Frerk noted that district heating "is not within [Ofgem's] remit unless we were asked to pick it up."[115] She further observed:

> You have the problem that once you have a district heating system in place, it is a monopoly. Customers cannot change supplier. There are a number of different ways to address that. It does not have to be through network regulation. I think you are aware that there is a voluntary code in place. On whether that could be given more teeth, there is the CMA,[116] and there are general consumer protection regulations that could apply in this area. There are a number of different ways that it can be addressed. I am not sure it is about them being treated as guinea pigs at this early stage. I think there is an inherent issue in the fact that it is a monopoly provision of a service that has a long infrastructure cost.[117]

50. Denmark, which developed district heating networks in response to the oil crisis of the 1970s, now uses them to provide for approximately 60% of its heat needs.[118] When we visited Copenhagen, scientists at the Technical University of Denmark (DTU) described the tripartite Danish heat system: district heating in urban areas, some gas-network coverage, and individual boilers in rural areas. Danish district heating is decentralised, usually under municipality control, and this local ownership—combined with the low prices it offers consumers—has cemented its popularity. Heat is supplied by CHP plants, mostly small, though we did visit Avedøre Power Station, which provides significant heat to the Copenhagen area. Danish energy experts we met agreed that the UK could not reach Denmark's levels of district heating provision, but did believe there was considerable scope for new-build housing to be connected to such systems. We feel there is much to learn from the Danish model of small, local CHP plants feeding district heating with effective local ownership and oversight.

51. ***The Government has rightly set an ambitious target for district heating—one which requires significant private-sector investment. A regulatory investment framework for district heating, similar to those for other networks, would aid this. It would also***

113 Q142 [Dr Rotheray]

114 Q139

115 Q275

116 Competition and Markets Authority, a non-ministerial Government department responsible for improving market competitiveness

117 Q276

118 "Lessons from Denmark: how district heating could improve energy security", The Guardian, 20 August 2014

complement existing voluntary schemes in providing independent safeguarding for consumers. Ofgem should be required by the Government to regulate district heating networks, and the Government should seek to make whatever legislative changes are necessary to enable this.

3 Managing networks flexibly

52. Network impacts of low-carbon electricity generation are not confined to the initial process of connection. Wind and solar do not typically provide power at the steady, constant rate which coal, gas and nuclear plant can. Together, wind and solar met approximately 10% of the UK's electricity demand in 2014, an approximately fourfold increase in absolute and relative terms since 2010.[119] This proportion is set to more than double, to 24%, by 2020.[120] Wind and solar are sometimes referred to as 'intermittent', but we heard from Dr Gordon Edge, Director of Policy at RenewableUK, that this adjective is inaccurate. He argued "wind and solar are variable: they vary with the availability of the resource, but they are also forecastable, whereas intermittency implies one or zero and a random move between the two" and noted that National Grid forecasts wind 24 hours ahead with 94% accuracy.[121]

53. We adopt Dr Edge's preferred terminology, but the rapid expansion of variable renewables as a proportion of the UK's electricity generation creates challenges for security of supply unless flexibly managed, meteorological advances notwithstanding. We considered three potential solutions in this inquiry. Technological advances in electricity storage could be a viable means to shift energy from times of peak supply to those of peak demand. Increased Demand Side Response (DSR), on the other hand, could mould electricity demand to the more-variable new shape of electricity supply. Interconnection between the UK and other European countries allows it to import electricity when needed and to export any surplus generated.

Storage

54. Variable generation could be managed by storing electricity at times of peak supply for use at times of peak demand. Electricity storage technology is advancing rapidly. We therefore examined the level of support that storage at different scales could offer networks now and in the future. There is a plethora of electricity storage technologies, encompassing a wide range of levels of capacity, response time, cost and maturity. Two broad categories of storage emerged as important: small-scale storage, typically in battery form, which could help DNOs and individual consumers balance their systems, and large-scale storage, such as Pumped Hydroelectric Storage (PHS) and Compressed Air Energy Storage (CAES), which could provide such services at the national level. Many witnesses complained about the regulatory framework for storage: we explored these concerns and the Government's timetable to tackle them.

Large-scale storage

55. Pumped Hydro Storage (PHS) uses electricity to pump water up a reservoir, which can then be released back through turbines. PHS is the most mature storage technology, accounting for 99% of global storage installation.[122] The UK has approximately 2.7 GW of PHS,[123] of which approximately 1.7 GW is at a single site, Dinorwig.[124] PHS can be built

119 DECC, DUKES, Electricity fuel use, generation and supply (DUKES 5.5), July 2015
120 *Intermittent Electricity Generation*, POSTnote 464, POST, May 2014, p1
121 Q32
122 International Energy Agency (IEA), Technology Roadmap: Energy storage, 2014, pp16–17
123 DECC, DUKES, Electricity fuel use, generation and supply (DUKES 5.5), July 2015
124 Engie, First Hydro, accessed 13 June 2016

at large scale but only at certain sites due to geological requirements.[125] Another form of large-scale storage is Compressed Air Energy Storage (CAES), which uses electricity to compress air and store it underground, where it can also be released back through turbines. Gaelectric is planning to develop a CAES site near Larne.[126] We heard contrasting views on the future of large-scale storage in the UK: Dr Jill Cainey, Director of the Electricity Storage Network, a trade association, told us "there is potential for more pumped hydro storage in the UK" but that "it is very expensive up front" and "securing planning is one of the biggest issues";[127] Stephen Goldspink of Siemens argued "in the UK we won't see anything like Dinorwig built again" due to "geographical restrictions" and that "more economic [storage] technologies are emerging".[128] National Grid told us that further PHS would be "a great service provider" to the System Operator.[129] The Minister told us that the Government would "potentially" support large-scale storage.[130]

56. ***Further large-scale storage, such as Pumped Hydro and Compressed Air Energy Storage, could be of great value in managing variable generation, but there is uncertainty as to the potential for future deployment. We recommend that the Government commissions a study on the future of large-scale storage in the UK which includes consideration of potential sites and what support such projects would need to be viable.***

Small-scale electrical and thermal storage

57. Lithium-ion batteries, the technology used to power many portable electronic devices and Electric Vehicles (EVs), are falling in cost and could have network applications. Other battery technologies of note include lead-acid and sodium-sulphur. Flow batteries, which store energy in liquids, are an alternative to conventional batteries. Hydrogen fuel cells can work like batteries and play similar roles, but are replenished through a fuel source (hydrogen) rather than recharged with electricity. Flywheels—which charge and discharge by spinning—and supercapacitors (high-capacity electrochemical capacitors) are fast to respond but have limited capacity, compared to batteries.[131]

58. Battery costs are dropping, but remain high relative to generation.[132] Chris Morrison, Head of Energy Construction Services for Centrica's Distributed Energy and Power group, noted that an "increase in capacity of supply for batteries will lead to significant reductions in cost and we are already starting to see costs fall very quickly on batteries".[133] Other stakeholders agreed that batteries, particularly lithium-ion, were the storage technology most able to be rolled out with scale and pace.[134] Dr Philipp Grünewald, Research Fellow at Oxford University's Environmental Change Unit, giving evidence on behalf of the Institution of Civil Engineers (ICE), made the important observation that the efficiency of a storage technology in isolation may not accurately reflect the improvement it can make to system-wide efficiency.[135] However, he also likened the lithium-ion battery to a

125 *Energy Storage*, POSTnote 492, POST, April 2015, p2
126 Gaelectric, Project-CAES Larne, NI, accessed 13 June 2016
127 Q54
128 Q54
129 Q227 [Phil Sheppard]
130 Q307
131 *Energy Storage*, POSTnote 492, POST, April 2015, p2
132 Lazard, Lazard's levelized cost of storage analysis—Version 1.0, November 2015, pp8–10
133 Q7
134 Qq61–4 [Dr Cainey and Dr Grünewald]
135 Q42

"Porsche", stating that "what we need for grid service is a bit like delivering gravel, and what we are proposing to do with lithium-ion batteries would be like delivering gravel with a Porsche, whereas in fact we need lorries";[136] he clarified that PHS was the "lorry" in this metaphor.[137]

59. We heard mostly about electricity storage, but also that heat storage is an important option. Dr Tim Rotheray of the ADE noted that "thermal storage costs about 100 times more than storing fuel in tanks and so forth. Electrical storage costs 100 times more again, so 10,000 times more than storing [fuel]".[138] Dr Jill Cainey observed:

> There are 14 million system boilers with hot water tanks in the UK. Those hot water tanks with immersion heaters represent a huge source of flexibility, yet we tend to be ripping those system boilers out and replacing them with a different type of boiler. Additionally, there are electric hot water tanks and households with just electricity heating with immersion heaters. Again, that is another significant source of system flexibility that we could look at now.[139]

Scott Mathieson of SPEN concurred that storing heat in immersion heaters was "a more readily available technology" and "more cost effective potentially" than domestic batteries.[140]

Storage regulation

60. The glacial pace with which regulation is adapting to storage may be a greater impediment than any technological immaturity: overcoming regulatory barriers to storage has become a dominant theme of this inquiry. The REA observed that "energy storage technologies (batteries and pumped hydro for example) have been around for decades in the UK but require an appropriate policy framework to deliver".[141] Phil Sheppard of National Grid emphasised the importance of this work:

> I was at a carbon-limiting technology conference that DECC was hosting with investors and developers, and the No. 1 thing—immediately after predictability of policy—was changing the rules on storage or clarity on how storage is going to be treated from a regulatory and policy perspective.[142]

61. The ICE observes two regulatory barriers to storage deployment. Firstly, storage is classified and licensed as generation: this limits network companies to operating no more than 100 megawatts (MW) of storage.[143] Secondly, storage is liable for BSUoS charges, which they are charged twice—once for 'consuming' the electricity they store, then for supplying it back to the grid—costing UK storage approximately £14.9 million annually.[144] They are also double-charged the Climate Change Levy (CCL).[145] Storage helps system balancing rather than the opposite; we find it odd that these charges are levied at all, let alone twice. Drs Edge and Cainey further noted that storage being classified as

136 Q55
137 Q58
138 Q154
139 Q65
140 Q9
141 REA (LCN0033)
142 Q229
143 ICE, Electricity Storage: Realising the Potential, October 2015, p15
144 ICE, Electricity Storage: Realising the Potential, October 2015, pp13–14
145 Q74 [Dr Cainey]

'demand' and as 'generation' subjects it to two different connection regimes and charging methodologies.[146] These barriers all flow from storage's classification as generation; creating a new, distinct, asset class may therefore solve them. Dr Cainey described the classification as "an accident of history".[147] Scott Mathieson also considered this a "strange anachronism".[148] Government has been slow to address this 'accident'; Dr Cainey further noted there had been no individual responsible for storage policy at DECC during the last Parliament.[149]

62. The Government told us it is now looking at storage. Lord Bourne of Aberystwyth, Parliamentary Under-Secretary of State for Energy and Climate Change, recently stated:

> In relation to storage, if we are talking battery storage here, this is something clearly of great significance. The Department is working very hard on this across Government, with DfT in particular; it has issues. We are aware of the potential. It is not oven-ready for legislation yet but it is something that we are working up. Within this Parliament certainly, and I hope earlier rather than later, we will be doing something on this.[150]

He added that such legislation would be "not for the [2016–17 Parliamentary] session".[151] In April 2016, Andrea Leadsom MP, Minister of State for Energy and Climate Change, noted that DECC was "literally about to publish a call for evidence on smart systems"[152] and that "there is an enormous urgency in DECC to resolve the issues for storage".[153] Despite this professed urgency, we are at time of writing still awaiting the launch of this consultation. Ofgem committed in September 2015 to "clarify the legal and commercial status of storage" over the next year.[154] The National Infrastructure Commission (NIC) recommended that "DECC and Ofgem should review the regulatory and legal status of storage and remove outdated barriers […] the reforms should be proposed by Spring 2017 and implemented as soon as possible thereafter".[155] The Government has accepted this recommendation.[156] However, when questioned, it did not wish to commit to a more precise timetable for advancing storage regulation.[157]

63. Andy Burgess of Ofgem told us "defining [storage] as a specific asset class might be the answer, but from the analysis we have done so far that is not the immediate solution".[158] He expounded on the difficulties of this approach:

> If you create a new licence, then it is a question of what goes with that licence. You would need to amend primary legislation to create a new licence category.

146 Q77
147 Q71
148 Q19
149 Qq72–3
150 Energy and Climate Change Committee, Oral evidence taken on 22 March 2016, HC (2015–16) 776, Q187
151 Energy and Climate Change Committee, Oral evidence taken on 22 March 2016, HC (2015–16) 776, Q188
152 Q302
153 Q313
154 Ofgem, Making the electricity system more flexible and delivering the benefits for consumers, September 2015, p6
155 National Infrastructure Commission, Smart Power, March 2016, p11
156 HM Treasury, Government response to Smart Power, April 2016, p2
157 Q312 [John Fiennes]
158 Q259

> We would need to check that whatever we were doing was consistent with wherever European law was going, because storage is quite an important issue at European level.[159]

He did not think the same problems applied to a modified generation licence.[160] We asked the Minister about changing the licensing for storage, which appears a straightforward approach. She noted "that is absolutely one answer but it is not the quick and easy solution that some might think because it would require massive changes to network codes, which could themselves take two or three years."[161] She announced that the upcoming consultation would seek a speedier approach.[162]

64. ***The current regulatory conditions for storage are hindering its development. We welcome the Government's consultative approach to this matter, but hope it will proceed with a sense of urgency. We urge the Government to publish its plans, as soon as possible, for exempting storage installations from balancing charges, and from all double-charging of network charges.***

65. There has also been debate about the role of network companies regarding storage: should they own, operate, install and utilise storage? We take these terms to mean the following:

- '*owning*' storage is self-explanatory;
- '*operating*' storage means controlling its energy flows and market participation, but not necessarily owning it;
- '*installing*' or '*procuring*' storage means contracting services from currently non-existent storage; and
- '*utilising*' storage means contracting services from currently existent storage.

Stephen Goldspink of Siemens Energy Management argued "allowing DNOs to install, operate and utilise storage would be a really positive step".[163] The REA called for "energy storage technologies to be operated and owned by DNOs";[164] the Power Systems Group at Newcastle University made a similar contention.[165]

66. However, not everyone was convinced that DNOs should have a major role in owning and operating storage. Chris Morrison argued "the DNO and the DSO[166] would be a monopoly provider in a certain area and, while they would be procuring solutions for flexibility and management of the grid, it is important that we have an open and competitive framework that allows everyone to participate in the procurement of those services".[167] Andy Burgess warned of dangers:

159 Q259
160 Q260
161 Q302
162 Qq310–11
163 Q75
164 REA (LCN0033)
165 Newcastle University (LCN0034) para 13
166 Distribution System Operator
167 Q23

> Our principle is that we want to see competitive markets develop—generally competitive markets and flexibility—and storage is part of that. Procuring storage is fine, and using storage is fine. Owning and operating storage immediately raises some issues about whether you can develop a natural competitive market for storage if you allow natural monopolies, particularly with regulated income, to start playing in those markets. Therefore our principle is that the network companies should not own or operate storage. We recognise there might be some exceptions to that based on particular circumstances or needs, or where you define storage as something where you just could not develop a competitive market. However, we think if you want competitive markets to develop it is important to keep the regulated monopolies out of them.[168]

67. **Storage technologies should be deployed at scale as soon as possible. We support network utilisation of storage: this helps balance the system, and provides storage operators with a revenue stream that encourages its development. Allowing networks to operate and procure storage, especially in the short run, could also facilitate these benefits. However, we have concerns about network ownership of storage. In the long run, we do not want networks to have vested interests in particular technologies that discourage them from switching where more cost-effective solutions emerge; we are also concerned about any expansion of networks' monopoly power more generally. DECC and Ofgem should analyse the long-term risks of network ownership, operation and procurement in their work on storage.**

Demand Side Response

68. Demand Side Response (DSR) denotes mechanisms by which electricity users can be encouraged to reduce their consumption at specific times: this is particularly useful at times of narrow system margin. From a system perspective, widespread DSR would make energy demand more flexible. The system could be balanced by curtailing consumption rather than firing up reserve generation. It has been estimated that expanding DSR could reduce electricity system costs by 10%, annual transmission-network investment by £800 million and peak generation capacity by £266 million.[169] There are three major types of DSR:

- Industrial and commercial DSR, where large factories and offices are paid to reduce electricity consumption at peak times;
- Aggregation, where companies called 'aggregators' pay large groups of individuals to reduce electricity consumption at peak times; and
- Individual load-shifting, where individuals reduce energy consumption at peak times in response to incentives.

Note that on-site generation is occasionally considered a type of DSR: a factory with a diesel generator can reduce the demand it places on networks by running that generator. Whether or not this is DSR, it is unlikely to be low-carbon, and we do not consider it here.

168 Q261
169 *Electricity Demand-Side Response*, POSTnote 452, POST, January 2014, p4

69. Dr Philipp Grünewald described DSR as "the least well understood" of major options for balancing the system.[170] Individual load-shifting requires consumers to have an incentive to use energy at off-peak times. However, suppliers do not have access to consumers' half-hourly data without smart-meters, and cannot reward them for using electricity at cheaper times. Half-hourly settlement, where actual half-hourly data (rather than estimated usage patterns) determines what suppliers pay for electricity, could create an incentive for them to encourage their customers to shift loads. They could do so by offering Time of Use (ToU) tariffs, where consumers pay different energy rates at different times of the day.[171] Asked to suggest regulatory changes to bring DSR forward, Sara Bell, CEO of Tempus Energy, told us her "No. 1 ask would be half-hourly settlement of all customers as quickly as possible".[172] The Government plans to introduce elective half-hourly settlement in 2017, and will consider making it mandatory thereafter.[173] Our recent pre-legislative scrutiny of the Government's draft legislation on energy considered half-hourly settlement in greater detail.[174]

70. Stephen Goldspink told us the smart meter roll-out "kick-starts this whole behavioural change within the UK".[175] Dr Philipp Grünewald was more sceptical as to the powers of smart meters to trigger behavioural change, noting "there is the neo-classical approach—that we just set a price signal and they will respond—but there is also a school that says these behaviours are more complicated and deserve more scrutiny to understand what triggers flexibility on the demand side".[176] We learned in Copenhagen that Denmark is currently rolling out smart meters, and has already installed 2 million. These are owned by the distribution networks and feed information to a central data hub at Denmark's TSO, Energinet.dk. However, Denmark has so far seen little evidence of individual load-shifting; it was felt that greater use of smarter, automated appliances may be needed for this.

71. Aggregators can be better placed than lone individuals to untap load-shifting potential: they "coordinate groups of end users who are able individually to offer only small amounts of demand flexibility, combining these into more substantial reductions in demand which they can sell" and "cover the risk of not delivering this flexibility".[177] However, the National Infrastructure Commission (NIC) notes that "aggregators are unable to access the UK's electricity markets on equal terms with generators" as "there is no defined role for third parties" in the balancing market (where the TSO micro-manages electricity supply and demand into balance in the immediate run-up to real time).[178] This denies the TSO a tool for balancing the system.

72. DSR can be traded in the Capacity Market, an auction system designed to improve security of supply. However, KiWi Power, a DSR provider, argued that "the UK market has not provided a level playing field between supply and demand, with the first Capacity Market auction resulting in just 0.3% participation from DSR" and that "biases towards

170 Q81
171 Ofgem, Elective half-hourly settlement: conclusions paper, May 2016, paras 1.1–1.7
172 Q91
173 Q323 [John Fiennes]
174 Energy and Climate Change Committee, Sixth Report of Session 2015–16, Pre-legislative scrutiny of the Government's draft legislation on energy, HC 776, paras 30–31
175 Q89
176 Q82
177 NIC, Smart Power, March 2016, p51
178 NIC, Smart Power, March 2016, p54

generation exist in the [Capacity Market] design, such as the ability for generators to tender for 15-year contracts while DSR is only able to tender for 1-year contracts”.[179] Tempus Energy claimed that “the UK capacity market presents a huge missed opportunity for energy intensive industries and innovators to come together”.[180] Our predecessors raised these concerns with DECC last year.[181] In response DECC told us that:

> Analysis of currently-available evidence indicates that DSR and existing generation do not require such significant up-front capital investment, which would potentially necessitate access to long-term capacity agreements. In fact, current evidence suggests that DSR is a relatively low-cost solution and should therefore be able to compete effectively on the basis of one-year agreements.[182]

73. Citizens Advice, a consumer watchdog, identified risks to consumers from the increasing complexity of DSR:

> The two main issues raised by DSR are first that it could complicate an already over-complicated market, meaning some consumers end up on unsuitable deals without due protection; and second that it could create a two-tier market of flexibility haves and have-nots, where those who cannot shift their usage do not receive any of the benefit from overall system efficiency.[183]

74. The NIC recommends that “Ofgem should start an immediate review of the regulations and commercial arrangements surrounding demand flexibility with a focus on making participation easier and clarifying the role of aggregators”.[184] The Government has committed to undertaking this work, “through the forthcoming call for evidence on a smart systems route map” (referred to in paragraph 62), by Spring 2017.[185]

75. ***The promised review of Demand Side Response (DSR) by Ofgem is a sensible first step towards clarifying and unlocking the potential for DSR technologies and business models. However, we maintain the views of our predecessor Committee that the Government needs to set out a more detailed strategy for DSR. This strategy and any work on this issue by Ofgem must also pay close attention to the risks of DSR for vulnerable customers, and how best to mitigate these.***

Interconnection

76. Interconnectors are transmission lines that connect one country’s transmission system to another, allowing for import and export of electricity or gas: we focus here on electricity. They earn revenue from arbitrage—buying electricity from the country in which it is more expensive, and selling to the other. Interconnectors help balance the system both by effectively counting as extra generation capacity (electricity can be imported to make up any shortfall on one side) and by providing emergency services to

179 KiWi Power (LCN0053)

180 Tempus Energy Supply (LCN0056)

181 Energy and Climate Change Committee, Eighth Report of Session 2014–15, Implementation of Electricity Market Reform, HC 664, para 38

182 DECC, *Government Response to the Energy and Climate Change Committee Report on the Implementation of Electricity Market Reform*, Cm 9090, June 2015, p6

183 Citizens Advice (LCN0013), para 20

184 NIC, Smart Power, March 2016, p59

185 HM Treasury, Government response to Smart Power, April 2016, p3

the TSO.[186] Ofgem's Cap and Floor (CaF) regime sets interconnectors' upper and lower revenue limits, though some interconnectors (such as BritNed and ElecLink) choose to operate without a CaF.[187] Informal discussions with engineers in Copenhagen suggested that 2 GW is the upper limit on the capacity of a single interconnector.

77. In 2014, wind provided for 39.1% of Denmark's electricity needs.[188] As wind is variable, this is an average: the proportion varied between 0% and 132% in 2014.[189] Energinet.dk, the Danish TSO, has retained a secure supply, with only 41 seconds of electricity outage last year.[190] We learned, when visiting Copenhagen, that Denmark's high level of interconnection—its import capacity represents 85% of its peak demand—[191]is key to this management. As EDF Energy pointed out, the UK has comparatively "greater costs to ensure interconnection" than other EU countries;[192] yet the value of interconnection in balancing variable generation should not be underestimated.

78. The GB transmission system is currently linked to those of Ireland, France and the Netherlands. Charlotte Ramsay, Head of Strategy Markets and Regulation at European Business Development, a National Grid subsidiary focused on interconnection, said "at the moment we are not very heavily interconnected", noting 4 GW of current interconnection and "between 9 and 11 GW being on stream by the early 2020s".[193] The table below describes GB's current and planned future interconnection:

Table 1: Current and future UK interconnection

Interconnector	Countries	Capacity	Stage	UK owner
BritNed	GB-Netherlands	1 GW	Operational	National Grid
East-West	GB-EIRE	0.5 GW	Operational	EirGrid
IFA	GB-France	2 GW	Operational	National Grid
Moyle	GB-NI	0.5 GW	Operational	Mutual Energy
ElecLink	GB-France	1 GW	Proposed	Star Capital Partners
FAB Link	GB-France	1.4 GW	CaF approved	Transmission Investment
Greenlink	GB-Ireland	0.5 GW	CaF approved	Element Power
IceLink	GB-Iceland	1 GW	Proposed	National Grid
IFA2	GB-France	1 GW	CaF approved	National Grid
Nemo Link	GB-Belgium	1 GW	Construction	National Grid
NSN	GB-Norway	1.4 GW	Construction	National Grid
Viking Link	GB-Denmark	1.4 GW	CaF approved	National Grid

Sources: Q237 [Charlotte Ramsay]; Elexon, Interconnectors, accessed 13 June 2016; National Grid, Interconnectors, accessed 13 June 2016; Ofgem, Electricity interconnectors, accessed 13 June 2016

The table shows that up to 8.7 GW of new interconnection is planned. The Government "supports the market delivery of at least 9GW of additional interconnection capacity".[194]

186 Energy and Climate Change Committee, Oral evidence taken on 24 November 2015, HC (2015–16) 509, Q55 [Duncan Burt]
187 Ofgem, Electricity interconnectors, accessed 13 June 2016
188 Energinet.dk, Annual report 2014, April 2015, p10
189 Energinet.dk, Annual report 2014, April 2015, p23
190 Energinet.dk, Annual report 2015, April 2016, p8
191 Energinet.dk, Annual report 2014, April 2015, p15
192 EDF Energy (LCN0027)
193 Q252
194 HM Treasury, Government response to Smart Power, April 2016, p1

79. We heard that Ofgem's cap and floor regime is "an open and competitive process".[195] The ENA "are in the early stages now of forming an interconnectors forum".[196] Be that as it may, a glance at the table above reveals that National Grid continues to dominate this market. We would like to see greater competition for new interconnector developments in the future, particularly given potential conflicts of interest relating to National Grid's interconnector holdings, which we return to in chapter 4.

80. We discussed Viking Link, the proposed GB-Denmark interconnector, during our visit to Copenhagen. Scientists from the Technical University of Denmark (DTU) noted that GB and Denmark tend to be windy at different times: we later heard, from Danish energy experts, that Viking Link could therefore combine GB and Danish wind into 'virtual baseload' with high reliability. We also noted that due to existing interconnection between Denmark and Norway, Viking Link would give the UK an indirect link to Norwegian hydropower.

81. The NIC recommends that Government "focus its efforts on exploring increased interconnection to markets with abundant sources of flexible low carbon electricity, such as Norway and Iceland."[197] Aurora Energy Research, a consultancy, is more critical of building interconnectors. It cites "significant costs […] big enough to make the net GB welfare impact of most new interconnector projects negative" with the exception of Norway.[198] Aurora argues that interconnectors have a net negative effect on CO_2 emissions, as they create bigger demand peaks in export countries (thus incentives for fossil-fuel generation).[199] It contends that "the fundamental economics of interconnection dictate that GB is likely to be a net importer of electricity from European markets".[200] In response to Aurora's research, the Minister argued Aurora "seem to have overestimated the downside and underestimated the positives" and that "Ofgem does its own very thorough cost-benefit analysis, taking into account the energy trilemma".[201] She also noted "we tend to receive electricity rather than export it, but that does not make us a net importer".[202]

82. **Significant interconnector expansion will help balance a low-carbon network, and we support it for that reason. We note that Great Britain is likely to be a net importer of electricity; development of interconnection should be accompanied by a strategy to develop sufficient low-carbon generation capacity for export.**

83. The NIC highlights "a role for government-led diplomacy to unlock those markets that can offer potentially large benefits to UK consumers".[203] Charlotte Ramsay stated that "Government have already been very helpful in this space", noting that "with a lot of the countries that [National Grid] connect to, the decision making around whether or not you build an interconnector and how you connect two markets rests with the Government rather than with the regulator".[204] The Minister added that "whenever a Foreign Office Minister or another Minister is travelling somewhere that could have useful energy

195 Q244 [Charlotte Ramsay]
196 Q244 [Tony Glover]
197 NIC, Smart Power, March 2016, p34
198 Aurora Energy Research, Dash for interconnection, February 2016, p2
199 Aurora Energy Research, Dash for interconnection, February 2016, p7
200 Aurora Energy Research, Dash for interconnection, February 2016, p8
201 Q337
202 Q339
203 NIC, Smart Power, March 2016, p34
204 Q241

interests communicated, then we always make sure that is included in their brief as a point to raise".[205] We welcome this approach, and encourage the Government to continue diplomatic efforts to develop interconnection.

84. Interconnectors are traditionally a direct link between two countries fed into by pre-existing sources of generation. However, we have come across different business models in the course of this inquiry. IceLink, the proposed GB-Iceland interconnector, was described as "something of a special case, because it does not have the same business case or commercial case as a traditional point-to-point interconnector."[206] The NIC elaborates that "the overall project is likely to require a package of new generation along with the interconnector".[207] Charlotte Ramsay added that an intermediary connection to the Faroe Islands was "part of the discussion" around IceLink.[208] She noted that IceLink's first milestone to achieve would be a Government-to-Government agreement between GB and Iceland.[209] The project was "a definite possibility" but also "high-risk":[210] it would, after all, be the longest subsea cable in the world.[211] The Prime Minister has established a taskforce looking at IceLink.[212]

205 Q343
206 Q238 [Charlotte Ramsay]
207 NIC, Smart Power, March 2016, p3
208 Q245
209 Q238
210 Q238 [Charlotte Ramsay]
211 Q343 [Andrea Leadsom MP]
212 Qq340, 343 [Andrea Leadsom MP]

4 Network governance and regulation

85. Networks' governance and regulation determines, to some extent, their ability to connect new energy sources and balance the resultant system. We analysed the frameworks in which networks operated insofar as they help or hinder progress towards the goals outlined in preceding chapters, and focused on four aspects. Innovative solutions are crucial to reinforcing and balancing the networks, and so we scrutinised Ofgem's programme of innovation stimulus. The distribution networks need to take greater responsibility for balancing the system, perhaps through the creation of Distribution System Operators. The role of National Grid as Transmission System Operator merits scrutiny at a time of significant change in network needs. Finally, a more joined-up or 'whole-systems' approach to energy is among the most iterated requests we received: we consider what this means and how it might be implemented.

Innovation

86. We detail new technologies for networks to decarbonise and balance the system in previous chapters: a strong innovation programme is crucial to this pipeline of solutions. Ofgem provides considerable funding for network innovation. The RIIO price controls contain a package of support for trials of new techniques and technologies, known as Network Innovation Stimulus (NIS). This comprises:

- The Network Innovation Allowance (NIA), for each network, to fund small projects and prepare submissions to the Network Innovation Competition;
- The Network Innovation Competition, an annual competition with 'prize' funding of up to £81 million p.a., usually spread across multiple winners—this was described as a "Dragon's Den" for network companies;[213] and
- The Innovation Rollout Mechanism (IRM), which aims to enable wider deployment of more developed technologies.

These follow the Low Carbon Networks Fund (LCNF), a £500 million fund under the previous price control for similar purposes. This ended and was succeeded by NIS in 2015; much of our evidence therefore referred to the LCNF, which was widely praised.

87. Nevertheless, our evidence has highlighted three remaining difficulties in network innovation. Collection and dissemination of information from completed trials could be improved, and this would improve the impact of such testing. Successes of the LCNF and NIS are concentrated at early-stage development of new ideas, and lacking at end-stage rollout and commercialisation. We have also heard that the corporate structure and incentives of network companies make them innovation-averse, and we have taken suggestions on how this may be fixed. Network innovation is heavily funded and critical to developing the technology that networks need to adapt to modern challenges, and we must carefully scrutinise any flaw in the system.

213 Q29 [Scott Mathieson]

Information

88. Citizens Advice, while acknowledging the "extremely valuable work"[214] of the LCNF, also criticises its collection and dissemination of results, noting "the projects often did well individually at documenting their work, but there is an urgent need for a central resource that pulls findings together".[215] Simon Moore, Policy Manager in Strategic Infrastructure at Citizens Advice, elaborated that "both the types of data being collected and the quantities of data being collected are very inconsistent between the different projects".[216] It is difficult to compare different types of data, or to compile accurate information when different sources provide different quantities of data, and so innovations become hard to evaluate. Mr Moore noted this as a particular issue at the consumer end of projects.[217] Funding should aim to deliver at least some innovations with widespread potential, and standardised collection and dissemination of results would help achieve this. Citizens Advice also claimed that LCNF projects "tend to overlap in some areas and leave gaps in others".[218] This may be a problem with any system in which individual companies create their own projects for their own needs, as there is no central guidance to address shared issues and avoid duplication. However, improved information would highlight which fields are significant and untilled and which are exploited.

Commercialisation

89. Successes in early-stage research and development appear not to be continued into commercial maturity. Technology Readiness Levels (TRLs) are a helpful tool to measure an innovation's progress from concept to reality. The European Commission defines TRLs as follows:

Table 2: Technology Readiness Levels

TRL	Definition
1	Basic principles observed
2	Technology concept formulated
3	Experimental proof of concept
4	Technology validated in lab
5	Technology validated in relevant environment
6	Technology demonstrated in relevant environment
7	System prototype demonstration in operational environment
8	System complete and qualified
9	Actual system proven in operational environment

Source: European Commission, Horizon 2020 Work Programme 2016–17, Annex G, October 2015

90. The ETI argues "in TRL 4–7, there has been a gap" and that the UK is "relatively heavy on investment at the front, low TRL level, but light on late TRL spend (pre-commercialisation)".[219] Dr Phillip Grünewald of the ICE and Oxford University emphasised the importance of this later-stage research:

214 Citizens Advice (LCN0013) para 23
215 Citizens Advice (LCN0013) para 24
216 Q169
217 Q169
218 Citizens Advice (LCN0013) para 23
219 ETI (LCN0022) para 31

> The important thing is that this innovation does not happen just in the labs. The fundamental research is important and there is a lot that we can do in that area, especially on storage. The UK has the potential to be a real world leader, but it is important that we feed that through into demonstration and application.[220]

British Gas concurred that "there is a need to focus available funding on more commercial trials and better enabling routes to market".[221] Dr David Clarke of the ETI observed that later stages of development are more costly—giving an example of a design for a new wind-turbine blade which cost £1 million to research, £10 million to develop, and an estimated £100 million to bring to market—[222]but noted "the final hurdle—the investment decision around the £100 million or whatever the number turns out to be—is more difficult in the UK".[223] Dr Jill Cainey of the Electricity Storage Network raised the point that "often with these innovation projects it is specified that it has to be completely new learning", and consequently it can be difficult for networks to further develop others' projects.[224]

91. We accept that bringing innovations to commercial readiness is expensive, and likely successes are difficult to identify at an early stage. There have been some successes, such as the Consumer-Led Network Revolution's demonstration of dynamic line rating and voltage control;[225] we would like to see many more. The ETI contends that "failure to fund and develop timely demonstrations will result in consumers paying higher costs".[226] The UK's aim should be to deliver network innovations with potential for export, and Sara Bell of Tempus Energy argued "we need a much clearer plan around what technologies could be exportable".[227] This would mean focusing on projects that fill gaps not just in UK but in European and international markets.

Network culture

92. We heard that the culture and incentives of network companies are not conducive to innovation. UKERC noted that "for the most part, the network licensees are seen by their shareholders, i.e. by their investors, as low risk investments with unspectacular but safe returns".[228] Sara Bell told us:

> Distribution networks are not known for their innovative approach. In the UK, most of them have been bought by infrastructure investors. That is really about parking cash that is earning a higher rate of return than it would at a bank. They are not in it because they want to innovate or want to drive a smarter energy system, and it is incredibly important to understand that.[229]

Dr David Clarke agreed with Ms Bell, claiming "I just don't think the DNOs, in a regulated environment, have the capacity to handle that scale of investment" (referring to his earlier

220 Q105
221 British Gas (LCN0015)
222 Q146
223 Q149
224 Q109
225 Ofgem, Correspondence regarding Ofgem's innovation allowances, May 2016
226 ETI (LCN0022) para 28
227 Q110
228 UKERC (LCN0016)
229 Q75

remarks, given above, on the high cost of later-stage development).[230] UKERC delved further into this cultural problem, arguing that "as a result of reduced R&D spending over the past 25 years, the network licensees have forgotten how to manage and report R&D":[231] this worsens the information difficulties outlined earlier. Professor Keith Bell, Co-Director of UKERC, noted "the culture is changing slowly"[232] but "there is still a further road to be travelled down, in terms of changing the culture of the network companies towards innovation".[233]

93. These traits—risk aversion and limited access to capital and research methods—may preclude otherwise fruitful areas of investigation. UKERC claims that "only projects with a high chance of 'success' are commissioned, and negative or inconclusive results are at risk of being hidden even though they contain important learning".[234] Professor Bell added that "a lot of the projects have been kind of kit driven" and that "the next step is, to a large extent, back to first principles, back to the concepts, back to how you operate the system as a whole and how you interact with consumers".[235]

94. Innovation can be driven by need as well as creativity. Stephen Goldspink of Siemens Energy Management noted that some innovations "need to have the pull from the demand side to make it happen".[236] New connections and variable renewables will create new challenges for network companies to fulfil basic requirements of reliability, controlling costs and consumer satisfaction. Innovations that overcome these protect networks' returns under RIIO.

95. A number of suggestions to solve these innovation problems were made. Phil Jones of Northern Powergrid advised Ofgem "to concentrate on system-wide innovation" rather than on distribution networks in insolation.[237] Dr David Clarke argued for non-network companies, which are already involved with NIS in partnership with the networks, to be able to lead projects "so that you would get a broader cross-section and potentially alternative routes to market for the outputs";[238] Simon Moore agreed, noting "there are many ideas out there, which are not held within networks at the moment, which could have quite a strong bearing on the cost of networks over time".[239] Maxine Frerk of Ofgem was "keen" to "bring in more third parties as partners for the network companies".[240] The ENA "run a portal for companies who have an idea and want to find a network partner".[241]

96. ***We strongly support Ofgem's commitment to network innovation, but feel there is room for improvement. Ofgem must collect standardised trial data to optimise learning from projects. Furthermore, it should allocate proportionally more funding to later-stage development, and seek opportunities to leverage other sources of funding to***

230 Q152
231 UKERC (LCN0016)
232 Q171
233 Q170
234 UKERC (LCN0016)
235 Q172
236 Q80
237 Q175
238 Q153
239 Q175
240 Q258
241 Q258 [Maxine Frerk]

achieve project commercialisation. A stronger role for non-network companies in using Network Innovation Stimulus could also balance DNOs' propensity for risk aversion in the short term, while counteracting it in the long run.

Distribution System Operators

97. Distribution Network Operators (DNOs) as they currently exist are network owners without a corresponding operator function. For example, the UK's solar generation—mostly connected to the distribution networks—cannot be seen directly and is measurable only as a reduction in transmission-system demand.[242] In chapter 2, we identified smart-grid technologies as crucial to low-carbon network infrastructure. These technologies could enable DNOs to move from a blind, passive role to one of responsibility for balancing energy flows at a distribution level as the TSO does for transmission: they would become Distribution *System* Operators (DSOs). UKPN said:

> A DSO would undertake the conventional role of a DNO but would also make full use of smart techniques to create value for the wider electricity system, e.g. by undertaking an element of regional balancing and providing reserve and frequency response services to the national System Operator. Such services will become increasingly important to maintaining a stable balanced national electricity system as conventional 'synchronous' generation associated with coal and gas fired power stations gives way to higher volumes of intermittent renewable generation technologies.[243]

98. The Electricity Storage Network argued that "a move to the DSO model is urgently needed as this would facilitate the development of innovative models for our future networks".[244] Tony Glover of the ENA claimed that "if DNOs were to become DSOs, it would ultimately reduce costs";[245] he did not envisage any short-term, transitional harms to consumers.[246] The Minister concurred that "there will be enormous cost savings for consumers as a result of DNOs becoming more active in managing their part of the network".[247] On our visit to Copenhagen, we learned that some Danish distributers already have control-room functionality and can be considered DSOs: one project, EcoGrid 2.0 on Bornholm Island, is trialling a DSO in conjunction with DSR. RWE, a major supplier, recommended that DSOs be introduced before RIIO-ED2 begins in 2023—perhaps through "a RIIO-ED1 reopener"—"particularly because distributed generation has grown beyond expectations".[248]

99. It remains unclear how exactly DNOs would transform into DSOs, and whether they could be established without modifications to licence codes. Phil Jones argued:

> It can happen naturally to a degree […] New pieces of equipment on a network would start to contribute to that almost automatically and nothing else would need to be done. But there would come a point where if the obligation is going to shift from National Grid, where it very clearly rests right now, on to, for

242 Q225 [Phil Sheppard]
243 UKPN (LCN0049) para 5.2
244 Electricity Storage Network (LCN0014)
245 Q230
246 Q234
247 Q291
248 RWE (LCN0017) para 6.1

> example, my own company for that part of the world, then yes, there would have to be some changes to licences and legislation presumably. Certainly our licence obligation would have to change, and the codes that govern the way the industry works would then have to change and adapt to suit it. There is some quite dry, regulatory work to do eventually.[249]

100. Andy Burgess of Ofgem told us "there is nothing to prevent the DNOs from becoming DSOs now, or at least the early stages of DSOs".[250] On the other hand, there are advantages to the universal responsibility that National Grid currently bears as a monopoly system operator—it is clear who does what. It would not be acceptable, in a new world of DSOs, for these lines of responsibility and accountability to be muddled. UKERC observed that "as now, the interactions between different items of equipment owned by different parties are likely to depend on appropriate technical standards".[251] This may imply that even early-stage DSO creation necessitates modifications to technical codes, at the very least. The Minister gave an account of networks' current and future governance structure:

> DECC would be responsible for looking at the structure of how the energy system works and the policy areas. Ofgem will look to DECC for policy steers on how they should then regulate and implement the topline policy, so Ofgem is then responsible for looking at the factors. In direct answer to your question, if and as we move away from DNOs to DSOs, it will be through Ofgem's regulation of the system that they make clear to National Grid, as the national systems operator, and to the DNOs, as they become more like DSOs, as to where the boundaries lie. Obviously those will tend to be geographic. The national system operator operates the big highways and motorways of the grid and the DNOs look at the more local and regional. Ofgem will be regulating both and then of course National Grid manages the day to day operations of the system, so the expectation is that more system operation at the distributed area is going to add to National Grid's ability to manage the system more efficiently and, therefore, cheaply.[252]

101. ***The benefits of Distribution System Operators (DSOs) seem near-universally acknowledged, yet there is no clear Government road map to their implementation. The Government should develop and publish a road map for DSO introduction, identifying future legislative and regulatory changes needed. The road map should include a plan to require small-scale generators to provide real-time information to DSOs. The relationships across DSOs and between DSOs and the Transmission System Operator must also be clarified.***

102. We did not assume that the DSO should be run by the same company as the corresponding DNO. However, Tony Glover told us "we cannot see any practicable and cost effective way for the DSO not to be the DNO".[253] Andy Burgess said "in principle, we think it probably makes sense for it to be the same company, because you introduce an extra complication if you separate it out".[254] He cautioned, however:

249 Q193
250 Q265
251 UKERC (LCN0016)
252 Q295
253 Q223
254 Q268

> The important things is to make sure that the monopoly DSO does not impede competition, that there is the right level of regulatory control over what markets it can be active in and, as far as possible, that we have competitive markets providing services, rather than the DSOs.[255]

103. **The evidence favours Distribution System Operators (DSOs) being run by the same companies as the corresponding Distribution Network Operators (DNOs), at least in the short-term transition to DSOs. However, DSOs are an extension of DNOs' monopoly power, and Ofgem are right that this should be appropriately regulated. Given risks to consumers from accumulation of monopoly power, DECC and Ofgem should be prepared to review the governance of distribution networks as DSOs' functions develop, and to separate distribution networks' operation from their ownership if their conjunction proves to have a negative impact on consumers.**

National Grid and an Independent System Operator

104. National Grid plc, a private company listed on the London Stock Exchange, and its subsidiaries have a wide variety of roles in ownership and operation of GB network infrastructure. They own and maintain the physical electricity transmission network in England and the gas transmission network in GB, act as Transmission System Operator (TSO) for both, develop, own and operate much of the UK's interconnection, and play a role in administering Electricity Market Reform (EMR).[256]

Conflicts of interest?

105. Dr Philipp Grünewald stated:

> In general terms, I would agree that when an entity owns the electricity transmission network, large parts of the gas network, is responsible for capacity mechanism, whose subsidiary owns interconnectors and is the system operator, it stands to reason that there are some conflicts that ought to be addressed, because they just get bigger as we go forward.[257]

106. Specifically, two potential conflicts of interest have been raised which would undermine the development of low-carbon network infrastructure. Firstly, National Grid has the power and incentive to encourage physical infrastructure development and then profit from it: this is known as 'asset padding'. For example, Standard Condition C27 of the Transmission Licence requires the licensee (National Grid) to publish a Network Options Assessment report;[258] this is "effectively saying what additional network investment was needed".[259] National Grid also reports on electricity capacity requirements for the Capacity Market.[260] In both cases, National Grid could advocate more capacity than necessary in order to be allowed to build, then own, such assets. These are merely examples illustrating

255 Q268

256 EMR refers to the Capacity Market, an auction system designed to improve security of supply, and Contracts for Difference (CfDs), a subsidy and price-stabilisation mechanism for renewable generation; these were introduced in the Energy Act 2013.

257 Q93

258 Ofgem, Transmission Licence Standard Conditions, Condition C27: The Network Options Assessment process and reporting requirements, para 9

259 Q270 [Maxine Frerk]

260 The Electricity Capacity Regulations 2014 (SI 2014/2043), section 7

a wider problem of accountability: National Grid as TSO and transmission-asset owner is in the position of both benefitting from asset development and being in an influential position to recommend it. Sara Bell observed that "there is a fundamental difference between an infrastructure investor who wants to grow and grow and grow the asset and the role of cost-effectively managing a system that should be run in a most cost-effective manner".[261]

107. In response to the question of asset padding, Phil Sheppard of National Grid told us:

> One of the clever pieces of regulation in RIIO is that we are incentivised around our total expenditure. That is a combination of revenue and CapEx. Therefore there is an incentive on National Grid as a [transmission operator], as it is with all [transmission operators], to find ways of not building and delivering an output that is part of the regulatory deal.[262]

Citizens Advice argued, however, that "even if the efficiency incentive within each price control militates against overspending, there is still temptation to 'pad your assets', as this confers an advantage at the next price control".[263]

108. The second potential conflict of interest concerns National Grid's role, through its subsidiaries, in owning interconnectors. EDF Energy contended that "there must be a clear process to ensure that potential conflicts of interest can be managed for National Grid, between its role as System Operator and its commercial interests, such as the development of interconnection."[264] National Grid uses interconnector imports as backup in event of narrow system margins.[265] Moreover, interconnectors are eligible for the Capacity Market. Again, National Grid could overstate capacity requirements, which would generate a higher clearing price in the Capacity Market—perhaps for its interconnectors. The fundamental issue here is that National Grid could act in a way that inefficiently advantages interconnection over other balancing tools, such as storage and DSR.

109. Charlottte Ramsay of National Grid's European Business Development responded that "European Business Development and all of the interconnector projects and companies that we run are wholly separate from the UK core activities, which means that the relationship we have with the system operator is the same as any other connectee into the system".[266] She concluded "there is potential for conflicts, and I think that they are thoroughly mitigated through the processes we have in place."[267] Phil Sheppard continued:

> If Charlotte [Ramsay] came to visit me in Warwick, she would be treated as an external visitor and escorted to the meeting room. We would have the meeting, and then she would be escorted out. We are physically in different locations, with different security systems, and our [information] systems are all separate. In terms of that process, the governance is different. We have different boards. Our main board have all signed undertakings that they are never going to

261 Q92
262 Q253
263 Citizens Advice (LCN0013) para 30
264 EDF Energy (LCN0027)
265 Energy and Climate Change Committee, Oral evidence taken on 24 November 2015, HC (2015–16) 509, Qq22, 55 [Duncan Burt]
266 Q242
267 Q243

> require or allow a licenced entity to breach its licence as a consequence of actions. There are a whole load of very thorough rules and regulations around that.[268]

Stephen Goldspink similarly counselled against hasty action on National Grid, noting it "has taken considerable steps to silo its network operation and system operation" and that "there is a lot of mature experience" at the company.[269] We would not want to lose that experience.

110. Maxine Frerk of Ofgem admitted "there is the potential for conflicts of interest, and that comes from their role as SO owning the interconnectivity, and also their role as SO owning network investment".[270] Nonetheless, Ofgem has powers to hold National Grid to account on "a spectrum between a conversation and ultimately taking enforcement action", including "being able to impose financial penalties on them, up to 10% of turnover."[271] Ms Frerk continued "we would expect to pick up if there was something where the SO was taking some balancing action that looked odd to us in that context, and we could follow that up" and concluded that "we are confident that, at the minute, we are able to manage those conflicts, and that there are not any issues".[272]

An Independent System Operator

111. There have been suggestions that DECC plans to separate the TSO function from National Grid. The Rt Hon Amber Rudd MP, Secretary of State for Energy and Climate Change, stated in her 'reset' speech that "there is a strong case for greater independence for the system operator".[273] In March 2016, *The Times* reported on documents purportedly leaked from DECC that proposed options for separating the TSO function from National Grid. It claimed that DECC's preferred option was to create a non-profit Independent System Operator (ISO) overseen by Ofgem. The documents are quoted stating that "this option maximises independence of the System Operator both from market participants and the government. It is the approach taken by the majority of [other countries] and has been demonstrated to work well."[274] There are, for example, 7 ISOs in the USA, including one for each of the three largest states (California, Texas and New York).[275] In Copenhagen, we met with Energinet.dk, Denmark's TSO. Energinet.dk is a non-profit enterprise owned by the Danish Ministry of Energy, Utilities and Climate; it has both efficiency and social-welfare objectives.

112. Maxine Frerk told us:

> The importance of having an independent system operator, in our view, is that it is independent of Government, as well as independent of National Grid. So if there were an ISO, we would expect it to be a licensed entity that we regulated in the same way as we regulate Grid.[276]

268 Q254
269 Q93
270 Q270
271 Q271 [Maxine Frerk]
272 Q270
273 Rt Hon Amber Rudd MP, Speech on a new direction for UK energy policy, 18 November 2015
274 *"Ministers ready to pull the plug on National Grid"*, The Times, 3 March 2016
275 Federal Energy Regulatory Commission, Regional Transmission Organizations (RTO)/Independent System Operators (ISO), accessed 13 June 2016
276 Q272

113. Phil Sheppard cautioned against an ISO in the short run, noting that:

> If you look at the models used elsewhere in the world, there is a whole raft of market rules that have to work with an ISO, because the incentivisation and the methodology of delivering value to consumers is very different. Injecting that sort of uncertainty into the UK market at this point in time seems counterproductive.[277]

He contended that "at some future point [an ISO] may be appropriate, but certainly not in the short term or the medium term".[278] We agree with Mr Sheppard that the role of System Operator is complex and important, and should not be changed at a pace that would spook investors or outstrip the speed of appropriate regulatory development.

114. The Minister explained the Government's position:

> We have been very clear from the Secretary of State's reset speech last November that we would like to see more independence in the system operation. We are looking very closely at what the options are. Those range from "stick with what we have" to a fully independent system operator. We are looking at models elsewhere in the world and the Committee will be aware that in the States they have fully independent system operators. There are strengths and weaknesses of all models and there is a kind of possible "best of both worlds" or you might call it a halfway house, depending on your perspective, where you would have much greater independence but within the National Grid umbrella. We are looking at a number of different options and we will be making an announcement later this year on that, but, rest assured, we are looking very closely at what will be the best system to ensure that there are no conflicts of interest, that there is genuinely the empowerment to be able to meet the challenges of the changing energy landscape and that it will be very clear and very cost effective.[279]

115. ***We recommend creating an Independent System Operator (ISO). Despite strong efforts by National Grid itself and Ofgem to mitigate the potential for conflicts of interest, it seems intractable and growing. Unnecessary asset development, or giving interconnectors an unfair advantage over existing and emerging balancing tools, could dilute the impact of other efforts to develop low-carbon network infrastructure. We note these concerns may also arise for Distribution System Operators in future. The Government should set out its intentions regarding an ISO as soon as possible, and consult on a detailed, staged plan for their implementation, so as to avoid injecting uncertainty into the energy sector. In particular, it will be important to act in a fashion that retains National Grid's considerable technical expertise.***

A whole-systems approach

116. Whole-systems approaches take general energy objectives, such as decarbonisation or security of supply, and consider actions to meet these objectives across energy vectors (such as electricity, heat and transport fuels), rather than simply within each silo. Whereas

277 Q255
278 Q255
279 Q298

individual-systems approaches to climate targets might look only at how electricity or heat may independently be decarbonised, a whole-systems approach would consider how energy supply and consumption could be shifted and balanced between these vectors. Dr David Clarke of the ETI illustrated the basics:

> Probably the best thing is to step back a second from the detail of heat and gas networks and so on and say, "Well, we've got a set of CO_2 targets for emission reductions to try to reduce CO_2 by 80% by 2050". If you look at that the other way round, that says you are emitting 20% of the CO_2 in 2050 that you do today. Logically—no great analysis—where would you keep using fossil fuel? Where would you allocate those CO_2 emissions if you had to, that remaining 20%? It would be in transport—various forms of transport, on-road, off-road, marine, aircraft in particular. By the time you do that, with a bit of industry emissions as well that you have to accept and probably a tiny amount of power sector emissions, your 20% has gone—you've used it.[280]

117. There are concerns that DECC and Ofgem do not currently adopt this whole-systems approach. Sara Bell told us:

> The challenge with the energy system is always that we have taken a very siloed approach. Even within DECC, generation sits in one department, demand sits in another, transmission networks in another, and so on. There are very few people with the expertise to look across the whole area, so naturally the optimisation between all of them is not done. For example, when we brought in the feed-in tariff for solar we did not ensure that there was the right incentive to use the solar power on the premises, so distribution networks had to start installing voltage regulation technology. If we had had a joined-up policy, the whole policy could have been implemented more cost-effectively.[281]

Ofgem agreed that a whole-systems approach was "critical".[282]

118. One mechanism to implement whole-systems thinking would be the creation of a system architect—an organisation responsible for long-term planning of the energy system with a whole-systems approach. Several stakeholders voiced support for such a system architect.[283] Dr Clarke noted:

> The overall system design needs to be at a national level. It does need to be considered, and we need to consider it as engineering, economics and consumer acceptance. […]
>
> You then need to recognise that local implementations will be completely different from place to place.[284]

Ofgem felt a system architect would be a step too far: Andy Burgess said "it is about having coherent system architecture rather than necessarily having a single architect";[285] Maxine Frerk noted it would be "a new body in what is already quite a complicated landscape,

280 Q127
281 Q42
282 Q277 [Maxine Frerk]
283 ICE (LCN0010), REA (LCN0033), Q43 [Stephen Goldspink]
284 Q128
285 Q279

with different responsibilities shared between what we do, what Grid does as SO and what Government does”.[286] DECC’s *Future Power Systems Architecture* project, undertaken by collaboration between the Institution of Engineering and Technology (IET) and the Energy Systems Catapult (ESC), seeks to address some of these questions.

119. **Implementing a whole-systems approach could produce better solutions for the kinds of challenges discussed throughout this report. We note Ofgem’s concerns regarding a systems architect, but believe the Government should take any proposal from the Future Power Systems Architecture group seriously, and look for opportunities to work across silos and departments in the meantime. We will continue to investigate the whole-systems approach in our ongoing inquiry into 2020 renewable heat and transport targets.**

286 Q278

5 Flexible policy for a flexible energy system

120. The Minister gave an account of the complexity of energy policy:

> There are an awful lot of people involved in energy policy. It hits so many Departments, and three, a trilemma[287] is very complicated. The issues for keeping costs down, lights on and decarbonising often work against each other. We have the added complexity of this is not just about—I don't want to belittle anyone else's policy area but you will all be aware of black and white issues—shall we do this or shall we do that? With energy it is like that alien's game where you bop one on the head and another one pops up here, so everything you do has a counter-reaction somewhere else. In order to not make a bad decision we do have to go around a lot of loops and look at things from different perspectives.[288]

121. We appreciate these necessary difficulties; however, throughout this inquiry we have found examples of low-carbon network development being hindered by inertia in the Government machinery. The rise of distributed generation appears to have overtaken networks' and the regulator's capacity to respond. What seem to be straightforward regulatory changes required to deliver widespread storage deployment still have no clear solution in sight. The pathways to creating Distribution System Operators and eventually an Independent System Operator remain unclear. The scale of networks' challenges is great, but the Government has not presented a holistic plan to meet these; policy in this area instead seems fragmented, with different ideas moving at different speeds. Technologies may develop quickly, but as RWE noted, "network infrastructure typically takes a long time to design, consent, and construct" and "can be the bottle-neck in low-carbon generation deployment".[289] The UK's electricity and heat may need to be carbon-free by 2050 (see paragraph 116). The Government therefore cannot afford substantial delay in the process of creating suitable network infrastructure.

122. **We understand the complexity of energy systems and of the policy framework to meet them. We would not want DECC, Ofgem, National Grid or any other body with strong influence to make rushed and consequently poor decisions. However, sometimes making no decision on a rapidly-moving issue is worse than an imperfect one. The timescales for important decisions regarding the regulation of connections, storage, Distribution System Operators and an Independent System Operator—to pick but a few of the issues covered in this report—have often been neither efficient nor transparent, and this undermines confidence in the Government's ability to support an evolving UK energy system. Networks are transforming. We recognise that this presents challenges for the Government, but it has been slow to present a clear, holistic plan for the evolution networks need; instead, it seems to have disconnected policy ideas at varying stages of implementation. Our overarching message to the Government is to take seriously the criticisms about its speed of delivery, as expressed in this report and**

287 The 'energy trilemma' refers to the challenge of pursuing three aims—affordability, decarbonisation and security of supply—which often require trade-offs in practice.

288 Q318

289 RWE (LCN0017) para 1.3

elsewhere, and to learn lessons from its approach to energy networks that can be used to improve its change readiness in future. We will look deeper into the Government's adaptability to emerging technologies in our ongoing inquiry into Energy revolution.

Conclusions and recommendations

Distributed generation

1. *We call on the Government to establish a cross-departmental working group to investigate and report on improving the integration of the connection and planning-consent processes in England. This investigation should include an assessment of mechanisms—such as heat maps and centralised, standardised connection applications—that could simplify these processes and better inform generators about them.* (Paragraph 17)

2. We support anticipatory investment in principle: it is likely to improve networks' speed at connecting distributed generation. However, it also bears the risk of creating stranded assets at bill-payer expense. Anticipatory investment must therefore be accompanied by up-to-date modelling to minimise this risk. (Paragraph 22)

3. *Ofgem should carry out further impact assessment on systems of cost recovery for anticipatory investment; this should include analysis of who bears the costs of stranded assets, so that relevant decision-makers are properly incentivised to avoid them.* (Paragraph 23)

Network charges and connnection costs

4. *Cost-reflective charging should account for the reality that many renewable-energy sources are location-specific and distant from demand sources, particularly as UK transmission charges remain high by EU standards. DECC should investigate the disadvantage UK generators may consequently face against other European generators as Great Britain becomes more interconnected, and the impact this may have on development of domestic renewable generation.* (Paragraph 31)

5. *Ofgem should analyse the costs and benefits of levelling connection costs across Great Britain.* (Paragraph 33)

Smart grids

6. We are concerned that the roll-out of smart meters is not progressing quickly enough to achieve the necessary mass to truly create a smart energy network. (Paragraph 41)

Gas and heat networks

7. *Ofgem should build on the promise of green gases by continuing to investigate and clarify safe levels for their injection. Both the Government and Ofgem should set indicative targets for biomethane and hydrogen deployment, and consider what support might be needed to deliver consequential changes to network infrastructure.* (Paragraph 46)

8. *The Government has rightly set an ambitious target for district heating—one which requires significant private-sector investment. A regulatory investment framework for district heating, similar to those for other networks, would aid this. It would also*

complement existing voluntary schemes in providing independent safeguarding for consumers. Ofgem should be required by the Government to regulate district heating networks, and the Government should seek to make whatever legislative changes are necessary to enable this. (Paragraph 51)

Storage

9. *Further large-scale storage, such as Pumped Hydro and Compressed Air Energy Storage, could be of great value in managing variable generation, but there is uncertainty as to the potential for future deployment. We recommend that the Government commissions a study on the future of large-scale storage in the UK which includes consideration of potential sites and what support such projects would need to be viable.* (Paragraph 56)

10. *The current regulatory conditions for storage are hindering its development. We welcome the Government's consultative approach to this matter, but hope it will proceed with a sense of urgency. We urge the Government to publish its plans, as soon as possible, for exempting storage installations from balancing charges, and from all double-charging of network charges.* (Paragraph 64)

11. Storage technologies should be deployed at scale as soon as possible. We support network utilisation of storage: this helps balance the system, and provides storage operators with a revenue stream that encourages its development. Allowing networks to operate and procure storage, especially in the short run, could also facilitate these benefits. However, we have concerns about network ownership of storage. In the long run, we do not want networks to have vested interests in particular technologies that discourage them from switching where more cost-effective solutions emerge; we are also concerned about any expansion of networks' monopoly power more generally. DECC and Ofgem should analyse the long-term risks of network ownership, operation and procurement in their work on storage. (Paragraph 67)

Demand Side Response

12. *The promised review of Demand Side Response (DSR) by Ofgem is a sensible first step towards clarifying and unlocking the potential for DSR technologies and business models. However, we maintain the views of our predecessor Committee that the Government needs to set out a more detailed strategy for DSR. This strategy and any work on this issue by Ofgem must also pay close attention to the risks of DSR for vulnerable customers, and how best to mitigate these.* (Paragraph 75)

Interconnection

13. Significant interconnector expansion will help balance a low-carbon network, and we support it for that reason. We note that Great Britain is likely to be a net importer of electricity; development of interconnection should be accompanied by a strategy to develop sufficient low-carbon generation capacity for export. (Paragraph 82)

Innovation

14. *We strongly support Ofgem's commitment to network innovation, but feel there is room for improvement. Ofgem must collect standardised trial data to optimise learning from projects. Furthermore, it should allocate proportionally more funding to later-stage development, and seek opportunities to leverage other sources of funding to achieve project commercialisation. A stronger role for non-network companies in using Network Innovation Stimulus could also balance DNOs' propensity for risk aversion in the short term, while counteracting it in the long run.* (Paragraph 96)

System operation

15. *The benefits of Distribution System Operators (DSOs) seem near-universally acknowledged, yet there is no clear Government road map to their implementation. The Government should develop and publish a road map for DSO introduction, identifying future legislative and regulatory changes needed. The road map should include a plan to require small-scale generators to provide real-time information to DSOs. The relationships across DSOs and between DSOs and the Transmission System Operator must also be clarified.* (Paragraph 101)

16. The evidence favours Distribution System Operators (DSOs) being run by the same companies as the corresponding Distribution Network Operators (DNOs), at least in the short-term transition to DSOs. However, DSOs are an extension of DNOs' monopoly power, and Ofgem are right that this should be appropriately regulated. Given risks to consumers from accumulation of monopoly power, DECC and Ofgem should be prepared to review the governance of distribution networks as DSOs' functions develop, and to separate distribution networks' operation from their ownership if their conjunction proves to have a negative impact on consumers. (Paragraph 103)

17. *We recommend creating an Independent System Operator (ISO). Despite strong efforts by National Grid itself and Ofgem to mitigate the potential for conflicts of interest, it seems intractable and growing. Unnecessary asset development, or giving interconnectors an unfair advantage over existing and emerging balancing tools, could dilute the impact of other efforts to develop low-carbon network infrastructure. We note these concerns may also arise for Distribution System Operators in future. The Government should set out its intentions regarding an ISO as soon as possible, and consult on a detailed, staged plan for their implementation, so as to avoid injecting uncertainty into the energy sector. In particular, it will be important to act in a fashion that retains National Grid's considerable technical expertise.* (Paragraph 115)

18. Implementing a whole-systems approach could produce better solutions for the kinds of challenges discussed throughout this report. We note Ofgem's concerns regarding a systems architect, but believe the Government should take any proposal from the Future Power Systems Architecture group seriously, and look for opportunities to work across silos and departments in the meantime. We will continue to investigate the whole-systems approach in our ongoing inquiry into 2020 renewable heat and transport targets. (Paragraph 119)

Flexible policy for a flexible energy system

19. We understand the complexity of energy systems and of the policy framework to meet them. We would not want DECC, Ofgem, National Grid or any other body with strong influence to make rushed and consequently poor decisions. However, sometimes making no decision on a rapidly-moving issue is worse than an imperfect one. The timescales for important decisions regarding the regulation of connections, storage, Distribution System Operators and an Independent System Operator—to pick but a few of the issues covered in this report—have often been neither efficient nor transparent, and this undermines confidence in the Government's ability to support an evolving UK energy system. Networks are transforming. We recognise that this presents challenges for the Government, but it has been slow to present a clear, holistic plan for the evolution networks need; instead, it seems to have disconnected policy ideas at varying stages of implementation. Our overarching message to the Government is to take seriously the criticisms about its speed of delivery, as expressed in this report and elsewhere, and to learn lessons from its approach to energy networks that can be used to improve its change readiness in future. We will look deeper into the Government's adaptability to emerging technologies in our ongoing inquiry into Energy revolution. (Paragraph 122)

Annex: Committee visit to Copenhagen, 24–25 February 2016

Wednesday 24 February

Energinet.dk

Energinet.dk is Denmark's publically-owned TSO. We met Torben Brabo, Senior Vice-President, Peter Jørgensen, Vice-President, Associated Activities, System Development and Electricity Markets, Jens Møller Birkebæk, Senior Manager, Renewables Integration and System Development, Stina Willumsen, Head of Strategy and Politics, and Søren Damsgaard Mikkelsen, Chief Project Manager, Energinet.dk, and Oliver Wood, Viking Link Project Director, National Grid. We discussed Energinet.dk's role and objectives, its balancing of variable wind generation, European energy-grid collaboration, and the planned UK-Denmark Viking Link interconnector.

Technical University of Denmark (DTU)

DTU is a specialist university ranked among the best in Europe for engineering and technology. We met Poul Erik Morthorst, Head, Marie Münster, Senior Researcher, and Klaus Skytte, Head of Energy Economics and Regulation, Systems Analysis Division, DTU Management Engineering. We discussed strategies for integrating wind power into networks, and Denmark's district-heating system.

DONG Energy

DONG Energy is Denmark's largest energy company and the world leader in offshore wind. We met Ulrik Stridbæk, Head of Group Regulatory Affairs, and Jane Cooper, UK Head of Regulatory and Stakeholder Relations, DONG Energy. We discussed DONG's corporate strategy, and technological development in offshore-wind and biomass power.

British Embassy Copenhagen

We met Vivien Life, HM Ambassador to Denmark, Stine Leth Rasmussen, Head of Department, Danish Energy Association, Lea Wemelin, Member of the Folketing[290] (Social Democratic Party) for Bornholm Greater, and Stina Willumsen, Head of Strategy and Politics, Energinet.dk. We discussed renewable energy, community energy in Denmark, interconnection, and electrification of transport.

Thursday 25 February

Danish Energy Agency and Ministry for Energy, Utilities and Climate

The Danish Energy Agency is the executive agency delivering Denmark's energy policy, reporting to the Ministry for Energy, Utilities and Climate. We met Mikkel Vinter Henriksen, Head, EU Coordination Office, Ministry for Energy, Utilities and Climate, and Lykke Mulvad Jeppesen, Head of Division, Danish Energy Agency. We discussed the governance of Denmark's energy sector and state support for renewable energy.

290 Danish Parliament

Copenhagen Infrastructure Partners (CIP) and PensionDanmark

PensionDanmark is a pension fund managing €25 billion in assets; CIP is a fund management company investing in regulated energy infrastructure: both have investments in the UK. We met Torben Möger Pederson, CEO, PensionDanmark, Christian Skakkebæk, Partner, and Jesper Krarup Holst, Vice-President for Biomass Assets, CIP. We discussed these companies' low carbon investment strategies and investor confidence in the UK energy sector.

Danish Energy Association

The Danish Energy Association represents energy companies in Demark. We met Lars Aagaard, CEO, and Jørgen S. Christensen, CTO, Danish Energy Association. We discussed security of supply, decarbonisation policy, interconnection, and Distribution System Operators.

Avedøre Power Station

State of Green, a public-private partnership between the Danish Government, the Danish Energy Association and others, facilitated our tour of the Avedøre Power Station, a 793 MW Combined Heat and Power plant on the outskirts of Copenhagen.

Formal Minutes

Tuesday 14 June 2016

Members present:

Angus Brendan MacNeil, in the Chair

Rushanara Ali
Mr Alistair Carmichael
Glyn Davies
James Heappey
Matthew Pennycook
Antoinette Sandbach
Julian Sturdy

Draft Report (*Low carbon network infrastructure*), proposed by the Chair, brought up and read.

Ordered, That the draft Report be read a second time, paragraph by paragraph.

Paragraphs 1 to 122 read and agreed to.

Summary agreed to.

Annex agreed to.

Resolved, That the Report be the First Report of the Committee to the House.

Ordered, That the Chair make the Report to the House.

Ordered, That embargoed copies of the Report be made available (Standing Order No. 134).

[Adjourned till Tuesday 28 June at 9.15am

Witnesses

The following witnesses gave evidence. Transcripts can be viewed on the inquiry publications page of the Committee's website.

Tuesday 15 December 2015	*Question number*
Chris Morrison, Head of Energy Construction Services, Distributed Energy and Power, Centrica, and **Scott Mathieson**, Director, Network Planning and Regulation, Scottish Power Energy Network	Q1–30
Tuesday 12 January 2016	
Dr Jill Cainey, Director, Electricity Storage Network, **Dr Philipp Grünewald**, Research Fellow, Environmental Change Institute, Oxford University, **Dr Gordon Edge**, Director, Policy, RenewableUK, **Stephen Goldspink**, Director, Strategy and Business Development, Siemens Energy Management, and **Sara Bell**, Chief Executive, Tempus Energy	Q31–110
Tuesday 26 January 2016	
Dr Tim Rotheray, Director, Association for Decentralised Energy, **Dr David Clarke**, CEO, Energy Technologies Institute, and **Chris Clarke**, Director of Asset Management, Wales and West Utilities	Q111–165
Tuesday 2 February 2016	
Simon Moore, Policy Manager, Strategic Infrastructure, Citizens Advice, **Phil Jones**, Chief Executive Officer, Northern Powergrid, and **Professor Keith Bell**, Co-Director, UK Energy Research Centre	Q166–193
Tuesday 12 April 2016	
Tony Glover, Director of Policy, Energy Networks Association, **Phil Sheppard**, Director of SO Operation, and **Charlotte Ramsay**, Head of Strategy, Markets and Regulation, European Business Development, National Grid	Q194–255
Maxine Frerk, Acting Senior Partner, Networks and **Andy Burgess**, Associate Partner Energy Systems, Ofgem	Q256–289
Tuesday 26 April 2016	
Andrea Leadsom MP, Minister of State and **John Fiennes**, Director, Energy Strategy, Networks and Markets, Department of Energy and Climate Change	Q290–390

Published written evidence

The following written evidence was received and can be viewed on the inquiry publications page of the Committee's website.

LCN numbers are generated by the evidence processing system and so may not be complete.

1 AES UK & Ireland (LCN0019)

2 Association for the Conservation of Energy (LCN0024)

3 Balfour Beatty (LCN0044)

4 British Gas (LCN0015)

5 Carbon Capture and Storage Association (LCN0038)

6 Citizens Advice (LCN0013)

7 Confederation of UK Coal Producers (Coalpro) (LCN0007)

8 Department of Energy and Climate Change (LCN0041)

9 Drax Group Plc (LCN0052)

10 Durham Energy Institute, Durham University (LCN0021)

11 E.On (LCN0036)

12 Ecuity Llp (LCN0012)

13 EDF Energy (LCN0027)

14 Electricity Storage Network (LCN0014)

15 Electricity Storage Network (LCN0060)

16 Energy Networks Association (LCN0018)

17 ETI (LCN0022)

18 GE and Element Power (LCN0063)

19 Haven Power Limited (LCN0008)

20 Institution of Civil Engineers (LCN0010)

21 Kiwi Power (LCN0053)

22 LDA Design (LCN0025)

23 Mr Brian Gerrard (LCN0040)

24 Mr Dominic McCann (LCN0001)

25 Mr Hugh Small (LCN0045)

26 Mr John Phillips (LCN0006)

27 Mr Michael Fell (LCN0051)

28 Nationalgrid (LCN0047)

29 Newcastle University (LCN0034)

30 Northern Powergrid (LCN0037)

31 Ofgem (LCN0043)

32 Prospect (Union for Professionals) (LCN0026)

33 Rail Freight Group (LCN0002)

34 REA (LCN0033)

35 Renewable Energy Systems Limited (LCN0059)

36 RenewableUK (LCN0055)

37 RSPB (LCN0009)

38 RWE (LCN0017)

39 Scottish Renewables (LCN0035)

40 SGN (LCN0057)

41 Siemens Energy Management (LCN0050)

42 Smarter Grid Solutions (LCN0032)

43 SP Energy Networks (LCN0031)

44 Sussex Energy Group (LCN0039)

45 Tempus Energy Supply (LCN0056)

46 TGE Group (LCN0003)

47 The Association for Decentralised Energy (LCN0046)

48 The IET (LCN0029)

49 UK & Ireland Nuclear Free Local Authorities (LCN0005)

50 UK Energy Research Centre (LCN0016)

51 UK HFCA Ltd (LCN0061)

52 UK Power Networks (LCN0049)

53 Wales & West Utilities Ltd (LCN0020)

List of Reports from the Committee during the current Parliament

All publications from the Committee are available on the publications page of the Committee's website.

Session 2015–16

First Report	Our priorities for Parliament 2015–20	HC 368
Second Report	Future of carbon capture and storage in the UK	HC 692
Third Report	Investor confidence in the UK energy sector	HC 542
Fourth Report	Home energy efficiency and demand reduction	HC 552
Fifth Report	Setting the fifth carbon budget	HC 659
Sixth Report	Pre-legislative scrutiny of the Government's draft legislation on energy	HC 776
First Special Report	Linking emissions trading systems: Government response to the Committee's Fifth Report of Session 2014–15	HC 376