House of Commons
Energy and Climate Change Committee

The future of Britain’s electricity networks

Second Report of Session 2009–10

Volume I
House of Commons
Energy and Climate Change Committee

The future of Britain’s electricity networks

Second Report of Session 2009–10

Volume I
Report, together with formal minutes

Ordered by the House of Commons
to be printed 10 February 2010
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.

Current membership

Mr Elliot Morley MP (Labour, Scunthorpe) (Chairman)
Mr David Anderson MP (Labour, Blaydon)
Colin Challen MP (Labour, Morley and Rothwell)
Nadine Dorries MP (Conservative, Mid Bedfordshire)
Charles Hendry MP (Conservative, Wealden)
Miss Julie Kirkbride MP (Conservative, Bromsgrove)
Anne Main MP (Conservative, St Albans)
Judy Mallaber MP (Labour, Amber Valley)
John Robertson MP (Labour, Glasgow North West)
Sir Robert Smith MP (Liberal Democrats, West Aberdeenshire and Kincardine)
Paddy Tipping MP (Labour, Sherwood)
Dr Desmond Turner MP (Labour, Brighton Kemptown)
Mr Mike Weir MP (Scottish National Party, Angus)
Dr Alan Whitehead MP (Labour, Southampton Test)

Powers

The Committee is one of the departmental select committees, the powers of which are set out in House of Commons Standing Orders, principally in SO No 152. These are available on the Internet via www.parliament.uk.

Publication

The Reports and evidence of the Committee are published by The Stationery Office by Order of the House. All publications of the Committee (including press notices) are on the Internet at www.parliament.uk/ecc.cfm. A list of Reports of the Committee in the present Parliament is at the back of this volume.

Committee staff

The current staff of the Committee are Tom Goldsmith (Clerk), Robert Cope (Second Clerk), Farrah Bhatti (Committee Specialist), Francene Graham (Senior Committee Assistant), Jonathan Olivier Wright (Committee Assistant), Steven Everett (Committee Support Assistant), Estelita Manalo (Office Support Assistant), and Hannah Pearce (Media Officer).

Contacts

All correspondence should be addressed to the Clerks of the Energy and Climate Change Committee, House of Commons, 7 Millbank, London SW1P 3JA. The telephone number for general enquiries is 020 7219 2569; the Committee's email address is ecc@parliament.uk
Contents

Report

Summary 3

1 Introduction 5

2 Creating a vision for Britain’s electricity networks 11
   Does Britain need a vision? 11
   Building a long-term vision 12
      Avoiding lock-in 12
      Integrating energy demand 14
      Minimising regulatory uncertainty 16
      The industrial structure 17
   Progress so far 18

3 Transforming transmission 19
   Investing in capacity 19
      The role of planning 19
      Strategic investment in transmission 22
      How strong is the case for investment? 23
   Network charging 25
      Constraint costs 26
      Transmission Network Use of System charges 29
   Grid access 32
      The queue for network access 32
      Interim measures 33
      An enduring access regime 34
   The industry’s rule-making process 39
   Developing offshore transmission 40
      The challenges 40
      The licensing regime 42
      Strategic investment 43
   Interconnection 45
      Security of supply 45
      Competition 46
      Demand flexibility and fuel substitution 47
      The ‘super-grid’ 48

4 Making distribution smarter 50
   The changing role of distribution 50
      Greater distributed generation 50
      Changes in demand 51
      Technical and regulatory challenges 51
   Investment 54
   The role of innovation 55
   Embedded benefits 58
<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>5  Network skills</td>
<td>60</td>
</tr>
<tr>
<td>Current challenges</td>
<td>60</td>
</tr>
<tr>
<td>Action to address the skills gap</td>
<td>61</td>
</tr>
<tr>
<td>Conclusions and recommendations</td>
<td>63</td>
</tr>
<tr>
<td>Glossary</td>
<td>71</td>
</tr>
<tr>
<td>Formal Minutes</td>
<td>73</td>
</tr>
<tr>
<td>Witnesses</td>
<td>74</td>
</tr>
<tr>
<td>List of written evidence</td>
<td>75</td>
</tr>
<tr>
<td>List of Reports from the Committee during the current Parliament</td>
<td>77</td>
</tr>
</tbody>
</table>
Summary

The creation of a low-carbon economy requires a new way of thinking about our energy system. The expansion of renewable energy will entail a greater number of generators connecting to Britain’s networks, ranging in size from roof-top solar panels to large offshore wind farms. These sources of generation cannot respond to fluctuations in energy demand in the way households have been accustomed. At the same time, consumers’ demand for electricity could increase as a result of the electrification of the transport and heating sectors. The only way Britain can respond cost-effectively to these challenges is by applying a smarter approach to managing the energy system. This could occur in a range of ways—from the household level with the use of smart meters to manage customers’ energy consumption, through to the high voltage transmission network where generators may need to develop methods of sharing access to the grid.

The existing regulatory and policy framework, and industrial structure, is a product of the fossil fuel economy of the twentieth century. This Report examines the issues that will be integral to the development of a smart grid that is able to meet Britain’s future needs. We note the progress the Government has made in developing a vision for the smart grid, and argue that it should take account of the following principles:

- The need to avoid locking the UK into a particular outcome for the future energy mix at an early stage;
- Integration and management of energy demand within the energy system;
- Minimisation of regulatory and policy uncertainty for network companies who must invest in network assets; and
- The possibility of a new industrial structure emerging over time.

Achieving a smart grid will have implications for the high voltage transmission network. We call for the Government to investigate the potential to make better use of the existing network, whilst acknowledging too that greater and more strategic investment is necessary in the coming years. We also recommend further work to develop a fair and open transmission access and charging regime. For the lower voltage distribution networks we welcome recent initiatives to improve innovation and call for these to be extended over time if there is demand. We also express concern at proposed changes to the network charging regime for small generators at a time when the Government hopes distributed generation will play a greater role in the future energy mix. Finally, we call on network companies and the regulator to do more to ensure the industry has the skills it needs to meet the future challenges posed by the smart grid.
1 Introduction

1. The 2007 Energy White Paper set out two long-term challenges for the UK’s energy policy—the reduction of carbon dioxide emissions; and ensuring secure, clean and affordable energy supplies. Britain’s electricity networks will play a crucial role in the delivery of both these objectives.1 A large proportion of our network assets are now approaching the end of their useful life. The need for renewal, combined with the necessity to respond to future challenges, presents a once-in-a-lifetime opportunity for us to revolutionise Britain’s electrical energy system and facilitate the transition to a low-carbon economy. This is why we chose to consider the future of Britain’s electricity networks as one of our first inquiries.

2. Britain’s current electricity infrastructure was designed to support post Second World War economic growth.2 The system is characterised by a relatively small number of large fossil fuel-based and nuclear generators, which are connected to a high voltage transmission network—often referred to as the national grid. This allows the efficient transportation of electricity nearer to the sources of demand. It is delivered to consumers via 14 lower voltage regional distribution networks. These are almost entirely passive in nature with relatively little connected generation. Overall, power flows in one direction across the system from higher to lower voltage levels, as illustrated in Figure 1.

---

1 Throughout this Report we consider only the electricity networks of Britain—that is England, Wales and Scotland, though we will refer to the UK with regard to energy and climate change policy where appropriate.

2 Ev 264 (Prof Goran Strbac, Imperial College London)
3. The transmission network in England and Wales is owned and operated by National Grid Electricity Transmission. Subsidiaries of Scottish Power and Scottish and Southern Energy each own and maintain part of the transmission system in Scotland, although National Grid has responsibility for overseeing and managing the flow of electricity across the whole British network. Figure 2 shows the transmission networks in Scotland, and England and Wales.

3 Transmission in England and Wales is defined as 275 kV or above, whereas in Scotland it is defined as 132 kV or above.

Source: Department of Energy and Climate Change
Figure 2: the transmission networks of England and Wales, and Scotland

Source: National Grid

4. The 14 distribution networks across England, Wales and Scotland are owned and operated by seven companies known as distribution network operators (DNOs). These are shown in Figure 3. Scottish and Southern Energy and Scottish Power own both the transmission and distribution networks in their respective regions. Electricity supply companies pay the DNOs for consumers’ use of their networks. In turn, suppliers pass these charges on to consumers through their bills.
5. The primary function of the electricity networks is to balance supply and demand across the system at all times. This is managed through the British Electricity Trading and Transmission Arrangements (BETTA), which involves bilateral trading between generators, suppliers, traders and customers across a series of markets operating on a rolling half-hourly basis. Because changes in demand are met by a near instantaneous response in the amount of electricity produced, the total level of installed generating capacity connected to the system has been designed to meet peaks in demand throughout the day and across the year. Because there is a possibility of some power stations not being
available, historically, there has been a capacity margin over peak demand of around 20-24% to ensure security of supply. Today’s transmission system has been built to accommodate the simultaneous output of all power stations connected to the network. This approach has underpinned the development of Britain’s electricity infrastructure in the modern era. As one witness told us: “nothing has fundamentally changed since 50 years ago”.5

6. However, there is now a new challenge. If the likelihood of dangerous climate change is to be avoided, Britain and the rest of the world must drastically cut their carbon dioxide emissions in the next 40 years. To fulfil its part, the Government has committed the UK to an 80% reduction in emissions over 1990 levels by 2050. As part of the trajectory to this objective, the Government has also signed up to a legally-binding target for 15% of energy to come from renewable sources by 2020, as part of an EU target for 20% renewable energy. To achieve this, the Department of Energy and Climate Change’s (DECC) lead scenario suggests more than 30% of electricity could be generated from renewables.6 To meet the longer-term target the electricity sector will need to be almost entirely decarbonised by 2030, all the while maintaining security of supply.7 The task is colossal, not least because demand for electricity may increase considerably through the electrification of parts of the heat and transport sectors. It is also ambitious by international standards. One witness said: “there is nothing on the scale that we are envisaging”.8

7. Not only will the transition to a low-carbon economy entail massive changes in the sources of electricity generation, it will also necessitate a transformation in our networks. Indeed, the Institution of Engineering and Technology told us that: “Without the right networks, few of the UK’s energy ambitions can be realised”.9 The Department described the electricity networks as “a key enabler” to future investment in generation capacity.10 Without the physical assets in place and the right regulatory framework, there is a real danger of new generation being delayed, increasing the likelihood of the lights going out. Furthermore, the networks will be crucial in allowing consumers to play a greater role in managing their own energy demands. To achieve this, we need to become smarter at controlling the flow of electricity across the system—“Making energy cleverer” as one witness put it.11 This is the overarching theme of our Report.

8. We received a large volume of written evidence for which we are grateful. We also took oral evidence from academics with expertise in energy networks—Dr Michael Pollitt from the Judge Business School, University of Cambridge, Professor Goran Strbac from Imperial College, and Dr Jim Watson of Sussex Energy Group; transmission network owners—National Grid, Scottish Power, and Scottish and Southern Energy; the sector skills council—Energy and Utility Skills; the main trade associations—the Energy Networks

---

4 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
5 Q 47 (Prof Goran Strbac, Imperial College London)
7 Ev 267, para 1.6 (Prof Goran Strbac, Imperial College London)
8 Q 63 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
9 Ev 187, para 4 (Institution of Engineering and Technology)
10 Ev 147, para 8 (Department of Energy and Climate Change)
11 Q 48 (Prof Goran Strbac, Imperial College London)
Association, the Renewable Energy Association, the British Wind Energy Association, Scottish Renewables, and the Association of Electricity Producers; distribution network owners—CE Electric UK and Electricity North West Ltd; the Institution of Engineering and Technology; the regulator—Ofgem; and the Minister and officials at the Department of Energy and Climate Change. We would like to express our thanks to all those who contributed to our evidence-gathering. We particularly thank Professor Goran Strbac and Dr Jim Watson who were specialist advisers on the inquiry, although we emphasise the conclusions and recommendations of this Report are the Committee’s own.

9. The remainder of this Report is split into four chapters. Chapter 2 considers what a vision for Britain's electricity networks should take in. Chapter 3 analyses the various challenges faced by the transmission network. Chapter 4 looks at the changing role of the distribution networks. In particular, it highlights the importance of innovation in delivering networks fit for the 21st century. Finally, Chapter 5 asks whether the current networks sector workforce has sufficient skills to deliver the changes required in the coming years.

12 A list of those who gave evidence can be found on page 74.
2 Creating a vision for Britain’s electricity networks

10. The transition to a low-carbon economy will require a fundamental change in the philosophy of power generation and supply, and the development and operation of a new, much larger and significantly more complex electrical energy system. The costs of achieving this will be huge—Scottish Power, for example, has estimated £37 billion for the required network investment between now and 2020. The scale of the challenge, combined with the timeframe over which it is to be achieved, has led many within the industry to call on the Government to provide more strategic direction on how it expects the networks to evolve over time. In this Chapter we look at the progress to date in developing a vision for Britain’s electricity networks and the potential key principles we believe should underpin such a vision.

Does Britain need a vision?

11. Several of our witnesses argued the Government needed to provide more leadership on the future development of the electricity networks. The risk that the market might otherwise fail to deliver in time, especially given the longer lead time for new network infrastructure, was a primary concern raised, for example by the Energy Networks Association. Similarly, Electricity North West Ltd said that: “To make a change of this magnitude in the short timescales available requires the identification of a unifying strategic direction for the GB energy industry. To rely on hope and market mechanisms alone is doomed to failure”. Dr Jim Watson told us: “there is a need for more coordination and some semblance of a strategy, a plan of where we are going”, while the Institution of Engineering and Technology noted: “There is no vision document showing a joined-up transmission-distribution-end-user picture”.

12. In general, the view of many within the industry was that given Government policy is currently shaping the future low-carbon energy mix, for example through the Renewables Obligation and the facilitation of new nuclear build, it is therefore reasonable to expect the Government to provide some high-level guidance to ensure the networks develop in a way that is consistent with its overall vision for the energy sector. As the British Wind Energy Association put it: “Government is the one that is setting the targets; […] it has to be the one that actually actively propels us forward”. Any vision for our electricity networks must therefore sit within a wider strategy for our future energy mix. It is important too that it is built on a consensus of stakeholders, rather than determined top-down by the

---

13  Ev 258, para 7.2 (Scottish Power)
14  Ev 164 (Energy Networks Association)
15  Ev 158, para 3.3 (Electricity North West Ltd)
16  Q 6 (Dr Jim Watson, Sussex Energy Group)
17  Q 279 (Institution of Engineering and Technology)
18  For example, see Ev 129, para 11 (Centrica)
19  Q 150 (British Wind Energy Association)
Department.\textsuperscript{20} We note Ofgem’s recent Project Discovery report, and we have arranged to take further evidence on this work.

13. The transition to a low-carbon economy will transform the role of our electricity networks over the next 40 years. Whereas today the networks are seen as a means to an end in the transportation of electricity from generators to consumers, in the future they will play an integral and active role, enabling supply and demand to be managed in a much more complex and decentralised energy system. The market alone will not be able to deliver these changes—it requires strategic leadership from Government delivering a vision for the future that engages actively both consumers and the energy sector.

\textbf{Building a long-term vision}

14. We believe the Government’s strategy for the development of the electricity networks should contain four key features. It should: avoid locking Britain into a particular outcome for the future energy mix at an early stage; seek to integrate and manage energy demand within the energy system; minimise regulatory and policy uncertainty for the companies who must invest in new network assets; and be open to the prospect of a new industrial structure evolving over time. The following sections consider each of these in more detail.

\textbf{Avoiding lock-in}

15. The long-term vision for our electricity networks will to a large extent depend on the future generation mix, or as one witness told us: “we should not let the network tail wag the generation dog”.\textsuperscript{21} The Government believes the market should determine the contribution of different technologies to the energy mix, though in reality it is influenced by public policy through the target for 15% renewable energy by 2020, and the stated desire for nuclear power and carbon capture and storage to play a future role, albeit delivered by the private sector. In the short to medium term there is some certainty as to how the system will evolve. For example, in its \textit{UK Renewable Energy Strategy} the Government stated that the majority of growth in electricity from renewable sources between now and 2020 will come from wind power, both onshore and offshore, with bioenergy making an important contribution.\textsuperscript{22} National Grid also expects up to 14 GW of new gas-fired capacity to come on-stream in the next few years.\textsuperscript{23}

16. Beyond 2020 it is more difficult to predict how our energy system will evolve. A useful example of this is Ofgem’s \textit{Long-Term Electricity Network Scenarios} (LENS) project.\textsuperscript{24} This set out five plausible network scenarios for 2050, dependent on the direction of policy over time and the underlying energy mix. One potential outcome is for ‘bigger’ transmission and distribution networks to cope with the variability of large renewables. Another is a micro-grid based scenario, which would include higher levels of local renewable generation.

\textsuperscript{20} Q 281 (Institution of Engineering and Technology)
\textsuperscript{21} Q 8 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
\textsuperscript{22} Department of Energy and Climate Change, \textit{UK Renewable Energy Strategy, July 2009}
\textsuperscript{23} House of Commons, \textit{Official Report, Col 1336W, 16 December 2009}
\textsuperscript{24} Ofgem, \textit{Electricity Network Scenarios for Great Britain in 2050, November 2008}
and less strongly interconnected local grids. A key conclusion of the study was that a large degree of uncertainty existed over what the final outcome might be, although all the scenarios posed a potential challenge to the status quo. Ofgem told us: “it is not clear whether we will need much larger networks or much smaller networks in the future”.  

17. In the face of such uncertainty, some of our witnesses made calls for the Government to do more to narrow the range of options for the future. Electricity North West Ltd told us: “it is now necessary to move the whole weight of the industry behind a clearly stated, preferred option if we as a nation are serious about achieving targets”. Similarly, Centrica said: “there is a need to recognise the overall direction—is it towards a 2050 ‘big’ transmission, ‘small’ distribution network scenario or vice versa […]”. However, other witnesses took a different view. Dr Michael Pollitt told us keeping technological options open has benefits, noting that: “We just don’t know at this stage what the best network configuration is for 2020 or 2050, not least because of price, policy and technological uncertainty”. Another cautioned: “Government and the regulator should not try to ‘pick winners’”.  

18. The primary disadvantage with adopting a single approach is that it risks locking the system into an outcome that is sub-optimal in the long run, either because it proves more expensive, or because it does not make the best use of emerging technologies. Moreover, Britain’s existing electricity infrastructure is already highly centralised, built as it is around large-scale fossil fuel and nuclear plants. Dr Jim Watson of Sussex Energy Group told us: “The ‘lock-in’ of this system […] presents a challenge when government policies now require the system to change”. In other words, our existing model of ‘big’ transmission and passive distribution increases the likelihood of the same approach continuing in the future, unless regulation and policy allows for the possibility of other outcomes. As the Department put it: “We […] need to ensure that our policy framework is flexible and supports innovation in network development and operation”. Fortunately, in the short term it is possible for the existing networks to accommodate changes in demand and increased renewable generation without radically changing our energy networks. This should allow some time to experiment with different technological options.  

19. Although we know with some confidence how the electricity mix will evolve in the run up to 2020, there is much less certainty over what a completely decarbonised energy system might look like in the long run. The Government’s vision for the future of our electricity networks must take account of the range of possible scenarios for the evolution of the energy mix, ensuring it does not lock Britain into a particular outcome at an early stage.

25 Ev 211, para 1.4 (Ofgem)  
26 For example, Ev 174, para 3.5 (E.ON)  
27 Ev 159, para 3.4 (Electricity North West Ltd)  
28 Ev 130, para 20 (Centrica)  
29 Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)  
30 Ev 182 (Helius Energy)  
31 Ev 270, para 4 (Dr Jim Watson, Sussex Energy Group)  
32 Ev 147, para 10 (Department of Energy and Climate Change)  
33 Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
**Integrating energy demand**

20. Britain’s current electricity system is demand driven. When a consumer increases their electricity use, somewhere generation increases by a commensurate amount to satisfy that demand. This is possible because our electricity mix includes a large amount of capacity that is able to respond to changes in demand. For unexpected demand fluctuations, National Grid can use pumped storage or call on reserve capacity.\(^{34}\) In addition, gas and coal-fired power stations, which currently provide around 68% of electricity supply, can to varying degrees respond flexibly to changes in demand.\(^{35}\) Historically, generation capacity has expanded as a result of increases in demand. As Professor Strbac told us: “The whole culture and philosophy of the system is based on a predict-and-provide mentality”.\(^{36}\)

21. The transition to a low-carbon economy, however, poses a challenge to this traditional *modus operandi*. In the next few years, the expansion of large-scale wind power will increase dramatically the amount of variable generation entering the system. Whilst the network system operator will be able to estimate the availability of wind power using weather forecasts, this form of generation cannot respond directly to changes in consumer demand. At present, and in the short to medium term, this may not be a significant issue for the networks because the level of wind-based generation will be manageable within the overall system. However, if in the longer term up to 30% of electricity comes from wind, this could pose major challenges for the networks, particularly as such variable capacity will operate alongside baseload nuclear power, which cannot be switched on or off to meet differing network load demands. Without mitigating action it is likely electricity supply will often exceed demand, for example during the night, or fall short, such as when the wind fails to blow.

22. If Britain were to maintain the existing approach whereby supply is entirely responsive to demand, then the solution to the inflexibility of wind and nuclear power would be to build more back-up capacity for when the wind fails, and curtail wind farms when their output exceeds demand. This option would, however, be very expensive. Furthermore, to achieve the Government’s 2050 target for carbon emissions it is likely that it would also require the electrification of both the heat and transport sectors combined with a large increase in renewable generation, much of which would be variable wind. Accommodating these changes within the electricity system under the current approach would necessitate massive reinforcement of the transmission and distribution networks, and lead to very low levels of generation and network asset utilisation, and hence low utilisation of capital investment. Electric vehicles provide one example of why this would happen. If in the future they charged from the time they were plugged in, they would add significantly to the peak in electricity demand that occurs in the early evening each day when people come home from work. The approach Britain has at present would mean greater generating and network capacity would be necessary to meet this demand peak, though these assets would remain idle at most other times.

---

\(^{34}\) Pumped storage is a form of hydroelectric power generation where low-cost off peak electricity is used to pump water to a higher elevation, which is then used to drive turbines during peak periods when prices are higher.

\(^{35}\) Department of Energy and Climate Change, *Energy Trends*, September 2009

\(^{36}\) Q 47 (Prof Goran Strbac, Imperial College London)
23. Denmark, which relies on wind power for about a fifth of its electricity needs, has already begun to experience problems managing generation across its system.\textsuperscript{37} However, its small size, combined with its interconnection with mainland Europe and the Nordic countries, enables it to export excess supply to neighbouring countries. Britain does not benefit, at present, from the same level of interconnection. Moreover, we cannot assume that closer linkage to European markets would bring the same benefits as it has for Denmark, given Britain’s expected expansion in wind power will take place against a backdrop of similar drives to increase renewable energy across the Continent to meet the European Commission’s 20% target by 2020. We consider interconnection in greater depth in Chapter 3.

24. The solution to the problem of inflexible supply lies in making demand flexible instead.\textsuperscript{38} More intelligent demand-side management could take a variety of forms. For example, heating, refrigeration and air-conditioning systems could provide a form of energy storage to accommodate short-term variations in electricity supplies.\textsuperscript{39} The mass deployment of electric vehicles could also offer such storage, charging up when there is enough system capacity and, if necessary, exporting electricity back into the system during periods of constrained supply.\textsuperscript{40} The inherent storage potential from the electrification of the transport and heating sectors, therefore, presents the opportunity to decouple energy production and use.

25. Elsewhere, smart metering could allow customers to respond more dynamically to market prices, changing their demand profile through arrangements such as dynamic demand technologies so that they consume more energy when the system is less constrained. A blunter form of this already exists with Economy 7 (an electricity tariff which charges less for overnight usage), but it has the potential to be linked more closely to real-time fluctuations in the energy system. Integrating demand into the overall management of the energy system is a core part of the concept of what has become known as the ‘smart grid’—“an electricity network that can intelligently integrate the actions of all users connected to it—generators, consumers and those that do both—in order to efficiently deliver sustainable, economic and secure electricity supplies”.\textsuperscript{41}

26. Creating a smart grid will require distribution networks to transform their current approach, moving away from their traditional passive role towards more active management of the potentially highly complex flows of energy entering their systems at all voltage levels.\textsuperscript{42} This will only be achieved through the deployment of advanced information and communication technologies (ICTs), combined with a radical rethink of how the system is controlled, and the role of the electricity supply company in delivering energy services to customers. We discuss this more in Chapter 4. The potential benefits are huge. Revolutionising the relationship between consumers and electricity producers could foster greater public awareness of the relationship between energy use and the need for

\begin{itemize}
\item \textsuperscript{37} Danish Energy Agency, \textit{Energy Statistics 2007}, October 2008
\item \textsuperscript{38} See for example, Q 285 (Institution of Engineering and Technology)
\item \textsuperscript{39} Ev 185, para 3 (Institute of Physics)
\item \textsuperscript{40} Q 277 (Institution of Engineering and Technology)
\item \textsuperscript{41} EU SmartGrids Technology Platform definition, quoted by Ev 188 (Institution of Engineering and Technology)
\item \textsuperscript{42} Ev 164 (Energy Networks Association)
\end{itemize}
new energy infrastructure. Furthermore, the Centre for Sustainable Energy and Distributed Generation estimates the smart grid approach could halve the level of investment in generating capacity needed to meet future demand, compared to a scenario that assumes a continuation of the existing philosophy.  

27. Whatever the scenarios for the future development of the electricity mix, it is likely that they will include a much higher proportion of generating capacity that is not able to respond easily to demand. The only cost-effective response is for demand itself to be more flexible and play a more active role in the management of our energy system. This should sit at the core of the Government’s vision for Britain’s electricity networks.

Minimising regulatory uncertainty

28. The UK was one of the first countries to liberalise its energy markets 20 years ago. At that time the regulator’s main objective for the electricity networks was to improve operational efficiency. It achieved this through an RPI-X regime that linked companies’ allowed revenues to the rate of inflation (RPI), minus some factor ‘X’ calculated to incentivise them to cut costs in order to make a profit. Now Ofgem’s primary focus is the efficient delivery of a low-carbon economy and continued security of supply both for present and future consumers. This change in the objectives for the regulatory framework, therefore, requires a fundamental rethink of the regime itself. Accordingly, 20 years after privatisation the regulator is currently conducting a review of network regulation known as RPI-X@20. Due for completion later in 2010, the initiative should see a significantly different regulatory regime designed to meet the new challenges the networks face.

29. One of the key messages from our evidence was the need for the future regulatory framework to provide long-term certainty to market participants. Scottish Renewables told us: “a strong and long-term signal to the investors is absolutely crucial if a fit for purpose electricity network is to deliver a decarbonised and reliable electricity supply”. Similarly, Dr Michael Pollitt said: “it is important that network investments face a more consistent policy framework going forward than at present”. Elsewhere, ESB International Investments said: “Investors such as ourselves require a stable regulatory regime and policy framework”. The British Wind Energy Association also gave the example of how stability would be important for ensuring the increased cable manufacturing capacity necessary to ensure the future connection of offshore wind.

30. The regulatory framework will need to adapt to meet the new challenges of facilitating the transition to a low-carbon economy, whilst ensuring security of supply. As such, we welcome Ofgem’s current RPI-X@20 review. At the same time as ensuring flexibility in the potential outcome for how the networks might evolve, it is important

---

43  Q 47 (Prof Goran Strbac, Imperial College London)
44  Ev 211, para 1.1 (Ofgem)
45  Ev 260, para 12 (Scottish Renewables)
46  Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
47  Ev 179, para 1 (ESB International)
48  Ev 116 (British Wind Energy Association)
that reforms arising from the review and the Government’s vision for the electricity networks take account of the need for long-term regulatory and policy stability to give firms the confidence to make the investments required.

**The industrial structure**

31. The current industrial structure of the networks sector reflects the evolution of the GB market since privatisation. At present, five companies operate as distribution network owners, one firm—National Grid—is the transmission owner for England and Wales, while two firms have both transmission and distribution networks. These latter two—Scottish Power and Scottish and Southern Energy (SSE)—additionally own generating assets. National Grid is also the system operator for the whole GB system.

32. There are various ways in which the industry’s composition could change in the future either as a consequence of regulation, or through the market response to developments in the networks sector outlined already. For example, the vertical integration of the Scottish companies was questioned by some of our witnesses, including the regulator, who thought it could constrain competition. Dr Michael Pollitt told us: “the evidence, though fairly anecdotal, is quite strong that countries that have independent transmission companies do better and have more successful electricity systems”. Scottish Power and SSE disputed strongly any assertion their position gave them undue market power that was not compliant with EU law. Whilst the Minister also supported this position, Ofgem told us third parties connecting to the Scottish networks felt “uncomfortable” about the current situation.

33. Elsewhere, international experience points to different ways of managing transmission. For example, it is not clear whether there should be an onshore monopoly of new build for transmission assets, such as that held by National Grid in England and Wales, and regionally by the two Scottish companies. In Chile, Argentina and some US jurisdictions, the system operator role is separate to network ownership and run on a not-for-profit basis, thus allowing different firms to take responsibility for owning and maintaining the networks. The Government is already pursuing this approach for offshore transmission, which we discuss further in Chapter 3.

34. Finally, in the future there may be a more general debate over the separation of distribution and transmission. The development of a smart grid could lead to distribution network owners also becoming system operators for their areas, actively managing the flow of electricity between the distribution and transmission networks. In this situation the old distinction between the two types of network would become blurred. This could bring into question the need for separate asset ownership between the two sectors as is currently the case in England and Wales. The existing 14 distribution networks are a remnant of the pre-privatisation organisation of the electricity sector. It is conceivable that these could fragment or merge in the future depending on how the smart grid develops.

---

49 Qq 111 (National Grid) and 355 (Ofgem)
50 Q 26 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
51 Qq 110 (Scottish and Southern Energy) and 111 (Scottish Power)
52 Qq 355 (Ofgem) and 422 (Minister for Energy)
35. Britain’s networks sector currently has a hybrid structure that is largely the result of the evolving regulatory framework since privatisation. Whilst it may be adequate for now, the transition to a low-carbon energy system may require a different organisation of the industry. The Government and the regulator should not be afraid to allow this to happen, whether through regulation or otherwise, so long as it provides transparent and fair access to natural monopoly network assets for both generators and consumers. In particular, we recommend Ofgem monitors closely the market behaviour of the two vertically integrated Scottish firms. These arrangements could be changed if they are found to be detrimental to consumers.

**Progress so far**

36. During 2009 the Government made progress in developing a vision for Britain’s electricity networks. In March the cross-sector Electricity Networks Strategy Group (ENSG) published *Our Electricity Transmission Network: A Vision for 2020*. This set out the strategic investment the transmission system could require over the next decade if the system is to have enough capacity to connect the large expansion of renewable energy, particularly wind power, needed to meet the Government’s 2020 target. We discuss the case for such transmission investment in the next chapter.

37. In December 2009 the Department published *Smarter Grids: The Opportunity*. This set out a high-level vision of what a UK smart grid might look like. It highlights three main challenges to overcome for the successful deployment of the smart grid. First is the importance of engaging consumers who will play a key role within the future energy system, potentially as micro-generators, but also through the management of their energy demand, whether passively or proactively. Second is the testing and application of new technologies, particularly ICT, that are crucial components of the smart grid. Underlying both these challenges is a third, which is to ensure the regulatory and commercial framework evolves in parallel to facilitate the changes required. The report states: “The overall aim will be that smarter grid investments are increasingly seen as ‘business as usual’”. The Department has now asked the Electricity Networks Strategy Group to develop a road map for the delivery of the smart grid. DECC will combine this with its own analysis and will publish later in 2010 its views on the actions required to deliver the smart grid in Britain.

38. We note the progress the Department has made in beginning to develop a strategic vision for how Britain’s electricity networks will evolve over time. In preparing a road map for delivery of the smart grid, it should take account of the following principles:

- The need to avoid locking the UK into a particular outcome for the future energy mix at an early stage;
- Integration and management of energy demand within the energy system;
- Minimisation of regulatory and policy uncertainty for network companies who must invest in network assets; and
- The possibility of a new industrial structure emerging over time.
3 Transforming transmission

39. Because we do not know yet what the energy mix of the future will look like, neither do we know with any certainty how the transmission network will evolve. We have already identified, however, that there is a risk of continuing Britain’s ‘lock-in’ to a ‘big’ transmission system if the regulatory framework does not allow for the possibility of other outcomes. In this Chapter we consider a range of issues that have concerned policy-makers in recent years in determining transmission policy.

Investing in capacity

40. Ownership and operation of the transmission networks in Britain is permitted under licence, the terms of which restrict the revenue of the licensed network businesses. The revenue allowed to transmission companies is based on a pre-determined programme of investment agreed between them and the regulator. It is reviewed every five years by Ofgem through what is known as a Transmission Price Control Review (TPCR). The current TPCR period runs from 2007 to 2013, having recently been extended by one year. In 2009/10 it will allow companies to recover around £1.5 billion in revenues. For households, the cost of transmission equates to around 4% of electricity bills. Growth in companies’ revenues is determined using the RPI-X framework. This approach has encouraged firms to reduce costs over time through efficiency improvements. The next TPCR will be based on a new regulatory framework, arising from the current RPI-X@20 review.

41. Ongoing investment in the transmission network is necessary to ensure the system remains operational, for example, through the replacement of ageing or obsolete assets. It is likely that a system of balancing supply and demand such as BETTA will continue to operate in the longer term, and therefore new investment will also be crucial to assist with the migration of less efficient and older plant towards a marginal supply position on the basis of continued availability as installed capacity. However, many within the industry now argue that further investment to expand the system is required in order to connect the expected growth in renewable generation in the coming years. In this section we look at the main barriers to expansion of the transmission network and the case for further investment.

The role of planning

42. The planning system is a fundamental determinant of whether investment in new transmission capacity is delivered on time, and was highlighted as a potential barrier by the Department, the regulator and the industry. Past experience explains why this is the case. In the 1990s it took over six years to acquire planning consent for a 50-mile stretch of new...
high voltage power lines in North Yorkshire. More recently, the upgrade of the 137-mile line between Beauly near Inverness, and Denny near Falkirk, replacing the existing 132 kV cables with high voltage 400 kV lines, entered the planning system in 2005. Seen as key to allowing the connection of new onshore wind farms in northern Scotland, the project was first conceived in 2001, and awarded funding by Ofgem in 2004. Consent was finally granted in January 2010, which means construction work could be completed by 2012, when projects would be able to connect to the new line. From conception to completion, the upgrade will have taken 11 years. Smaller projects have also faced difficulties. Scottish Power told us about a 20 km wooden pole line it wished to build between Lostock and Carrington in Lancashire. The company submitted its planning application in 2003, but is not expecting to receive consent until later in 2010.

43. Overall, many of our other witnesses were highly critical of the planning process. The Scottish Chambers of Commerce described it as “sclerotic”. Another witness said that, left unaddressed “the planning system is likely to thwart aspirations for connecting renewable generation”. Elsewhere, Scottish and Southern Energy told us: “The shortcomings of the planning systems need to be addressed if the UK is to meet the EU 2020 target and longer-term security of supply and climate change goals”.

44. Several organisations, however, sought to defend the planning system. Scottish Natural Heritage, for example, told us the length of inquiry into the Beauly-Denny line was partly the result of the transmission companies having not undertaken sufficiently thorough exploration of alternative options, such as burying cables underground in areas of environmental sensitivity. The Campaign to Protect Rural England (CPRE) noted that the delay to consenting the North Yorkshire line had been the result of the developer having to consider ways of lessening the impact of the line on the landscape that it had not fully addressed in its initial proposal. Both organisations rejected the idea that the planning process should be considered a ‘barrier’ to network expansion—rather, as CPRE told us: “it is a vital means of ensuring that the future development of the transmission network takes full account of the public interest”.

45. In order to address some of the concerns with the current planning system, the Planning Act 2008 established an independent Infrastructure Planning Commission (IPC), which will operate a streamlined consenting process. Under the new arrangements Ministers will retain responsibility for the policy framework, which will be set out in National Policy Statements (NPSs). The IPC will make decisions on consents based on these NPSs, which will set out the need for the infrastructure and how the IPC should consider impacts. Consultation on applications will be required before they are submitted.

56 Ev 111, para 15 (Association of Electricity Producers)
57 Ev 262, para 32 (Scottish Renewables)
58 Q 103 (Scottish Power)
59 Ev 237 (Scottish Chambers of Commerce)
60 Ev 179, para 6 (ESBI International)
61 Ev 232 (Scottish and Southern Energy)
62 Ev 252, para 9 (Scottish Natural Heritage)
63 Ev 120, para 10 (Campaign to Protect Rural England)
64 Ev 119, para 7 (Campaign to Protect Rural England)
to the IPC, and guidance given on what constitutes a good application. The hope is that this will mean the Commission can consider applications more quickly, which it will do within set timetables. The Government published the draft NPS on electricity networks infrastructure in November 2009, as part of a suite of energy NPSs. They are subject to consultation and parliamentary scrutiny, for which this Committee is playing a key role, before likely designation sometime in 2010.

46. Only planning applications for power lines in excess of 132 kV, or network infrastructure that is associated with a nationally significant power station, will be subject to approval by the IPC. This means that consenting for lower voltage distribution lines will still fall to local planning authorities. The new system applies only to England and Wales. In Scotland, reform has also taken place: measures announced in 2008 include the requirement for promoters of major developments to conduct a consultation with the community before submitting the planning application. A statutory four-month time period for a decision on applications will also be put in place. Other reforms in Scotland include: simpler and more transparent processes; quicker decision-making by councils on high-quality applications; a greater focus on matters of national interest; and up-to-date development plans to provide investors and communities with greater certainty. In 2009 the Scottish Executive also published its second National Planning Framework (NPF2), which designated 14 national developments of strategic importance to Scotland, of which electricity grid reinforcements was one.

47. The network industry broadly welcomed reform of the planning system. There is a high level of expectation on the ability of the changes to speed up the planning process. E.ON UK told us: “The success of the new IPC planning process […] will be key to the delivery of major infrastructure projects”. Scottish and Southern Energy said: “The importance of the National Policy Statements cannot be overemphasised […] the NPSs must be clear and have sufficient depth to form the basis for authoritative decisions”. The Association of Electricity Producers noted its concern, though, that there remains a disjointed approach between the systems in England and Wales and Scotland, with varying timescales, considerations and processes. It believed greater consistency was needed.

48. Reform of the planning process is vital if network improvements are to be delivered on time to connect new generating capacity in the future. We note the recent changes to the planning systems in England and Wales, and Scotland, and are pleased to be playing a role in scrutinising the draft National Policy Statement for Electricity Networks Infrastructure. We hope the new system will lead to a faster decision-making process, but one that nonetheless will take account of the environmental concerns associated with new proposals. For this, developers have a duty to ensure their initial applications take adequate account of alternative options. The Government should also look closely
at the consenting process for applications in England and Wales that will not fall to the Infrastructure Planning Commission to see whether reform or improved guidance is necessary at this level as well.

**Strategic investment in transmission**

49. Under the existing TPCR framework investment is reactive—transmission companies do not undertake reinforcement or line extension work until individual generating companies have guaranteed they will meet the cost of those connections. This approach, whereby network capacity is expanded only if there is a power plant ready to use it, has helped reduce the risk of investment capacity not being utilised, otherwise known as stranded assets. However, this can cause problems for generating companies that are not able to guarantee their connection until they are confident their projects will proceed, for example, once they have received planning permission. We have already seen, though, that the consenting process for new grid capacity can take time. This can lead to a mismatch between when a project is ready to connect to the grid, and when the grid capacity is available to connect it. The problem is exacerbated by the fact that, as the share of renewables in the electricity mix expands, transmission reinforcement is being driven increasingly by a large number of relatively small projects.

50. The existing regulatory framework is now affecting the ability of transmission owners to provide connections in the necessary locations. For example, National Grid told us: “A more flexible mechanism is required to deliver the infrastructure investment in our vision”. This would also align better the construction programmes of the transmission companies and power station developers. Accordingly, a consensus has emerged within the industry in support of strategic investment in grid capacity—that is, investment ahead of individual projects being able to give specific financial commitment for their connections. This is possible because the general geographical location of a significant amount of future renewable generation, particularly wind power, is already well known.

51. To identify where areas of investment were required, in 2008 Ofgem and the Government asked the Electricity Networks Strategy Group (ENSG)—a senior industry group—to consider what the transmission system would need to look like to meet the 2020 targets for renewable energy. The ENSG published the first phase of its work in March 2009. It identified reinforcement work for a range of projects in areas of Scotland, Wales, East Anglia, London and the South West. It includes potential high voltage subsea cables between Scotland and the north of England along both the east and west coasts. In total, the work could amount to £4.7 billion between now and 2020. This is in addition to network investments already approved to connect renewable generation and through the current transmission price control. Combined, the cost of this work would be equivalent to £5 billion.

---

71 Ev 227, para 9 (Renewable Energy Association)
72 Ev 149, para 29 (Department of Energy and Climate Change)
73 Q 154; Ev 227, para 9 (Renewable Energy Association)
74 Ev 131, para 33 (Centrica)
75 Ev 202, para 6 (National Grid)
76 For example, Ev 164 (Energy Networks Association), Ev 171 (Energy Technologies Institute), Ev 227, para 11 (Renewable Energy Association), Ev 258, para 7.3 (Scottish Power) and Ev 270 (Sussex Energy Group)
the asset value of the existing transmission system—potentially the biggest grid development since the Second World War.\textsuperscript{77} It is also worth noting that this excludes the cost of connecting future offshore wind. The report notes that provided the work is taken forward in a timely manner, subject to planning consent, the reinforcements could be delivered within the required timescales. They would be phased over the next decade with the resulting network able to accommodate between 29 and 45 gigawatts of new generating capacity.\textsuperscript{78}

52. The ENSG work has received widespread support from the industry.\textsuperscript{79} E.ON called for transmission companies to be permitted immediately to commence with pre-construction work for the projects identified.\textsuperscript{80} Scottish Renewables said: “It is important […] that work on these upgrades and reinforcements should start as quickly as possible”.\textsuperscript{81} Ofgem responded in April 2009 by approving up to £12.5 million of funding outside the current TPCR for the transmission companies to begin feasibility studies and preparatory work. Since then the regulator has been working with the firms to establish longer-term funding arrangements that will facilitate a programme of strategic investment. In January 2010 the regulator approved additional funding of up to £1 billion for construction work on specific projects.\textsuperscript{82} Further investment will be funded through the next TPCR, due to begin in April 2013. A key part of Ofgem’s work will be to ensure that additional funding does not lead to the construction of unused, stranded assets. In its evidence to us the regulator acknowledged that its new approach entailed making a judgement on the level of stranded asset cost that was reasonable to incur for consumers, and that this represented “a fundamental philosophical shift” in its regulation of network investment.\textsuperscript{83}

**How strong is the case for investment?**

53. Although there was a consensus between the generators and network companies in favour of significant new investment in transmission reinforcements, this view was not shared by all who gave evidence to the Committee. For example, Dr Michael Pollitt told us a key concern should be “making sure that we do not […] give network incumbent companies a licence to massively increase capacity, which might not be necessary”.\textsuperscript{84} Prof Strbac noted too that the ENSG work presents a solution that involves a ‘business as usual’ response by the industry that is a direct consequence of the existing regulatory framework.\textsuperscript{85} Although both acknowledged that investment in the network infrastructure will be needed, they also believed that, in addition to new capacity through network reinforcements, a range of other solutions that can release latent network capacity should also be considered. These include, for example, the application of a variety of operational

\textsuperscript{77} Q 3 (Prof Goran Strbac, Imperial College London)
\textsuperscript{78} Electricity Networks Strategy Group, *Our electricity transmission network: a vision for 2020*, March 2009
\textsuperscript{79} For example, Ev 110, para 11 (Association of Electricity Producers), Ev 113, para 10 (Arup), Ev 129, para 9 (Centrica) and Ev 232 (Scottish and Southern Energy),
\textsuperscript{80} Ev 174, para 3.6 (E.ON UK)
\textsuperscript{81} Ev 261, para 22 (Scottish Renewables)
\textsuperscript{82} Ofgem, *Transmission Access Review—Enhanced Transmission Incentives: Final Proposals, January 2010*
\textsuperscript{83} Q 307 (Ofgem)
\textsuperscript{84} Q 12 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
\textsuperscript{85} Ev 268, para 2.5 (Prof Goran Strbac, Imperial College London)
measures, emerging local generation coming on stream, or allowing a greater role for responsive demand—all of which could substitute for network investment.

54. A further important concern raised by Phil Baker and Dr Bridget Woodman at the University of Exeter was that existing network assets should be fully utilised before making the case for further investment. The GB Security and Quality of Supply Standards (SQSS) set out the criteria and methodologies that National Grid must use in the planning and operation of the electricity transmission system. In other words, they determine the level of transmission asset utilisation. Baker and Woodman told us there is scope to improve the utilisation of the existing transmission assets. One example could be a move towards weather-related security standards. At present around 70% of transmission faults relate to weather conditions. However, the weather is not taken into account when operating the transmission system, even though it may be possible to relax operational security standards during fair-weather conditions, and so release latent network capacity. Such an approach could significantly decrease the external costs of operating the transmission system and reduce the need for investment without posing a risk to customer supplies.

55. Another way of releasing latent capacity from the existing network is through the use of special protection schemes. These are intelligent tripping systems that mitigate unexpected faults that could lead to a disconnection of a transmission line by automatically tripping generation or shedding demand load from elsewhere on the system. Although limited in scope at present, network operators already use some of these technologies to enhance the capability of their existing systems. Worldwide, there is growing interest in the development and application of such approaches, which entail more sophisticated system operation, but also minimise or avoid the need for network reinforcements. Solutions such as special protection schemes are more widely used in other parts of the world, including the US, Brazil, Chile, Australia and Taiwan, thus allowing system operators to achieve a higher level of network utilisation.

56. Prof Goran Strbac argued that the SQSS, which have remained largely unchanged since 1948, present a barrier to a range of other solutions that could release latent capacity from the existing network. Among others, these include more sophisticated system operation, such as the application of advanced network control, protection and maintenance techniques and innovative decision-making tools. They also include non-network solutions such as the greater role of demand in managing the electricity system as discussed in Chapter 2. This is important because these alternative approaches could not only enable the release of latent capacity from the existing transmission assets and facilitate the connection of greater amounts of wind power in the short term, but also in the longer term play a key role in the development of a smart grid.

57. Phil Baker and Dr Bridget Woodman also criticised the incentives in place for new transmission capacity. At present the regulated income of transmission operators

---

86 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)  
87 Ibid.  
88 Ev 267, para 1.6 (Prof Goran Strbac, Imperial College London)  
89 Ev 264 (Prof Goran Strbac, Imperial College London)  
90 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
through the transmission price control review (TPCR) is a function of the value of their asset base. This, therefore, places an incentive on companies to grow that base by building as much transmission capacity as they can justify, rather than actively looking for operational alternatives. In June 2008 the transmission companies began a fundamental review of the SQSS. This could provide a major opportunity to reform the Standards to maximise utilisation of the existing network and encourage the take-up of smart grid technologies. The review team’s terms of reference set a target date of September 2009 to report and consult on detailed proposals. These have not yet been published. We note that the ENSG work that proposes significant strategic network investment is based on the existing SQSS.

58. To avoid delays in connecting new power stations a more strategic approach to investment in transmission capacity is necessary. We welcome the Electricity Networks Strategy Group’s work to identify the reinforcements it believes are needed in the next ten years. We also note Ofgem’s cautious approach in allowing funding to advance particular projects and we urge them to be more proactive in promoting ways of avoiding delays.

59. Given the costs involved, the resulting impact on customers’ bills, and the risks of delay, it is vital that the case for investment is as robust as possible and preferable to any alternatives. There is some concern that the existing regulatory framework is driving the case for transmission investment presented by the industry at the expense of other more cost-effective options that seek better to utilise the existing network infrastructure. The current fundamental review of the Security and Quality of Supply Standards (SQSS) presents a major opportunity to address these issues. However, the review, which had aimed to publish detailed proposals in September 2009, has not yet reported. Therefore, we are concerned that some of the currently proposed strategic network investment that is based on the existing SQSS may prove unnecessary. Furthermore, reform of the SQSS will be vital for the development of a future smart grid. It would be totally unacceptable if Ofgem failed to fulfil its duties to consumers by not ensuring the timely completion of this review, especially as the regulator has already begun to grant funding for additional investment. We consider it essential that consideration of new investment in transmission has the benefit of the outcome of the SQSS review and strongly recommend that urgent measures are taken to complete and publish the review.

Network charging

60. On connection to the GB transmission system, generators are required to pay the following charges:

- **Connection Charges:** These enable National Grid to recover the costs involved in providing the assets that allow connection to the transmission system.

- **Balancing Services Use of System (BSUoS):** This charge recovers the cost of balancing demand and supply across the system.

---

• Transmission Network Use of System (TNUoS): This charge recovers the cost of installing and maintaining the transmission network required to allow the bulk transfer of power between sites and to provide transmission system security.\(^92\)

In this section we focus on current issues concerning the second and third of these charges.

**Constraint costs**

61. The transmission system has a finite capacity to transport electricity between power stations and consumers. Constraints can occur when the system is unable to transmit the power supplied at a particular location to where demand for it is situated. This may be because heating ratings on electricity lines have been exceeded, or because of an inability to maintain voltages on the system within the limits set out in the GB Security and Quality of Supply Standards (SQSS) discussed in the previous section. Constraints can also be exacerbated by transmission outages arising, for example, from network reinforcements, or unexpected generation failure. When such constraints occur National Grid, the system operator, will take action to reconfigure the system and/or go to the wholesale electricity market to increase or decrease the amount of electricity being supplied to the system at different locations.\(^93\) If National Grid has to require a power station to reduce its output because of constraints on the transmission network, the generator is compensated for the reduction in the grid’s capability to take their full output. The costs incurred are referred to as constraint costs. Along with all the other costs associated with keeping the system in balance and maintaining security of supply, these are passed onto users of the system through Balancing Services Use of System (BSUoS) charges. They are paid equally by generators and consumers, and do not vary by location.

62. In recent years the level of constraint costs have risen from £70 million in 2007/08 to £262 million in 2008/09 and are forecast to be £198 million in the current financial year.\(^94\) Constraint costs have caused growing concern for Ofgem since the establishment of the British Electricity Trading and Transmission Arrangements (BETTA) in 2005. The Arrangements brought together the electricity markets for Scotland, England and Wales. Under the regime, generators self-despatch their plant. In other words, they have guaranteed access to the grid, except at times when they are constrained off by the system operator. Because the interconnection between England and Scotland, known as the Cheviot Boundary, does not have the capacity to always meet the demands placed on it by electricity flows between the two countries, Ofgem has issued the boundary a derogation from the requirement to comply with the Security and Quality of Supply Standards (SQSS).

63. Constraint costs are key to informing investment decisions in new network capacity.\(^95\) Accordingly, an investment programme is underway to upgrade the Cheviot Boundary as this is seen as a main pinch-point on the network. It is important that constraint costs send the right signal of investment needs. The evidence we received suggest two factors have

\(^{92}\) [www.nationalgrid.com](http://www.nationalgrid.com)

\(^{93}\) Based on Ofgem, *Addressing Market Power Concerns in the Electricity Wholesale Sector—Initial Policy Proposals*, para 1.28-9, March 2009


\(^{95}\) Ev 267, para 1.5 (Prof Goran Strbac, Imperial College London)
contributed to the level of these costs being higher than they otherwise could be—the inherent nature of BETTA and the alleged exploitation of market power by the Scottish transmission companies.

64. One of the key differences between the BETTA system and the electricity ‘Pool’ trading arrangements that preceded it is that the market does not explicitly reward companies for providing generating capacity. Indeed, the debate on the future of BETTA includes substantial argument that a new system able to cope better with variable demand may need, at least in part, to reward installed capacity. Phil Baker and Dr Bridget Woodman at the University of Exeter argue that this means firms must instead attempt to recover some of their investment costs through the BETTA market. However, in an efficient market constraint costs should only be driven by fuel costs—i.e. the relative difference it costs for, say, a coal-fired power station in southern England to generate, versus a similar plant in Scotland. They note that the costs of resolving transmission congestion are observed to be around £90 per MWh, whereas under an efficient market only costs of £10 per MWh should apply.66 Similar work conducted by the Centre for Sustainable Energy and Distributed Generation demonstrates the same effect.67 This implies that BETTA potentially overstates the true level of constraint costs and, therefore, the need for additional transmission capacity to meet these constraints may also be overstated.

65. Ofgem also believes constraint costs have been made artificially high in recent years through the exploitation of market power by certain electricity companies. In April 2008 it launched a formal investigation under the Competition Act 1998 into the behaviour of Scottish Power and Scottish and Southern Energy. The complainants alleged that the companies may have withheld generating capacity from the wholesale forward market while using the same plant to supply balancing power to National Grid at excessive prices.68 Ofgem closed the investigation in January 2009, stating that to continue would have been an inefficient use of resources given the low likelihood of making an infringement decision under the Act.69 Nevertheless, the regulator estimates that up to £125 million of the £262 million of constraint costs incurred in 2008/09 could potentially have been the result of the misuse of market power.70 Because of the difficulties Ofgem believes it faces in applying the Competition Act 1998 legislation to the wholesale electricity market, it has argued in favour of being able to place a Market Power Licence Condition on generators that would strengthen its ability to carry out investigations.71 The Energy Bill currently before Parliament includes provisions which would give the regulator these powers.

66. In February 2009 Ofgem wrote to National Grid highlighting concern at the level of constraint costs, and asked it to conduct a review considering possible changes in the way

96 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
97 Ev 264 (Prof Goran Strbac, Imperial College London)
100 Ofgem, Addressing Market Power Concerns in the Electricity Wholesale Sector—Initial Policy Proposals, para 1.15, March 2009
101 Ibid.
they are recovered. In May the company proposed a modification to the BSUoS charging methodology—referred to as GB ECM-18. This would see constraint costs that arise from the non-compliance of a derogated transmission boundary, such as the Cheviot interconnection, being levied on a locational basis to all exporting generators behind that boundary. Ofgem is now consulting on this proposal and expects to make a decision before the start of the next charging year on 1 April 2010.102

67. If implemented, GB ECM-18 will inevitably shift the burden of BSUoS charges from generators in England and Wales onto those in Scotland. Depending on how generators respond, it will also potentially reduce the level of constraint costs across the system by encouraging less generation north of the border and more in the south. National Grid also believes the reforms would reduce companies’ ability to exercise market power when the system is constrained.103 The proposals met with criticism from some other witnesses. Scottish Renewables told us: “It is conceivable that generators behind a number of boundaries will face significant additional […] charges which may cause the suspension of a number of projects”.104 However, National Grid’s analysis suggests that though wind generators in Scotland would pay more, it would be marginal thermal (i.e. fossil fuel-based) plant that would be incentivised to generate less.105 Scottish Power, which would be most affected by GB ECM-18, also expressed concern stating: “[…] we do not see ourselves as a cause of the balancing costs. We are unable to generate as much as we would like because the network is not strong enough”.106 However, others were in favour of greater locational pricing within the BSUoS charges, noting that the current system, which does not minimise constraint costs, creates incentives for inefficient investment in transmission assets.107 Prof Strbac also argued that moving towards locational BSUoS charges would facilitate greater sharing of network capacity by, for example, encouraging conventional power stations in Scotland to reduce their output on windy days.108 He also considered that, in the future, the sharing of network capacity between generators will be a key feature of the smart grid.

68. It is also worth noting that once the current upgrade of the Cheviot Boundary is complete it is possible that it will then comply with the SQSS and no longer require a derogation. Given the locational charges under GB ECM-18 apply to a derogated boundary, many of the concerns raised by the Scottish generators may prove unfounded in the long run. The debate may also be superseded by new charging arrangements that could arise from DECC’s consultation on an enduring access regime for new generators, which we discuss later in this Chapter.

69. Constraints occur on the transmission network when the system is unable to transmit the power supplied at a particular location to where demand for it is situated.

103 National Grid, *GB ECM-18 Addendum*, November 2009
104 Ev 260 (Scottish Renewables)
106 Q 88 (Scottish Power)
107 Ev 268, para 2.10 (Prof Goran Strbac, Imperial College London) and Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
108 Ev 268 (Prof Goran Strbac, Imperial College London)
National Grid’s management of these constraints gives rise to costs, which are met by generators and consumers. The level of constraint costs are an important signal of investment needs. It is, therefore, vital that this signal is accurate. We are concerned that the nature of the British Electricity Trading and Transmission Arrangements (BETTA) appear to artificially inflate the level of constraint costs. We note the general review of the BETTA market announced by the Government in the Pre-Budget Report in December 2009. However, we recommend Ofgem conducts a specific review of the BETTA market with a view to addressing this issue. We also support the Government’s intention to enhance Ofgem’s powers to regulate against companies artificially inflating constraint costs.

70. Whilst we agree in principle with the current proposals to implement locational pricing for the Balancing Services Use of System charges as a means of reducing constraint costs in the short run, we question whether Ofgem should continue to pursue the modification brought forward by National Grid, given it could be replaced by another set of charging arrangements in the short to medium term when DECC implements a new regime for determining transmission access.

**Transmission Network Use of System charges**

71. The amount transmission companies can spend on operating and maintaining the system, as well as investment in new network capacity, is set through five-yearly price control reviews. These costs are recovered from both generators and suppliers through Transmission Network Use of System (TNUoS) charges. In 2009/10 the amount collected through these charges will be over £1.4 billion, representing around 3-4% of electricity customers’ bills. From April 2009, the TNUoS generation tariff has comprised four separate elements. Three of these vary according to the location of the generator on the system, the largest component of which is the ‘wider’ locational charge, which varies from £21.59 per kW in North Scotland to a negative charge of £6.68 per kW in the Cornish Peninsula. These locational charges will net around £85 million of revenue in 2009/10. The remaining component of the TNUoS generation tariff is a residual charge, which is non-locationally specific, and is paid at a flat rate. This raises a further £300 million. Generators pay 27% of total transmission costs with the rest met directly by consumers through electricity suppliers—around £1,041 million in 2009/10.

72. The locational element of the TNUoS charges was the source of considerable debate in the course of our inquiry. The tariff is in place because National Grid’s licence obligations require it to charge its customers cost-reflectively. Higher costs in the north are meant to reflect the greater cost of transporting electricity across longer distances to centres of demand in the south, where network capacity is also greater. In so doing, the TNUoS charges are designed to provide an economic signal to generators and developers to work within existing network capabilities and locate nearer to the source of demand. This then reduces the need for investment in new network capacity, which can be expensive and time-consuming to deliver as has been the experience to date, for example, with the Beauly-Denny Line. It also has potential environmental benefits, both in decreasing the

---

109 Ev 153 (Department of Energy and Climate Change)
110 Ev 202 (National Grid)
transmission losses arising from the transport of electricity over long distances, and in reducing the need for new pylons that can blight the landscape.\textsuperscript{111}

73. Both Ofgem and the Government argued strongly in favour of cost-reflective transmission charges. The regulator believes it promotes efficient development and use of the network, which is in the interests of current and future consumers.\textsuperscript{112} The Minister told us: "If we do not have a signal that helps people think […] about how and where they will locate their plant, then there is a risk obviously that we get too much investment in areas across the system that are too far from demand".\textsuperscript{113} In their evidence to us, organisations including the Association of Electricity Producers, the Institution of Engineering and Technology, the Renewable Energy Association and E.ON UK, among others, also supported the principle of locational pricing.\textsuperscript{114}

74. Generators in Scotland have, by contrast, been highly critical of the locational element of the TNUoS generation tariff, arguing that it creates an uncertain environment for investment and discriminates against renewable generation. Scottish Renewables argued that some forms of renewable energy, such as wind, are not able to respond to the locational price signal in the same way that gas-fired power stations can. The trade union Prospect told us that locational pricing is “a legitimate mechanism for encouraging construction of fossil fuel fired or nuclear generation near the load centres, but acts as an additional disincentive to remote renewable generation”.\textsuperscript{115} Scottish Renewables argued this results in income derived through the Renewables Obligation in Scotland effectively being transferred to conventional generators in the south.\textsuperscript{116} Scottish and Southern Energy too were critical of the level of locational tariffs, noting that the current approach had created charges that were “volatile and unpredictable”.\textsuperscript{117} The company told us this acted as a deterrent to investment by generators and that this uncertainty also undermined the signals for investment in additional transmission capacity.\textsuperscript{118}

75. With the support of the Scottish generators, in 2008 the Scottish Executive brought forward a proposed modification to National Grid’s transmission charging methodology, known as GB ECM-17. This proposed an alternative model based on a ‘postage stamp’ approach to charging where a GB-wide tariff is levied for each unit of energy exported onto the network. Scottish Renewables argued this would create a regime that was “proportionate, predictable and stable and will do much to promote new generation in the UK”.\textsuperscript{119} It would also reduce transmission charges for generators in Scotland. Socialising the cost of transmission across all generators, irrespective of location, is also the approach

\textsuperscript{111} Ev 153 (Department of Energy and Climate Change)
\textsuperscript{112} Ev 217 (Ofgem)
\textsuperscript{113} Q 400 (Minister for Energy)
\textsuperscript{114} Qq 166 (Renewable Energy Association), 204 (Association of Electricity Producers) and 282 (Institution of Engineering and Technology); Ev 114, para 13 (ARUP), Ev 175, para 3.17 (E.ON UK) and Ev 180, para 7 (ESBI)
\textsuperscript{115} Ev 223, para 12 (Prospect)
\textsuperscript{116} Q 163 (Scottish Renewables)
\textsuperscript{117} Ev 232 (Scottish and Southern Energy)
\textsuperscript{118} Q 90 (Scottish and Southern Energy)
\textsuperscript{119} Ev 262, para 39 (Scottish Renewables)
used in countries such as Germany.\textsuperscript{120} National Grid consulted on the proposal in 2009. It found that cost reflective charging was still consistent with the Government’s objectives for increasing renewable generation and reducing carbon dioxide emissions, and that the existing approach did produce tariffs that were stable and predictable for the vast majority of sites. The company, therefore, rejected the modification.\textsuperscript{121}

76. Ofgem was highly critical of ‘postal charging’ for transmission access.\textsuperscript{122} The regulator argued such an approach would discriminate unduly against generators in the south who impose lower costs on the system, whilst also creating incentives for over-investment in transmission capacity in the north. It also noted the mirroring of charging methodology for gas transmission, where gas users in Scotland benefit from lower charges than those further south because they are closer to the major entry points to the gas transmission system. Ofgem told us it would be difficult to justify changing the charging approach for electricity without doing likewise for gas.

77. Some witnesses suggested that the level of transmission charging did not target costs to location enough. Prof Strbac told us the revenue derived from the locational element of the TNUoS charge was small relative to the revenue from the residual charge, which is spread across all generators—£85 million as opposed to £300 million.\textsuperscript{123} This in turn is dwarfed by the £1,041 million of transmission charges paid by consumers. Dr Michael Pollitt noted too that the potential growth of offshore wind meant generators had many more options of where to locate new renewable capacity and, therefore, respond to locational signals.\textsuperscript{124} The Renewable Energy Association also told us that whilst Scotland is an extremely important resource for renewable energy, “it is not, however, the only show in town”.\textsuperscript{125}

78. The Department and Ofgem argued that locational charges were not harming the development of renewable generation in Scotland. DECC stressed that the nature and level of the TNUoS charge and other related transmission-related costs were taken into consideration when determining the level of subsidy available through the Renewables Obligation.\textsuperscript{126} The regulator’s Chief Executive told us proposed onshore wind projects as far north as Orkney typically had estimated rates of return on investment of up to 40%, in contrast to around 12% for a gas-fired power station.\textsuperscript{127} Moreover, access to finance in the current economic climate, gaining planning consent, and securing a grid connection are all seen as more important determinants of investment in new renewable generation.\textsuperscript{128}

79. However, the treatment of wind generation specifically within the charging regime was raised as a concern.\textsuperscript{129} At present, generators are charged according to their peak load

\textsuperscript{120} Q 63 (Dr Jim Watson, Sussex Energy Group)
\textsuperscript{121} National Grid, Conclusions Report: GB ECM-17, Transmission charging—A new approach, September 2009
\textsuperscript{122} Ev 217 (Ofgem)
\textsuperscript{123} Ev 264 (Prof Goran Strbac, Imperial College London)
\textsuperscript{124} Q 18 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
\textsuperscript{125} Q 166 (Renewable Energy Association)
\textsuperscript{126} Ev 153 (Department of Energy and Climate Change)
\textsuperscript{127} Q 317 (Ofgem)
\textsuperscript{128} Q 399 (Minister for Energy)
\textsuperscript{129} Q 165 (British Wind Energy Association)
condition—i.e. the output they contribute to meeting peak demand. Yet wind generation is variable in nature, having a low load factor of around 30%, and so makes a low contribution to peak demand. This is not, though, reflected in the network charges—if it were wind generators would pay significantly less. National Grid acknowledged this concern in its Conclusions Report on GB ECM-17. Whilst this may not be a significant factor in determining the investment case for new wind generation at present, it could become more so as financing conditions ease, and reform of the planning system and grid access regime are implemented. We discuss the latter of these in the next section.

80. **We are concerned that the current system appears to charge wind generators disproportionately more than conventional generators for grid usage.** We believe that it is imperative that transmission charges should not discriminate against renewable energy wherever it is located in Britain. Whilst we received conflicting evidence on this matter and acknowledge that other factors such as the planning system, grid access and financing play an important role in determining the investment case for new renewable generation, we believe it is vital that this issue be fully investigated as soon as possible. We note Ofgem’s long-term commitment to the model of locational charging, but given the evidence we have received we recommend the Department establishes an independent review to develop an appropriate transmission charging methodology.

**Grid access**

81. Access to the network is vital for electricity producers as without it they cannot deliver their product to consumers, nor do they have confidence to invest in new generating capacity. The issue also ties closely with the case for investment in new transmission assets and the network charging regime. In this section we look at the problems new generators face in acquiring network connections and the Government’s response to these concerns.

**The queue for network access**

82. Under the existing transmission access arrangements the grid operator follows an ‘invest and connect’ approach for new projects whereby they are only connected if there is sufficient grid capacity to accommodate their maximum potential output without causing a restriction on the production of existing generators. The speed with which a generator can gain access will depend on the amount of grid reinforcement needed; the ease with which planning consent can be acquired for any work; and the amount of generating capacity applying to connect in each part of the network. Unless there is already spare capacity on the grid, generators must wait until the operator has made the requisite reinforcements before they can connect. Those applying for access are treated on a first-come-first-served basis, which means projects that are less viable can block those that are further ahead or could be advanced earlier. Indeed, the position is rather similar to people

130 Ev 264 (Prof Goran Strbac, Imperial College London)
132 Ev 227, para 3 (Renewable Energy Association)
133 Ev 217 (Ofgem)
booking rooms in hotels before they have found out whether they can get the time off work.

83. These arrangements have resulted in a queue of projects at various stages of development waiting for connection with a combined capacity estimated at between 60 GW and 80 GW—equivalent to all Britain’s existing generating capacity.134 Around 17 GW of this is renewable generation, with some projects holding a connection date as late as 2023. At present half of the queue will have to wait at least five years for grid access.135 In Scotland 9 GW of renewables is waiting for connection, a large proportion of which has connection dates later than 2018.136 Many projects with connection offers do not come to fruition. However, even with an attrition rate of 50% assumed by several of our witnesses, the backlog of schemes is long. For projects in Scotland the queue is primarily the result of the delayed upgrading of the Beauly-Denny line and the Cheviot Boundary. Scottish Renewables estimate that once the former of these is in place more than 5 GW of renewables in Scotland will be able to connect to the system.137 Scottish Renewables told us: “If you apply a planning attrition rate of 50% to the 9 GW [...] then these reinforcements will be sufficient to provide the necessary firm access”.138

84. It is clear that the existing regime creates considerable uncertainty for both renewable and conventional generators and restricts access to the energy market. As one independent generator said: “This makes continued investment in the UK very difficult in comparison with some other jurisdictions”.139 Scottish and Southern Energy told us: “[...] it is not surprising that potential investors (particularly in emerging renewable technologies) are opting to locate elsewhere in the global energy market”.140 The Government and the regulator have recognised the need for change.141 Accordingly in 2008 they launched the Transmission Access Review (TAR), the aim of which was to provide a programme of reform that would significantly reduce grid access barriers. The TAR process is still underway. It was meant to deliver both short-term measures to reduce the current queue, as well as an enduring access regime for the long term. We consider each of these in the next two sections.

**Interim measures**

85. In the debate over improving grid access one approach has come to the fore, at least as a short-term solution—the concept of ‘connect and manage’. This can take a variety of forms, though the common basis is that all generators who wish to connect to the grid are allowed access irrespective of whether any necessary transmission reinforcements have been completed.142 In so doing both existing and new generators have firm access rights.

---

134 Ev 147, para 16 (Department of Energy and Climate Change) and Ev 232 (Scottish and Southern Energy)
135 Ibid.
136 Ev 261, para 31 (Scottish Renewables)
137 Ibid.
138 Ev 261, para 32 (Scottish Renewables)
139 Ev 196, para 13 (Intergen)
140 Ev 232 (Scottish and Southern Energy)
141 Ev 148, para 18 (Department of Energy and Climate Change) and Ev 212, para 3.3 (Ofgem)
142 Q 161 (Renewable Energy Association)
The system operator manages any resulting congestion on the network on a day-by-day basis by taking offline generating capacity where there are pinch-points, for which the owners are compensated—these give rise to the constraint costs discussed earlier in this chapter. This is the approach currently used in Germany and Denmark.143

86. In May 2008 Ofgem announced that it had approved National Grid’s proposal to introduce changes to the rules on connections known as ‘interim connect and manage’. This will enable both renewable and conventional generators to link to the grid as soon as their local connections are ready, rather than wait until any wider system reinforcements have been completed. The regulator expects the measures to be in place only in the short term in anticipation of their replacement with an enduring access regime in the near future. Initially, the combination of this and more proactive queue management by National Grid allowed around 450 MW of renewable projects to gain earlier connection dates in Scotland.144 National Grid has now identified a further 450 MW of renewable projects that can connect earlier than expected. This constitutes about a fifth of the current queued capacity in Scotland that could be delivered in the next decade (again, assuming a 50% attrition rate).145

87. Overall, the industry has welcomed the introduction of the interim measures.146 There has, however, been some concern over the level of constraint costs that will arise from their implementation.147 Where other countries have introduced ‘connect and manage’ it has led to a significant increase in network congestion and associated constraint costs.148 The extent of these will be determined by the time it takes for planned investment in new capacity to take place and, before then, by how the costs are distributed across network users. We have discussed already in this Chapter National Grid’s proposal to make the Balancing Services Use of System (BSUoS) charges locationally determined, rather than socialised across all generators. The level of anticipated constraint costs arising from the 900 MW of additional renewables capacity, and hence the impact locational pricing might have, has been a matter of disagreement between the industry and the regulator.149 Moreover, National Grid believe locational pricing within the BSUoS will have a greater effect on conventional capacity in Scotland than on renewables. However, debate over these issues is likely to be superseded by the introduction of a long-term access regime.

An enduring access regime

88. The arrangements by which generators gain access to the network are set out in the Connection and Use of System Code (CUSC). This is a modifiable document such that Ofgem can change any part of the access regime. However, it can only do so with amendments proposed to it by the industry—the regulator cannot change the CUSC of its

---

143 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
144 Ofgem Press Notice, Ofgem speeds up connections for 450 megawatts of low-carbon generation, 8 May 2009
145 Q 158 (Scottish Renewables)
146 Ev 111, para 20 (Association of Electricity Producers), Ev 253, para 15 (Scottish Natural Heritage) and Ev 262, para 34 (Scottish Renewables)
147 Ev 131, para 30 (Centrica)
148 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
149 Q 199 (Association of Electricity Producers); Ev 116 (British Wind Energy Association)
own accord. This meant it was the industry’s responsibility to lead on developing an enduring access regime. As an incentive the Government included in the Energy Act 2008 a provision for the Secretary of State to impose a regime if the industry failed to develop a satisfactory solution.

89. National Grid began the process by proposing in April 2008 a suite of amendments to the CUSC which over the course of 2008 and 2009 were discussed and developed by industry working groups. The regulator’s role was to monitor and report on progress to the Department. In early 2009 it became apparent to Ofgem that the emerging proposals for enduring reform would lead to significantly higher network charges for low-carbon generation, particularly renewables, than for conventional generators. In evidence to us in May the regulator’s Chief Executive referred to an analysis by National Grid suggesting that one of the proposed approaches would give rise to charges of £70 per kW for a wind farm in Scotland versus £10 per kW for a generator in England and Wales. He described this kind of outcome as “absurd”. Frustrated by what it saw as the industry’s unwillingness to engage in other options, in June 2009 the regulator wrote to the Secretary of State recommending he use his powers under the Energy Act 2008 to take action into his own hands. In his letter the Chairman of Ofgem, Lord Mogg, wrote: “The electricity generation sector must clearly play a major role in delivering the UK’s ambitious emission reduction targets and it is regrettable that the industry appears to have fallen at the first hurdle”.

90. Accordingly, in August 2009 the Department published a consultation setting out three possible variations of the ‘connect and manage’ model, summarised below:

- **Socialised**—A model that fully socialises any additional constraint costs. Under these arrangements costs would be shared between all users of the network and ultimately borne by consumers;

- **Hybrid**—This targets some, but not all, of the additional constraint costs on new entrant power stations; and

- **Shared cost and commitment**—This offers the choice to new and existing power stations to commit to fixed network access in return for greater certainty over charges, or to opt out and be exposed to additional constraint costs.

91. The Department’s consultation came after the Committee had completed its evidence-gathering. We note, though, Ofgem’s recent response to the consultation. This expressed concern that all three of the approaches would create significant additional constraint costs in the range of £2.9 billion to £3.5 billion between 2009 and 2020 (on a net present value basis), which it states would ultimately be borne by consumers. It argues too that until additional grid capacity is in place these regimes would create opportunities for generators to exploit market power and increase constraint costs further. Furthermore, the regulator criticises the Department for failing to take a holistic approach in its proposed reforms. For example, they fail to address wider issues concerning the current arrangements, including

---

150 Q 304 (Ofgem)
152 Department of Energy and Climate Change, Improving Grid Access, August 2009
153 Ofgem, Response to DECC’s Consultation on ‘Improving Grid Access’, December 2009
the nature of access rights; the way in which generators commit to use the system and the costs of doing so; and the compensation they receive when constrained off the network.

92. There are a variety of ways in which the Department could define a long-term grid access regime. For it to be successful, however, the evidence we received suggests it should contain four key features. First is the principle of generators sharing access to the network. While the development of the smart grid will reduce the need for investment in generating capacity significantly over a continuation of the current approach of building supply to always meet peak demand, it is still the case that total generating capacity in the future is likely to be higher than it is now for a given level of demand, primarily because of the intermittency of wind generation. DECC’s memorandum suggests Britain’s total capacity could be around 105 GW in 2020 for current levels of demand, compared to 80 GW today. Consequently, the Department believes there is an opportunity to share network access more efficiently. In so doing this reduces the need for new investment in transmission capacity.

93. Sharing access represents a move away from the current approach whereby all generators have guaranteed entry rights to the grid and are compensated when they are constrained off the system. Instead it means a system where generators potentially choose the extent of their access rights, and pay accordingly through their transmission charges. For example, there are already situations where wind farm generators have agreed contractual arrangements with conventional power stations to share grid entry capacity, with the latter providing back-up for the former when the wind does not blow. The concept of sharing access was also a key part of the original amendments to the CUSC put forward by National Grid in 2008 in developing an enduring access regime.

94. Sharing network capacity has met with considerable opposition because it would entail the removal of existing transmission rights from incumbent generators. The Association of Electricity Producers (AEP) argued that generators would have made investments on the basis of having secure transmission access rights for the lifetime of a power station’s operation, and that this was what they paid Transmission Network Use of System (TNUoS) charges for. In evidence, the AEP quoted a Chief Executive from the industry who had said: “I simply cannot sign off the building of a brand new power station to come into use occasionally to deal with the variable supply of energy from renewables”. Ofgem, in turn, have questioned the companies’ assertion that their access rights are guaranteed in perpetuity. Generators are liable only for one year’s TNUoS charges at any given time, and are free to reduce the amount of access they require with only five days’ notice to National Grid leaving consumers to cover the cost of any assets stranded. The regulator concludes: “This lack of user commitment undermines the efficiency of network

154 Ev 147, para 15 (Department of Energy and Climate Change)
155 Qq 17 (Prof Goran Strbac, Imperial College London) and 21 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
156 Ev 196, para 14 (Intergen)
157 Ev 111, para 22 (Association of Electricity Producers)
158 Q 208 (Association of Electricity Producers)
159 Q 314 (Ofgem)
160 Ev 217 (Ofgem)
investment, and will delay the connection of new generation”.\textsuperscript{161} Disagreement over this issue contributed to Ofgem’s decision to recommend the Secretary of State to intervene in the process.

95. One reason why generators are unwilling to surrender their guaranteed grid entry is because the regulatory framework distorts the relative cost of firm versus finite access rights. With firm access, companies have the security of knowing they will receive compensation if they are constrained off the system, whereas non-firm access is comparatively expensive because power stations do not know whether they will be able to export to the grid. Under the existing regime there is little incentive for generators to relinquish access capacity, even if they do not make full use of it at all times. The key to solving the impasse, as one witness noted, is to ensure that both options have efficient costs attached to them so that generators’ decisions on the level of grid access they require reflects the costs they will incur to the system.\textsuperscript{162} This may need to be combined with some kind of incentive mechanism within the market that ensures a degree of spare generating capacity, such as existed under the previous electricity trading arrangements, known as the ‘Pool’. This is because, at present, generators rely on the receipt of constraint payments— which would be significantly reduced if they did not have firm access to the network—to cover some of their investment costs.

96. The second key feature of an enduring regime, which is linked to the issue of access sharing, is the priority of low-carbon technologies over conventional generation. The Association of Electricity Producers argued that all forms of generation technology should compete on a level playing field and network connection, access and charging arrangements should be non-discriminatory, cost-reflective and transparent.\textsuperscript{163} This would be more persuasive if the Government did not have a clear strategic objective to decarbonise the electricity system. Phil Baker and Dr Bridget Woodman at the University of Exeter told us the replacement role of renewable generation suggests that it should: “[…] be endowed with a natural priority in terms of energy dispatch and also in accessing the electricity system, thereby ensuring the maximum contribution to decarbonisation”.\textsuperscript{164}

97. The third key feature is the greater role of demand in the access regime. We saw earlier in this Chapter that the bulk of TNUoS charges are paid directly by consumers. This imbalance in the apportionment of costs means a one megawatt reduction in demand is treated differently by the charging regime to a one megawatt increase in generation, despite the impact of both actions on the system being the same.\textsuperscript{165} Furthermore the current DECC proposals for an enduring regime exclude the demand-side from playing a greater role in the access regime to alleviate constraints when they arise. We have seen already that the greater role of active demand-side management will be a vital part of a future smart grid.

\begin{flushleft}
\textsuperscript{161} \textit{Ibid.}\textsuperscript{162}  Q 19 (Prof Goran Strbac, Imperial College London)\textsuperscript{163}  Ev 112, para 24 (Association of Electricity Producers)\textsuperscript{164}  Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)\textsuperscript{165}  Ev 264 (Prof Goran Strbac, Imperial College London)
\end{flushleft}
98. Finally, several witnesses stated that an enduring access regime, whatever form it takes, has to provide long-term regulatory certainty to all market participants for them to have the confidence to make investments. Scottish and Southern Energy told us: "Stability and certainty in the grid access and charging arrangements are essential to achieving the EU 2020 target". E.ON UK also said: "Long-term regulatory certainty […] is essential to give confidence to and ensure investment in the network and generation with longer lead times, such as nuclear". Achieving this outcome would have to be balanced with the need to develop a regime that also facilitated access sharing.

99. The old arrangements for gaining access to the transmission network gave rise to a queue of at least 60 GW of projects at various stages of development, a large proportion of which are renewables, some of which have potential connection dates as late as 2023. A new regime is vital if the Government is to meet its targets for renewable energy and emissions reductions. We welcome the ‘interim connect and manage’ arrangements, which should facilitate the earlier connection of 900 MW of renewable capacity in Scotland. We are, however, concerned by the lack of progress in developing a long-term access regime. It is extremely disappointing the industry has not been able to agree reforms and the Government has had to intervene. As far as possible, it is important an enduring regime is based on consensus between all parties—the Government, the regulator and the industry.

100. We believe that to facilitate cost-effectively the formation of a smart grid and the delivery of the Government’s strategic objectives, a long-term regime must contain four key features:

- Greater sharing of network access, particularly between renewable and conventional generators. This will reduce the need for investment in grid capacity, and the likelihood of large constraint costs, although it may need to be supported by additional market arrangements that guarantee spare generating capacity on the system;

- Prioritisation of renewables in electricity dispatch to maximise their contribution to decarbonising the energy system;

- An equal role for the demand-side in managing network access; and

- Arrangements that provide a degree of stability and regulatory certainty for generators to have the confidence to make investments.

We urge the Department to move quickly to ensure an enduring regime is in place as early as possible in 2010.

166 Ev 232 (Scottish and Southern Energy)
167 Ev 175, para 3.17 (E.ON UK)
The industry’s rule-making process

101. In November 2007 Ofgem announced its intention to conduct a review of the various arrangements for governing the industry’s code and charging methodologies. The regulator believes the existing governance procedures are not effective at bringing about the coordinated and timely reform needed to deliver the Government’s climate change and security of supply objectives—a view borne out by its recent experience in attempting to implement an enduring transmission access regime.168

102. The Codes Governance Review, as it is known, has a number of work streams on which Ofgem is currently consulting. One set of proposals covering Major Policy Reviews would give the regulator power to require network licence holders to implement code modifications consistent with the conclusions of any such reviews.169 Although changes would be subject to thorough consultation, this would see a major reallocation of rule-making power away from the industry to the regulator. The Chief Executive of Ofgem told us: “[…] what we have to be able to stop going forward is the vested interests within the sector, either filibustering or just straight blocking reform […] we want as an organisation to be able to initiate change”.170 As a quid pro quo Ofgem has proposed that where code modifications are likely to have only minimal impact on consumers or competition the industry would be allowed to self-govern, rather than requiring authority from the regulator. In a separate consultation, Ofgem has also proposed opening up the procedures for modifying network charges. At present, these are determined by the network owners—network users, interested parties and consumers are not able to influence how use-of-system or connection charges are determined. The regulator’s proposals seek to address this disparity. In both cases, Ofgem expects to implement its reforms in 2010. It notes that any changes to the governance procedures will not inhibit network companies from seeking judicial review or a Competition Commission referral with respect to any future changes to the industry codes or charging methodologies by the regulator, which they see as unreasonable.

103. We welcome Ofgem’s decision to review the industry’s rule-making process. The existing system, under which only network owners can propose changes to the grid codes and charging methodologies, has for far too long forestalled reform in areas such as transmission access. The regulator’s proposal that it take powers to implement code amendments arising from major policy reviews, whilst conceding power in areas of less significance to consumers or competition, is a sensible approach. So too is the proposal to make governance of the charging methodologies more inclusive. Changes in both these areas will facilitate the delivery of the Government’s climate change and security of supply objectives.

168 Ofgem, Review of industry governance code—scope of the review, June 2008
170 Q 304 (Ofgem)
Developing offshore transmission

104. Britain has some of the best wind resources in the world. It is for this reason the Government expects wind power to be the main contributor in meeting our share of the EU 2020 target for renewable energy. A large proportion of this will be built offshore, primarily in the North Sea, but also in the Irish Sea.

105. Offshore wind development in British waters began in 2000 with the Crown Estate’s first round of leases for 13 locations. The first project under Round 1, North Hoyle, came into operation in December 2003, and a number of projects have followed since. In 2002 and 2003 the Crown Estate ran a second licensing round, awarding 10 companies the rights to develop a total of 15 sites in three strategic offshore areas. The estimated potential generating capacity arising from Round 2 was between 5.4 and 7.2 GW. At present, nine offshore wind farms are operational with a combined capacity of 688 MW. Another five schemes with a capacity of 1.1 GW are under construction. In January 2010 the Crown Estate announced the results of its third licensing round, awarding contracts for development in nine zones, which are much further out to sea, that could lead to 32 GW of offshore generation. In this section we look at the difficulties faced in connecting offshore wind farms to the onshore network, and the Government and Ofgem’s framework for ensuring timely investment in offshore transmission.

The challenges

106. Delivery of the scale of generating capacity anticipated in Round 3 will require substantial investment in offshore networks. The Department estimates that investment worth up to £15 billion is necessary over the next decade to connect all three rounds of sites licensed so far. This equates to more than twice the asset value of the existing onshore network. In addition, the large flows of electricity expected from offshore wind farms will necessitate reinforcement in particular parts of the onshore network. These investment needs formed part of the Electricity Networks Strategy Group’s (ENSG) recent analysis discussed earlier in this Chapter. These works will need to progress in good time as the level of offshore generating capacity connecting to the mainland grows.

107. Building networks offshore poses significant technical and regulatory challenges. The construction of large electrical power infrastructure in difficult offshore environments, particularly for the Round 3 projects, has not been attempted anywhere else on the same scale. The Institution of Engineering and Technology (IET) told us: “the installation of rather sophisticated electronic and other equipment offshore is new and […] something that will be pioneered in UK waters”. Offshore transmission will use high-voltage direct current (HVDC) as opposed to alternating current (AC) onshore because for undersea

---

171 British Wind Energy Association Briefing Sheet, Offshore wind
172 www.bwea.com/statistics
174 Ev 150, para 43 (Department of Energy and Climate Change)
176 Q 285 (Institution of Engineering and Technology)
cables it is cheaper and has lower losses. There will also be operation and maintenance risks once the infrastructure is in place. The harsh North Sea environment will mean turbines and network connections are not always accessible. This will require much higher levels of system reliability than onshore. The IET argued the regulatory framework needs to recognise these risks.177

108. To manage electricity flows from offshore the Department has extended National Grid’s GB system operator role. Accordingly, the company and the regulator have been working to modify the various grid codes to take account of offshore transmission, which is defined as 132 kV or above—the same as in Scotland—as opposed to 275 kV or above onshore in England and Wales. Some of our witnesses raised concern at the potential inequitable treatment of offshore wind within the regulatory framework. Centrica highlighted that offshore generators would not pay Transmission Network Use of System (TNUoS) charges in the same way as onshore generators, where the majority of costs are currently socialised across all generators and consumers. Instead, the company notes that substation and cable costs will be targeted directly at the offshore generator, thus, it says, increasing their network costs by a factor of ten or more.178

109. Prof Strbac pointed to further discrimination in the regulations concerning the compensation generators receive when the network is unavailable for them to input electricity. Whereas onshore power stations are entitled to such compensation, provided they comply with the network standards, this is not available to similarly compliant offshore wind farms.179 On the grounds that both onshore and offshore network security standards are based on the same principles, Prof Strbac saw no justification for this differential treatment and thought it could undermine seriously the financial viability of any offshore generators that did experience difficulties with their transmission connections.180 In response National Grid argued that offshore wind farms would have to meet lower connection and security standards than their onshore counterparts and, therefore, could not expect the same level of compensation.181

110. A further challenge for offshore networks is in ensuring the supply chain is able to deliver the equipment on time to connect new wind farms. The British Wind Energy Association (BWEA) estimates that approximately 7,500 km of HVDC cable will be required by 2020 to link up all the offshore projects planned. Yet current global production of this cable is only around 1,000 km per year.182 There will also be demand for cabling as part of other countries’ offshore programmes, for example, Germany. The industry, therefore, believes there is a major export opportunity for Britain developing domestic cabling production. BWEA told us: “If the right signals are sent to the cable companies, the resulting factories could be sited in the UK, with benefits in terms of jobs and exports”.183

177 Ev 189, para 26.2 (Institution of Engineering and Technology)
178 Ev 132, para 38 (Centrica)
179 Ev 269, para 3.6 (Prof Goran Strbac, Imperial College London)
180 Q 38 (Prof Goran Strbac, Imperial College London)
181 Q 101 (National Grid)
182 Q 178 (British Wind Energy Association)
183 Ev 116 (British Wind Energy Association)
The licensing regime will be a key determinant of the UK’s attractiveness as a place to invest.\textsuperscript{184} We discuss this in the next section.

111. **There are many challenges associated with the expansion of the electricity network offshore.** It is important the regulatory framework reflects these difficulties and treats generators connecting offshore equitably vis-à-vis their onshore counterparts. The offshore wind industry presents a significant commercial opportunity for British industry, which requires a regulatory regime that will stimulate domestic investment in cabling and associated equipment manufacture.

**The licensing regime**

112. The Department and the regulator have been working together to develop the licensing regime for the developing offshore transmission network. In the same way as for the onshore network, licensed companies will be responsible for building, owning and maintaining the offshore cables. However, rather than the area-based monopolies currently enjoyed by the existing three companies, licences will be awarded by tender as new offshore generators seek connection. Offshore transmission owners (OFTOs) will receive a 20-year regulated income stream from Ofgem and generators will pay to use the cables through annual transmission charges. These costs, along with those associated with the stranded assets of any failed projects, will ultimately be borne by consumers.\textsuperscript{185}

113. The first round of competitive tenders began in summer 2009. In December Ofgem announced a shortlist of six companies or consortia bidding for nine projects.\textsuperscript{186} The total value of the work is more than £1 billion and will connect 2 GW of offshore wind capacity. The regulator expects to announce the winning bids in May 2010. The first tenders to appoint OFTOs will entail taking over the ownership and maintenance of cables that are already under construction from developers. Ofgem refers to these as transitional arrangements. In the future, OFTOs will be appointed to design and build the grid connections themselves, as well as own and maintain them. The regulator is currently consulting on the enduring regulatory framework that will govern these activities.\textsuperscript{187}

114. Britain is not the first to use an auctioning approach for new transmission wires—Argentina and Chile have done so previously and successfully.\textsuperscript{188} However, it is the first to use auctioning for offshore connections. Both the Department and Ofgem argued that there are various advantages to their approach. First, they are keen to increase the number of parties able to build the offshore connections and deliver them quickly so as to minimise the risk of delaying new wind farms coming on-stream.\textsuperscript{189} Second, they believe the auctions will create cost savings for consumers, which the regulator predicts could total around £1 billion from all three offshore rounds. Third, the 20-year income streams for OFTOs will, the Department argues, require less regulatory oversight than the current five-yearly price

\textsuperscript{184} Ev 103, para 5.1 (ABB) and Ev 164 (Energy Networks Association)
\textsuperscript{185} Ev 150, para 40-42 (Department of Energy and Climate Change)
\textsuperscript{186} Ofgem Press Notice, Shortlist for over £1 billion of offshore electricity links announced, 14 December 2009
\textsuperscript{187} Ofgem, Offshore Electricity Transmission: Consultation on the Enduring Regime, December 2009
\textsuperscript{188} Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
\textsuperscript{189} Op. cit.
control reviews. Finally, Ofgem hopes the competitive approach will also encourage greater innovation.

115. Several of our witnesses supported the new framework for licensing OFTOs. The Association of Electricity Producers told us: “the competitive arrangements [...] will deliver benefits in terms of lower costs, more innovation, and getting more companies in to finance these networks”.

Another witness noted that Britain will benefit from being one of the first countries to adopt this approach, and will therefore attract European and American companies that have not previously been involved in the British market. This appears to have been borne out in the current auction where only one of the six shortlisted bidders is an incumbent transmission company—National Grid.

116. However, a number of witnesses also voiced concern over the new licensing regime. The Energy Networks Association highlighted the complexity of the arrangements, which ARUP argued could undermine some of the expected benefits. Another risk is that the rules may prevent the exploitation of synergies between different network concessions in the operation of offshore generation and transmission assets. Also, the tendering for individual projects potentially reduces the incentive for companies to invest in their capability to deliver offshore connections because they will face uncertainty over whether they will win future work. Moreover, with limited experience of the costs and risks of these investments, combined with potential supply chain constraints, companies may underestimate such factors and fail to deliver on their bids.

Strategic investment

117. The Department told us the majority of Round 1 and 2 projects will connect ‘point to point’. This means each offshore wind farm will have its own transmission cables that connect with the onshore network. Later Round 3 schemes, though, are likely to follow a more zone-based approach whereby a group of wind farms in a particular area, whether coming on-stream simultaneously or phased over time, use a single link to connect onshore. The Department believes this will ensure the development of the offshore grid in a co-ordinated way.

118. Many of our witnesses argued the Government and Ofgem’s licensing framework failed to take a long-term strategic view of the development of the offshore network.

190 Ofgem Press Notice, shortlist of over £1 billion of offshore electricity links announced, 14 December 2009
191 For example, Ev 112, para 25 (Association of Electricity Producers), Ev 116 (British Wind Energy Association) and Ev 131, para 35 (Centrica)
192 Q 212 (Association of Electricity Producers)
193 Q 29 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
194 Ev 114, para 16 (ARUP) and Ev 164 (Energy Networks Association)
195 Ev 208 (Nuclear Industry Association)
196 Ev 205, para 15 (National Grid)
197 Ev 114, para 17 (ARUP)
198 Ev 150, para 44 (Department of Energy and Climate Change)
199 Ev 103, para 5.3 (ABB), Ev 116 (British Wind Energy Association), Ev 131, para 36 (Centrica), Ev 164 (Energy Networks Association), Ev 189, para 25 (Institution of Engineering and Technology), Ev 256, para 4.3 (Scottish Power), Ev 262, para 41 (Scottish Renewables), Ev 271, para 10 (Sussex Energy Group) and Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
particular concern was that ‘point to point’ connections would result in the construction of radial transmission lines dedicated to individual wind farms, leaving little scope for the later development of an integrated offshore network that may connect together a number of different projects in the future. Many believe this will result in the construction of connections in a piecemeal fashion and the evolution of a sub-optimal offshore network that is more costly and less efficient. The Association of Electricity Producers (AEP), for example, argued that the Government instead needed to adopt a more holistic approach, ensuring the development of connections for the first offshore wind farms was in line with what would be required in the future when the much larger Round 3 schemes start to come on-stream—investment ahead of need in the same way that Ofgem is implementing for the onshore network.\footnote{Ev 112, para 26 (Association of Electricity Producers)} Scottish Renewables argued too that such an approach would facilitate the greater interconnection of the British and European electricity networks.\footnote{Ev 262, para 43 (Scottish Renewables)} As one witness said: “A strategic and coordinated approach to offshore subsea networks which link offshore renewables and also interconnect with Europe will deliver a better solution in the long term”.\footnote{Ev 103, para 5.3 (ABB)} One approach suggested by the British Wind Energy Association (BWEA) was for the appointment of a single OFTO for each of the Round 3 zones. They would be responsible for connecting a number of schemes in the same geographical area. This, BWEA argues, would allow them to adopt a more coordinated approach, investing in a transmission link to the onshore network early on that provided efficient connection for later projects.\footnote{Ev 116 (British Wind Energy Association)}

119. In response to these criticisms Ofgem told us the primary advantage of using ‘point to point’ links was that they helped ensure the timely connection of new offshore wind farms, which might otherwise be delayed if it adopted a more strategic approach.\footnote{Q 327 (Ofgem)} It noted too that OFTOs’ licences would include headroom of up to 20%, allowing them to extend further their cable or develop a small network within clusters of wind farms.\footnote{Ibid.} Elsewhere, the Minister argued ‘point to point’ connections were more cost-effective.\footnote{Q 411 (Minister for Energy)} The construction of even simple offshore infrastructure is expensive and involves technical challenges. As one witness said, there is “a simple technical and economic argument that tells you to [use] ‘point to point’ for these sorts of amounts”, referring to the size of the current Round 1 and 2 schemes.\footnote{Q 38 (Prof Goran Strbac, Imperial College London)} Finally, the Chief Executive of the regulator also noted that the asset bases of the transmission companies impacts upon their stock market value. As such it was unsurprising they would oppose the auctioning of offshore transmission licences whilst advocating investment in network assets ahead of need.\footnote{Q 330 (Ofgem)}

120. Connecting the first three rounds of licences for offshore wind farms will require a capital investment of £15 billion—twice the value of the existing onshore transmission

\addcontentsline{toc}{section}{References}
network. We therefore note the auctioning approach for the delivery of future offshore transmission links to ensure costs are minimised for the consumer. In the short to medium term this will lead to the direct ‘point-to-point’ connection of Round 1 and 2 wind farms as the most cost-effective and technically feasible way forward, which also militates against the possibility of delays. However, risks remain, particularly if companies underestimate the cost of the work for which they have tendered. This means the Department and Ofgem must keep its approach under review. Moreover, it is not yet clear how the present framework will deliver the most efficient network solution to connect the 33 GW of offshore wind that is possible under Round 3. There remains a risk that the current approach could lead to the piecemeal development of the offshore network that is less cost-effective in the long run. We note that the Department merely believes that zone-based approaches to connecting wind farms onshore will develop. We do not consider this is a sufficiently robust approach, and recommend the regulator conducts more analysis to develop a route-map of how it expects the competitive tendering regime to evolve to meet this long-term challenge.

Interconnection

121. The anticipated expansion of wind generation in Britain has led to greater discussion of the potential role of interconnection in the energy system. This is the trading of electricity between countries through grid connections known as interconnectors. At present the GB system has two such links—one with France and another with Northern Ireland. Under European law, interconnectors may be funded as regulated assets, which means consumers are exposed to the risks of their costs exceeding the benefits. However, under certain conditions a merchant approach is permitted that allows investor-led companies to build interconnectors themselves.209 At present a number of projects are in development under the latter method. A link with the Netherlands is under construction and projects are at an advanced stage of planning for new links with Belgium, Ireland and France. Proponents argue there are two main benefits to greater interconnection—improved security of supply and greater competition. In this section we consider each of these in turn, as well as alternatives to interconnection. We then assess the potential of the next generation of interconnection in the form of a European ‘super-grid’.

Security of supply

122. One of the main advantages of linking the GB electricity grid to other markets is that interconnectors can provide balancing services when there is either a shortage or a surplus on the system. In so doing they can help ensure security of supply. Most of our witnesses acknowledged the importance of this role.210 Interconnection will also have a part to play in managing the impacts of intermittency as the level of wind generation in Britain increases.211 Work conducted by the Centre for Sustainable Energy and Distributed

---

209 Ev 214, para 5.3 (Ofgem)

210 Ev 103, para 6.1 (ABB), Ev 132, para 41 (Centrica), Ev 135, para 14 (Chemical Industries Association), Ev 151, para 50 (Department of Energy and Climate Change), Ev 164 (Energy Networks Association), Ev 176, para 3.20 (E.ON UK), Ev 205, para 19 (National Grid), Ev 237 (Scottish Chambers of Commerce) and Ev 275 (Town and Country Planning Association)

211 Ibid. and Ev 104, para 1.5 (Areva), Ev 112, para 28 (Association of Electricity Producers), Ev 116 (British Wind Energy Association), Ev 208 (Nuclear Industry Association), Ev 214, para 5.1 (Ofgem), Ev 229, para 29 (Renewable Energy Association) and Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
Generation (SEDG) suggests that wind curtailments on the GB system may become material when the level of wind penetration exceeds 20%. This would be particularly prominent when low demand conditions coincide with high wind outputs. Excess supply could also lead to within-day collapses in electricity prices, and even negative prices. Such price volatility would undermine the investment case for new generation capacity. However, many believe greater interconnection would allow wind farms to maintain output, exporting surplus electricity to neighbouring countries. In turn, during spells of low generation, the system operator would potentially draw from reserve capacity in other countries. Overall, this would reduce the need for domestic reserve capacity and help ensure generating assets are used more efficiently, thus reducing costs for consumers.

123. Denmark, which has a high penetration of wind generation, already uses this approach—interconnections with Germany, Norway and Sweden allow it to export excess wind power during periods of low demand and, at other times, draw on the Nordic countries’ vast hydroelectric resources. However, Denmark’s size in relation to its neighbours enables the management of output fluctuations fairly easily. The balancing services the GB system may require, if over a quarter of the electricity mix was wind, would be an order of magnitude greater. This suggests it would be difficult to manage wind intermittency even if there were a number of interconnections. Moreover, as one witness noted: “weather fronts are, in fact, bigger than countries”. It is likely that when wind generation is high on the GB system, the same will be true in neighbouring countries. This would reduce the system operator’s ability to export excess supply.

124. Some witnesses questioned too the overall value of interconnection as a means of securing electricity supplies. Dr Michael Pollitt told us there is tentative evidence that greater links between power control areas actually increases the risk of multinational blackouts. This may be attributed to the additional complexity of system operation over different jurisdictions, and the greater vulnerability of an interconnected network to disturbances arising in other countries.

**Competition**

125. Another potential outcome of more closely linking the GB system with other countries is that consumers may profit from greater competition in electricity supply. However, several of our witnesses were sceptical of any such benefits, not least because four of the ‘Big 6’ energy suppliers in Britain are already European companies. The Chemical Energy Centre for Sustainable Energy and Distributed Generation, *Economic and Environmental Impact of Dynamic Demand*, November 2008

---

212 Centre for Sustainable Energy and Distributed Generation, *Economic and Environmental Impact of Dynamic Demand*, November 2008
214 Quoted by Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
215 Ev 176, para 3.20 (E.ON UK)
216 Q 41 (Prof Goran Strbac, Imperial College London)
217 Ev 176, para 3.20 (E.ON UK) and Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
218 Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
219 Ev 105, para 5.2 (Areva) and Ev 114, para 20 (ARUP)
220 Ev 180, para 8 (ESBI) and Ev 205, para 18 (National Grid)
Industries Association noted: “The UK is effectively on the end of the European network and there is a risk of gaming where pan-European suppliers can make more profit by ensuring shortage of supplies to the UK”.\textsuperscript{221} Ofgem too argued there is “the potential for exposure to less competitive and less transparent markets”.\textsuperscript{222} It pointed to current and past experience in Britain’s interaction with the European gas network, where there is a greater level of interconnection. There the relative lack of liberalisation on the Continent has arguably led to the British gas market acting as ‘lender of last resort’ to the European system.\textsuperscript{223} Nor has interconnection for gas prevented large price spikes during times of short supply. Dr Michael Pollitt told us that, given the interaction of the gas and electricity markets in Britain, improving the competitiveness of the European gas market might prove a more cost-effective pursuit than trading electricity.\textsuperscript{224}

\textbf{Demand flexibility and fuel substitution}

126. Although interconnection has a role to play in managing wind intermittency there are also other solutions. In Chapter 2 we examined how greater flexibility and integration of demand through smart grid technologies will be crucial in providing balancing services across the network. Smart metering could also facilitate greater fuel substitution where excess electricity could be channelled into domestic water and space heating thermal storage that would otherwise use gas.\textsuperscript{225} Denmark has recently begun to adopt a similar approach, preferring to make use of its excess renewable generation to provide heating rather than exporting it at very low prices. Prof Goran Strbac told us the future energy storage capacity of the heating and transport sectors, through the integration of demand and generation, has a much greater potential to provide balancing services than further interconnection.\textsuperscript{226}

127. As the level of wind generation in the electricity mix increases over the next decade, its intermittency and unpredictability will make it increasingly difficult for the system operator to balance supply and demand. A potential solution may be greater interconnection with European networks. However, the lack of progress in liberalising the European energy sector, means Britain risks tying itself closer to markets that lack competition and transparency, as has already happened, many would argue to its detriment, in the gas sector. The Government should continue its efforts to ensure the European Union makes rapid progress on implementing full transparency of Member States’ energy sectors so that the UK is not further disadvantaged. In addition, it is not yet clear to what extent the GB system would be able to rely on other countries to provide balancing services, given weather systems rarely conform to national boundaries. The regulator should, therefore, proceed with caution in licensing future interconnection. Moreover, the electrification of the transport and heating sectors combined with active management of demand through smart grid technologies could

\begin{itemize}
\item \textsuperscript{221} Ev 135, para 13 (Chemical Industries Association)
\item \textsuperscript{222} Ev 214, para 5.2 (Ofgem)
\item \textsuperscript{223} House of Commons Business and Enterprise Committee Eleventh Report of Session 2007-08, \textit{Energy prices, fuel poverty and Ofgem}, July 2008, HC 293
\item \textsuperscript{224} Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
\item \textsuperscript{225} Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
\item \textsuperscript{226} Q 41 (Prof Goran Strbac, Imperial College London)
\end{itemize}
provide a means of managing wind intermittency in the future. We believe it will be necessary to attain a clear view of the cost/benefits of interconnection in the context of UK energy security and the balancing of services, and recommend that Ofgem conducts research to better establish this view.

**The ‘super-grid’**

128. In addition to the growth of interconnection, the idea of a European ‘super-grid’ has gained recent attention. This would connect European electricity markets with renewable energy sources at the boundaries of the system, such as offshore wind from the North Sea and Baltic Seas, hydropower from Scandinavia, and in the long term, solar power from North Africa. Supply and demand would be linked through dedicated very high voltage (HVDC) transmission lines. Various super-grid concepts have been proposed over time. One, the Desertec Industrial Initiative, launched in 2009, would see concentrating solar power systems and wind farms located over 6,500 square miles of the Sahara Desert. Requiring a substantial investment, it could provide up to 15% of Europe’s electricity needs by 2050.

129. The main advantages of the ‘super-grid’ are similar to those for greater interconnection in terms of ensuring security of supply and creating a pan-European market for electricity. It could also make a significant contribution to European efforts to decarbonise electricity generation, as well as having financial benefits for the North African countries involved. However, there would be a number of challenges. First, there are the technical and engineering difficulties that such a project would entail. The Institution of Engineering and Technology told us that whilst these were surmountable in theory, it was still the case that any such project would be the first of its kind so more work would be necessary to establish feasibility. Linked to this is the skills capacity required to deliver such a project. As the union Prospect told us: “This cannot simply happen overnight and requires a whole set of engineering skill sets in designing, specifying, planning, building, testing and operating the network”. A third concern is the regulatory challenge of harmonising grid codes and standards across the various jurisdictions covered by the ‘super-grid’. Finally, timely delivery of the network assets may also prove difficult, especially as the deployment of offshore wind in the North Sea is already underway. The Department told us it would not want to see the development of a super-grid delaying its plans for offshore wind.

130. Some witnesses raised questions about the security of supply benefits that a super-grid would bring. Primary among these are the geopolitical implications of being dependent on North African states for a large proportion of our energy needs. The Institution of Engineering and Technology likened the potential outcome to current concerns over

---

227 Ev 151, para 51 (Department of Energy and Climate Change)
228 Q 295 (Institution of Engineering and Technology)
229 Ev 223, para 13 (Prospect)
230 Ev 257, para 5.1 (Scottish Power)
231 Ev 151, para 53 (Department of Energy and Climate Change)
232 Q 41 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
European dependency on Russian gas.\textsuperscript{233} Moreover, the Minister acknowledged: “cross-border pipelines in countries where political stability is not always there does present a risk […]”.\textsuperscript{234} Initial costs were also a significant concern.\textsuperscript{235} It was argued that the required outlay would displace domestic investment in network and renewable generation infrastructure.\textsuperscript{236}

131. To date, the Government has taken a cautious approach in engaging with the super-grid proposals. The Department told us it believed: “the costs and benefits […] relative to the alternatives are not well-understood”.\textsuperscript{237} The Minister said, however, that they were prepared to engage on the issue and that DECC was part of a European Commission working group looking at a potential North Sea project.\textsuperscript{238} The Government was also maintaining contact with its EU counterparts on potential plans for a super-grid connection with North Africa.\textsuperscript{239} He noted too that the case for investing in the super-grid would depend on its cost-effectiveness relative to other means of ensuring security of supply, such as demand flexibility discussed above, or more sophisticated energy efficiency measures.\textsuperscript{240}

132. The ‘super-grid’ could make a significant contribution to a low-carbon economy. However, there are major technical and regulatory challenges, while the necessary funding would likely require the redirecting of capital from domestic investment in network and renewable energy infrastructure. The super-grid would have some energy security benefits such as reducing Britain’s exposure to fossil fuel price volatility, but would also bring with it new energy security risks, for example, through a new energy dependency on North African countries. We recommend the Government remains engaged at a European level in exploring the super-grid’s potential. Any future decision to invest would require a robust analysis of the scheme’s cost-effectiveness relative to other means of securing electricity supplies, such as greater demand flexibility.

\textsuperscript{233} Q 295 (Institution of Engineering and Technology)
\textsuperscript{234} Q 428 (Minster for Energy)
\textsuperscript{235} Q 39 (Dr Michael Pollitt, Judge Business School, University of Cambridge); Ev 176, para 3.21 (E.ON UK)
\textsuperscript{236} Ev 182 (Helius Energy)
\textsuperscript{237} Ev 151, para 52 (Department of Energy and Climate Change)
\textsuperscript{238} Q 425 (Minister for Energy)
\textsuperscript{239} Ev 151, para 52 (Department of Energy and Climate Change)
\textsuperscript{240} Q 429 (Minister for Energy)
4 Making distribution smarter

133. Massive investment in Britain’s distribution networks took place in the 1950s and 1960s, and now, as with the transmission system, many of these assets are coming to the end of their natural life. The need for renewal provides an opportunity to ‘future proof’ the networks, allowing flexibility to incorporate new technologies.\(^{241}\) In this Chapter we look at the changing role of the distribution networks; the importance of investment and innovation for developing a smart grid; and the current means by which distribution network operators (DNOs) recoup their costs.

The changing role of distribution

134. Britain’s 14 distribution networks deliver electricity from the transmission system to consumers via successive stages of transformation from higher to lower voltage systems. Power flows in one direction and is fairly predictable in terms of daily and seasonal demand fluctuations. This traditional approach could face a major shake-up with the development of more active management of the networks by the DNOs. As a chief executive of one of the companies told us: “[…] the role of the distribution network will be very different in five, 10, 15 or 20 years’ time”.\(^{242}\) In this section we consider the various developments in electricity generation and consumption that will facilitate the creation of a smart grid that involves active demand-side participation, and some of the technical and regulatory challenges which must be overcome.

Greater distributed generation

135. Since the introduction of the Renewables Obligation (RO) in 2002 there has been a steady increase in the number of renewables projects, mainly wind farms, connecting at the distribution level, either because they are too small or not close enough to connect to the transmission system. This is known as distributed or embedded generation. The Government’s target for 15% renewable energy by 2020 may lead to an increase in the amount of new distributed generation coming on-stream in the next decade. In addition, from 2010 feed-in tariffs will provide financial support for new small-scale low-carbon electricity generation up to 5 MW. The Department hopes this will encourage households, communities and organisations, such as schools, hospitals, universities and businesses to consider installing renewable technologies, such as wind turbines, combined heat and power systems or solar photovoltaics.\(^{243}\) This smaller type of generating capacity is usually referred to as microgeneration.

136. The distribution networks are able to manage easily the level of generating capacity currently connecting to their systems. The Minister told us up to 3.5 GW of microgeneration could be absorbed without the need for network reinforcement.\(^{244}\) There is also substantial headroom for larger forms of distributed generation, depending on its

\(^{241}\) Ev 152, para 57 (Department of Energy and Climate Change)

\(^{242}\) Q 235 (Electricity North West Ltd)

\(^{243}\) Ev 151, para 46 (Department of Energy and Climate Change)

\(^{244}\) Q 385 (Minister for Energy)
size and location. Moreover, financing and planning consent are currently the main barriers to new distributed generation. It is not yet clear what impact the new feed-in tariffs will have. The Institution of Engineering and Technology told us, however, that as the level of capacity grows beyond a certain point, the cost of connecting it would increase significantly. Investment in the distribution networks is, therefore, important to create more flexibility before the system reaches this ‘knee point’.

Changes in demand

137. In addition to changes in the supply of electricity at a local and household level, the next decade will see developments in how consumers use energy. One area will be the take-up of electric vehicles. Though still at an embryonic stage, the electrification of the transport sector could be a key part of a future decarbonised energy system. Space heating too could largely be provided by electricity. The resulting changes to the demand profile of households and businesses will present new challenges to the design and operation of the distribution networks. The heating and transport sectors will also have the potential to provide a significant energy storage capacity that has, hitherto, not existed. We examined in Chapter 2 the role this could play in coping with the intermittency of wind generation, thus allowing a greater level of distributed generation to connect to the networks than would otherwise be the case.

138. Further changes on the demand side should arise from the national roll-out of smart meters to all households over the next decade. They will provide real-time information to consumers about their energy usage, which will be relayed automatically to electricity suppliers. The Government believes smart metering will make households more aware of how they use energy, hopefully resulting in behavioural changes that reduce their consumption. Smart meters could also allow companies to offer more sophisticated pricing tariffs that enable customers to manage their demand so they consume more during periods when the system is less constrained. Looking further ahead, it is envisaged that energy companies could control remotely household appliances, determining the operation of washing machines, dish washers and immersion heaters overnight, for example, according to the availability of supply. The charging of electric vehicles could also be managed in the same way. Hence, smart meters are seen as a vital enabling technology for the creation of a smart grid.

Technical and regulatory challenges

139. Smart metering and financial incentives for household and community renewables provide the means for people to become more engaged with their energy consumption, and their potential role in reducing carbon emissions. Although, as one witness noted,

245 Q 335 (Ofgem)
246 Q 242 (CE Electric UK)
247 Q 296 (Institution of Engineering and Technology)
248 Ev 103, para 7.1 (ABB)
249 Ev 152, para 58 (Department of Energy and Climate Change), Ev 206, para 25 (National Grid) and Ev 258, para 9.4 (Scottish Power)
250 Qq 248 (CE Electric UK) and 41 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
consumers “[…] will always be more interested in soap operas than in exactly how the power system is being balanced”. 251 Therefore, if DNOs are to manage greater levels of distributed generation, and make best use of the flexibility provided by the remote operation of appliances and vehicle charging, they will have to play a more active role in managing electricity demand and supply across their networks. 252 At the same time, a large expansion in the level of distributed generation could in the future give rise to situations where the distribution system exports electricity back into the high voltage transmission network. This will require an additional role for the DNO in managing power flows at the interface of the distribution and transmission networks. Whereas at present there is only one system operator, National Grid, which balances demand and supply across the entire system, it is possible to envisage a situation where the DNO may become a system operator as well. 253 The Minister told us that at present this issue was “an open question”. 254

140. Creating a smart grid poses regulatory challenges. For example, the introduction of EU electro-technical standards for household appliances will provide the necessary functionality for the development of ‘smart demand’. 255 Elsewhere, DNOs will need the appropriate incentives to encourage them to take a more active role in managing their networks. Dr Jim Watson told us: “the rules and regulations we have are designed for the incumbent system and they have served us well, but they will probably have to change fairly radically […]”. 256 Phil Baker and Dr Bridget Woodman of the University of Exeter noted: “there are few incentives for DNOs to invest in technologies, which would allow their networks to be more actively managed”. 257 Prof Goran Strbac noted, for example, that electricity sold on the wholesale market can more than double in cost by the time it reaches consumers, reflecting the cost of transmission and distribution services to transport the electricity from the generator to the customer. In contrast, distributed generation that is located near to the source of demand may circumvent these costs and, therefore, have a higher value than conventional generation. However, these potential benefits are not fully recognised within the regulatory framework. Prof Strbac told us: “Realising the value of distributed generation and responsive demand […] requires the creation of a level playing field”. 258 This means fair treatment in terms of network access and charging for both generation and demand, and within the BETTA market.

141. There are also technical challenges involved in the delivery of a smart grid. The distribution networks were not designed to accommodate large volumes of small and medium-scale generation. Potential difficulties include: accommodating bi-directional power flows; maintaining electricity flows at a level that is consistent with equipment ratings; ensuring voltage variations remain within safe and statutory limits; and ensuring power flows from local generation do not create short-circuit currents in the event of

251 Q 256 (CE Electric)
252 Ev 152, para 56 (Department of Energy and Climate Change) and Ev 258, para 6.9 (Scottish Power)
253 Q 339 (Ofgem)
254 Q 423 (Minister for Energy)
255 Ev 190, para 41 (Institution of Engineering and Technology)
256 Q 2 (Dr Jim Watson, Sussex Energy Group)
257 Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
258 Ev 264 (Prof Goran Strbac, Imperial College London)
network faults.259 Several witnesses told us many of these issues are already well-understood by engineers, though there is a lack of experience to date in applying the solutions in a smart grid context.260 We discuss the available incentives to adopt new technologies later in this Chapter.

142. For DNOs to take on a system operator role will also require the installation of sophisticated information, communication and control technologies to monitor and control the electricity system.261 These will be needed to manage, for example, the potential unpredictability of greater levels of embedded generation. The ability for all parts of the system to communicate with one another will be a vital component of smart grids. This will require a highly capable communications platform, able to meet a demanding set of requirements, including coverage, reliability, responsiveness and security.

143. There are various technologies available in Britain that the communications regulator, Ofcom, is considering as options for providing smart grid services, including the 3G mobile network and fixed line broadband. However, countries such as the US that have already begun to deploy smart grid technologies have eschewed these solutions because they either do not provide reliable coverage or operate at sufficiently low cost. Instead, they have opted for a ‘wireless mesh’ approach. This is a communications network made up of radio nodes, which allows appliances and smart meters to speak to one other. The technology works best on sub-1 GHz spectrum because the radio waves can travel further and penetrate deeper. However, there is a lack of suitable spectrum currently available in the UK, which is preventing companies wishing to deploy the ‘wireless mesh’ approach from entering the market here. Ofcom is currently consulting on the future use of the 872-876 MHz and 917-921 MHz frequency bands, which could be ideally suited for smart grid use.262 One of the companies keen to develop ‘wireless mesh’ technology told the regulator that allocating this spectrum for the smart grid would “enable the rapid deployment of cost-effective, standards-based communications technology that will place the UK among the worldwide leaders in smart grid deployment”.263

144. In the future there could be potentially thousands of generators connected to the distribution networks at scales varying from domestic solar panels to large wind farms. Energy demand could also evolve and increase through the electrification of the transport and heating sectors. The deployment of smart grid technologies, such as smart meters, will therefore be crucial to the effective and economically efficient management of an increasingly complex energy system. This necessitates a fundamental rethink of the role of distribution companies who in the future will need to play a more active role in balancing demand and supply across their networks, potentially taking on a local system operator role.

---

259 Ev 164 and (Energy Networks Association) and Ev 278 (P.E. Baker and Dr B. Woodman, University of Exeter)
260 Qq 296 (Institution of Engineering and Technology) and (CE Electric UK)
261 Ev 176, para 3.23 (E.ON UK)
262 Ofcom, Consultation on the way forward for the future use of the band 872-876 MHz paired with 917-21 MHz, August 2009
263 Consultation Response by Silver Spring Networks
145. Creating smarter distribution poses significant challenges. Although many of the technical aspects are well-understood there is relatively little experience of their application to the smart grid. Furthermore, the regulatory framework does not at present provide a level playing field for the adoption of smart grid solutions, such as active demand management. Ofgem must address these issues in the coming years. One area in which we believe it could make an immediate difference is to work with Ofcom to ensure the allocation of suitable spectrum for smart grid use as soon as possible, thus enabling the full range of smart grid technologies to be considered for deployment in Britain.

**Investment**

146. The DNOs are regional monopolies. This means that, in the same way as for the transmission system, the ownership and operation of the distribution networks is permitted under licence from Ofgem, the terms of which restrict the revenue of each DNO. The regulator reviews these revenues every five years through a Distribution Price Control Review (DPCR) that, when agreed, establishes a programme of network investment the DNOs will carry out over the next five years. Ofgem operates an RPI-X approach, which links DNOs’ revenues to the rate of inflation, therefore encouraging them to make operational efficiencies. One of the companies, Electricity North West Ltd, told us since privatisation RPI-X regulation had led to firms halving their work forces and their costs, while doubling the quality of supply for consumers. These achievements are significant because electricity distribution accounts for around 17% of households’ bills as opposed to 4% for transmission.

147. The chief executive of one of the DNOs, CE Electric UK, told us “After 20 years of radical reductions the price cannot keep coming down and […] investments […] need to come forward now”. In 2009 Ofgem conducted its fifth DPCR, which will run from April 2010 to April 2015. One of its objectives is to allow companies to renew assets that have become age-expired, replacing them with higher specification equipment that will increase the capacity of the networks. Scottish and Southern Energy told us the review needed to provide “a stable platform for investment, adaptation and growth”. E.ON UK said: “The framework must also recognise the need to provide for network developments for both known connection projects, and also the expected large number of unknown connection and development requirements”. Electricity North West Ltd expressed a similar view, highlighting reinforcements in Cumbria and Manchester it could proceed with which would accelerate the connection of low-carbon generation in those areas.

148. In December 2009 Ofgem published the outcome of DPCR5. It has allowed the DNOs to collect revenues of around £22 billion over the five-year review period. Charges will rise by an average of 5.6% each year, although this will vary according to company, ranging

---

264 Ev 161, para 6.1 (Electricity North West Ltd)
265 Ev 232 (Scottish and Southern Energy)
266 Q 241 (CE Electric UK)
267 *ibid.*
268 Ev 175, para 3.11 (E.ON UK)
269 Ev 159, para 4.4 (Electricity North West Ltd)
from a fall of 4.3% per annum to a rise of 11.1%. The regulator estimates this will add an extra £4.30 each year to households’ bills. The DPCR also establishes clear outputs for each of the DNOs which they must deliver in return for the revenues they will receive from customers. This means they will not be able to outperform their settlement by allowing their networks to deteriorate. A key aspect of the review is the consideration given to the future role of distributed generation and demand-side management, acknowledging the fact that the previous regime had encouraged investment in transformers and cables over other potentially more cost-effective options. One way DPCR5 seeks to address this is through the equalisation of incentives so the regulatory framework will treat network investment, network operating costs and closely associated indirect costs in the same way. 270 We consider other outcomes of the DPCR in the remaining sections of this Chapter.

149. We welcome the outcome of Ofgem’s fifth distribution price control review (DPCR), which seems to balance the requirement for network renewal on the one hand, with the need to minimise the resulting impact on consumers’ bills on the other. However, the success or otherwise of the DPCR will need to be assessed against whether it encourages a significantly greater role for distributed generation and demand-side management within the energy system over the review period, and the extent to which it leads to the deployment of smart grid technologies.

The role of innovation

150. The creation of a smart grid will require significant investment in research, development and deployment (RD&D) by the transmission and distribution companies. It is an area where British industry is potentially well-positioned to be a world leader. The probable large expansion of renewable power over the next decade, combined with relatively little interconnection with other countries, means Britain will need to deploy smart grid technologies sooner than many other countries. 271 The rewards could be huge. The Department of Energy and Climate Change estimates the size of the global industry could be £27 billion over the next five years. 272 However, many of our witnesses told us current levels of RD&D expenditure by the industry were insufficient and that this was a direct consequence of the early RPI-X framework, which encouraged the minimisation of operating costs over the DPCR period by ‘sweating assets’, and did not reward investment in innovation that would reduce firms’ costs in the longer term. 273

151. In the last DPCR Ofgem acknowledged the impact the regulatory framework had had in running down RD&D levels by introducing two new incentive mechanisms for network companies—Registered Power Zones (RPZs) and the Innovation Funding Incentive (IFI). RPZs are a way of encouraging distribution companies to develop innovative ways of connecting distributed generation. One example is a scheme on the Orkney Islands that

270 Ofgem, Electricity Distribution Price Control Review Final Proposals, December 2009
271 Ev 254 (Scottish Power)
272 Department of Energy and Climate Change, Smarter Grids: The Opportunity, December 2009
273 Ev 116 (British Wind Energy Association), Ev 164 (Energy Networks Association), Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge), Ev 269, para 4.1 (Prof Goran Strbac, Imperial College London) and Ev 273, para 20 (Sussex Energy Group)
has used active network management technology to allow multiple renewable generators to connect to the system without the need for expensive network reinforcement. The Institution of Engineering and Technology described the RPZs as “world-class developments”. However, still only a handful have been established in the five years since the scheme’s introduction.

152. The IFI has fared similarly. It aims to encourage DNOs to invest in R&D that focuses on the technical aspects of network design, operation and maintenance. The Incentive allows companies to pass on to customers 80% of their R&D costs up to a maximum of 0.5% of their total revenues. The industry has generally welcomed the initiative. Scottish Power described it as a “resounding success”. Another said it was “excellent”. However, network companies have failed to make full use of the allowance. In 2007/08 National Grid spent £3 million on R&D, while the DNOs spent a total of £12.1 million, representing just 0.33% of their revenue, and well below the £5.4 million and £20 million respectively available to them. The Minister told us: “the kindest interpretation is that it reflected a rather static situation”. Although this represents a sizeable increase since 2005, when R&D activity for the DNOs totalled less than £1 million per annum, many feel the industry is still not investing enough given the scale of future investment required. As the Institution of Engineering and Technology put it: “There is [still] little culture of innovation in much of the industry”.

153. Whilst the very low base from which R&D has needed to grow is the primary reason for the slow take-up of the IFI, witnesses also told us the incentives themselves were not strong enough. Furthermore, one DNO described the rules governing the areas they could innovate in as “narrow and strict”. In response, some have called for the level of the IFI to be significantly increased up to 2% of network companies’ revenues and for its scope to be widened. However, in the latest DPCR Ofgem decided to keep it at 0.5%. The regulator noted in its submission that the underspend by network companies demonstrated the current provision was sufficient. It argued also, though, that one of the main challenges was in encouraging companies to apply the lessons learnt in the laboratory in commercial demonstrations. Several DNOs agreed with this view with one telling us:

---

274 Department of Energy and Climate Change, Smarter Grids: The Opportunity, December 2009
275 Q 282 (Institution of Engineering and Technology)
276 Ev 112, para 28 (ARUP), Ev 164 (Energy Networks Association), Ev 177, para 3.28 (E.ON UK) and 202 (National Grid)
277 Ev 259, para 10.1 (Scottish Power)
278 Ev 112, para 28 (ARUP)
279 Q 419 (Minister for Energy)
280 Ev 171 (Energy Technologies Institute), Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge) and Ev 274, para 25 (Sussex Energy Group)
281 Ev 191, para 50 (Institution of Engineering and Technology)
282 Ev 270 (Sussex Energy Group) and Ev 104 (Areva)
283 Q 245 (CE Electric UK)
284 Ev 202 (National Grid) and Ev 218 (Dr Michael Pollitt, Judge Business School, University of Cambridge)
285 Ev 216, para 10.2 (Ofgem)
286 Q 333 (Ofgem)
“We do not need to invent things that do not exist, but we do need to apply them and really understand how they would work”.287

154. Accordingly, in the new distribution price control period Ofgem introduced a £100 million per annum Low Carbon Networks (LCN) Fund, the aim of which is to encourage DNOs to trial the new technologies, systems, and commercial and network operating arrangements that are necessary for the deployment of the smart grid. The fund will provide 90% of the financing for projects with DNOs expected to make up the rest. Ofgem will allocate each of the firms a proportion of the funds, though it will distribute the majority (around £320 million) through competition. The regulator also wants the network companies to share learning and this will be a condition of their receiving funds. Firms that do not apply the lessons learnt from projects conducted under DPCR5 will not receive funding for their own trials in future price control periods.288 Ofgem hopes the IFI in combination with the LCN Fund will increase the level of RD&D within the networks sector to more than the 2.5% of revenue that is the Government’s economy-wide target.289

155. Looking to the future, the role of innovation in delivering the networks needed to support a low-carbon energy system forms a key part of Ofgem’s RPI-X@20 review. The regulator’s current emerging thinking is to introduce a single innovation stimulus for all the energy networks sectors that builds on the new LCN Fund. The regulator would also like it to be open to non-network parties, such as communications companies. Funding would be available for all types of innovation, ranging from R&D to commercial demonstration trials.290

156. Elsewhere, the Government has also made available greater public funding for R&D, including £30 million to support the infrastructure required for low emission vehicles, and £6 million for a Smart Grid Demonstration Fund. Further funding is also available through the Technology Strategy Board and the Energy Technologies Institute—a public/private partnership that aims to invest up to £110 million a year over the next decade on the development of low-carbon energy technologies, including the smart grid.291

157. The level of research and development conducted by the networks sector has risen significantly over the last five years, though still represents just 0.33% of firms’ income. If Britain is to be one of the first to deploy smart grid technologies on a wide scale, the industry must invest sufficiently to turn what is at present a vision into a reality. To the extent that the lack of R&D is a result of the rules governing companies’ expenditure under the Innovation Funding Incentive, Ofgem should look again at this matter. To the extent that the underspend is the result of the absence of a “culture of innovation”, the industry must accept that it has failed in its responsibilities and that it needs to show significant improvement not just in the interests of both the nation and the consumer, but also to grasp the huge opportunities that the global market offers.

287 Q 231 (CE Electric UK); and also Ev 177, para 3.28 (E.ON UK) and Ev 259, para 10.4 (Scottish Power)
288 Ofgem, Electricity Distribution Price Control Review Final Proposals, December 2009
289 Q 343 (Ofgem)
290 Ofgem, Regulating energy networks for the future: RPI-X@20 Emerging Thinking, January 2010
291 Ev 152, para 63 (Department of Energy and Climate Change)
158. We welcome the introduction of the Low Carbon Networks Fund and the continuation of the Innovation Funding Incentive. We recommend Ofgem keeps both these mechanisms under review with the aim of increasing the available funding for both within the current distribution price control period if there is demand. We welcome also new public sector funding for smart grid demonstrations, and hope the Government will continue to support this area despite the current fiscal constraints.

Embedded benefits

159. In Chapter 3 we examined how National Grid levies Transmission Network Use of System (TNUoS) charges on generators and demand to cover the costs of maintaining and operating the grid. These charges consist of locational tariffs and additional flat tariffs, known as the residual. The current framework for transmission charging treats distributed generation as negative demand. In other words, it is seen as offsetting local demand. Because of this, distributed generators do not pay the TNUoS generation tariff and also usually receive a payment from the TNUoS demand tariff. In simple terms, because such generators are nearer to the point of end-use for electricity, they have historically avoided the charges associated with transmitting power over the transmission system. This is known as an embedded benefit.

160. Since the establishment of the British Electricity Trading and Transmission Arrangements (BETTA) in 2005 Ofgem and National Grid have been concerned about the treatment of distributed generation within the charging regime. Both believe there is a case for generators paying the non-locational part of the TNUoS generation charges, and no longer receiving a payment through the non-locational part of the TNUoS demand tariff. In other words, they argue that if generators were charged on a cost-reflective basis they should only receive a reward from the part of the TNUoS charges that relate to location. The residual element is the largest part of the TNUoS charges. National Grid estimates that if distributed generators only received the embedded benefit from the locational element of the charges, then it would fall from around £20 per kW to between £6.25 and £7.25 per kW.292

161. The regulator has placed a licence condition on National Grid to implement an enduring set of arrangements by 2011. Accordingly, in January 2010 the company published a pre-consultation on modification GB ECM-23, which proposes two models. National Grid’s preferred option would treat output from distributed generation and transmission-connected generation as having a broadly similar impact on the need for transmission infrastructure investment. Distributed generators would pay both the Transmission Network Use of System (TNUoS) and the Balancing Services Use of System (BSUoS) generation tariffs that are also levied on transmission-connected generation, minus a discount that reflected the avoided local investment.

162. The second option would still treat embedded generation as negative demand, but it would pay for the net electricity flow that physically passes onto or off the transmission system. This approach is supported strongly by the renewables industry, though National Grid believes this option would not treat transmission and distribution-connected

292 National Grid, Pre-Consultation: GB ECM-23 Transmission Arrangements for Distributed Generation, January 2010
generation in the same way in terms of the costs they incur across the whole network.\textsuperscript{293} The firm also believes it would be more expensive and time-consuming to implement. In evidence to the Committee the Minister agreed that reform of the treatment of distributed generation would be necessary, stating: “[…] on a network with a lot more DG capacity, there may be a case for looking at whether the charging principles as they stand at the moment are right”.\textsuperscript{294}

163. Generators connected to the distribution networks do not currently pay transmission network use of system charges because it is assumed their output is absorbed by local demand and therefore reduces the need for transmission capacity—a concept known as ‘embedded benefits’. The level of distributed generation, particularly renewables, could increase significantly in the next decade, to the extent that local supply will at times exceed local demand, resulting in spillovers back into the transmission system. Moreover, where renewable generation is intermittent, transmission capacity will still be necessary to respond to shortfalls in supply. For this reason, the current treatment of embedded generation is not sustainable in the long run.

164. Because the proportion of distributed generation in the electricity mix is still very low, there is no need for Ofgem and the industry to reach an immediate decision on an enduring set of arrangements. Instead, it should wait until it can be shown clearly that distributed generation is impacting on the transmission system. We recommend the regulator develops a set of criteria to determine when it would be appropriate to reconsider this issue as the risk of change too soon is that it may exacerbate the ‘lock-in’ of a centralised energy system. Central to the debate over the two options proposed by National Grid is the question of whether in the future there should be separate regulatory frameworks for the distribution and transmission networks, or if there is a case for regulating the whole system as a single entity. The regulator must resolve this question first, which forms part of its RPI-X@20 review, before it can conclude on an enduring set of charging arrangements for distributed generation.
5 Network skills

165. The creation of a smart grid in Britain will not be possible without a skilled networks workforce capable of meeting the challenges posed by the need to move towards a low-carbon economy. In this Chapter we examine the current make-up of the sector’s workforce and the difficulties it faces. We then consider the current public sector and/or industry-led initiatives that work to raise the profile of the sector and improve its skills base.

Current challenges

166. The sector skills council, Energy and Utility (EU) Skills, characterised the workforce of the energy sector as predominantly white, male and middle-aged.295 The bulk of those currently employed started working in the sector during the 1970s and the Department expects the industry to reach a retirement peak in 2023.296 At the same time, there also appears to be a decline in the number of students studying science subjects from 16 to 18, combined with a dramatic reduction in the number of engineering graduates.297 This is a concern not just for the networks sector, but for the whole energy industry.

167. In addition to demographic factors, the overall size of the networks workforce has also fallen over time because of regulation. Earlier in this Report we examined the impact the RPI-X framework had in reducing firms’ capacity to innovate. The focus on reducing operating expenditure has also led to many companies reducing their headcount as well as cutting the level of training provided.298 Unite—the union told us some distribution network owners (DNOs) did not carry out any training whatsoever.299 EU Skills argued that the regulatory framework also meant contractors in the supply chain for the DNOs operated on shorter-term contracts that fitted within the five-yearly distribution price control review (DPCR) period, reducing their incentive to invest long-term in skills.300

168. However, the networks sector faces a range of new challenges over the next decade as the Government seeks to achieve its targets for renewable energy and carbon emissions. The greater complexity of the energy system resulting from the shift towards more active network management will require the application of new skills. The Renewable Energy Association also told us it was highly likely that a lack of electrical engineers would hamper the deployment of a large increase in renewable generation.301 Elsewhere, the Department noted that offshore networks will call for skills and experience with high voltage direct current (HVDC) connections, which are at present rare in Britain.302 The Institution of Engineering and Technology said too that the development of smart grids will also require

295 Ev 163, para 18 (Energy and Utility Skills)
296 Q 430 (Minister for Energy)
297 Ev 162, para 13 (Energy and Utility Skills)
298 Ev 163, para 14 (Energy and Utility Skills) and Ev 223, para 10 (Prospect)
299 Ev 278, para 4 (Unite—the union)
300 Q 127 (Energy and Utility Skills)
301 Ev 229, para 25 (Renewable Energy Association)
302 Ev 150, para 36 (Department of Energy and Climate Change)
the industry to persuade consumers that their demand must play a greater role in managing the system. This will call for skills from the social sciences, such as psychology, that have not been applied to this field before. The sector skills council summarised the potential situation, stating: “there is a 50-year programme of work that we need to do […] This is an exciting agenda”.

169. The industry faces a massive recruitment challenge. Energy and Utility Skills estimates around 9,000 additional skilled employees, split between the distribution companies and their external contractors, will be necessary to deliver the investment set out in DPCR5. This corresponds to roughly half the existing sector workforce. Skilled workers will be required at all levels, including craft and technician apprentices as well as electrical engineers.

170. EU Skills believes that improving the UK’s record on network skills presents a major opportunity for it to become an exporter of new technology services. However, there are some significant challenges to achieving this aspiration. First, there is a negative perception of the industry, which is seen as being of lower status and poorly paid in comparison to other professions. The Institution of Engineering and Technology contrasted this attitude with that held by students in China and India where engineering is seen as a prestigious occupation. The Energy Networks Association acknowledged the networks sector needed to become “more ‘career attractive’ to young people”. Even where people are attracted into the industry, it takes time to train them. The union Prospect told us it can take up to five years to turn a good engineering recruit into an effective engineer, and at least another five years for them to acquire the skills required to deliver the kinds of new investment projects expected in the future. Moreover, the sector’s capacity to train new workers is also limited. The sector skills council acknowledged all of these concerns, noting: “[…] the option of doing nothing is not available”.

**Action to address the skills gap**

171. There are currently various initiatives that are seeking to address the skills gap in the networks sector. In 2007 EU Skills established the Power Sector Skills Strategy Group (PSSSG), which is an energy sector-wide group working to address strategic skills issues in the medium and long term. It has developed a strategy for the 2010-15 period, which,
among others, aims to develop industry thinking on the impact of new technologies and demands on craft, technical and engineering skills; promote careers in the power sector; and improve the attractiveness of the industry to under-represented groups.\textsuperscript{315}

172. The PSSSG and EU Skills are also working together to develop the National Skills Academy for Power. Still at the business planning phase, this will provide national co-ordination of regional clusters of existing training providers. These may include network companies’ own training provision, as well as further and higher education, and private sector providers. EU Skills told us its main priorities would be: to raise the skills of the existing workforce, particularly at the craft and technician level; working with schools to improve the attractiveness of the sector; and working collaboratively with the higher education sector.\textsuperscript{316} Elsewhere, the Institution of Engineering and Technology runs the IET Power Academy which is a partnership of academic institutions and energy companies that provides financial support for students wishing to study engineering.\textsuperscript{317} The Centre for Sustainable Energy and Distributed Generation, which is an academic centre established by the former Department of Trade and Industry, has also received praise for its research on networks in recent years.\textsuperscript{318}

173. Finally, whilst the industry must lead in tackling the skills shortage it faces, the regulatory framework must also play a role by providing the right incentives for companies to invest in their employees. EU Skills told us: “[…] there needs to be an understanding of how the regulatory framework can be more helpful to long-term skills investment and the cost of that investment as well”.\textsuperscript{319} It is unfortunate then that Ofgem’s recent emerging thinking paper for its RPI-X@20 review makes no reference to the importance of long-term investment in skills in the same way that it has considered incentives for innovation.

174. The transition to a low-carbon economy will require trained people that have the skills to deliver the many challenges the networks face in the coming years. Yet an aging workforce and a lack of new recruits mean the industry currently faces an acute skills shortage. This problem has been exacerbated by a regulatory framework that has reduced firms’ expenditure on skills over time. We welcome the establishment of the National Skills Academy for Power, but believe DECC and the Department for Business, Innovation and Skills need to do more to inspire young people and graduates to take up a career in the energy sector. Network companies too should face improved incentives through the price control reviews. Accordingly, this must form a key part of Ofgem’s RPI-X@20 review. Looking forward, firms must also accept their role in ensuring employees have the opportunity to improve their skills. A skilled workforce will be crucial to the development of a cost-effective low-carbon energy system. As one witness put it: “Without the broad skills of all participants within the sector, the UK faces a dirtier, more expensive and less efficient future”.\textsuperscript{320}

\textsuperscript{315} Power Sector Skills Strategy Group, \textit{Power Sector Skills Strategy 2010-15}
\textsuperscript{316} Q 117 (Energy and Utility Skills)
\textsuperscript{317} Ev 189, para 24 (Institution of Engineering and Technology)
\textsuperscript{318} Ev 160, para 4.8 (Electricity North West Ltd)
\textsuperscript{319} Q 128 (Energy and Utility Skills)
\textsuperscript{320} Ev 162, para 10 (Energy and Utility Skills)
Conclusions and recommendations

Does Britain need a vision?

1. The transition to a low-carbon economy will transform the role of our electricity networks over the next 40 years. Whereas today the networks are seen as a means to an end in the transportation of electricity from generators to consumers, in the future they will play an integral and active role, enabling supply and demand to be managed in a much more complex and decentralised energy system. The market alone will not be able to deliver these changes—it requires strategic leadership from Government delivering a vision for the future that engages actively both consumers and the energy sector. (Paragraph 13)

Building a long-term vision

2. Although we know with some confidence how the electricity mix will evolve in the run up to 2020, there is much less certainty over what a completely decarbonised energy system might look like in the long run. The Government’s vision for the future of our electricity networks must take account of the range of possible scenarios for the evolution of the energy mix, ensuring it does not lock Britain into a particular outcome at an early stage. (Paragraph 19)

3. Whatever the scenarios for the future development of the electricity mix, it is likely that they will include a much higher proportion of generating capacity that is not able to respond easily to demand. The only cost-effective response is for demand itself to be more flexible and play a more active role in the management of our energy system. This should sit at the core of the Government’s vision for Britain’s electricity networks. (Paragraph 27)

4. The regulatory framework will need to adapt to meet the new challenges of facilitating the transition to a low-carbon economy, whilst ensuring security of supply. As such, we welcome Ofgem’s current RPI-X@20 review. At the same time as ensuring flexibility in the potential outcome for how the networks might evolve, it is important that reforms arising from the review and the Government’s vision for the electricity networks take account of the need for long-term regulatory and policy stability to give firms the confidence to make the investments required. (Paragraph 30)

5. Britain’s networks sector currently has a hybrid structure that is largely the result of the evolving regulatory framework since privatisation. Whilst it may be adequate for now, the transition to a low-carbon energy system may require a different organisation of the industry. The Government and the regulator should not be afraid to allow this to happen, whether through regulation or otherwise, so long as it provides transparent and fair access to natural monopoly network assets for both generators and consumers. In particular, we recommend Ofgem monitors closely the market behaviour of the two vertically integrated Scottish firms. These arrangements could be changed if they are found to be detrimental to consumers. (Paragraph 35)
6. We note the progress the Department has made in beginning to develop a strategic vision for how Britain’s electricity networks will evolve over time. In preparing a road map for delivery of the smart grid, it should take account of the following principles:

- The need to avoid locking the UK into a particular outcome for the future energy mix at an early stage;
- Integration and management of energy demand within the energy system;
- Minimisation of regulatory and policy uncertainty for network companies who must invest in network assets; and
- The possibility of a new industrial structure emerging over time. (Paragraph 38)

Transmission: the role of planning

7. Reform of the planning process is vital if network improvements are to be delivered on time to connect new generating capacity in the future. We note the recent changes to the planning systems in England and Wales, and Scotland, and are pleased to be playing a role in scrutinising the draft National Policy Statement for Electricity Networks Infrastructure. We hope the new system will lead to a faster decision-making process, but one that nonetheless will take account of the environmental concerns associated with new proposals. For this, developers have a duty to ensure their initial applications take adequate account of alternative options. The Government should also look closely at the consenting process for applications in England and Wales that will not fall to the Infrastructure Planning Commission to see whether reform or improved guidance is necessary at this level as well. (Paragraph 48)

Transmission: strategic investment

8. To avoid delays in connecting new power stations a more strategic approach to investment in transmission capacity is necessary. We welcome the Electricity Networks Strategy Group’s work to identify the reinforcements it believes are needed in the next ten years. We also note Ofgem’s cautious approach in allowing funding to advance particular projects and we urge them to be more proactive in promoting ways of avoiding delays. (Paragraph 58)

9. Given the costs involved, the resulting impact on customers’ bills, and the risks of delay, it is vital the case for investment is as robust as possible and preferable to any alternatives. There is some concern that the existing regulatory framework is driving the case for transmission investment presented by the industry at the expense of other more cost-effective options that seek better to utilise the existing network infrastructure. The current fundamental review of the Security and Quality of Supply Standards (SQSS) presents a major opportunity to address these issues. However, the review, which had aimed to publish detailed proposals in September 2009, has not yet reported. Therefore, we are concerned that some of the currently proposed strategic network investment that is based on the existing SQSS may prove
unnecessary. Furthermore, reform of the SQSS will be vital for the development of a future smart grid. It would be totally unacceptable if Ofgem failed to fulfil its duties to consumers by not ensuring the timely completion of this review, especially as the regulator has already begun to grant funding for additional investment. We consider it essential that consideration of new investment in transmission has the benefit of the outcome of the SQSS review and strongly recommend that urgent measures are taken to complete and publish the review. (Paragraph 59)

Transmission: constraint costs

10. Constraints occur on the transmission network when the system is unable to transmit the power supplied at a particular location to where demand for it is situated. National Grid’s management of these constraints gives rise to costs, which are met by generators and consumers. The level of constraint costs are an important signal of investment needs. It is, therefore, vital that this signal is accurate. We are concerned that the nature of the British Electricity Trading and Transmission Arrangements (BETTA) appear to artificially inflate the level of constraint costs. We note the general review of the BETTA market announced by the Government in the Pre-Budget Report in December 2009. However, we recommend Ofgem conducts a specific review of the BETTA market with a view to addressing this issue. We also support the Government’s intention to enhance Ofgem’s powers to regulate against companies artificially inflating constraint costs. (Paragraph 69)

11. Whilst we agree in principle with the current proposals to implement locational pricing for the Balancing Services Use of System charges as a means of reducing constraint costs in the short run, we question whether Ofgem should continue to pursue the modification brought forward by National Grid, given it could be replaced by another set of charging arrangements in the short to medium term when DECC implements a new regime for determining transmission access. (Paragraph 70)

Transmission Network Use of System charges

12. We are concerned that the current system appears to charge wind generators disproportionately more than conventional generators for grid usage. We believe that it is imperative that transmission charges should not discriminate against renewable energy wherever it is located in Britain. Whilst we received conflicting evidence on this matter and acknowledge that other factors such as the planning system, grid access and financing play an important role in determining the investment case for new renewable generation, we believe it is vital that this issue be fully investigated as soon as possible. We note Ofgem’s long-term commitment to the model of locational charging, but given the evidence we have received we recommend the Department establishes an independent review to develop an appropriate transmission charging methodology. (Paragraph 80)
Transmission access

13. The old arrangements for gaining access to the transmission network gave rise to a queue of at least 60 GW of projects at various stages of development, a large proportion of which are renewables, some of which have potential connection dates as late as 2023. A new regime is vital if the Government is to meet its targets for renewable energy and emissions reductions. We welcome the ‘interim connect and manage’ arrangements, which should facilitate the earlier connection of 900 MW of renewable capacity in Scotland. We are, however, concerned by the lack of progress in developing a long-term access regime. It is extremely disappointing the industry has not been able to agree reforms and the Government has had to intervene. As far as possible, it is important an enduring regime is based on consensus between all parties—the Government, the regulator and the industry. (Paragraph 99)

14. We believe that to facilitate cost-effectively the formation of a smart grid and the delivery of the Government’s strategic objectives, a long-term regime must contain four key features:

• Greater sharing of network access, particularly between renewable and conventional generators. This will reduce the need for investment in grid capacity, and the likelihood of large constraint costs, although it may need to be supported by additional market arrangements that guarantee spare generating capacity on the system;

• Prioritisation of renewables in electricity dispatch to maximise their contribution to decarbonising the energy system;

• An equal role for the demand-side in managing network access; and

• Arrangements that provide a degree of stability and regulatory certainty for generators to have the confidence to make investments.

We urge the Department to move quickly to ensure an enduring regime is in place as early as possible in 2010. (Paragraph 100)

The industry rule-making process

15. We welcome Ofgem’s decision to review the industry’s rule-making process. The existing system, under which only network owners can propose changes to the grid codes and charging methodologies, has for far too long forestalled reform in areas such as transmission access. The regulator’s proposal that it take powers to implement code amendments arising from major policy reviews, whilst conceding power in areas of less significance to consumers or competition, is a sensible approach. So too is the proposal to make governance of the charging methodologies more inclusive. Changes in both these areas will facilitate the delivery of the Government’s climate change and security of supply objectives. (Paragraph 103)
Offshore transmission

16. There are many challenges associated with the expansion of the electricity network offshore. It is important the regulatory framework reflects these difficulties and treats generators connecting offshore equitably vis-à-vis their onshore counterparts. The offshore wind industry presents a significant commercial opportunity for British industry, which requires a regulatory regime that will stimulate domestic investment in cabling and associated equipment manufacture. (Paragraph 111)

17. Connecting the first three rounds of licences for offshore wind farms will require a capital investment of £15 billion—twice the value of the existing onshore transmission network. We therefore support the auctioning approach for the delivery of future offshore transmission links to ensure costs are minimised for the consumer. In the short to medium term this will lead to the direct ‘point-to-point’ connection of Round 1 and 2 wind farms as the most cost-effective and technically feasible way forward, which also militates against the possibility of delays. However, risks remain, particularly if companies underestimate the cost of the work for which they have tendered. This means the Department and Ofgem must keep its approach under review. Moreover, it is not yet clear how the present framework will deliver the most efficient network solution to connect the 33 GW of offshore wind that is possible under Round 3. There remains a risk that the current approach could lead to the piecemeal development of the offshore network that is less cost-effective in the long run. We note that the Department merely believes that zone-based approaches to connecting wind farms onshore will develop. We do not consider this is a sufficiently robust approach, and recommend the regulator conducts more analysis to develop a route-map of how it expects the competitive tendering regime to evolve to meet this long-term challenge. (Paragraph 120)

Interconnection and the super-grid

18. As the level of wind generation in the electricity mix increases over the next decade, its intermittency and unpredictability will make it increasingly difficult for the system operator to balance supply and demand. A potential solution may be greater interconnection with European networks. However, the lack of progress in liberalising the European energy sector, means Britain risks tying itself closer to markets that lack competition and transparency, as has already happened, many would argue to its detriment, in the gas sector. The Government should continue its efforts to ensure the European Union makes rapid progress on implementing full transparency of Member States’ energy sectors so that the UK is not further disadvantaged. In addition, it is not yet clear to what extent the GB system would be able to rely on other countries to provide balancing services, given weather systems rarely conform to national boundaries. The regulator should, therefore, proceed with caution in licensing future interconnection. Moreover, the electrification of the transport and heating sectors combined with active management of demand through smart grid technologies could provide a means of managing wind intermittency in the future. We believe it will be necessary to attain a clear view of the cost/benefits of interconnection in the context of UK energy security and the balancing of services,
and recommend Ofgem conducts research to better establish this view. (Paragraph 127)

19. The ‘super-grid’ could make a significant contribution to a low-carbon economy. However, there are major technical and regulatory challenges, while the necessary funding would likely require the redirecting of capital from domestic investment in network and renewable energy infrastructure. The super-grid would have some energy security benefits such as reducing Britain’s exposure to fossil fuel price volatility, but would also bring with it new energy security risks, for example, through a new energy dependency on North African countries. We recommend the Government remains engaged at a European level in exploring the super-grid’s potential. Any future decision to invest would require a robust analysis of the scheme’s cost-effectiveness relative to other means of securing electricity supplies, such as greater demand flexibility. (Paragraph 132)

The changing role of distribution: technical and regulatory challenges

20. In the future there could be potentially thousands of generators connected to the distribution networks at scales varying from domestic solar panels to large wind farms. Energy demand could also evolve and increase through the electrification of the transport and heating sectors. The deployment of smart grid technologies, such as smart meters, will therefore be crucial to the effective and economically efficient management of an increasingly complex energy system. This necessitates a fundamental rethink of the role of distribution companies who in the future will need to play a more active role in balancing demand and supply across their networks, potentially taking on a local system operator role. (Paragraph 144)

21. Creating smarter distribution poses significant challenges. Although many of the technical aspects are well-understood there is relatively little experience of their application to the smart grid. Furthermore, the regulatory framework does not at present provide a level playing field for the adoption of smart grid solutions, such as active demand management. Ofgem must address these issues in the coming years. One area in which we believe it could make an immediate difference is to work with Ofcom to ensure the allocation of suitable spectrum for smart grid use as soon as possible, thus enabling the full range of smart grid technologies to be considered for deployment in Britain. (Paragraph 145)

Distribution investment

22. We welcome the outcome of Ofgem’s fifth distribution price control review (DPCR), which seems to balance the requirement for network renewal on the one hand, with the need to minimise the resulting impact on consumers’ bills on the other. However, the success or otherwise of the DPCR will need to be assessed against whether it encourages a significantly greater role for distributed generation and demand-side management within the energy system over the review period, and the extent to which it leads to the deployment of smart grid technologies. (Paragraph 149)
Innovation

23. The level of research and development conducted by the networks sector has risen significantly over the last five years, though still represents just 0.33% of firms’ income. If Britain is to be one of the first to deploy smart grid technologies on a wide scale, the industry must invest sufficiently to turn what is at present a vision into a reality. To the extent that the lack of R&D is a result of the rules governing companies’ expenditure under the Innovation Funding Incentive, Ofgem should look again at this matter. To the extent that the underspend is the result of the absence of a “culture of innovation”, the industry must accept that it has failed in its responsibilities and that it needs to show significant improvement not just in the interests of both the nation and the consumer, but also to grasp the huge opportunities that the global market offers. (Paragraph 157)

24. We welcome the introduction of the Low Carbon Networks Fund and the continuation of the Innovation Funding Incentive. We recommend Ofgem keeps both these mechanisms under review with the aim of increasing the available funding for both within the current distribution price control period if there is demand. We welcome also new public sector funding for smart grid demonstrations, and hope the Government will continue to support this area despite the current fiscal constraints. (Paragraph 158)

Embedded benefits

25. Generators connected to the distribution networks do not currently pay transmission network use of system charges because it is assumed their output is absorbed by local demand and therefore reduces the need for transmission capacity—a concept known as ‘embedded benefits’. The level of distributed generation, particularly renewables, could increase significantly in the next decade, to the extent that local supply will at times exceed local demand, resulting in spillovers back into the transmission system. Moreover, where renewable generation is intermittent, transmission capacity will still be necessary to respond to shortfalls in supply. For this reason, the current treatment of embedded generation is not sustainable in the long run. (Paragraph 163)

26. Because the proportion of distributed generation in the electricity mix is still very low, there is no need for Ofgem and the industry to reach an immediate decision on an enduring set of arrangements. Instead, it should wait until it can be shown clearly that distributed generation is impacting on the transmission system. We recommend the regulator develops a set of criteria to determine when it would be appropriate to reconsider this issue as the risk of change too soon is that it may exacerbate the ‘lock-in’ of a centralised energy system. Central to the debate over the two options proposed by National Grid is the question of whether in the future there should be separate regulatory frameworks for the distribution and transmission networks, or if there is a case for regulating the whole system as a single entity. The regulator must resolve this question first, which forms part of its RPI-X@20 review, before it can conclude on an enduring set of charging arrangements for distributed generation. (Paragraph 164)
Network skills

27. The transition to a low-carbon economy will require trained people that have the skills to deliver the many challenges the networks face in the coming years. Yet an aging workforce and a lack of new recruits mean the industry currently faces an acute skills shortage. This problem has been exacerbated by a regulatory framework that has reduced firms’ expenditure on skills over time. We welcome the establishment of the National Skills Academy for Power, but believe DECC and the Department for Business, Innovation and Skills need to do more to inspire young people and graduates to take up a career in the energy sector. Network companies too should face improved incentives through the price control reviews. Accordingly, this must form a key part of Ofgem’s RPI-X@20 review. Looking forward, firms must also accept their role in ensuring employees have the opportunity to improve their skills. A skilled workforce will be crucial to the development of a cost-effective low-carbon energy system. As one witness put it: “Without the broad skills of all participants within the sector, the UK faces a dirtier, more expensive and less efficient future”. (Paragraph 174)
Glossary

**Allowed revenue**—the amount of money that a network company can earn on its regulated business.\(^{321}\)

**Constraints**—the costs incurred through paying generators to vary their power output to prevent unacceptable post fault transmission system operating conditions.

**Demand-side management**—any mechanism that allows a customer’s demand to be intelligently managed in response to events in the power system. Such events would include a lack of network capacity or insufficient generation.

**Distributed generation**—also known as embedded or dispersed generation. It is an electricity generating plant connected to a distribution network rather than the transmission network.

**Distribution network operator**—a DNO is a company which operates an electricity distribution network, which includes all parts of the networks from 132 kV to 230 kV in England and Wales. In Scotland 132 kV is considered to be part of transmission rather than distribution, so their operation is not included in the DNOs’ activities.

**Distribution Price Control Review 5**—the next price control, determining the allowed revenues of distribution network operators, which runs from 1 April 2010 until 31 March 2015.

**Feed-in tariffs**—the price per unit of electricity that a utility or supplier has to pay for renewable electricity from private generators. These are used to encourage distributed renewable generation through private generators.

**GB SQSS**—the Great Britain Security and Quality of Supply Standard, which provides the basic parameters and conditions to which the transmission network is designed.

**HVDC**—High Voltage Direct Current (exceeding 650 V).

**Interconnector**—Connection between the assets of different Transmission Owners.

**Licence conditions**—an obligation placed on the network companies to meet certain standards of performance. The regulator has the power to take appropriate enforcement action in the case of a failure to meet these obligations.

**Net present value**—the valuation of future expenditures, incomes, assets etc in today’s terms (for example, taking account of interest payments over a given length of time).

**Price control**—the control developed by the regulator to set targets and allowed revenues for network companies.

---

\(^{321}\) This Glossary includes selected terms from: Ofgem, *RPI-X@20 Emerging Thinking Consultation Document Glossary of Terms*, January 2010; and Electricity Networks Strategy Group, *Our Electricity Transmission Network: A Vision for 2020*, March 2009
**RPI-X**—the form of price control currently applied to, for example, energy network monopolies. Each company is given a revenue allowance in the first year of the control period. The price control then specifies that in each subsequent year the allowance will move by ‘X’ per cent in real terms.

**Smart grid**—an electricity network that can intelligently integrate the actions of all the users connected to it—generators, consumers and those that do both—in order to efficiently deliver sustainable, economic and secure electricity supplies.

**System operator**—the entity responsible for operating the GB transmission system and for entering into contracts with those who want to connect to and/or use the transmission system. National Grid is the current GB system operator.

**Transmission owner**—a company which owns the electricity transmission network, which includes all parts of the network above 132 kV in England and Wales, and including 132 kV in Scotland.

**Transmission price control review**—this establishes the price control for the transmission licensees. The current price control began in April 2007 and will run until the end of March 2013.

**Vertically integrated company**—a company that is active in more than one level of an industry’s supply chain (for example, a firm that generates electricity and also operates electricity distribution networks).
Formal Minutes

Wednesday 10 February 2010 (afternoon)

Members present:

Mr David Anderson
Colin Challen
Sir Robert Smith
Paddy Tipping
Mr Mike Weir
Dr Alan Whitehead

In the absence of the Chairman, Paddy Tipping was called to the Chair in accordance with the resolution of 20 May 2009.

Draft Report (The future of Britain’s electricity networks), proposed by the Chairman, brought up and read.

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

Paragraphs 1 to 174 read and agreed to.

Summary agreed to.

Glossary agreed to.

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

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

Ordered, That embargoed copies of the Report be made available, in accordance with the provisions of Standing Order No. 134.

Written evidence was ordered to be reported to the House for printing with the Report, together with written evidence reported and ordered to be published on 25th March, 1st, 22nd and 29th April, 10th and 17th June, and 16th July.

Adjourned till Wednesday 24 February at 8.45 am
Witnesses

Wednesday 1 April 2009
Dr Michael Pollitt, Electricity Policy Research Group, Judge Business School, University of Cambridge, Professor Goran Strbac, Chair in Electrical Energy Systems, Imperial College London, and Dr Jim Watson, Sussex Energy Group

Wednesday 22 April 2009
Ms Alison Kay, Commercial Director, Transmission, National Grid, Mr Mike Barlow, Head of Systems Management, Scottish and Southern Energy, and Mr Rupert Steele, Director of Regulation, Scottish Power

Mr Tim Balcon, Chief Executive, Energy and Utility Skills

Wednesday 29 April 2009
Mr Gordon Edge, Director of Economics and Markets, British Wind Energy Association, Mr Tim Russell, Russell Power Ltd, Renewable Energy Association, and Mr Jason Ormiston, Chief Executive, Scottish Renewables

Mr David Porter, Chief Executive, Ms Barbara Vest, Head of Electricity Trading, and Mr Alistair Tolley, Head of Renewable Energy, Association of Electricity Producers

Wednesday 6 May 2009
Mr David Smith, Chief Executive, Energy Networks Association, Mr Phil Jones, President and Chief Operating Officer, CE Electric UK, and Mr Steve Johnson, Chief Executive, Electricity North West Ltd

Dr Simon Harrison, Chairman of the Energy Sector Panel for the Institution of Engineering and Technology and Director of Energy, Mott MacDonald, and Mr John Scott, Director, Network Innovation for KEMA Consulting, and Member of the Energy Sector Panel, Institution of Engineering and Technology

Wednesday 20 May 2009
Mr Alistair Buchanan, Chief Executive, Ofgem

Wednesday 17 June 2009
Rt Hon Lord Hunt of Kings Heath OBE, Minister of State, Miss Lorraine Hamid, Head of Future Electricity Networks Team, and Mr John Overton, Deputy Director, Renewables Deployment Team, Department of Energy and Climate Change
## List of written evidence

<table>
<thead>
<tr>
<th></th>
<th>Name</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ABB</td>
<td>Ev 102</td>
</tr>
<tr>
<td>2</td>
<td>Areva</td>
<td>Ev 104</td>
</tr>
<tr>
<td>3</td>
<td>Association of Electricity Producers</td>
<td>Ev 108</td>
</tr>
<tr>
<td>4</td>
<td>ARUP</td>
<td>Ev 112</td>
</tr>
<tr>
<td>5</td>
<td>British Wind Energy Association</td>
<td>Ev 116</td>
</tr>
<tr>
<td>6</td>
<td>Campaign to Protect Rural England</td>
<td>Ev 119</td>
</tr>
<tr>
<td>7</td>
<td>Centrica</td>
<td>Ev 128</td>
</tr>
<tr>
<td>8</td>
<td>Chemical Industries Association</td>
<td>Ev 133</td>
</tr>
<tr>
<td>9</td>
<td>Consumer Focus</td>
<td>Ev 135</td>
</tr>
<tr>
<td>10</td>
<td>Crown Estate</td>
<td>Ev 144</td>
</tr>
<tr>
<td>11</td>
<td>Department of Energy and Climate Change</td>
<td>Ev 146</td>
</tr>
<tr>
<td>12</td>
<td>Department of Energy and Climate Change (supplementary)</td>
<td>Ev 153</td>
</tr>
<tr>
<td>13</td>
<td>Dr Patrick Devine-Wright</td>
<td>Ev 154</td>
</tr>
<tr>
<td>14</td>
<td>Electricity North West Limited</td>
<td>Ev 158</td>
</tr>
<tr>
<td>15</td>
<td>Energy and Utility Skills/Power Sector Skills Strategy Group</td>
<td>Ev 161</td>
</tr>
<tr>
<td>16</td>
<td>Energy Networks Association</td>
<td>Ev 164</td>
</tr>
<tr>
<td>17</td>
<td>Energy Networks Association (supplementary)</td>
<td>Ev 170</td>
</tr>
<tr>
<td>18</td>
<td>Energy Research Partnership</td>
<td>Ev 170</td>
</tr>
<tr>
<td>19</td>
<td>Energy Technologies Institute</td>
<td>Ev 171</td>
</tr>
<tr>
<td>20</td>
<td>E.ON</td>
<td>Ev 173</td>
</tr>
<tr>
<td>21</td>
<td>ESB International Investments</td>
<td>Ev 178</td>
</tr>
<tr>
<td>22</td>
<td>Global Marine Systems</td>
<td>Ev 181</td>
</tr>
<tr>
<td>23</td>
<td>Helius Energy</td>
<td>Ev 182</td>
</tr>
<tr>
<td>24</td>
<td>Institute of Physics</td>
<td>Ev 184</td>
</tr>
<tr>
<td>25</td>
<td>Institution of Engineering and Technology</td>
<td>Ev 187</td>
</tr>
<tr>
<td>26</td>
<td>Institution of Engineering and Technology (supplementary)</td>
<td>Ev 192</td>
</tr>
<tr>
<td>27</td>
<td>Intergen UK</td>
<td>Ev 194</td>
</tr>
<tr>
<td>28</td>
<td>Joint Association (Association of Electricity Producers, British Wind Energy Association, Scottish Renewable Forum)</td>
<td>Ev 197</td>
</tr>
<tr>
<td>29</td>
<td>Living Fuels Ltd</td>
<td>Ev 200</td>
</tr>
<tr>
<td>30</td>
<td>National Grid</td>
<td>Ev 202</td>
</tr>
<tr>
<td>31</td>
<td>Navetas</td>
<td>Ev 208</td>
</tr>
<tr>
<td>32</td>
<td>Nuclear Industry Association</td>
<td>Ev 208</td>
</tr>
<tr>
<td>33</td>
<td>Office of Gas and Electricity Markets (Ofgem)</td>
<td>Ev 210</td>
</tr>
<tr>
<td>34</td>
<td>Office of Gas and Electricity Markets (supplementary)</td>
<td>Ev 216</td>
</tr>
<tr>
<td>35</td>
<td>Office of Gas and Electricity Markets (further supplementary)</td>
<td>Ev 217</td>
</tr>
<tr>
<td>36</td>
<td>Dr Michael Pollitt, Judge Business School, University of Cambridge</td>
<td>Ev 218</td>
</tr>
<tr>
<td>37</td>
<td>Prospect</td>
<td>Ev 221</td>
</tr>
<tr>
<td>38</td>
<td>Renewable Energy Association</td>
<td>Ev 226</td>
</tr>
<tr>
<td>39</td>
<td>RLtec</td>
<td>Ev 230</td>
</tr>
<tr>
<td>40</td>
<td>Royal Academy of Engineering</td>
<td>Ev 231</td>
</tr>
<tr>
<td>41</td>
<td>Scottish and Southern Energy</td>
<td>Ev 232</td>
</tr>
<tr>
<td>42</td>
<td>Scottish Chambers of Commerce</td>
<td>Ev 237</td>
</tr>
<tr>
<td>43</td>
<td>Scottish Council for Development and Industry</td>
<td>Ev 240</td>
</tr>
<tr>
<td>44</td>
<td>Scottish Natural Heritage</td>
<td>Ev 251</td>
</tr>
<tr>
<td>45</td>
<td>Scottish Power</td>
<td>Ev 254</td>
</tr>
<tr>
<td>46</td>
<td>Scottish Renewables</td>
<td>Ev 260</td>
</tr>
<tr>
<td>47</td>
<td>Scottish Renewables (supplementary)</td>
<td>Ev 263</td>
</tr>
<tr>
<td>48</td>
<td>Professor Goran Strbac, Imperial College London</td>
<td>Ev 264</td>
</tr>
<tr>
<td>49</td>
<td>Sussex Energy Group</td>
<td>Ev 270</td>
</tr>
<tr>
<td>50</td>
<td>Town and Country Planning Association</td>
<td>Ev 275</td>
</tr>
<tr>
<td>51</td>
<td>Unite the Union</td>
<td>Ev 278</td>
</tr>
<tr>
<td>52</td>
<td>Phil Baker and Dr Bridget Woodman, University of Exeter</td>
<td>Ev 278</td>
</tr>
<tr>
<td>53</td>
<td>Office of Gas and Electricity Markets (further supplementary)</td>
<td>Ev 285</td>
</tr>
</tbody>
</table>
List of Reports from the Committee during the current Parliament

The reference number of the Government's response to each Report is printed in brackets after the HC printing number.

**Session 2009–10**
First Report  Work of the Committee in Session 2008-09  HC 133

**Session 2008–9**
First Report  UK offshore oil and gas  HC 341 (HC 1010)