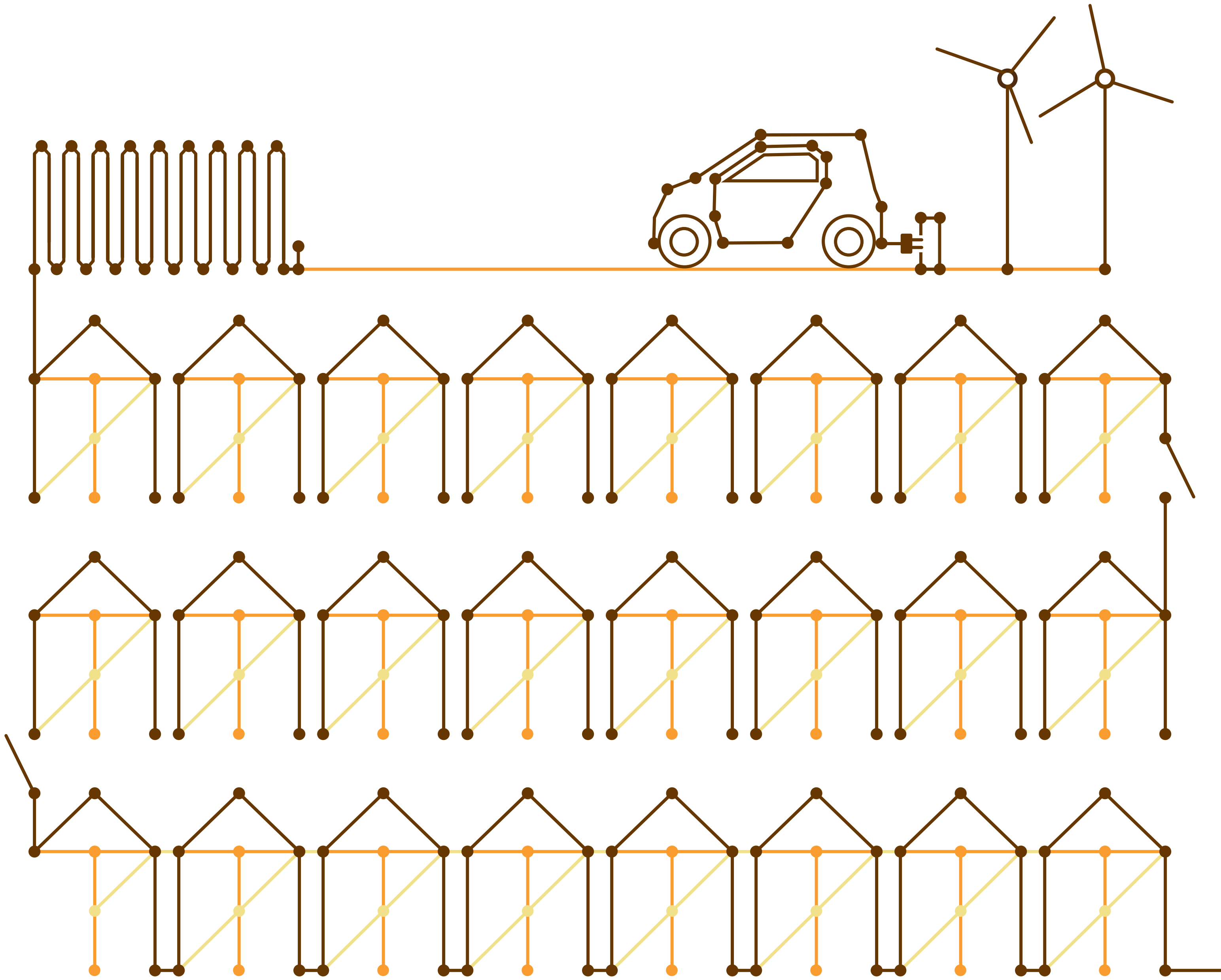
Future proof

An electricity network for the 21st century

green alliance...



Future proof:
an electricity network for the 21st century
By Rachel Cary

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Executive summary

Electricity transmission and distribution networks are a critical part of our energy infrastructure. We cannot meet our carbon reduction targets and combat climate change without technological and operational changes within these networks and the greater involvement of end users. We cannot take a laissez-faire stance and hope for the best. We should instead take a proactive approach, preparing for future challenges while we still have time.

Limited access to transmission networks has slowed progress towards achieving renewable electricity targets. We need to catch up with years of underinvestment in transmission networks and push a number of major projects through planning processes. Without swift action on distribution networks, they risk being as big a barrier to the achievement of our carbon targets as transmission access has been in recent years.

As we approach a period of heavy investment in the networks and make dramatic changes to the way we produce and use electricity, we need to take a step back and consider what we want from our electricity system. A 'microgrid' scenario with a wide mix of distributed generation and active management of the distribution networks is cheaper and saves more carbon. Plans for the networks should be ambitious and we should work backwards from this end goal to ensure progress in the short to medium term.

We must also persevere with attempts to reduce energy wastage across the whole energy chain and make demand more flexible. Otherwise we will need to oversize our electricity networks even more than we do today. This will be very expensive and to the detriment of the natural environment.

The introduction of electric vehicles, microgeneration and heat pumps will require a change in the way we operate our local networks. Early and well co-ordinated preparation will be essential if we are to maximise uptake and take advantage of the benefits that these technologies offer.

Everyone will need to play a role in this transformation, from DECC to the end user. Ofgem needs to ensure it continues to integrate all aspects of sustainable development into the way it works and take more risks. The distribution network operators need to play a central role in optimising local networks. One or more distribution systems operators should be created to oversee activities and maintain the balance of the networks.

We need to streamline the decision-making process to enable the involvement of small generators and new entrants. Engaging end users will be vital. They will need to see clear benefits from the transition as they will pay for the upfront investment required. The public needs to be reassured about data security issues to avoid a backlash against smart meters. Without significantly more interaction with the end user we will struggle to move to a low carbon electricity system and costs will be significantly higher.

In essence, a new approach to developing and running the electricity networks is necessary, one which is guided by six key principles, set out opposite. By following these principles we can embark on an exciting transformation of our electricity system and move to a system that is less centralised, fairer for all and less reliant on fossil fuels. Our networks should be at the centre of a new flexible electricity system that successfully integrates a wide range of low carbon technologies.

Six key principles to future proof the electricity network

1. Work towards the future
We need to determine what we want from our networks and set out a clear path towards the end goal. We must not wait until we definitely need new infrastructure as this could delay progress and put off developers. We should push ahead with regulatory reform and consider allowing different parts of the supply chain to work more closely together. Calculating costs using conventional economics that compares future approaches to the current system will not get us to where we want to be.

2. Maintain and increase investments
We need to catch up with years of under investment in transmission and prepare to step up funding at the distribution level. Early and strategic investment can save money. Planning must be speeded up and more transmission lines put underground or rerouted offshore.

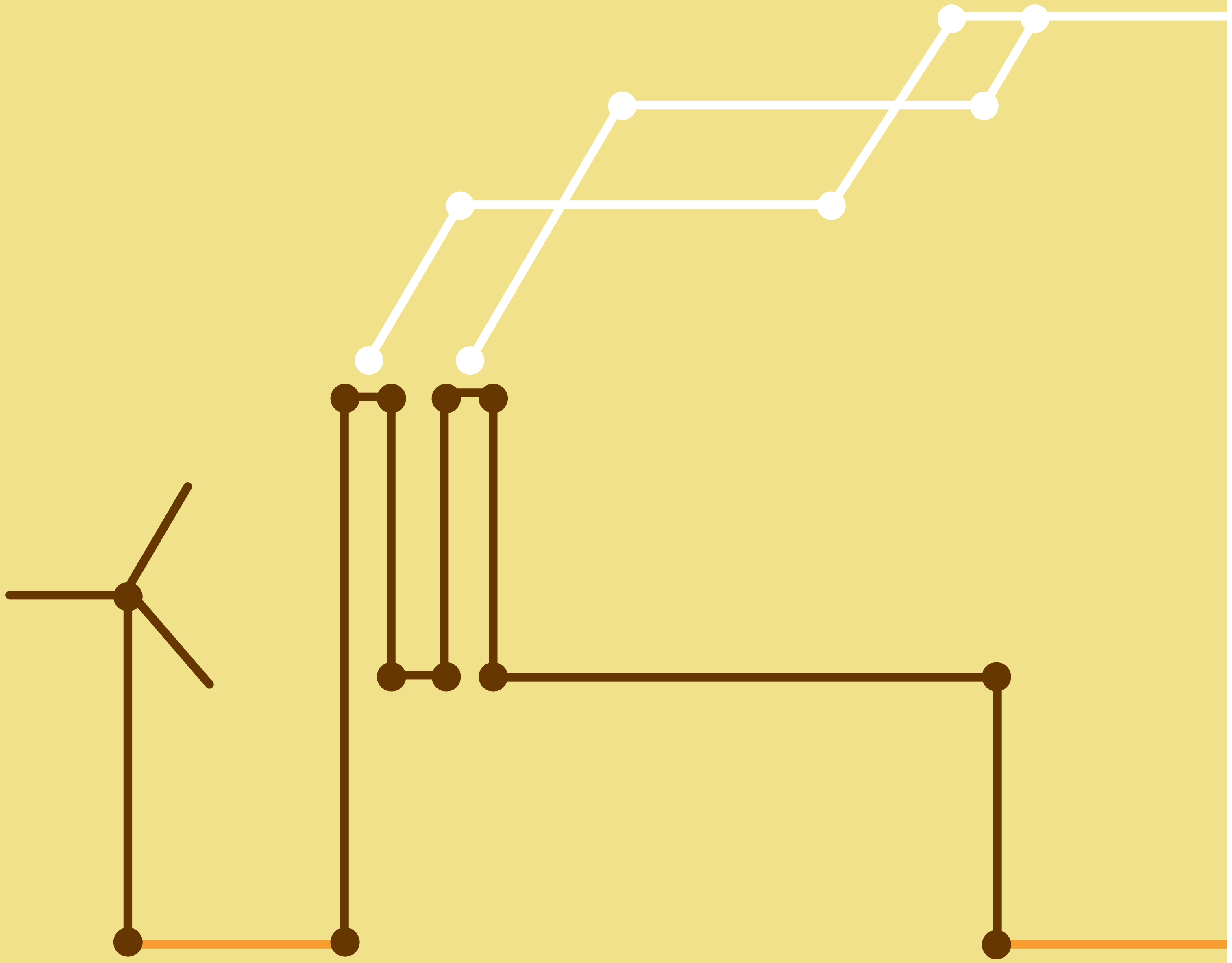
3. Reform charges for users
Locational charging may not be suitable as we shift to new forms of low carbon generation. Proposals to charge distributed generation for use of the transmission networks when they do not export electricity onto them is unfair and should be dropped. End users may have to be charged in a more cost reflective way in the future to encourage measures that make electricity demand more flexible to come forward. However, we need to balance cost reflectivity with wider policy objectives and not penalise early adopters of low carbon technologies.

4. Make demand more flexible
If we carry on supplying electricity to meet demand for the majority of end users we will need to oversize generation and networks even more than we do today. There is a range of technical and financial ways to make demand more flexible, these need to be trialled now to see what works. We need to differentiate between different types of electricity demand and not treat all types of electricity the same.

5. Prepare for electric vehicles, microgen and heat pumps
We should prepare for these technologies now for example by developing electric vehicle charging infrastructure and ensuring that electric vehicles can communicate with network operators. More effort is needed to understand the impact of these technologies on the networks (eg the reactive power from heat pumps). A co-ordinated approach is required both across government and across the many different groups involved, from local authorities to car manufacturers.

6. Make distribution networks more intelligent
There should be a clear framework for the mandatory development of smart grids, as leaving it to the market may not deliver. Additional funding outside of the regulatory package may be required that trial different ways of operating the networks. Developing a smart grid will take time and we should not wait until it is too late. The smart meter roll out must contribute to a smart grid. All visual display units need to adhere to minimum standards based on proper consumer testing so that they are easy to understand and use and we must not miss the opportunity for consumer engagement in the roll out process.

Introduction



There are growing discussions about the wide range of changes that will need to be made to the UK electricity network over the coming decades. These range from expanding the grid offshore to capture electricity from offshore wind farms to increasing the interaction with energy users to shift the timing of electricity use. Much of the existing network infrastructure and power stations are reaching the end of their lives. We are seeing a shift to increased amounts of renewable generation, often located in remote areas of Scotland or offshore. It is clear that we will need to invest in our networks.

We need to make radical changes to our electricity system if we are to have any chance of decarbonising it by 2030. We know that the nature of electricity generation will need to radically change however we also need to consider how we want to transport electricity and whether our current networks are fit for the job. Significant investment is required in our existing networks and new additional networks may need to be built if we are to use energy optimally. At this important junction it is vital that we take a step back and consider what we actually want from our networks.

The amount of infrastructure we need to build is not entirely clear as it will depend on a number of factors. It is important we make sure that we get on and build the infrastructure that we definitely need to meet our short-term renewables targets. However, it will also be important to ensure we maximise efforts to minimise the amount of expensive network infrastructure we need for example by reducing overall electricity demand, reducing electricity use at peak times, maximising energy efficiency across the networks and getting more out of existing networks by making them more 'smart'. However, there are many no regrets investments that need to be made quickly. For example work by the Electricity Network Strategy Group identified a number of new networks or network reinforcements that will be needed under a range of different future generation scenarios.

Most of us do not understand or think much about our electricity networks until someone proposes to construct a number of pylons in a beautiful part of the countryside. Whilst many people have strong and often conflicting opinions on how we should *generate* electricity, we do not give much thought to how we should *transport* it. As we run out of North Sea oil and gas and need to urgently reduce our carbon emissions, it is vital that we diversify the types of fuels we rely on and increase the amount of renewables in our electricity mix. Problems getting planning permission are a well-known barrier to the take-up of renewables however increasingly problems with the networks are slowing renewable projects as well. Going forward the networks will face growing challenges as we introduce low carbon low generators, electric vehicles and efficient electric heating systems.

So why should we care? Our networks were built for an electricity system that wasn't designed for high levels of renewables and need to be transformed to accommodate them. Changing the way we use electricity will be essential if we are to make the dramatic cut in carbon emissions. The end of electricity networks, the electricity meter, is our point of contact with the electricity system. If done right, we can introduce new meters and displays that will enable us to better understand our electricity demand and shift our use in response to the amount of electricity available or the situation across the local or regional networks. If we plan and use the networks intelligently we can save significant amounts of money and improve our security of supply.

The structure of the electricity networks and the way they are operated is technically complex and it can be difficult for a wide range of people to get involved in decisions about the networks. This needs to change. We need to put more thought into how the networks are developed and run if we are to end up with a network that is capable of dealing with a wide range of different technologies, involves end users and makes life easier for small local low carbon generators. In this report we aim to explain how the electricity networks work and what we might want from them.

How did we get here?

So how and why did our current electricity networks develop? The first electric systems in the 1870s produced light for individual buildings using a single steam engine or water wheel based generator. Over a decade later, Thomas Edison started to connect a number of houses via a network so that they could run on a single generator.[1] In London there was such a concentration of people and money that there was a sudden epidemic of small electricity systems. This meant that some parts of the city became overrun with electric cables. This contrasted with other parts of the developed world, where networks tended to be developed by a single entrepreneur who quickly monopolised a particular area.

Parliament made a number of attempts to develop network franchises and put in place licence requirements. A number of legal issues had to be overcome so that network operators could get access to property. After the First World War, an electricity commission was set up to try and co-ordinate the large number of local systems. By the 1930s a central common network was established and technical standardisation was introduced to ensure that electricity was transported across the networks as alternating current (AC) and at the same frequency (50Hz).

The establishment of the 132kV 'Grid Iron' and the merit order for central dispatching power stations followed.[2] Initially all power generators were embedded in the lower voltage networks. It was only in the 1960s and 70s that larger stations were constructed either close to coal fuel sources ('electricity by wire') or then remotely because of the safety issues associated with nuclear power stations. This was done through the construction of a 400kV super grid, although unlike today none of the costs were ascribed to the generators.

Gradually the electricity networks connected more and more end users and generators became progressively larger in a quest for increasing economies of scale. The move towards larger and larger centralised generators connected to far away users was reversed by the introduction of gas turbine power stations in the 1980s.[3] Gas turbine generators are economic and efficient at a much smaller scale than steam or water turbine powered generators. Their low cost, quick construction time and the low air emissions they produce (compared to other conventional generators) made them very popular in the UK and around the world.

Over time, other generating technologies such as small scale Combined Heat and Power (CHP) (where both the electricity and heat produced from an internal combustion engine is used) and renewable electricity technology such as photovoltaics and wind generators have grown in popularity. These decentralised, distributed (or embedded) technologies can be used at a range of sizes and can be installed closer to end users, reducing losses of electricity across the electricity networks. As we aim to decarbonise our electricity system, we will need to greatly increase the use of these low carbon electricity-generating technologies.

Our electricity networks now need to evolve to meet the changing nature of the generating technologies we use and also to match our changing electricity use patterns. We need to modify and extend the large networks that were designed over eighty years ago for a system dominated by large fossil fuel based generators. We may also need to install new smaller networks to connect local users. To get more people to generate their own electricity and engage them in the way they use energy, we need to change the rules under which the system operates to make it simpler and more relevant to the new technologies. We also need to open up the system to allow more people to get involved.

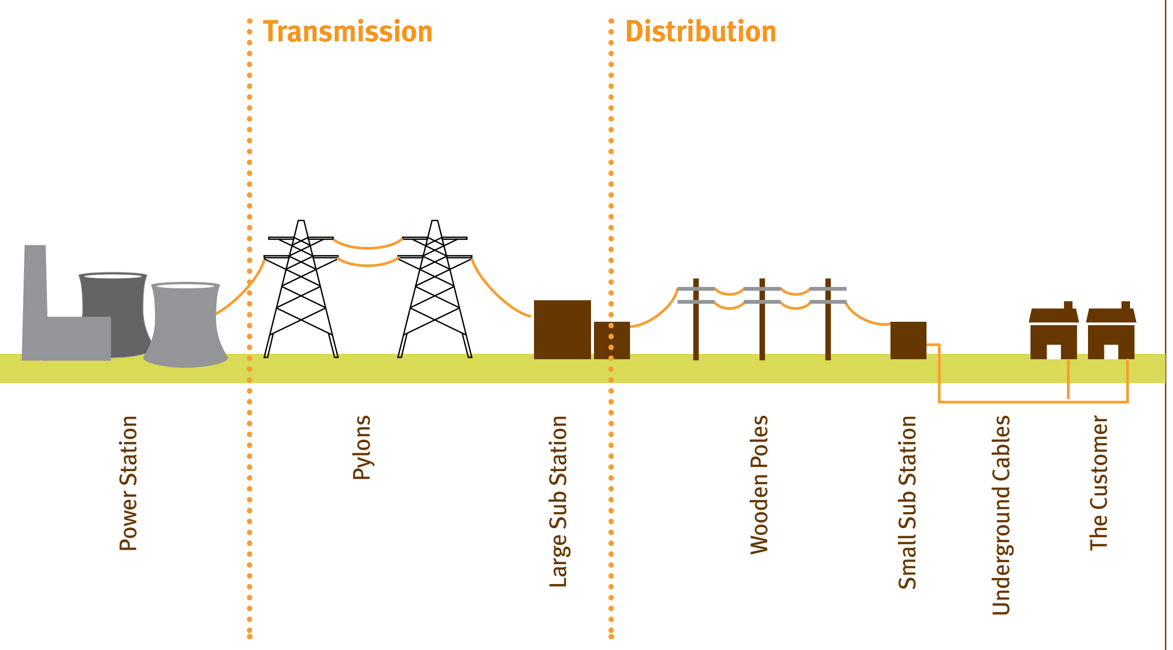
The current electricity network – functioning ok but room for improvement?

The UK's electricity network system consists of two layers of electricity networks, Transmission and Distribution (T&D):

- **Transmission network:** consists of high voltage transmission lines (>132kV in England and Wales[4]). The transmission network is the backbone of the electricity network system. Transmission networks are typically at 275kV and 400kV.
- **Distribution network:** consists of low voltage (<132kV) power lines. These are like the ribs of the electricity system.

Electricity from power stations or other forms of electricity generators for example offshore wind farms travels down the transmission networks into the distribution networks. It then passes through a series of substations to the end customer, as shown in the diagram below. Smaller generators such as medium-sized wind farms connect to the distribution networks. As the electricity passes through each substation the voltage drops until it is 230V – the voltage used in homes.

Diagram 1: the delivery of electricity
Image courtesy of the Energy Networks Association



So who owns the electricity networks?

- **Transmission:** Electricity transmission assets are owned and maintained by regional monopoly Transmission Owners (TOs): National Grid Electricity Transmission plc (NGET) in England, Scottish Power Transmission Limited (SPTL) in southern Scotland and Scottish Hydro-Electric Transmission Limited (SHETL) in northern Scotland.

- **Distribution:** There are 14 Distribution Network Operators (DNOs) owned by seven different groups.[5] There are also four independent network operators who own and run smaller networks embedded in the DNO networks.

The different network operators are shown in the diagram below.

National Grid is also the system operator for the entire UK electricity system. It has a responsibility to ensure that all of the transmission networks are run in an efficient and co-ordinated manner. It ensures that the system remains stable even if some generators fail or electricity demand is higher than expected, by bringing on reserve generators or decreasing electricity demand.[6] Recently its responsibility has been extended to the offshore networks as well.

Diagram 2: who owns the networks?
Image courtesy of the Energy Networks Association

System Operator

National Grid

Transmission companies

Scottish and Southern Energy
(Asset Owner North of Scotland)

Scottish Power
(Asset Owner South and Central Scotland)

National Grid
(Asset Owner England and Wales)

Distribution companies

The current electricity networks function relatively well. They move electricity around the country at a reasonable cost. However, there is room for improvement, for example there is scope for improved efficiency (see below). There is also concern about the 'brain drain' in the networks due to the rapidly ageing workforce. Much of the infrastructure is also getting old.

Problems getting timely and affordable access to the transmission networks (and to some degree the distribution networks) have slowed progress towards our renewable targets. We need to reinforce and extend the grid quickly or we could end up limiting output from new generators. Obtaining planning permission for network extensions and reinforcements has been a real barrier.

Offshore wind projects have also faced significant delays getting connected to the electricity networks. The new competitive tender process and planning regime should help to speed up delivery, however some have concerns about the way the offshore networks will develop. The construction of the offshore grid will involve innovative technology that may take time to optimise.

These issues not only delay the introduction of renewable projects once they have been embarked on, they also put off investors. They increase project risk and therefore the costs of borrowing for project developers.

Reducing energy waste

Our current electricity system is hugely wasteful. Energy is lost during generation, mainly as heat through water vapour plumes from cooling towers. In 2008 the average efficiency of gas power stations (combined cycle gas turbines) was 52 per cent. Coal plants were only 36 per cent efficient.[7] This means that less than half the energy used in these plants is converted into electricity.

Electricity is then lost as heat as it passes along the transmission and distribution networks through a number of transformers. Finally further electricity is then wasted by the end user. It is used to power inefficient appliances such as plasma televisions and old fridges, inefficient lighting systems such as spotlights and incandescent light bulbs, inefficient fixed motors and old air conditioning systems. It is also used to generate heat through old electric heaters that heat leaky and badly insulated buildings.

The network infrastructure in the UK is ageing, with roughly half of all power grid assets over 38 years old and 20 per cent over 50 years old.[8] The average transformer in the UK is 40 years old. This not only reduces efficiency but also the chance of failure begins to increase exponentially after a transformer reaches the 40-50 year mark. Transformer failure can lead to blackouts and can result in dangerous explosions.

Monitoring and diagnosis can help to reduce transformer failure (see smart grid section below) however in the end they need to be replaced when they get too old. Some academics argue that we could get more out of the existing networks if we relaxed security and quality standards, and that the estimates for the level of investment required is overplayed. However, even if we manage to get more out of our existing networks, they will still need to be reinforced in many areas and extended to connect new generators in new locations.

Measuring the losses from the distribution network is currently difficult due to a lack of data. However, it is estimated that around two per cent of electricity is lost at transmission and five to six per cent is lost across the distribution networks. New efficient transformers and larger cables can be introduced to reduce the electricity lost as it travels across the distribution network. Most of our transmission network uses AC voltage lines. These can be replaced in some areas with High Voltage Direct Current (HVDC) lines that lose less energy (see box below).

There is also the potential to improve the way in which demand for electricity is controlled so that it is more closely aligned with generation and is more constant throughout the day. The total generating capacity in the UK is roughly 80GW however average demand is only half of this. A high proportion of the total capacity is only used to provide electricity during peak times for example on a winters evening. It's the equivalent of running a large people carrier in which you occasionally have six passengers but most of time have only two or three. This is expensive as it means that we have to pay to build and maintain spare electricity generating capacity. It also has an impact on the networks as we need to oversize the transmission networks to accommodate the large amounts of generation needed to meet peak demand. Making demand less 'peaky' and more constant reduces the size of the distribution networks we need.

It also means that some generators are run at a low level, reducing their efficiency. This is similar to over sizing a condensing gas boiler in a house. If a condensing boiler only runs at 30 per cent of its full capacity, it can't reach the temperatures required for it to go into condensing mode, and it works less efficiently. This means that it burns more fuel to produce the same amount of heat than if it were running at its full capacity.

An uncertain future

Not only is there potential to improve the network for our current needs, there are even greater opportunities for changes to the electricity network in future so that it is fit for purpose in a low carbon electricity system. The electricity network will need to adapt to changes in both electricity demand and supply.

Different types and quality of electricity

There are two types of electricity, AC and DC:

Alternating Current (AC) is an oscillating current produced by turbines. The electric charge swings back and forth producing a magnetic field at right angles to its direction of motion. The majority of our electricity networks carry AC electricity. The wires used to carry AC can be much smaller and cheaper than those used to carry Direct Current (DC). In addition AC can be put through different sizes of transformers to change the voltage and current. (Current and voltage for a given power are inversely proportional. If the voltage goes up, the current comes down). This is useful as it enables us to transport electricity at a low current (which reduces the amount of electricity lost as it travels) and then transform it up to a higher current close to where we want to use it. On the down side, AC produce harmonics that can result in network problems. Also as the current and voltage of AC oscillates, it can create reactive power and some energy can flow back towards the generator. Reactive power causes heating and needs to be controlled. If you put AC up to very high voltages it starts to ionise the air and can create lightning discharges. AC electricity is used in electrical motors.

Direct Current (DC) is where the electrons flow in one direction along a conductor. As it does not oscillate it is far more stable than AC. DC is produced by renewable technologies such as solar photovoltaics and fuel cell CHP units. Until the invention of power electronics, the current of DC could not be changed so that it could travel at a low current and was not suitable for transmitting electricity over long distances. In addition the cables required to carry DC are much more expensive. Nowadays however DC is used to carry large amounts of electricity at a low current (or high voltage) across long distances (HVDC) for example across the interconnector to France. It is then converted into AC again so it can be transformed down to increasingly lower voltages. Adding HVDC sections into networks can reduce losses and improve system stability as disturbances cannot travel down DC cables. Electronics and high-performance lights for example Compact Fluorescent Lights (CFLs) use DC. The power packs attached to electronic and Information and Communications Technology (ICT) equipment convert AC electricity from the mains into DC. This wastes energy (you can feel them get hot fairly soon after they are turned on).

In the future we may use a mixture of DC/AC and a combination of local and central electricity networks to optimise efficiency. We could use HVDC lines to transport electricity over long distances which is then put through a converter into local AC networks. On-site generators may feed DC directly into electronic equipment – any additional electricity needed could then come from the local AC network.

Future electricity demand is uncertain

Electricity demand should be reduced as a result of government policies to increase end user energy efficiency for example through the introduction of energy efficient appliances and light bulbs. However, the impact of energy efficiency policies so far has been disappointing and more will need to be done to lower electricity demand. Whilst the recession has dampened electricity demand over the past 18 months, there is an underlying upwards trend as people use more and increasingly large gadgets and air conditioning etc. In the medium to long term, the uptake of electric vehicles and a switch from gas to efficient electric heating (in the form of air and ground source heat pumps) is expected to increase overall electricity demand. Other factors that affect electricity demand such as economic activity and population growth are also uncertain.

Future electricity generation is also uncertain

Under the government's main support mechanism for renewables, the Renewable Obligation, the amount of large-scale renewable generation should increase dramatically. Up to 23GW of onshore wind and 25GW of offshore wind is expected to be delivered by 2020. Measures to increase microgeneration (renewable generators under 50kW) should also increase due to the introduction of a feed in tariff (FIT). Combined heat and power will provide a useful tool as it generates both heat and electricity, comes in a range of sizes and can be run on renewable fuels. The technology is supported by a number of government subsidies and tax breaks and should play a growing role in our electricity mix.

However, the amount and nature of low carbon and renewable generation will depend on a number of factors and is hard to predict. Uptake of many low carbon technologies to date has been disappointing.

We currently treat all electricity as if it were the same however there are different types. As discussed in box 1 above, the type of electricity each low carbon technology produces is different. Certain renewables for example solar photovoltaics will produce DC that needs to be converted into AC if it is to be fed into the main networks. There are also different levels of quality. Using the same quality of electricity for all uses whether they need it or not is similar to using drinking-quality water to have a shower or wash the car.[9] In future we may need to separate out the type and quality of electricity needed for different purposes.

The timing of different types of electricity generation will also vary. Some technologies are dependent on the weather for example photovoltaics and wind. Photovoltaics are very predictable however they often produce electricity when demand is fairly low. Wind is harder to predict but tends to match demand for electricity better for example it tends to be windy during the winter when demand is higher. Others will be more constant for example tidal.

Some of the generation will be inflexible (for example nuclear, which becomes very expensive if not run as base load) whilst others will be more flexible for example biomass electricity generators or CHP. Fossil fuel generation, such as gas-fired power stations that currently provide the majority of our electricity, will increasingly be used for back up generation rather than base load.

Spreading technologies out across the country should help. For example wind generators spread out over a large area should help to even out weather-related variation in wind speed. By promoting a diverse set of generators at different scales across the country we can make generation levels more constant. However, even with a range of technologies spread out across the country, the generation we have will not match our demand for electricity. We therefore need to make demand much more flexible.

The combination of increased demand for electricity for heat and transport, and the need to provide back-up for intermittent wind generation could mean that our central electricity system may have to grow from a capacity of around 80GW to something in excess of 100GW. Some predict that a full shift to electric vehicles and heat pumps could result in our electricity system growing to over 200GW by 2050, particularly if we continue to pursue a centralised model.

Two way power flows

The current electricity network is analogous to the cardiac system where the heart is the centralised power generators, the arteries the transmission network and the veins the distribution network. Like blood in the human circulatory system, power mainly flows in one direction.

As we move to a low carbon future however, power will increasingly flow in both directions and small scale decentralised (or embedded) generators will connect to the distribution network. This represents a significant challenge for the system and will require the introduction of new technologies and greater control of power production and throughout use the system. Luckily there is a range of established technologies that can be deployed to make the grid operate more dynamically and efficiently to help with a shift to a low carbon electricity network.

The electricity flow from the transmission network to the distribution networks is tightly monitored and controlled however the flow between them will have to become increasingly flexible. Balancing local systems will also get more important with a greater penetration of embedded generation.

Generation following demand

To date we have built our electricity systems to keep a pace with our need for electricity at any one time. There are however a number of additional tools that allow us to match demand better to supply and reduce the need for increasing the size of the electricity system:

- Increased efficiency across the networks and at end-use to reduce total demand for electricity.
- Greater use of distributed generation so that people generate and use electricity locally and require less electricity from the central networks.
- Making demand more responsive and better aligned to electricity supply. 'Demand side management' or 'Smart' demand techniques, ranging from simple technical fixes such as installing chips in white goods through to sophisticated automation of appliances, could help to balance the total system. By moving demand away from peak times, the long-term load profile can be changed. This can help to reduce overall network size and the amount of standby plant required.
- Greater use of electrical storage – currently the storage of electricity is very expensive and it is difficult to store large amounts of electricity. The potential for more large storage systems such as pumped water storage is limited.[10] However, R&D into new forms of storage such as compressed air and work to reduce the cost of batteries may help in the future. Electric vehicles may also be able to act as a battery, soaking up electricity overnight and discharging during periods of high demand and/or low supply.
- Electricity can be used to generate heat. A number of households currently use cheap night time electricity to heat water that is kept in hot water cylinders to be used the next day. Waste heat from CHP systems can be stored in district heating systems.
- Interconnection. Greater connection with Europe could help us balance demand and supply on our electricity networks more effectively.

However, government suggests that energy efficiency, smart demand management and opportunities for increased storage and interconnection will have a limited impact on the size of electricity system we need, particularly given the potential increase in demand for electric heating and transport.[11] It suggests that whilst measures such as 'smart' demand that react to the availability of power will be useful, they may not reduce peak demand as they will be offset by the introduction of heat pumps and electric vehicles and a growth in the number of households.

It is essential that we don't give up on the significant potential to reduce the amount of electricity we use through things like better building and appliance design and ensuring we maximise the great potential for managing our electricity demand better.

Lots of work underway

The future of the UK electricity system is far from certain and several organisations have recently undertaken work to explore what future options might look like. A number of working groups have been developed and consultations released that look at our electricity system. They consider both the immediate changes required and whether more fundamental changes may be required in the long term to meet future challenges. Some of these are described in the box below.

Studies like Project Discovery are useful in that they allow us to take a step back and consider what our future energy system could look like, and the environmental and security of supply benefits associated with a 'go green' or sustainable energy system. Other projects, such as the Transmission Access Review and the resulting grid access consultation, focus on a specific area that needs to be addressed (in this case improving access to the large transmission networks).

Of particular note is Ofgem's LENS project. This looked at a number of possible future scenarios for electricity networks in 2050. These scenarios ranged from a development of the current system but with much more large scale wind and fossil power plants with CCS and a much larger transmission and distribution (scenario: Big T&D), to a more decentralised scenario with less use of the transmission network and much more local CHP and microgeneration supplied across small, local networks (scenario: Microgrids).

The LENS work showed that the highest reduction in energy demand and carbon emissions from the electricity sector could be achieved in the Microgrids scenario, where energy users would be right at the centre of activity in the networks and would be significantly more engaged in their energy use than they are today. In the Microgrids scenario electricity networks are transformed with lots of generation and demand management at the distribution level. The Big T&D scenario delivered considerably lower reductions in both energy demand and carbon emissions.[13] This would suggest that we need to overhaul the electricity system and move onto a path towards decentralisation. However, there is significant technological, regulatory and institutional 'lock-in' that needs to be overcome. Moving away from business as usual is risky – it is much easier to continue with the status quo and hope for the best.

Lots of initiatives underway

Ofgem

The Long-term Energy Network Scenarios (LENS) work looked at the impact of different energy scenarios on the networks through to 2050.

Ofgem and the Department for Business, Enterprise and Regulatory Reform (BERR) undertook a Transmission Access Review, which considered options for new generators getting access to the transmission networks.

Project Discovery looks at the adequacy of Britain's energy supplies under different scenarios over the next 10-15 years and beyond. The findings have recently been published and put out for consultation.

Ofgem announced its final proposal for the next five year distribution price control review in December 2009 (see section on investing in the distribution networks below).

The RPI-X@20 review is considering whether the existing regulatory model for the gas and electricity networks is still fit for purpose after twenty years. An emerging thinking consultation was released in January 2010 and the final outcome of the review will be announced in summer 2010.

National Grid

Consultation in 2009 on operating the system beyond 2020 – this looked at the challenges operating the transmission networks with variable wind generation and new nuclear and how increased demand side management and making the grid more intelligent could help.

National Grid has recently launched a consultation on new ways to charge Distributed Generation (DG) for using the transmission network.

The Department for Energy and Climate Change (DECC)

DECC consulted on improving transmission grid access and has recently launched a second consultation on its proposed model for enduring arrangements.

It launched a smart grid vision, Smarter Grids: The Opportunity in December 2009 – this work came out of the ENSG smart grid work (see below).

DECC is also working on a Roadmap to 2050 to achieve emission reductions to be launched in the spring.

Electricity Networks Strategy Group (ENSG)

The ENSG is composed of representatives from Ofgem, Energy Companies, DECC, National Grid, various DNOs and energy experts.

In 2008 the group undertook research into the various options for transmission network reinforcements that would allow us to meet our 2020 renewables targets. In March 2008 it published a report Our electricity transmission network: a vision for 2020, which set out the results.

The group then looked at smart grids and published both its smart grid vision report in November 2009 and a smart grid route map in February 2010. The ENSG has now finished its smart grids work programme.

Electricity Networks Association

Drawn up engineering standards for distributed generation to connect at a range of voltages.

Developed guidance for distributed generation developers to make it simpler (due to be launched in April).

Set up the Electricity Networks Future Group (ENFG), which is split into nine task groups that look at various issues from the integration of heat pumps to future information that technology requires.[12]

There are growing concerns that the current arrangements will simply not deliver and we may need to question the fundamental aspects of the current system, for example the regulatory model, the market design and the role of different actors rather than just tweak the design of the current system. Projects such as RPI-X@20 that consider major changes to the current regulatory system are therefore to be welcomed.

A shift to a sustainable energy system will not only involve changes in technology and the way the networks are operated, it will also require behaviour change across a range of actors. It will therefore be important to align and co-ordinate efforts going forward and enable a broader range of people to get involved in the decisions made.

What do we want from our networks?

In order to understand how we might want the electricity networks to develop, it is useful to consider the fundamental things we want from our networks rather than just carry on with business as usual and hope that they will evolve to meet our changing needs.

The way that we develop and operate our electricity networks needs to be aligned with the three main objectives of energy policy: carbon reduction, energy security, and economic competitiveness and affordability. However, balancing these three objectives can be difficult.

In many cases they are aligned, for example investing in increased energy efficiency should result in benefits across all three areas. However, in some cases there will be conflict between the three objectives. A shift to a low carbon electricity system will require some upfront investments in infrastructure that may or may not be required but will result in increased costs in the short term. However, waiting to see whether or not the infrastructure will definitely be required could jeopardise success against our future carbon targets. For example always waiting for a firm commitment from a potential generator before re-enforcing or extending the electricity network to their location could result in significant delays and undermine our renewables targets.

So what exactly do we want from networks? You could argue that t hey need to be:

Reliable

Networks balance supply and demand on a second by second basis. There are a limited number of disturbances so that there are infrequent blackouts.

Efficient

Get electricity from the generating equipment (whether large or small) to the end user with as little energy wasted as possible. Deliver electricity to users as close as possible to where it is generated. Work as part of an optimally designed system that minimises fossil fuel use.

Able to accommodate renewable generators

Allows easy connection – renewable or low carbon generators can get access to either the transmissions network (for generators over roughly 50 MW) or the distribution networks (under 50 MW) in a reasonable (and predictable) period of time and for a reasonable fee.

Charges low carbon users in a fair way: once connected, renewable and low carbon generators should be charged proportionately.

Able to accommodate changing demand

Future networks will need to be able to accommodate a growing numbers of electric road vehicles and trains. They will also need to provide electricity for heat pumps that provide efficient low carbon heating.

Increasing 'Smart'

- Responsive – Able to automatically control varying voltages and fluctuations in demand and supply. Able to smooth and control demand by using a number of automatic and controlled points that can be turned off to reduce demand.

- Allow for communication – Allows for two way flows of information. This could involve providing different actors with real time information on demand and supply across the network. It could provide end users with information on their electricity demand and possibly the electricity price at a particular instant.

Able to connect all users and generators?

Onshore transmission and distribution networks will need to be reinforced to accommodate increasing amounts of renewables.

The offshore transmission network needs to be developed to bring in electricity generated by offshore wind farms.

Cost reflective both in terms of electricity generation and use?

- Generation – should the amount paid for connection to and use of the system accurately reflect the actual costs imposed on the system?

- End use – should end users pay more for connecting to the networks if they are based in an area that has little spare capacity? Should end users pay more for using electricity at times when the network is very busy?

The last two points are contentious. It may not be economical to connect all generation sources to the main transmissions and distribution networks. Buildings that require electricity all of the time (for example hospitals) have their own electricity generators in case of failure across the main electricity networks. In circumstances where network connection is very expensive, stand-alone renewables are much more attractive.

Some argue that we need to bypass the existing electricity networks and develop more small local networks to connect distributed generators and increase competition. Some small 'private wires' that link local generation with end users in the local area have been developed. These could reduce electrical losses by using electricity closer to where it is generated.

The advantage of a large system is that connecting more generators and users enables supply and demand levels to be smoothed out. This is particularly important if generation becomes more 'peaky' as we move to intermittent wind. One way of smoothing out demand at a smaller level may be to combine a range of users and serve them on a local electricity and heat network. By connecting hospitals, schools, homes and offices the demand for heat and electricity can be levelled out as different users want energy at different times of the day.

By connecting many end users, the output from a large generator can be split into lots of small packages that are the right size for individual users. Connecting lots of end users reduces costs as a central controller can select the cheapest electricity from all of the generators on the system. This has been the philosophy that has been followed and has resulted in the creation of our existing centralised network model. However, we may have gone too far with this model and may need to explore greater use of energy service type models in order to optimise efficiencies and provide both low carbon power and heat.

The amount of cost reflectivity we want in the system is also worth considering. Should remote generators and end users have to pay more for using the networks given that they result in increased electrical losses and expensive extensions of the network to serve them? Should end users pay in a way that better mirrors the actual cost associated with their electricity use? Or should costs be made consistent and shared across users to make things simpler?

The reliability of our networks may become increasingly difficult to maintain as we shift to new forms of generation. We currently have a centralised system with electricity produced from large scale generators and transmitted across a single system that has to be synchronised. If faults develop, they can cause disturbances across large areas very quickly. Locating generation closer to demand, using sections of DC lines and developing a number of networks rather than one central system, may help to ensure the lights don't go out.

Some fundamental questions also need to be addressed

There is concern that current market arrangements will not enable us to decarbonise the electricity system at a sufficient pace nor will it necessarily ensure we achieve security of supply. There will need to be a change in technologies and behaviours across the whole electricity chain from generation, transmission and distribution and importantly end use. This will involve many actors and need a co-ordinated approach. Leaving it to market signals alone may not deliver the results we want.

The liberalisation of the electricity sector may have helped to reduce costs however it remains to be seen whether a liberalised market can meet new challenges. Some question whether we can achieve the full benefits of a 'smart' grid and a shift towards energy services (rather than just selling units of electricity) without vertical integration.

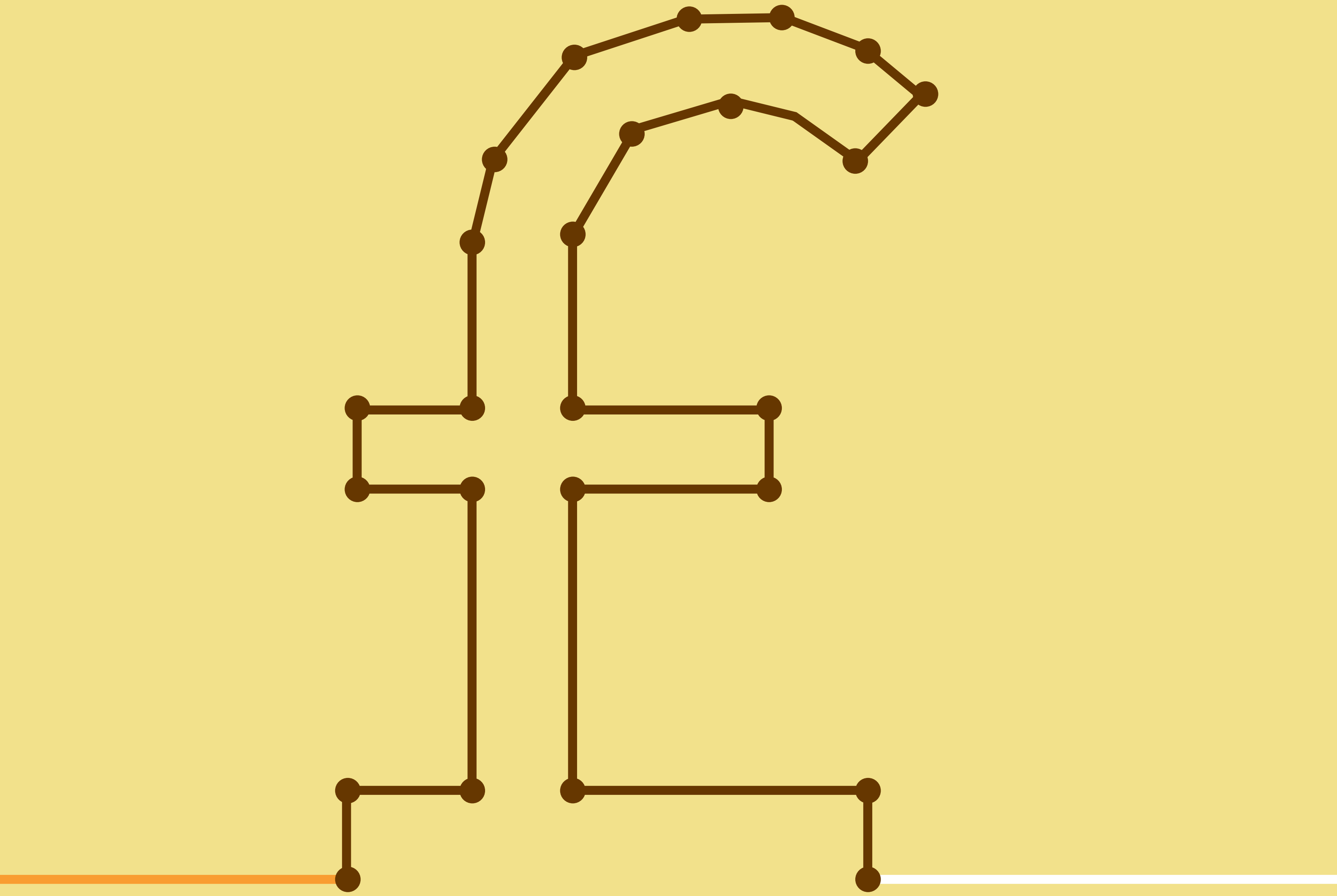
Some people are beginning to argue that there is a need for a guiding hand to ensure there is an alignment of efforts across the electricity system and proper integration with heat and transport policy, whilst at the same time ensuring issues around funding and affordability, and social aspects are properly addressed. We also need to accept that like electricity generation, choices about electricity networks are political and will always be shaped by government policy.

In future we may have to accept a lower quality of service as it becomes increasing uneconomical to maintain the current levels of service. However, electricity loads are becoming more sensitive to disruption (for example data centres) and consumer surveys suggest that energy users are not prepared to accept higher frequencies of blackouts. A way of avoiding this will be to increase the number of loads that can be switched off remotely or respond to a change in frequency of the system so that power to essential loads can be maintained. A move to the use of more local electricity networks, rather than always relying on the main T&D networks, may also be used as insurance against failures on the main networks.

Structure of this report

In the following chapters we consider some of these elements further. In the first chapter we consider the investments that need to be made across both our transmission and distribution networks both now and in the future. We then consider the way users are charged to connect to and use the electricity networks in chapter two. In chapter three we consider the impact that distributed generation, electric vehicles and heat pumps could have on the electricity networks. We then look at how greater levels of interconnection and making our networks more 'intelligent' might help us in the future, in chapter four. Finally we consider the role of the different people and organisations involved in the transformation and how we might pay for it.

Investing in the networks



In order to meet our short-term renewables targets, there needs to be significant investment in the transmission network so that more electricity can travel down from Scotland (which has large amounts of natural resources such as wind) to the South (where there is lots of demand for electricity). In order to do this we urgently need to speed up the planning process so that network reinforcements and extensions (both on and offshore) can be put in place in time.

The distribution networks will also need to be reinforced to accommodate higher amounts of local generators, electric vehicles and heat pumps. They will need to become more intelligent so that losses and faults can be easily detected and allow for two way power flow.

So who decides what needs to be done to the networks and how much money can be spent? As is the case around the world, the electricity networks in the UK are currently monopolies. In any given area there is only one distribution or transmission network. As a result both the transmission and distribution networks are regulated to ensure that the operators do not charge users unreasonable amounts to connect to and use the networks. The regulator, Ofgem, tells both National Grid and the 14 distribution companies how much they can spend to operate and maintain their networks, and the amount they are allowed to charge in defined five year periods, or 'price controls'.[14]

Ofgem also uses the price control mechanisms to try and incentive particular behaviours by network operators. For example the distribution price controls have been modified over the past few years to try and incentivise DNOs to reduce losses across their networks and to penalise those that perform badly.

Investing in transmission

Currently some areas of the transmission network are busier than others. The north to south and east to west power corridors are particularly strained. Electricity tends to flow from the north of the UK to the south and the circuits between Scotland and England are already operating at their maximum capacity.[15]

To ensure that we have enough capacity in our transmission networks, the Electricity Networks Strategy Group (ENSG) undertook a study into the network requirements under a range of different scenarios with varying amounts of renewable generation that might be achieved by 2020. They grouped projects into three groups:

- those that definitely need to go ahead now;
- projects that can wait for a second phase of improvements but pre-construction work needs to start quickly and consents obtained to increase investor confidence; and
- those that need to go ahead dependent on the level and location of future growth in renewables.

They also set out a timeline for when different projects need to be completed. The finding of their research is summarised in the box below.

However, agreeing what needs to be built is only the first step. Ofgem then has to agree to the cost of any reinforcements or upgrades to either the transmission or distribution networks. The proposals then need to get through planning, which can take a number of years. Finally if the project gets through planning, work can start however the replacement or reinforcement of networks can take several years. The construction of new lines can take even longer, as much as ten years.

This puts us on a fairly tight timetable considering the first phase of work identified by the ENSG needs to be completed within five years. In addition some of the technology being deployed is new for example that used under the seabed in offshore networks. Some time may be required to resolve unforeseen practical problems.

It is therefore essential that Ofgem approves investments quickly and that there are no significant delays in obtaining planning permission. The ENSG recommended that planning applications are submitted as part of pre-construction engineering work, ahead of any commitments from new generators.

Approving funding

The ENSG estimates that the projects identified will cost around £4.7bn. So where is the £5bn for this work going to come from? Financing all of the projects identified by the ENSG would add more than 60 per cent to the total regulatory asset value of the transmission companies. Much of it will need to be financed through the next transmission price control (TPCR5) which starts in 2013[18] however some work needs to start well in advance of the next price control review. In recognition of this, in November 2009 Ofgem suggested that £1bn of funding for specific projects should be released over two years, of which over 70 per cent is in Scotland.[19] In January 2010 Ofgem announced that it would authorise a total of £78m of pre-construction funding and £241m of construction funding over the period to the end of 2011/12 and would make decisions about further funding at a later date.[20] The rest of the £5bn investment is likely to be considered under future price reviews.

ENSG study on transmission network investment required by 2020

The ENSG has set out the investments that need to be made between 2010 and 2015 under a number of low carbon generation scenarios that would comply with the Scottish government and UK Government's renewable targets for 2020 and accommodate new nuclear plants.

The amount of reinforcement required to accommodate these generation scenarios will depend on:

- the amount of network sharing that goes on (whether intermittent generators such as wind can share the network with a base load generator such as nuclear) and
- the degree to which all generators should be able to put electricity onto the transmission networks at all times. This is defined under the GB Security and Quality of Supply Standard (GB SQSS).[16]

As well as traditional methods to address shortfalls in network capacity (such as reconductoring circuits, upgrading to a higher voltage and constructing new lines) the group considered new or previously unused technologies such as series compensation,[17] new types of HVDC and subsea cables.

The study found that:

- The upgrading of the transmission line from Beauly, west of Inverness to Denny, west of Falkirk – the 'Beauly-Denny' project – is a priority as it will enable a transmission network to develop in the north of Scotland that will be big enough to incorporate renewable growth in the region.
- Further improvements to the existing transmission network are required (for example through re-conducting and re-insulation, new substations or extensions to existing substations. Areas that require improvements include the Scotland-England interface, north and central Wales, English East Coast & Humber, London and the South West.
- Some new transmission lines need to be constructed (both onshore and offshore). For example a new line is needed to connect areas like Wylfa in Wales, which is next to an area of the Southern Irish Sea where a number of offshore wind farms are expected to be developed. A new HVDC line will need to be built to carry power from new offshore wind turbines off the east coast. New overhead lines and cable sections will need to be built to expand the transmission network to areas of Wales so it can connect to a 'hub' that will bring in power from a number of small to medium sized wind farms that are expected to be developed. A new transmission network may need to be constructed in the South West to export power produced from potential offshore and onshore wind farms, new gas and replacement nuclear power stations.

Planning

In recent times there has been vehement opposition to new electricity generators with many people against onshore wind farms, new nuclear or unabated coal-fired generators. However, opposition to overhead pylons in the 1950s can be considered to be the first example of the Not In My Back Yard (NIMBY) syndrome that has since cursed electricity generation. Whilst most people accepted that if they wanted electricity then there needed to be pylons, they didn't want them coming through their area.

The track record of getting planning permission for transmission network expansion or reinforcement in recent years across the UK is poor. In 2004 Ofgem approved the funding for the Beauly-Denny line. In 2005 it went for planning approval yet was only recently approved by the Scottish government in January 2010. Questions still remain about the project, with some arguing that sections of the project should be put underground.[21]

Even once it is approved it will take at least two to three years to build. The 220km project has attracted 18,000 objections even though it involves upgrading an existing network; new lines that traverse unspoilt countryside could attract even more opposition. Even if work was to start tomorrow the whole process will take nearly ten years from approval by Ofgem to completion. The Second Yorkshire line took ten years to get through the consents and public enquiry process.

Difficult decisions have languished on the desks of secretary of states for months, even years. As electricity networks can pass through a number of local authorities, getting permission from each one can take a long time.

So what is being done to speed up planning? The Scottish Government's National Planning Framework 2 (NPF2) prioritises a range of strategic onshore and offshore grid reinforcement in Scotland.[22] An independent body has been created to consider applications for large infrastructure projects in England (and some in Wales) that have a national impact. The Infrastructure Planning Commission was created in October 2009 and will make decisions within nine months. The IPC is guided by a number of National Policy Statement (NPS) that include an overarching energy NPS and one for networks. The energy NPS only covers large generation projects (above 50MW onshore and above 100MW offshore). The NPS for networks only covers transmission lines (ie those above 132kV).[23]

National Policy Statements and Infrastructure Planning Commission

Subject to the consultation and parliamentary scrutiny, the government intends to finalise and formally approve the energy National Policy Statements in 2010. These National Policy Statements would then be used by the Infrastructure Planning Commission when it makes decisions on applications for development consent for nationally significant energy infrastructure.

Once the National Policy Statements are approved (designated) the IPC will make decisions on new projects within nine months of receiving an application. If the NPS are not designated, the IPC will act as an advisor to the secretary of state and will not have the final decision. It is unlikely that all of the National Policy Statements will be designated before the general election.

The Conservatives have pledged to keep the IPC if they come into power, however it would only serve as an advisor to the secretary of state. The secretary of state would then make decisions within nine months.

The requirement to make decisions within a defined timeframe (whether by the IPC or secretary of state) and the development of a clear NPS that sets out the need for new or reinforced networks should go a long way to resolve some of the issues. However, some suggest that the draft National Policy Statements need to be strengthened to include a greater spatial element so that it is clear where new networks might need to be located or where existing networks may need to be reinforced and no real alternatives exist.

As planning is devolved, the IPC will not have the power to permit all elements of certain transmission projects. For example a transmission project in Wales would need to get permission from the IPC for the lines and permission from local authorities or the Welsh government for the substations. Nor is not entirely clear how the IPC will interact with local authorities and how the National Policy Statements will work alongside guidance for smaller projects set out in Planning Policy Statements (which are currently being revised).

Many suggest that transmission lines should be put underground or below the seabed where possible and particularly in areas of outstanding beauty or where there are delicate habitats. The use of underground and subsea cables should help to reduce the visual impact of new cables and may be essential if we are to get projects through the planning process.

Even undergrounding cables causes some environmental impacts and can still face opposition. They use more material than an overhead line, and the excavation process is very energy intensive and the aggregates used to backfill can be exported. It can result in soil destruction and tree root damage. The materials for underground cables can be hard to get hold of as there is such strong global demand.

Although costs are very project specific, undergrounding lines tends to cost more than overhead lines. National Grid suggests that underground lines cost between 12 and 17 times as much per unit length as for an overhead line.[24] However, others suggest that these estimates are overly pessimistic. Depending on the type of undergrounding, information from Ireland and Denmark shows that undergrounding may only be 3 to 12 times more expensive than overhead lines.

It is also important to consider full lifecycle costs, not just initial capital costs. This is especially the case for long distance electricity transmission, where HVDC, although more expensive initially, can reduce overall costs in the long run as the electrical losses are lower.

It may be difficult for the IPC to determine how much of a network should be buried. The degree to which lines are put underground is ultimately a political decision and will need to be resolved by the government.

As with generation, we need to get the public on side if the planning issue is to be resolved. We need to ensure that routes are carefully planned to minimise environmental impacts and that demand is managed to minimise the need for new infrastructure. Where new or reinforced lines are required, we need to educate the public so it understands the strategic need for upgrading the networks.

Investing in the distribution networks

Significant investment will also be required at the distribution level over the coming decades to:

- Replace ageing or failing assets such as transformers and cables;
- Provide additional capacity where use of the network is growing;
- Improve the efficiency of the networks to reduce electricity losses; and
- Trial innovative new technologies that:
  - help incorporate low carbon distributed generation (DG)
  - make networks more 'intelligent' or smart (see section 4 below).

These factors are taken into account by Ofgem when setting the five year price control review. The final proposals[25] for the next five year distribution price control (April 2010 to March 2015) for the distribution companies were published in December 2009.[26] The new price control contains a number of elements that should help to increase investment in distribution networks, whilst encouraging greater use of demand management and maintenance to reduce the need for network replacement or enforcement.

Step up in investments

In recognition of the need to replace assets installed in the 1950s and 1960s and the need for some additional capacity to be built where use of the network is growing, the price control allows for an increase in investment of 40 per cent from the last price control. Ofgem has allowed £14bn to be spent on the distribution networks over the next five years, of which the majority is expected to be used to replace ageing, unreliable or failing assets.[27]

However, there is some concern that the cost of borrowing money to finance these investments has been set too low. Ofgem set the cost of borrowing under the fifth price control to be 4.7 per cent (or 4.0 per cent post tax). Some DNOs said they would not accept anything under 5.4 per cent however all of them accepted the final proposals. This is lower than under the last price control[28] and below the cost of capital set for other regulated infrastructure.[29] Whilst each industry has different risk profiles making it hard to compare them directly, there is some concern across the industry that the rate is too low, particularly as the industry is entering new territory and having to invest in new technologies and adopt new behaviours.

The amount that shareholders receive is dependent on the performance of the DNO in terms of network efficiency, reliability and customer service. Under DPCR5, the DNOs will have to work harder across these areas to outperform their targets and will be measured against increasingly complex metrics.[30] There is concern amongst the industry that the low rates of return and the complexity of the regulatory incentive package may put off investors.

Innovation

There has been concern that previous price control reviews have increased economic efficiency at the expense of innovation and investment in workforce training and renewal. This has lead to low levels of spending in R&D and an ageing workforce.

In 2005 Ofgem introduced the Innovation Funding Incentive (IFI) to encourage the DNOs to conduct research and development. The IFI allows each DNO to spend up to 0.5 per cent of allowed revenues on R&D which equates to around £20m per year under the new price control. Half a percent was considered to be lower than typical practice in the private sector however, particularly as DNOs face considerable challenges with the introduction of electric vehicles and distributed generation.

In reaction to this DPCR5 marks a dramatic increase in innovation spending. It includes a new Low Carbon Networks Fund (LCNF), which will allow the DNOs to spend up to a total of £500m over the five year price control period in order to trial new technology and commercial arrangements. Funding will be awarded through a competitive tender process and DNOs will be required to capture and disseminate the learning from the trials to other DNOs to ensure knowledge sharing and inform future decision-making. Whereas IFI funded small one-off projects that were at the Research and Development (R&D) stage, the LCNF is to trial the real-life application of various combinations of technology or new commercial applications.

At £100m a year LCNF should therefore equate to around 2.5 per cent of DNO turnover. In sum the IFI and LCNF amount to roughly 3.5 per cent of turnover, which is above the figure recommended by the Sustainable Development Commission in 2007.[31]

Changes to the losses incentive

The current losses incentive rewards or penalises DNOs at a rate of £48 per MWh if losses are lower or higher than a target based on historic losses on the DNO's system. This is designed to incentivise the DNOs to invest in lower loss equipment, to change the way they operate their systems to reduce losses and to detect theft and unregistered meters.

Without smart metering it is difficult to accurately measure losses and DNOs currently use different techniques to calculate and report losses. This is problematic as it makes it difficult to accurately reward or penalise DNOs for their performance and also makes it difficult to detect theft on the networks.

The losses incentive has been revised in DPCR5 in two ways:

- Provides £16m of upfront funding for DNOs to invest in equipment to reduce losses (where they have made a business case using the electricity wholesale price including the government's shadow price of carbon). Companies will then be set tougher targets to make sure the investments deliver the losses reductions they claim,
- Increase of losses incentive from £48 to £60 per MWh (before tax). To address problems with measuring losses, DNOs will have to use a common approach for reporting losses. Ofgem is also introducing caps and collars in the mechanism to recognise that performance at the extremes could be driven by other factors. This will mean that DNOs will not be able to earn or lose more than 97 basis points in shareholder returns through the losses incentive, including the five year losses rolling retention mechanism.

If any DNO finds a better way of measuring losses on their network, for example by installing smart metering, the cap on rewards will be removed and the collar may be tightened further.

The increase in innovation spending is to be welcome, however as we go forward it will be important that we go from trialling these innovative processes and technologies to widespread adoption across the networks. This is no easy task and will require sustained investment and a change in role of the DNOs. It will also be important that a range of both commercial and technical projects are trialled and that projects are allowed to go across the full chain of actors (see section on smart grids below).

Incentives

The DNOs also need to invest in their networks to increase efficiency and connect distributed generators. The price control include mechanisms that reward or penalise the DNOs according to the percentage of units that are lost in distributing electricity to customers (losses incentive) and according to the efficiency of connection of distributed generation (DG incentive). The losses incentive from DPCR4 has been revised to ensure DNOs have more of an incentive to reduce losses on their network. This is important as distribution losses account for 1.5 per cent of total GB greenhouse gas emissions. The changes to the losses incentive are set out in the box below.

The increase in the losses incentive is to be welcome however at £60/MWh, the incentive falls well below the level recommended by the SDC in its 2007 report of £85/MWh. In its 2007 report, the SDC recommended that the distribution losses incentive should be set at a level consistent with the social cost of carbon (which they suggest is equal to £80/tC) raising the losses incentive to £85/MWh.[32]

Whilst the strengthened losses incentive is to be welcomed it does not go far enough and is unlikely to trigger a large-scale improvement process. At £60/MWh, the losses incentive simply doesn't justify the cost of installing low lost transformers or larger wires across the networks.

Distribution networks are incredibly long and maintaining them is a drawn out process. The length of the network run by one distribution operator alone goes round the world three times and has around 100,000 substations. As it is very expensive to access the wires (you need to dig up roads etc) improvements generally occur either when new networks are being constructed (for example to connect a new housing development) or when they are failing and in need of replacement.

Given the slow turnover of technology and maintenance programmes, it is essential that the kit being put in now is ready for future demands. Network operators should oversize cables both to reduce losses and to accommodate two-way flows of electricity as we shift to DG, electric vehicles and heat pumps. However, this approach is counter to the price control philosophy, which demands that need is clearly demonstrated before investment.

The DG incentive remains the same as in DPCR4; however the price control does include a number of other features that should help DG to connect (see section on connecting to the distribution network below).

Ensuring the most is made out of existing infrastructure

When an area of the distribution networks becomes strained, the network operators may need to spend money reinforcing them (capital expenditure or capex). However, spending more money on maintaining the networks or controlling demand better may reduce the need for reinforcement. This type of spend is counted as operational expenditure (opex).

Under previous price control reviews, if DNOs spend less than they allowed on their operating costs they are able to keep much more of it than any underspend they achieve in capital investments. In addition they were not able to pass any overspend on operating costs onto customers. This has incentivised the DNOs to invest in new 'fit and forget' assets such as transformers and cables over other options such as properly maintaining existing assets to extend their life or taking measure to better manage loads, which could be cheaper.[33]

To promote the use of alternatives to reinforcements, the latest price control equalises the incentives associated with network operating costs and network investment (and closely associated indirect costs).[34] In future Ofgem could consider going even further and make operational spending more attractive than capital spending to drive the use of demand response.

Offshore arrangements

To accommodate the growing amount of new offshore wind capacity, an offshore electricity network needs to be developed quickly. To reduce costs and help speed things up, the design, construction and operation of offshore transmission networks has been put out to a competitive tender process. The appointed Offshore Transmission Owners (OFTOs) are currently being selected by Ofgem and once selected will operate for 20 years.

In the past offshore wind projects have been significantly held up by the planning process. You currently need three separate consents, only one of which has a defined timescale for consideration. (The consent for the onshore element should be considered by the town and country planning authority (TCPA) within three months.)

The developers of the Greater Gabbard offshore wind farm found the consent process very complex and slow. It took 15 months despite relatively little public opposition. The London Array project was heavily delayed by problems getting planning permission for the substations. It can also be difficult to get planning permission for the infrastructure associated with offshore wind. The substations on land can be very large and can attract a lot of public resistance.

The National Policy Statements and the decisions made by the Infrastructure Planning Commission (IPC) will only cover onshore transmission (above 132kV) and will not cover offshore networks unless they are deemed to be 'associated' infrastructure. Offshore networks that connect to offshore wind farms are likely to be considered to be 'associated works' and should be covered by the new regime however interconnectors are unlikely to be included. In addition to the National Policy Statements, the IPC will need to consider the Marine Policy Statements which are yet to be drawn up.[35]

Under the revised planning system, an offshore wind project will need to get more consents. Some renewable developers are concerned that they will no longer have control of the planning process, as the Offshore Transmission Owners (OFTOs) will apply for some of the consents. This may make it harder for developers to manage the overall project.

The wind turbines built under round three of the offshore wind programme will be much bigger than previous offshore projects and may result in onshore transmission upgrades. This will add more complexity as National Grid will need to obtain further consents.

Some critics have suggested that developers should have the flexibility in some cases to design and construct the network and then hand it over to a third party if it would speed up the overall process.

Designing the offshore networks

The design of the offshore grid has also attracted controversy. The current system awards contracts to the bidder that can construct lines at lowest cost to a particular offshore wind farm. This creates a porcupine-like network with a number of individual networks going from the shore to each wind farm.

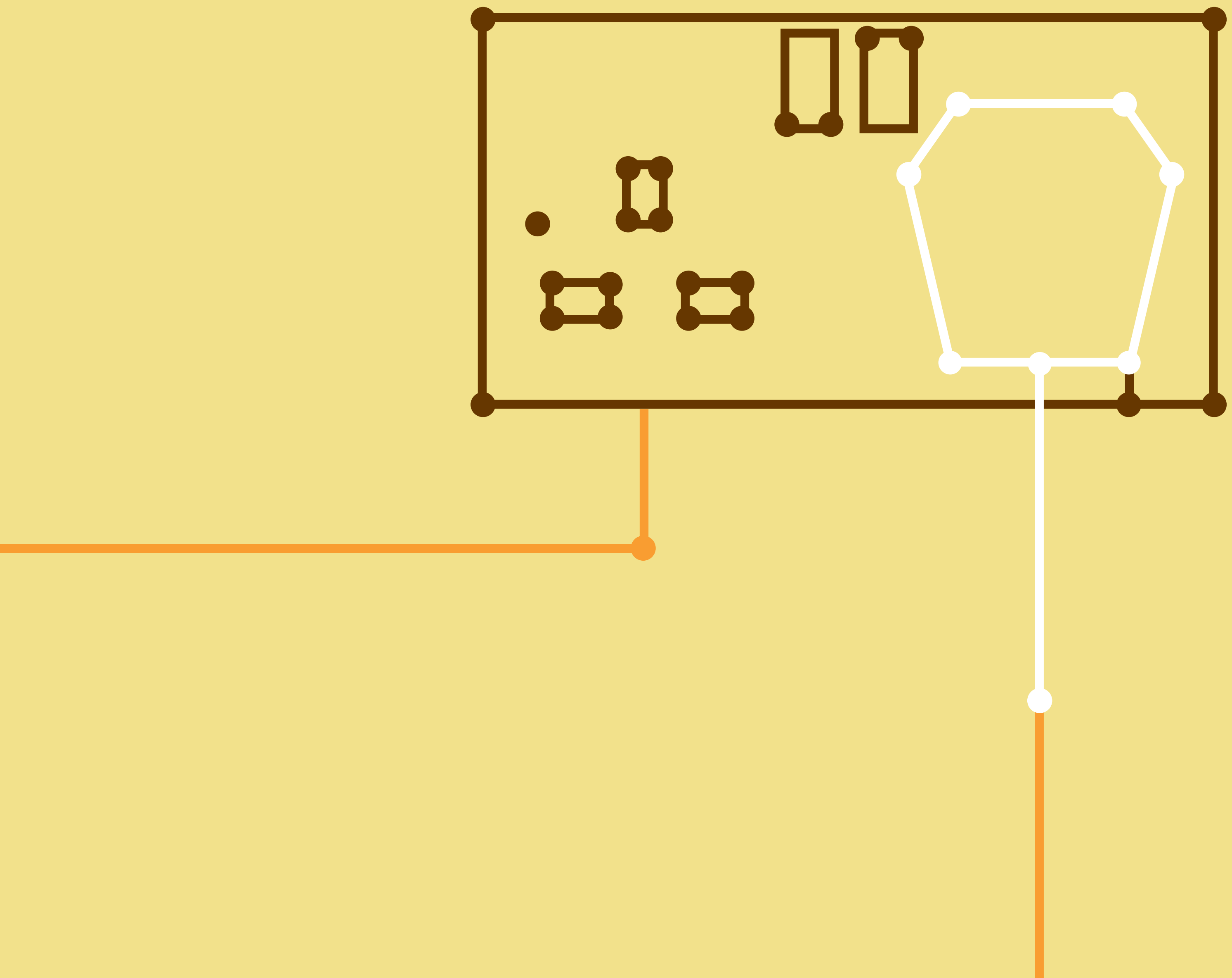
Some argue that offshore network contracts should be awarded on a zonal basis so that tree-like configurations would develop in which large trunk networks from onshore substations branch off into smaller branches out to individual projects. This might reduce costs and network losses.

Others suggest that the ability of lines to carry power from more than one project will not be possible for example that a project as big as the London array may need two cables alone. The right answer may be a combination of the two. In some cases point to point connections may be the best solution. However, there may be opportunities for greater co-ordination between projects, particularly where there are a large number of small projects in a given area. The current regime however may mean that point to point is pursued in most cases.

It has also been suggested that the current approach of waiting for commitment from developers before each line is developed may mean that the infrastructure is not developed in time. Instead the network could be developed to points that have been identified as suitable for offshore wind projects so that developers could be guaranteed that they would be able to connect to the network when the project is complete.

The development of a new network offshore provides a great opportunity for trying out new technologies and ideas. Various combinations of AC/DC cables are being considered that could avoid the need to use expensive offshore converters.

Network connection and use



It is essential that renewable and low carbon generators can get quick connections to both the transmission and distribution networks for a reasonable price. Once connected they should then be charged a fair amount to use the networks. However, determining what is reasonable is far from simple. It will depend on how cost reflective the charging is and whether costs are put on new generators alone or shared across all users.

Both the connection process and charging system should be as simple as possible and additional support needs to be given to small generators or new entrants to enable them to understand the process. Unfortunately experience to date has not always adhered to these principles.

DECC has recently consulted on how generators connect to the transmission networks and who pays for the costs associated with connection. However, the way generators and end users are charged for using the networks once they are connected may need reviewing as well.

In this section we discuss the issue of cost reflectivity and summarise some of the problems faced by generators trying to access and use the transmission and distribution networks.

How are users charged for using the electricity networks?

So how do we currently charge people that use the networks? Generators and end users pay to connect to the networks and are then exposed to a number of different types of charges for using it – see the box below. The way the various costs are calculated and shared between users is fairly arbitrary. Some charges reflect the actual cost a user imposes on the system more closely than others.

The costs associated with maintaining the networks account for around a fifth of an end electricity bill yet they are regulated costs and not determined by a market.[36]

Different charges for using the main electricity networks

- Charge for losses across networks: Transmission Loss (Tloss) and Distribution Loss (Dloss) The charges for losses are spread across all users and so do not vary between users. Proposals for transmission loss factors to vary by region are currently being considered.
- Charge for use of networks: Transmission Use of System (TUoS) and Distribution Use of System (DUoS) The TUoS charge you pay (whether you are a generator or user of electricity) depends on where you are – they are locational (see below). The DuOS charges are not locational. From April 2010 the DuOS charges will become more cost reflective – they could be positive for some users and negative for others however they will not vary depending on your location. Cost reflective charging for users connected to the distribution networks at higher voltages (above 22kV) will be introduced in 2011 – these will include locational charges.
- National Grid also charges for balancing the system through Balancing Use of system (BSUoS). These charges cover a number of things including the services required to keep the networks stable (ancillary services) and payments to generators that can't put their electricity onto the networks as it is too busy (constraint costs). The BSUoS costs are shared amongst all users.

Cost reflectivity

A fundamental question that needs to be considered is the degree to which network users are exposed to the real cost of connecting to the networks and then for using them to export electricity (generators) and import electricity (energy users). There is a balance to be had between charging users in a detailed way that changes quickly over time to better reflect the costs they actually impose on the system with a system that is simple and predictable.

Some argue that the charging mechanisms need to be as cost reflective as possible so that the market decides the most economically efficient configuration for example so that new generators are added where there is space on the networks. They suggest for example that generators in remote locations should pay more to reflect the additional costs they impose on the system.

However, with much of our onshore wind resources in Scotland, if we make costs very dependent on location we could make the cost of meeting our renewables targets significantly higher. If we deter onshore developers through high network charges we may have to invest more in offshore projects, which are significantly more expensive and receive higher levels of government subsidy.

It is also important to consider what types of costs are included in the calculations. It is easy to only consider direct costs associated with making changes to the network, for example to accommodate new generators or allow for two way flows of electricity. However, we may need to consider the wider costs associated with the transformation of our electricity system, and consider costs at a societal level.

Making all charges cost reflective may not be practical. It is easier to adopt complex charging regimes for users at high voltages where there are only hundreds or thousands of users. At lower voltages where there are millions of people connected, it could be very complicated to introduce sophisticated tariffs.

Growing attention has been given to the way in which we charge generators however as we seek to involve energy users more, the way we charge end users for both electricity generation and network costs may have to change.

The cost of electricity mainly depends on generation but network costs (especially distribution) are also significant. The cost of producing electricity is likely to become more volatile as we move to increased amount of wind. The real costs of developing and operating the networks already vary significantly between different areas – this will only increase. The costs users impose on the system will also vary depending on when they use or export electricity.

End users may need to be exposed to increasingly variable prices if we are to trigger the range of demand side management tools we may need to deploy as we move to a low carbon electricity system. The tariffs offered by suppliers may have to increasingly reflect network costs as well as wholesale electricity prices.

The introduction of time of use tariffs whereby domestic energy users are charged different rates for using electricity at different times may be a vital tool to maintain system integrity and reduce peak demand. However, the degree to which they would drive behavioural change and whether they would be politically acceptable is far from certain.

In the future additional costs will be created as we move from our centralised networks with one-way power flow to more decentralised, intelligent local networks.

We need to be careful that these additional network costs are not unfairly borne by people that adopt low carbon technologies such as electric vehicles and distributed generation (DG) as it could put people off. For example should people switching to heat pumps or electric vehicles in one area have to foot the associated costs to reinforce the networks? It is not their fault that our current system is not set up to accommodate low carbon technologies. It may

be asking too much of government subsidies to cover network costs as well as the capital costs associated with new renewable generators.

We may need to make network costs more cost reflective where it would alter behaviour (for example a micro CHP operator could decide where to locate and when to run equipment) and socialise costs that are a result of having to reconfigure the networks to accommodate low carbon technology. Whatever the arrangements, we should seek to find a balance between cost reflectivity and the need for network arrangements to support wider policy objectives.

What are the legal requirements?

The way users are charged is constrained by EU law. The UK has a legal duty to ensure that low carbon generators can connect to the networks easily and that the charging regime does not penalise them. The box below sets out the requirements under the Renewables Directive. These privileges have been extended to CHP by the Cogeneration Directive.

So what has been the experience of low carbon generators getting access to the networks to date and how does this match up to requirements set out by the Renewables Directive?

What are the legal requirements?

The Renewables Directive (or RES-E Directive)[37] requires member states to guarantee access to the grid for electricity produced from renewable sources. In order to accelerate grid connection, member states may provide for priority connection or reserved connection capacities for new installations producing electricity from renewable energy sources.

Under the Directive connected renewable installations should be given the ability to put all of the electricity they sell onto the networks so that the maximum amount of electricity from renewable installations connected to the grid is used. However, in reality this is not usually a problem as most infrastructure electricity has a zero or low marginal cost, so it will always be lowest cost and will therefore be dispatched first. Biomass plants are the only type of renewables that use fuel but as they are fairly inflexible they tend to get run as base load. Also as they are fairly capital intensive compared to fossil fuel generators, operators tend to want to run them as long as possible to recoup their investment.

If however in certain circumstances it is not possible fully to ensure transmission and distribution of electricity produced from renewable energy sources without affecting the reliability or safety of the grid system, the Directive suggests that 'it may be appropriate' for financial compensation to be given to the renewable generators involved. This is why renewable generators are paid for their lost revenue if they cannot export electricity as the networks are constrained. Currently only generators connected to the transmission networks are compensated in this way however in the future this may become more of an issue for distributed generators, and they may need to be compensated as well.

When it comes to charging methodologies for connection to the grid, the Directive calls for TNOs and DNOs to have standard, publicly available and transparent rules for charging and for the shared bearing of the costs of integrating new producers into the electricity network.[38] Therefore, TNOs and DNOs are required to provide new generators with detailed estimates of the costs associated with the connection, as well as reasonable and precise timetables for processing and satisfying requests for grid connections.

The Directive requires member states to ensure that distribution and transmission charging fees do not discriminate against electricity from renewable sources especially those based in peripheral regions.

Finally, the commission has also recommended that grid operators cover or share some of the costs associated with grid infrastructure development.[39]

Problems connecting to the transmission network

Connecting to the transmission network has become a significant barrier to progress of both renewable and conventional power generation projects. Historically access has been on a first come, first served basis. Projects that are only at the feasibility stage could sign up for connection and get a connection date ahead of projects that are nearly ready to be connected.

This has led to a queue of over 60GW of new generation capacity seeking connection to the grid, with connection dates now being offered as late as 2023.[40] Furthermore, the offered connection dates are not firm as connection could be delayed as a result of delays in network reinforcement.

Following the Energy White Paper in May 2007, and in response to the growing GB queue a Transmission Access Review (TAR) project was undertaken to review how access to the transmission network could be modified to speed up connection. TAR followed the usual formal code modification (MODS) process whereby an industry working group works to develop options and makes recommendations to Ofgem.

However, Ofgem was concerned that the working group didn't submit the full range of options. Ofgem felt that the model that was most popular with the working group majority support within the industry would 'give rise to significantly higher charges for new, low carbon generation (such as renewables) than for existing high carbon emitting coal and gas generation in similar locations'.[41] Attempts to develop a fourth model were unsuccessful and Ofgem asked DECC to step in. There was some frustration as DECC then consulted on many of the same issues that had been addressed in the previous consultation.

An interim 'connect and manage' regime was introduced in May 2009 to try and reduce the GB queue quickly. This meant that new generators didn't have to wait until the networks were reinforced before they could connect. Instead generators were offered firm connection dates within a reasonable time frame, and were entitled to use the system from that date even if the networks weren't ready. If the network becomes overloaded at times because of this, some generators may have to stop generating but are paid incremental constraint costs to compensate them for the lost electricity sales they would have made. The constraint costs are currently paid for by all users of the electricity network and passed onto customers in their electricity bills (fully socialised). The interim measure has been very helpful and has led to around 1GW of renewable projects in Scotland being offered an opportunity for earlier connection to the transmission networks.

As the current arrangements are only temporary, government consulted on long-term options for grid access in August 2009. It put forward three variants of the 'connect and manage' model:

1. Connect and manage (socialised) – where any constraint costs are fully socialised (like existing interim arrangements)

2. Connect and manage (hybrid) – where some but not all of the additional constraint costs are put on new entrant generators depending on their location and operation profile

3. Connect and manage (shared cost and commitment) – new entrants can either commit to being definitely connected to the network or if not they can opt out but be exposed to additional constraint costs

Views on the best approach varied across industry. Some people thought that the connection costs should be shared between all users but that new generators in a busy area of the network should have to pay some of the additional balancing costs that could result from their use of the network. This would give them an incentive to generate at times when the network is less busy. However, this would only be possible for generators that can choose when to generate.

Another option put forward was to socialise costs between new and existing users in the surrounding area. This would encourage existing users to share connections with new users and could lead to less new (and expensive) capacity having to be built into the network. The amount you need to build will depend not only on what you are trying to connect, it will also depend on the existing generators on the network. It may be that new renewables could complement existing fossil fuel based generators (as they may generate at different times) and share some network capacity, making the most of existing infrastructure. However, imposing congestion costs on those behind the constraints could hit renewable generators. Such a system would introduce uncertainty and existing generators could face new costs that they did not expect to face when they decided to invest in a particular project.

However, many suggested that a fully socialised model should be used as it will be the best way to maximise the amount of renewables on the system. The Renewables Directive suggests that costs should be fully socialised and it is interesting to note that countries with a much higher penetration of wind such as Germany have gone for fully socialised costs. In a number of member states a 'shallow' cost approach has been adopted: grid connections costs are borne by the new generators whereas grid reinforcement and extension costs at distribution or transmission level are covered by the grid operators and ultimately passed on to energy users. In Denmark, the grid operator also covers some connection costs for wind generators.

Others argued that a fully socialised model would lead to very high constraint costs. However, estimates of likely constraint costs vary widely between studies depending on the assumptions used and the scope of the analysis for example whether or not you consider any avoided fossil fuel consumption (see cost section below).

There were suggestions however that the constraint costs were overestimated and that there are many tools we could use to reduce the constraint costs that have yet to be exploited. There are suggestions that the current regulatory system may create an incentive for National Grid to overestimate constraint costs as it gets to keep a proportion of any underspend.[42]

In addition one of the main drivers for constraint costs is not the location or behaviour of new generators, but the lack of timely investment in the transmission networks to date. It is important we act strategically for example by pushing ahead with the work set out by the ENSG, to ensure we catch up and build the networks we need urgently and minimise future constraint costs.

DECC has recently released a second consultation[43] on grid access and has decided to fully socialise costs but with an increase in the amount of time new generators have to commit to staying on the network from one year (the current situation) to two years. DECC has selected this approach as it is simple, should help bring forward new generation and will enable us to meet our renewables target.

Whilst connect and manage is to be welcomed as it should speed up the connection of renewables, connections will still be subject to 'completion of local works' and there could still be delays in areas where a significant amount of work needs to be done on the transmission network. Connect and manage can only offer partial relief and should not be seen as a substitute for making strategic and timely investments in the networks.

This issue demonstrates how important network arrangements are and the delay they can cause to the progress of new generation projects. It also shows the wide range of opinions involved and that they may not be a single correct answer. It is vital to consider the impact any arrangements have on a wide range of different users when determining how the networks should be operated.

Charges to use the transmission network

Whilst government has focussed its attention on the way generators get access to the transmission networks, the way users are charged once they are on the system may need revision. Some renewable supporters have argued that the charging regime penalises renewables for two reasons:

1. It includes a significant locational element. The amount you pay to use the transmission network depends heavily on where you are (for example transmission use of system (TuoS) charges). Generators in remote locations can be charged a lot to use the transmission network whereas those in the southeast can actually be paid to use the system. As significant amounts of renewable resources are far from end customers, this penalises renewables.

2. An additional problem is that the charges to use the transmission network are based on capacity not generation – this penalises generators with low load factors. This is similar to renting a four bed house when you only usually occupy two bedrooms and very occasionally have guests to stay.

The methodology used to calculate is complex and can change rapidly as generators enter or leave the market. This damages investor confidence across all forms of generation.

In addition locational charging may not incentivise best use of energy overall as it may deter CHP developers in areas where the network is constrained or in remote areas but where there are lots of industrial heat sources (for example in the North and Midlands). The arrangements also penalise pumped water storage projects as they are located in remote locations and by their very nature only run for small periods of time.

Locational charging may have been a good option when we mainly relied on fossil fuel power stations to provide us with all our electricity. Gas fired power stations can choose from a number of locations and it makes sense to have price signals that encourage new generators to pick sites near to their customers to minimise the distance electricity has to travel across the country and the resulting electrical losses. However, the type of low carbon generation we are moving has some geographic constraints for example wind will need to go where it is windy, fossil fuel powered stations will need to be built near suitable carbon storage sites and nuclear will be built on sites already developed etc. Locational charging may therefore become increasingly redundant as we shift to low carbon power sources.

The most common approach across Europe is the postage stamp model whereby all users pay the same amount wherever they are to use the transmission networks. Indeed the current approach could go against the Renewables Directive as it discriminates against electricity from renewable energy sources.

Others argue that locational charging is required to ensure that generators are optimally placed close to demand to minimise losses of electricity across the network. They suggest that the current locational charging hasn't put off developers in Scotland where there has been a strong growth in onshore wind. However, others suggest that the high charges in remote locations has already meant that some wind projects have been smaller than they could be to limit the transmission charges and that it has put some schemes off altogether. It appears that the current charging regime may be slowing the development of low carbon generation and further thought needs to be given to this area.

Charging distributed generation (DG) for impact on transmission

Larger generators connected to the distribution network (those typically above 100MW) are also charged for use of the transmission network. These generators have to pay for any electricity they export onto the transmission network on a net flow basis (generation minus demand).

However, anything below this currently receives a double or 'embedded' benefit:

- they don't have to pay to use the transmission networks; and
- they get paid for reducing demand (as distributed generation reduces the demand for electricity from the transmission network by users in their area, they get paid a proportion of the avoided transmission charges by energy suppliers to users in their area).

However, National Grid believes that all generators should pay transmission charges even if they are connected to the distribution networks and do not export electricity onto the transmission network. Charging DG in this way would remove the benefits that small distributed generation receive as a result of not having to pay transmission charges. It would also add complexity.

National Grid has recently published a pre-consultation document on the subject.[44] In its pre-consultation National Grid suggests that it favours an approach where DG pay transmission charges on a gross basis ie for their total capacity rather than for the net flow that actually flows onto the transmission system.

National Grid argues that all DG have an impact on the transmission system (by reducing demand) and should therefore be exposed to TNUoS on a gross installed basis. When this issue was considered by the industry previously, there was a consensus view that DG should only pay where it exports onto (uses) the transmission system; that is net of demand.

A shift to gross charging doesn't appear to be fair. It would harm distributed generators and does not appear to be cost reflective. Distributed generators should not have to pay for using the transmission network if none of the electricity they produced actually spills onto the transmission networks. In addition, if this approach were to be applied consistently we would need to charge users across continental Europe and equally they should charge us back for using their networks.

Problems getting access to distribution networks

Generally connecting to the distribution networks is less of a problem than connecting to the transmission networks. The distribution networks can be reinforced or extended relatively easily and can be put underground, avoiding the five to ten year public enquiries that have held up transmission projects. There has been significant progress in developing standards and licences that enable small generators to connect to the distribution networks more easily.

However, connecting to the distribution networks has not always been easy due to a number of issues:

Slow connection. It often takes DNOs a long time to give cost estimates and provide connection to the distribution network. For example in 2009 Ofgem fined EDF Energy Networks £2m for failing to connect customers to its networks within three months. This affects both end users that wish to import electricity from the network and small generators that wish to export electricity into the networks. Many of the connection delays in the past have been as a result of having to wait for necessary transmission reinforcements before DG can connect to the distribution networks. This increases the uncertainty and risk of a low carbon distributed generation project.

Confusing connection process. Small developers may not understand what they need to do to get connection. The process also varies between DNOs. Many customers wanting to connect DG complain that the DNOs do not provide the information in a simple and accessible way and are more geared towards their larger, well-informed customers. Each DNO needs to produce simple guidance to explain connection process for example through a flow diagram.

Problems with connection charging methodologies. There is currently no standard and unified methodology for calculating the cost to connect to the distribution network. Methods to work out distribution access charging not only vary among DNOs; charging arrangements by the same DNO are also worked out on a project-by-project basis.

Some people suggest that DNOs tend to overcharge and over-design for network reinforcements. It falls on the generators to take things further with the regulator if they are overcharged but due to the lack of clarity in charging methodologies this can be hard to work out. This is particularly difficult for small generators that don't have the resources for this.

Grid connection tools and feasibility reports. Potential generators can use a Geographic Information System (GIS tool), which calculates the costs of connection according to location. This is extremely useful but prohibitively expensive for small generators.

- The 2008 Energy Act meant that DNOs could charge generators for feasibility reports (estimates of the costs to connect to the network in a certain location). Currently generators do not pay for feasibility reports unless a scheme actually goes ahead. However, this is being contested by some generators and Ofgem is considering whether or not DNOs should charge for things associated with connection such as feasibility reports.

- Easy to understand information on where distribution grid is less busy and indicative costs of connection needs to be made available to DG developers. This would help to encourage DG but also help DNOs to balance their networks better.

There is a website that allows developers to do rough and ready calculations for connections above 33kV but it is not useful for smaller projects.[45]

Complicated technical standards. A new generator connecting to the distribution network needs to adhere to technical engineering standards. Some people suggest that the standards set overly onerous conditions on small generators to ensure that any failure of the generator does not cause problems on the local networks.

- For example some distribution network operators require even small generators to adhere to very strict standards for example Neutral Voltage Displacement. This has been a real barrier to the development of CHP. Progress to date to address these standard related issues has been slow.

However, there have been a number of recent developments that should address some of these issues. Last year, Ofgem relaxed the need for distributed generation to wait for transmission reinforcement before it could connect to the distribution networks. The connect and manage arrangements for transmission are to be extended to distributed generation which should speed up connection times. The latest revision of the technical engineering standards removes the need for Neutral Voltage Displacements for projects <5MW in all but a few cases.

The costs of using the distribution networks has also been a problem as it currently varies between DNOs and the charges can be changed quickly, creating uncertainty for existing generators. The amount you pay to use the network does not accurately reflect the real costs you impose on the distribution networks. Only one of the network operators, Western Power Distribution (WPD) applies cost reflective charging for all voltage levels. However, Ofgem is introducing a new charging regime for using the distribution networks that is more cost reflective in April 2010. It should make the charging system fairer and reward customers who make less use of the network by installing generation or who use less electricity.[46]

In addition the latest price control mechanism for the distribution companies (DPCR5) includes a number of features that should help DG:

- DNOs will need to improve the information available to DG developers;

- They need to undertake a review of their existing contracts with distributed generators to ensure that users' rights are clear and that charging is non-discriminatory in nature;

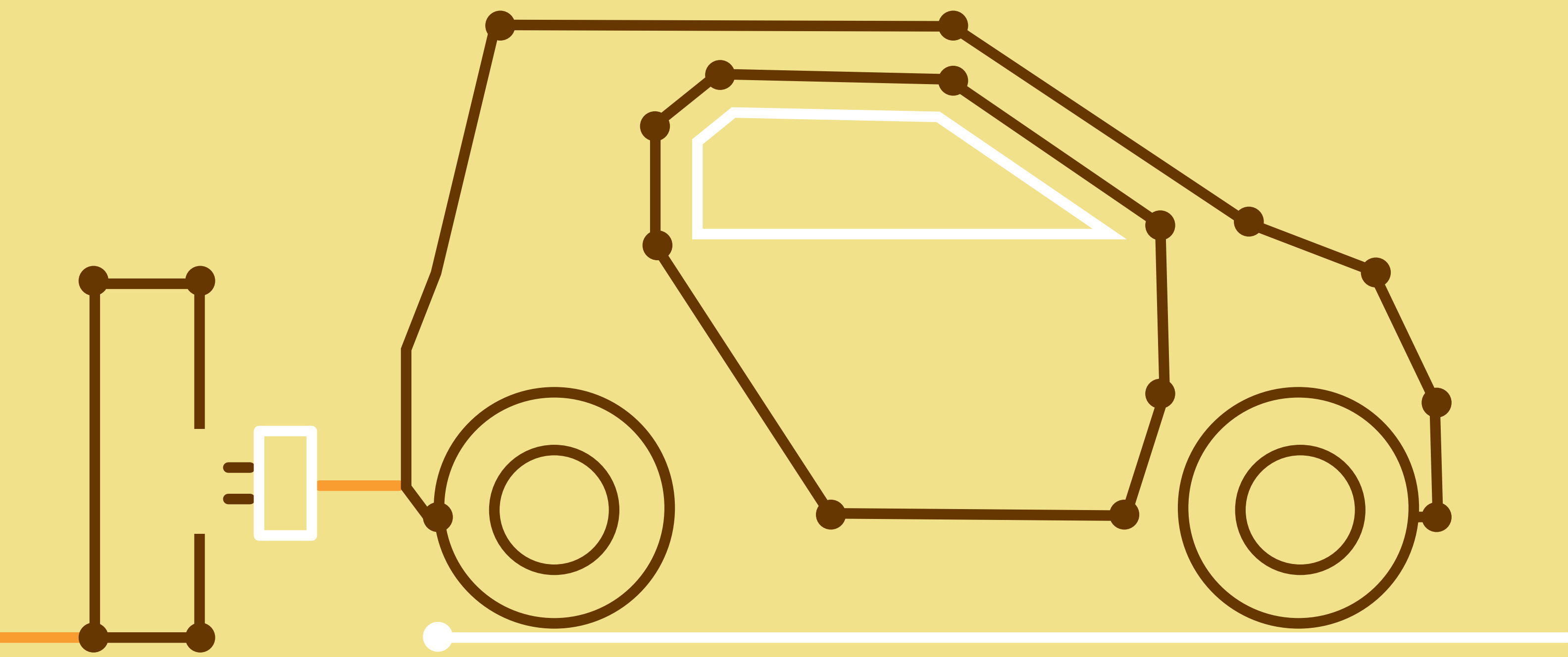
- They will be exposed to transmission network interface costs – this should incentivise them to increase the level of DG to reduce these costs;

- It introduces new guaranteed standards and licence conditions relating to connections service, including the connection of distributed generation. Customers will get compensation if they do not receive connection quotes within a defined timeframe and if their connection is not completed within the timeframe agreed with the DNO; and

- It merges the revenue pots for demand and generation so that well located distributed generation should be rewarded by negative use of system charges.[47]

It will be vital that these new arrangements are implemented quickly across each DNO. The guidance that the DNOs need to give distributed generators needs to be easy to understand and should be user tested. Ofgem will need to oversee the development of the guidance to ensure that it is developed soon and is consistent between DNOs. Ofgem may also need to conduct a review after a year or two of the new regime to check that fair charging regimes are in place.

Impact of microgen, electric vehicles and heat pumps



The decarbonisation of our electricity sector is essential for us to meet our ambitious carbon targets. This is not only because electricity production is a significant source of carbon emissions, but we also need to provide low carbon forms of energy for transport and heat. The introduction of ground and air source heat pumps that use electricity to produce heat could provide a low carbon way of heating a range of buildings. The introduction of electric cars, buses and even vans will play an important role in reducing emissions from road transport. Our current diesel dominated train system is to be slowly electrified and new high speed rail networks developed.

Some question whether it would be sensible to completely shift to electricity for heating and transport. The potential peak in demand that could result would mean we would have to significantly scale up our electricity system which would be very expensive. The Low Carbon Transition Plan suggested that it was possible that demand for electricity could be 50 per cent higher than current levels between 2030 and 2050 as a result of electrifying much of the UK's transport and heating.

The level of uptake of all of these technologies is very uncertain and will depend on a number of factors, in particular the level of government support they get. The suggestion that we run everything on electricity is not new and was suggested by nuclear enthusiasts in the 1970s. If we do have a significant shift, it will be even more important to make demand for electricity significantly more flexible than it currently is if we are to avoid having massive demand peaks.

More work needs to be done to understand the potential impact electrification could have on electricity demand and on the networks. Detailed research is currently underway at Imperial College to look at the costs of integrating microgeneration or 'microgen', electric vehicles and heat pumps with or without making the distribution networks more intelligent. Trials of heat pumps and electric vehicles will give us insight into consumer behaviour and the real loads that these technologies put on the networks.

There is a broad consensus that the current networks should be able to cope with the likely uptake of distributed generation (DG), electric vehicles and heat pumps over the 2010 to 2015 period however beyond that a range of tools may have to be deployed to manage both the distribution and transmission networks. These include making the distribution networks more intelligent, introducing time of use tariffs and automation (ie some cars can only charge during periods when the networks aren't constrained).

The next five years provide a vital window for the DNOs. During this time they need to trial new technology, different configurations of technology and just as importantly, new commercial arrangements to enable them to successfully integrate new low carbon technology in the future. It will also be important to conduct trials to better understand how energy users react to the new arrangements. By using innovative techniques, the costs associated with integrating these new low carbon technologies can be significantly reduced. In the long-term electric vehicles and heat pumps may be seen as useful tools to help balance the networks as they are not as time sensitive as many other sensitive loads.

In this section we look at the impact DG might have on the networks. We also consider the possible magnitude, type and timing of electricity demand associated with electric vehicles, heat pumps and the impact they may have on the electricity networks.

Distributed Generation

Currently distributed generation accounts for around ten per cent of total electricity generation capacity in the UK[48] – much of this consists of CHP plants and wind farms connected at higher voltages on the distribution networks. Microgeneration that connect at lower voltages account for less than half a percent of the total capacity of the electricity system. However, the introduction of zero carbon homes, more stringent planning requirements from certain local authorities that will require some on-site generation, and cash back schemes for both renewable electricity and heat projects should increase this.

Government hopes to get two per cent of electricity from microgenerators by 2020. However, this is a very unambitious target and many suggest that we should have set the level of the Feed in Tariffs higher and aim for six per cent as a minimum.

Connecting distributed generation

As discussed above, significant progress has been made towards making it easier for distributed generators to connect to the networks. Currently if you connect less than 16 amps per phase you can 'plug and play')ie connect your microgen and then inform your DNO within 28 days). If you connect something above this you have to get permission from your DNO first and get a quote for connection.

Currently the cost of a quote can vary significantly between areas however there is concern that as microgeneration penetration increases, the costs of connecting DG to the distribution networks will start to vary enormously depending on the amount of spare capacity on the local distribution network and whether it has modern transformers that can cope with higher levels of demand and generation.

Impact on distribution networks

The impact of microgen on the networks will depend on where it is connected and how much there is in a particular area. Unless lots of distributed generators connect in a particular area, there are unlikely to be problems with the network. There is typically plenty of space or 'headroom' on the medium to high voltage parts of the distribution networks. However, problems could arise at the low voltage parts of the network for example in residential areas if there is a significant 'cluster' effect through street wide take up of a particular generation type. The impact will also depend on the type of microgen and how close it is to end users. For example micro CHP close to end demand may prove less of an issue than wind turbines placed far from end users.

In some cases distributed generation will help to relieve networks that are becoming constrained. This could be particularly useful as we start to install heat pumps and charge electric vehicles at home. To maximise the benefits of DG, it will be important to the local networks to be actively managed so that supply and demand can be balanced in real-time.

In areas with large volumes of photovoltaics there can be problems when there is a lot of sunshine and low demand. For example in Germany in August when lots of people are abroad on holiday. If the voltage increases significantly it can lead to a fault developing.

Controls will need to be installed across the distribution networks to deal with the two way power flows that distributed generation introduce. In the longer term new, larger cables and transformers may have to be installed in areas with lots of DG.

Impact on transmission networks

Historically electricity has only been imported from the transmission network into the various distribution networks. However, in some areas National Grid is beginning to see small amounts of electricity being exported from the distribution network onto the transmission network. If DG is connected to an area that is already exporting to the transmission network, there may need to be some reinforcements made to the transmission network. However, we are unlikely to reach this situation in most areas in the foreseeable future.

Electric vehicles

Electric vehicles were around as early as the 1830s, however they never managed to compete with the popularity of the conventional Internal Combustion Engine (ICE). Over the past few years however, the interest of policy makers and businesses in electric vehicles has been revived due to their potential contribution to lowering carbon emissions from road transport.

London and other cities in the UK and Europe have already set out plans for large-scale electric vehicle schemes aiming to accelerate their rollout. Many foresee a mass shift to electric vehicles for personal, commercial and public transport, which could have a significant impact on our electricity networks.

There are different types of electric vehicles (EVs) available today, each with different CO_2 benefits and fuel savings:

- Hybrid EVs (HEVs) use both an electric motor and a conventional ICE. HEVs do not plug into the grid and do not need infrastructure to support them so they will not impact on the electricity network.
- Plug-in hybrid EVs (PHEVs) connect to the grid and store enough electricity in their on-board battery to fuel an electric motor for a range of about 40 miles. Beyond that, they function as full hybrids, running off fuel. A number of manufacturers including Nissan, Vauxhall Toyota and others are preparing to roll out mass-produced plug-in hybrid electric cars later this year.
- Battery Electric Vehicles (BEVs), use a single electric motor powered solely by electricity supplied by the network and stored in an onboard battery.

There are currently no commercially available PHEVs or full EVs. EVs are however already being used in niche applications and pilot projects. Several car manufacturers are planning a large-scale commercial roll out of several PHEV models in the UK by the end of 2010.

The range of the first models of electric vehicles varies between 90 and 160km and over time is expected to reach as much as 400km. In PHEVs the range provided by the on board battery can be up to 64km and with the ICE taking over it reaches a total of 400km.[49]

Energy users might initially be discouraged by the limited range of EVs, and worry about running out of power mid-journey. In reality, however, 96 per cent of daily trips in the UK are less than 160km,[50] which means that EVs would be able to cover the large majority of trips, particularly in densely populated cities.

Benefits

There are a number of benefits associated with electric vehicles:

- **Reduce energy use for transport.** Electric vehicles may enable us to reduce our reliance on imported road transport fuels. The battery EV can be over 60 per cent more energy efficient than today's conventional ICEV.[51] Although electric powertrains are vastly more energy efficient than standard engines,[52] when comparing efficiency from 'plant to wheel' the efficiency of electric vehicles shrinks to 21-25 per cent vs 15-19 per cent for conventional cars. This is because oil refineries are highly energy efficient, as opposed to power stations burning coal and natural gas. Electric vehicles also take more energy to manufacture than conventional ICE vehicles. However, over time battery performance should increase, increasing the overall efficiency.

- **Carbon savings.** Unlike conventional vehicles, EVs produce no CO_2 emissions from their exhaust pipes. However, there are carbon emissions related to the production of the electricity supplied by the central electricity networks. Nevertheless, even when the grid electricity emissions are taken into account, EVs emit up to 44 per cent less GHGs than petrol or diesel cars even under the current electricity mix.[53] This potential for carbon savings will become even more significant in the future, as the UK moves towards a more low carbon electricity generation mix.

- **Air quality** Battery. EVs could help to significantly improve local air quality, particularly in congested areas such as city centres, as they produce no emissions at the point of use. However, overall emissions of NOx and SOx can be higher for EVs if you take into account the emissions occurring during the extraction, transport and combustion of fossil fuel at electricity power stations outside urban areas. However, these emissions are easier to control as they occur in fixed locations. Projections suggest that over time EV air quality impacts will reduce and will be comparable to those of ICVs in 2020 or 2030 as renewables make a greater contribution to the electricity mix.[54]

- **Noise.** Electrical engines are also much quieter than ICEs, and could help to reduce the noise created by road vehicles. There have been concerns however about pedestrian safety related to quieter cars.

Electric vehicles can therefore have a positive impact on a number of areas, however as with any technology, the benefits need to be considered on a full life cycle basis. To maximise benefits there needs to be significant progress made towards decarbonisation of the electricity system. In addition there are concerns about the scarcity of a number of precious and rare earth metals that are used in electric vehicles.[55]

The widespread adoption of EVs should not however be seen as a substitute for a comprehensive sustainable transport policy. PHEV and electric vehicles should help us to reduce the carbon intensity of our vehicle fleet, however demand reduction will also play an important role if we are to get onto the emission trajectory set out in the Climate Change Act. The CCC's annual report found that the total car kilometres will have to have peaked in 2009, even with an ambitious take up of low carbon vehicles.[56]

Charging requirements

Electric vehicles can be charged at home or at public charging points. Neither at home nor on-street charging currently accommodates fast charging (which requires a three phase connection). Whilst on street charging points are important in reassuring users concerned about the range of electric vehicles, many think that most electric vehicles will be charged at home.

Slow charging at home uses standard plugs and a single-phase electricity supply. Off-street home charging points could cost as little as £50 per household. For households with no off-street parking, on street charging using extension power cables from buildings would most likely be an easier and more economical solution for the near term than installing standalone on street charging points

Public charging points (in car parks, supermarkets etc) are currently similar to the connections in homes (240V/13A). Charging in these points can take as long as eight hours for a full charge, as is the case with home charging. However, drivers are unlikely to be charging a fully flat battery, as letting the battery discharge by more than 50 per cent regularly begins to reduce the battery's life.

Fast-charging points allow a significant proportion of the battery to charge in about two to three hours. However, the cost of a fast-charging point could be as much as £40,000. In addition as fast charging needs a much higher power supply than slow charging, their installation in some places might result in the need for grid reinforcement, further increasing their cost.

A promising alternative to battery charging points is battery swapping where discharged batteries would be exchanged with fully charged ones in just a few seconds. If this network was extensive enough, it would allow full EVs to cover much longer journeys and would help make EVs more popular, as it would eliminate the need to wait for battery charging. However, for this option to work there would need to be a full standardisation of batteries and battery platforms across all EV models, which is likely to require regulation. Project Better Place (see below) has proposed the development of a battery exchange network, in conjunction with the construction of public charging points in London.

Paying for charging points

For the sector to really take off, charging infrastructure needs to be developed to increase consumer and manufacturer confidence. A chicken and egg scenario could potentially develop with no-one in the private sector wanting to invest in expensive infrastructure until there is a guaranteed market, and energy users not wanting to buy electric vehicles until they know they can charge them anywhere they go. Others suggest that this would not be an issue and that the charging infrastructure would follow if there were a significant increase in electric vehicles.

However, there is a clear role for the public sector to play with its procurement policies, ensuring that it starts to buy increasing numbers of electric cars. In this way, it can stimulate the market and increase confidence in the technology.

So far the majority of public charging points in the UK have been developed by councils (for example Westminster Council). In London today there more than 200 charging stations with 70 being in Westminster Council. The Draft Electric Vehicle Infrastructure Strategy has set out the goal of creating a network of 25,000 charging points: 22,500 at London's workplaces, and 2,500 in public spaces (streets and car parks). The aim is that no Londoner is more that one mile from a publicly available charging point. Faster charging points are planned to be installed on the road network and motorways.

In the long term local authorities and other public bodies are unlikely to be able to pay for a widespread network of charging points. It is not yet clear who should pay for and operate on street charging points. Should it be the car manufacturer, network operator, local authority or energy supplier for example? Some suggest that the distribution network operators are well placed to develop and maintain the charging points as they would be a natural extension of the existing networks. Whoever operates them, they will need to liaise with the network operator, systems operator, energy supplier or local generator to ensure that the networks can cope.

Novel financing approaches could be adopted for example developing charging infrastructure as a regulated asset similar to the rest of the electricity networks. This would enable the person developing the infrastructure to recover the installation and operating costs and achieve an adequate return on investment.[57]

Paying for the electricity to charge your vehicle

Currently it is free to charge a vehicle at a public charging point, however as EVs are deployed on a larger scale this will no longer be sustainable and begs the question of what pricing arrangements councils and providers will deploy. There are a number of potential methods for pricing including an annual fee or charging by the unit of time used.

There is also the issue of taxation – currently road users pay significant amounts of fuel tax. A way to tax electric vehicles will need to be developed unless the Treasury is to lose a significant source of revenue.

Failure to tax electricity used for road transport could make motoring significantly cheaper and could result in people travelling further, reducing the environmental benefits associated with electric vehicles and causing increased congestion. Ensuring users are charged in a way that reflects the availability of electricity and the conditions on the local network will also be important to minimise network problems (see below).

Uptake

A number of car manufacturers are planning a market rollout of EVs in the next few years. However, because of the length of product development cycles, large-scale volume production of EVs is unlikely to happen before 2014, restricting the supply of EVs in the short-term.[58]

EVs and PHEVs may not prove to be popular in the immediate term due to their high upfront cost, consumer perceptions around their smaller range and charging times. Their widespread roll out and adoption will rely on a wide range of factors which are often interdependent:

- consumer confidence and education – as barriers to the adoption of electric cars can often be more psychological than technological;
- advancements in battery performance;
- lifecycle cost of EVs for the consumer compared to conventionally-fuelled vehicles (dependent on battery cost, fuel prices versus electricity prices and government subsidies);
- time taken for charging; and
- availability of charging infrastructure.

Electric cars currently have a price premium over conventional cars. Early EV and PHEV models in the UK will cost from £6,000 to £20,000 more than comparable conventional cars but this is bound to fall as the market for electric vehicles matures. This upfront cost is partly offset by the significant running cost savings over the lifecycle of electric vehicles. At the moment, an electric car costs between 1.6p to 2.7p per km to run while a petrol car uses from 6p to 14p per km.[59]

Even with the current government subsidies offered for electric cars (ranging from £2,000 to £5,000 per car) the cost of buying an EV will be significantly more expensive than standard vehicles in the short-term. In addition, energy users tend to heavily discount the future fuel cost savings when deciding to buy a car. Therefore the role of government support is particularly important in order to boost and sustain the EV market until it reaches the scale it needs to be able to compete with the cost of petrol vehicles.

New ownership models could also help. One of them is battery leasing, where one buys an electric car but leases the battery from the car manufacturer – this is the set up for Leaf, Nissan's EV model planned for rollout in the UK at the end of 2010. A model similar to mobile phone contracts is developed by Project Better Place, a US-based provider of electric vehicle services, whereby EV owners pay to access to a network of charging points and battery swapping stations. The battery and charging infrastructure is owned by the company. If the rapid pace of change in performance and cost of laptop and mobile phone batteries is anything to go by, EV batteries could soon become much more affordable. And if new car ownership models take off and change the face of car markets, electric cars could soon be able to compete with petrol vehicles.

However, the consensus among experts and government expectations is that the uptake of EVs will be slow, at least in the near term. The Department for Transport (DfT) has developed a number of scenarios for the deployment of EVs based on varying levels of government support, battery technology development and cost of EVs. According to these scenarios, the number of EVs and PHEVs on UK roads could vary between 270,000 in 2020 and three million vehicles in 2030 in the business-as-usual scenario, and three million in 2020 and 20.5 million in 2030 in the 'extreme-range' scenario. This means that under business as usual, electric vehicles could account for less than one per cent of the roads in the UK by 2020 and around ten per cent by 2030.

PHEVs are expected to see a wider adoption than EVs in the early stages of the development of the EV market due to their greater range and flexibility. The uptake of EVs is likely to be concentrated primarily in urban centres in the medium term, as there is a better match between the range they offer and urban travel needs.

Impacts on networks

There is a widespread perception that the large-scale adoption of EVs will increase electricity demand significantly and will therefore require a large amount of investment in new electricity generation and network reinforcements. However, most experts do not expect there to be a significant impact on the transmission networks, particularly if electric vehicles are charged during late night off-peak hours rather than high-peak daytime and early evenings.

A recent study by a consortium including E.ON and Ricardo[60] showed that in a scenario of a ten per cent PHEV and BEV market penetration in the UK (adding three million cars to the UK fleet) and with uncontrolled domestic charging (the worst-case scenario in terms of peak loads on the network), there would be a daily peak increase in electricity demand of less than two per cent (1GW approximately). With off-peak charging tariffs and smart metering in place that would incentivise charging during the night, the impact on peak electricity demand would be close to zero. Given that a ten per cent market penetration is not projected to occur for around 10-20 years, the electricity networks should be able to accommodate a growing electric car market. Analysis by Element Energy carried out for the CCC reached the same conclusions.[61]

Analysis by E4Tech suggested that if all the UK fleet were to be entirely replaced by electric vehicles (and with 2004 levels of transport demand) the increase in the electricity demand would be of the magnitude of 16 per cent of the electricity compared to 2007 levels.[62]

Impact at distribution level

At the local level, however, there are worries that EV charging could present challenges at the distribution level where there are many early adopters in one area. Currently maximum demand per household is or the order of around 1.5kW however electric vehicles need around 7kW to charge.

Experience with electric and fuel cell vehicles in California suggests that the new vehicles may become popular in specific areas and a number of 'hot spots' may develop on the distribution networks where demand is particularly high. This might mean that distribution networks will need to be reinforced in particular areas where there is likely to be a high concentration of EVs or where networks are already close to capacity. However, others suggest that charging at home will be popular in the suburbs and demand will be dispersed across the country. Targeting suburban areas first might make more sense anyway as there is less potential for walking and public transport.

Fast charging points have much larger loads therefore they use up more network capacity, and will also be used for charging predominantly during the day and not during off-peak hours. Therefore, where there are plans for a high number of fast charging points, local networks might need to be reinforced and where possible fast charging points will need to be strategically placed in parts of the network that are not close to capacity.

Not much is currently known about how people will actually charge up their vehicles, however ESB Networks in Ireland is currently doing trials to understand the load characteristics of electric vehicles in both rural and urban areas.

Concerns over the potential impacts of electric vehicle deployment on the network should not be a reason to delay the adoption of electric vehicles. Existing network capacity seems to be enough to support the new technology, at least in the near term. However, it is important to ensure that the introduction of electric cars will not cause disruptions to the network. To achieve that, detailed assessments are necessary to understand where the local impacts on the grid will be so that network upgrades are correctly targeted and done in enough time.

Ensuring people charge vehicles at right time

In order to minimise the impact on the networks and smooth out electricity demand, it will be important that vehicles charge during periods when demand is lower and electricity is cheap and/or when the local networks are not constrained. The simplest way to achieve this would be a delay timer which would enable charging during off-peak periods. Electric vehicles could also be charged overnight on a simple two level tariff such as economy 7.

As the uptake of EVs increases however, controlling the time of charging of EVs will need to be more sophisticated. Vehicles will need to communicate with the charging point (if on the street) or with the smart meter (if charged at home). This will allow signals about electricity price or network conditions to be sent to the vehicle. The vehicle could then be automated to only charge when the supplier or network operator wants it to. Alternatively energy users could charge their vehicles whenever they like, but the cost of charging will vary depending on the availability of electricity and network conditions. This may however not result in enough predictable load shifting and some automation may be required to ensure there is a reliable response.

Initially it was assumed that charging points would be 'intelligent' however as charging points are already expensive and prone to vandalism, it is now thought that it is better to build the extra intelligence into the vehicles (for example be able to communicate with supplier so it can charge for electricity etc).[63] European standards are being developed for electric car plugs – it will be important that these align with the standards being developed for smart meters and communication models.

However, people may be reluctant to commit to having their vehicles controlled in this way and may wish to choose when they charge. So far little is known about the potential behavioural response of energy users to variable tariffs. In addition with increasing amounts of wind, the availability of electricity may vary within the day and energy users may not be able to react to the market at short notice.

Whilst people charging their vehicles at home will be incentivised to charge overnight, charging at public spaces is more likely to occur during the day. Demand in urban areas where there is limited space for home charging may therefore be harder to shift.

Using electric cars for electricity storage

A widespread adoption of EVs could provide a valuable balancing tool for the grid, particularly as the electricity network becomes more reliant on variable renewable energy sources like wind and solar. With the development of lithium (Li-ion) batteries, electricity can be stored more efficiently and economically.

Vehicle-to-Grid (V2G) technologies could allow electric vehicles to have a bi-directional connection to the grid. This way, owners of EVs could be incentivised to charge their vehicle's battery overnight when demand is low and the wind is blowing and sell the electricity back to the network during peak demand at a price higher than that of charging. This would help even out the peaks and troughs of electricity demand.

However, there is concern that the life time of batteries can be significantly reduced if they are constantly charged up and down. More research will need to be done to improve battery performance if V2G technology is to take off.

If EVs are to be deployed on a broad scale for V2G applications, the electricity network will need to manage distributed energy storage and two-way power flows on a large scale. EVs and the management of their distributed storage potential will be an important part of a smart grid (see section below). Although most estimates show a measurable deployment is at least three to five years away, the different electricity network players should be planning now to make the necessary system changes both to cope with and capitalise on the use of EVs.

Arrangements between electricity suppliers and electric vehicle manufacturers are already beginning to develop. For example Better Place is working with a Danish company to store electricity in extra EV batteries and use it when there is excess wind generation.

Heat pumps

Heat pumps can be an efficient way of using electricity to provide heating or cooling by taking advantage of the temperature difference between a building and the air, ground or body of water outside.

In a ground source heat pump (GSHP), an electric motor is used to circulate a fluid around a loop of plastic piping that either goes down into the ground or is passed through a reservoir. The loop of piping can be put into either a flat or vertical borehole in the ground next to the building. As it travels the fluid in the loop heats up and expands. The fluid then passes through a compressor and gives off the heat it has gained through a heat exchanger, so that it heats water that is used in a central heating system. Alternatively a GSHP can be run in reverse so that it acts like a traditional refrigerator and cools a building. GSHP provide a very efficient way of heating (or cooling) a building. For every unit of electricity used by the motor, around three to four units of heat can technically be produced by a heat pump. However, in reality performance can be much worse with the ratio of heat out to electricity in of typically around 2.6 (see below). In addition it can be difficult to install heat pumps in existing buildings as they require new large radiators or underfloor heating systems to deliver the low temperature heat produced.

Instead of using the temperature difference between a building and the ground, air source heat pumps just use the difference in temperature between the air inside and outside a building. They tend to be slightly less efficient than GSHP however new models are becoming increasingly efficient. As they can be easily retrofitted to the side of a building, ASHP are easier to install than GSHP which require borehole drilling.

Avoiding poor performance

Whereas there is a definite carbon benefit associated with electric cars (even with the current grid mix), the benefits associated with heat pumps are not as clear. This could be a recipe for disaster if the grid is not decarbonised and we install low quality heat pumps in the wrong way. There is also concern that developers that install microgen and heat pumps can skimp on insulation and still comply with building regulations.

As the carbon benefits with the current grid mix begin to look uncertain if the ratio of heat out to electricity in falls below three, we need to ensure heat pumps perform well. We need to ensure that good quality, well-fitted systems are picked and that they are only put in suitable buildings for example those that are well insulated and air-tight. It will also be important for heat pumps to be correctly sized and proper heating controls to be installed and that occupants are trained to use them correctly. Follow up work will be required to resolve technical problems and help occupants calibrate systems. The introduction of heat pumps must therefore be carefully aligned with policies to improve the efficiency of buildings.

ASHP perform badly in cold conditions and may need conventional 3kW electric heaters to back up them up during cold spells. This can significantly reduce carbon savings as standard electric heating is very carbon intensive.

Likely uptake

Some supporters of heat pumps suggest that they should be installed everywhere as they represent the most efficient way of heating a building.[64] Whilst heat pumps are widely used across Scandinavia and North America they are a relatively unknown technology in the UK. Full electrification of heat will not be technically possible nor desirable if the electricity system is not sufficiently decarbonised. It may be very expensive to meet peak demand if everyone had a heat pump. It might not be sensible to size heat pumps to deal with extremely cold weather. Instead we might want to get back up systems run on natural gas for cold days. Other forms of renewable heat may offer greater carbon savings than individual heat pumps. One report for DECC suggested that whilst stand alone heat pumps would play a role in decarbonising heat, district heat schemes may offer significantly greater carbon savings.[65]

Heat pumps are significantly more expensive than conventional gas or oil fired boilers. The introduction of financial support from the government (in the form of the Renewable Heat Incentive) should help to make them appear more economical. However, there are also a number of non-financial barriers to their uptake including low awareness of the technology, and the need to drill boreholes (for GSHP) which is expensive and needs planning. Heat pumps cannot be used in every type of building as they require there to be sufficient space. In addition as they require buildings to be air-tight and well insulated, they may not perform well in old buildings.

Heat pumps are predicted to provide around 20-25TWh of heat by 2020.[66] If the heat pumps were on all the time for half the year this would correlate with around 2GW of additional electricity demand.[67]

Impact on networks

Like microgen, the impact on the networks will depend on how busy the networks were previously and the concentration of heat pumps in a given area. Having distributed generation nearby should help. A high concentration of heat pumps in some areas for example where a social housing provider or local authority has embarked on a large heat pump programme could mean that the local distribution network needs to be reinforced.

Putting heat pumps into new build should be easier as both the design of the building and the electrical connections can be designed to accommodate the pump. Also new builds are much more thermally efficient and so require smaller heat pumps.

As discussed above maximum demand per household is around 1.5kW. Heat pumps however have a whopping 10kW power requirement. Most domestic properties only have a simple single phase connection to the distribution network which can only go up to 12kW before the local network needs to be reinforced. Larger heat pumps will require a three phase supply. Whilst most commercial and industrial buildings have a three phase supply, domestic properties have a single phase supply. Large heat pumps may not therefore be suitable for homes.

Using high quality heat pumps should help reduce the impact on the networks. There are potential issues with the high starting currents[68] and reactive power associated with heat pumps. Soft start systems can be fitted to help with this but cost more. To minimise the impact on the networks and to reduce the peak demand associated with heat pumps, it will be important to be able to turn them on and off but some brands of heat pumps can't cycle on and off.

The Jersey Electricity Company is currently conducting trials to determine what the load profile of both air and ground source heat pumps look like and to see whether they can be cycled on and off to manage demand. Initial indications suggest that the load profiles from certain heat pump models can be successfully controlled. However, the high starting currents (from the compressors within the heat pump) require careful consideration, particularly on weak rural networks.

If there is no form of heat storage for example water tank or if the building has no thermal lag it will be difficult to control the timing of operation as as soon as the temperature drops all the heat pumps will have to come on. If however buildings have a decent thermal mass you can delay when the heat pumps come on. This will reduce the need for stand-by and the size of distribution network required.

Reactive power

In addition to the 'real' power that is used by machines and appliances, reactive power is also created as the voltage and current oscillate in alternating currents. Some loads absorb reactive power whilst others create it. Reactive power is not used by loads but instead it swishes back and forth, heating the wires. 'Real' power is measured in Watts (W) whereas reactive power is measured in volts-amperes-reactive (VAR).

When designing electricity system, engineers have to account for the flow of both 'real' and reactive power. They ensure that generators and networks are sized adequately so that the lines can cope with both types of power flows so they don't over heat. Generators produce more power than the real power used by loads on the system. However, customers only pay for the 'real' electricity they use. Therefore reactive power is provided by generators as an essentially free service.

Network operators face a number of costs associated with reactive power. They have to use various automated controls to curb the amount of reactive power on their networks and may have to increase the size of cables and transformers in areas where reactive power flows are high. However, the network operators have no control on the way customers are charged. The electricity retailers offer customers different packages – some reflect power factor more than others.

Currently only commercial and industrial customers are penalised for having loads that have a poor 'power factor' ie those that create a lot of reactive power on the networks (via kVAR charges). However, the way they are charged for it varies and does not necessarily reflect the actual impact their loads have on the networks. Rather, they are fined an arbitrary amount to encourage them to invest in equipment that reduces the amount of reactive power they create and 'clean' up their electricity demand. Domestic customers however are not charged for reactive power at all, they just pay for units of electricity (kWh). This is not a significant problem at the moment as most domestic loads do not create significant amounts of reactive power.

However, heat pumps create a significant amount of reactive power and if there were to be a large uptake of heat pumps in any given area, this could have a significant impact on the networks. Distribution companies may have to invest in larger cables and transformers to accommodate the heat pumps. The lack of a price signal given to domestic customers could prove to be a growing problem as the number of heat pumps grows, and the network operators have to make investments they can't recover.

To limit the amount of reactive power and pay for any network reinforcements, energy suppliers may need to adopt cost reflective charging for the reactive power associated with heat pumps. The additional charges would then need to be passed onto the distribution network operators so that they can invest in the networks to correct for reactive power.

To minimise the impact on the networks, efforts could be taken to ensure that all heat pumps sold are power factor corrected. This could be done through the Energy Using Products Directive which currently only looks at energy efficiency but could potentially be extended to encompass the power factor of appliances.

Creating a smart and super grid

There have been growing discussions about the need for a move towards a 'smart' and 'super' electricity network. But what exactly do these terms mean and why and how should we move towards a 'smart' future?

The upgrading of the networks both in the UK and across Europe over the coming decades provides a good opportunity to digitalise the networks so they work better. It is an opportunity we should not miss. In addition the way we implement a smart grid will be vital if we are to achieve the full range of associated benefits.

Other countries are embarking on similar transformation to their networks and innovative technologies and processes are being tried out all over the world. International knowledge sharing should help speed up the process. Internationally there are a number of trials looking at smart grids and growing interest in greater interconnection across Europe and the USA.

In the UK, our transmission networks are already fairly 'smart' as they already deploy communication technology.[69] However, there is significant potential to make distribution networks more intelligent. This will be increasingly useful as we move to different forms of large scale electricity generation and increase the amount of distributed generation on our distribution networks. It will also be vital as we move to electric heating and vehicles, changing the amount and way we take electricity off the distribution networks.

What is a smart grid?

The term 'smart grid' means different things to different people. A smart grid is the integration of electrical networks with communication networks. It allows you to get more out of existing infrastructure by managing the flows of electricity better. It also allows you to interact with end users to control demand. The box below sets out some of the definitions used by different agencies to describe a 'smart grid'.

There are a number of benefits associated with a 'smart grid':

- **Increased security of supply.** Smart grids enable operators to anticipate possible failure on networks so that blackouts can be avoided.

- **Allows you to get more out of the networks.** If the operator has more information about the conditions on its lines for example the temperature etc it can optimise the way it runs the network. There is less of a need to be cautious – network operators can send more current down the lines without risking the possibility of problems for example overheating.

- **Can help to reduce losses across the networks.** The grid is operated more efficiently – reducing direct losses. The losses at a local level are very varied and not well understood. More data would help to highlight where losses occur across the system.

- **Enables the introduction of time-of use (TOU) tariffs.** Smart meters enable a range of new tariffs to be introduced to encourage end users to use less electricity at certain times. This can help to shift demand away from the peak to reduce the required overall system capacity (generation capacity, T&D capacity and back-up generation). Appliances and other loads (for example air conditioning systems) can be remotely controlled so that they turn off when the electricity price is high or when the networks are busy.

Different definitions of a 'smart' or 'intelligent' grid

DECC definition

In its vision for a smarter grid, DECC[70] suggest that a smarter grid will use information and communications technologies (ICTs) within the electricity system enabling more dynamic real-time flows of information on the network and greater interactivity between suppliers and energy users. Integrating new monitoring, communications and control software into the existing system as well as additional hardware will allow the network to become more 'intelligent'. These technologies can help deliver electricity more efficiently and reliably, from a more complex range of generation sources, optimising the use of infrastructure to minimise costs and environmental impact. This will provide flexibility to the network allowing the UK to develop an effective low carbon path within the constraints of the current network.

According to DECC a smarter grid is one that is:

- Observable: extend the ability to view a range of operational indicators for the distribution network in real-time (as can already be done for the transmission network) so that any problems or losses can be detected.
- Controllable: ability to better manage and optimise the power system so that is able to adjust some demand to better match the supply available, and enable the large scale use of intermittent renewable generation sources.
- Automated: able to make certain automatic demand response decisions and respond to power fluctuations or outages for example by being able to reconfigure itself.
- Fully integrated: able to work with existing systems and compatible with new devices such as smart consumer appliances.

National Grid

According to Steve Holliday from National Grid a smart grid is:

"..an 'intelligent' electricity transmission and distribution network that uses two-way communications, advanced sensors, and embedded intelligence that can help manage and reduce customers' energy use. It facilitates the connection of distributed generation facilities to the system and allows demand management to handle intermittancy. And finally it will ensure the system can handle the introduction of electric cars".[72]

Electricity Network Strategy Group (ENSG)

In their smart grid vision[71] ENSG envisages a smart grid that forms part of an electricity power system that can intelligently integrate the actions of all users connected to it – generators, energy users and those that do both – in order to efficiently deliver sustainable, economical and secure electricity supplies. A smart grid employs communications, innovative products and services together with intelligent monitoring and control technologies to:

1. Facilitate connection and operation of generators of all sizes and technologies
2. Enable the demand side to play a part in optimising the operation of the system
3. Extend system balancing into distribution and the home
4. Provide energy users with greater information and choice of supply
5. Significantly reduce the environmental impact of the total electricity supply system
6. Deliver required levels of reliability, flexibility, quality and security of supply

US Department of Energy (DoE)

It is interesting to see what other countries consider to be a 'smart' grid. The DoE considers a smart grid to adhere to seven principles:[73]

1. Enabling informed participation by customers
2. Accommodating all generation and storage options
3. Enabling new products, services and markets
4. Providing the power quality for the range of needs in the 21st century
5. Optimising the use of infrastructure and operate efficiently
6. Addressing disturbances – automated prevention, containment and restoration
7. Operating resiliently against physical and cyber attacks and natural disasters

- **Enables introduction of more microgeneration.** The ability to monitor the amount of electricity exported onto the networks from micro generators helps distribution companies to balance the grid as penetration increases. It may also enable distributed generators (DG) to be rewarded for generating at a particular time when there are constraints on the local system.
- **Enables electricity providers to predict demand.** The data from smart meters will enable suppliers to better understand how much and when their customers demand electricity. This will reduce the amount of resources spent modelling demand and enable them to better understand customer behaviour.

All of this helps to maintain system integrity whilst we move to more low carbon generation, whilst reducing overall costs.

However, some suggest that although smart grids enable you to get more out of existing structure, they could result in efficiency losses when the network is used at high capacity.[74] To offset these losses it will be vital to increase the amount of distributed generation so that electricity is used close to where it is produced.

Smart meters

The first step in developing a smart grid is to put in 'smart' gas and electricity meters so that you have a better idea of what is actually going on in the network and can send signals between different parts of the system. Currently distribution operators do not know how much electricity is being used by any one thing nor how much electricity is being lost at any one point of the network.

Smart meters are digital meters that can measure the nature of flows of electricity and gas. They replace traditional analogue meters. Smart meters enable data on electricity and gas use to be sent out to a third party and for signals to come back for example on the price of electricity at any one time or how busy the networks are. Information from the smart meter can then be sent via radio waves or another type of communication channel to a home hub. Information from the smart meters can also be shown on a screen or visual display unit. This can enable customers to see how much electricity or gas they are using at any one time or how much it is costing them.

The information collected by the smart meter can be periodically sent via various communication channels to a remote third party. So for example data on how much electricity a particular building has used every half hour can be collected and then sent to the energy supplier every quarter so it knows how much to bill the customers. In this way smart meters can get rid of the need for meter readings. A third party could potentially use the data to conduct a remote energy audit ie analyse electricity use patterns to see where energy is being wasted.

Rolling out smart meters

The progress with the roll out of smart meters in the UK has already created frustration. There have been discussions for a number of years about what the meter should be able to do (its functionality) and how the data collected by the smart meter should be transmitted and kept (the communications model). It has taken a number of years to agree the functionality of the smart meter and what communication model should be used. The agreed approach is to use a central communications model, whereby all data is sent to a central data hub and for the smart meters to be installed and owned by electricity retailers. Government has committed to agree the functionality each smart meter must have by summer 2010 and common communication standards.

The roll out of over 25 million smart meters will be no small task. Currently only around half a million gas and electricity meters are replaced each year. Any delay to the start of the roll out will only increase the installation rate.

Whereas in the US electricity and gas meters tend to be outside properties, in the UK they tend to be kept insides in hallways or communal areas that might be difficult to access during the day. US meters tend to be 'plug and play' whereas UK meters tend to be hard wired, electromechanical devices. Removing the old meters will therefore be more disruptive. It will be important that where possible the smart meters installed are future proofed so that their functionality will allow for a wide range of future uses. Where possible they should be standardised so that they are easy to replace in future.

Getting smart meters and communication models right

The current needs of the energy retailers and the distribution network operators are not necessarily the same. For example:

- **Suppliers:** want smart meters in every home and business and may only need data on a quarterly basis for billing purposes. They may only want aggregated data on how much people are using across a region or nationwide to predict how much electricity they need to generate at any given time. They may also want data on how much electricity distributed generators are producing each quarter so they can pay them accurately.
- **Network operators:** want smart meters at the first point and last point in a low voltage network to enable them to balance each local network. To detect faults and balance the network they may want data on a second by second basis. They will also want to know how much electricity distributed generators are producing on a second by second basis so they can control demand accordingly.

However, in future suppliers may require more information (similar to the requirements of the distribution companies) as they move into the energy service market and wish to better understand energy demand. Currently suppliers may only want to send updates to change tariffs once a quarter, however in future they may wish to change tariffs much more frequently for example to encourage people to charge their electric cars at night.

A supplier led, uncoordinated roll out will not therefore necessarily provide network operators with the information they need. A lot more data is needed by the network operators. In addition the security level and robustness of the communication system would need to be significantly greater if DNOs were to rely on it to operate their networks in real time. The radio-wave communication system (similar to the existing mobile phone network) currently being considered would not be resilient enough for the DNOs to rely on and would be an extremely expensive way to handle large volumes of data.

The other big issue is the need to align the data collected from domestic smart meters with that from the existing population of smart meters that are used across the industrial and commercial sectors. Many large industrial and commercial customers are obliged to have smart meters. A number of organisations that fall under the Carbon Reduction Commitment have started to install them as they get additional 'points' for putting them in before the first year of the new scheme. However, the central communications model does not currently integrate the two sets of data. This is problematic for distribution network operators who need to know what is going on across all users on their networks.

It is vital that both the smart meter functionality and communications model fits with network requirements. The Energy Networks Association is working on the smart meter functionality that would be required to enable its members to actively manage their networks – we need to align the smart meter roll out with these requirements. In addition we will need to ensure that both the smart meters and communication model comply with the standards that are currently being developed at the European level.

There is also concern over whether the current plans will fully exploit the potential to engage energy users and help them to reduce their energy use. DECC has announced that all smart meters will come with visual display units however there is debate over the design of the basic visual display unit that all meters will have to come with. It is essential that we ensure smart meters come with easy to understand visual display units. The actual installation of each smart meter gives us a one off opportunity to inform householders about how smart meters work and to conduct an energy audit to see if there is potential for greater energy efficiency.

Data protection

It is important that smart meters should adhere to a set of common standards so that data can flow freely between different actors. It is vital that no one body 'owns' the data. Both retailers and network operators will need to access the data. Organisations that offer new energy services such as remote energy audits should also be given access. Government and local authorities could use the data to target support more effectively by identifying the worst performing households.

There will however be a balance between making data freely available and ensuring that energy users' right to privacy is protected. DECC is currently exploring how information can be shared between all actors involved without contravening the Data Protection Act. Even if the data sharing issues are resolved and a suitably robust system is developed, there could still be significant concern amongst the public about data security.

Who benefits?

The benefits associated with a smart grid are split across a number of actors:

- **Electricity suppliers:** the introduction of smart meters means that meter reading does not need to take place. It will enable demand patterns to be better understood and forecasted. It would enable easier switching between suppliers and suppliers could develop new packages for customers.
- **Transmission/system operators:** the increased demand response enabled by smart grids should help National Grid balance the networks as generation gets more intermittent. For example the introduction that sophisticated time of use tariffs for electric vehicle charging could help National Grid balance the network by charging up vehicles when it is windy and there is excess electricity flowing across the transmission network and not charging them when electricity supply is low. The ability to reduce peak demand will reduce the need for increasing the capacity of the transmission networks. Increased information about distribution generators will be required by the systems operator to balance the networks.
- **Distribution operators:** smart grids could help reduce the number of failures on the networks and enable the DNOs to quickly detect them. They will enable the DNOs to be more strategic about maintenance and replacement. It will also provide increased information about electricity demand and on-site electricity generation, and enable the DNOs to operate their networks more efficiently. By providing the DNOs with more information on where and when losses are occurring, DNOs can invest in a more strategic way to reduce losses for example through upgrading wires or transformers in constrained areas.
- **End user:** smart meters with real time displays should enable energy users to better understand and control their electricity use. Smart meters will put an end to estimated bills. Those with on-site generation will be able to easily monitor the amount of electricity they generate.

Everyone will benefit indirectly from smart grids due to the increased security of supply, greater efficiency of electricity transmission and distribution and the ability to accommodate renewables and DG more easily. As smart grids enable more electricity to flow for a given network capacity, they should reduce the need for expensive investments. By helping to reduce peak demand, smart grids should help to reduce the required capacity of the overall electricity system.

However, the financial benefits associated with a smart grid are uncertain and it will be important to ensure that all of the actors involved receive a fair portion of the benefits. Failure to do so would be inequitable. It will also slow progress as the various actors are not given the right economic signals to cooperate fully or are not rewarded for taking risks. In addition many of these benefits are dependent on access to data.

How do we get there?

Whilst the government has mandated smart meters, it is less clear how and when we could achieve a smart grid. The fragmented nature of the UK electricity system makes it hard for different parts of the chain to work together. In other countries it is easier for the government to mandate the move to a smart grid and get a vertically integrated company to carry out the work and recover the costs.

Distribution network operators across Europe are concerned that they will have to foot the bill for making their electricity networks increasingly intelligent but will fail to receive the resulting economic benefits.[75] A smart grid will enable a shift to low carbon generation, however some suggest that it will be the low carbon generators and suppliers themselves who will receive much of the financial benefits as they will have to buy less carbon allowances and receive government subsidy for their low carbon generation. Under current arrangements it is not clear how the distribution companies could profit from a shift to a smart grid.

There is widespread concern that the majority of regulators across Europe are still focussed on short term economic efficiency rather than the need to invest now to achieve a sustainable electricity system in the long-term.[76] Whilst Ofgem has dramatically increased the amount of money that the DNOs can spend on R&D, a full deployment of smart grid technology will involve investment at a higher order of magnitude.

A separate funding stream for Research, Development and Demonstration (RD&D) may need to be developed outside of the regulatory regime. In Denmark for example, there is a separate funding mechanism for RD&D that allows the system operator to run strategic projects on a system level in co-operation with the distribution companies. In Germany the government's eEnergy programme provides direct funding to companies for smart grid pilot projects where individual technologies are combined to test new system solutions.[77]

A lot can be done in the short to medium term by integrating existing electricity networks with existing ICT infrastructure. At some point in the future however we may need bigger cables as they start to overheat. We may only want to 'smart' some areas where there is a high amount of DG, electric vehicles or heat pumps for example Harrogate or Doncaster. It will be important to learn both from trials over the next five years in the UK for example under the LCNF and also from international experience.

As discussed above it is essential that the smart meter roll out is aligned with the smart grid strategy. Whilst the government is starting to align the two, some suggest that more could be done to align work on smart meters, smart grids and importantly consumer engagement. The three areas all sit in different teams within DECC which could potentially make it more challenging.

The smart grid route map developed by the ENSG shows that we have significant work to do across a number of areas to get to a smart grid. However, leaving it entirely to the market may not suffice and government may have to step in to ensure we make progress. Whilst the projects under the LCNF will trial smart grid solutions in small areas, we may need a more strategic, mandated approach post 2015 to ensure we get full roll out across the areas of network that would benefit from smart grid technology.

In addition, the LCNF is a competitive process and whilst successful applicants have to share lessons learnt, we may need to allow greater co-operation in future. A national framework that allows the network operators to work together may be required to make large areas of the networks smart and to enable optimal systems to develop.

The government needs to give Ofgem a strong direction on the outcomes that must be delivered. The think-tank E3G suggests that the government needs to use a series of performance indicators to track progress towards a smart grid and that there will be three phases of action:[78]

- **Prepare (2010 – 2015):** Early in this period the government must identify a series of key indicators and associated targets for the implementation of a smart grid and ensure that Ofgem is obliged to deliver these targets. The network operators need to develop their plans to meet the targets and this will need to be based on sufficient testing and trialling of the solutions to be adopted. During this period Ofgem needs to ensure that the appropriate regulatory and commercial arrangements are in place.
- **Enable (2015 – 2025):** During this decade the power network needs to become fully automated and interconnected and this process must be driven by obliging Ofgem to ensure that staged targets are met against a series of key indicators.
- **Deliver (2025 onwards):** The power system will have changed enormously by this time and the regulatory and commercial arrangements for the networks must support the ongoing progress towards a fully decarbonised future.

The indicators used to ascertain progress towards a smart grid might include the proportion of total meters that are 'smart', network efficiency achieved, the amount of demand that can be controlled or shifted, and the amount of non-generation balancing services.

Interconnectors

Large high voltage DC lines can be built under the sea to connect the electricity networks of different countries. Greater interconnection with Europe and potentially even northern Africa in the longer term could help to balance out variations in renewable output.[79]

Our electricity system is fairly isolated at the moment. We have a 2 GW link to France, and a 450 MW link between Northern Ireland and Scotland. National Grid is currently building a 1GW interconnector to Holland and is looking at connectors to Belgium, Norway, and a second one to France. If all of the interconnection projects being considered are built, it would raise our level of interconnection to nearly ten per cent of installed generation capacity.

There are growing calls for a North Sea 'supergrid' that would connect wind and wave arrays in the North Sea, and link Ireland, Britain, Norway and Sweden to the European mainland. In the long term electricity from concentrated solar plants in north Africa could be transmitted to Europe. Such a grid would be an engineering feat and would cost hundreds of billions of pounds of investment. There are also concerns about relying on electricity from politically unstable countries. In December 2009 Ministers of the North Sea Countries announced that they would develop an offshore grid as a step towards a European super grid.

Views over the contribution greater interconnection would bring are mixed. In its draft Energy National Policy Statement, government notes that you cannot rely on being able to always import electricity as it will depend on the amount of spare electricity available. It suggests that going significantly beyond the current plans for interconnection would not be either economically or technically realistic.[80]

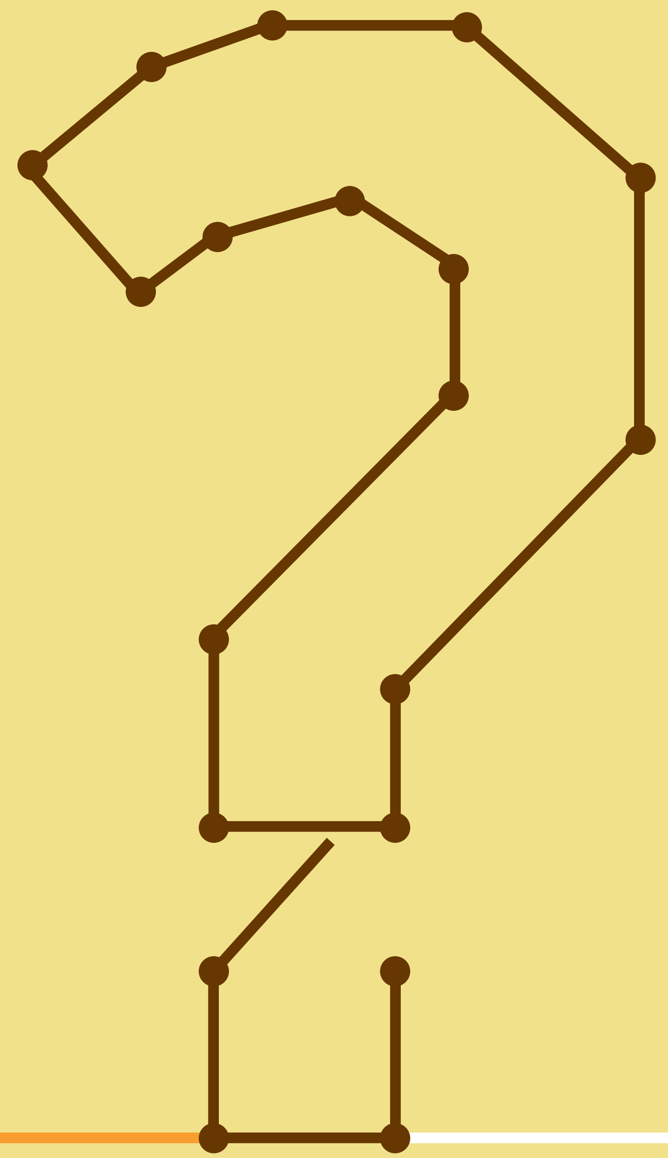
Some question whether interconnections would be much help when dealing with intermittent wind generation. Weather systems move across Europe so interconnection may only provide temporary relief for example wind stops blowing in Germany and two hours later it stops in the UK. Others however suggest that the wind is always likely to be blowing somewhere in Europe.

However, not all renewable electricity will come from wind and greater interconnection with Europe could help to balance out the output of different types of renewable generators. Norway for example has large volumes of hydro electricity it can export to its neighbours. It would also enable us to share back-up fossil fuel generation, reducing the need for standing reserve.

Greater levels of interconnection would require some harmonisation with the regulatory regime in Europe. In the UK we favour a merchant model for buying from or selling electricity to Europe. However, on the continent they tend to use a regulated model. As the commission and other member states are unlikely to alter their model, we may have to compromise and adopt a similar model to that used across Europe.

Some suggest that whilst interconnection may be a good medium to long term option, there is simply not enough money around to invest significantly in it now. DECC has recently commissioned a study into the costs and benefits of greater levels of interconnection with Europe which should provide a steer on whether it is an option that the government wishes to pursue.

Who does what? Who pays?



As we move to a low carbon energy system that may be significantly different to the one we are familiar with today, the role of the various actors will have to change. Everyone from government to the end user will have a part to play.

The existing energy regulator, Ofgem, will have to make increasingly difficult decisions to achieve a much broader set of objectives than it has had to consider in the past. It is also important to consider which type of decisions should be made by the DECC and which should be made by Ofgem. New models of regulation may have to be introduced to achieve a shift to low carbon energy and to make demand for electricity more flexible and responsive.

Energy companies will need to install smart meters and offer new tariffs and energy services to their customers. New ways of supplying energy services to customers will need to be encouraged for example Energy Service Companies (ESCOs)[81] and Virtual Power Plants (VPP).[82] The distribution companies will have to play a more active role in managing the two-way flows of electricity on their networks. The distribution network operators will have to work with the transmission operators as more two-way power begins to flow between the two networks. Data will need to be shared between multiple organisations to enable the distribution networks to be optimised and the overall system to remain stable. The system will also have to be opened up to enable small energy generators and end users to participate.

It will also be increasingly important for the different actors to work together. However, the Chinese walls that exist due to competition laws between energy companies and network operators can result in suboptimal arrangements.

In this chapter we focus on the changing role of Ofgem, the distribution network operators and end users. We also consider how new entrants and small generators can get more involved.

The changing role of Ofgem

The Office of the Gas and Electricity Markets (Ofgem) was created in the 1990s to ensure the efficient operation of the electricity and gas markets. It has been successful in increasing competition between electricity suppliers and reducing energy bills. It also manages to efficiently administer a growing number of environmental initiatives such as the Renewables Obligation (RO) and the Carbon Emissions Reduction Target (CERT).

Until relatively recently Ofgem's main focus has been on reducing costs whilst maintaining security of supply. However, in recent years Ofgem has started to consider how it can better meet both current and future consumer needs and deliver a 'sustainable' energy sector.

The need for Ofgem to broaden its remit is slowly being formalised through changes and clarification to its legal remit. The Energy Act 2004 introduced the need for Ofgem to consider its contribution to sustainable development as one of a number of its statutory duties. In 2007 the Sustainable Development Commission (SDC) released an in-depth analysis considering Ofgem's role in meeting the needs of future energy users in a low carbon society, and called for its primary remit to include the reduction of greenhouse gases.[83]

Further changes to Ofgem's remit were introduced following the publication of the SDC report. The Energy Act 2008 widened Ofgem's primary duty to include the protection of future as well as existing energy users. It also raised the need to contribute to the achievement of sustainable development to a secondary duty.[84]

The Energy Bill 2009 seeks to clarify that protecting energy users also means ensuring that security of supply and climate change issues are effectively dealt with, rather than just through promoting competition to reduce prices. These changes introduce some interesting questions and makes Ofgem's role increasingly complex and difficult.

The broadening of Ofgem's remit could make it increasingly difficult to determine whether Ofgem is acting in line with its statutory duties. The 2007 SDC report suggested that were Ofgem's primary remit to change, it should publish an interpretation document to provide clarity on the interests of present and future energy users. Further information on Ofgem's thinking about the impact its new remit might have on its decision-making might be useful.

The change in remit also raises questions about the degree to which Ofgem is involved in policy making. Some decisions may prove difficult as Ofgem seeks to balance its three primary objectives. It is important that DECC provides a clear guiding hand and continues to make important decisions quickly and does not refer everything to Ofgem.

The 2007 SDC report suggested that Ofgem needed to embed sustainable development in the organisational culture and that there needed to be an internal capacity building programme. Some suggest that the organisation has already started to make this transition and the changes or clarifications to its remit are unnecessary. Ofgem has already made some decisions that are not most cost effective for example allowing distribution companies to underground some lines in areas of outstanding natural beauty. It flagged the problems with the transmission access review process to DECC, as it felt it was penalising renewables.

A new Sustainable Development division has recently been created. Ofgem has also commissioned the Centre of Sustainable Energy (CSE) to run internal workshops and conduct stakeholder interviews to consider what 'sustainable energy' means and how it relates to the interests of current and future energy users. The work seeks to explore the challenges Ofgem may face in trying to incorporate these considerations into its work. Ofgem needs to continue to explore the implications of the change in its remit and successfully integrate a consideration of sustainable development into all areas of its operations.

However, others suggest that the organisation has moved very slowly and is still focussed on affordability and existing rather than future customers and that there will need to be a significant cultural change within Ofgem for it to rise to the challenge of protecting future energy users and enabling a shift to a 'sustainable energy' system.

There have been suggestions that Ofgem's economist heavy workforce relies too heavily on theory and markets to solve problems and can fail to appreciate the real-life practicalities involved. A more pragmatic approach may need to be taken across Ofgem so that it can function more as an administrator and overcome practical barriers.

Ofgem needs to ensure that the practices of all staff across the organisation reflect the change to its new remit rather than just those in the new Sustainable Development division factor. Ofgem may need to recruit more technical or specialised staff to ensure new outcomes are met. For example staff with technical renewables knowledge may be required to help assess industry led rule modification processes. Staff from environmental or fuel poverty groups could be seconded to Ofgem to ensure that a wider range of views are taken on board.

Defining the new objectives

Part of the challenge is the difficultly in defining exactly what 'sustainable' energy means. Whereas cost effectiveness is relatively easy to define and measure, sustainability can mean different things to different people. Whilst the needs of current energy users can be hard to determine; the needs of future energy users are even more difficult to pin down and involve a lot of guesswork.

An important shift will be the need for Ofgem and the wider industry to stop perceiving consumer needs as at conflict with climate change objectives. To date the two have often been seen as opposing forces (ie 'how can we minimise the cost to energy users of reaching our environmental targets?'). However, this fails to acknowledge the fact that meeting climate change targets may well be itself a consumer need. This can be thought of on two levels:

- **Personal level** – many individuals consider it a moral imperative to act to reduce their impact on the climate. By failing to help decarbonise the electricity sector, Ofgem would not be enabling them to reduce the carbon emissions associated with their personal electricity use.

- **National level** – the government has agreed to legally binding targets to reduce carbon emissions both at a domestic and EU level. Failure to meet targets will mean that the taxpayer incurs additional cost, for example the government will have to buy permits from the compliance carbon market. Work such as Project Discovery suggests that continuing to rely on fossil fuels will lead to higher energy prices. Waiting to act may well be more expensive as other countries compete for low carbon technology and expertise.

Ofgem has started to do increasing amounts of consumer outreach work. However, when consulting consumer groups it can be difficult to ascertain all of the requirements they may have. Responses will depend heavily on the way in which questions are framed. For example if you ask people what they want from a cup of coffee they may say they want it to be a particular strength and temperature, made from good quality beans and sold at an affordable price. They may fail to say that they would want the farmers producing the coffee beans to earn a fair price for the beans they grow or that the way that the coffee is farmed should not be detrimental to future growers in the same area. If however they were asked about these issues directly, many energy users would support these wider objectives.

It will be important that Ofgem seeks to try to effectively portray these complex issues in its external communications. For example, rather than framing investments required to accommodate growing numbers of energy users as a cost of being 'green', it should be seen as an essential step to achieving security of supply and protection against fossil fuel price volatility.

Which decisions should be made by the regulator?

This broadening of Ofgem's remit also raises questions over the split of responsibility with DECC. Is it appropriate for DECC to make strategic decisions about changes to the networks and Ofgem to act more as a facilitator? Some argue that DECC has an overview of all three energy policies and should make more decisions about networks not just generation. However, what if DECC fails to make timely decisions? In this case would Ofgem be failing in its role as independent regulator if it did not step in? Does removing some decisions from the political process ensure that we adhere to our long-term goals which may involve some unpopular short-term pain or is it undemocratic?

In addition Ofgem only has limited control over progress towards our carbon targets. It can only change licence conditions. Many of the problems appearing in the networks are due to problems with planning permission yet Ofgem has no control over the planning process. Many areas of EU and government policy will impact on the networks for example new nuclear build, introduction of electric vehicles and heat pumps, product policy etc. Ofgem may need to be more explicit about how it intends to balance its wider set of objectives but also make clear where progress is reliant on other actors or developments.

Approving investments

One of the vital roles Ofgem will play is in approving the funding required to reinforce existing networks and to extend them offshore so that the networks can accommodate the growing amounts of renewables. There will need to be a certain amount of risk taking as decisions will need to be made quickly to ensure the infrastructure is in place when it is needed to connect new low carbon generators.

For example the Transmission Access Review final report said that transmission operators needed to be able to make investments ahead of user commitment if we are to meet our 2020 renewable targets. In response, Ofgem gave transmission operator enhanced incentives encouraging anticipatory investment on 1 April 2009, and is now working on developing long-term measures for implementation. It also implemented licence changes allowing the transmission operators to recover £12.5m for 2009/10 for preconstruction works related to specific grid reinforcement projects.[85]

This is a good step but much more funding needs to be released. As discussed above, the ENSG has identified £4.6bn of investments required across the transmission network and developed a high-level plan including timescales. So far Ofgem has responded in a cautionary manner by slowly approving schemes that are urgently needed (those where a contract needs to be let in 2011 at the latest) however other schemes identified by the ENSG are yet to get approval.

The impact of each and every investment on current energy users has to be assessed before Ofgem can approve it. This piecemeal approach may need to be revised to enable progress to be made at sufficient speed. Rather than annual increments in funding, Ofgem may need to commit to a programme of upgrades. This would allow everyone involved to plan and gradually scale up their activities over the coming years in a more efficient manner. There is concern that the current approach may be too slow and will not enable the companies involved to gear up in time.

Price Control Mechanisms

The five year price control mechanisms have included a growing number of features to incentivise distribution companies to reduce their direct environmental impact for example through reducing losses, connecting distributed generation and adopting innovative technologies and approaches. In the fourth price control review (DPCR4) Ofgem introduced three new incentives (Distributed Generation Incentive, Registered Power Zones and the Innovation Funding Incentive) to encourage the distribution companies to connect new DG and drive innovation.

The innovation funding incentive (IFI) allowed distribution companies to spend money on general R&D whereas Registered Power Zones (RPZs) were focused specifically on efforts to improve the connection of generation to distribution systems. Under the price control mechanism, DNOs are allowed to pass on most of the costs of connecting DG to their networks. As they are not allowed to pass all of the costs on, they have an incentive to connect DG in an efficient way. The DG incentive gives them an additional £1 a year per kW of DG they connect. Overall the mechanism is designed to make sure the DNOs get a rate of return that is one per cent higher than the cost of capital ie they should make a small profit by connecting DG.

However, many of the measures have been fairly ineffectual to date:

- The losses incentive has been set at too low a level and there is difficultly measuring losses without smart meters.

- Uptake under the Registered Power Zone (RPZ) was so low the scheme was dropped.

The failure of the RPZ may have been due to the DNOs having to ramp up R&D activities from a standing start. The decline in R&D spending meant that many of them no longer had R&D departments.

In order for innovation to take place, risks will need to be taken and some money will inevitably be wasted. Money needs to be spent now so we can learn lessons and ensure we transform our networks in time. In the final proposal for the DPCR5 Ofgem notes that DNOs may need to use innovative approaches to deal with challenges in the long-term for example electric heating and vehicles. However, it suggests that "in some circumstances there may be greater value in delaying investment and extending asset lives until there is greater certainty of the future demands on the networks. This may be more expensive in the short term but could result lower long term charges to customers as there may be fewer stranded assets". Getting this balance right is extremely difficult however more risks may have to be taken.

In reflection of the need for the DNOs to trial new technologies and approaches in the 2010-2015 period, the latest price control review includes a significant increase in the amount of money available for innovation. The introduction of the Introduction of Low Carbon Network Fund (LCNF) is a real step forward. Funding comes with the caveat that the distribution companies have to share any lessons learned or developed.

However, there is concern that innovation will be hampered by Ofgem placing very stringent requirements on what can receive funding under DPCR5. The need for the DNOs to part fund R&D projects may also prevent some of them taking part. This may also limit knowledge sharing as companies will want to ensure any investments put them at a competitive advantage from other DNOs.

Currently it seems that the innovation funding can only be spent on the networks and not let the DNOs conduct trials that go across the full chain from generation right to end users. Even though funding under the Low Carbon Network fund is subject to conventional Cost Benefit Analysis, network operators have to use pessimistic predictions for future uptake of DG, electric vehicles and heat pumps and so undervalue the benefit of smart grid technology.

Despite some positive changes to the latest price control review, there is still concern that the current regulatory framework will not provide sufficient impetus for the level of change required. The distribution companies are used to dealing with a centralised one-way electricity system and will have to dramatically change the way they operate to meet future needs. Overcoming this 'lock-in' will require a significant push that simply may not be provided by just tweaking the five year price controls.

Current arrangements may mean that those most exposed to risk may not be rewarded and that financial benefits may be unfairly split. We may need to look at different models that introduce competition into the networks and enable the introduction of new entrants.

Need for new regulatory models?

Despite privatisation of the electricity markets in the 1990s, competition only exists amongst generators and the networks remain regulated monopolies. As such around a fifth of a unit of electricity is not determined by the market but is regulated. A number of critics argue that we need to create competition in the networks, particularly at a distribution level, to lower costs and stimulate innovation and the offering of new low carbon services.

Pollit[86] argues that the electricity sector should use lessons learnt in the telecoms sector which was initially regulated after privatisation of British Telecoms in 1984 but has since been further deregulated, driving innovation and competition. In addition a shift to high levels of DG and renewables will need communication technology to manage electricity demand and supply so the two sectors will become increasingly interdependent.

Options to introduce competition at the distribution level could include:

- making the existing DNOs allow new entrants to use existing networks
- the development of new networks in parallel to the existing wires

To accommodate a large proportion of DG, users may need to be given choices between complete reliance on the main grid, partial reliance (via micro grids) or total disconnection. Independent networks could be developed as part of an efficient electricity system developed by a new entrant supply company (for example a local energy service company based on a local combined heat and power scheme) offering services to both existing and new customers.

It has been assumed that developing more than one network in any one area is uneconomical. However, experience in the telecoms industry shows that if even a very small market share is gained by new entrants, incumbent operators make massive attempts to innovate and provide new services to ensure they do not lose further customers. These services could include helping users to reduce energy use and offering lower carbon electricity.

It has been suggested that in the future demand for network services may be created with generators and customers deciding on what investments are necessary. The regulator would act more like a referee in the negotiations rather than a decision maker. This approach has been used in airports and in the Americas.

The RPI-X@20 project is considering whether the current regulatory model is fit for purpose in the future. The current system (where the amount the regulated network operators can spend goes up in line with the Retail Price Index (RPI) minus an efficiency savings) is widely acknowledged to promote cost efficiency. However, there is concern that it might not drive the innovation in our networks required by 2020. The five year structure may not be suitable given the long-term investment we need in the networks.

Ofgem will report its findings from the RPI-X@20 project this summer however their emerging thinking consultation[87] proposes a shift to a more flexible, outcomes based model. The proposals include the extension of some areas of the regulatory package to more than five years to allow for longer term investments. Network operators will need and may even be required to lease or sell some of their assets so that new energy service companies can reach customers to promote competition. Additional funding for innovation would be provided (similar to the LCNF) but it would be opened up to bids from other parties other than the network operators (for example communication companies).

The proposals build on the existing RPI-x regulatory regime, with the network operators being rewarded or penalised for their performance against a number of outcome focused indicators. As with the current regime however, the effectiveness of the new approach will depend on the relative strength of each incentive.

There is still a strong emphasis on predicting future costs and making a business case for network projects throughout the proposals, which may not align with the need to take risks and adopt new approaches. It may be difficult to prove the business case of innovative projects using conventional economic appraisals. The details of the new approach are yet to be developed however it is not yet apparent that the revised approach is significantly different to the current regime to deliver the step change required.

The future role of the distribution network operators

The role of the DNOs may change dramatically over the coming decades. The introduction of growing amounts of microgeneration, heat pumps and electric vehicles will increase the flows of electricity across the distribution networks and the networks will have to become increasingly sophisticated to handle two way flows of electricity. The network operators will increasingly need to deploy Information Technology (IT) to control their networks and will have to engage more with end users.

This transition presents a real opportunity for distribution network operators that should be embraced. If they take a proactive stance, the DNOs will benefit from the shift rather than fall victim to the growing numbers of operating challenges. In many cases, helping customers reduce their energy use and make their demand more flexible will be cheaper than investing further in networks. The DNOs need to move from being passive operators to increasingly manage their networks in way that reduces carbon and saves money. To enable this shift, there may need to be changes to the regulatory system and a cultural change within the DNOs.

Even with the increase in innovation funding in the latest distribution price control review, some of the DNOs feel like they are being given mixed messages. On one hand they need to continue to reduce short-term costs, on the other they are expected to invest in new technologies and facilitate the shift to a smart grid.

There are a number of challenges that the DNOs face over the coming decades:

- **Taking risks.** DNOs tend to be risk adverse. They are used to steady incomes and using well established procedures and technologies. Funding R&D can be challenging when access to finance can be tricky, especially given the low cost of capital set under the current price control. The DNOs currently look to government and Ofgem to tell them how to operate their networks. In future they may need to be given more freedom to innovate and offer new products.
- **Need to future proof networks.** Under a traditional 'non-smart grid' the DNOs would need to start to install larger cables and transformers, capacitors and substations that can deal with two way flows of electricity now. However, this will cost them more and may not be economical under the current regulatory regime.
- **Lack of vertical integration.** The current regulatory arrangements mean that the DNOs cannot own their own distributed generation however DG could help to balance the local networks and help to avoid expensive reinforcement. Thus restriction should be reviewed. This is an example of how the fragmentation of the current system may prevent us from developing an optimal arrangement to maximise efficiency.
- **Working with others.** Network operators will increasingly need to work with generators, retailers and end users to trial new technologies and processes. The distribution price control reviews may need to allow for increased funding for community engagement projects. In Australia the regulator allows utilities to spend money on projects to see how people would react to having their air conditioning systems controlled remotely by their distribution operator.

- **Enabling and promoting the connection of distributed generation.** As discussed above, some distributed generators have found it difficult in the past to connect to the distribution networks. Whilst progress has been made in recent years there is scope to further improve the ease of connection. Currently DNOs tend to deal with connections of distributed generation on a case by case basis. However, they could take a more systematic approach, identifying areas of the network where there is spare capacity and encouraging developers to consider sites nearby. However, this is currently seen as investment ahead of need and its treatment is uncertain under the current regulatory regime.

- **Innovating.** Historically the DNOs have focused on maintenance and performance. Increasingly they will need to deploy innovative processes and technologies. The UK is a hot bed for R&D into the networks and there are lots of exciting new ideas being developed. The challenge will be the commercialisation and widespread adoption of new technology. In the interim stages, it will be a challenge to maintain performance whilst integrating disruptive new technologies. As discussed above, Ofgem may need to become more flexible about what can and can't be included in R&D funding and fund projects that work right across the supply chain into energy users' homes. In this way the DNOs can see how things like DG, electric vehicles and heat pumps can be integrated into a smart local network.

- **Offering new products and services.** By controlling the demand of lots of small electricity users, the distribution companies can develop new products which they can then sell to retailers. They could for example control the loads of hundreds or thousands of customers and then sell this 'demand response' into the electricity market. They could go a step further and enter into contracts with loads of small generators as well as controlling demand and operate like a 'virtual power plant'. This would require the DNOs to bring in new staff with trading experience that was lost following privatisation. DNOs could also take on a more active role in optimising their networks, and act as a distribution systems operator (see below). However, it is not yet clear whether it should be the DNOs or new entrants that offer these sorts of products and services.

- **Lack of data.** Currently network operators have very little idea of what is actually going on across the networks at any one time. The first time the DNO may become aware of a fault is when a customer rings up to complain that their lights have gone out. The introduction of smart meters will help but only if the roll out is strategic and the communications model is right as discussed above. Further monitoring might be required in addition to smart meters to enable the DNOs to actively manage their networks for example to monitor unmetered loads such as street lighting and to monitor power quality and power factors.

- **Handling large amounts of data.** In future the DNOs may suffer from the opposite problem. Handling the data from 33 million smart meters on a real time basis will be no small task. Instead of all data from smart meters travelling to a central hub, it may be more efficient to send data to local hubs instead. The DNOs can then use the information collected at the local hub to control the local network and even embed controls locally so the whole thing manages itself. Only the data required by the suppliers and other third parties could then be sent to the central hub from the local hub.

- **Step up in IT spending.** Smart grids will involve thousands of data transfers and transactions between different parts of suppliers, business processes and IT support teams. In future the DNOs may need to spend as much on IT as on network infrastructure however this increase in IT will be partially offset by reduced maintenance costs as it should enable the DNOs to get more out of the existing infrastructure. It will be important for the DNOs to prepare for growing IT requirements and include them in price forecasts.

A role for a distribution system operator?

As the levels of distributed generation, electric vehicles and heat pumps increase, there will be a growing need to balance the distribution networks and to ensure that the overall network remains stable (for example there is a balance between T&D networks). There may be a need for a distribution system operator (DSO), similar to the transmission system operator role currently played by National Grid, to manage demand and prevent areas becoming constrained. The distribution operator could work with the transmission network operator so that the overall system works efficiently. This could be a separate body or each DNO could act as a DSO.

A DNO led approach should facilitate higher levels of distributed generation and demand management than a model where the entire network is managed by a single system operator as it is at present. As each DNO operates its local networks, it knows how they work and will be best placed to optimise the systems, increasing energy efficiency.

However, funding would need to be found to establish a system operator. The current regulatory model does not enable the distribution operators to recoup any of the investment this shift would require. Whilst the return the DNOs can make on capex and opex have been levelled, this is a very small step towards the full dynamic operation of the networks. There may be potential to use funding from the LCNF to trial the DSO function in certain areas if the DNOs are able to work across the full chain to the end customer. However, this would only enable small areas to be actively managed and more investment will be required to enable a full roll out across the networks.

Others suggest that until there is a significant amount of DG, electric vehicles and heat pumps, there simply isn't a case for the establishment of a DSO. However, if we wait until there is a need in some areas we could be pushed into a reactive stance, fire fighting problems on the local networks. The early creation of a DSO that could invest heavily in demand side management and distributed generation to help balance the local networks could help drive the uptake of these techniques and significantly reduce costs overall.

Involving small energy generators and new entrants

The transition to a low carbon economy will require the introduction of new services and organisations to stimulate innovation and to find exciting news ways to involve energy users. Organisations developing new products such as Virtual Power Plants will be increasingly important and these types of services should not necessarily be left to existing players alone. Organisations offering local energy services will also be needed (with energy users entering into long-term heat contracts) if we are to decarbonise both electricity and heat production and maximise efficiency.

The data provided by smart metering must be made freely available to new players to help them enter the market and so they can offer new services. Organisations that are trusted by end users, for example community groups and local authorities, should also be able to have easy and cost effective access to data so they can develop novel ways of engaging with householders.

The networks also need to make life seamless for distributed generators, whether or not they have complete technical expertise, and the development of new guides for these groups is to be welcomed.

However, elsewhere in the energy market place it is often difficult for small generators and new entrants to get involved:

- The complexity of the regulatory framework makes it difficult for a wide range of external parties to understand and engage with the decisions being made. The price control mechanism for both transmission and distribution have a significant impact on generators however each review involves four to five consultations and it can be very time consuming to respond to each one.
- The industry self-governance process is both complex and time consuming. The industry working groups require significant input from members, however small renewable generators are unlikely to have sufficient resources to get fully involved. The groups therefore mainly consist of large electricity companies.[88]

The failure of the Transmissions Access Review to develop a model that would not penalise renewables highlights the weakness of the current industry led governance process. It is vital that decisions about the regulations of the networks are made in a fair way. In addition this process has taken a long time. Whilst it is important to ensure that changes are made in a careful way with sufficient consultation with industry to ensure investor certainty is maintained, we do not have the luxury of dwelling on important decisions in this way in future. Ofgem needs to review how the code modification (MODS) process deals with major policy reforms and how small players can be better represented.

In recognition of the need to help DG connect to the networks, the current distribution price control includes a number of features to help small developers, for example improved information. Similarly, the Emerging Thinking document from the RPI-X@20 project suggests that much more could be done to help energy service companies to enter the market. In future network operators may have to provide much easier access to their networks or even sell assets to promote greater competition. It is vital that Ofgem monitors progress at improving access to both DG and energy service providers in the future and ensures that it improves.

Involving end users

A successful shift to a low carbon economy will not happen unless there is a major change in the way people use energy. We will need everyone to:

- Reduce the amount of electricity they use for example through
  - Buying the most efficient electricity using products (for example appliances, electric vehicles and heat pumps) and ensuring they are used correctly and maintained
  - Turning things off when not in use
- Make their demand more 'smart' so that it follows electricity supply better

We need to win over the public if it is to make the radical changes to the way it uses energy that we need. This will require careful messaging so that energy users fully understand the benefits of smart meters and grids and are prepared to pay the initial capital costs. We need to explain to customers that unless we make demand for electricity more responsive, average electricity prices will rise. Energy users will want to see the cost savings resulting from smart grids being passed on.

We also need to address concerns over data security. Experience in other countries, for example USA and the Netherlands, suggest that many energy users are worried about the 'Big Brother' aspect of smart meters. There is also concern about terrorists hacking into the electricity system.

Reducing electricity demand

By using more efficient appliances the amount of electricity we need to generate and therefore the size of the networks can be dramatically reduced. Government needs to work hard to ensure the uptake and correct maintenance and operation of efficient appliances for example through:

- Lobbying at a European level for increasingly stringent standards in the Ecodesign of Energy-Using Products Directive.
- Lobbying to expand the use of labelling to all energy-using products.
- Working with retailers to provide advice to energy users at the point of purchase and to explore the possibly of entering into voluntary agreements to only sell more efficient appliances.
- Providing the domestic sector with advice on correct siting, maintenance and operation of appliances.

Much more needs to be done to curb our growing demand for electricity.

Making demand more smart

As storing electricity is expensive and wastes energy, it is important to try and match electricity supply with demand. The use of demand reduction measures is essential for maintaining the balance of the system and is often cheaper than bringing on new generation. There are a number of benefits associated with making demand more flexible (see box on the right).

Benefits of making demand more responsive

Demand for electricity is currently very uneven. Demand for electricity at 5pm on a cold January night can be nearly double the average demand throughout the year. This has a number of negative impacts. It means that we have to oversize the amount of generating capacity we have on the network and the capacity of the distribution and transmission networks. This is very expensive. Reducing peak demand would enable us to delay the construction of new generating capacity in the short to medium term. GE estimates that a reduction in peak demand of only five per cent could deter the construction of five conventional power stations.

The use of electricity at peak times also results in greater carbon emissions. The carbon intensity of the generators used to satisfy peak electricity demand is often higher than the system average. For example water pumping stations are often used to provide extra supply during peak demand. They act as a battery, by using cheap night-time electricity to pump water up a hill and releasing it later on to generate electricity during peak demand. However, as the system is around 75 per cent efficient, electricity is lost in the conversion process and more carbon is produced overall per unit of electricity. Reducing peak demand reduces the need for stand-by fossil fuel generators and spinning reserve.[89] If the carbon price under the EU Emissions Trading Scheme (ETS) were sufficiently high, it would result in high carbon generating capacity being pushed to the margin. Operators with very carbon intensive generators would only want to sell electricity during peak times when prices are high, so they could recover the cost of purchasing carbon credits.

There is a second reason why this has a carbon impact. As the loss of energy on an electricity network is proportional to the square of the current flowing, losses are much higher when lots of people are demanding electricity and the current is high. Until our electricity is completely decarbonised, any electricity wastage results in extra carbon emissions.

Controlling electricity demand better so that it is more in line with electricity supply would therefore reduce costs and carbon emissions, even if the way we generate electricity were to remain unchanged.

National Grid already uses a range of services to balance the electricity system that either:

- **Increase electricity generation** – for example it can buy power from reserve power stations that are spinning at the frequency of the networks (spinning reserve) or pumped storage.

- **Reduce electricity demand** – for example it has contracts with large industrial customers to reduce their electricity demand when the system is 'constrained' (where demand for electricity is very close to supply).

However, there is potential to increase our use of the existing demand management techniques rather than just building a larger and larger electricity system that is underused for most of the year. In addition there are a number of new methods we could introduce to better control demand for electricity.

They can be split into financial and technical measures:

- **Financial** – new electricity tariffs can be introduced to try and get energy users to use electricity at times when there is spare generation (for example during a windy day) or when demand is low (for example during the night).

- **Technical** – there are a number of technical ways that demand can be controlled. These include low level technical fixes – for example chips inside appliances or 'smart plugs' that can be used to turn them on or off in response to the frequency of the network (dynamic demand control). Alternatively the supply to everything from a whole factory to an individual freezer in someone's house can be controlled so that it is turned off. This can be done through remote control (where the supplier or network operator controls the supply of electricity) or automated (for example supply is stopped when the networks are busy or the price of electricity is high).

The two can also be combined as appliances can be automated to stop working or work at a lower rate when the price of electricity goes above a certain threshold.

A lot can be done with existing appliances and smart plugs and controls. Smart appliances that react in a sophisticated way to signals from suppliers could be useful in the future (for example washing machines that lower their temperature when the electricity price is high rather than just turn on or off). However, agreeing energy efficiency standards for conventional appliances has taken years and it could take more than a decade to roll out even a small number of smart appliances.

Some of these help to stabilise the networks whilst others can move the time of electricity use (load shaping). Whilst most of these new measures are reliant on the roll out of smart meters and smart grids, some of the simple technical options such as dynamic demand control could be used straight away.

There is a lot of different technologies available to control demand. Some help to improve system reliability, others can reduce carbon emissions. However, it is not clear what configurations of technologies will give the best results overall. The technology is currently fairly expensive and it is not clear what types of packages will be popular with energy users.

In its draft NPS the government suggests that measures to reduce peak demand may not be that useful as they may only lead to a corresponding increase in demand at a later time (when electricity is available).[90] They will help balance the system but not reduce the total capacity of the system required.

However, research for DECC suggests that a significant amount of demand can be shifted away from peak demand. It estimated that there is between 10-40GW of demand that can be shifted to different times across the domestic, commercial and industrial sectors.[91] Even if the amount we could realistically achieve is half this it could be an extremely useful tool to manage variations in wind generation.

As wind may vary from hour to hour, we need to shift demand over short time scales. We cannot expect domestic and commercial customers to make decisions about whether they buy electricity on a half-hourly basis. It will therefore be important to automate much of the load shifting.

There may be a number of barriers to introducing flexible tariffs and using technology to control when things use electricity. For example in the domestic sector:

- Time of use tariffs (where the cost of electricity varies depending on the time)[92]
  - Potential confusion about new or complex tariffs resulting in reluctance to switch.
  - Concern that fuel poor groups that may be less able to shift demand could increasingly face exposure to peak prices as others shift to time of use tariffs.
  - Price signal insufficient to change behaviour.
  - End users not having enough time to switch tariffs and then once switched, respond to signals.
- Maximum demand (where customers pay according to their maximum demand. If they exceed the agreed limit their supply is either cut off or they incur a financial penalty)
  - Price signal would need to be very high.
  - Large users may not be prepared to switch, yet account for significant amount of total electricity.[93]
- Direct load control (where supplier controls the electricity supply to particular load or building)
  - Fear of disconnection – especially the fuel poor.
  - Lack of trust in suppliers – 'Big Brother' syndrome.

Different approaches will work for different end users depending on a number of factors such as the level of trust energy users have in their energy supplier, their price sensitivity, and the level of discretionary electricity use in their home.

It will be important to better understand which electricity loads are time sensitive (can't be moved to another time) and which aren't. For example householders may be prepared to have their washing machine on in middle of night but will want to be able to control when they use their television. However, we don't have much data on what actually contributes to peak electricity demand.

There will also be a need to educate end users about the ability to time shift electricity use and maintain services and meet H&S requirements. Turning a fridge off for half an hour will probably not make the food go off. There may be significant public opposition to moving time sensitive loads such as televisions however the really big loads, for example things that provide heating and hot water and electric vehicles, may not be that time sensitive.

Although energy users may agree to a certain amount of automation, they may want to override the settings for certain uses. It is worth noting that many industrial customers that sign up to interruptible supply contracts complain bitterly when they are asked to curb their demand.

Engaging energy users

In its smart grid vision, the government commits to ensuring that every smart meter will come with a real time display so energy users can see how much electricity and gas they are using, and how much it costs at any one time. It is essential that these real time displays are customer tested so they can be easily understood.

Smart meters will not only provide us with much needed data on our energy use to better manage the networks, they also provide a vital opportunity to engage with end users. If done well they can allow people to better understand their energy use and the price of electricity at different times.

The government has decided to give electricity suppliers the job of rolling out smart meters. It says this will introduce competition and help drive innovation. However, research by the Centre for Sustainable Energy (CSE) shows that nearly all of the models currently available on the market are not sufficiently user friendly. In addition, the research suggested that far from wanting a number of different options, most energy users want simple models that are similar or identical to their neighbours so that they could share information easily.[94]

Leaving the design of the real time displays entirely to the market may not therefore be a good idea. Instead government should ensure that all of the real time displays adhere to minimum standards that have been developed through proper consumer testing.

There is also significant potential to make electricity demand more responsive in the commercial, public and industrial sectors. However, many commercial sector customers are very price insensitive as energy represents an insignificant proportion of total costs. The landlord-tenant relationship could present a problem where tenants do not directly control the Heating Ventilation Air Conditioning (HVAC) systems in the buildings they occupy.

As energy generally represents a greater proportion of overall costs, there may be fewer barriers to increased uptake of demand management in the industrial sector. Energy managers are more likely to be able to understand and welcome the introduction of new tariffs and direct load control arrangements, particularly if they significantly reduce costs.

New ways of buying electricity

Currently end users buy electricity from a handful of large energy companies that sell units of electricity rather than energy services. However, in the future new types of organisations may be created that supply energy rather than units of energy. Energy Service Companies (ESCOs) could develop and run local networks as well as generating units, optimising overall system efficiency.

As discussed above aggregators or 'virtual power stations' may play an important role. Individual households could enter into contracts with aggregators to allow them to turn off certain loads in their home when required or sell electricity generated from any on-site generation they might own. This would enable them to access the financial benefits associated with the demand reduction or on-site generation they could offer with minimal administrative burden.

What will it all cost?

As with all changes to the electricity systems, attention quickly turns to how much the various changes will cost and who is going to pay for them. So what does our shopping list look like? In the short to medium term we need to heavily invest in both our onshore and offshore networks:

- **Transmission.** The ENSG report suggests that £4.7bn will be required for essential improvements to the onshore transmission network. This could represent a fairly conservative figure as some possible extensions were not included in the overall cost estimates for example the development of a subsea line to the Scottish Islands.
- **Distribution.** Ofgem has allowed £14bn to be spent on the distribution networks over the next five years of which the majority is expected to be used to replace ageing, unreliable or failing assets. Significantly more money will need to be spent to increase the capacity of the distribution networks post 2015 and to make them more intelligent.
- **Offshore.** The offshore networks are expected to cost around £400/kW or £15bn[95] however this is fairly insignificant when you consider that the total cost of the government's Renewable Energy Strategy comes to £100bn.
- **Interconnectors.** The cost of interconnectors depend on the distance and terrain covered and the capacity involved, however, the BritNed interconnector between Holland and England (260km and 1GW) costs around £0.5bn.

However, longer term costs are harder to ascertain as they will depend on the level of uptake and location of new generating capacity and our future electricity needs.

It will be important for us to make timely and co-ordinated investments in some areas to reduce costs overall. Our underinvestment in the transmission networks has meant that some renewables can't export electricity onto the system so we are paying for electricity that isn't being used (as generators are paid 'constraint costs' which reflect their lost revenue from electricity sales). This is particularly bad as a number of the generators are renewables, meaning that we are wasting electricity that we are subsidising through the Renewables Obligation and that could lower the carbon intensity of our electricity.

Making timely investment in the onshore networks could reduce the costs of facilitating offshore networks (saving around £850m).[96] Investing now in making our distribution networks more intelligent will save money due to increased efficiency and should reduce the cost of integrating microgeneration, electric vehicles and heat pumps in the future.

As well as paying for infrastructure, for example new wires and pylons, we need to consider the impact of any changes on the costs to balance the system and pay generators for any lost revenue if they can't export electricity at busy times (constraint costs). However, these types of costs are hard to calculate and depend on the assumptions used and the scope of the analysis. For example work to calculate the constraint costs associated with the connect and manage system vary widely between studies.

One study carried out by Redpoint for DECC puts total constraint costs under the fully socialised model at a Net Present Value of £195m for the period 2010-2020[97] However, this is fairly trivial amount for something that could nearly double the amount of renewables on the system. In addition Redpoint found that customers would be better off overall: the extra constraint costs were offset by the reduction in wholesale electricity prices caused by the increased amount of renewable generation the new arrangements would bring forward.[98] Once you have wind on the system it has a very low marginal cost (amount of money to generate a unit of electricity) as it doesn't require any fuel to run.

The cost of innovation and making our distribution networks 'smart' is harder to estimate. In the short term, £630m will be spent on R&D into innovative technologies.[99] Estimates for making large areas of the network intelligent in the longer term will be significantly higher. It will cost £10bn to roll out smart meters alone and some suggest that making the whole network smart would cost somewhere in the region of £20-30bn. Korea has recently announced that it will invest $24bn over the next 20 years to make its electricity network more intelligent.

Greenpeace has estimated that a cross European 'supergrid' that extends down to Africa could cost around €200bn in total or just over €5bn per year till 2050.[100] However, this would only represent around €5 per household per year.[101]

Many of these initiatives will result in savings too for example smart meters and grid. GE estimates that the introduction of smart grids could reduce transmission losses by up to two per cent and distribution losses by up to seven per cent. It should help energy users reduce their energy use and reduce the need for investment in new wires. DECC estimates that smart meters should result in an overall benefit for energy users, even without considering the wider network benefits they could enable.

As discussed in the section on electric vehicles above, the charging infrastructure costs will depend on a number of factors including the level of uptake and whether people demand slow or fast charging points.

Who pays?

There is increasing political pressure to minimise the impact of environmental initiatives on rising energy bills, with growing concern about vulnerable groups. In its Low Carbon Transition Plan, DECC said that the strategy would add six per cent to the average household energy bill.[102] However, it also stressed that the alternative scenario, in which we continue to rely heavily on fossil fuels, would also result in significant energy price increases. Similarly it is worth noting that even without the introduction of new forms of generation, much of the existing electricity network infrastructure is in need of replacement anyway. We have to invest more in our networks whatever the future generating mix looks like.

There is concern in the renewables industry that the financial support given to renewables (such as the Renewables Obligations, FITs and RHI) is meant to support investment in generating technology for example the purchase and installation of a wind farm. However, in some cases there needs to be new infrastructure to connect the new renewable installations to end customers for example a new section of the electricity network or construction of a heat network. The current electricity and gas networks were mostly built when the electricity system was publicly owned. They were not constructed by private companies who seek to make a competitive rate of return on their investment.

It is interesting to note that whilst much press is given to the cost of various environmental legislation such as the EU ETS, CERT, CCL etc, little attention is given to what makes up the remainder of electricity bills. We are not provided with a breakdown of what makes up our bills. For example electricity customers currently pay £3.6bn annually for electricity distribution which amounts to approximately 15 per cent of an average domestic customers' bill.[103]

It is also important to consider whether things should be paid for by the tax payer or the end user. Some suggest that energy users should pay for the cost of providing electricity and the associated waste produced now, according to a 'polluter pays' model. Investment needed to provide electricity in the future or to protect future generations should be paid by the tax payer.

The tax payer currently pays for climate change adaptation for example increased flood protection however this only benefits a relatively small number of people.

What actually happens may not follow these theoretical lines but will ultimately be what is politically acceptable. In most cases putting additional costs onto energy users is more acceptable than raising taxes. It does however raise concerns over the ability of vulnerable households and energy intensive industry to foot the higher bills.

However, our preoccupation with the cost of each electricity unit rather than the cost of providing an energy service is misleading. Low unit electricity prices may not necessarily lead to lower bills. High unit energy prices mean that people have an incentive to invest in measures to reduce energy use and end up lowering their overall energy bills.

In addition as energy users may value stability over low unit energy prices, levies on electricity that are linked to some external factor for example carbon price or oil price may help to protect them from volatility and help them prepare for a future of high fossil fuel prices. Economies like Japan that have significantly higher electricity unit prices are far more energy efficient.

Funding smart grids

Finding the money for making our distribution networks more intelligent is particularly problematic. Smart networks may take 20 years or more for operators to recoup investment. Currently operators have to go to Ofgem to get approval for funding, they then need to make an internal business case and decide which assets or new technologies to invest in. There may also be problems getting access to the large amounts of upfront capital required.

The Low Carbon Network fund will enable some new technologies to be trialled but much more significant investment will be required if we want to make whole areas of the distribution network 'smart' beyond 2015.

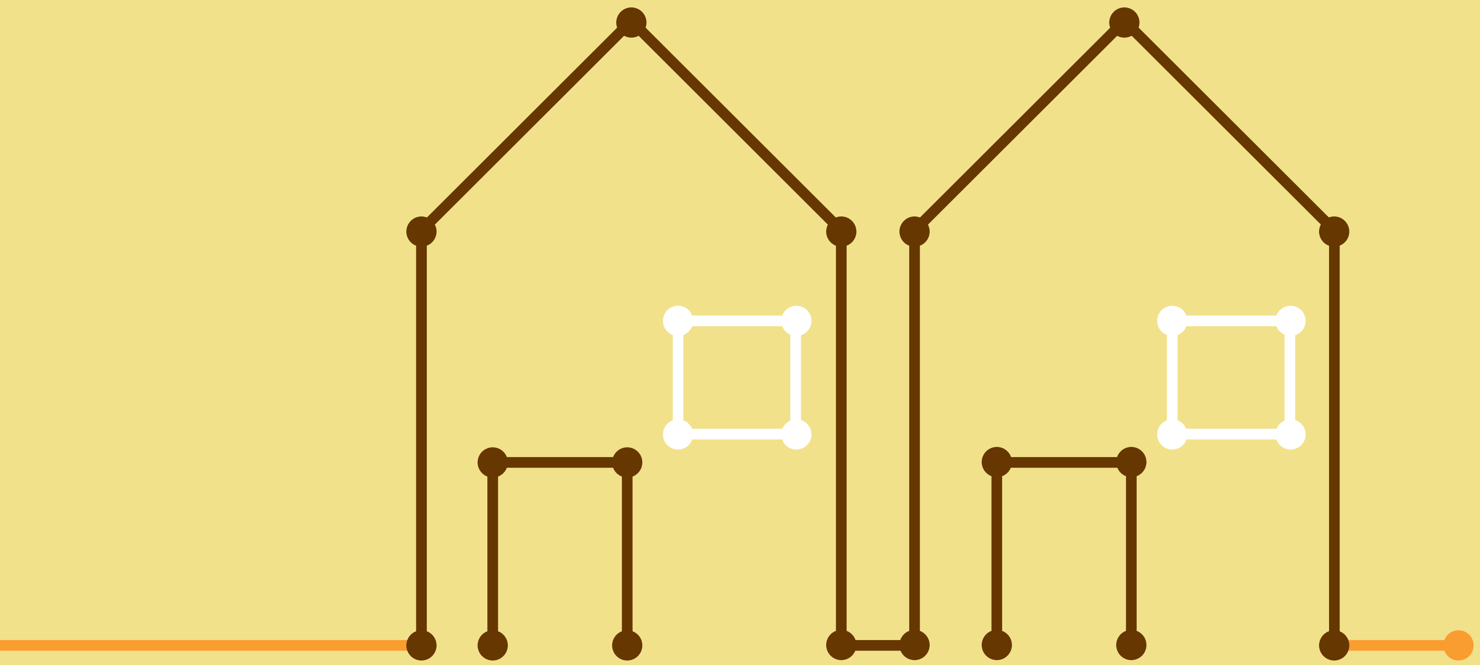
DECC has provided a small amount of funding through its £6m Smart Grid Capital Grants Programme which provides money to both network and non-network organisations to spend on smart grid technology by the end of this financial year (2010/11). However, there has been limited enthusiasm for the scheme, with only £4m of bids being submitted. The criteria for the funding is seen by many to be too restrictive as 90 per cent of it has to be spent on assets.

Additional funding may need to be found outside of the regulatory regime. The government may be able to access wider funding for example from the European Commission and intelligent cities programme. Funding within the UK could be channelled through the recently created UK Infrastructure and in future possibly through a Green Investment Bank.

Although the introduction of smart meters and making the networks more intelligent will require a fairly large amount of investment in the short term, as discussed the benefits of a smart grid are split across multiple actors. It is not therefore clear exactly who should pay for the upfront investment required to reform the networks and how the various economic benefits should be shared between the various actors.

It may not be possible or desirable to put an economic value of all of the benefits of a smart grid. However, we need to ensure it is done in a way that maximises benefits to energy users and that we reward those who need to take risks and make the necessary investments to ensure we get there. Without vertical integration or the shift to an energy services model it is difficult to see how the benefits and risks can be adequately aligned.

Conclusions and recommendations



This report has looked at the wide range of changes that need to take place in order for our electricity networks to evolve and meet our future needs. Much of the technology required for this transformation is already available – it is more a case of ensuring that there are sufficient incentives and alignment between everyone involved to ensure that it gets delivered in time. Most importantly it is not only a matter of technical and process change, it will involve behavioural change and getting a wider set of people involved.

Working towards the future

We need to start thinking about what we want from our electricity system including our networks and determine how we can get there.

Calculating costs in relation to the status quo will lock us into our current system which is becoming increasingly untenable. Conventional economics will only get us so far and the results depend heavily on the assumptions used and the scope of the analysis.

Waiting until we are definite about the need for new infrastructure could delay progress and put off developers. Some risks will need to be taken as we learn lessons and to push infrastructure forward to increase investor confidence.

The current regulatory framework may not get us where we need to go and significant reform may be required over the coming decade.

The lack of vertical integration in the UK may make smart grids hard to achieve. Legislation may need to be changed to allow different parts of the supply chain to work more closely together.

We need to maintain and increase investments in the networks

In the short-term we need to catch up with years of underinvestment that has led to a queue of generators waiting to connect to the networks.

Early and strategic investment can save money – for example timely investment reduces constraint costs, investing in onshore network reinforcement now will reduce offshore costs.

Overcoming planning issues will be essential if we are to build the onshore and offshore networks needed. We need to educate the public about the need for reinforcement of the existing networks and the need for new networks and substations.

Greater amounts of undergrounding of transmission lines or re-routing them offshore may be required if we are to minimise the environmental impact of expanding our electricity networks and get projects through planning.

The offshore networks are a blank canvas on which we can start afresh. The offshore network needs to be developed in a co-ordinated way that ensures timely delivery and avoids harming delicate ecosystems.

The way we charge users needs to be considered further
Locational charging may not be suitable as we shift to new forms of low carbon generation.

We need to ensure that distributed generation does not pay for use of the transmission networks when they do not result in any flow of electricity onto the transmission networks.

We need to consider how cost reflective charges should be for the end user as well as generator. Both the real costs of generation and the cost of using the networks are likely to get more volatile in future.

Greater exposure to price volatility on the demand side may be required to make people more responsive and to bring the various demand technologies forward. More of the real costs associated with both generation and operating the networks may have to be passed onto energy users. However, we need to consider how politically acceptable it will be to expose end users to volatile prices, particularly in the domestic sector.

We need to use a range of technologies and approaches to make demand for electricity more flexible
If we carry on supplying electricity to meet demand for the majority of energy users we will need to oversize generation and networks even more than we do today – this will be very expensive.

One size doesn't fit all. Different end users will want different packages and will respond differently. Some will want to have a high level of automation whereas others will want freedom to react to price signals.

We need to differentiate between different types of electricity demand and not treat all types of electricity the same.

- We need to determine which loads are time sensitive and which aren't so that non time sensitive loads can be moved.
- We also need to identify which loads are very sensitive to changes in quality and which aren't and preserve high quality electricity for applications where it is essential.
- In the future we many want to use a mixture of AC and DC in our networks, both to stabilise the networks and to better match the electricity we produce from different types of generator with the type of electricity needed by different end users.

We need to reassure the public and get it on board – concerns over data security could delay or even stop the roll out of smart meters. Energy users need to be convinced of the benefits as they will end up footing the bill.

The introduction of electric vehicles, microgen and heat pumps will require a change in the way we operate our local networks
The flow of electricity across the distribution networks is likely to increase as there is an increase in the amount of electricity being put into them from distributed generators and there is a growth in the number of electric vehicles and heat pumps.

Managing these new low carbon technologies should not be a problem but early preparation should make the transition easier and reduce overall costs.

Electric vehicles could help to reduce emissions from the transport sector however they are only part of the solution and we will need proper demand management to meet our carbon targets.

- Charging points may need to be developed as a regulated asset so that developers can earn an income to pay for their initial investment.
- It is not clear who should develop charging points however all actors will need to work together: car manufacturers, energy suppliers, local authorities and network operators etc.
- To enable the time of charging to be controlled, vehicles will need to communicate with the networks – this intelligence needs to be built into vehicles.
- In the long-term Vehicle to Grid technology (V2G) could enable electric vehicles to soak up electricity during periods of low demand of excess generation however the penalty on battery performance could limit the ability to constantly charge electric vehicles up and down.
- Battery swapping could offer an alternative to fast charging however this would mean that the base of all electric vehicles would need to be standardised – this may require regulation.

Heat pumps could help contribute to the decarbonisation of heat however there are a number of issues that need to be considered further:

- Poor performance of heat pumps could eat away at the carbon benefits. It is vital that their uptake is accompanied by decarbonisation of the electricity networks and that heat pumps are only put in suitable buildings for example that are well insulated and air-tight. Heating controls and occupant training will also be important. The need for conventional back-up electric heaters to top-up air source heat pumps during cold spells could significantly reduce carbon savings.
- We will need to be able to control when heat pumps operate using some form of automatic control. We should only install heat pumps that can be turned on and off. It will also be important to ensure they are installed in buildings with sufficient thermal mass so that we can delay turning them on as soon as the temperature drops.
- Starting currents from the compressors within the heat pump could create problems, especially in weak rural networks. Soft-start technology is available but costs more. We need to ensure all heat pumps installed include soft-start technology to reduce the impact on local networks.
- We may need to start charging customers for reactive power if there is a widespread adoption of heat pumps.

Making our networks more intelligent will save money and help with integration of new low carbon generation and new uses of electricity

We may not need to make the entire network smart – only some areas where there is a high amount of two way power flow and the networks are close to their full capacity.

However, it will take time to implement and will not replace the need to make timely investments in the networks. We need to ensure that the smart meter roll out gives us what we need for a smart grid:

- Meters will be required at certain key points in the network to enable the DNOs to see what is going on.
- The smart meter communication model needs to work for smart grids. Local hubs may be a better way to gather the large amounts of data required by the network operators to optimise the local networks.

All visual display units need to adhere to minimum standards based on proper consumer testing so that they are easy to understand and use.

Installation of smart meters provides a one-off opportunity for explaining the technology and its benefits to energy users and looking for energy saving opportunities around the building. This must not be missed.

We need to ensure that the distribution companies learn lessons from trials over the next five years on new technologies and then embark on a phase of widespread adoption.

Additional funding for RD&D outside of the regulatory package may be required that trial different ways of operating the networks.

Government needs to set out a clear framework for the mandatory development of smart grids – leaving it to the market may simply not deliver.

Government should set out a series of performance indicators for Ofgem to track progress towards a smart grid across the different network operators.

We need to plan ahead for example start to put in larger cables and transformers that enable two way flows as part of normal maintenance and replacement programme.

Everyone will need to play a role in the transformation

We need to get a wider set of people interested in the electricity system as a whole not just in generation.

DECC – needs to ensure that decisions are made quickly and provide strategic leadership. It needs to be prepared to step in when there are differences in opinion for example on transmission access. Some decisions will be political and should not be left to Ofgem alone.

Ofgem – needs to ensure it continues to integrate all aspects of sustainable development into the way it works and makes decisions across the whole organisation. It needs to quickly rise to the challenge of its new remit and seek to make decisions that facilitate our long-term goals. A higher level of risk taking is required given the significant innovation that needs to take place and the urgency of decarbonisation.

Transmission network operators – will need to invest heavily in the networks to expand them to remote locations and reinforce existing corridors. They should be given sufficient freedom to enable them to plan ahead and carry out the necessary work in a strategic way. They will need to work increasingly with their customers and the distribution network operators to maximise the contribution flexible demand can make to balancing the networks.

Distribution network operators – should play a central role in optimising local networks as we increase the amount of distributed generation, electric vehicles and heat pumps and increase demand response. Changes to the regulatory framework may be required to enable them to co-ordinate efforts with other actors across the whole chain. We should review whether the DNOs should be allowed to own their own distributed generation as it could help to balance the local networks and reduce the need for reinforcement. The DNOs will need to adopt new skills, invest in IT and engage with energy users. One or more distribution systems operators should be created to oversee activities and maintain the balance of the networks.

Small generators – need more support to negotiate the complex process of connecting to and using the networks. We may need to reform the governance process to ensure they can be represented in decision-making.

End users – are absolutely vital. They will be the ones that pay for a lot of the investment required. We need to ensure benefits for them are maximised and effectively communicated. Without more interaction with the end user we will struggle to move to a low carbon electricity system and costs will be significantly higher. End users will need to be convinced of the benefits of smart grids and have some of the financial benefits passed onto them. They will need to be reassured about data security issues to avoid a backlash against smart meters.

Endnotes

1 Walt Patterson, 2009, Keeping the lights on: towards sustainable electricity.

2 In the UK, each generator tells National Grid how much electricity it can provide the following half hour and the price at which it is prepared to sell it. National Grid then asks the cheapest generator to feed electricity into the network or 'dispatch' electricity. It then goes to the second cheapest generator and asks it to dispatch and so on until it has enough to supply the expected demand for electricity. It then fine tunes demand and supply by either increasing supply slightly or reducing demand slightly (see below).

3 Note Gas Turbines were invented much earlier than this and used in aeroplanes. However, it was not until the 1980s that a change in the law concerning the ability to burn gas for power generation allowed the technology to be used for power production.

4 The 132kV network in Scotland is part of the transmission network.

5 CE Electric UK, E.ON Central Networks, Western Power Distribution, Scottish and Southern Energy (SSE) Power Distribution, Northern Ireland Electricity plc (NIE), Electricity North West Limited and Edf.

6 Initially by contract but in extreme situations by technical disconnection.

7 Digest of UK Energy Statistics, 2009, Online: http://www.decc.gov.uk/en/content/cms/statistics/source/electricity/electricity.aspx

8 Estimate from General Electric.

9 Walt Patterson, 2009, Keeping the lights on: towards sustainable electricity.

10 The UK currently has four pumped storage facilities with a maximum capacity of approximately 3 GW (less than three per cent of total generation capacity) and there is limited further potential in the UK. Other than pumped storage, there is little large-scale storage technology capable of commercial deployment above 5 MW. Source: DECC, 2009, Draft Overarching National Policy Statement for Energy, Online: http://data.energynpsconsultation.decc.gov.uk/documents/npss/EN-1.pdf.

11 DECC, 2009, Draft Overarching National Policy Statement for Energy, Online: http://data.energynpsconsultation.decc.gov.uk/documents/npss/EN-1.pdf.

12 Task 1: Transmission scenarios. Task 2: Distribution scenarios, Task 3: Smart metering, Task 4: Heat and energy saving, Task 5: Electric vehicles, Task 6: Smart grids, Task 7: Gas futures, Task 8: Feed in tariffs and Task 9: ICT.

13 Ofgem, 2008, Electricity Scenarios for Great Britain in 2050 – Final report for Ofgem's LENS project. Online: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/lens/Documents1/20081107Final%20Report.pdf

14 We are currently in the middle of the fourth five year price control for the Transmission Operators – it runs from April 2007 and has been extended to April 2013. The rules for fifth five year price control (DPCR5) for the distribution operators were announced in December 2010 and will take effect from April 2010.

15 Electricity Networks Strategy Group, 2009, Our electricity transmission network: a vision for 2020.

16 The analysis assumed that the networks were regulated in a way to encourage a high amount of transmission access sharing and adherence to security and quality of supply standards. However, as both the way generators get access to the transmission networks and the security and quality of supply standards are under review, the group acknowledges that the scenarios may have to be revisited in future once these factors have been resolved.

17 Series compensation systems allow you to get more out of existing transmission networks. It enables more power to be transmitted and stabilises voltage levels. It also reduces power losses and inductive reactance.

18 The fifth transmission price control mechanism has been postponed by one year and will be subject to the outcome of the RPI-X@20 project.

19 Ofgem, 2009, Press release, Online: http://www.ofgem.gov.uk/Media/PressRel/Documents1/TII%20DRAFT%20releaase%20final.pdf

20 Ofgem, 2010, Transmission access review – enhanced transmission investment incentives : final proposals, Online: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=204&refer=Networks/Trans/ElecTransPolicy/tar

21 BBC, Beauly to Denny power line 'could go underground', Online: http://news.bbc.co.uk/1/hi/scotland/highlands_and_islands/8454725.stm

22 Electricity Networks Strategy Group, 2009, Our electricity transmission network: a vision for 2020.

23 DECC, 2009, Draft Overarching National Policy Statement for Energy, Online: http://data.energynpsconsultation.decc.gov.uk/documents/npss/EN-1.pdf.

24 National Grid, 2009, Online: http://www.nationalgrid.com/uk/LandandDevelopment/DDC/Undergrounding

25 Ofgem, 2009, Electricity Price Control Review Final Proposals, Online: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/FP_1_Core%20document%20SS%20FINAL.pdf

26 All seven owners of the distribution networks agreed to the proposals so they will be introduced in April 2010.

27 The network cost allowances are eight per cent lower than the companies asked for, although these cuts have not fallen equally across the companies.

28 Under DPCR4 the cost of capital was set at 5.55 per cent post tax Vanilla (4.9 per cent post tax).

29 The cost of capital in the water industry it is set at 4.5 per cent (post tax) and in the gas industry it is set at 4.3 per cent (post tax).

30 For example Ofgem wants to move to using indicators that better measure how well the DNOs maintain and invest in the networks. By the end of DPCR5, the DNOs will have to achieve a predefined package of output measures associated with network loading and network health by 2015.

31 The 2007 SDC report suggested that the IFI should be increased from 0.5 per cent to two per cent of turnover, so that it would be more aligned with wider industry spending on R&D.

32 Sustainable Development Commission, 2007, Lost in transmission: the role of Ofgem in a changing climate, Online: http://www.sd-commission.org.uk/publications/downloads/SDC_ofgem_report%20(2).pdf

33 It also creates an incentive for DNOs to reclassify costs from operating expenditure to network investment, so that Ofgem has to spend a lot of effort policing the boundaries between the categories.

34 Under previous price control reviews, if DNOs spend less than they are allowed on their operating costs they are able to keep much more of it than any underspend they achieve in capital investments. In addition they are not able to pass any overspend on operating costs onto customers. This has incentivised the DNOs to invest in new 'fit and forget' assets such as transformers and cables over other options such as properly maintaining existing assets to extend their life or taking measures to better manage loads, which could be cheaper. It also creates an incentive for DNOs to reclassify costs from operating expenditure to network investment, so that Ofgem has to spend a lot of effort policing the boundaries between the categories.

35 The marine environment will be governed by the Marine Management Organisation (MMO) who will follow marine policy statements (MPS) which are yet to be drawn up. DECC and Defra are working to ensure that the two sets of policy statements are aligned however the interaction between the two bodies is not clear. The MPS will be spatial unlike the NPS.

36 Transmission accounts for three per cent of bills and distribution accounts for around 15 per cent.

37 Directive 2001/77/EC of the European Parliament and of the Council. (2001) on the promotion of electricity produced from renewable energy sources in the internal electricity market. 27 September 2001. Available at: http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2001:283:0033:0040:EN:PDF

38 "Member States shall require transmission system operators and distribution system operators to set up and make public their standard rules relating to the bearing and sharing of costs of technical adaptations, such as grid connections and grid reinforcements, improved operation of the grid and rules on the non-discriminatory implementation of the grid codes, which are necessary in order to integrate new producers feeding electricity produced from renewable energy sources into the interconnected grid."

39 European Commission, 2005, The support of electricity from renewable energy sources, COM(2005) 627 final {SEC(2005) 1571}

40 DECC, 2009, Consultation on improving grid access, Online: http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

41 Ofgem, 2009, Sustainable Development Report 2008/09, Online: http://www.ofgem.gov.uk/sustainability/Documents1/SD_Report_200809.pdf

42 Each year National Grid predicts constraints costs for the following year; if it then brings the actual cost in below that, it gets to keep a share of the cost savings

43 DECC, 2010, Improving grid access – second consultation, Online: http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

44 National Grid, 2010, Pre consultation: transmission arrangements for distributed generation, Online: http://www.nationalgrid.com/NR/rdonlyres/B630B1A6-679B-4D13-8BF8-B597189DB6A1/39333/GBECM23 TransmissionArrangementsfor Distributed Gener.pdf

45 www.gridconnection.co.uk.

46 Ofgem is working on a common distribution charging methodology to ensure that use of system charges are more cost reflective across the 14 DNOs. The new methodology will apply to both electricity users and generators. The DNOs can choose to apply one of two common charging methodologies for generators connecting at higher voltages (above 11kV) from April 2011.

47 Under DPCR4 each DNO had one pot of money it could recover from demand and a separate one to recover from generators. This limits its ability to charge negative amounts to generation – because by definition other generators must fund this. Under DPCR4 there is just one pot of money so any negative charges for generators that are located to reduce network costs can be funded by demand (whose costs they reduce).

48 Accurate data on the amount of DG is currently unavailable.

49 For example the General Motors EV has 400 km range with an onboard range extender generator.

50 Committee on Climate Change, 2009, 'Meeting Carbon Budgets – the need for a step change'

51 WWF, 2008, 'Plugged-In. The end of the oil age.'

52 Ibid. IEA and Lund University studies cited in the report place the energy efficiency of the electric motor at 74-76 per cent vs 18-23 per cent for a mechanical powertrain – mostly because electric motors have fewer parts, thus have less losses, and through the ability to recuperate motive power through regenerative breaking.

53 See BERR & DfT (2008), Investigation into the Scope for the Transport Sector to Switch to Electric Vehicles and Plug-in Hybrid Vehicles and The Society of Motor Manufacturers and Traders, 2009, New car CO_2 report 2009.

54 Ibid.

55 Smith School of enterprise and the environment, Future of mobility roadmap – ways to reduce emissions whilst remaining mobile. Online: http://www.smithschool.ox.ac.uk/__data/assets/pdf_file/0003/10983/Future_of_Mobility.pdf

56 Committee on Climate Change, 2009, Meeting carbon budgets: the need for step change. http://www.theccc.org.uk/reports/progress-reports

57 DfT BERR (2009), Investigation into the scope for the Transport sector to switch to electric vehicles and plug-in electric vehicles.

58 Ibid.

59 Committee on Climate Change, 2009, 'Meeting Carbon Budgets: the need for a step change.'

60 http://www.ricardo.com/en-gb/News--Media/Press-releases/News-releases1/2009/UK-power-infrastructure-has-capacity-for-significant-rise-in-use-of-electric-and-plug-in-hybrid-vehicles/

61 Committee on Climate Change, 2009, 'Meeting Carbon Budgets: the need for a step change.'

62 E4Tech, 2007, A review of the UK innovation system for low carbon road transport technologies.

63 The communication equipment needed to allow smart meters to control EV charging can be integrated into vehicle chargers and will come standard in GM's Chevrolet Volt plug-in hybrid sedan.

64 David MacKay, 2008, Sustainable energy without the hot air, Online: http://www.withouthotair.com/

65 Poyry for DECC, 2009, The potential and costs of district heating. Online: http://www.ilexenergy.com/pages/documents/reports/electricity/District_heating_exec_summary.pdf

66 AEA and NERA, 2009, The UK Supply Curve for Renewable Heat.

67 Assuming the average Coefficient of performance for ASHP is 2.5 and for GSHP it is 4.25.

68 They can cause currents to swell to six times their normal level.

69 National Grid use sensors to monitor conditions on its networks and locate networks failures. It can remotely switch circuits.

70 DECC, 2009, Smarter Grids: The opportunity.

71 Electricity Networks Strategy Group, 2009, A smart grid vision.

72 Steve Holliday, 2009, Energy Futures Lab Annual Lecture 2009.

73 Eric Lightner, 2009, Smart grid development updates at the U.S. Department of Energy, US Department of Energy, Office of Electricity Delivery and Energy Reliability.

74 Euractiv, 2009, Eurelectric conference 2009, Power firms want funding model for smart grids , Online: http://www.euractiv.com/en/energy/power-firms-want-funding-model-smart-grids/article-187773

75 Ibid.

76 Ibid.

77 Sussex Energy Group, 2009, Response to House of Common's Energy and Climate Change Committee's enquiry: The future of electricity networks, Online: http://www.sussex.ac.uk/sussexenergygroup/documents/decc_committee_on_networks.pdf

78 E3G for Green Alliance, 2009, A road map to deliver smart grid in the UK, Available on the Green Alliance website.

79 In addition the UK is increasing imports of Liquefied Natural Gas (LNG) and building up LNG storage to increase security of supply.

80 DECC, 2009, Draft Overarching National Policy Statement for Energy, Online: http://data.energynpsconsultation.decc.gov.uk/documents/npss/EN-1.pdf.

81 An ESCO sells energy services rather than units of energy. There are several different models available but typically ESCOs make sure the demand for energy in the buildings it serves is as low as possible by installing energy efficiency measures. They then design, install and operate energy generators on-site so that they optimise the efficiency of the overall system.

82 A virtual power plant is where an organisation controls lots of distributed generation and aggregates it up and sells it into the electricity market as if it were a single large power station. At busy times, the VPP can also earn money for not using electricity by turning off loads that it controls.

83 Sustainable Development Commission, 2007, Lost in transmission: the role of Ofgem in a changing climate, Online: http://www.sd-commission.org.uk/publications/downloads/SDC_ofgem_report%20(2).pdf

84 Energy Act 2008. Online: http://www.statutelaw.gov.uk/content.aspx?LegType=All+Legislation&title=energy&searchEnacted=0&extentMatchOnly=0&confersPower=0&blanketAmendment=0&sortAlpha=0&TYPE=QS&PageNumber=1&NavFrom=0&parentActiveTextDocId=3540328&ActiveTextDocId=3540452&filesize=5128

85 Ofgem, 2009, Sustainable Development Report 2008/09, Online: http://www.ofgem.gov.uk/SUSTAINABILITY/Documents1/SD_Report_200809.pdf

86 M. Pollit, 2009, University of Cambridge Electricity Policy Research Group, Does Electricity (and Heat) Network Regulation have anything to learn from Fixed Line Telecoms Regulation? Online: http://www.eprg.group.cam.ac.uk/wp-content/uploads/2009/06/binder11.pdf

87 Ofgem, 2010, Emerging thinking document, Online: http://www.ofgem.gov.uk/Networks/rpix20/publications/CD/Documents1/emerging%20thinking.pdf

88 When you connect to the transmission network you have to enter into a Bilateral Connection Agreement (BCA) with National Grid and adhere to various codes for example the Connection Use of System Code (CUSC). Once signed up, new generators are then eligible to sit on panels which determine how the codes should be modified. The code amendment documents can be as long as 800 pages and respondents only have a few weeks to respond. This can make it difficult for small players to contribute to the process and keep up with the frequent changes made to the CUSC, which inevitably have an effect on distributed connected generators. It also introduces uncertainty to both new and existing generators.

89 Power plants that are running at the frequency of the electricity network but not producing real power. This enables them to produce real power quickly if needed, rather than starting up from cold.

90 DECC, 2009, Draft Overarching National Policy Statement for Energy, Online: http://data.energynpsconsultation.decc.gov.uk/documents/npss/EN-1.pdf.

91 IHS Global Insight (for DECC), 2009, Demand side market participation report, Online: http://www.decc.gov.uk/en/content/cms/consultations/electricsecure/electricsecure.aspx

92 Two types of Time of Use (TOU) tariffs exist. TOU dynamic periods – tariff is pre-defined and fixed, but the periods when each tariff is applicable can vary. During some periods of the year the highest tariff is applied. The customer is warned the day before. TOU dynamic tariffs – both price of the tariff and the times they are applied varies. The changing tariffs are then communicated to energy users.

93 The top 12 per cent of domestic electricity energy users in the UK account for nearly half of the total amount of electricity used in households. Source: IHS Global Insight report.

94 Centre for Sustainable Energy, 2009, Exploring consumer preferences for home energy display functionality. Online: http://www.cse.org.uk/downloads/file/consumer_preferences_for_home_energy_display.pdf

95 Electricity Networks Strategy Group, 2009, Our electricity transmission network: a vision for 2020.

96 Ibid.

97 Redpoint for DECC, 2010, Improving Grid Access: Modelling the Impacts of the Consultation Options, Online: http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

98 The Redpoint study estimates that Connect and Manage will bring forward an extra 10GW of renewable power by 2020 than in the central case without Connect and Manage.

99 Under the next price control review DNOs will receive £500m over five years from LCNF and £100m for IFI. In addition government has given £30m in direct funding for smart grids though research councils.

100 Greenpeace, 2010, Renewables 24/7: infrastructure needed to save the climate, Online: http://www.greenpeace.org/international/press/reports/renewables-24-7

101 Euractiv, 2010, Smart grids to enable renewables at 'moderate' cost, Online: http://www.euractiv.com/en/energy/renewables-super-grid

102 DECC, 2009, Low carbon transition plan. Online: http://www.decc.gov.uk/en/content/cms/publications/lc_trans_plan/lc_trans_plan.aspx

103 Ofgem, 2009, Electricity Price Control Review Final Proposals, Online: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/FP_1_Core%20document%20SS%20FINAL.pdf

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