The Role of Transmission Networks in the Evolution of a Low Carbon Electricity System in the UK

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Abstract

The UK's commitments to addressing climate change require a radical restructuring of the electricity sector. This thesis examines what role the electricity transmission networks could play in this transformation. In order to examine the possible role of policy making within a socio-technical system under conditions of long-term uncertainty, a novel scenario method is developed which accounts for political values, actor dynamics and technological networks. The approach is used to examine possible pathways for the electricity transmission network within alternative policy value-sets, which are defined by the level of locational signal provided to generators in respect of their network usage, and the degree of anticipatory or strategic planning involved in network policy. The scenarios emphasise the importance of a locational signal which acts at the operational timescale as well as the investment timescale. They also suggest a role for strategic coordination, particularly to join up planning across onshore, offshore and interconnector regimes. However, due to the range of possible generation and network configurations the scenarios span, they do not support the idea of a central design authority working to a single network blueprint. Specific policy recommendations aim to incorporate these suggestions within the grain of the existing policy trajectory and its prevailing value system. The two principle policy recommendations are therefore, the inclusion of a locational signal within the BSUoS charge in order to better reflect network usage at the operational timescale, and the establishment of an independent body with a remit to identify and contributed needs cases for cross-regime strategic coordination opportunities. The latter recommendation could be achieved with some adaption and clarification of the remit of the ENSG.

Declaration

The content of this thesis represents original work undertaken by the candidate. Where the work of others is drawn upon, this is fully referenced within the text.

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I am very grateful to the seven anonymous interviewees whose views are recorded in Chapter 5, and greatly appreciate their willingness to volunteer their time in support of the thesis.

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DEDICATED TO

IVAN FRANCIS

AND TO ALL THE STUDENTS AT

INTO UNIVERSITY HACKNEY SOUTH AND INTO UNIVERSITY HACKNEY DOWNS

IN RECOGNITION OF YOUR HARD WORK AND COMMITMENT

Publications

The following papers in the academic literature were published during the writing of this thesis, and are in part included or cited within:

Hughes, N. and Strachan, N (2010) Methodological review of UK and international low carbon scenarios, *Energy Policy* 38, 6056-6065

Hughes, N., Strachan, N. and Gross, R. (2013) The structure of uncertainty in future low carbon pathways, *Energy Policy* 52, 45-54

Hughes, N. (2013) Towards improving the relevance of scenarios for public policy questions: a proposed methodological framework for policy relevant low carbon scenarios, *Technological Forecasting and Social Change* 80, 687-698

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Acronyms

AF	Availability Factor
BETTA	British Electricity Trading and Transmission Arrangements
BGSA	British Grid System Agreement
BM	Balancing Mechanism
BSUoS	Balancing Services Use of System
CUSC	Connection and Use of System Code
DECC	Department of Energy and Climate Change
DUKES	Digest of UK Energy Statistics
GB	Great Britain
GW	Gigawatt
ICRP	Investment Cost Related Pricing
LF	Load Factor
LMP	Locational Marginal Pricing
LNP	Locational Nodal Pricing
MW	Megawatt
MWh	Megawatt-hour
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standard
NETA	New Electricity Trading Arrangements
NG	National Grid
OFTO	Offshore Transmission Owner
RO	Renewables Obligation
SHETL	Scottish Hydro-Electric Transmission
SO	System Operator
SPT	Scottish Power Transmission
TEC	Transmission Entry Capacity
TIRG	Transmission Investment for Renewable Generation
TNUoS	Transmission Network Use of System
TO	Transmission Owner

TPCR	Transmission Price Control Review
UK	United Kingdom

Glossary

Availability Factor (AF): a measure of the available output of a generator at any given time, given by the ratio of the available output at that time to the theoretical maximum output.

Balancing Mechanism (BM): the mechanism through which the System Operator ensures that supply and demand is balanced across the system, and that the relative location of generation and demand respects transmission constraints.

Balancing Services Use of System (BSUoS) charge: charge levied on generators, and large consumers and retailers of electricity, to cover the costs incurred by the System Operator in balancing the network.

British Electricity Trading and Transmission Arrangements (BETTA): electricity market arrangements which have governed the GB market since 2005, when the principles of NETA were extended to include Scotland as well as England and Wales, making GB a single integrated market.

British Grid Systems Agreement (BGSA): contractual arrangements which governed technical issues associated with interconnecting the English and Scottish systems, before they were integrated under BETTA.

Connect and manage: a principle under which new generation could be accepted onto the transmission network as soon as its local connection had been built, without needing to wait for wider grid reinforcements.

Connection and Use of System Code (CUSC): the contractual framework for connection to and use of the national electricity transmission system.

Constraint costs: costs incurred by the System Operator as a result of having to trade in the Balancing Mechanism to rearrange the distribution of generation, as a result of network constraints.

Constraints: imposed limitations in power output of generators, caused by limitations in the power carrying capability of the network

Deep connection charging: a connection charging approach where the costs of both local enabling works and wider reinforcement works are targeted at the new generator.

Gate closure: under the BETTA electricity trading rules, the point in time up to which trading for any given settlement period may occur - gate closure is one hour before the start of the settlement period.

Gigawatts (GW): unit of power - 1,000,000,000 Watts.

Great Britain (GB): the island which includes the nations of England, Scotland and Wales.

Interim connect-and-manage: a policy approach adopted from 2008-2010 in GB, when the principle of 'connect and manage' was adopted as an interim measure, before being adopted as an enduring regime in 2010.

Invest-then-connect: a principle under which new generation can only be accepted onto the transmission network once necessary wider reinforcements have been made to the transmission network, sufficient to accept that generator's output under most conditions.

Investment Cost Related Pricing (ICRP): approach to transmission charging which reflects the different costs imposed on the network by generators in different locations.

Load Factor (LF): a measure of the annual average output of a generator, given by the ratio of the actual measured output to the theoretical maximum output.

Local enabling works: electricity network infrastructure sufficient to enable the carrying of electricity from a generating station to the nearest access point on the electricity network.

Locational charging: the principle that the different costs imposed on the maintenance and operation of the transmission network by generators and users in different locations should be reflected in appropriately weighted charges.

Locational marginal pricing (LMP): a system in which the price of electricity is allowed to vary at each location on the system, reflecting the value of additional generation at that point, given transmission constraints.

Locational Nodal Pricing (LNP): a system in which the price of electricity is allowed to vary across the system, as in LMP, but with prices smoothed across zones surrounding central nodes.

Market coupling: the joining up of previously separate markets to become price zones within a single market

Market splitting: the division of a market previously operating under a single price, into zones with their own prices, which may vary from each other.

Megawatt (MW): unit of power - 1,000,000 Watts.

Megawatt-hour: unit of energy - the quantity of energy delivered in one hour by a rate of power of 1 MW.

National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS): the document which defines the technical standards for the operation of the National Electricity Transmission System in Great Britain

New Electricity Trading Arrangements (NETA): measures introduced in 2001 to change electricity trading in England and Wales from a wholesale pool market with a single price set by the marginal trade, to a voluntary market more closely modelled on conventional commodity markets, allowing multiple bilateral trades between participants.

Renewables Obligation (RO): policy introduced in 2002 to promote renewable generation, by placing an obligation on suppliers to source a certain percentage of their electricity from renewables, facilitated by a system of tradable certificates representing generated renewable electricity.

RIIO: Revenue set to deliver strong Incentives, Innovation and Outputs. The approach to regulating transmission charging which replaced RPI-x from 2013.

RPI-x: a formula used by a regulator to control price rises levied by the owner of a monopolistic infrastructure. Prices are permitted to rise in accordance with the retail price index (RPI), reflecting inflation, with a percentage (x) subtracted, reflecting the potential for increased efficiencies. The formula is intended to mimic the effect of a market in driving real cost reductions in infrastructure charges. In electricity network charging, RPI-x was replaced from 2013 by the RIIO formula.

Shallow connection charging: a connection charging approach where only the costs of local enabling works are targeted at the new generator.

Socialisation: the principal of recouping a system cost in a charge levied equally across all users, regardless of their relative responsibility for causing the cost.

System operator (SO): the entity responsible for the operation and balancing of the electricity system.

System peak: the point in the year when the electricity system experiences highest demand - typically between 5pm and 6pm on a winter evening in December or January.

Transmission Entry Capacity (TEC): the maximum declared power output of a generator.

Transmission Investment for Renewable Obligation (TIRG): scheme introduced in 2004 to allow Transmission Owners to make investments outside of the normal price control review process, when the need to do so was a direct result of investments in renewable generation.

Transmission Network Use of System (TNUoS) charge: charge levied on generators and large consumers / retailers of electricity, for their use of the transmission network

Transmission Owner (TO): company that owns and maintains electricity transmission network infrastructure.

Transmission Price Control Review (TPCR): periodic review of the charges levied by Transmission Owners on generators and suppliers. Under RPI-x, the review took place every 5 years. Under RIIO, the review period was extended to 8 years.

United Kingdom (UK): the nation state comprising the countries of England, Scotland, Wales and Northern Ireland.

Wider reinforcement works: any additional grid reinforcement works, beyond local enabling works, that may been required by the change in power flows caused by a new generator connecting to the electricity network.

1 Introduction

Most modern large-scale electricity systems rely on networks of high voltage transmission wires to integrate generation and demand across the geographical area they cover. High voltage wires are able to transfer electrical energy in large quantities, over long distances, and with minimal losses[1]. These characteristics mean that high voltage transmission networks can enable the system to benefit from potential advantages which may arise from having generation sources located distantly from load centres – for example, the economies of scale accruing to larger generators, or the benefits to the generator of locating closer to its primary fuel source. Networks strongly interconnected by high voltage high capacity wires may also benefit from higher security of supply, if these networks provide greater capacity for trading of electrical energy between regions. Highly interconnected networks may also reduce costs for customers, by providing wider access to the most efficient generators. Transmission networks have therefore been described as the 'motorways to the market' (Helm, 2003).

However, there is of course a trade-off in that high voltage transmission wires do not come for free – notwithstanding the potential benefits listed above, they have a significant visual and aesthetic impact upon the areas they traverse, and have significant costs. The decision to build a new transmission line – whether it is taken in a centrally

[1] This is because for a given power flow, current is inversely proportional to voltage, and resistive losses are proportional to the square of the current. See Appendix A.1.1.

controlled manner by a committee, as happened in Britain in the early and mid-twentieth century, or whether it is a more decentralised process involving a policy regime which conveys price signals to generators and transmission network owners – essentially comes down to the costs and benefits of this trade-off.

As such the evolution of transmission networks is strongly influenced by the pattern and location of generation investments, but equally by political decisions relating to energy system priorities – such as decisions on market separation or integration, commitment to intervention or devolution of decision-making, or approaches to regulation. The interaction of these factors since the earliest years of the electricity industry has contributed to the development of the transmission network we now inherit. The continuing interaction of these factors over the coming decades will contribute to the development of the system that emerges by the end of that period.

One of the most significant long-term political commitments undertaken by a British government in recent years is to reduce national greenhouse gas (GHG) emissions by 80% from 1990 levels by 2050 (HM Parliament, 2008). Meeting this commitment will have a major impact upon the structure of the electricity system (Ekins et al., 2013, Skea et al., 2011). Given the importance of high voltage transmission networks to large electricity systems, and their inherent relationship to the structure of generation and demand on the system, it is a reasonable supposition that the major structural changes required in the electricity system over the coming decades will have major implications for the transmission network. The aim of this thesis is to test this supposition in some detail, by exploring possible evolutionary paths of the electricity transmission networks over the next two decades in the context of this low carbon objective, and to consider how policy choices might affect or improve the path taken.

1.1 Background: the UK's climate commitments and the role of electricity

The United Kingdom (UK)'s commitment to reduce national GHG emissions by 80% from 1990 levels by 2050 became legally binding with the passing into primary legislation in 2008 of the Climate Act (HM Parliament, 2008). Energy system modelling studies have explored the implications of this target for the technological transformation of the energy system. A highly consistent outcome of these studies is the conclusion that achieving the 2050 target will ultimately require reducing the carbon emissions from electricity generation to close to zero. A further, very common outcome is the suggestion that the total amount of electricity produced will at the same time have to grow, as low carbon electricity replaces high carbon fuels such as natural gas and liquid fossil fuels as an energy vector for heating buildings and for meeting transport demand (Usher and Strachan, 2010, Skea et al., 2011, AEA, 2011, Ekins et al., 2013).

More specifically, energy system studies have increasingly converged around the recommendation that the cost-effective path to the 2050 target requires a near-total decarbonisation of electricity generation to an average carbon intensity of 50gCO_2/kWh by as early as 2030 (Usher and Strachan, 2010, AEA, 2011, Ekins et al., 2013) (CCC, 2008, CCC, 2010a). As a result the recommendations of the Committee on Climate Change (CCC) in relation to the fourth carbon budget make clear that this should be the objective, and base their discussions and recommendations around electricity system decarbonisation on this assumption (CCC, 2010a, CCC, 2013a, CCC, 2014).

The critical role of the electricity sector in the process of decarbonisation is related to the wide range of low carbon energy conversion technologies which produce electricity as their output vector. Nuclear power, onshore and offshore wind, fossil fuelled plants with carbon capture and storage (CCS), wave, tidal power and solar photovoltaics (PV) are all technologies which have the potential to be suppliers of low carbon electricity, and all are selected to different degrees in the energy system modelling studies referred to above. In the case of cost-optimising models such as MARKAL, the quantities of each technology selected in any given model run are highly dependent upon the input assumptions provided to the model, in relation to their future cost and performance characteristics. The numerical ranges from which these input assumptions can be selected in turn reflect high levels of uncertainty around these parameters.

Bringing these points together, it can be said that there is a high level of certainty that achieving the UK's legally binding carbon emissions reduction target will require a radical reconfiguration of the electricity generation mix; but there remains a high level of uncertainty around precisely what combination of low-carbon generation technologies will in fact deliver this mix (Ekins et al., 2013). The aim of this thesis is to explore what implications this transformation of the electricity sector may have for the transmission networks which are indispensable to its operation. The extent to which the challenges on the generation side as a result of the certain need for transformation, but a highly uncertain pathway, create equivalent challenges in the planning and development of transmission networks is the central area of interest for the thesis. In exploring the interaction of generation and transmission over future pathways within the context of a decarbonising system, this thesis aims to identify policy recommendations appropriate to a network which may have to undergo considerable change within conditions of uncertainty.

1.2 The challenges of decarbonisation for electricity transmission networks

The challenges which could be posed by a decarbonising generation mix to the electricity transmission networks relate to two critical features of low carbon generation technologies – their geographical location, and their operational characteristics.

The structure of the current network owes much to the preferred location of what was the dominant generation technology for much of the industry's history – coal. Thus the most well-developed areas of network run from the coalfield areas of the Midlands and north of England, to the biggest demand (or load) centres in the south of England (Hannah, 1979). The structure also relates to political decisions to develop first the northern Scotland area as a separate system, and then to separate off southern Scotland from the England and Wales system (Hannah, 1979, Hannah, 1982). In each case, decisions on major network expansions historically were not taken with the location of renewable resources in mind, and so the network has not evolved to be a close fit with the relative location of renewable resources to load centres. One of the key network challenges of decarbonisation therefore is the prospect that many of the most renewable resource-rich areas most suited to the development of renewable energy technologies, may be located in the areas of the network with the lowest levels of interconnection capacity with the rest of the system, and most distantly located from the largest load centres.

An additional challenge relates to the operational characteristics of low carbon technologies. Most renewable generators are dependent on weather conditions which means that their output can vary substantially. The average output of a renewable generator is usually estimated to be 30-40% of its total maximum output (see Appendix E.5.4). This large difference between average and peak output becomes a challenge for networks, as if networks are designed with sufficient capacity to meet the peak output of the generator, there may be times when they are heavily under-utilised.

1.2.1 Insights from scenario and modelling studies

Given the potential challenges to the existing design of the electricity transmission network posed by the prospect of decarbonising electricity supply, investigating how transmission networks may be required to evolve in the face of this prospect is an important research priority. However, a relatively few number of studies have addressed this in detail.

A first important point to make is that the influential and policy-facing energy system modelling studies mentioned in the Section 1.1 do not have a spatial dimension. In their standard modes of operation, these models balance aggregate energy supply and demand on an annual basis, but do not account for the geographic location of either, and are thus unable to consider possible requirements of transmission and distribution infrastructure. One study (Strachan et al., 2009a) reports on soft-linking the UK MARKAL model to a geographical information systems (GIS) framework in order to investigate spatial aspects connected with possible future hydrogen distribution infrastructures; however comparable work to extend energy system models such as MARKAL and TIMES for electricity transmission infrastructure analyses have not so far been undertaken.

National Grid's Future Energy Scenarios (FES) are re-issued annually and consider possible changes to the electricity supply mix and electricity demand profiles (e.g., National Grid (2013c)). The precise drivers and content of the scenarios vary from year to year, however they are in general derived from broad, high-level drivers such as 'affordability' and 'sustainability', which give rise to 'axioms' – effectively a series of instructions for how the high level drivers are interpreted within the various sectors of each scenario, to produce quantitative assumptions across a range of indicators. An ever-present feature of the FES report has been the inclusion of a scenario called 'Gone Green', though the precise numbers which constitute the scenario have been modified from year to year. The essence of Gone Green is a scenario which meets Government targets on renewables and carbon budgets. As a result, it is typically the most quoted and analysed of the scenarios in any FES year, as it provides a convenient set of figures for testing the possible implications of government policy. Reports from ENSG (2009, 2012) and Gerber et al (2012), which are discussed further below, based their analysis on versions of the Gone Green scenario. As an example of an FES output, ***Figure 1*** shows the GB Average Cold Spell (ACS) peak demand and electricity generation installed capacity evolving through time in the Gone Green scenario.

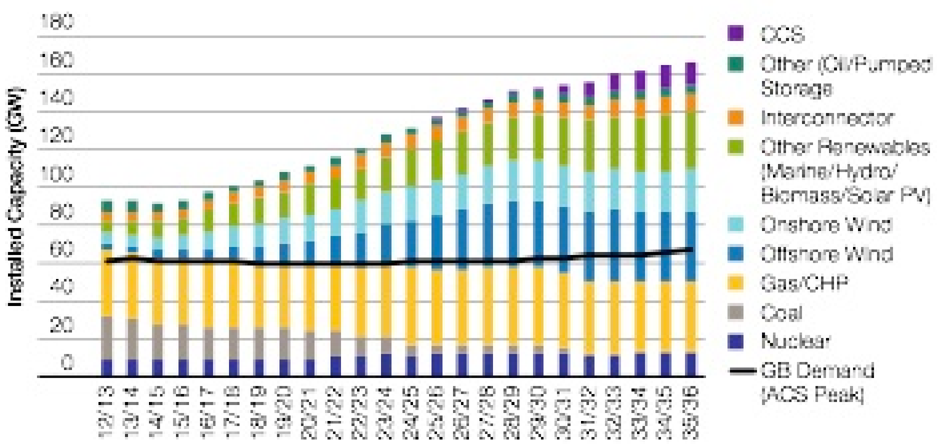


Figure 1: *Demand and generation background for 'Gone Green' scenario. Source: (National Grid, 2013c)*

Although the FES method of deriving quantitative assumptions from high level trends and axioms is in contrast to the linear-programming optimisation energy system models referred to in studies such as Ekins et al (2013), the results outputs are similar in that they relate to the aggregate annual balancing of supply and demand across the whole system. Although National Grid's detailed commercial knowledge of the prospects for particular plant, and its access to demand data are likely to feed in to the development of the scenarios, the final publicised versions of the scenarios are geographically aggregated, with no detail on locational changes in the balance of supply and demand, or on resulting implications for networks. The network development plans of the transmission companies

(National Grid, 2012d, SP Transmission, 2012, SHETL, 2011a, SHETL, 2011b), discussed in more detail in Chapter 4, use the National Grid FES and particularly Gone Green as an external evidence base, but the transmission companies are required to make their own assumptions about the geographical distribution of the scenarios' plant mix, as these assumptions are not made explicit at least in the public versions of the FES.

The Transition Pathways to a Low Carbon Economy project has focussed on the electricity system, exploring alternative pathways differentiated by contrasting power dynamics within society, with the activities of government, business and civil society alternately setting the agenda in the different pathways (***Figure 2***).

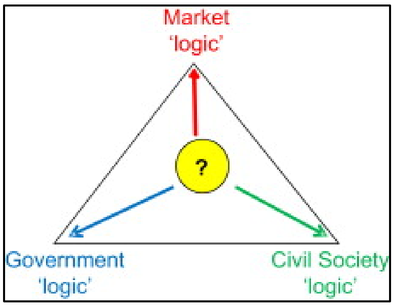


Figure 2: *Patterns of governance: the action space for competing 'logics' in a transition. Source: J. Burgess and T. Hargreaves (Foxon, 2013)*

These have produced rich narrative storylines associated with each pathway, alongside quantitative outputs (Foxon, 2013). Initially the quantitative outputs were defined, as in the other work so far discussed, on an aggregated non-spatial basis, that is on the basis of the total supply, demand and installed capacity in the system as a whole. Despite being non-specific in spatial terms, the storylines do mention networks and suggest different implications for transmission and distribution networks. Two of the pathways ('Market Rules' and 'Central Coordination') describe supply mixes dominated by large-scale generators, which suggest a continuing important role for high voltage transmission infrastructure. By contrast, the other pathway, known as 'Thousand Flowers' has high levels of distributed generation, which could be interpreted to require a slimmed down role for transmission networks, with considerable investment at the distribution level (Foxon, 2013). Work has been undertaken by Barnacle et al (2013) to interpret the pathways' generation and demand figures spatially, and to identify network implications from this. Their analysis has so far been conducted as far as 2020 for one of the pathways, Market Rules. It uses a genetic algorithm to identify optimal transmission infrastructure investment plans compared to the base year of 2009, required to resolve transmission constraints arising from the generation mix in the stated year and pathway (Market Rules in 2020). The study finds the required transmission investment for this pathway and year to be relatively small, being in a similar range to the planned Beauly-Denny upgrade, suggesting that beyond this project little further transmission investment would be needed by 2020 to accommodate the generation mix associated with this pathway. The cost figures from Barnacle et al (2013) will be returned to in comparisons with outputs from the scenarios undertaken in this thesis, in Chapter 8.

The Ofgem commissioned Long-term Electricity Network Scenarios (LENS) project (Ault et al., 2008) was a scenarios project more explicitly concerned with the future prospects for electricity network architecture and management, both at transmission and distribution level. The broad drivers through which scenarios were generated in this project were the level of environmental concern (high or low), level of consumer participation in the electricity market (active or passive) and preferred model of institutional governance (market led or government led). The selective combination of different levels of these three variables produced five scenarios, initially characterised in some detail with narrative storylines which described investment in electricity generation capacity, network investment, consumer behaviour and changes in market structures and institutions, albeit in an almost entirely qualitative way. The quantification of the storylines took place within the MARKAL model which was used subsequently to reproduce as closely as possible the scenario descriptions. As a non-spatial model, the MARKAL analysis dealt with spatially aggregated energy supply-demand balances, and did not produce network information. In some cases the MARKAL generation mix produced contrasting results to those suggested in the scenario storylines, as the model was not constrained to reproduce the scenario storylines exactly. As a result the relationship between the narrative, network focussed storylines, and the quantitative generation-supply focussed modelling, was a loose and flexible one. The LENS scenarios, while useful as explorations of the range of possible network futures, do not directly assess and quantify network requirements arising from particular generation mixes.

The Electricity Networks Strategy Group (ENSG), a group convened from representatives of the electricity industry, has produced reports examining the possible case for upgrades to the transmission network on the basis of assumed generation mixes in line with meeting the government's renewables targets for 2020 (ENSG, 2009, 2012). The analysis is based on high-level assumptions about the location of a plant mix which would succeed in meeting the government's 2020 targets. The generation mix assumptions are based on National Grid's FES Gone Green scenario, which, in the version used by ENSG (2012) includes 28 GW of wind (11.2 GW onshore, 16.6 GW offshore), 12.3 GW of nuclear and 41.7 GW of gas (ENSG, 2012). In response to this generation mix scenario, ENSG recommends a number of transmission system reinforcements, most notably a significant strengthening of the England-Scotland boundary through two 1.8 GW HVDC subsea cables, off the east coast between Peterhead and Hawthorne Pit, and off the west coast between Hunterston and Deeside. Other potential offshore HVDC strengthening projects include a connection from the north to the south of Wales (Wylfa to Pembroke), and from Caithness to the Moray Coast, across the Moray Firth. Additionally, other strategic onshore upgrade needs are identified, notably in the north-west and on the east coast of England, and in mid-Wales (***Figure 3***). The ENSG work provides rich spatial detail around specific transmission network upgrade possibilities, in relation to the possible future electricity mix considered. However, the reliance on a single scenario, 'Gone Green', means that the analysis does not engage explicitly with questions of alternative policy options, or with the interrelated uncertainties affecting both transmission and generation investment. The analysis is also relatively near term – so far, the ENSG has not undertaken studies extending beyond 2020. The ENSG scenario analysis is compared with relevant outputs from the current analysis in Chapter 8.

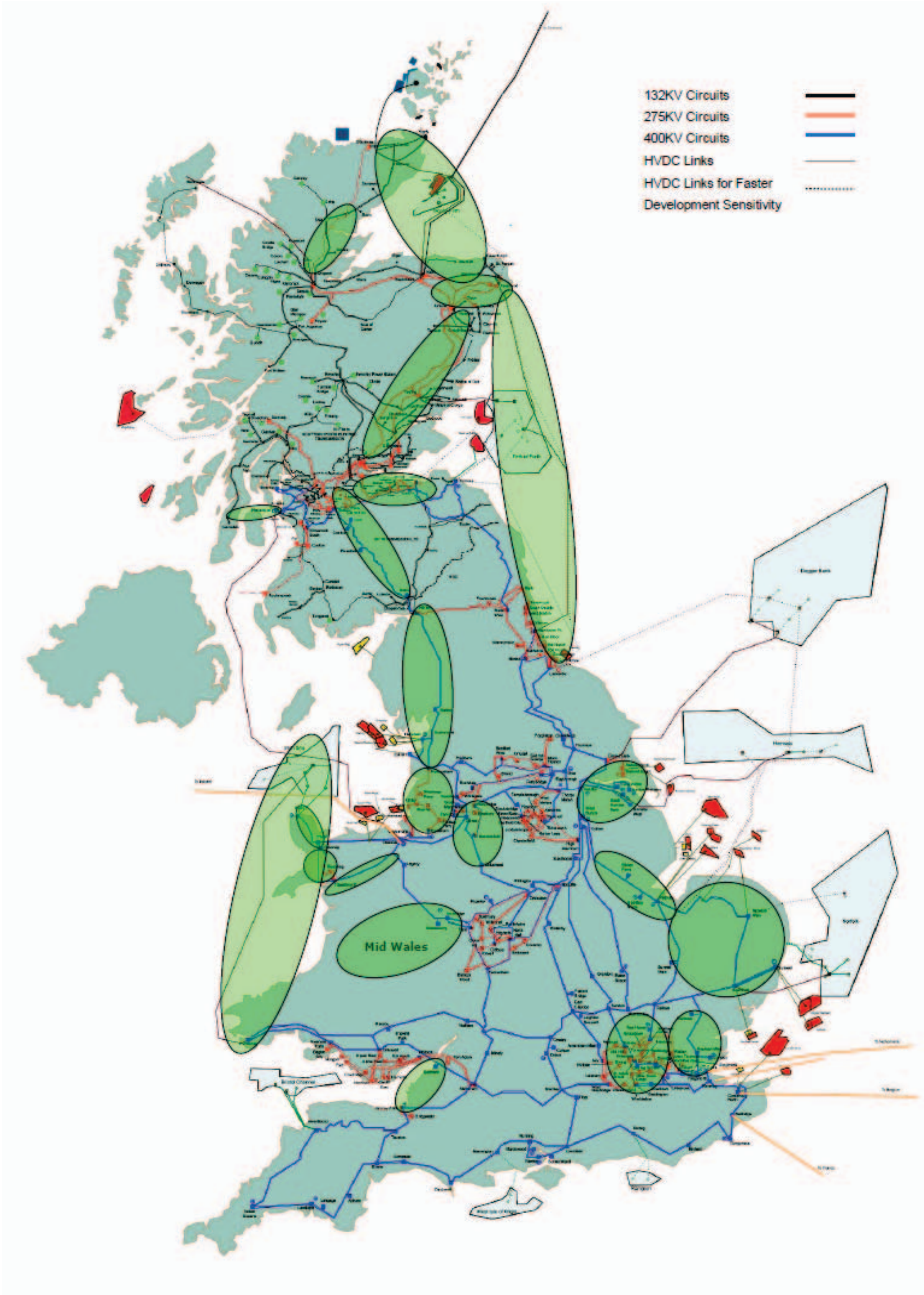


Figure 3: *GB Electricity Transmission System showing potential reinforcements by 2020, according to ENSG analysis. Source: (ENSG, 2012)*

Using a DC power flow of the winter peak, (Gerber et al., 2012) also model the Gone Green scenario. The reference case scenario which includes 'expected' transmission reinforcement (e.g. including the Beauly-Denny line, but not the additional lines proposed by ENSG), shows that roughly 2 GW of wind generation in Scotland is curtailed. The addition of the eastern HVDC link reduces curtailment by 1GW, and with both the eastern and western HVDC links, no wind curtailment is necessary. This reduces system costs as the wind displaces comparatively costly gas fired generation, in comparison to the reference case. Thus, the analysis of Gerber et al(2012)broadly agrees with that of ENSG (2012), as would be expected given that they analyse the same scenario (Gone Green) at the same future year (2020).

The analyses undertaken by ENSG and by Gerber et al suggest that the need to consider quite substantial changes in the architecture of the transmission network in the context of the decarbonising generation mix is already significant. However, the analyses also reflect a relatively near-term situation in which the strong growth of renewables in northern areas of GB is comparatively certain, due to a strong queue of projects in Scotland, arising from decisions taken in relation to the unification of the Scottish system with the England and Wales system under the British Electricity Transmission and Trading Arrangements (BETTA) in 2005, and the subsequent connect-and-manage regime (discussed in Chapters 4 and 5). Beyond 2020 there is greater uncertainty about the precise pattern of connections that will occur; but nonetheless the pace of decarbonisation will also be required to increase substantially in order to fulfil the CCC's recommendation of a carbon intensity of around 50g/kWh by the early 2030s (CCC, 2013a).

Despite the critical role for the electricity sector raised by energy system modelling studies (Usher and Strachan, 2010, AEA, 2011, Ekins et al., 2013, CCC, 2008, CCC, 2010a) and growing awareness of the possibility of significant implications of this decarbonisation for electricity networks (Ofgem, 2010c), there is a relatively small body of literature which explicitly and systematically explores implications for the transmission network of deep decarbonisation of electricity generation in the UK. ENSG (2012), Barnacle et al (2013) and Gerber et al (Gerber et al.) are most the relevant studies in that they offer detailed, systematic and transmission focussed analyses – however each of these extends only to 2020. Further, none of the above studies engage with transmission network policies, and how different policy choices could affect the way the transmission network evolves and its suitability to deal with and adapt to the decarbonising generation mix.

If the transmission upgrade requirements for meeting the needs of system decarbonisation up to 2020, according to ENSG and Gerber et al, are likely to be very significant, as the pace of decarbonisation accelerates through the 2020s it is a reasonable hypothesis that transmission upgrade requirements out to 2030 may be even greater. There is therefore a need to consider the transmission network implications of the decarbonisation of the electricity system to a carbon intensity of 50g/kWh, and of doing this within the next twenty years. Because of the particular characteristics of low carbon generators, and the particular challenges these could pose for transmission networks in large quantities, the analysis needs to involve sufficiently high spatial as well as temporal resolution, in order to consider both how the location of generators affects transmission requirements, but also how the interaction of supply and demand under different weather conditions could affect power flows. The approach also needs to take account of the uncertainties which increase significantly as we look beyond 2020, and to consider the effect that transmission policy choices could have on the direction of evolution of the system, in order to deliver tractable policy recommendations from the analysis.

1.3 Research question

The discussion in the previous section suggests the following key points:

- UK energy policy is driving a major transformation in the electricity generation sector over the next fifteen to twenty years

- Given the critical role of transmission networks in large electricity systems, and the particular locational and operational characteristics of low carbon generators, it is a plausible hypothesis that the proposed major structural changes in electricity generation will have major implications for the electricity transmission network

- Despite a variety of long and short term UK energy scenario and modelling work, some of which has considered aspects of network development, no studies have yet fully explored the implications of a long term heavily decarbonised electricity mix for transmission networks, including a quantified spatial analysis of network power flows and representation of alternative network policy regimes

- Therefore there is a need to explore in detail the implications of electricity decarbonisation for networks. In order for such an exploration to be of practical use for policy makers, it must have embedded in it options which relate to real policy options that could be pursued in transmission network management.

This leads to the following research question for the thesis:

- How can transmission network policy choices affect the role that the transmission network plays in helping to deliver a low-carbon electricity system by the early 2030s?

The question clarifies that the area of interest is the role of electricity transmission networks in delivering a low carbon electricity system within the next two decades – defined in this research as a system with a carbon intensity of 50gCO_2/kWh. More specifically, the interest is in exploring how policy choices made in relation to the management and operation of the transmission network could (positively or negatively) affect the role that the transmission network plays in that process.

1.4 Methodology

This section briefly outlines the methods employed in order to address the central research question of the thesis. In this thesis several aspects of the method are original, therefore methods are developed and explained in greater detail in specific relevant chapters of the thesis, and constitute part of the original contribution of the thesis. This section however provides an overview of the methods used and how they relate to each other.

The research question concerns a technological system (the GB electricity generation and transmission network). It deals with the way in which policy choices could impact upon this network, and by implication, it acknowledges that alternative policy choices could contribute to different outcomes, and therefore that there are multiple possible future outcomes for the system. Addressing this research question will therefore require three synthesising areas of work:

- **Technical analysis**: a technical understanding of the transmission network and electricity generation system, and a means of simulating aspects of its performance under alternative future hypothetical conditions.

- **Policy analysis**: an analysis of GB electricity transmission network policy, and its context within broader UK energy policy paradigms

- **Scenario analysis**: a process for ordering and analysing hypotheses about the future, which, while acknowledging uncertainty, is nonetheless conducive to deriving policy relevant insights. This process also needs to be capable of integrating largely qualitative policy analysis with quantitative generation and transmission power flow analysis

The next section discusses for each of these synthesising requirements what tools and methods were fed in, and why they were chosen.

1.4.1 Technical analysis

At the heart of the research question is a technical system, which, although it has numerous interactions with other energy subsystems, is primarily defined in this project as the GB high voltage electricity transmission network, and the large-scale generators that connect to it. The research question therefore demands technical and quantitative representation and simulation of the output of generators, and the transmission networks through which their power output is connected to demand.

An analysis of how power flows through a network under given generation and demand conditions is called a load flow analysis. A load flow analysis enables the consideration of power transfers between different areas of the network, which can in turn suggest requirement for re-dispatch of plant, or in the longer term, network upgrades. It is a widely used approach for considering the impact of future generation scenarios on network infrastructures, and was accordingly the method employed in the studies by ENSG (2012), Gerber et al (2012) and Barnacle et al (2013) reported in Section 1.2.1. A load flow is an analysis of the power flows across a network at an instantaneous point in time, when demand and generation at each node have been defined. The division of power across the various junctions of the network is dictated by the relative arrangement of load and generation around the network, but also by the relative impedences of the various sections of circuit. When presented with two parallel lines, current divides between them in inverse proportion to their impedances. This follows Ohm's law (Equation 4, Appendix A.1.1), which shows that current is inversely proportional to resistance (or impedance in AC circuits).

Load flows can be simulated of both AC and DC systems. AC simulations record reactive power, losses and voltage drops, and are required for sufficiently accurate simulations of distribution networks. DC load flows have the advantage of being computationally simpler, and with a faster simulation time (Gerber et al., 2012). They treat the network as if it were DC, and although this simplification is not appropriate for distribution networks, DC load flows can simulate high voltage transmission networks with a high degree of accuracy (Gerber et al., 2012). Although they do not account for resistive losses, this simplification is considered acceptable for high voltage networks, where losses are significantly lower than on distribution networks. On the GB transmission networks, losses are typically 2% of generation (Elexon, 2013). The DC load flow tool provided by the open source programme MATPOWER (Zimmerman et al., 2011), provided as a plug-in to the MATLAB software, is used for this analysis.

The load flow requires three separate input matrices. One matrix defines the line parameters of the network connecting the various nodes. In this study, these were based on real line data provided by National Grid (National Grid, 2011b, National Grid, 2012a), as reported in further detail in Chapter 6 and Appendix E.1, and on assumptions about future upgrades to this existing network, developed as part of the scenario process, as described in Chapter 7. Another matrix defines the demands at each node on the system. As reported in Chapter 6 and Appendix E these were based on current information from National Grid (2013a) and DECC (2012b, 2013a), and by assumptions on future trends drawing on National Grid (2013c). A third matrix defines the generator output at each node. As described in Chapter 6 and Appendix E this required data on current installed capacities which were largely drawn from National Grid (2011b)as well as from RenewableUK(2013b) and other commercial sources. As described in Chapter 7 these were added to by assumptions on future generation installed capacities which were elaborated as part of the scenario process. Each generator was also subject to limits on availability which vary according to the time of year and the weather conditions, and set within a merit order, as reported in Chapter 6. An Excel spreadsheet was assembled to combine the various data assumptions on the nodal demands, generation mix and output of renewable generators in different seasons and weather conditions, in order to produce a **merit-order dispatch** of generation to meet various specified combinations of seasonal demand and weather conditions, as reported in Chapter 6. The combination of these various data therefore enabled production of the three matrices – network, demand and generation – required to perform a load flow in MATPOWER.

The branch flow outputs from the load flow tool were fed back into the Excel spreadsheet for a **constraint analysis**, which was also assisted by visual representation of the power flows and constraints using **geographical information systems (GIS)** software, Quantum GIS (QGIS), as described in Chapter 6. The constraint analysis in Excel highlights precise quantities of power flow as well as exceedences across individual sections of line; the visual and spatial representation of GIS is useful for clearly identifying patterns of exceedences, and evidence of inter-regional power flows in addition to specific line exceedences.

1.4.2 Policy analysis

As well as being focussed on a particular technological system (the GB electricity transmission network), the research question is also explicitly concerned with how alternative policy choices could affect the development of this technological system. This policy element of the research question demands an analysis of existing policies and institutions in relation to the transmission network, what possible options there may be for altering these policies and institutions, and the motivations or propositions that might provide the rationale for doing so.

The question of what motivations underlie policy choices has been examined by various authors in political economy and political science literatures, who have considered the role of 'doctrine' (Crick, 1964), 'ideology' (Sunderlin, 2003) or 'policy paradigms' (Hall, 1993) in shaping policy discourse. These and other authors' contributions are considered in Section 2.5, and inform the inclusion of a 'values' level within the scenario process developed in Chapter 2. Identifying the deep ideological or value-trends and paradigm shifts which have affected the practice of energy policy in the UK is then the task of Chapter 3 – this chapter undertakes a **historical review** of the evolution of the GB electricity system and the long-term policy trends and value shifts that have accompanied this process. This historical review is based on a literature review of works by energy system historians, with a particular debt to Leslie Hannah's two-volume history of the British electricity industry (Hannah, 1979, Hannah, 1982), as well as on historical data published by DECC and other internet sources including archived media reports.

Chapter 4 then **summarises and analyses the current policy mix** in relation to transmission network planning and regulation. This was undertaken through an analysis of consultation documents, evidence submissions and other documents relating to the policy areas of direct relevance to transmission networks, which are available on the relevant pages of Ofgem and National Grid websites. This chapter also uses the context of the long-term historical analysis undertaken in Chapter 3 to identify how different elements of the current transmission network-related policy mix appear to be expressions of different policy 'value-sets'. It further uses the context of Chapter 3 to suggest that if one of these policy 'value-sets' were to become more dominant, this would create a different forward pathway of evolution for the system.

A further important element of bringing together the present set of policy options with the deeper historical context was provided by the outputs of **semistructured qualitative interviews**, reported in Chapter 5. Semistructured interviewing is an established social science research method which allows researchers to engage with the viewpoints and opinions of a particular relevant set of participants. The method 'reflects an ontological position that is concerned with people's knowledge, understandings, interpretations, experiences, and interactions' (Mason, 2004). In contrast to structured interviews, which involve a rigid schedule of questions posed in exactly the same way to each of the interviewees, semistructured interviews have a 'flexible and fluid structure' organised around an 'interview guide', which provides a list of topics to be covered, but allows flexibility in how they are explored and the order they are explored in, as well as allowing the possibility for other topics to be brought up by the interviewee (Mason, 2004). Thus, in the semistructured approach 'the interview can be shaped by the interviewee's own understandings as well as the researcher's interests, and unexpected themes can emerge' (Mason, 2004). The approach is broadly characterised by 'the interactional style of dialogue; a relatively informal style; a thematic, topic-centred, biographical, or narrative approach; and the belief that knowledge is situated and contextual, and that therefore the role of the interview is to ensure that relevant contexts are brought into focus so that situated knowledge can be produced' (Mason, 2004).

Accordingly in the case of the current research the role of the interviews was to make a connection between the broader value trends identified as applying to the UK energy system in Chapter 3, and the specific policy choices identified in Chapter 4. The interviews explored participants' views on a number of specific transmission policy options, but also situated these views within the context of broader narratives and paradigms about the appropriate ways of governing energy systems, aiming to uncover how these broader contexts could translate to and inform policy preferences in the specific area of transmission policy. The flexible and fluid structure of the semistructured approach also allowed for the experts being interviewed to raise additional areas of interest and concern which may not have already been identified in the literature reviews – in a complex and evolving technological system it is possible that certain aspects of its practical operation, or issues concerning its future development, may not be spelled out explicitly in the various codes and consultation documents which relate to the industry, but rather held as tacit knowledge by those whose full time occupation is to work in and run that industry. The semistructured interview approach leaves open the opportunity for such tacit knowledge to emerge.

In the semistructured interviews for this thesis key system actors discussed their views on the current transmission policy arrangements, and future options. In these interviews, the context was set by framing the different value-systems which could underlie decisions to take policy in a certain direction, and participants views on the current policy mix were collected in the context of having asked them to state their position on the principles of the broad values. These helped to connect the current policy mix to broader value trends and to clarify how current actors think about the options going forward. This further illuminates possible alternative policy pathways based on different combinations of value-systems. The interviews were undertaken on the basis of the 'Chatham House Rule', meaning that views could be quoted but not attributed to individuals or organisations. A potential disadvantage of this was the possible loss in explanatory power which might have been available in being able to connect views to organisations – as some views could be affected by the commercial interests of the organisation to which the individual belonged. However, the benefit of offering anonymity from the outset was in facilitating a more open and less guarded discussion, and given the seniority of those approached for interviews, was considered a price worth paying in order increase the chances of interviews being given. Moreover the loss of being able to connect views to organisational interests was not considered grave given the purpose of the interview process. The aim of the interviews was not to provide data for mounting a critique of any particular view by exposing the possible vested interests that support it; rather, the aim was to identify the spectrum of principles held by different actors, each of which could then be explored within scenarios. In this context, the identification of who holds any particular view or value-set is not critical.

1.4.3 Scenario analysis

The research question invokes the consideration of alternative possible futures. Creating hypotheses about the future inherently involves uncertainty. The future is uncertain in part because of unpredictable or uncontrollable factors which could impact upon it; however, it is also uncertain because human actors could take decisions the effect of which would be to construct the path of the future in one direction or another. 'The plurality of the future and the scope for freedom of human action are mutually explanatory; the future has not been written, but remains to be created' (Godet, 1987). A scenario process is a structured approach to considering the future in a way that assists scenario users in assessing the uncertainties, including both threats and opportunities, and considering their own decision options within this context. Far from dismissing or diminishing uncertainty, scenario analysis should help users to 'accept uncertainty, try to understand it, and make it part of [their] reasoning' (Wack, 1985b). As a result, the process should have a positive impact on improving the robustness of decisions which must be taken in spite of the uncertainty, helping users in 'making choices today with an understanding of how they might turn out' (Schwartz, 1991), and allowing users to weigh 'opportunities and threats carefully when making short-term and long-term strategic decisions' (Scearce and Fulton, 2004).

The literature on scenarios is vast and varied, which attests to the widely understood need to think about the future when making strategic decisions, to the utility of having some kind of structured process for doing so, but also to the impossibility of applying a single universal scenario method template to the great variety of sectors in which scenario thinking has been applied. Taking a scenario approach to a new problem therefore requires careful engagement with the existing body of literature, combined with the ability to pick out key insights and approaches which are of relevance to the question under consideration. In particular, for the current research question, a scenario process is required which allows for the integration of technical system analysis and qualitative policy analysis, in a way that allows the elaboration of technically precise scenarios which have the potentially to usefully inform the decisions of policy makers. Chapter 2 presents the results of an extensive **review of the scenario literature**, identifying salient distinctions between scenario methods, before **drawing together an original scenario development process** tailored to the needs of the research question. This original process provides the overarching unifying structure within which the other methods and tools described in this section are integrated.

1.5 Synthesis, analysis and contribution of the thesis

The bringing together of technical system analysis and policy analysis within an original scenario development process, produces transmission network scenarios which are conducive to being analysed for their implications for technical system performance and policy choices. The analysis of the scenarios allows conclusions to be drawn, and recommendations to be made, in relation to electricity transmission policy. Reflection on the overall process also produces insights relating to the process of scenario development itself.

Thus the original contribution of the thesis is two-fold. The primary contribution of the thesis is to answer the central research question, and explore how policy choices can affect the role played by the transmission network in a decarbonising system. In doing so it produces policy recommendations.

Additionally, in order to successfully achieve the primary aim of the thesis, it will have been necessary to develop a scenario process tailored to the needs of the question. Reflections upon the scenario process itself produces methodological insights gained from carrying out a novel mixed-method scenario process. These insights are a relevant methodological contribution to the scenario literature, in particular for scenarios considering policy-led energy system decarbonisation.

1.6 Structure and outline of the thesis

Figure 4 illustrates the discussion of Sections 1.4 and 1.5 by showing how the various methods and processes described fit together, also indicating the chapters in which the full discussion of each element takes place. The top level shows the various existing research methods and tools that are drawn upon to support the research. The middle level shows how these research methods and tools feed into synthesis and analysis: the research methods and tools feed into the three synthesising areas, as described in sections 1.4.1 – 1.4.3, which in turn produce original transmission network scenarios, which are analysed. The lower level shows the outcome of this work, which is in two forms of contribution: conclusions relating to electricity transmission policy choices, and methodological insights into the process of low carbon scenario development.

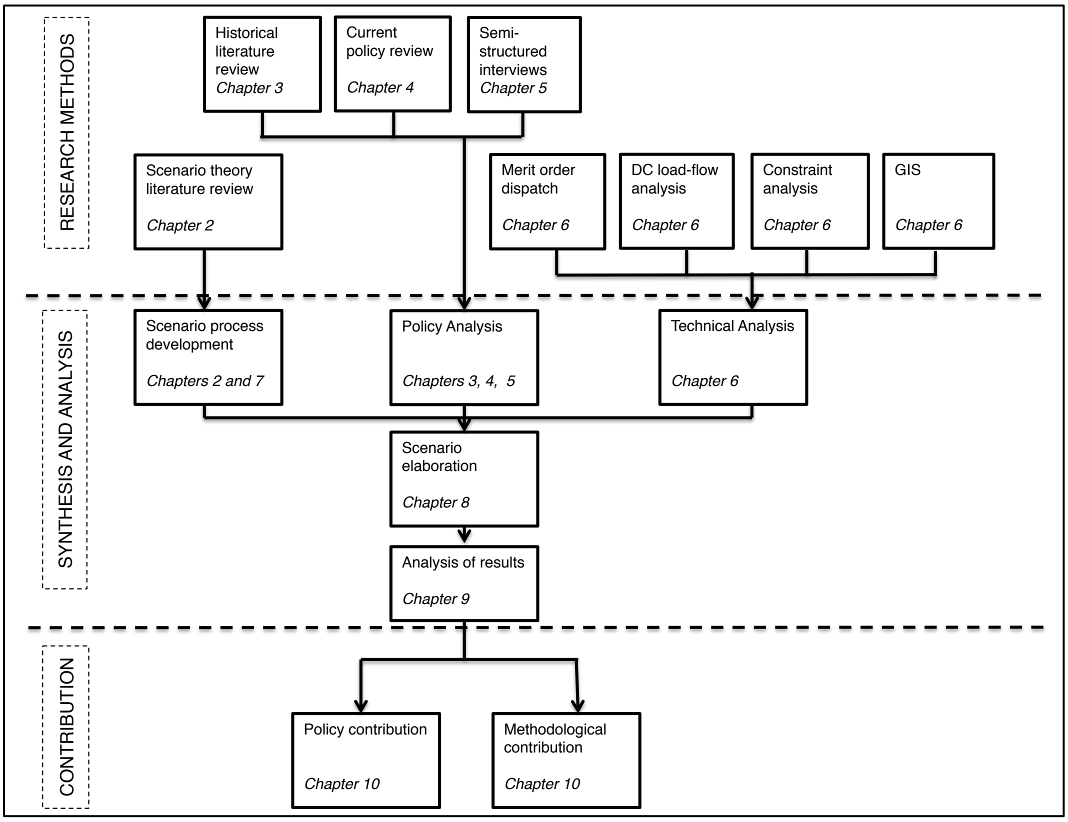


Figure 4: *Schematic outline of thesis*

The sequential ordering of these chapters in the remainder of the thesis is as follows:

- Chapter 2 reviews the literature on scenario methods and sets out the original scenario development process used in this thesis
- Chapter 3 undertakes a historical analysis of the evolution of the GB electricity system and associated policy trends and values
- Chapter 4 analyses the current policy mix pertaining to the management and operation of the GB electricity transmission networks
- Chapter 5 reports on the outcomes of semi-structured interviews with key system actors on the current mix of policies pertaining to electricity transmission networks, and future options
- Chapter 6 describes the construction and parameterisation of the technical simulation tools used as part of the scenario process

- Chapter 7 summarises how the various technical tools and policy analyses are integrated into the scenario process developed in Chapter 2
- Chapter 8 describes the scenarios which emerge from this process
- Chapter 9 discusses the insights and analysis arising from the scenarios
- Chapter 10 draws conclusions. It reflects upon the validity of the new scenario process, and sets out the recommendations on transmission network policies arising from the scenarios. It also makes recommendations for future research.

1.7 Conclusions

In order to meet the carbon budgets set out by the CCC, the UK's electricity system will have to undergo profound structural change, with significant implications for the GB electricity transmission network. Low carbon generators, in particular renewables, will present challenges to the existing GB transmission network structure, due to their locational and operational characteristics. However there is significant uncertainty around the precise mix of future low carbon generation, and hence also around the precise implications for the future electricity transmission network. This thesis aims to explore how policy choices could affect the role that the transmission network plays in a decarbonising electricity system. In order to address this question it develops a novel scenario development process which integrates a variety of quantitative and qualitative information and approaches. The contributions of the thesis are therefore, first, policy recommendations on approaches to transmission network planning and management in the context of a decarbonising electricity system, and second, the development of a new scenario method suitable for deriving tractable policy relevant outcomes to questions of long term energy system change and decarbonisation.

2 Principles of scenario theory and their application to questions of energy policy

The research question of this thesis is concerned with the possible effect that policies could have on the development of electricity transmission networks in a possible future transition towards a highly decarbonised electricity system. This is not a question which can be addressed purely empirically, as such a transition has not yet happened, in the UK or any other country. The question requires the hypothetical analysis of the possible future impact of alternative sets of decisions which could be taken now. This type of thinking is commonly referred to as 'scenario analysis'. Scenario analysis has been undertaken in a wide range of contexts by widely contrasting organisations – and the literature on scenario theory is correspondingly broad. This chapter engages with that literature in order to assemble a coherent approach to undertaking a scenario analysis suitable for the consideration of the research question of this thesis, and of potentially wider application to other questions of energy policy and long-term system decarbonisation.

2.1 Thinking about the future – introduction to scenarios

The use of the imagination to think hypothetically about alternative possible future outcomes is an intuitive, and apparently unique, human capability. 'As far as we know, no other species is able to envision something that does not exist' (Gabora, 2010). The ability to imagine the future for strategic purposes is believed to have developed early in the evolution of the human family, and is associated with the arrival of *Homo erectus* approximately 1.8 million years ago (Gabora and Kaufman, 2010, Donald, 1991). *Homo sapiens*, arriving 40-50,000 years ago, added to this capability increased cognitive fluidity and 'meta-representational thought', enabling increased connection between 'previously encapsulated (functionally isolated) brain modules' (Gabora and Kaufman, 2010). Modern human minds are able to 'shift smoothly between past, present and future almost without our being aware of it' (Gabora, 2010), and our ability to imagine the future in order to inform and improve the decisions we make, is one that we readily and naturally deploy almost continuously throughout our lives.

More formal and collaborative attempts at thinking about the future – in military planning, business strategy and public policy – also draw on this innate skill. 'The unceasing transformation of *facta* into *futura* by summary processes in the mind is part of our daily life, and thus the undertaking of conscious and systematic forecasting is simply an attempt to effect improvements in a natural activity of the mind' (de Jouvenel, 1967). However, converting an internal and personal process undertaken within the mind of an individual to a public process whose genesis, reasoning and outcomes can be shared and understood by multiple parties, is not always straightforward. Indeed the apparent intuitiveness of the process at the individual level can be an obstacle to its application within organisations or in public contexts, if this perceived intuitiveness works against the perception of any requirement for formalisation.

The term 'scenario' has become commonly used as a collective term for the images that arise out of speculation about the future – the particular hypothetical future situations or conditions that are imagined. The original use of the term in this context has been attributed to strategists working in the US Air Force Research and Development (RAND) arm in the late 1940s, one of whom, Herman Kahn, later became a well-known futurist in his own right. The term is said to have been borrowed by the RAND group from the lexicon of film-making, where the scenario is the outline of the plot of a proposed film

(Kleiner, 1996). Attempts to define the term more specifically than this in the context of strategic futures thinking however, quickly run into controversy as there are widely varying interpretations as to what it may cover. The sheer range of activities from which the word 'scenario' emerges within the equally broad field of 'futures studies', renders impossible any attempt to define a single 'scenario method'. As reported by Bradfield et al (2005), the wide usage of the term has been commented on, often with barely concealed irritation, by a number of scenario theorists. Schnaars (1987) observes that the futures research literature 'offers a plethora of methods for constructing scenarios, some of which are reasonable, many of which are arcane and impractical, most of which have never been fairly tested'. The lack of clear definition of the term (Mason, 1994), which is 'increasingly misused and abused' (Godet, 1990) has resulted in 'methodological chaos' (Martelli, 2001), and accordingly 'few techniques in futures studies have given rise to so much confusion as scenarios' (Khakee, 1991). Useful contributions to impose some order upon this 'methodological chaos' have been made by authors who have summarised the literature through typologies of scenario methods, bringing out the main 'schools' or traditions within the field (Bradfield et al., 2005, Börjeson et al., 2006, van Notten et al., 2003, McDowall and Eames, 2006, Huss and Honton, 1987). However, such is the apparent flexibility of the term that even agreement on a broad typology of scenario approaches has not yet been achieved amongst these and other reviews. Nonetheless, each alternative typological arrangement is useful in as much as it brings out important common factors as well as contrasting approaches within scenario methods – even if the definitive scenario typology remains elusive.

It may in fact be necessary to acknowledge that methodological diversity is and always will be associated with the term 'scenario'. Thinking about the future is a requirement of almost every human activity. That those who attempt to formalise this process within fields as diverse as military planning, political strategy, business strategy, health, education, welfare and energy policy should all converge on just a handful of methods which between them are applicable to all possible situations, may be an expectation which is unrealistic and potentially counter-productive. However, even if a new scenario practitioner could, on the basis of this argument, feel justified in customising a scenario method to his or her own particular needs, this is not equivalent to justifying a studied ignorance of the various methods which have been developed before, or the undertaking of a scenario process without any reflection on or consideration of methodology. This chapter therefore reviews previous approaches to low carbon energy scenarios, in the context of a review of the broader scenario literature. It brings out concepts and techniques of most relevance to the current research question, and combines these into a scenario development process designed for use in this thesis.

2.2 The objectives of scenario thinking

Intuitively when thinking about the future we think sometimes about risks or threats against which we would like to be resilient, as well as scanning for opportunities from which we could benefit if prepared. The objectives of scenario thinking are often summarised in a similar way: 'Scenarios serve two main purposes. The first is protective: anticipating and understanding risk. The second is entrepreneurial: discovering strategic options of which you were previously unaware' (Wack, 1985a). A similar two-fold distinction is made by various other theorists (Wright and Cairns, 2011, Schwartz, 1991, Scearce and Fulton, 2004). Different scenario exercises will strike a different balance between these two objectives, with perhaps the most important factor affecting this balance being the agency of the 'scenario user' – the actor or organisation using the scenarios to improve their decision making – in relation to the 'system under study' – the system within which that scenario user acts, and which the scenarios are exploring. De Jouvenel writes that for any actor, the future may be divided into 'dominating' elements, which cannot be controlled by that actor but only reacted to, and 'masterable' elements over which the actor in question has some agency to exert influence (de Jouvenel, 1967).

Typically, scenarios conducted by businesses will find themselves more frequently in a protective mode – searching for external threats and planning accordingly. The classic example of such a use of scenarios is provided by the series of scenario exercises conducted by Shell during the 1970s (Wack, 1985b, Wack, 1985a). By contrast, public policy scenarios, for which the implicit 'scenario user' is often the policy making body of a nation state, an actor with greater agency within its own 'system', more elements of the future may be considered potentially 'masterable', hence the scenarios may operate more frequently in a proactive mode. An example of this approach is the 'Prospective' school of scenario building, developed in the late 1950s in academic institutions in France but with an explicit intention to link to policy making processes, such as the five year French National Plans (Bradfield et al., 2005). The language of the Prospective school is clearly about forming the future, as an alternative and preferable strategy to passively allowing the future to take shape. Thus, 'it is not so much about divining the future as constructing it, not so much about forseeing a probable future as preparing one that is hoped for. It amounts to making desirable ends a powerful enough lever to act on the present' (Massé, 1966).

However, in many public policy situations, the model of the policy making executive as a highly powerful actor able to turn policy options on and off in line with centrally devised plans, would appear too simplistic. A policy process is often less about a simple proactive forcing of a strategy by one actor (the policy maker), and more about coordination and alignment of activities and viewpoints of multiple actors. In this context too scenarios can be used to illustrate the potential outcomes of different combinations of activities and alignments of multiple actors. A key example of this approach is the Mont Fleur scenarios process which occurred in South Africa during the transition period from apartheid system to multi-party democracy. The process drew together actors from across the political spectrum, with accordingly divergent views. Emphasising that 'the future is not fixed but can be shaped by the decisions and actions of individuals, organisations and institutions' (Le Roux and Maphai, 1992), the scenarios were used to elicit agreement as to how decisions and actions taken by various actors in the present could lead to future outcomes, to 'find and enlarge the common ground' (Le Roux and Maphai, 1992), thereby enabling the building of consensus between actors.

Three potential objectives of scenarios processes can therefore be identified. Scenarios can be used to assist with:

- Protective decision making
- Proactive decision making
- Consensus building

These objectives, though contrasting, are by no means mutually exclusive. However, as discussed, the balance between these aims in any particular scenario process depends upon the level of agency of the scenario user or users in the context of the system under study. Therefore, a clear identification of the scenario user or users – the actor or actors who will be using the scenarios to assist their decision making – and their level of agency within the system under study, is crucial to understanding the objectives of the process. A clear definition of the system under study, including its boundaries, is also critical to understanding the role and level of agency of the scenario user or users within it. Table 1 shows how these three objectives map onto different types of low-carbon, climate and energy scenarios, and the connection in each case to the agency of the explicit or implied scenario user in the context of the system under study.

Table 1: *Low carbon, climate and energy scenarios: comparison of focal questions, scenario users, system under study and type of objective*

Scenario examples	Focal question	Scenario user and system under study	Type of objective
Climate impact scenarios (IPCC, 2007b, IPCC, 2007a, UKCIP, 2009)	What is the possible range of greenhouse gas concentrations by a given date, and what is the possible range of impacts associated with them?	National policy makers; global climate system	Protective: suggests actions to adapt to climate change Proactive: informs discussion of what a global emissions target should be
Socio-economic scenarios (Berkhout et al., 1999, UKCIP, 2001)	How would different policy trajectories be affected by different socio-economic contexts?	National policy makers; social, economic and cultural system	Protective: suggests actions to improve robustness of particular plans to a range of (external) socio-economic conditions
Technical energy-emissions scenarios (IEA, 2012, CCC, 2008, DECC, 2010a, Skea et al., 2011)	How can the energy system reduce its greenhouse gas emissions to a given level by a given date?	National and international policy makers; technical energy system	Proactive / consensus building: aiming to demonstrate how policy driven technological deployment can achieve desired emissions reduction targets

The three objectives also identify another important characteristic of scenarios: a scenario process is purposeful activity, in which thinking about the future is done in order to inform and improve current and near-term decision making. Scenarios are not simply stories about the future, told with no other objective than the enjoyment and amusement derived from story-telling itself. Scenarios have a strategic purpose, connected with near-term actions. Thus, for Schwartz (1991), 'scenario planning is about making choices today with an understanding of how they might turn out', and for Scearce and Fulton (2004), they allow us to weigh 'opportunities and threats carefully when making short-term and long-term strategic decisions'. Godet (1987) emphasises that 'despite the unknown horizons, we have to take decisions today that commit us for the future', and that in this context, a scenario process helps us 'to create the future rather than submit to it'. Speaking of business scenarios, Wack (1985a) asks, 'Do they lead to action? If scenarios do not push managers to do something other than that indicated by past experience, they are nothing more than interesting speculation', and in the context of public policy scenarios, Volkery and Ribeiro (2009) affirm that 'having an impact on the design and choice of policies remains a litmus test for the relevance of scenario planning'.

The requirement for the futures explored within scenarios to assist with current decision making has implications for the structure of the scenarios themselves. In order to see how current decisions could affect future outcomes, it is usually important for scenarios to describe not just a future ‘snapshot’, but an evolving sequence of events through time, connecting the actual present in which current decisions can be made, with a range of possible future pathways, defined at least in part, by the different sets of decisions taken. Thus for Kahn and Wiener (1967), ‘scenarios are attempts to describe in some detail a hypothetical sequence of events that could lead plausibly to the situation envisaged. By the use of a fairly extensive scenario, the analyst may be able to get a feeling for events and the branching points dependent upon critical choices’. A further benefit of scenarios as sequences of events through time is the requirement for the argumentation of a logical, causative process. As was found during the Mont Fleur scenarios process (Le Roux and Maphai, 1992), and by Pierre Wack during the development of Shell’s early scenarios (Wack, 1985b, Wack, 1985a), this can lead to the challenging of preconceived ideas or entrenched world views, which can cloud judgement. For Wack, this process of working through sequences of events was a key part of how scenarios enable users to understand the system under study: ‘power comes with an understanding of the forces behind the outcome’ (Wack, 1985a).

The value of undertaking a scenario process at any given time is therefore in exploring the potential longer term impacts (both positive and negative) of near-term choices. As the future is less fixed the further ahead we look, it follows that the further ahead we look the greater potential we have to construct the future in a desirable way. This is the fundamental justification for long-range planning. As de Jouvenel writes, if decision makers ‘cannot be blamed for a decision that was in fact inevitable, they can hardly escape censure for letting the situation go until they had no freedom to choose’. However, as found by Volkery and Ribeiro (2009) in the context of public policy scenarios, the many hetereogenous concerns and short-term time frames within which decision makers usually operate, can make it hard for an issue that is fundamentally about long-term planning to gain traction within the policy making process. Therefore, a key challenge for scenarios in public policy issues is to show how long-term planning goals can be connected with the near-term decisions which are required to bring them about, in a way which locates the issue alongside the nearer-term issues which normally dominate the policy-making field of vision.

2.3 The nature of future uncertainty and the role of human agency

The justification for a scenario approach is often made with a strong reference to the uncertainty of the future, and the assertion that other methods for considering the future, such as extrapolative forecasts, take insufficient account of this inherent uncertainty (Wack, 1985b, Wack, 1985a). With this in mind, scenario studies are often quick to reassure the reader that the future descriptions contained in the report are not predictions. They rather seek to outline a range of possible outcomes. Whether scenarios should be limited to describing futures in terms of 'possibility', or whether they can invoke concepts of 'probability', is a matter of debate amongst practitioners. Whilst some practitioners are comfortable with ranking possible scenarios according to calculated probabilities (Godet and Roubelat, 1996, Godet, 2000), others maintain that probabilistic ranking is too close to prediction, and has the effect of closing down perceptions of what is possible. For such commentators, both prediction and probabilistic ranking are antithetical to the scenario approach, which should be fundamentally about opening up, rather than narrowing horizons (Wilson, 2000). In either case however, the single point predictions of forecasting models tend to be viewed as naïve; the scenario approach with its fanning out of multiple possible outcomes, proclaimed as more subtle.

However, although it may be a prudent approach on behalf of the futures thinker, bearing in mind the well-known 'perils of long-range forecasting' (Smil, 2000), to avoid single point forecasting and to emphasise the uncertainty, or even unknowability of the future, neither is it always immediately clear what the point is of making any speculation about the future, when every aspect of such speculation is so heavily caveated by the authors' insistent emphasis upon doubt and indeterminacy.

It would be generally accepted by most that anyone who claims to have the ability to predict the future in every aspect is excessively hubristic. However, it would also be widely recognised that anyone who, conversely, proposes that a pall of total uncertainty is draped over every aspect of the future, and that nothing at all can be known or reasonably predicted about it, is guilty of going too far to the opposite extreme. Uncertainty will always surround human decision making, however, it is not clear that a process which provides only the insight that 'the future is very uncertain' is of any practical use to a decision maker. What is more useful is an analysis which provides some reasonable basis on which to make some kind of decision, despite the uncertainty and its attendant risks.

A structured scenario approach delivers this kind of analysis, not by simply asserting the obvious fact that there is variability concerning possible future outcomes, but by categorising the different kinds of future variability, and connecting these to the different strategic options available to the scenario user. The future is not a homogenous canvass, but can be viewed as consisting of many different components. These different components have different levels of variability – or degrees to which they could be different in the future. Moreover, this future variability is in different cases a result of different forces. Consideration of the causes of the variability of the future reveals that there are different kinds of uncertainty about the future, which can be understood and considered in different ways. A particularly important consideration is the extent to which the variability of the future is related to the scope for freedom of human action – there is an important distinction to be made between aspects of the future whose variability depends on the choices that human actors could make to behave in one way or another, compared to those which are outcomes of systemic processes, and those which may be associated with a more profound or random kind of uncertainty.

2.3.1 The distinction between process and action in human systems

In his extensive discussion of futures thinking, *The Art of Conjecture* (1967), Bertrand de Jouvenel recalls a physical scale model of Rangoon Harbour constructed by Scottish civil engineer Sir Alexander Gibb. The model successfully predicted the build up and subsequent dispersal of a silt bar in the harbour. The accuracy of the model was due to its ability to capture all of the significant variables affecting the build up of the silt, and to reproduce their interactions with sufficient accuracy in the simulation – the laws that govern the movement of silt and water in Gibb's scale model are the same as those that apply in the real Rangoon harbour. In principle, in natural systems where bodies and fluids are governed by fixed laws, as long as these laws are known, highly accurate simulations of future conditions can be made.

Models of human systems can also be constructed based on 'laws of human behaviour', however, as de Jouvenel notes, 'in the models human behaviour is represented by rigid behavioural equations, whose only justification lies in statistical observations' (de Jouvenel, 1967). Many would argue that in most situations such evidence is sufficient, in that, despite the appearance of free will at the individual level, at the aggregate level, mass human behaviour can indeed be predicted with laws of immutability approaching that of the laws of motion of physical bodies. Godet proposes that 'history does not exactly repeat itself, but, over time, people show disturbing similarities in their behaviour, which leads them to react, when faced with comparable situations, in an almost identical way, *viz* predictably' (Godet, 1987).

In contrast to such a position however, it might be proposed that as well as being part of larger processes, human actors can also at times take decisive and influential actions, which are external (exogenous) to any essentially predictable systemic process, but which have a significant subsequent effect on the ongoing dynamics of the system.

De Jouvenel observes that human behaviour 'has a *twofold* role: it is both internal (endogenous) and external (exogenous) to the process... Men are *submitted* to the process (as objects), but are also *masters* of it (as acting subjects); and this twofold role of men is characteristic of the social and political order as a whole' (de Jouvenel, 1967). Thus de Jouvenel draws a crucial distinction between *process* – the dyamics which take place within a system and which are not explicitly willed by any individual human actor; and *action* – the conscious intervention of a human actor upon a system. Described as a process, a sequence of events is not susceptible to human intervention. By contrast, what de Jouvenel refers to as actions in this context, are attempts to act exogenously on the system, with a consciously sought goal in mind. With the dual role of humans as objects within processes, as well as subjects of actions upon processes, it might be asked what causes or allows a human agent to move between being an object and a subject. This is clearly a question of the level of agency of the actor in relation to the system in question: 'things are different for the agents of exceptional weight who figure in the system. It is a matter of indifference to the railways if I decide to take my sons on a journey I normally make alone, but not so if the minister of war requires railway facilities for an important movement of troops' (de Jouvenel, 1967). The level of agency of the actor in respect of the system being analysed is thus a crucial factor in considering whether to analyse change in terms of process or action. In many cases, of course, an actor could be both able to exogenously affect the system through an action, as well as affected by it subsequently as an object within an ensuing process.

For de Jouvenel, ultimately, the recognition of both process and action is necessary in considering the future development of human systems. 'If we understand that processes exist in human affairs and grasp their dynamics as well as possible, we stand to gain everything in the spheres of both intellect and utility'. However, 'we gain nothing in the intellectual order, and lose a great deal in the field of action, if we insist on integrating all history into a process that embraces all human actions. What is important is to find points of fulcrum on which we can exert pressure, thereby deflecting the course of events in one direction rather than another. The common sense distinction between process and action is therefore salutary' (de Jouvenel, 1967).

Whilst the consideration of human actors as 'objects' within 'processes' relies for its evidence on statistical observations of past aggregated behaviour, consideration of human actors as 'subjects' of 'actions' requires some kind of hypothesis about what motivates the free-thinking actor to act in a particular way. It requires an attempt to understand the internal motivation of human actors and how this might cause them to choose to act.

Such attention to actor motivations was central to the approach of several of the more renowned scenario processes. In the 1950s, the US Air Force think-tank RAND pioneered scenario work exploring possible reactions of the various actors in the emerging 'cold war' drama under a variety of different conditions, such as the development of new technologies and weaponry (Ghamari-Tabrizi, 2005, Kleiner, 1996). A key figure to emerge from RAND was Herman Kahn, who in later work developed the concept of the ‘escalation ladder’ to explore actor motivations and responses to emerging conflict situations (Kahn, 1965). In his descriptions of the 1970s Shell scenario processes, Pierre Wack describes his team’s characterisations of the views and motivations of the various oil producing and consuming countries; in one telling illustration, the various oil producing countries are grouped into four quandrants, and it is illustrated that no country has both the means as well as the motivation to increase production (Wack, 1985b). This lack of motivation on the part of major oil producing countries to keep pace with growing demand was an example of an actor motivation which was not being represented in forecasting models. A Saudi oil minister declared, ‘we should find that leaving our crude in the ground is by far more profitable than depositing our money in the banks’ (Wack, 1985b), and considering the emergence of a similar position from Iran, Wack’s team realised, ‘if we were Iranian, we would behave the same way’ (Wack, 1985b). In post-apartheid South Africa, the Mont Fleur scenarios process worked through the interactions of the various motivations of key actors in South African society. In this process the motivations of the various actors became seen as source of future variability with a strong upside – that harnessing the influential power of actor choices could facilitate the co-creation of desirable futures: it was shown that ‘the future is not fixed but can be shaped by the decisions and actions of individuals, organisations and institutions’ (Le Roux and Maphai, 1992), or in de Jouvenel’s terminology ‘points of fulcrum on which we can exert pressure’ were identified. In each of these cases the identification and understanding actor motivations was undertaken using intuitive methods: ‘brain-storming’ and role play were important tools in the Shell and RAND processes (Wack, 1985b, Wack, 1985a, Kleiner, 1996, Ghamari-Tabrizi, 2005), and guided discussion between relevant system actors provided the material for the Mont Fleur scenarios (Le Roux and Maphai, 1992). Intuitive methods draw on the natural skill of human participants to imagine their own reactions or the reactions of others in a range of alternative future conditions. Whereas quantitative models of agent behaviour can powerfully be applied in situations where the aggregation of human behaviour creates an effect as if human actors were bodies with fixed propensities – ‘objects’ within a process; intuitive methods on the other hand are often the appropriate tools to consider human motivation emerging from a human actor with choice and agency – a ‘subject’ of an ‘action’.

2.3.2 Different kinds of future variability

With the distinction between process and action in mind, it is now possible to consider more specifically how different types of future mobility may be characterised. In order to gain this more constructive view of the contours of the future system, an essential starting point is a detailed scoping of the present system – for one certain thing that can always be said about any future system, is that it evolves out of the present system. Hence much can potentially be known about the future system through the identification of signs or indications in the present one. The first phase of Godet’s ‘structural analysis’ approach to scenario generation is to obtain 'as thorough a representation as possible of the system under study' (Godet, 1987), and de Jouvenel describes a possible future element, or futurible, as 'a possible descendant from the present state of affairs… a descendant to which we attach a genealogy' (de Jouvenel, 1967). The scoping of the present system can reveal different types of emergent element, each of which contributes to future variability in different ways. Drawing on a typology proposed in (Hughes et al., 2013), they are summarised here as pre-determined, actor-contingent, and non-actor-contingent elements.

2.3.2.1 Predetermined elements

Although scenarios are traditionally associated with uncertainty, a detailed scoping of the system can reveal that some aspects of the future system can be known with greater certainty than others. Wack writes, 'scenarios structure the future into predetermined and uncertain elements. The foundation of decision scenarios lies in exploration and expansion of the predetermined elements: events already in the pipeline whose consequences have yet to unfold, interdependencies within the system (surprises often arise from interconnectedness), breaks in trends, or the "impossible". Decision scenarios rule out impossible developments; they deny much more than they affirm' (Wack, 1985a). Wack's image of 'events already in the pipeline whose consequences have yet to unfold' resonates with a view of the system as a process – preconditions are set and the playing out of resulting dynamics is a matter of inevitability. Such reasoning enabled Wack's scenarios team to conclude with a high degree of certainty, in the 1972 scenarios that an oil shock should be expected (Wack, 1985b), and in the 1974 scenarios, that governments would attempt to reflate their economies in the aftermath of the crash (Wack, 1985a). In both of the above cases, the conditions which led to the predetermined elements included motivations of system actors which the team had assumed to be unchanging; in the first case that governments of oil consuming countries would not legislate to reduce consumption, and oil producing companies would not sell oil when it would become more valuable left in the ground; and in the second case that the electoral pressure on governments would be such that they would inevitably attempt to reinflate their economies. The decision to treat actor motivations as fixed was a matter of judgement taken by the scenarios teams – in other situations actor motivations may have been considered as having the potential to change, creating potentially variable, not predetermined, future elements. These kinds of pre-determined elements are therefore outcomes of processes, in which the human actors are considered as 'objects' with fixed propensities, and thus predictable reactions in specified situations. Their implication is that the present system already contains a number of elements, the combination of which must inevitably lead towards a certain outcome.

In large technological systems, predetermined elements may also include the existence of physical systems and infrastructures which have been built to last for years into the future. Due to the sunk investments associated with such infrastructures, it is often reasonable to assume that they will remain a feature of the system for the remainder of their expected operational lifespan. Equally however, such predetermined elements have an expiration date – some pieces of infrastructure may be considered predetermined up to a certain time, but not beyond this.

On a more practical note, predetermined elements may also include elements which are treated as fixed because it is beyond the scope of the scenario process to consider their variability. This is different from claiming that they are fundamentally unvariable – rather they are being treated as unvariable because they are not one of the variables of primary interest. Understanding the variables of primary interest is achieved by having a clear focal question.

2.3.2.2 Actor-contingent elements

Having identified any predetermined elements which held within the system for the timefame of the scenario, Wack then proceeded to examine the uncertain elements. However, further differentiation can be made within this category as events are uncertain for different reasons. The uncertain elements were variable (in some cases) as a result of different decisions and actions that could be taken by different actors. For example, in the 1974 scenarios different policy choices by governments led to different outcomes in the form of the 'boom and bust' and 'muddle through' scenarios (Wack, 1985a). These are therefore *actor-contingent* variabilities; the variability of the future is dependent upon the choices which specific actors could make. The identification of actor-contingent elements is therefore predicated on the understanding that certain actors have sufficient agency within the system under study to be 'subjects' of 'action' and not only 'objects' of a 'process'. These actors may be thought of as 'prime mover' actors – in that their agency is such that their choices and actions can directly affect and alter system processes. Other lower agency actors who are part of those system processes may be thought of as 'second mover' actors – their behaviour is altered in response to prime mover actor decisions, and their ensuing impact on the system is as part of a system process, and less as a result of their own autonomous decisions.

In order to understand actor contingent elements, two things are needed. First we need to understand and describe the internal motivation, reasoning or value system which causes the prime mover actor to choose to implement the action. For example, Wack analysed the business strategies of the corporate players and governments in his system (Wack, 1985b, Wack, 1985a); Kahn considered the motivations of defence staff operating with limited information in a situation of high-loss risk, and a perception of an adversary whose own motivation was largely malevolent (Kahn, 1965). Scenarios that deal with longer term societal change also need to consider motivations that may change more dramatically from the status quo, as a result of long-term value shifts. Second, we need to consider how that action impacts upon ongoing processes within the system – this is because we understand that even high agency actors do not have a total god-like control over the system, they can act decisively but the full impacts of their action will be modified by system dynamics.

2.3.2.3 Non-actor-contingent elements

There remains a third category of future variability, not so much considered by Wack, but of likely greater importance to scenarios considering longer term futures, involving significant technological change. In any future system there remains the possibility of significant variability arising from events which are not easily ascribable to identifiable actors within the system. This may be because the event is external to the system. For example, a system defined by the boundaries of a nation state would still be susceptible to variability caused by events emanating from outside its borders. Additionally, variability may arise from events which although they might be said to have emerged within the system, are not easily ascribable to conscious willed decisions of system actors – for example, an unforeseen technological breakthrough. These are examples of events which could create significant system variability but are not entirely within the control of system actors to decide to bring them into being or not. Just as de Jouvenel argued for consideration of both 'masterable' and 'dominating' events, a prudent scenario process should consider the potential effects on the system of events which cannot be entirely controlled by system actors.

2.3.2.4 Typology of future variability

Thus, a synthesis of Wack's distinction between 'predetermined' and 'uncertain' elements, with de Jouvenel's distinction between 'masterable' and 'dominating' elements, in addition to his distinction between 'process' and 'action', leads to the following taxonomy of future elements.

- Pre-determined elements: process outcomes, fixed assets, variables out of scope

- Actor-contingent elements: variable elements dependent on choices of identifiable system actors

- Non-actor-contingent elements: variable elements outside of the control of system actors

Categorising the causes of future variability in this way is critically important for relating the content of each scenario to the strategic objectives of the scenario process, identified in Section 2.2. Pre-determined elements must be accommodated in all futures, and non-actor-contingent elements cannot be influenced by system actors; hence both of these elements prompt protective thinking, to ensure robustness against them. Actor-contingent elements, on the other hand are brought about by choices and decisions of system actors, and thus system actors have agency to directly influence these outcomes, which prompts proactive decision making (Hughes et al., 2013). Conflating these different types of future variability produces scenarios which emphasise uncertainty but leave the scenario user with very little information as to what kinds of decision can be taken with respect to this uncertain future. Separating and categorising future variability on the other hand, greatly increases the power of the scenario user's decision making, through enabling a clearer understanding of 'the forces behind the outcome' (Wack, 1985a). Table 2 summarises the taxonomy of future elements by type of variability, and relates each to the three scenario objective types identified in Section 2.2.

Table 2: *Taxonomy of future mobility*

Category	Sub-category	Example	Scenario objective type
Predetermined elements	Process outcomes – the logical outcomes of elements already present in the system	Due to an existing government policy, investment project A will definitely not proceed.	Protective
	Fixed assets	Existing power stations X,Y,Z will remain operational for the rest of their operational lifetime.	Protective
	Variables out of scope	Possible decisions of actors X,Y, Z are treated as fixed because it is beyond the scope of the focal question to treat their decisions as additional variables	N/A
Actor-contingent elements	Internal actor-contingent (prime mover)	Government may decide to implement policy X.	Proactive
	Internal actor-contingent (second mover)	If policy X were implemented, the logical response of company Y would be Z.	Proactive / consensus building
Non-actor-contingent elements	External to system	If country A (not a part of the system under study) strongly pursued market integration policies, this would have impact X on the system under study	Protective
	Profoundly uncertain	The cost-competitive breakthrough of technology X by year Y, would have impact Z on the system under study	Protective

2.4 Representing the 'system under study'

The previous discussion has identified different types of future system variability which could act on the system under study. As noted, a clear definition of the system boundary, which corresponds to the scope of the problem posed by the focal question, is vital to ensure that the analysis of the different kinds of variability is sufficiently clear to enable insightful analysis of the 'forces behind the outcome' (Wack, 1985a). A scenario process involves the consideration of different types of variability and their role in creating different alternative possible future system states. In addition to enumerating the sources of variability therefore, such a process also requires some kind of model or representation of the system to explore how the system could change from its present state to the number of possible future states dictated by the internal variables of the scenario. A model is a simplified version of some aspect of reality, created for the purposes of analysing and understanding particular dynamics of interest. In scenario literature, the means by which the system under study has been represented are as varied as other aspects of method, again reflecting the wide variety of sectors to which a scenario approach has been applied. This section groups scenario approaches according to the manner in which they have conceived the system under study. The way in which the system is represented affects which aspects of the present system are analysed, and how these aspects are extended into the future.

2.4.1 The system as the outcome of high level values and long range trends

A common way to delineate future systems in scenario approaches has been through the extrapolation of values and trends from the present system. Such an approach conceptualises the system primarily as an embodiment of certain cultural or socioeconomic trends or values. This is achieved either through the replication of historically observed trends or 'cycles', or by extending currently nascent aspects of the present system into major culturally defining future trends. This approach can be elaborated quantitatively, as shown by the work of Herman Kahn and the Hudson Institute, which was driven by fitting data to models designed to recreate long range trends such as Kondratieff's theory of economic cycles (Kahn, 1982). A trend based view also underlies qualitative approaches by which values evident to some extent in the current system are extended and imagined to become dominant cultural values, to provide socially and culturally contrasting scenarios. Thus future change is imagined almost entirely in terms of major cultural value shifts in one direction or another. This approach frequently uses a 2x2 matrix to represent the contrasting values being considered by the scenarios (Schwartz, 1991, Nakicenovic and Swart, 2000, PIU, 2001). Berkhout, Hertin and Jordan developed a 2x2 scenario generation matrix for the UK Socio-economic Scenarios (SES) as described in Berkhout et al (2002). Similar matrices were deployed by the Inter-governmental Panel on Climate Change (IPCC) (Nakicenovic and Swart, 2000), the UK Performance and Innovation Unit (PIU, 2001), and the UK Climate Impacts Programme (UKCIP, 2001). Berkhout et al's version combines a 'values' axis contrasting 'individual' with 'community' values, with a 'governance' axis, contrasting 'interdependence' with 'autonomy' as possible dominating preferences and trends in the nature of politics and governance. The four possible combinations of the extreme ends of each axis yield four scenarios (***Figure 5***). ***Figure 6*** shows a similar matrix as presented by PIU, with slightly different labels but the same broad spectrums of social values and governance or geopolitical trends. Interestingly, both highlight the same area on the grid corresponding to 'conventional development' (Berkhout et al., 2002) or 'BAU' (PIU, 2001), apparently suggesting that the 'world markets' scenario would be the least radical departure from current trends.

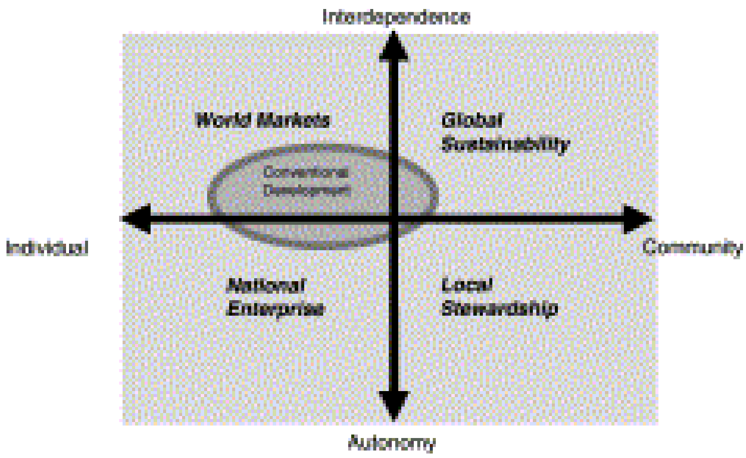


Figure 5: *2x2 scenario matrix for representing scenarios based on high level trends, as proposed by Berkhout et al (2002)*

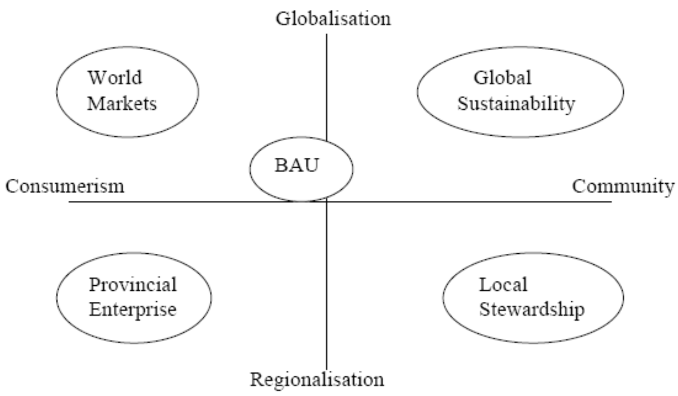


Figure 6: *2x2 matrix for representing scenarios based on high level trends, as proposed by PIU (PIU, 2001)*

The approach to producing scenarios based on the interaction of different high-level trends and values became influential and much imitated in subsequent low carbon scenarios, including those already discussed in Section 1.2.1. The National Grid Future Energy Scenarios (FES) are typically derived from a 2x2 matrix, the most recent of which representing the interaction of the axes of 'affordability' and 'sustainability' (National Grid, 2013c). The LENS scenarios were also derived from the interaction of high level trends, though in this case there were three axes: environmental concern, consumer participation and type of institutional governance (Ault et al., 2008).

The high-level trend or values based approach to scenario generation tends to be the most 'narrative' or novelistic of the scenario approaches. Indeed, such futuristic novels as Orwell's *1984*, Huxley's *Brave New World* and Atwood's *The Handmaid's Tale*, are essentially scenarios generated in a similar way, via the extrapolation of emergent trends or values the author perceives in their contemporary environment. Trend and value-based scenarios can produce broad and sweeping storylines, encompassing descriptions of technology, politics and culture. The conceptualisation of the system in terms of values and trends may allow for a view of system change which accords more easily with long range historical views of societal changes, incorporating major structural change. Over long time frames, major technological shifts, cultural, economic and political changes can appear to be interrelated phenomena propelled by an irresistable wave of history (Freeman and Louça, 2001). From the macroscopic perspective, the major historical changes appear to be driven by something larger than the plans of any individual human actor.

However, there are potential conceptual criticisms which can be made of high-level trend or values based approaches. The typology which separates and contrasts apparently opposite values in a manner which implies their mutual incompatibility can appear too simplistic. For example, as noted by Anderson et al (2005), in relation to the PIU axes (***Figure 6***) ''community values' are not at the opposite end of an axis which has 'consumerist values' at the other end and it is possible for an individual or collective to hold both sets of values concurrently'. Value-based scenarios can appear overly-polarised, 'rather than the more realistic, complex and 'messy' world in which we live, which entertains elements of all these ways of organising', and in which opposing values are in constant tension and debate. Responding to this criticism within a value-based approach is not straightforward. One approach would be to diffuse the polarisation inherent in the 2x2 matrix, by incorporate more intersecting axes, as the LENS scenarios did – however the number of combinations of these variables, and the number of possible resulting scenarios if all combinations are used, quickly becomes unmanageable. In the LENS scenarios some possible value-combinations generated by their three intersecting variables had to be left out for practical reasons. However the justification for doing so is not always straightforward – for example the LENS scenarios do not include a scenario with high environmental concern but low consumer participation, and it is not clear that such a combination is necessarily contradictory. Morphological analysis has been proposed as one method of combining and cross-checking the consistency of multiple variables (Ritchey, 2011, Zwicky, 1969). An alternative response is to reduce the scope of the system and the problem being addressed until it can satisfactorily be summarised by two intersecting variables. This would preserve the clarity of the 2x2 axis and give much greater focus to the key research question. However, it might be seen as a disadvantage that the broad horizons that high-level trend scenarios typically scan are somewhat closed down by such an approach.

Further problems can emerge when values appear to be responsible for technological choices – for example scenarios characterised by 'community' values often feature high levels of decentralised generation (Hughes and Strachan, 2010). Whilst the link between the value and the technology is on a superficial level understandable, nonetheless there is clearly nothing inherently contradictory about the valuing of social communities and the existence of a centralised generation system. Such scenarios can imply worlds in which values alone have a creative power which supersedes technological path dependency and magically unifies actors with previously conflicting world views and ideologies. Values certainly underlie the motivations of human actors, however the effect of values is modulated by how they are enacted by actors, and how these actions are accommodated by the rest of society and the technological system.

The failure to identify the effect of actor actions is also reflected in the fact that value based scenarios tend to make no distinction between masterable and dominating (actor-contingent and non-actor-contingent) elements. Events which could potentially be influenced by scenario users (domestic policy choices) and events which cannot (geopolitical dynamics) – are all wrapped up in an essentially fatalistic view of a society drifting to one corner of the values matrix or another. This may mean that, as a means of conceptualising a system for a scenarios project, a trend-based approach may be problematic as it appears to distance the evolution of the future system from the conscious actions of any particular system actor, or to identify with any specificity what forces lie behind particular outcomes. The structural issue is that broad trend based scenarios tend to aim for a very wide system scope. This is conscious and intentional, as the scenarios are desired to be rich and comprehensive descriptions of the various facets of society. The inevitable result of this is that each individual scenario attempts to vary simultaneously a large number of variables. Because attempting to vary each of these as strictly independent variables would produce more scenarios than is practical, the broad trend approach is to yolk a number of variables together as if they are all co-dependent on the same intangible force – the high level trend. However, this trend is not a real world action, but an imaginary novelistic construct. It is a fatalistic pre-determination of the outcome - a *deus ex machina* – rather than a genuinely explanatory force for which there is an understandable real world equivalent. Scenarios developed in this way therefore, whilst they may be appealingly rich, wide ranging and novelistic in content, can struggle to achieve genuine strategic effectiveness for the user, because they contain no mechanism through which the user can understand how these possible futures may be caused to evolve from the actual present. This makes it harder for the user to develop strategic insights on the basis of either being prepared for such futures, or to play an active role in bringing them about.

2.4.2 The system as the outcome of actor interactions

An alternative approach to constructing scenarios views the system as a network of human actors, the interactions between which define the manner in which the system changes through time. Thus for le Roux and Maphai (1992), 'the future is not fixed but can be shaped by decisions and actions of individuals, organisations and institutions', and for Godet 'the future of a system [can] be considered as resulting from the development of the balance of power between the actors driving the system'(1987). For many proponents of an actor-focussed approach, the key advantage of scenarios constructed in this way is the identification of how decisions taken by actors can cause bifurcations or 'branching-points' leading towards different future outcomes – this is potentially an empowering perspective for a scenario user. Thus, Kahn and Weiner write 'scenarios are attempts to describe in some detail a hypothetical sequence of events that could lead plausibly to the situation envisaged… by the use of a fairly extensive scenario, the analyst may be able to get a feeling for events and the branching points dependent upon critical choices' (Kahn and Wiener, 1967). De Jouvenel emphasises that 'what is important is to find points of fulcrum on which we can exert pressure, thereby deflecting the course of events in one direction rather than another' (de Jouvenel, 1967). The work of Kahn, Weiner and de Jouvenel was drawn on by Hughes (Hughes, 2009a, Hughes, 2009b) in placing 'branching points' arising from 'actor decisions' at the centre of a proposed scenarios approach for the Transition Pathways to a Low Carbon Economy project (***Figure* 7**). The 'branching point' concept was adopted within the Transition Pathways project as part of their socio-technical scenarios approach, in which it was defined as 'a key decision point on a pathway at which choices made by actors, in response to internal or external pressures, determine whether and in what ways the pathway is followed' (Foxon et al., 2013).

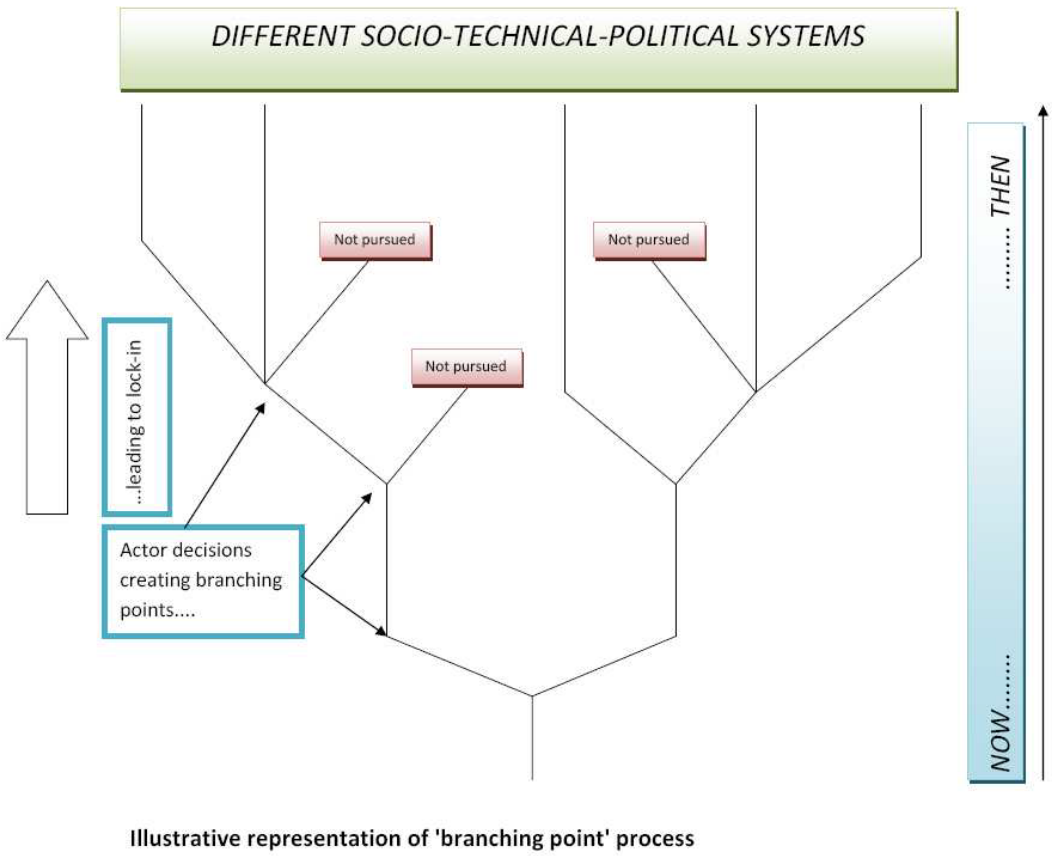


Figure 7: *Illustration of actor decisions causing 'branching points' which forge alternative scenario pathways. Source: (Hughes, 2009b)*

An actor-focussed approach then can potentially offer the scenario user a greater ability to identify how conscious decisions and actions upon the system can influence the direction of its development. However, this puts considerable emphasis on defining each of the relevant actors in the system, their relative power and influence, and on defining each actor's motivation. The outcomes of actor motivations can be explored through intuitive methods such as brain storming or role play, as used in Shell's original scenarios process (Wack, 1985b, Wack, 1985a) and by the US Air Force think tank RAND in the early 1950s (Ghamari-Tabrizi, 2005), as well as through guided discussion between all relevant system actors (Le Roux and Maphai, 1992). Equally, there is an important tradition of using models to replicate the numerous possible ways in which actors could interact, including matrix based approaches (Godet, 1987, Gordon and Hayward, 1968, Dalkey, 1971, Godet and Roubelat, 1996) and agent based modelling (An, 2012).

As discussed in Section 2.3.2.1, if actor motivations are assumed to be unchanging, actor interactions can be viewed as delivering predetermined elements, as was the case in particular in the Shell 1972 scenarios. However, if actor choices are linked to motivations which are not yet fixed, scenarios based on actor interactions also have the potential to explore how actor choices may contribute to different system outcomes. Thus an actor-based conceptualisation of the system may allow users to explore proactive and consensus building objectives. A significant advantage of the actor-based approach compared to the high-level trend approach is the clear linking of future events to tangible drivers – most frequently, the decisions and actions of actors. However, most actor-focussed scenarios have a relatively near-term focus, in contrast to the longer-range trend based studies. Understanding how future actor motivations which significantly contrast to current actor motivations could develop over longer time frames, may be a challenge for this type of scenario approach.

2.4.3 The system as a technological configuration

A third contrasting way of conceptualising the system for a scenarios process is as a configuration of technologies. In the manner of models of physical systems, such a system conceptualisation enables the application of fixed properties to its various components, such that with given preconditions a linear solution may be derived. Scenarios representing the system as a technical configuration have been developed in particular around questions of energy and low carbon policy. The properties with which the components of such systems are characterised include inputs (fuels), outputs (refined fuels, energy services, emissions) and the per-unit cost of these activities. With such properties defined, the model of the system can demonstrate how overall energy system demand can be met by supply technologies. It can further demonstrate how this condition can be met within an emissions constraint (DECC, 2010a, Anderson et al., 2005). Economic energy system models are additionally able to show how this constraint can be met at least cost, based on the assumptions of current and future technology costs provided (CCC, 2008, Skea et al., 2011, Ekins et al., 2013).

Low carbon scenarios based on systems represented as technological configurations have made important contributions to low carbon policy debates, both in the UK and internationally. Strachan et al (2009b) discuss the iterative role of low carbon scenarios in the UK context. They show such studies supported an initial aspirational target of 60% CO_2 reductions by 2050, as well as subsequently supporting efforts to strengthen the target to an 80% reduction across all greenhouse gases, through demonstrating the technical feasibility and economic viability of such targets. The latter target was established in UK law by the Climate Change Act 2008 (HM Parliament, 2008). At the international level similar studies have been undertaken by the International Energy Agency (IEA, 2012). As well as demonstrating overall technical feasibility, such studies can also identify important cross-sectoral interactions. In the UK context, for example, a consistent message to emerge has been the growing importance of electricity in the overall decarbonisation effort (CCC, 2008, Skea et al., 2011, Ekins et al., 2013).

These are clearly important insights. However, it must also be acknowledged that actor-level processes such as politics and investment uncertainties, as well as the role that values may have in influencing such decisions, are mostly absent from such system representations. Technical system scenarios achieve the desired end point as a result of the user-defined emissions constraint under which the quantitative model is forced to operate. In a comparable manner to the high level trends which pre-determine the outcomes of trend based scenarios, emissions constraints also operate as a kind of *deus ex machina* – a construct of the modelling process for which there is no clearly defined real-world equivalent. This is potentially problematic, if it is acknowledged that large technological systems are not autonomously self-assembling, but emerge as part of an iterative process involving human actors taking decisions in particular situations with imperfect knowledge. As noted by Thomas Hughes, large technological systems are 'both socially constructed and society shaping' (Hughes, 1987). Scenarios based purely on technological system representations do not represent this two-way interaction between human actors and the technological systems they create and are subsequently shaped by.

2.5 Representing the system for low carbon scenarios

The purpose of constructing scenarios of a low carbon system is to identify how the system can evolve over time from its current state to a future, usually more desirable one. From a policy maker's perspective this implies an interest in suggestions for proactive decision making. However, given the multiple actor nature of the energy system, some form of consensus building around the process may also be an important output. In addition, major technological or external uncertainties, not directly controllable by system actors, can draw in the need for protective decision making.

Hughes and Strachan (2010) reviewed the methods which have been applied to the construction of low carbon scenarios. The review found that previous low carbon scenarios have predominantly been concerned with representing the system as a technological configuration. There are also some examples of value- and trend-based system representations, but actor-based system representations are rare in low carbon scenarios. The Hughes and Strachan review made two main criticisms of the existing low carbon scenario literature. The first can be summarised as an unrealistic depiction of how technological transitions are achieved, which diminishes the role that networks of human actors play in the process. In technological scenarios this arises from reliance on exogenously imposed emissions constraints, and other ways in which the modeller can intervene directly in the technological system in a manner which is not analogous to a real-world process involving multiple actors. High level trend scenarios similarly provide a deterministic end point condition which pulls focus from the process by which transitions are achieved. The second criticism is related, and points to the lack of depiction of a fully 'socio-technical' system in which society and technology co-evolve through time – the low carbon scenarios were either primarily social value driven, or technologically defined. The result of both of these problems is that, although low carbon scenarios have provided detailed images of how aspects of low carbon futures could look, the scenarios are not explicitly connected to the actor decisions which cause them to come about. This means they have no direct relation to near term policy choices, and thus reduced 'strategic effectiveness'. The Hughes and Strachan review therefore called for low carbon scenario approaches which elevated the depiction of actor decisions and movements in the system, and the iterative co-evolution of these alongside technological system developments, through time (Hughes and Strachan, 2010).

It is undoubtedly the case that specific technological details are of major importance to understanding whether a system is successful in meeting an emissions reduction target. As low carbon scenarios are explicitly concerned with understanding how a system may successfully deliver low carbon energy, the representation of the system in terms of its technological configuration must remain central to low carbon scenarios. However, as noted by (Hughes and Strachan, 2010), it is equally important for low carbon scenarios to represent the network of actors which relates to this system, and to be able to trace the effects of actor decisions to related technical system changes. It is also the case that the effects of technical system changes upon actor behaviour must be represented, in order to reflect that long-term technological system change happens as a result of 'co-evolving' dynamics between social systems and technological systems (Berkhout et al., 2004, Geels, 2002, Freeman and Louça, 2001, Hughes, 1983, Hannah, 1979). The scenario must trace this development through time, as any actor decision is critically affected by the existing system at that time, as well as expectations about the future.

This suggests that a combination of actor-based and technological system representations would benefit low carbon scenarios. The technological system permits analysis of the technological effects of decarbonisation, the actor system of the effects that alternative actor motivations and decisions could have on technological configurations. However, if actor motivations are hypothesised as changing, this opens the question as to the justification of assuming that motivations will change, and requires some consideration of the processes which underlie changing actor motivations, in particular over long time frames. It is notable that actor focussed scenario approaches in the literature have tended to operate with a relatively high level of confidence in assertions of actor motivations, because, in general the time frames of such scenarios have been relatively short term. Investigation of potential actor motivations over long-time frames requires a framework for considering how actor motivations are formed.

Contributors in a number of disciplines have found it useful to describe the mental processes which underlie and inform the decisions that actors take, as a means of understanding how and why actors take important decisions under conditions of uncertainty. In his seminal work discussing the use of scenarios in a corporate context, Pierre Wack describes 'mental models' which affect the 'world views' of managers, and hence the decisions they take (Wack, 1985b, Wack, 1985a). The use of such mental models has an important practical benefit for the decision maker: in a complex world it is usually not possible to enumerate all the factors which could impact upon the outcome of any decision that may confront us, and to compute from all of these the best option. Instead, mental models provide a cognitive short-cut – by starting with a previously established idea of what the world is and how it works, we cut out potentially vast permutations and proceed more quickly to a decision. Thus, 'the image of the world around us, which we carry in our head, is just a model. Nobody in his head imagines all the world, government or country. He has only selected concepts, and relationships between them, and uses those to represent the real system' (Forrester, 1971). However, as Wack found, conditions in the external world can change, meaning that a previously useful and appropriate mental model can become misleading. In such a situation, decision makers need to attempt to change their mental model, or they run the risk of making poor decisions (Wack, 1985b).

Similar kinds of mental models, or internal world views, are drafted in to operate upon political decisions, which involve commitment of substantial resources to projects, despite high uncertainty about their outcome. De Jouvenel writes, 'It is all very well to say that the future is unknown. The fact remains that we treat many aspects of it as known, and if we did not we could never form any projects' (de Jouvenel, 1967). The approximations to certainty which human decision makers draft in to short-cut the pervasive uncertainties of the real world are largely drawn from internal models. In politics, the mental model of decision makers is identified by Sunderlin (2003) through the tem 'ideology' which, 'though tainted by negative connotations, is the best term available to describe the mental models we all carry of how the world works, of how it ought to be, and of how it should be set right so that our fondest hopes can be realised'. Sunderlin argues that the solutions which actors perceive as appropriate to addressing complex problems are inevitably affected not just by an objective assessment of the problem itself, but also by pre-conceived mental models, values and ideas. In public policy such values are frequently found as principles which are proposed despite the absence of concrete empirical evidence to prove their veracity, due to the singular context specific nature of most public policy issues, and the absence of counter-factuals. The impact of ideological values in influencing decisions about policy design and subsequent directions of travel in the UK electricity system, are discussed in Chapter 3. Mental models of the world can also be influenced by visions of what the future system could look like, the desirability of which influences current actions: 'the image summons a future reality… My imagination… jumps to a time not yet accomplished and builds something there… and this "construct" beckons and exercises a present attraction on me' (de Jouvenel, 1967). Bernard Crick, in his essay *In Defence of Politics* brings much of this together in his discussion of the concept of political doctrine. Crick writes, 'A political doctrine I take to be simply a coherently related set of proposals for the conciliation of actual social demands in relation to a scarcity of resources'. It is this attempt at providing coherence throughout the various trade-offs involved in resolving competing social demands that constitutes the attractiveness, indeed the necessity, of political doctrines. Crick continues his definition in a manner which reflects the inclusion of both visions and values in this level. Crick argues that a political doctrine is:

> … necessarily both evaluative and predictive. For a political doctrine always offers some generalisations about the nature of actual, or possible, political societies, but it always also offers some grounds, however disputable, for thinking some such possibilities desirable. By prediction I do not mean something that is necessarily measurable as in natural science, but merely something that guides our present actions according to our expectations of what will happen in the future… And it is evaluative not merely because all thought is an act of selection from a potentially infinite range of relevant factors, but because we do in fact seek to justify some act of selection as in some way significant. A political doctrine will state some purpose, but it will claim to be a realisable purpose; or it may state some sociological generalisation. But argument, if not analysis, will always reveal some ethical significance in wanting this relationship to be true, or remain true. A political doctrine is thus just an attempt to strike a particular harmony out of many possible different (temporary) resolutions of the basic problem of unity and diversity in a society with complex and entrenched rival social interests.
>
> Crick (1964)

The political economy literature has also drawn on the concept of ideology and explored its effect upon political decision making. Leach et al (2010) suggest that ideological framings become narratives that are employed by decision makers to justify sets of actions, while Naes et al ((2011) describe them as 'storylines that help identify competing ways of viewing a particular policy problem'. Clapp and Dauvergne (2005) identify broad sets of environmental ideologies – market liberals, institutionalists and bioenvironmentalists – each of which inform the perspectives of different groups. Chinsinga et al (2011) and Alam et al (2011) discuss how narrative framings or ideologies have influenced political and policy outcomes in Malawi and Bangladesh.

A similar phenomenon has been described by other authors who have noted the effect of prevailing ideas and systems of thought on how policy problems are interpreted, and the solutions proposed for them, describing these thought-systems as 'policy paradigms'. A seminal contribution was made by Hall (1993), who borrowed the term 'paradigm' from Thomas Kuhn's work on scientific revolutions (Kuhn, 1970).

Hall adopts Heclo's argument that 'policy-making is a form of collective puzzlement on society's behalf… Much political interaction has constituted a process of social learning expressed through policy' (Heclo, 1974) (305-6). By taking up the notion of policy making as social learning, Hall asserts the significance of the flow of ideas, as well as the struggle for power between various groups and interests, in the policy-making process.

He defines three distinct kinds of policy changes. First, changes in the levels or the settings of a given policy – where the policy itself is the same but its setting or level, such as the setting of a particular tax or incentive, is changed. Second, changes in the basic techniques used – a different policy mechanism is introduced – while overall goals remain the same. These two kinds of changes occur relatively straightforwardly as a learning process in response to events and the effectiveness of preceding policy choices. As such, Hall writes, these first and second order changes 'correspond quite well to the image of social learning presented by Heclo and many theorists of the state. Changes in policy at time-1 were clearly a response to policy at time-0 and its consequences' (Hall, 1993) (p.287-288). However, third order changes involve changes in the hierarchy of goals behind the policy. That is, a policy response is not carried out just by an adjustment to existing policy, or by the addition of a new policy within the same broad hierarchy of objectives – rather the objectives themselves and the values underlying them are entirely reappraised and reordered. Therefore, writes Hall, 'in order to understand how social learning takes place, we also need a more complete account of the role that ideas play in the policy process'(Hall, 1993) (p.279).

In considering the role that ideas play in the policy-making process, Hall begins from an observation by Anderson (1978) that 'the deliberation of public policy takes place within a realm of discourse… policies are made within some system of ideas and standards which is comprehensible and plausible to the actors involved' (p.23). Hall continues, 'more precisely, policy-makers customarily work within a framework of ideas and standards that specifies not only the goals of the policy and the kind of instruments that can be used to attain them, but also the very nature of the problems they are meant to be addressing. Like a *Gestalt*, this framework is embedded in the very terminology through which policy-makers communicate about their work, and it is influential precisely because so much of it is taken for granted and unamenable to scrutiny as a whole. I am going to call this interpretative framework a policy paradigm' (Hall, 1993) (p.279).

This definition reprises the concept found in the political science and political economy literatures, quoted earlier in this section, that a belief or view about the world can influence how a problem is understood, what the preferable means of addressing it is, and what the desirable end-state or outcome of the system is perceived to be. For a number of authors who have picked up on Hall's notion of policy paradigms, a key insight is that a prevailing paradigm can constrain views on preferred policy choices and desired outcomes

(Wilson, 2001, Hay, 2001, Mitchell, 2008, Campbell, 2001). Campbell writes that paradigms 'constitute broad cognitive constraints on the range of solutions that actors perceive and deem useful for solving problems' (Campbell, 2001). Mitchell argues that in the case of UK energy policy, the effect of a certain prevailing paradigm has been to exclude certain policy options which have been shown to be effective in other countries – thus, in her view, the paradigm has had an exclusionary and negative impact on the effectiveness of policy making (Mitchell, 2008). This view of policy paradigms as having a constraining effect on policy choices also emerges from Hall's discussion (1993), who writes, 'the terms of political discourse privilege some lines of policy over others, and the struggle both for advantage within the prevailing terms of discourse and for leverage with which to alter the terms of political discourse is a perennial feature of politics' (p. 289-290); and, 'policymaking in virtually all fields takes place within the context of a particular set of ideas that recognize some social interests as more legitimate than others and privilege some lines of policy over others' (p.292).

In Hall's analysis, paradigms are relied upon to strengthen the position in favour of certain policy options in the face of alternatives. For example, he argues that the failure of the Heath government in the early 1970s to introduce monetarist policies compared to the success of the Thatcher government in the 1980s, was due to the fact that during Heath's tenure, the paradigm shift away from Kenynesianism had not yet been achieved. 'Policymakers are likely to be in a stronger position to resist pressure from societal interests when they are armed with a coherent policy paradigm. If it does not dictate the optimal policy, at least it provides a set of criteria for resisting some societal demands while accepting others' (Hall, 1993) (p. 290).

Policy paradigms, as discussed by Hall and others, are thus comparable to what are described elsewhere as doctrines (Crick, 1964), ideologies (Sunderlin, 2003, Clapp and Dauvergne, 2005) or world views (Wack, 1985b). If these internal mental models or paradigms can have a strong effect on the goals of policy and the means chosen to achieve these goals, a phenomenon of particular interest for a developer of policy-driven scenarios is the process by which one dominant mental model is replaced by an alternative one, or 'paradigm shift'.

As discussed, a policy paradigm in the work of Hall and others, is a coherent set of ideas which affect policy choices by privileging some options over others, and considering some types of outcome more inherently desirable than others, based on a particular interpretation of how the system works. A prevailing policy paradigm therefore has a directive effect, and from some perspectives possibly a constraining effect, on policy choice. A shift in the prevailing paradigm, by contrast, would logically have the effect of very significantly altering the perception of a problem, the tools used to address it and the desired end state. With reference to his three-level categorisation of policy change, Hall

(1993) writes, 'first and second order change can be seen as cases of "normal policymaking", namely of a process that adjusts policy without challenging the overall terms of a given policy paradigm, much like "normal science". Third order change, by contrast, is likely to reflect a very different process, marked by the radical changes in the overarching terms of a policy discourse associated with a "paradigm shift" ' (p. 279).

Hall (1993) discusses the effect of a paradigm shift on UK economic policy between 1970 and 1989, from a 'Keynesian mode of policymaking to one based on monetarist economic theory' (p.283). He argues that the changes amounted to a paradigm shift because 'not only did the policy prescriptions of monetarists diverge from those of the Keynesians, they were also based on a fundamentally different conception of how the economy itself worked,' (p.284) meaning that the perceived hierarchy of the desirable goals of policy shifted, as well as the choice of instruments. 'Inflation replaced unemployment as the preeminent concern of policymakers. Macroeconomic efforts to reduce unemployment were rejected in favour of balanced budgets and direct tax reductions. Monetary policy replaced fiscal policy as the principal macroeconomic instrument, and it was reoriented toward fixed targets for the rate of monetary growth' (Hall, 1993) (p. 284).

Hall (1993) (p.280) considers how and why paradigm shifts occur. He begins by observing, again drawing by analogy on Kuhn's discussion of scientific paradigms, that 'paradigms are by definition never fully commensurable in scientific or technical terms. Because each paradigm contains its own account of how the world facing policy-makers operates and each account is different, it is often impossible for the advocates of different paradigms to agree on a common body of data against which a technical judgement in favour of one paradigm or another might be made'. This observation has three key implications for how and why paradigm shifts occur. 'First, the process whereby one policy paradigm comes to replace another is likely to be more sociological than scientific… the choice between paradigms can rarely be made on scientific grounds alone … [and]… will entail a set of judgements that is more political in tone' (p.280). This coexistence of subjective or normative judgement about the ethical significance of the paradigm, alongside evidence of effectiveness, when competing paradigms clash, recalls Crick's definition of doctrines as both 'evaluative and predictive', in that 'a political doctrine always offers some generalisations about the nature of actual, or possible, political societies, but it also offers some grounds, however disputable, for thinking some such possibilities desirable' (Crick, 1964).

As a result, Hall's second implication is that 'issues of authority are likely to be central to the process of paradigm change. Faced with conflicting opinions from the experts, politicians will have to decide whom to regard as authoritative, especially on matters of technical complexity… the movement from one paradigm to another is likely to be preceded by significant shifts in the locus of authority over policy' (Hall, 1993) (p.280).

Hall's third implication gets to the heart of what causes one paradigm to be threatened and eventually replaced by another. 'Finally… a policy paradigm can be threatened by the appearance of anomalies… developments that are not fully comprehensible… within the terms of the paradigm. As these accumulate, ad hoc attempts are generally made to stretch the terms of the paradigm to cover them, but this gradually undermines the intellectual coherence and precision of the original paradigm. Efforts to deal with such anomalies may also entail experiments to adjust existing lines of policy, but if the paradigm is genuinely incapable of dealing with anomalous developments, these experiments will result in policy failures that gradually undermine the authority of the existing paradigm and its advocates even further' (Hall, 1993) (p.280)

This account has strong resonances with Kuhn's account of scientific paradigm change, in which a 'model' of reality is increasingly challenged by initially apparently anomalous developments, which build up and cause the paradigm to be adapted and diluted to such a degree that eventually it must be replaced (Kuhn, 1970). The image of the paradigm being 'stretched' to accommodate anomalies has strong resonances with policy making, in which apparently fundamental principles of the aims and processes of policy making remain enshrined, even while increasing numbers of 'anomalies' are accommodated with measures which, apparently, go against these fundamental principles. As will be discussed in Chapters 3, 4 and 5, this description has strong correspondences with the current state of energy policy in the UK, especially following the rise of decarbonisation and security of supply as energy policy concerns, since the turn of the century.

The contest of ideas between old and new paradigms 'may well spill beyond the boundaries of the state itself into the broader political arena' (Hall, 1993) (p. 280-81). In the case of the economic policy change in Britain, 'the ensuing struggle to replace one paradigm with another was a societywide affair, mediated by the press, deeply imbricated with electoral competition, and fought in the public arena… Policy changed, not as a result of autonomous action by the state, but in response to an evolving societal debate that soon became bound up with electoral competition' (Hall, 1993) (p. 287-288).

Other contributors in this literature have also considered why and how paradigms can shift. Whereas Hall's model might suggest a gradual erosion or dilution of a paradigm, through its 'stretching' to accommodate anomalies, Mitchell (2008) conceives of the possibility of more sudden paradigm shifts, where the incumbent policy paradigm is like a 'band of iron', which for some time resists pressure to change, but is finally and suddenly broken following a long build up of pressure from a variety of actors. Mitchell views paradigms as obstinate but brittle – remaining in place despite contrary forces, but capable of eventually being broken by a build up of pressure: 'A paradigm is propelled into being by the very force that builds up behind it, and it is then 'lodged' and codified through principles, institutions and policies. It remains there until the force of a new paradigm is built up, like the stretching of an elastic band, and propelled forward, knocking the old paradigm out of the way' (Mitchell, 2008) (p.17). This image is somewhat in contrast to Hall's notion of a gradual dilution of the dominant paradigm through successive concessions. Perhaps elements of both apply – in retrospect it is often possible to identify moments at which a major paradigm shift appeared to occur, such as the 1979 election victory for the Conservatives; however as Hall argues this apparent sudden arrival of a new paradigm had been preceded by gradually increasing inconsistency in the Keynesian paradigm throughout the 1970s (Hall, 1993); and indeed it might be argued that the re-organisation of economic policy according to the new paradigm was a project not completed overnight, but one which developed throughout the 1980s, entailing considerable social conflict, and whose progress was still continuing in areas such as interest rate setting and the balance of public and private activity in services such as education and health, after the return of the Labour government in 1997 (Moran, 2003, Driver and Martell, 2006).

As will be discussed in Chapter 3, Hall's concept of gradually increasing incoherence of the dominant paradigm as a result of a series of incremental concessions made within it, has a strong resonance with current UK energy policy in which a paradigm of market-led policy, characterised by minimal state intervention, has been incrementally eroded with the state being increasingly drawn back into intervening in the system.

The underlying systems of thought which form and direct policy-making decisions under conditions of uncertainty, described variously in the literatures referred to in this section as mental models, ideologies, doctrines and paradigms, are of critical importance to explaining the policy making process. They therefore constitute the important 'third layer' – in addition to layers already mentioned which consider the activities of actors and the performance of technologies – of the overall system representation which will be proposed as part of the scenario development process in this thesis. In this system representation this third layer is given the more neutral term of 'values'. Values, in this thesis, are the systems of belief which provide the motivation to choose one policy over another, in the absence of incontrovertible evidence arising from clear counter-factuals as to which policy choice is in fact superior. As in the discussion of doctrines, ideologies and paradigms, values supply both a normative expectation of what the hierarchy of goals for policy should be, as well as preferred approaches by which these goals should be achieved.

It is also important to clarify that in this scenario process, the 'values' of primary concern are quite specifically those that apply to the area of policy with which the scenario focal question is concerned. As discussed in Section 2.6.2, achieving clarity about the scope of the system under study, and precisely relating this scope to the terms of the focal question (Section 2.6.1), is important for delivering a scenario process that is cogent, tractable and capable of producing clear policy recommendations. However, this means drawing a boundary around the system under study which precludes related but broader dynamics as 'out of scope'. The values pertaining to the specific area of the system under study may have links and correspondences to values associated with broader related policy areas, but are not necessarily entirely identical to the dominant direction of the values, or policy paradigms, in such broader policy areas. It is possible to explain this relationship using Hall's image of accumulating anomalies within a dominant paradigm. Value shifts in a particular sub-section of a policy area may undergo a shift even though the broader value system (or policy paradigm) remains in place – what Hall describes as responses to anomalies within the paradigm. In the longer term, it may be that the paradigm is capable of being 'stretched' to accommodate such anomalies, and thus broadly speaking remains in place; or an accumulation of similar anomalies contributes to an eventual paradigm shift. However the absolute correspondence of values in a particular sub-section of policy and the values of the broader policy paradigm is not fixed, and contrasts between values expressed within particular 'anomalous' policy decisions and the broader accepted paradigm are possible, as discussed by Hall. Therefore the values expressed in any particular policy sub-section, and the values contained within an overall policy paradigm, can be considered linked, or loosely coupled – but nonetheless essentially independent variables.

Therefore the 'values' which drive the policy-focussed scenario approach presented in this thesis are systems of thought within a particular area of policy, which may run with or against the direction of the values of the prevailing larger paradigm. The relevant values are identified by a scoping of both the broader policy area (Chapter 3) as well as a more focussed scoping of the particular system under study (Chapter 4).

2.5.1 The three-level system representation

Three levels of analysis are therefore relevant to the representation of the system in the development of low carbon scenarios. The interaction of actors and technical systems is key to an understanding of the system as a co-evolving sociotechnical system. However, in addition a basis on which to hypothesise future changes in primary actor motivations is required, and for this a third level of values is introduced.

The incorporation of values into the scenario process is not intended to provide fully-formed and pre-determined scenario end points, as is sometimes the case in purely value and trend based scenarios. Rather, the values are provided as starting points for hypothesising the possible motivations of prime mover system actors – the actors with a level of agency such that their choices have an impact on the positions of other actors (secondary movers) and on resulting processes in the system. The effect of these combined actor interactions ultimately result in decisions and investments which have an impact upon the technological system. Thus the overall system is viewed as consisting of three levels: the level of visions and values which underlies motivations; the level of actor networks which describes actor actions and reactions; and the level of the technological system which is physically constructed by the outcomes of actor actions and reactions. There is a movement through each of these levels, through motivations, actions and technological system outcomes. Further, as the scenario progress through time, there may be movement back through the levels in the opposite direction, as technological system changes effect subsequent actions of actors and may even refine and influence visions and values. The movement in both directions is the co-evolutionary dynamic of socio-technical systems.

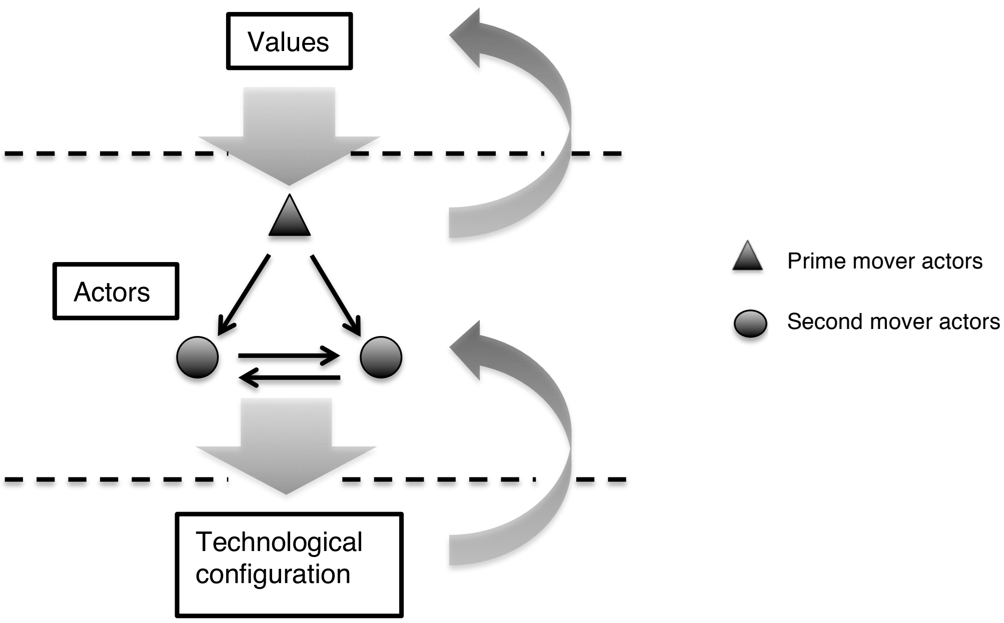


Figure 8: *3 level representation of the system for low carbon scenarios*

To this vertical plane of analysis must be added a horizontal plane, corresponding to movement through time. For as the dynamics between each of these levels unfold, they each contribute in different ways to establishing a 'lock-in' to a particular pathway, which *ex post* will be described as a historical sequence of events. In each case the values level provides a rationale for hypothesising the motivations of key system actors, the results of which are then traced through the dynamics of the other levels. Thus, this conceptualisation represents co-evolutionary system dynamics, or 'process' dynamics, but also maintains a clear view of how conscious actor actions can drive and influence system dynamics, as well as clarifying the values and motivations which would underlie these actions.

A brief illustration of the interaction between technological networks, actor networks and broader high level values as a temporal process, can be provided by considering the historical evolution of the electricity networks in the UK. The earliest electricity networks grew up in the UK in urban areas in the early years of the Twentieth Century, driven by activities both of public municipalities and private entrepreneurs. It took place against a more general political discussion around the relative merits of public vs. private provision of utilities and services. For political reasons, centralised government intervention in the emerging system was initially avoided (Hannah, 1979). However, the emerging realities of the technical network soon began to challenge this political orthodoxy, as the uncoordinated manner in which the networks had evolved was resulting in major operational inefficiencies. For example, by 1920 in greater London alone, 80 different supply companies were operating 50 different systems, under 24 different voltages and at 10 different frequencies, supplied by 70 different power stations (Gordon, 1981). By this time, electricity had become a culturally accepted commodity, and the presence of price-regulation (as early as the 1892 Electricity Act) was indicating an acceptance that access to this commodity was no longer simply a matter of luxury but of civil right. These factors combined to put pressure on the government to act, which they did in 1926 through the creation of a Central Electricity Board which had powers to direct planning and operation to improve overall system efficiency. The CEB decided to begin construction of a132kV interconnected network (which would later evolve into the 'national grid') which provided opportunities previously missing in the fragmented, piecemeal network, for large scale higher efficiency power stations. The result was that the average efficiency of British power stations increased from 9% in 1920 to around 20% in 1940 (Hannah, 1979). Moreover, the success of the programme locked-in, both technologically and institutionally, the principle of a centrally planned and operated high voltage transmission network, with uniform pricing, for many decades. This has had significant effects on the current structure of the UK electricity system as well as on public perceptions of both the pricing and production of electricity.

The above discussion is summarised in **Error! Reference source not found.** in terms of the three levels: visions and values; actor networks; technological networks. The figure also describes a progression through time from left to right along the horizontal plane. The interaction of values, actor networks and technological configurations through the historical evolution of the UK electricity supply system, is discussed in more detail in Chapter 3.

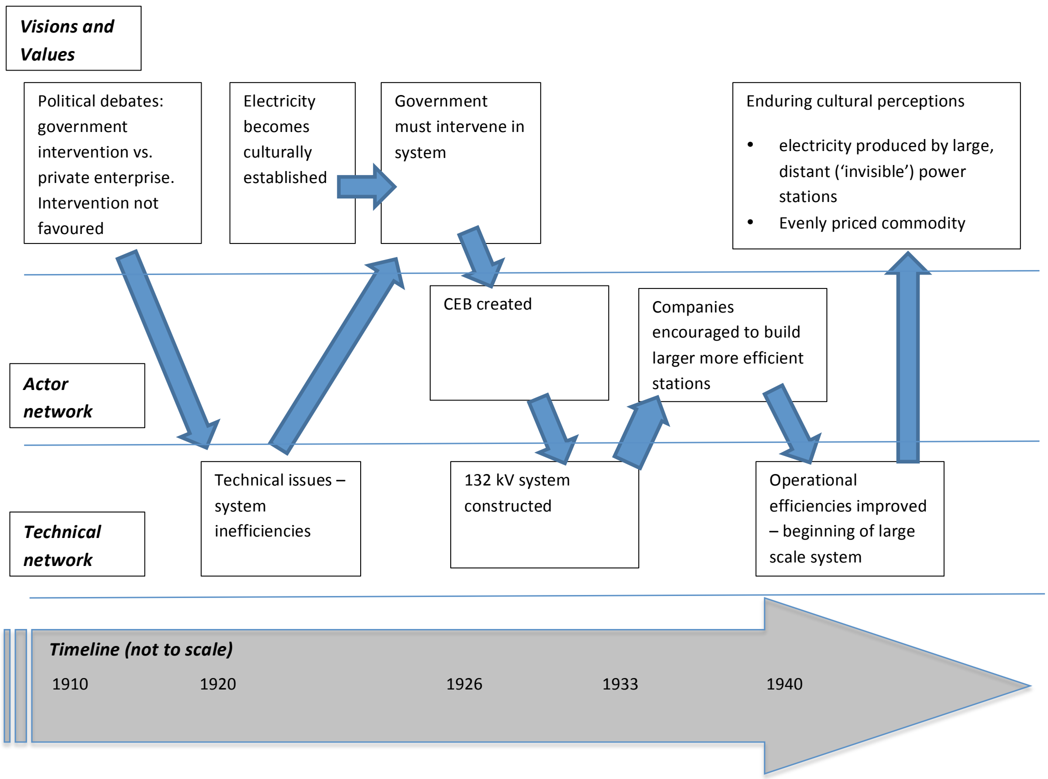


Figure 9: *Case study of early evolution of UK electricity networks in 3 level framework*

2.6 A process for low carbon scenario development

This chapter has explored the objectives of scenarios and their relation to the agency of the scenario user; the different kinds of uncertainties involved in considering the future; and the different ways of conceptualising the system under study that scenarios can employ. The final section of this chapter draws the discussion together to provide a development process for low carbon scenarios, as proposed in Hughes et al (2013). Although this process is presented as a linear sequence, there may in practice be some iteration between stages. For example, the scoping of the system may reveal details which require an adjustment of the focal question and objective type.

2.6.1 Define the question and objective type, and identify the scenario user or users

A scenario process requires clarity of purpose, and this can often be best expressed in the form of a focal question – the central question about the future that the scenarios are investigating. Another important step, which may be made explicit by the focal question, is to define the scenario user or users – the actor or actors who are intending to use the scenarios to improve their near term decision making in respect of the future. In turn, the type of actor or actors who will use the scenarios affects the type of objectives the scenarios may serve – proactive, protective or consensus building. The type of objective is also affected by the boundaries of the system under study, and the scenario user or users' relationship to this. Hence, the subsequent system scoping stage may also contribute to refining the focal question and objective type.

2.6.2 Scope and define the system in terms of visions and values, actor networks and technological configurations, and the system boundary

As well as identifying the scenario user or users, and the type of objective, a clear scenarios process depends on a clear definition of the system under study. The system under study will in part depend upon how the focal question is defined. One of the most important aspects of defining the system under study will be the drawing of boundaries around the system under study. Given that in reality most systems are almost endlessly inter-linked with other ones, the construction of a system-boundary to signify the limits of research scope can appear an artificial and arbitrary activity. Nonetheless, demarcation of research scope is an inevitable part of research, and therefore being clear and transparent about where those boundaries lie is an important part of research integrity. In energy scenarios, relatively clear system boundaries can sometimes be suggested by existing national jurisdictional boundaries. However, even in this case, imports and exports of energy cut across these boundaries, and within the national boundaries a variety of internal subsystems and interlinkages are present – for example, electricity generation, demand, transport, and industrial sectors. Decisions must be made about which of these systems and subsystems to define as being within the system under study.

The scoping of the system and the delineation of its boundary also has an important connection with the transparency and clarity of the process, and the policy-relevance of its output. The system boundary can be thought of as the area within which elements, which have the potential for variation, will be allowed to vary as part of the scenarios. Outside of the system boundary, it is possible that many other elements could vary in a way which also has an impact within the system under study, but these variations being outside the system are not the primary concern of the scenarios (though their impacts may be considered at a later stage in the process, as described below). As described in Section 2.4.1, many scenarios have been created which set very wide system boundaries which include a vast number of possible variables, many of which are varied simultaneously within single scenarios. As discussed, such value- or trend-driven scenarios effectively assume that large numbers of independent variables are in fact all dependent on the same high-level driver, using very broadly identified tendencies such as 'globalisation' or 'community values' as justifiers for correlating assumptions across a very wide and contrasting range of indicators. As noted in that discussion, the inherent co-dependence of possible areas of future variability such as energy technology deployment, shopping habits and living arrangements is very far from certain. Most of the variables which are co-varied in such scenarios are in fact not inherently coupled but largely independent variables. By contrast a more scientific approach to scenario building is to respect the independence of variables where this is stronger than their co-dependence. Respecting the independence of variables means varying them independently of one another. Clearly, with an increasing number of variables, each of which having more than one alternative state, the number of different combinations of those variables, and therefore different scenarios, increases exponentially. Therefore, a strict approach to the principle of independent and co-dependant variables is likely to require a much more tightly defined system boundary than is common in many broad trend based scenarios, in order to keep the number of independent variables treated as within system scope to a manageable level.

Once boundaries have been established, the internal structure of the system must be characterised. This chapter has argued that for low carbon scenarios, a strategically effective description of the future evolution of the system will be provided by the characterisation of the system in three interlinked levels – visions and values, actors and technological configurations.

2.6.3 Identify pre-determined or unvarying elements

The scoping of the system may reveal elements which can be regarded as fixed for a certain period of time within the scenario process, or inevitable future outcomes of processes in motion. Such elements could include physical pieces of infrastructure which have an expected lifetime, or policy processes which are committed to and can be considered reasonably certain to deliver particular outcomes. The system scoping may have excluded potentially mobile elements due to research practicalities, which are as a result 'out of system'. As such these elements will also be effectively unvarying – although the impacts of their variability may be considered via 'non-actor contingent elements' in a later stage of the process.

2.6.4 Identify actor-contingent elements

This involves identifying the key variable elements within the system under study, the variation of which as a result of actor decisions, will create the different scenario pathways. These elements begin in the values level as alternative value sets which are understood as creating motivations in key 'prime mover' system actors, and are followed through in terms of their effects on system actors and subsequent effects on technological configurations. If it is found that there are too many mobile actor contingent elements to be practically considered, this may require a further narrowing of the system boundary, to put those elements which for practical reasons cannot be considered, 'out of system'.

2.6.5 Describe system evolution via branching points along alternative pathways

The alternative actor-contingent elements – sources of variability contingent upon explicit actor choices – will create different dynamics within the system under study, creating alternative 'branching points' (Kahn and Wiener, 1967, Hughes, 2009b, Foxon et al., 2013). Branching points lead the system to progress along different pathways – the sum of which at the end of the process will constitute the 'scenarios'. The scenarios are developed through a number of timesteps. At each timestep analysis is made of the conditions which have been reached and how these would influence actor decisions in respect of the future. Thus, the scenarios become rooted in their emerging historical context, illustrating the path dependencies that emerge in socio-technical systems.

2.6.6 Assess actor contingent scenarios against non-actor contingent uncertainties

The scenarios have thus far been developed focussing on how active choices of actors within the system under study may influence the development of the system. This provides information about how proactive decisions may affect system development. However, it is also important to consider how the outcomes of these decisions may be robust against variable elements external to the system under study, or outwith the control of the system actors. A selected number of key non-actor contingent uncertainties can be applied to the scenarios, to test their resilience.

2.7 Conclusions

Consideration of possible future scenarios to support and improve decision-making is a natural human activity, practised intuitively by individuals on a day-to-day basis, as well as in more formal structured settings by a range of business and government organisations. There is a wide range of approaches to undertaking formal scenario building, reflecting the wide range of situations within which scenario thinking has been applied. This chapter has engaged with the scenario literature and identified aspects of method of particular relevance to the construction of low carbon scenarios. There are two main outcomes of this. The first is the observation that the future is not uniformly uncertain, and that a categorisation of different kinds of future element which may be present in the scenarios assists with the connection of scenario content to strategic decision making. Specifically, the identification of future elements which are pre-determined, those which are variable but beyond the control of system actors, and those whose variability is contingent upon decisions within the remit of identifiable system actors, clarifies whether the appropriate response to each element is protective, proactive or consensus building decision making. The further ahead one looks, the more that proactive choices of actors can affect future outcomes, for 'the plurality of the future and the scope for freedom of human action are mutually explanatory; the future has not been written, but remains to be created' (Godet, 1987).

The second outcome is the identification of the need for low carbon scenarios to conceptualise the system under study in three levels: values, actors and technologies. This three level conceptualisation acknowledges the co-evolutionary nature of sociotechnical systems, where large technological systems are 'both socially constructed and society shaping' (Hughes, 1987). It also provides a coherent structure through which alternative pathways for that system can be hypothesised, based on alternative decisions by prime mover actors, whose motivation is understood on the context of prevailing value systems, drawing on commentary in the political economy literature of the importance of values, ideologies or framing narratives in influencing political decision making.

These two structural aspects were brought together through a proposed scenario approach which clarifies the aims and scope of the question, and provides a process through which the iteration between the three system levels can be seen to evolve into alternative pathways of development for the system. These pathways are primarily differentiated by the alternative value sets which lead to alternative actor-contingent outcomes – suggesting options for proactive or consensus building decision making. These actor-contingent scenarios can subsequently be tested against non-actor-contingent elements, which may suggest requirements for protective decision making.

The next four chapters of the thesis are concerned with scoping the system under study, providing information of relevance to each of the three levels required for the scenario framework outlined in this chapter. The system scoping considers the guiding values which have ebbed and flowed during the development of the system, and how emergent value-sets may guide its future development. It considers the actors and institutional networks which have emerged from previous system configurations and which currently govern the operation of the system. It considers the technologies and infrastructure which are physical and technical embodiment of the system, and their link to investment decisions and policy choices of system actors. The scoping is undertaken through historical analysis (Chapter 3) analysis of current policies and institutions (Chapter 4), semi-structured interviews with system actors (Chapter 5) and the assembling of data pertaining to the physical properties of the current configuration of technologies and infrastructure (Chapter 6).

3 Scoping the system: historical evolution of the UK electricity system

Large socio-technical systems are conditioned by history – at any time the contemporary configuration of the system shows the impact of past policy choices and investment decisions. In order to understand the current state of the system and the possible directions of its future development, it is necessary to understand its historical development. This chapter therefore reviews the historical development of the UK electricity system and of the GB electricity transmission network based on a literature review of historical accounts of UK electricity system development. This broad historical review enables a mapping of the major policy currents, how these were related to shifts in underlying values, and the impact these had on the organisation of the actors and the development of the technological configuration of the system.

3.1 Early development and consolidation

Demand for electrical services began to grow in the UK from the 1880s onwards, with growth picking up rapidly around the turn of the century (***Figure 10***). However, the piecemeal development of the industry and lack of overall coordination had resulted in a large number of companies supplying highly specific loads on dedicated lines (Gordon, 1981). This absence of network benefits resulted in low load factors for individual stations and resulting low overall system efficiencies (Hannah, 1979).

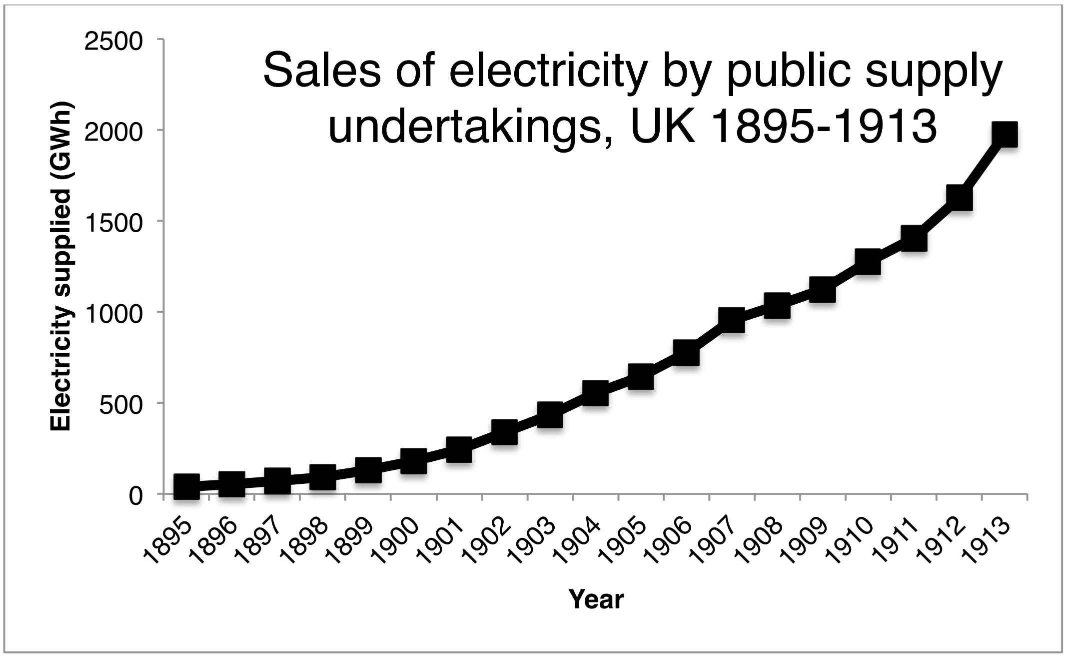


Figure 10*: Sales of electricity by public supply undertakings, UK 1895-1913. Source, (Hannah, 1979), citing Byatt, I.C.R,* The British Electricity Industry 1875-1914*, unpublished D. Phil thesis*

The early years of the industry also saw some jostling for position between private entrepreneurs, often responsible for demonstrating innovations, and public municipalities who were keen to take over the technologies for the public benefit (Hannah, 1979). The political debate reflected this, and was ongoing. In 1894, Joseph Chamberlain wrote, 'it is most desirable that… the municipality should control the supply, in order that the general interest of the whole population may be the only object pursued'; whereas in 1925, in cabinet minutes, Conservative Andrew Bonar Law was recorded as arguing that 'it was the private enterprise man and not the municipal man who would run the business to the best advantage and make the most money out of it' (Cited in (Hannah, 1979)).

An important exception to the problems arising from the extreme lack of coordination and piecemeal development in the majority of the country was found in the North East of England. Here, by 1908 the Newcastle-upon-Tyne Electric Supply Company

(NESCo) was running an interconnected network of generators and transmission lines operating at 20 kV (then the highest voltage in the country) at a standardised frequency of 40 Hz, supplying the majority of the Northumberland coal field area, and various municipalities including Newcastle, Tynemouth, Cleveland, Durham and Middlesbrough. The diverse loads connected to the system meant that its stations achieved an average 45% load factor, more than double those in other industrial areas. The success of NESCo's integration of the electricity supply of the area was in large part due to an early merger of two local private companies, whose amicable cooperation was a result in part of existing close family ties. The cooperation of these two companies allowed the sharing of loads which gave them an initial critical advantage over competitors, which was increased the more customers took the logical decision to commission their supply from the NESCo. Thus family cooperation had laid the foundation for what could not be achieved elsewhere in the country (Hannah, 1979).

Meanwhile, a report into the problem of lack of coordination in the rest of the country, which was leading to inefficient system operation, was commissioned by Lloyd George's liberal government in 1917. It advised that the operation of the six hundred separate supply undertakings which had grown up throughout the country should be consolidated into 16 electricity supply districts, each of which would be charged with constructing large power plants. The system would benefit from the economies of scale of the larger plants, the combination of diverse loads would increase load factors, and interconnections between districts would decrease the margin of spare plant required. It also suggested that the ownership of generation, transmission and high voltage power sales should be centralised (Hannah, 1979).

The recommendations of the report were transferred into a bill which came to parliament in 1919, but the strong Conservative opposition objected that it amounted to a prelude to nationalisation – an idea to which they were strongly opposed. The bill was eventually passed with several crucial amendments. Instead of the creation of District Electricity Boards with powers to take over generation and establish interconnection, the provision was made for the creation of Joint Electricity Authorities which were to have the same aims but without the compulsory purchase powers. The process would be overseen and encouraged by Electricity Commissioners, who would be tasked with bringing about greater integration, but again with no compulsory powers to draw upon (Hannah, 1979).

This voluntary approach proved unsuccessful, and by the mid 1920s no further progress had been made towards integration. The Weir report was commissioned in 1925 to address the continuing problem of the industry's failure to capitalise on the large potential efficiencies which would result from greater integration. It stated frankly:

> The policy of persuasion can only be written down as failure… delay and procrastination are widespread… the resultant loss to the country has been heavy and becomes daily heavier.
>
> Cited in (Hannah, 1979)

Thus by 1926, it was the turn of a Conservative Government to propose a bill, proposing to create a Central Electricity Board, with powers to force integration. Prime Minister Stanley Baldwin was however eager to stress:

> When I speak of a Board I do not mean a nationalised authority. I do not mean a Government Department. What we have in mind is a Board managed by practical men closely in touch with the industry.
>
> Cited in (Hannah, 1979)

The1926 Electricity (Supply) Act did bring into being the Central Electricity Board (CEB). This was a panel of engineers and businessmen, independent of government control. Its function was to take judgements about the optimal development of the sector from a whole-system perspective, and it had the powers to exert its will on the industry- a change from the 1919 legislation. The board's main task was to plan and commission a new interconnected 'gridiron' network of transmission lines. It would then be able to select the most efficient stations to connect to this network, control their operation, and buy and sell their output to the supply undertakings. Between 1926 and 1933, the CEB designed and built a network of circuits running at132 kV and 50 Hz. The bulk of the construction of the grid took place during the recession years of 1929-33, when most of British industry was cutting expenditure. The programme was thus able to make use of ample labour, and also provided increases in jobs in depressed industrial areas (Hannah, 1979).

Figure 11: *The 132kV grid at its inception, 1932. Source: Hannah (1979)*

The network became known as the gridiron or 'grid' because of its lattice-like structure, with two major North-South lines running along the East and West of the country; and five major East-West Links. This structure remains the backbone of the present national grid. However, the grid was not initially intended as national network for the purpose of facilitating large scale long distance transmission, but as a network of separately controlled regional grids with the potential for some interconnection between them, in order to make best use of the most efficient plants. The links between the regions in most cases allowed for only 50 MW of transfer capacity. The regions were thus intended to be run separately, at seven regional control centres in Glasgow, Newcastle, Manchester, Birmingham, Bristol and London. The structure of the 1933 grid provides for large rings around different regions of the country, with sub-rings in the industrial areas of the country where generation and demand was highest, for example the central belt of Scotland, Lancashire, the Midlands, South Wales and London. The grid saved money for suppliers by breaking private monopolies, maximising use of most efficient plants, and reducing the need for reserve margin (Hannah, 1979).

Power stations were still built, owned and run by the corporations, but their planning, expansion and operation was directed by the CEB. Hannah notes that this influence was highly material, as by the end of the '30s, 'more than half the capacity of the Grid power stations had been installed in the previous decade, during which the CEB's influence had been clearly felt' (Hannah, 1979: 132). Hannah notes that 'the essence of inter war progress in electricity generation was improvement and economy rather than fundamental innovation, but the effect of such steady progress on efficiency could none the less be large'. The impact of the grid was in aggregating loads in a way that justified the construction of larger, more efficient power plants, benefitting from economies of scale. The average efficiency of British Steam Generating Stations had improved from around 9% in 1920 to around 20% in 1940. By the end of the 1930s, the wide gap in efficiency between British and American stations which had been present in the 1920s, had been virtually eliminated (Hannah, 1979).

Although the grid had not been conceived for bulk long distance transmission, it did have an impact on increasing the development of hydro power in Scotland, which now had the potential for export to Southern load centres. New coal stations were growing in size and efficiency as a result of the aggregated loads available from the grid.

The Grid was first run as a national grid experimentally in 1936. In 1938 the harsh winter demonstrated the advantages of this for real, as the nationally integrated system was used to overcome fuel shortages in the South. From 1938 onwards the Grid increasingly began to be operated as a fully nationally interconnected system. The Second World War further demonstrated the advantages of a fully 'national' grid, as for example when air raids knocked out power stations, supplies were available from more remote stations. Various new grid connections were made during the early years of the war to allow for changes in load flow in response to wartime conditions. Manchester needed to be connected to Sheffield to improve security of supply in these areas of munitions manufacturing, though this had not been deemed necessary in peace-time. Other strengthening of links to munitions areas in the West, Midlands, North West and Scotland were needed. New connections were also made between the South East and South West – stations in London and the South East were being underutilised due to evacuations and the decline of commercial activities, but munitions factories in the South West and Midlands were expanding output. By 1943, London was exporting 292 MW to the Midlands and South West at peak demand. Between 1940 and 1943 544 miles of new 132 kV lines were constructed (Hannah, 1979).

Another significant war-time development was the decision in 1941 of Labour MP Tom Johnston, newly appointed Secretary of State for Scotland, to appoint a committee for investigating the potential for developing hydro power in North Scotland. This led to the decision to create a new, publically owned North of Scotland Hydro-

Electric Board, alongside already existing undertakings. The board was created in 1943, began generating power in 1950, and was to become a vertically integrated utility in the North of Scotland. It was to retain its independence from the rest of Britain in the nationalisation of 1947, as well as resisting moves to merge it with the South Scotland board in the early 1960s (Hannah, 1979, Hannah, 1982).

3.2 Nationalisation

The CEB had largely been regarded as a success in increasing power station efficiencies and effecting benefits of increased interconnection through the grid. However, electricity distribution and supply still remained a complicated picture, with distribution networks owned by a large number of different undertakings within each region – there were close to 600 franchised electricity supply undertakings across the country (Hannah, 1982). The fragmented structure of the distribution industry, together with uncertainty caused by the fact that many private undertakings held their franchise on a tenure basis which would soon be elapsing, leaving them vulnerable to take over by municipalities, was holding back investment and preventing the benefits of efficiencies from economies of scale. 'Both companies and municipalities found that their franchised supply areas were too small for efficient operation' (Hannah, 1979)(p. 329). The patchwork nature of the distribution networks resulted in a lack of standardisation – the London area for example was still operating with 17 different DC and 20 different AC voltages. (Hannah, 1982) (p. 70). At the same time, electricity demand was increasing rapidly throughout the 1920s and 1930s (*Figure 12*).

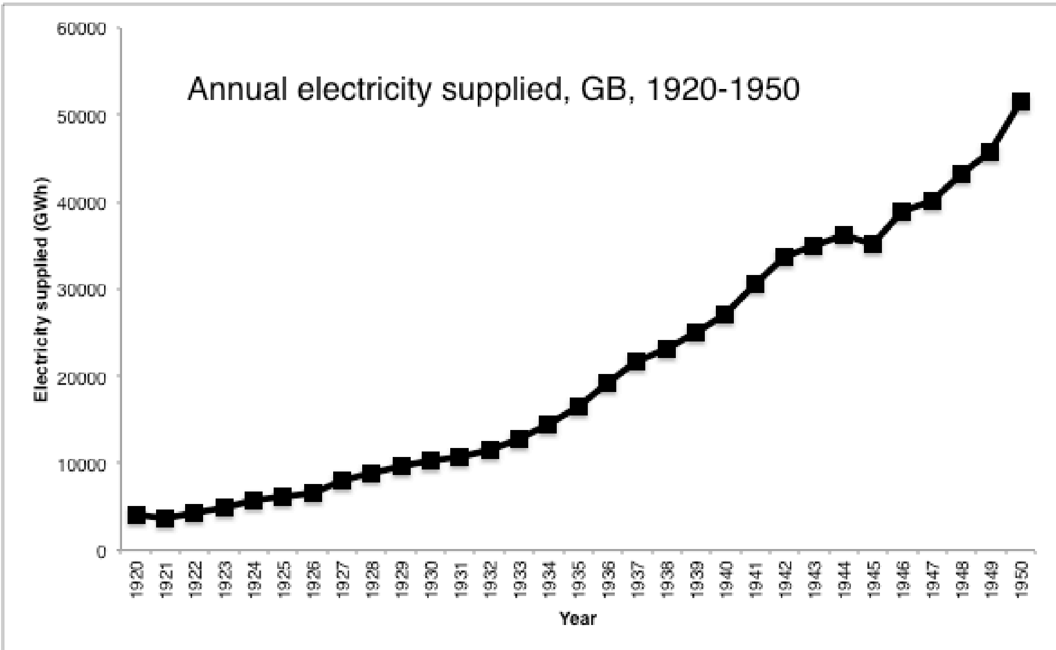


Figure 12: *Annual electricity supplied, GB, 1920-1950. Source: DECC*

It seemed that intervention would again be required. There were essentially two proposed options emerging from political debates around the issue. The first was to facilitate and encourage the take over of smaller undertakings within regional distribution areas by the most successful existing companies or municipalities in each region; the second was for the government to acquire all of the undertakings and reorganise them into large publically owned distribution boards. The latter option began increasingly to appeal to the Labour party as it would fit within a programme of nationalisation, a process which it was increasingly beginning to propose for a number of industries in line with the principle of Clause 4 of its constitution:

> To secure for the producers by hand and brain the full fruits of their industry, and the most equitable distribution thereof that may be possible, upon the basis of the common ownership of the means of production and the best obtainable system of popular administration and control of each industry and service
>
> (Cited in Hannah (Hannah, 1979) p. 330)

For the Conservative government in power during the 1930s, the latter option was clearly unpalatable; however the former was appearing to be unworkable. Despite various efforts, a stalemate in resolving the problems with the distribution system emerged during the 1930s. Again, the prospect of Government intervention in the industry began to seem to many an increasingly reasonable option. The Times commented:

> The electricity industry, for its part, cannot ignore the issue; nor can it refuse to admit that the continuation of competitive enterprise is consistent with, and indeed requires, a definition in the national interest of limits beyond which competition degenerates into waste. (The Times, in Hannah (1979) p. 306)

In opposition, the Labour party began to develop a blueprint of full national ownership with a national electricity board, and regional boards controlling large distribution areas. Though this fitted well with the ideological values of the party and its commitment to public ownership suggested by Clause 4, Herbert Morrison also proposed the programme as a practical solution to the otherwise intractable problems of the industry, espousing as Hannah puts it, ‘the public corporation as a technocratic solution to a business problem’ (Hannah, 1979)(p. 332).

The success of previously created public corporations to manage industry sectors, including the London Passenger Transport Board (of which Morrison himself was the architect), the BBC and the Central Electricity Board, was contributing to a growing section of opinion that this was a reasonable way forward.

> Nor was this merely a convenient practical gloss on the ideology of Clause 4: it was a view which was increasingly accepted by those outside of the Labour Party… Both within the industry and among the Liberals and younger Conservatives, also, the Central Electricity Board model was increasingly admired as a businesslike and

> effective way of managing the public utility industries… As alternative attempts at distribution reorganisation were seen to have failed and at the same time technical developments seemed to dictate even larger enterprises, the schemes first formulated by Morrison in 1930-1 were attracting growing support as the only way in which economies of scale could realistically be obtained. (Hannah, 1979: 334).

In 1945 then, the newly elected Labour government acted on its electoral mandate to nationalise the electricity supply industry. The 200 companies and 369 local authority undertakings which now made up the industry, were merged, together with the CEB, to form the British Electricity Authority (BEA), which would have responsibility for generation and transmission. The distribution and supply functions were devolved to 14 Area Electricity Boards, which were given the freedom to act autonomously from the BEA. In so doing, the new procedures tried to strike a balance between centralisation and decentralisation of control in the industry.

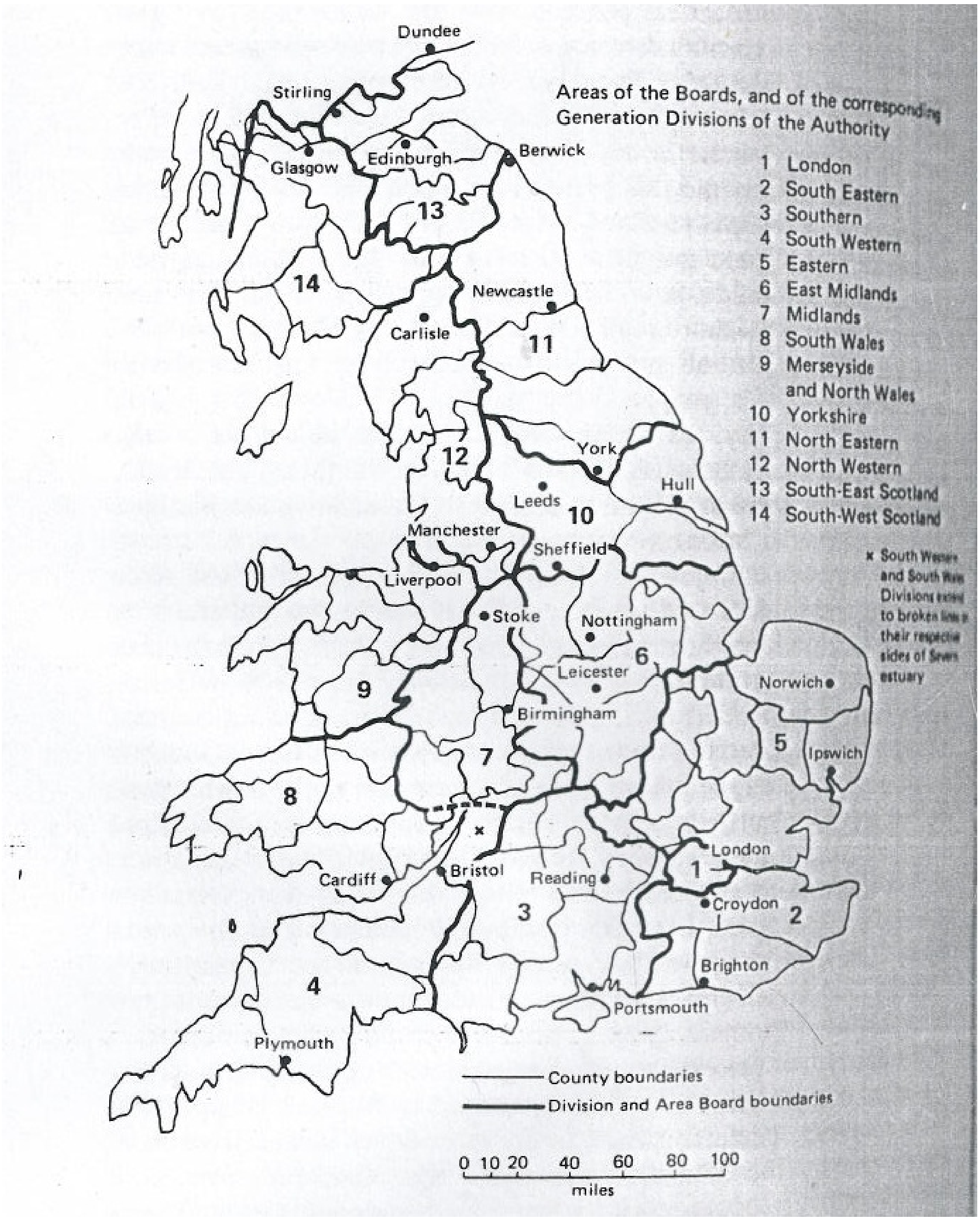


Figure 13: *The area boards of the BEA, 1952. Source: Hannah (1982)*

Hannah concludes that although there may have been some exaggeration of the benefits of nationalisation on the part of its proponents during the 1930s and 1940s, overall the efficiency gains from the economies of scale at the distribution level brought about by the reorganisation, were material. The centralisation of metering, billing and accounting functions all made savings, as did the more coordinated approach to distribution network planning and engineering (Hannah, 1982).

As noted, power shortages in the 1930s and the particular conditions imposed by conditions during the war had pressed the grid into use as a network for long distance power transfer, rather than only a number of narrowly interconnected regional grids. However, apart from the inter-regional upgrades made during the war years, there had been little additional development of the 132kV grid. As the growth in electricity demand became even steeper in the immediate post-war years (***Figure 12***), a report by Graeme Haldane argued that there was an economic case for the high voltage transportation of electricity from power stations in coal mining areas, rather than the transportation of coal via rail to power stations closer to loads. As the original grid had done, a superimposed high voltage grid (or 'Supergrid') would also further aggregate national demands, allowing economies of scale and a smaller plant margin. In eventually being persuaded by these arguments, the BEA was taking the significant step of using a planned transmission upgrade programme to facilitate the transfer of power to load from the most suitable generation centres – rather than compelling generation to site closer to load. The next extension of the grid therefore was made with strong awareness of the optimal locations of coal generating plants. The proposal accepted by the BEA in 1950 was for a £52 million project over ten years to build 1150 miles of 275kV Supergrid lines (Hannah, 1982).

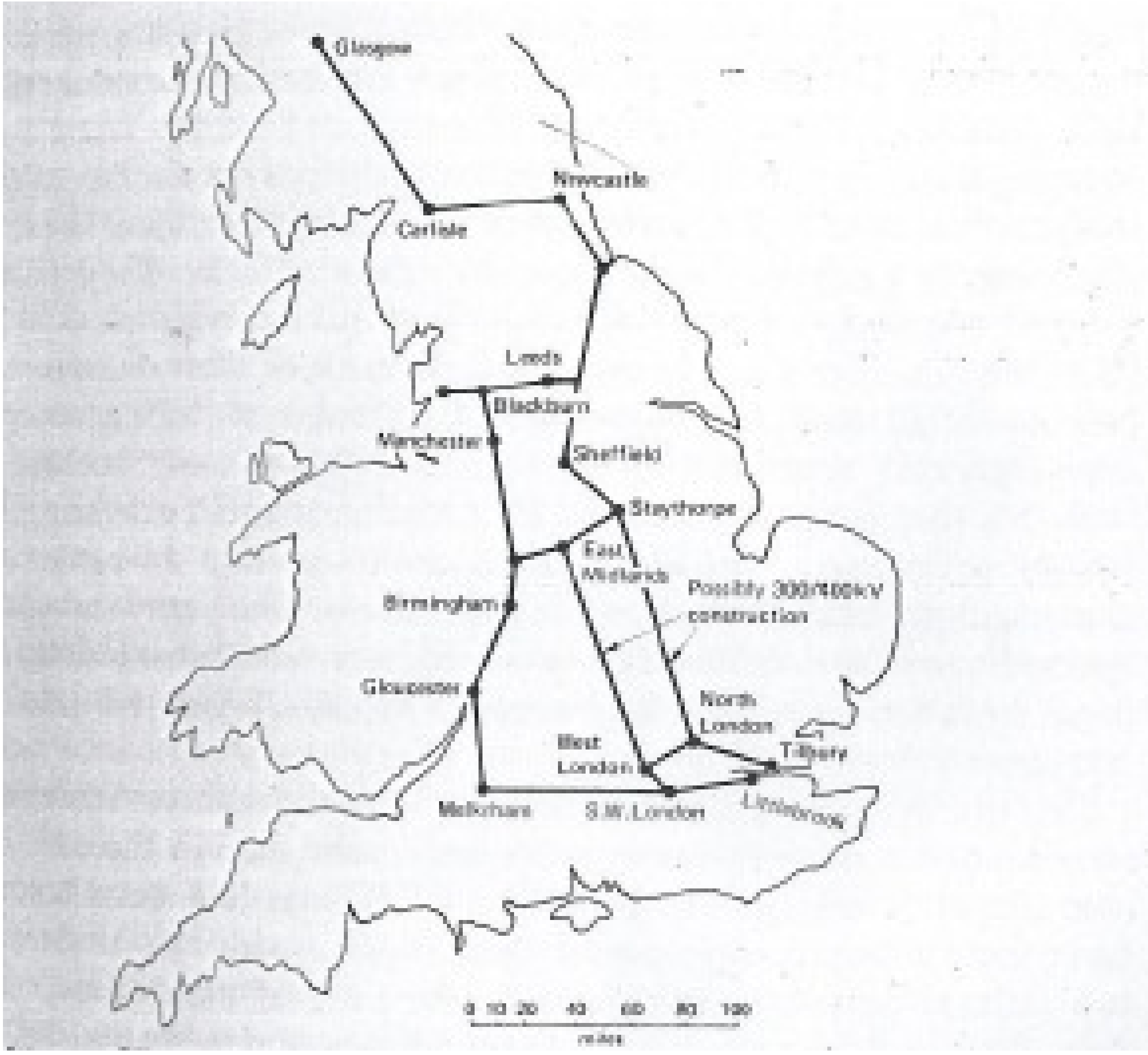


Figure 14: *Outline of 275kV Supergrid, 1950. Source: Hannah (1982)*

The clear aim was to strengthen north-south interconnections, which had been limited in the 132kV network. The new lines had more than six times the capacity of the 132kV lines. Further, sections expected to have growing loads, such as those connecting the East Midlands coal fields and London, were constructed with wide clearances to allow for subsequent additional voltage upgrade.

The investment in the 275kV network was vindicated by continuing rapidly growing demands during the 1950s (***Figure 15***). Additionally the existence of the new network influenced subsequent planning decisions on generation by the BEA. Sites close to towns and cities were increasingly less likely to gain planning permission; with the new network the BEA now had the flexibility to site new plants away from load centres, and optimise their location by other criteria – close to the coast for access to cooling water, or to coal fields for access to fuel. Discussions with the coal board also indicated that cheaper coal would be found in the East Midlands and Yorkshire than in Kent, South Wales and Scotland – again the grid provided the flexibility to locate stations according to these considerations. The network was therefore now developing in a way which prioritised the optimal location of plant according to its own operational criteria, not according to its relative location to load.

The Conservatives returned to power in 1951. In opposition they had attacked Labour for inefficient over-centralisation. Whilst eventually ruling out a full reversal of Labour's nationalisation programme, the Conservatives resolved to go some way towards decentralising the electricity industry by splitting off the two southern Scottish boards. This happened in 1955, when both regions were taken over by a new South of Scotland Electricity Board, a vertically integrated board with responsibility for generation, transmission and distribution. In addition to the existing North of Scotland Hydro-Electric Board, this then meant that there were two boards in Scotland, both vertically integrated. The BEA was renamed the Central Electricity Authority (CEA).

Subsequent efforts to merge the two Scottish boards were not successful, however, the two boards developed good working relations and physical interconnections (Hannah, 1982). Scotland as a whole, however, became effectively a separate system from England and Wales, with the systems planned on the basis of zero-trade across the Scottish border. Limited interconnection was maintained, though primarily for security of supply rather than bulk trade (Chesshire, 1996). The separation of Scotland persisted until the British Electricity Trading and Transmission Arrangements (BETTA) came into force in 2005.

Further reforms followed with the Electricity Act of 1957, which responded to an inquiry criticising the over-centralisation of control and bureaucracy in the CEA. The Act created a Central Electricity Generating Board (CEGB) with specific responsibility for generation and transmission. It would not have the hierarchical oversight over the Area Boards that the CEA had had. The Area Boards, as well as the new CEGB, reported directly to the Minister. The CEA was reduced to an Electricity Council, with a remit to oversee labour relations and coordinate research, but not to issue directives to any of the boards.

Decisions on the design of generation sets remained centralised throughout the nationalised period, successively by the BEA, the CEA and the CEGB. This had mixed results. At times the board pushed for innovation and increased efficiency in station design; at other times a cautious conservatism dominated the outlook, and the efficiency of Britain's stations lagged behind those of other countries. The combination of political influence and the management of the BEA and CEGB of the nuclear programme, caused a rush for Magnox and AGR designs before their economic viability was established, resulting in a programme which had exhausted its capital on sub-standard designs by the

1970s, at which point other countries began to invest more successfully in now-mature designs. The difficulties which emerged from the centralisation of generation planning contrast with the relative success of the centralisation of decisions around transmission planning. Hannah observes, ‘centralised control of transmission had had a successful and continuous history since its inception under the CEB. In contrast, the generation side had been plagued with organisational problems which they had been unable to resolve’ (Hannah, 1982) (p. 253).

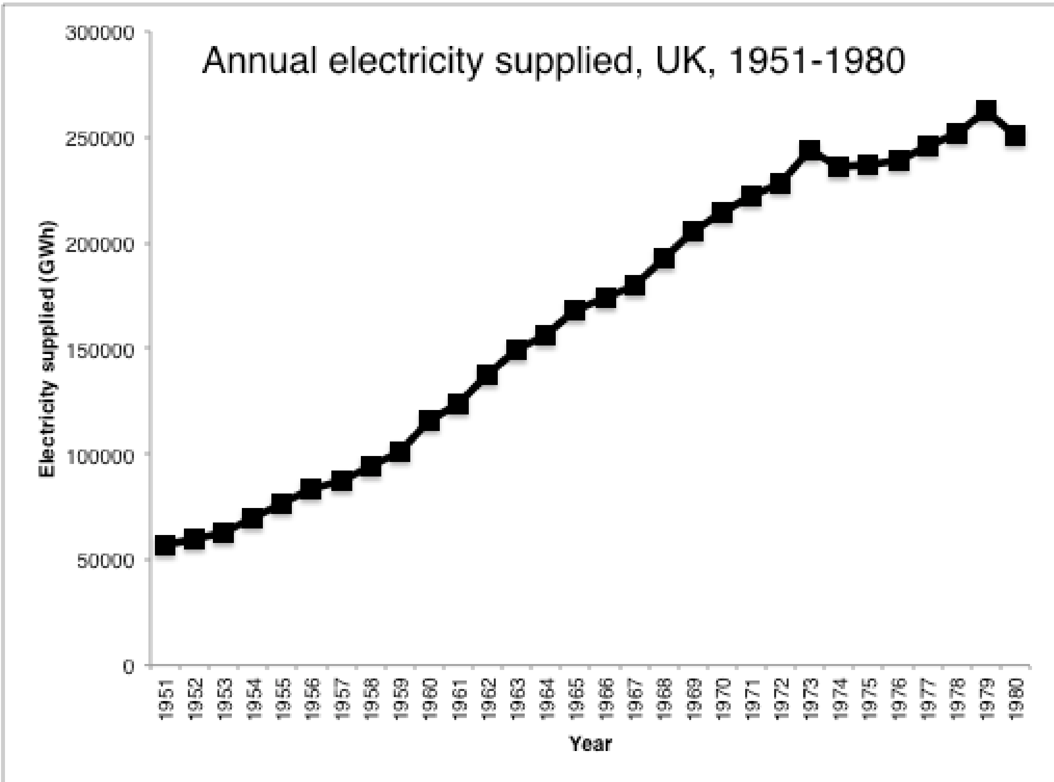


Figure 15: *Annual electricity supplied, UK, 1951-1980. Source: DECC*

Despite the problems with the early nuclear designs, demand for electricity was still growing rapidly in the early 1960s (***Figure 15***), and the CEGB made orders for several 2000 MW coal stations (based on 500 MW sets), and also ordered some small-scale gas turbine plants for peak-lopping. With the new large sizes of coal plants, and increasingly stringent planning regulations, it became clear that the location of plant close to load was no longer possible. ‘In the early 1960s, then, when they were embarking on large investments in new power stations, planned expenditure on the Supergrid also rose markedly, and the two investments were seen as complementary’. (Hannah, 1982) (p. 253). It was decided that a new Supergrid would be required, at higher voltage, to carry power from increasingly large and remote power stations. The CEGB decided to upgrade 275kV lines to 400kV where possible, and also construct some new 400kV lines. The design of the new supergrid was centralised in a new CEGB transmission group (Hannah, 1982).

From 1955 to 1970 UK electricity demand continued to grow rapidly, at an average of 7% per year (Chesshire (1996)and ***Figure 15***). However, in the 1970s the discovery of North sea oil and gas, and the economic downturn, contributed to a significant slowing in demand for electricity, the first sustained slow down since the start of the industry, as gas gained an increasing share in domestic and industrial energy demand. Electricity's share in national investment declined. As a result the CEGB's five-year forecast made in 1970 proved to be 24% too high. In addition the CEGB had increased its planned capacity margin, due to the number of new station designs, both nuclear and coal, and the perceived increased risk of their breakdown. The capacity margin for forward planning was therefore raised from 17% to 28% between 1968 and 1977. The combination of over-optimistic demand forecast and a highly risk averse forward planning margin, meant that in the winter of 1975/6 the CEGB met a peak demand of 41,353 MW with 58,677 MW installed capacity – a margin of 42%. (Hannah, 1982)(p. 287). There were comparable margins for the UK as a whole (***Figure 16***). Having comparatively recently emerged from a period of post-war boom in which it was struggling to maintain pace with a rapidly growing demand, by the end of the 1970s the CEGB was running a system which was over capacity for both generation and transmission, just as the apparently unending exponential growth in demand for electricity was finally levelling off (***Figure 15***).

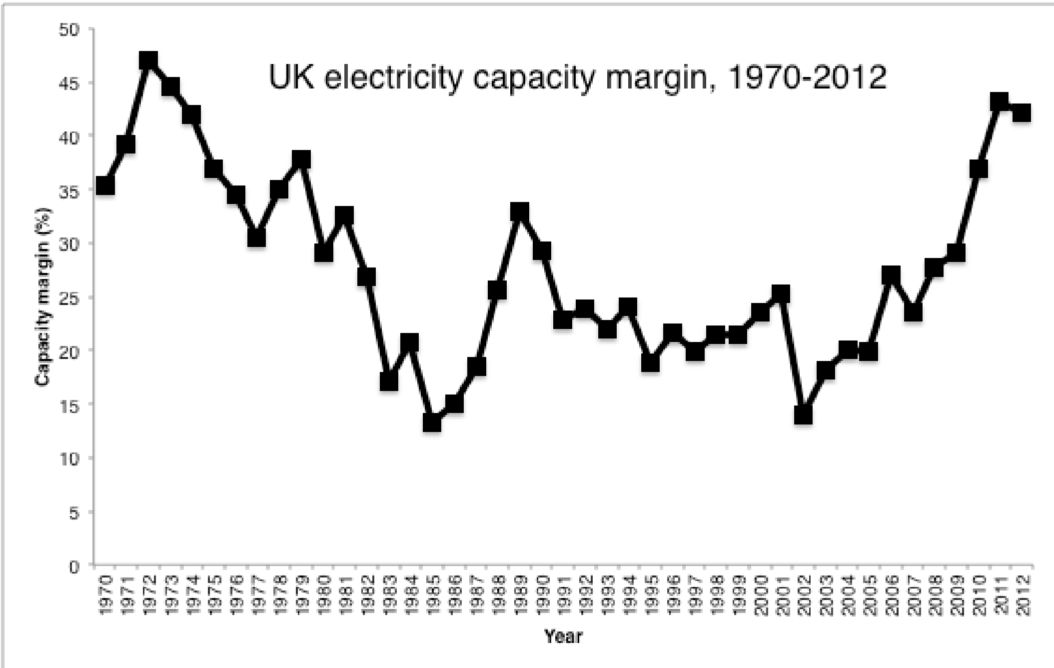


Figure 16: *UK electricity capacity margin, 1970-2012. Source: DECC*

3.3 Privatisation

The period from the early 1980s to the present time was one in which demand for electricity grew at a markedly slower rate than in any previous period. This slow-down in demand served to further emphasise the high levels of investment which had occurred during the later phase of nationalisation, creating a high margin of manoeuvrability for the supply side. It was against this backdrop that a major reorganisation of the industry occurred.

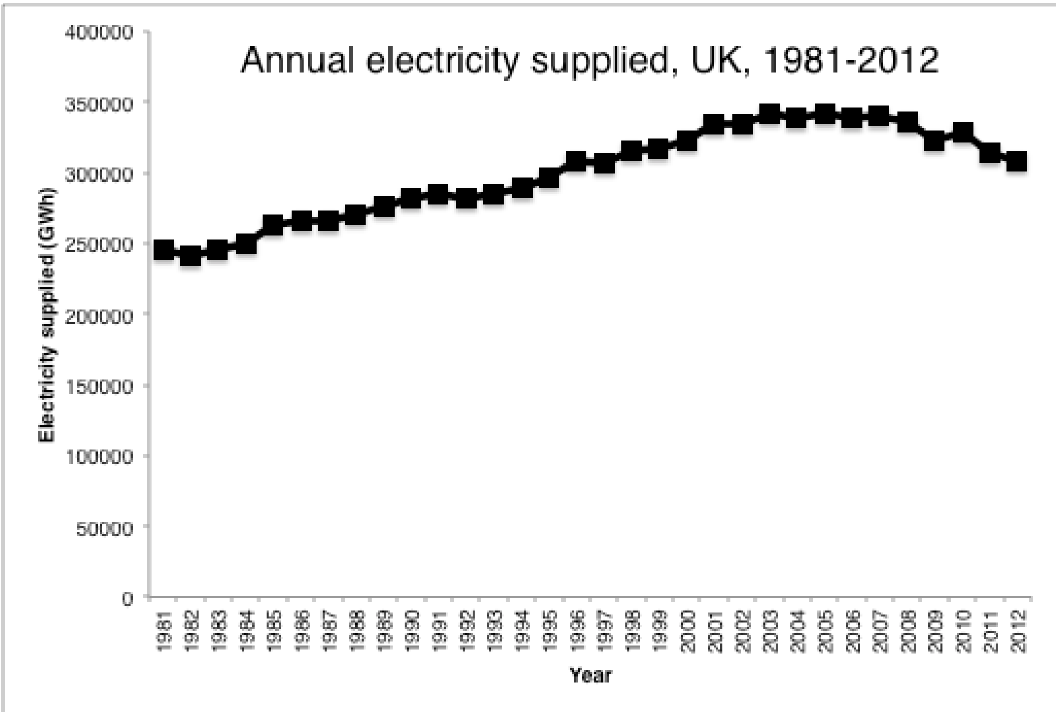


Figure 17: *Annual electricity supplied, UK, 1981-2012*

In 1979 a Conservative government was elected. This marked the beginning of a new phase in which, after 30 years of state ownership of the electricity industry, the debate on private and public ownership was to be profoundly shifted. Nigel Lawson, as Secretary of State for Energy set out his principles in a speech to the BIEE conference in 1982. 'The proper business of government is not the government of business… Our task is rather to set a framework which will ensure that the market operates with a minimum of distortion and energy is produced and consumed efficiently' (Pearson and Watson, 2012).

Privatisation began in earnest with the Electricity Act 1989. This privatised the 12 Area Electricity Boards in England and Wales into Regional Electric Companies (RECs). The new companies had the monopoly of distribution and supply to their regional customers, but purchased electricity from a wholesale market. The National Grid Company, of which the RECs were initially made joint owners, was created to manage the transmission network and the 'pool', a wholesale power market (Pearson and Watson, 2012). The Office of Electricity Regulation (Offer) was created to regulate the charges levied by the National Grid Company. The CEGB's generation assets were split between two new private companies, National Power and Powergen. The nuclear plants could not be privatised and so were subsumed into a state owned company, Nuclear Electric. Another state owned company, Scottish Nuclear, was created to take over the Scottish nuclear plants. British Nuclear Fuels would handle supply and disposal of fuel and decomissioning. In Scotland, with the exception of the nuclear assets, the two boards – the South of Scotland Electricity Board (SSEB) and the North of Scotland Hydro-Electric Board (NSHEB) – became vertically integrated private companies, Scottish Power (SP) and Scottish Hydro-Electric (SHE).

The 1989 Act also created the Non-Fossil Fuel obligation (NFFO), requiring the RECs to purchase a fixed percentage of their electricity from non-fossil sources, and the Fossil Fuel Levy to provide funds for nuclear reprocessing and waste management. The NFFO was initially created to support nuclear power generation, but the European Commission required that the scheme also extend to renewable generators (Rai and Watson, 2013).

There was a phased opening up of competition in supply. Customers with maximum demands more than 1 MW could choose their supplier from 1990, greater than 100kw from 1994, with all remaining domestic and small consumers able to choose supplier from 1998 (Rai and Watson, 2013).

The National Grid Company was listed on the stock exchange in 1995, and the RECs, at the instigation of the regulator, were required to sell their shares soon afterwards (Thomas, 1996). Many of the RECs were subsequently purchased by domestic and foreign firms (Rai and Watson, 2013).

Privatisation marked the removal of the centralised plan for the electricity system. A 1995 review on the prospects for nuclear power, which found no evidence of the need for new nuclear build in the near future, also reaffirmed the principle that it saw no reason why the electricity market should not 'of its own accord provide an appropriate level of diversity'. The seven AGRs and Sizewell B were privatised in 1996 as British Energy. The Magnox stations had an estimated £7 billion of liabilities, and remained in public ownership, eventually to be transferred to BNFL (Pearson and Watson, 2012). The 1995 nuclear review therefore confirmed the complete withdrawal of the state from long-term planning in the electricity system, to a position of setting the conditions for a freely operating market.

The transmission network itself was considered a natural monopoly which would be regulated by a system which mimicked the effects of competition in the market.

This was the RPI-X formula: as a baseline charges levied by network owners could rise in line with inflation, indicated by the retail price index (RPI), but would be suppressed by a factor, X, 'reflecting the potential for real price reductions arising from both technical progress, and output expansion in a decreasing cost industry' (Weyman-Jones, 1990). The ownership of the GB network was now split, reflecting historical divisions – the England and Wales network, formerly the CEGB's region became owned by the National Grid company, the South of Scotland board area by SSE, and the northern board area by SHE. The three transmission owning companies inherited what might be called 'gold plated' networks – the investments leading up to the early 1970s had left the system over capacity at the time. There was no urgent need therefore for the companies to make significant new investments in the network, but neither was there any incentive within the RPI-X framework to consider longer term investment plans, as its focus was on near term cost reduction. RPI-X has been criticised for giving the incentive for utilities to cut costs and maximise profits in a manner not necessarily consistent with the long-term best interests of the consumer. For example, Helm (2009) and Helm and Tindall (2009) argue that the companies maximised profits, at the same time as driving down costs, by avoiding capital investment and running highly leveraged (debt heavy) balance sheets. Helm (2003) observes,

> RPI-X regulation in the hands of Offer, Ofgas and Ofgem proved successful at sweating the assets. It gave high-powered incentives to cut OPEX costs, and to cut CAPEX too… Prices fell as a result, and, as regulators screwed down the returns, the flight of equity and consolidating mergers began. By the early 2000s, most of these cost savings had probably been made… RPI-X does not encourage investment, and truncates the management of the networks into five-year periods, creating a mismatch between the time horizon of asset management and investment decisions, and those which are profit-maximising under RPI-X.

Arising from concerns about the lack of attention to long term quality of supply under RPI-X, Ofgem's Incentives and Innovation Project (IIP) project in 2000-2001 attempted to explore mechanisms through which quality of supply could be monitored alongside costs. Although in the short term the project did not lead to any radical reforms of RPI-X, it did, according to Helm, 'shift regulatory attention away from network prices and more towards investment and hence security of supply'(Helm, 2003). It is also perhaps noteworthy that its two 'I''s, 'incentives' and 'innovation', did appear at the centre of what was in fact to become the successor of RPI-X, RIIO, discussed in more detail in Chapter 4.

The only major structural change in the generation mix was the so-called 'dash for gas', which saw a significant move to CCGT due to recent technological advances in CCGT technology, the accessibility of North Sea Gas, the effect of environmental regulations in EU directives (Watson, 1997), as well as the lifting of European and UK legal restrictions on the use of gas in power generation (Pearson and Watson, 2012). By 1997, around 15 GW of CCGT was operating – the share of gas generation had grown from zero to 27% in six years, largely at the expense of coal (Pearson and Watson, 2012) and (***Figure 18***).

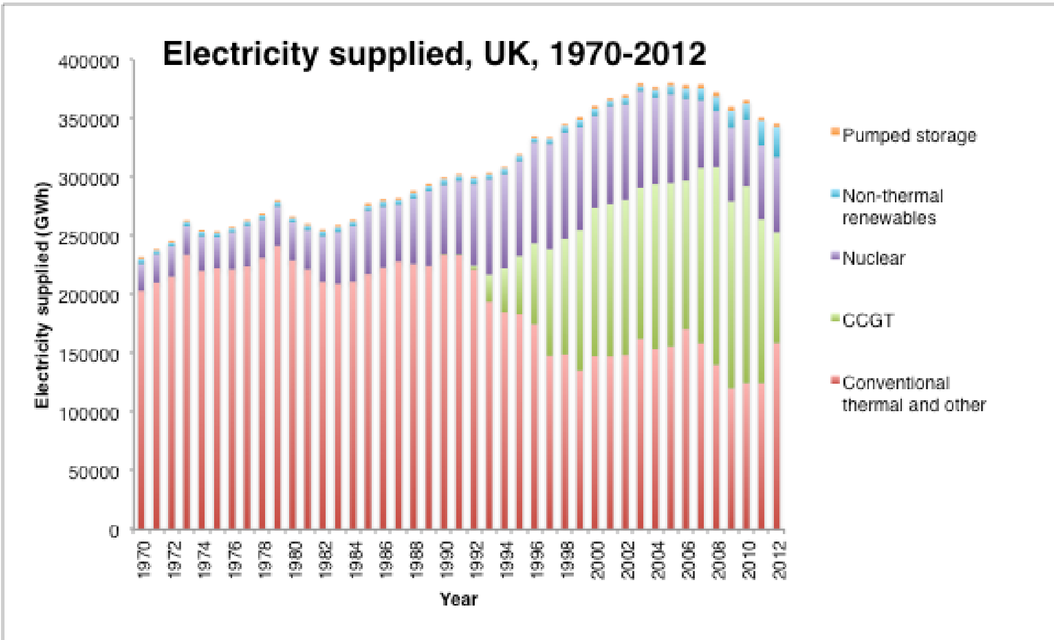


Figure 18: *Electricity supplied, UK, 1970-2012. Source: DECC / DUKES*

This period also saw a notable increase in the extent to which environmental impact was recognised in energy policy. Having been castigated by Scandinavian countries as 'the dirty man of Europe' during the 1980s, due to its coal plants' emissions of SO_x and NO_x which were a major cause of acid rain, in 1988 the UK finally signed up to the EU's Large Combustion Plant Directive (LCPD), aimed at reducing emissions of SO_x and NO_x from power plants. In 1990, Prime Minister Margaret Thatcher made a landmark speech to the Royal Society on the need for action on climate change, and the White Paper 'This common inheritance' acknowledged climate change as a major global issue. In 1993 a coal white paper acknowledged that energy policy should have regard to environmental impact (Pearson and Watson, 2012). One of the notable impacts of the dash for gas which followed liberalisation, was to allow the UK to claim substantial reductions both of acid pollutants and carbon emissions, owing to the lower content per unit of energy of both in natural gas compared to coal.

The liberalisation period also coincided with clear reductions in consumer electricity prices (***Figure 19***). There are a number of causes for this price fall. The effect of the RPI-X framework in reducing regulated charges for transmission and distribution was one factor. The costs of producing electricity from coal also fell due to the ability of generators to buy the fuel on global markets, rather than being tied into contracts with the British Coal Board. A reduction in the Fossil Fuel Levy from the early to late nineties may also have had an impact (Pearson and Watson, 2012). However, by the early 2000s these sources of cost reduction were more or less saturated, and prices began to rise again in real terms (***Figure 19***).

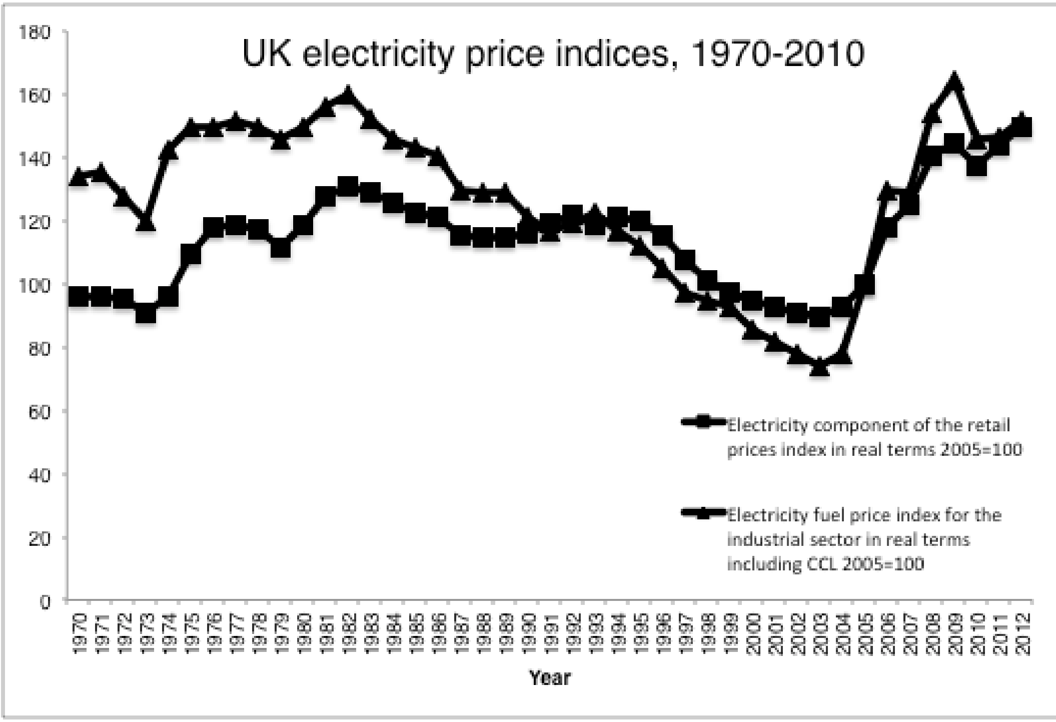


Figure 19: *UK electricity price indices, 1970-2010. Source: DECC*

3.4 Post-privatisation

The change of government following the 1997 election did not mark a value shift on the question of the relative roles of the private and public sectors. Just as, during the early 1920s, the practical experience of the failure of the industry to self-coordinate in an efficient manner decisively weakened objections of principle to increased centralised coordination in the industry, so now, with the view that the privatised industry was achieving efficiencies and cost-savings following the nationalised period of over-investment and inefficiency, and showing decisiveness in rejecting one government-sponsored failed technology (nuclear) and embracing a new innovative one (CCGT), whilst successfully maintaining system margins and a diverse supply mix, the argument against state intervention in energy systems seemed to have won the day. Tony Blair had succeeded in revising Clause 4 of the Labour Party's constitution, with its apparent commitment to nationalisation, in 1995. In an announcement to accompany the new government's first Energy White Paper in 1998, Peter Mandelson, the grandson of the architect of Labour's nationalisation programme, Herbert Morrison, affirmed his conviction that 'competitive markets are the best way of stimulating efficiency in industry, of providing consumers with real choice and bringing down prices. They are the cornerstone of our approach to energy and power generation' (Pearson and Watson, 2012).

The new government therefore continued with the programme of improving the functioning of the electricity market. Despite the growth in new CCGTs mostly commissioned by the RECs, they and the nuclear plants tended to run as baseload, leaving the two large companies National Power and Powergen to meet peaks and set prices in the spot market. The Utilities Act 2000 was a response to resulting concerns about market power in the pool, and paved the way for the New Electricity Trading Arrangements (NETA) in 2001 – a voluntary market much more closely modelled on conventional commodity markets. The Act also introduced the Renewables Obligation (RO) to replace the NFFO. Over the NFFO period (1990-2002) renewables only grew from 2 to 3% of UK generation (Pearson and Watson, 2012, Rai and Watson, 2013). The replacement of the NFFO with the RO preserved support for renewables but removed it from nuclear. NETA was subsequently replaced by the British Electricity Trading and Transmission Arrangements in 2005, which brought the whole of Scotland back within a single GB market. Ofgem's NGC review in 1999 established separate controls for the System Operation (SO) function of the company, and its function as the Transmission assets owner (TO), ultimately leading to a separation of these functions of the company (Helm, 2003).

In 2000, a report by the Royal Commission on Environmental Pollution drew on the available climate science of the time to propose that UK's fair contribution to a global greenhouse gas emissions reduction effort was a reduction of national greenhouse gas emissions of 60% by 1990 (RCEP, 2000). Although awareness of climate change had been growing through the nineties, this report was highly significant in re-establishing a long term policy goal for the energy sector – after just a decade of deliberate extrication of government planning from the energy sector, policy was now on the point of being dragged back into energy. The commitment to markets was to remain strong – now however there would be an aspiration that the markets would deliver on quite specifically defined policy objectives, in addition to simply achieving an efficient balancing of supply and demand. This was to become a significant tension in the energy arena.

An Energy Review undertaken in 2002 placed environment at the centre of energy policy, with strong reference to the RCEP's 60% target. The review downplayed concerns about energy security, which it argued could be addressed by strengthening international markets (Pearson and Watson, 2012).The UK was still a net energy exporter at this time. This fact, combined with the experience of steadily falling prices since privatisation put cost and security lower down the agenda, enabling a pole position for decarbonisation as the key energy policy priority. An Energy White Paper in 2003 endorsed the 60% target (DTI, 2003), but in the context of a government bail out in 2002 for British Energy, there was a lack of support for nuclear (Pearson and Watson, 2012).

The primary duty of the regulator Ofgem (formed in 1999 when Offer and Ofgas were merged) at this point was to protect the interests of consumers, and its primary means of doing this was to encourage competition. In June 2003 however, the DTI issued draft Guidance to Ofgem that it should take account of the 2003 White Paper. From this point, promoting decarbonisation therefore became a secondary duty of Ofgem, alongside the primary duty of protecting the interests of consumers (Helm, 2003). Exactly how these duties coexist was not entirely clear. Helm observed, 'it is not an *objective* of Ofgem to deliver a low carbon economy, and it does not have the machinery or powers to promote renewables and energy efficiency' (Helm, 2003).

The UK became an energy importer again in 2004 after two decades of being a net exporter (Pearson and Watson, 2012). Further, the future impacts of the EU Large Combustion Plant Directive, which the UK had signed up to in 1988, were beginning to seem closer – non-compliant plants would have to close before the end of 2015. The question of adequacy and security of supply was beginning to seem more pressing than had been the perception in the 2003 White Paper. By 2005, Prime Minister Tony Blair was signalling that he favoured nuclear power. In 2006, an Energy Review was launched which concluded that 'nuclear energy has a role to play in the future UK generating mix alongside other low-carbon generation options'. In the next Energy White paper of 2007, security of supply was firmly back on the agenda, and the nuclear option open – however the government at this stage maintained that no subsidies would be given to nuclear. A CCS competition was also announced. The mood of the time is summed up by the then Trade and Industry secretary Alistair Darling, in an interview with the Observer at the time of the publication of the 2007 White Paper (Morgan, 2007):

> What's clear in my mind is the urgency of the situation both in relation to climate change and security… in 10 to 15 years' time we will come terribly close to a situation where demand and supply come too close for comfort.

On nuclear, he remarked:

> In the Eighties I had huge reservations, but I did not know about climate change then, as very few people did. As Keynes said, 'when the facts change I change my mind. What do you do?'

A short time before this, as signalled in the 1995 review on nuclear, the government had been happy to accept the apparent judgement of the market that nuclear was yesterday's technology. The combination of climate change and security concerns was now prompting a shift in thought, which appeared at least in part to be suggesting that the market could get things wrong, or at least not have a sufficiently long term view, and that where important strategic long term objectives emerged, some kind of policy direction was needed. Whether direction counted as simply giving 'signals' or more concretely setting incentives or targets, would be an area for experimentation in subsequent years. The potential tension however was that this perception now existed alongside the previously established view that market decisions about energy technologies were the most efficient. These views are not logically compatible, and there must exist a line where one of these ideologies gives way to the other. Exactly where this line is, is unclear, and represents one of the ongoing confusions in UK energy policy.

Before these tensions became too apparent however, climate policy was moving quickly. A Climate Change Bill was in development which would establish a legally binding 2050 CO_2 reduction target. Following pressure (based on emerging climate research) the target was strengthened from the 60% recommended by the RCEP, to 80% (HM Parliament, 2008). It passed the Commons stage in 2008 with only 5 votes against. The strength of the Commons' resolution on this is worth remarking on. The bill was initially developed by a coalition which included a Conservative opposition with growing electoral credibility, and which was beginning to set up its environmental credentials as one of its major appeals to the electorate – opposition leader David Cameron having travelled by dog-sled through the Svalbard Arctic archipelago in 2006, to highlight his party's concern about climate change (Jowit and Nigar Aarskog, 2006). In the run up to the vote then, a debate had emerged in which all parties were competing to 'out-green' each other, which largely explains the significant consensus when it came to the vote. Enthusiasm for the bill may also have been bolstered by a strong sense of optimism around the delivery process. The UK was comfortably on track to meet its Kyoto targets for the 2008-2012 period, and has also successfully left behind its 'dirty man of Europe' image in meeting EU standards on NO_x and SO_x. There was a tendency of both Conservative and Labour politicians to attribute this to the direct success of environmental policies whilst in office, and not to emphasise that the displacement of coal by the 'dash for gas' was the main factor behind these successes, itself a side-effect of the liberalisation process. With memories of emission reductions successes still green, and the target in prospect such a far-off one, the moment at which the bill came to parliament may have been extraordinarily optimal from the perspective of garnering maximum support.

3.5 Austerity

In 2008, following an escalating crisis in the global financial markets, the collapse of Wall Street investment bank Lehman Brothers signalled the start of a global recession (Elliott and Treanor, 2013). The change in political climate was dramatic. In the UK, the balance between maintaining the country's financial deficit, and stimulating economic growth through government spending, was now the dominating topic of political debate in the run up to the 2010 general election (Winnett, 2010, Krugman, 2015).

For the time being however, energy policy continued to be propelled by the force of the wave that had carried through the climate act in 2008. A significant institutional change was the creation of a Department for Energy and Climate Change in October 2008. This new department emphasised the return to prominence of energy as a government policy portfolio, and also emphasised the main reason for its return to prominence, climate change. A civil service review of the department from 2009 declared, 'The Department of Energy and Climate Change (DECC) was created in October 2008 to take the lead across government for tackling climate change and securing clean, safe and affordable energy for the UK. The Department's mission is global change on a historic scale. Its role is to lead this change' (Civil Service, 2009). DECC's low carbon transition plan was published in 2009 (DECC, 2009), showing a 'roadmap' broken down by sector and technology, towards achieving the both the EU 2020 renewables targets and the first three carbon budgets set out by the Committee on Climate Change, under the provisions of the Climate Change Act. More broadly, since the 2003 Energy White Paper (DTI, 2003) a debate had been emerging around the institutional arrangements required for delivering on the UK's ambitions for cutting carbon emissions by 2050(SDC, 2006a, SDC, 2006b, Lockwood et al., 2007). In order to improve the investment climate for renewables, banding of the Renewable Obligation certificates had been undertaken to improve returns for higher cost renewables at an earlier stage of development (Carbon Trust, 2006). Now however, more profound market changes were also being discussed, and Ofgem's Project Discovery presented a series of institutional arrangements which spanned the spectrum from minimal to high government intervention (Ofgem, 2010b). With the UK's carbon targets now set into law by the 2008 Climate Change Act (HM Parliament, 2008), there was increasing acceptance in the possibility of a stronger intervention in electricity markets being justified. Thus, in 2009, Dieter Helm observed, 'As the replacement cycle bites in the next decade, and given the scale of the expenditure on wind, there are considerable doubts as to whether the privatised industry structure, with liberalisation and competition, is up to the task. A return to greater state intervention is almost inevitable' (Helm, 2009).

In this context, when the 2010 election returned a Conservative – Liberal Democrat coalition to power, there was already considerable momentum behind the idea that the electricity market was going to need another significant overhaul if it was going to deliver the kinds of structural changes required by a low carbon transition. Just as Labour in 1997 did not demur from the established value set of government extrication from the electricity markets, so now the new coalition did not challenge the new emerging value set which was increasingly justifying government policy intervention to deliver long-term policy goals. Thus in its White Paper of 2011 (DECC, 2011b) the new government introduced proposals for Electricity Market Reform, which were discussed from 2010 onwards eventually came before Parliament as the Energy Bill in 2012. The bill contained four main pillars: the provision of subsidies through differentiated feed-in-tariffs for all low carbon technologies including nuclear; the establishment of a carbon price floor; a capacity mechanism to reward generators for making capacity available, in view of increasing penetrations of intermittent generation; and a minimum emissions standard to prevent building of unabated coal. The Energy Act received Royal Assent in December 2013 (DECC, 2013b).

The role of Ofgem itself was evolving again. With the government's low carbon aspirations having been included in Ofgem's remit as a secondary duty following the 2003 White Paper, in July 2010 the new government launched an Ofgem Review, to consider again its duties. The conclusions, published in 2011 (DECC, 2011a), rephrased the body's principal objective as:

> To protect the interests of existing and future consumers where, taken as a whole, those interests include the reduction of greenhouse gases and security of supply

Its primary duties were now to further the principal objective, 'wherever appropriate by promoting competition', but also to consider 'how far promoting competition would protect consumers and whether there are alternatives that would better protect [their] interests' (DECC, 2011a). Thus the government effectively enshrined within the duties of its regulator, all of the cornerstones of its energy policy, with the facilitating of efficient markets only one of several possible means towards achieving these policy goals. The argument in favour of such an approach, as stated in the DECC report, is that the 'strategic direction' provided by the Government, and Ofgem's 'independent regulatory role' should be 'aligned and coherent' (DECC, 2011a) – in other words the latter should not frustrate the former. The argument against it is that the balancing of cost, decarbonisation and security of supply requires trade-offs between the objectives. Such trade-offs are inherently political decisions. It is perhaps unclear what basis Ofgem has to make these trade-offs, in a manner which preserves its independent and non-political nature. Considering the proposed alterations to Ofgem's remit in 2009, Helm observed, 'the relationship between the duties would need to be sorted out: it is not the role of regulators to make what are ultimately political trade-offs between customer bills, carbon, security, and other duties' (Helm, 2009).

The effect of the enlargement of Ofgem's remit may have encouraged a very public intervention made by Alistair Buchanan, the outgoing head of Ofgem, in 2013. This intervention, in turn, gave further support to the justification for government intervention in the electricity. Buchanan warned of power shortages as the margin between available capacity and peak demand narrowed in the years approaching 2015. He argued that this was due to the combination of factors: the remaining plant closures resulting from the LCPD, the lack of new investment in CCGT due to the low 'spark spread', and more generally due to the policy uncertainty caused by the unresolved EMR process (Buchanan, 2013). A similar argument was made by other industry and independent contributors (Royal Academy of Engineering, 2013), who pushed for the government to prioritise system security by fast-tracking measures to reward capacity credit. Whatever the rights and wrongs of this particular debate, Buchanan's intervention was notable as an example of how the line between Ofgem's role as a purely economic regulator, and as a kind of 'energy agency' with a broader policy remit, was becoming blurred.

Analysis was also being undertaken on the role of electricity networks in the low carbon future. This was prompted by the emergence of the work of the Electricity Network Strategy Group (ENSG) which effectively presented an engineering plan for the future network out to 2020. Whilst its reports (ENSG, 2009, ENSG, 2012) do not engage in policy discussion, the implication of their network plans derived from the impacts of government policies on the generation side, give a strong suggestion towards planned, long term strategic investment in electricity networks, in the name of delivering on long term government policies.

Meanwhile, the effect of the recession meant that increasingly financial debates began to impinge upon energy policy. From the early 2000s, electricity prices began to rise again as North Sea gas expired and the more straightforward network savings wrung out under RPI-X became more scarce (***Figure 19***). The costs of the low carbon transition became increasingly scrutinised. At the same time, mistrust in energy companies was growing. Energy price rises at a time of economic downturn were controversial, amidst allegations that the price rises did not reflect upstream costs but were the result of the companies acting unfairly as a cartel. Opposition leader Ed Milliband made political capital in a swingeing attack on the energy companies, the heads of which were soon called before a House of Commons Select Committee.

Thus, energy policy, which in the 1990s had been apparently extricated from policy intervention, had seen the creep back of policy goals in a remarkably short space of time. First decarbonisation, beginning with RCEP report in 2000. Then security of supply, as the UK became a net energy importer in 2004, and the impacts of the LCPD began to loom. Then, in the context of deep economic downturn, prices would become a dominant feature of the energy debate. These three objectives, now existing simultaneously, meant that analysts began to present UK energy policy as a 'trilemma', suggesting that optimising for one objective causes trade-offs against the others.

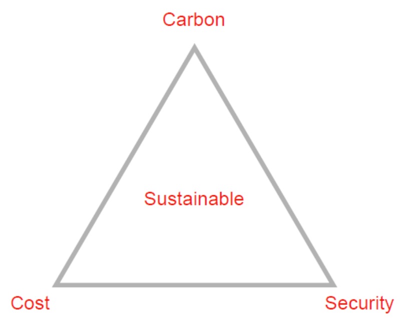


Figure 20: *'The trilemma'. Source: Boston (Boston, 2010)*

The trade-offs between these three corners were, deliberately or not, not always made explicit. For example, calls for government intervention through policies to guarantee capacity and avoid 'the lights going out', did not often address the alternative risk of 'gold-plating' the system to such an extent that the impact on consumer prices would be significant. The trade-off between cost and climate change measures on the other hand, were made more explicit, and in the midst of controversies around energy price rises, climate change and other policies appeared to be vulnerable to political claw back (Carrington, 2011, Mason, 2013).

3.6 Discussion

The evolution of the GB electricity system through the twentieth century provides an informative case study on political decision making within large sociotechnical systems. The impacts of decision making within such systems are long term, and therefore involve engaging with long term future uncertainty. As such, political decision making affecting large sociotechnical systems relies in part on evidence arising from the performance of the current system, but also on 'value systems' – evaluative judgements about what the appropriate governing principles should be for such a system, as well as images of what it could or should look like in the future (Sunderlin, 2003, Crick, 1964, Hall, 1993). The historical discussion of this chapter has traced the ebb and flow of different political value systems or paradigms, and seen their effect on political decision making in respect of the electricity system.

A value spectrum – or contest of paradigms (Hall, 1993) – which has been significant throughout the development of the electricity supply system, is that relating to the view on the relative roles of the state and the private sector. This debate has occurred since the earliest years of the development of the system, and was at the root of many of the most significant structural changes to the industry, notably the coordination and creation of the first national grid from 1926, the development of the Supergrid following nationalisation from 1950, and the privatisation of the industry from 1989, which preceded the 'dash for gas'. Although the opposing ends of this value spectrum appear broadly to have political colours, value waves have in several instances proved stronger than changes in the political colour of government. It was a Conservative government which eventually accepted the rationale for increased coordination of sections of the industry in 1926; a Labour administration which in 1997 fully accepted the rationale of stripping back government involvement in the electricity system; and a Conservative-Liberal Democrat coalition which accepted the need for electricity market reform in the direction of greater government intervention, in 2010. At the present time, the political management of the industry is still strongly affected by the value system that drove the privatisation process of the 1980s and 1990s, the central tenet of which is that markets deliver the most efficient outcomes. However, this value system is now increasingly jostling for position again with another long-held value system, which mistrusts the ability of markets to deliver long term policy goals for the public good, and accordingly perceives value in the state intervening upon the activity of private actors in order to make the delivery of these goals more secure.

There is currently therefore a slightly uncertain balance in the role of the State in the electricity system. The core evaluative principle of the privatisation process, that the system should be allowed to naturally find its most efficient course within an open market, without the need for the hand of the state upon the tiller, still has a strong influence on policy debate. However, such a condition has never quite been reached, and the hand of state guidance has consistently given into the temptation to make adjustments to help the system navigate the shoals of long term policy obligations – climate, cost and security. Decisions about levels of State intervention in the system, and which of these policy objectives should be prioritised, still remain political judgements, strongly rooted in political value systems.

A number of authors have used the concept of policy paradigms to analyse the tension between these alternative value systems in UK energy policy. In particular, they have considered the key attributes of the policy paradigm, or value system, that had been established by the late 1990s, and whether emerging new priorities around decarbonisation and security of supply will require a 'paradigm shift', or indeed whether a paradigm shift has already occurred. Mitchell (2008) defined the existing UK energy policy paradigm, at the time she wrote, as the Regulatory State Paradigm (RSP) (drawing on Moran (2003)). Her view is that this paradigm hands down key principles which define and constrain the way policy is designed and enacted: 'The essence of these RSP principles are that: markets and competition are seen as the most effective way of meeting society's choices; politicians should be legally separated from the regulation and decision-making of industry; the means of 'steering' the delivery of efficient management of the UK's industries should be based on 'expert' knowledge and economic analysis using open and transparent processes and data; markets should be designed to be technology and fuel blind so that outcomes are not 'picked'; if an outcome is wanted, the policy put in place should mimic markets as far as possible and should not intervene directly in the market or network rules and incentives (for example, the Renewables Obligation); as far as possible, direct regulatory measures should be instituted only in the face of substantial market failures (for example, the banning of incandescent light bulbs). It is these principles which inform and sometimes constrain, policies across Government, including (sustainable) energy policy' (Mitchell, 2008) (p.23).

Mitchell argues that the effect of this paradigm is that energy policy choices are constrained to those that fit within the logic of the existing paradigm, rather than following a neutral evidence based view on what policy is most effective. For example, she suggests that a feed-in tariff approach to subsidising renewables has been shown to be more effective in other countries than the UK's Renewables Obligation – the latter was nonetheless favoured as its structure more closely conformed to the principles of the RSP set out above (Mitchell, 2008). As a result, Mitchell concludes that the complete replacement of the RSP with an alternative paradigm is required as a pre-requisite of a sustainable energy transition. '… The current political paradigm in place in the UK will not help the UK to achieve sustainable development. In order for the UK to achieve a sustainable future, there is a need for a political paradigm shift' (Mitchell, 2008) (p. 198). Interestingly, however, her own definition of the RSP contains an ambiguity, an area of possible tension or 'anomalous' developments. The principle attributed to the RSP that 'as far as possible direct regulatory measures should be instituted only in the face of substantial market failures', of course implies that direct regulatory measures *could* co-exist with market based incentives in the case of a perceived 'substantial market failure', as proved by the example of lightbulbs which is provided. What is considered to be a 'substantial market failure' is open to interpretation, and the negotiation created by this caveat gives a clear example of the testing and stretching that goes on within a paradigm, without necessarily entailing its wholesale replacement. In recent years, as discussed in this chapter, strengthening perceptions of possible market failures in key energy policy areas has meant that the market paradigm has been increasingly tested and stretched by 'anomalies' of state intervention.

It is because of this increasing awareness of potential market failures in energy policy objectives that Dieter Helm (2007a, 2007b), by contrast, argues that a paradigm shift in UK energy policy has already occurred, and indeed pinpoints the moment of paradigm shift quite specifically to the year 2000. However, in much of Helm's discussion, his use of the term paradigm shift, and thus the criteria for understanding whether one has happened, is significantly different to its use by Mitchell (2008) and indeed Hall (1993). In Helm's discussion, a paradigm shift occurred in the year 2000 due to a marked change in oil market structure spelling an end to the low oil prices of the 1980s and 90s, and creating security of supply concerns; and the rise of climate change in the political agenda. His description of a paradigm shift tends to refer more to external events which change the context for policy-making decisions, rather than necessarily a reorganisation of the very ideas and principles which underlie policy-making, as described by Hall (1993) and Mitchell (2008). Of course, a significant change in the context of policy making may well in turn demand policy change: 'Paradigm shifts necessitate more radical policy reappraisals than gradual evolutionary changes' (Helm, 2007a) (p. 5) – however, in Helm's analysis, this is mainly presented as a rational reaction to a changing circumstance, rather than the paradigm shift itself. In discussing the challenge of 'designing energy policy in the new paradigm' he argues that a mixture of adding and improving existing market mechanisms, and creating 'new institutional structures to reflect the new priorities' is required (Helm, 2007a) (p. 7-8). In other words, for most of Helm's discussion, the paradigm shift seems to be about factors external to policies, where the job of policy design is to undertake a rational response to the requirements of this – using both market based and interventionist measures as most suited. This is somewhat different to previous definitions of paradigms which have emphasised paradigms as internal generators of ideas, which form, direct and at times constrain approaches to policy by defining both the objectives and the means of policy (Hall, 1993).

However, at other points in his discussion, Helm clearly does take up the notion of paradigm shifts occurring in policies: 'But paradigm shifts happen in policy, too: events can conspire to change the historical context to a sufficient degree to make it increasingly hard to reconcile the existing mindset of policy-makers with the evidence, leading eventually to new objectives and new policy instruments. Paradigm shifts in policy typically require a change in the context and a change in the ideas in response' (Helm, 2007b) (p.9). This understanding of the change in 'ideas' and the 'mindset of policy-makers' is closer to Hall's definition of policy paradigms. Helm continues, 'One policy paradigm in energy has been provided by the set of ideas surrounding privatisation, liberalisation and competition developed in the 1980s. It is an internally consistent view of the world, and provides a 'preferred solution' to problems as they arise. If a particular outcome is unsatisfactory in some way, the answer, in this paradigm, is more private ownership, the removal of restrictions on trading, and the promotion of competition.' Helm argues that this paradigm 'worked well in the 1980s and 1990s', but that circumstances have changed since then. Helm contends that 'this shift in external circumstances, combined with new knowledge about climate change, cannot be adequately addressed within this paradigm of privatisation, liberalisation, and competition. Though these polices continue to contribute both to the context and the outcomes, they are no longer sufficient.' (Helm, 2007b) (p.9-10).

Thus, whereas the paradigm shift in terms of events can be apparently quite sudden, the process of policy paradigm shift is slower and more 'evolutionary', as 'not surprisingly, energy policy has lagged events…' (Helm, 2007b) (p.32). Therefore, 'the paradigm shift in policy objectives has yet to be translated into a coherent set of policy instruments, which have to be grafted on to a privatised and liberalised market structure… Rather than adding on new interventions, and ever more institutions, in an *ad hoc* way to the existing framework, the new paradigm requires a greater degree of clarity and focus. But, contrary to Kuhn's description of paradigm shifts, the new paradigm is not incommensurate with the old. The task is to build upon the strengths of the 1980s and 1990s approaches, rather than reject it wholesale' (Helm, 2007b) (p.34-35). Thus Helm ultimately re-interprets the notion of policy paradigm shift, arguing for a rationally conservative policy response to changing events, which builds upon existing strengths, rather than rejecting old priorities and entirely re-ordering the hierarchy.

If this policy grafting project envisaged by Helm succeeds, it will be a matter of debate and opinion whether to call such an evolution a new policy paradigm. For example, Kuzemko (2013) argues that although the shift in UK energy policy since the rise in prominence of concerns around carbon emissions and security of supply represents 'a significant break from pro-market orthodoxies and institutions of the past, it cannot yet be described as a coherent and alternative policy paradigm… This is partly because neoliberal economic, or 'pro-market', ideas have not been completely rejected… while the government intervenes at a much higher rate than in the past the private sector maintains a high degree of responsibility, as well as influence, in delivering energy to consumers' (p. 3).

It may be that the accumulation of exceptions which are undoubtedly being made within the fabric of the 1980s and 1990s market based energy policy paradigm will eventually be of so substantial a nature that observers will agree that a new paradigm has been brought about. Alternatively, it may be agreed that the paradigm successfully stretched and adapted to accommodate the demands of what initially appeared to be anomalous developments, without being fundamentally displaced. At present UK energy policy appears to be undergoing that process that Hall (1993) describes during which the paradigm is being stretched to accommodate anomalies. In Hall's discussion, this process culminates in the incumbent paradigm becoming so weakened that it is entirely superseded. In the current case of UK energy policy, it seems, as argued by Kuzemko (2013) that the paradigm is being stretched but not yet entirely replaced. Further paradigm stretching may occur in different areas of energy policy, including transmission network policy. Whether the ultimate fate of the paradigm is Helm-style evolution or Mitchell-style complete displacement remains to be seen.

It is clear that the developments of the past have created the current system and also condition our current experience of it, and our views of its future. A strong element of this is how our understanding of past successes and failures feed into the values that we hold, and how these subsequently influence our perceptions of the right choices going forward. The nationalised period is a rich source of such value fortifiers: mistakes, particularly around the nuclear programme, have become a powerful cautionary tale against the folly of the Government attempting to 'pick winners'. The nationalised period has also been presented, especially during debates running up to privatisation, as a time of wasteful 'gold-plating' – essentially implying that the balance between cost and security of supply was not appropriate. On this point, it might be observed that for most of the 60-year period of centralised decision-making on transmission and generation, far from gold plating, the CEGB and its predecessors were struggling to keep up with burgeoning demand, at times appealing to domestic consumers to voluntarily reduce demand at peak times. It is true that during the 1970s, the CEGB was operating with somewhat risk averse planning margins, in part as a result of over-forecasting demand; however it should perhaps be conceded that this situation was in contrast to the comparatively thin margins within which the system had operated for much of the preceding decades. In the UK, the arrival of

North Sea gas and the domestic gas programme, which saw a prolonged flattening out of electricity demand for the first time in the industry's history, may have partially contributed to the gap between forecast and out-turn demand. However, CEGB's over-forecasting of demand was echoed in similar forecasts made in the US, including forecasts by the US Atomic Energy Commission and other independent analysts, as noted by Smil (2000) and Craig et al (2002). Contemporary commentators drew attention to potential flaws in such analyses which amounted to a simple extrapolation of past trends, for example Ehrlich and Holdren (1971) in the US, and Leach et al (1979) in the UK. Especially with hindsight it can be seen that over-forecasting of demand during the 1970s and 1980s was caused by a relatively simplistic extrapolation of past trends, without accounting for sectoral substitution and saturation effects especially in the case of electricity demand forecasts (Ehrlich and Holdren, 1971, Smil, 2000, Craig et al., 2002), or for substantial increases in energy efficiency across the whole of the economy (Leach et al., 1979, Craig et al., 2002, Smil, 2000).

Although forecasting errors are a major source of risk associated with a highly centralised and government co-ordinated model of energy system governance, history also shows that in large, highly-networked industries, there are significant upsides to some kind of more centrally controlled approach, at certain times – especially when on the cusp of periods of extensive new investment. Full nationalisation in 1947 may not have been the only possible way forward for achieving the kind of cross-industry co-ordination required at the time, and history cannot tell us how successful other routes would have been by comparison. However, what seems to be inescapable is that the problems with piecemeal development and lack of network coordination with which the industry grew up would have required some kind of intervention if the industry was to deliver the kind of investment required to support the growth in demands which were actually seen up to the 1970s. The successes and failures of both periods must be seen in context. As Helm observes, 'because the 1980s inherited assets built in the public sector in the 1960s and 1970s, the need to commit to investors was largely overlooked. The lessons of the 1930s and 1940s were forgotten' (Helm, 2009).

The physical configuration of the system is also a legacy of past decisions. The current distribution areas in large part reflect the layout of the 14 Area Boards established at nationalisation. The grid itself still carries the backbone of the 132kV network designed in 1926, and its current areas of capacity and bottlenecks strongly reflect strategic and political decisions taken since then – the construction of the 275kV and 400kV networks with a view to transporting power from the most economic coal producing regions, and the largely political decision to separate off the South of Scotland board, which became operationally distinct from the England and Wales network, reducing the need for interconnection.

The past has also bequeathed a network of actors and institutions, whose configurations reflect an overlay of various political and commercial decisions. The fact that there are three TOs in Britain relates to decisions taken in 1943 to establish the North of Scotland Hydro-Electric Board, in 1955 to split off the South of Scotland Electricity Board from the BEA, as well as the phased privatisation of these boards from 1989. The National Grid Company, as the inheritor of the CEGB's mantle, took over system operation functions through its responsibility to operate the pool. Its system operation functions were eventually split out in 1999. The current dominance of six large energy companies in the generation market reflects in part the hurried timetable to privatisation, such that the new system launched with just two fully privatised companies, and one state-owned nuclear company.

The evolution of actor networks reflects that fact that at each reorganisation a balance was struck between trying to create new actors and institutions to serve the aims of the new approach, and trying to work with what was already there. Actors (including organisations) can be harder to change than institutions, the 'rules of the game' (Young, 2002). Policy objectives can move and evolve quite fluidly, and sometimes move ahead of the organisational structure, which may be still constructed around a previous system. For example, there is some current ambiguity about the role of Ofgem, which nominally remains an economic regulator, but which is increasingly finding prominent politically derived objectives to be part of its remit. The current set of actors were established at privatisation on the basis of a market system allowed to find its way with minimum state intervention. Now that state intervention increasingly seems to be required, it is not always entirely clear which of the current actors has the remit to define the plan and set the boundaries for the behaviour of the others. Instead there is continually evolving a set of guidelines by which various actors are broadly expected to continue with their previously established duties but with increasing levels of implied responsibility for the delivery of the government's policy goals. In this context the question arises as to whether the current set of actors can be adapted to the needs of the current policy agenda, or whether new actors will be required in the future. Helm (2009) argues for the creation of 'arm's-length agencies' to deliver government specifications for new infrastructure requirements, noting that 'these are agency functions, and not ones which lie easily with notionally independent economic regulators' (Helm, 2009).

In reviewing the history of the system, an important observation is that almost without exception, electricity networks, which connect up diverse sources of demand and supply, either within regions or across the nation, have been planned and delivered as a result of significant intervention, planning and coordination by the state, or by a body with equivalent powers to make decisions about the optimal development of the system as a whole, and to make interventions upon the system accordingly.

The main exception is worth noting however – prior to the 1926 creation of the CEB, the North-East Supply Company (NESCo) had already created an AC interconnected network supplying industrial centres in the North East region. This early success can be attributed to far-sighted engineering decisions, but also to the company's critical early merger with a rival company, achieved in part due to family ties, which enabled the company to capture a larger range of customers, and to secure a reasonable rate of return on larger network investments – which companies in the fragmented supply areas in other parts of the country could never achieve. The rate-of-return is key for sunk investments; the development of networks in the private sector in other countries, notably the US, has relied upon Government intervention to mimic the long term commitment of this captive consumer through rate-of return regulation (Helm, 2009, Thomas, 1996). The NESCo example highlights that for the successful coordinated development of network infrastructures, it is not public ownership *per se* which is the key factor. However, it does appear that such infrastructures do depend on the activity of some level of coordination, and some means by which large scale investments can convey an acceptable rate of return to the investor. The situation is understandable in terms of the 'free rider' effect. Whilst it may be in every actors overall interest for some kind of infrastructure to be in place, nonetheless it cannot be expected that that infrastructure will emerge as the amalgamated result of all actors actions, because it is in no actor's interest to construct more infrastructure than is required for its own operations and provide 'free' infrastructure for the benefit of rivals.

Reflecting on the pattern of network design that has emerged from these periods of coordinated planning, it is worth noting that, at least from the 1950s on, the planning and design of transmission networks in Britain was based around facilitating the transfer of power from power stations optimally located according to their own criteria. Thus we have inherited a network which is largely constructed to transport power from the Midlands and northern coalfields to the South.

On the other hand, periods can also be cited in which centralised control and planning yielded less optimal decisions. This may particularly have been the case in relation to designs of generating units. Hannah (1982) reports that efficiencies of coal units in the UK lagged behind other countries, as the CEB continued to opt for tried and tested designs. It appears that lack of competition may have resulted in an overly risk-averse strategy which made little allowance for innovation. Similarly the choice of nuclear reactor design was dogged by wider political considerations.

The private sector is good at delivering efficiency within a given framework – however when new a framework or an upfront network-type expansion is required, it has historically required high levels of coordination, either as a result of state-intervention, or to circumstances leading to unusually high levels of coordination between actors. Whilst ‘picking winners’ on the generation side has a murky history, the benefits of long-term coordination and strategic planning for transmission networks have in general been high over the course of the system’s history. Helm (2003) writes that networks

> …are the motorways to the market, and over-provision is greatly preferable to under-provision. The optimal level of interconnection will not be developed by private vertically integrated oligopolists and their design and development have system-wide characteristics. An element of planning and a (heavy) dose of regulation is essential. It was a lucky coincidence that the market approach of the 1980s and 1990s was applied in the context of mature and well-invested electricity and gas networks. The assets could be sweated without worrying too much about the cost of capital or supply security. That luxury is no longer available, and hence the regulatory priority, and the appropriate instruments, need to shift towards investment. (p.423).

3.7 Conclusions

Political decision making in the GB electricity sector has been strongly influenced by the ebb and flow of alternative competing political value-sets. Value-influenced judgements about the appropriate relative roles of state ownership compared to private ownership, and of state coordination compared to market based self-coordination, have consistently overlain considerations of technical system issues. Values will continue to effect political decisions. The current system is influenced by a mixed value set. The appropriateness of market based self-organisation of energy systems, with minimal state intervention and regulation, continues to have an ideal and aspirational quality with which policy discussions are infused. However, the emergence of major long term challenges in the early twentieth century – particularly climate change and security of supply – have led to a situation which might be summarised as a market-based system in which the state is a very prominent player. The justification of significant state involvement has now established itself in the political value set, across party lines, in a way that marks a significant shift from the late 1990s. At the same time the actors established at the time of privatisation to operate the system with minimal intervention, have not fundamentally changed, although the duties laid upon them have. An important question for the electricity system is whether the existing set of actors is the appropriate one to operate a system in which a market-based structure is combined with high state intervention aimed at delivering major system change in pursuit of long-term public policy goals.

4 Current policy mix in relation to transmission networks

Policy approaches to any particular area of electricity system management are constructed within the context of the broader value shifts that occur within the politics that pertains to the system as a whole, as discussed in the previous chapter. Hence, the current chapter, which focuses on recent developments in the regulation of electricity transmission networks and of the use of networks by generators, will also reflect some of the themes identified in the previous chapter. The aim of this chapter is to set out the current arrangements for the governance of the transmission network, and its relation to the evolving generation mix, and to identify how broader objectives and value-sets are expressed within the specific area of transmission regulation.

As noted in Chapter 1, the central trade off in transmission investment is between the potentially increased benefits of greater transmission capacity, in terms of increased security and greater access to the cheapest or otherwise preferred technology types, and the costs and aesthetic impact of that transmission investment. Whereas for most of the history of the GB electricity system in the twentieth century – specifically between 1926 and 1989, as discussed in Chapter 3 – this trade off was made on behalf of consumers by central committees, the privatised era has required a decentralised approach to this trade-off, in which market mechanisms and resulting price signals inform transmission companies when new investments are required and recover costs for that investment, and also provide signals to generators about the costs that will be imposed on the network by decisions to build generation in specific locations. This chapter discusses the key mechanisms by which these signals are conveyed, with some reference to their emergence during the privatised era.

There are four main areas of interaction:

- Transmission access: the process by which generators gain access to the transmission network

- Transmission charging on long term costs: the process by which generators are charged for the right to maintain access to the transmission network

- Transmission charging on real-time operation: the process by which the System Operator recovers costs of real-time balancing of the electricity system, including the resolution of constraints caused by limited available transmission network capacity at key transfer points

- Planning and investment in transmission: the process by which new investments in the network are triggered and undertaken

4.1 Transmission access

When a new generator wishes to connect to the Transmission Network, two things must be considered: first, the requirement for local enabling works to allow the generator to physically connect to the nearest grid access point; second, the wider network effects of this new connection. If the generator is connecting in an area of the network which already has an excess of supply in relation to demand, then the new generator may add to congestion and network management costs.

In the nationalised system, the need for and location of new generation, as well as the need for expansion of new transmission network, could be co-ordinated internally by the CEGB (as for example discussed in Section 3.2). The privatisation of the electricity system enforced the separation of generation and transmission ownership. This required generation owners to make an application to the relevant Transmission Network Owner for the right to connect to the network. At this point, applications to the grid were dealt with on a first-come first served basis, and each application would only be granted when sufficient grid reinforcement throughout the network had been made such that the new generator's output could be accepted under most conditions, without imposing constraints on the system. As such it was known as an 'Invest-then-connect' approach (Green, 2010). To secure the costs of undertaking wider network investments, generators were required to pay a 'security' or deposit, to give transmission owners the confidence to proceed with the upgrade.

By the mid-2000s, generation incentives under the new RO scheme were encouraging greater investment in renewables, in particular in Scotland where average wind speeds are highest. In 2005, preceding the integration of the Scottish and England & Wales systems under BETTA, generators in Scotland were given the opportunity to submit connection applications without securing the costs of any required network upgrades (see interview discussions, Chapter 5). The number of applications following this amounted to a capacity significantly greater than could be accommodated by the historically low transfer capacity of the network between Scotland and the north of England. As applications from renewable generators for connections in congested grid areas accumulated faster than wider grid reinforcement could be undertaken under the 'invest-then-connect' standard, a queue began to emerge, at the back of which generators were being offered connections as late as 2025 (DECC, 2010b).

The length of this connection queue was seen to be jeopardising the government's targets for renewable energy in 2020. On 27 July 2010, following consultation, the Government announced that 'Connect and Manage' would be adopted as the enduring regime for grid access, along with 'socialisation of constraint costs' (Bell et al., 2011, DECC, 2010b). The overall effect of this regime is that generators are able to connect to the transmission network as soon as local enabling works are completed, but without waiting for wider reinforcement works to be completed (Bell et al., 2011). All constraint costs, 'including those arising from the advanced connection' would be 'socialised equally among all generators and suppliers on a per-MWh basis' (DECC, 2010b). The government's aims in establishing this regime were to 'provide sustained, commercially viable connection opportunities'; 'deliver security of supply and a clear path to delivering our renewable energy targets' which would be implemented 'in a time-scale consistent with delivery of the Government's aspirations for 2020' (DECC, 2010b). In other words, targets for renewable energy were the principal driver for this policy reform.

The implementation of 'connect and manage' does appear to have coincided with rising transmission constraint costs.

Table 3: *Annual constraint costs (£m) (National Grid, 2011a)*

	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
England & Wales	13	28	29	31	37	20
Cheviot boundary	44	25	22	178	86	132
Within Scotland	26	55	20	54	16	18
Total	**84**	**108**	**70**	**263**	**139**	**170**

As the table shows, there was a notable increase in constraint costs from the year 2008/09 onwards, which coincides with the introduction of 'interim connect and manage'. A high proportion of the constraint costs, particularly post-2008, are found at the Cheviot boundary (the boundary between the south of Scotland and the north of England). However, in interview discussions for this thesis (reported in Chapter 5), connect-and-manage was argued to be a rational response to the already existing queue arising from the pre-BETTA decision to waive the requirement for generators in Scotland to secure the costs of network upgrades. In any case, Bell et al (2011) suggest that such high constraint costs in Scotland and on the Cheviot boundary are 'arguably' evidence that transmission access rights have been oversupplied in northern Britain. Concerns have been raised that the current access regime, combined with socialisation of constraint costs, raises opportunities for the exploitation of transmission constraints – that is, generators may produce power behind a constraint in the knowledge that the SO will have to sell them back their power through the balancing mechanism (BM), at a margin (Bell et al., 2011).

4.2 Transmission charging on long-term costs: TNUoS

In the GB system, generators pay an annually calculated levy for their ongoing right to access the network, known as the Transmission Network Use of System (TNUoS) charge. The charge is calculated using a method known as Investment Cost Related Pricing (ICRP). The key features of this charge are:

- It is a capacity based charge, calculated per MW of Transmission Entry Capacity (TEC) required by the generator

- It contains a locational element, which is calculated based on the incremental increase in overall power flows (measured in MWkms) caused by adding an additional MW in each area of the network at the time of system peak demand

- The purpose of the charge is to reflect the network costs that generators impose from different locations, and thus encourage generators to make an efficient trade-off between expected marginal costs of generation and network costs; as well as to recover revenue for Transmission Companies for network upgrades that may be required.

It therefore provides a long-run smoothed marginal cost signal for generators – generators pay a charge that reflects the long term impacts of their location on network costs, but they do not directly pay for the wider works that their connection may trigger – otherwise the marginal generator triggering an upgrade would be charged significantly more than the previous or subsequent generator to connect in that location. More detail on the TNUoS charge calculation method is provided in Appendix B.2.

The table below presents the results of the TNUoS tariff calculation for 2013/14.

Table 4: *2013/14 generation TNUoS tariffs by zone (National Grid, 2013b)*

Zone	Zone Name	2013/14 Tariff (£/kW)
1	North Scotland	25.42
2	East Aberdeenshire	22.80
3	Western Highlands	26.15
4	Skye and Lochalsh	30.25
5	Eastern Grampian and Tayside	21.55
6	Central Grampian	19.75
7	Argyll	18.25
8	The Trossachs	16.49
9	Stirlingshire and Fife	16.40
10	South West Scotland	15.53
11	Lothian and Borders	12.84
12	Solway and Cheviot	11.07
13	North East England	8.64
14	North Lancashire and The Lakes	7.48
15	South Lanacashire, Yorkshire and Humber	6.34
16	North Midlands and North Wales	5.18
17	South Lincolnshire and North Norfolk	3.49
18	Mid Wales and the Midlands	2.44
19	Anglesey and Snowdon	7.41
20	Pembrokeshire	5.57
21	South Wales	2.92
22	Cotswold	0.04
23	Central London	-4.44
24	Essex and Kent	0.19
25	Oxfordshire, Surrey and Sussex	-1.69
26	Somerset and Wessex	-3.05
27	West Devon and Cornwall	-5.17

The table indicates the clear shift in the costs imposed upon the network by generation in different regions of GB. Generators in North Scotland experience high TNUoS charges due to the relative lack of need for generation in this region due to low demand. This low demand means that an incremental MW of generation will be exported out of the region, imposing costs on the transmission network. Conversely, in West Devon and Cornwall demand is greater than supply, hence an incremental MW of generation actually reduces network costs, because it can meet demand within the zone and cause a lower requirement for import. Thus generators in this region experience a negative TNUoS charge – in other words, they receive a payment.

The locational element of the charge is therefore intended to reflect the costs that generators impose on the network, and encourage them to locate new projects close to demand and where the network is less congested, thus helping the transmission network to develop efficiently and cost-effectively.

In September 2010 Ofgem launched project Transmit, a review of the transmission charging arrangements. In their commentaries on existing and potential future transmission charging arrangements for Ofgem's Project Transmit, academic reviewers raised a number of observations in relation to the ICRP methodology (Bell et al., 2011, Baldick et al., 2011, Newbery, 2011). An important point is that the charge is issued to each generator per MW of their TEC rights. For conventional generators which would typically aim to use close to their full TEC at the time of system peak demand, this is a reasonable approach. However, due to their inherent variability, renewable generators have lower load factors of around 30% - thus their average energy output at system peak may be considerably less than the TEC they might apply for in order to be able use all of the energy they generate when at full power. A MW-based charge therefore may be argued to considerably over-estimate the actual costs imposed by variable generators on the network.

The method of deriving costs directly from increased MWkm flows arising from a notional incremental MW increase in generation at a given node does not take account of the actual physical line ratings on the existing network – that is, an increased power flow over a branch that has ample capacity to accept the increase, is treated no differently to an increase in power flow over a branch which would not have that capacity. The effect of this is that the charge does not reflect when an investment actually takes place. It can be argued that a positive outcome of this is that it smooths the 'lumpiness' of network costs, rather than placing all of the costs of a given upgrade on the marginal generator who finally triggers the need for investment – it is in this sense a 'long-run' charge (Bell et al., 2011). However, by not accounting for available or spare capacity it may not be correctly valuing the actual stresses that additional generation places on different parts of the network.

The charge is reviewed annually and the load-flow exercise re-performed with the latest data on generation, load and transmission. Thus the TNUoS charge in a given region, as well as the boundaries of the regions themselves, can change annually. Notably, a generator which in the past took a decision to invest in a given region in part because of the TNUoS charge applied there, could see that charge increase during its operational lifetime, as a result of other generators deciding to connect in the same region, against a stable demand background within the region. Whilst noting this as a possible criticism, Bell et al.

(2011) also acknowledge the argument that despite its earlier connection date, the generator in this example is nonetheless continuing to put power onto the network at the time the charge is calculated, just as the other newer generators are, and should therefore experience the same charge. Baldick et al. (2011) however argue that 'it is unclear what market efficiency goal is served by setting locational TNUoS charges that change yearly for existing generation units, because their entry decision was typically in the distant past'. The authors hold as a principle that 'sunk costs should be recovered in a manner that does not distort usage of the transmission network'. Their preferred approach, therefore, is to separate out operational decisions of already existing assets from investment decisions of potential future plants, by including locational costs in the price of energy but not in the fixed transmission charges (Baldick et al., 2011). In Newberry (2011), the need for transmission charging to give both long and short term signals is discussed. Long term signals should be given regarding network investment and generation location; short term signals about dispatch to avoid congestion in real time. However, the author argues for the separation of these charges into different mechanisms, in particular with Locational Marginal Pricing of energy (explored in Section 4.5.1 and Appendix B.4) suggested as the best way of achieving efficient dispatch.

Project Transmit presented three possible future approaches to transmission charging for consultation.

- Status quo – retaining the existing form of ICRP
- Improved ICRP – making incremental changes to the ICRP model to improve the accuracy with which generation is charged
- Socialisation – changing the approach to entirely avoiding giving locational signals through the transmission charge

Modelling undertaken by Redpoint (2011b) for Ofgem showed that although the socialisation approach provided a slightly increased chance of meeting the Government's renewable targets, it did so at a significantly increased cost. Ofgem considered the cost to consumers of the socialised option to be excessive, and also noted that they considered that 'formulating regulatory policy on the basis that the EMR does not deliver would be inappropriate based on our discussions with the UK government' (Ofgem, 2012a). This rationale is admittedly slightly confusing as it appears to call into question why the study investigating the effect of the different charging models on the likelihood of hitting the Government's renewable targets was commissioned in the first place. It perhaps reflects some confusion around Ofgem's remit in relation to its now expanded duties, as discussed in Chapter 3. The argument for not using socialisation of network costs as a means of delivering on renewables targets is more strongly put by Baldick et al (2011) who hold as a point of principle that 'environmental objectives are most efficiently pursued through mechanisms that directly address those objectives'. In other words, direct mechanisms such as the feed-in-tariffs for low carbon generators should address low carbon objectives, rather than trying to deliver them by proxy through adjusting other kinds of charges.

In a decision document published on 4th May 2012, Ofgem instructed National Grid and the Connection and Use of System Code (CUSC) industry group to develop changes on the basis of the Improved ICRP approach. This approach was favoured because locational cost reflectivity was considered to be beneficial in terms of driving efficient investment decisions; however the changing energy mix required some alterations to the existing ICRP model (Ofgem, 2012a).

In the improved ICRP the approach of using load flow to identify network changes resulting from incremental generation at each grid location, will be maintained. However, Ofgem have proposed that instead of running load flows based on a single system peak condition, two separate conditions should be modelled, producing two components to the tariff. The system peak condition will continue to be modelled, producing a peak security charge, which intermittent generation will not pay on the basis that they are not assumed to provide firm capacity at system peak. In addition an alternative condition will generate a 'year-round' locational charge which all generators will pay based on their location. Ofgem has instructed the industry group to explore alternative ways of calculating the year round component of the charge, which would reflect more precisely the different ways in which different generator types use the system. Departures from the simple MW based charge, which is argued to be less appropriate for generators whose average load factor is substantially less than their peak output, are being considered. For example the TEC could be multiplied by a historic typical load factor for the generation type, or for the specific generator; or the charge could be levied ex-post based on actual load factors or actual MWh produced (Ofgem, 2012a).

In July 2014, Ofgem took the decision to adopt the above approach, with the additional split of the year-round charge into 'shared' and 'non-shared' elements to reflect the potential for network sharing between different types of generators. The code modification will be implemented from April 2016 (Ofgem, 2014).

In summary, the incremental revisions to the TNUoS charging methodology are primarily intended to achieve a more precise calculation of the usage made of the transmission network by different generator types. This should produce a more beneficial outcome for low load-factor renewables than the current system. The locational element of the charge will be maintained. The charge will continue to be re-calculated annually, which means that incumbent generators will continue to be affected by investment decisions of new entrants, as well as by their own activities.

4.3 Transmission charging on real-time operation: BSUoS

Under the British Electricity Trading and Transmission arrangements (BETTA), the majority of electricity trades are bilateral. It is the role of the system operator (SO) National Grid to monitor the trades and to ensure that overall the system remains balanced between supply and demand, at the same time as respecting transmission constraints. Bilateral trading ends one hour before real time (called 'gate closure') after which point only the SO may undertake further trades, within the Balancing Mechanism (BM) (Green, 2010). In the BM participants can volunteer to trade with the SO to increase or reduce their output. Increases in output will be sold to the SO at a premium, whereas decreases in output involve energy being 'bought back' from the SO at a discount. With all trades accounted for the BM typically results in an overall balancing cost for the SO. Further detail on the operation of BETTA and the BM is provided in Appendix B.1.

Some of the trades made by the SO within the BM may be required as a result of participants final contracted positions (the energy that participants have contracted to buy or sell as a result of bilateral trading) differing from their intended physical positions (the energy they actually expect to supply or consume, which may be different from the contractual position due to unexpected events). In this situation the participant is penalised through energy imbalance prices, which recover the cost of balancing as a result of contractual imbalances. However, there are also occasions when, even though a participant may be fulfilling its contractual position, its output cannot be accepted on to the network due to transmission constraints. In this case the SO must use the BM to sell energy back to the participant behind the constraint at a discount, and buy an equivalent amount of energy at a premium from a participant beyond the constraint. These activities also result in a cost for the SO, and these costs are recovered through the Balancing Services Use of System (BSUoS) charge.

The key characteristics of BSUoS are:

- it is an energy based charge levied *ex post* on generation and demand per MWh of energy actually produced or consumed

- the amount charged per MWh does not vary between different areas. This means that generators whose output contributes to constraints pay no more for each MWh generated than those whose output does not cause constraints, or ameliorates them

- the charging split between supply and demand is roughly 50/50.

- as well as constraint costs, it also covers the cost of paying for reserve, response and reactive power services.

The combined effect of the TNUoS and BSUoS charges on generators are therefore that generators receive an annual charge related to their expected contribution to power flows at system peak, charged on a capacity basis, and with locational diferentiation; they are also charged for the overall effects of constraints from real-time system operation – however these charges are not locationally targeted, but socialised amongst all users.

4.4 Planning and investment in transmission

4.4.1 Onshore transmission: RPI-x and RIIO

The evolution of the locational balance of generation and demand over time can lead to requirements for transmission investments. Transmission owners (TOs) must ensure that the networks are of sufficient capacity to manage system power flows as well as having resilience to additional stress factors. In the current GB system, the requirements for transmission network performance are defined in the document known as the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) (National Grid, 2012b). More detail on the NETS SQSS is provided in Appendix B.3. At the same time, this security requirement must be balanced against incurring unnecessary costs for consumers by over-investing in network to a level in excess of the requirements of the security standards.

During the nationalised period, both generation and transmission assets were owned and controlled by the CEGB, which set a 'Bulk Supply Tariff' related to the long run marginal cost of its assets, for the wholesale of electricity to the Area Electricity Boards (AEBs). As such, the particular costs of various components of the charge (for different generation and transmission assets) were relatively opaque. Criticisms levelled at the CEGB by the UK Monopolies and Mergers Commission in the run up to privatisation, which included that of an inefficient operation of the transmission system, as well as the unwillingness of the CEGB to relate its maximum demand tariffs to the level of unused capacity on the system (Weyman-Jones, 1990), suggest that the priorities in network investment during this period may have been more towards security than cost minimisation (as discussed in Section 3.2).

In this context, one of the key aims of privatisation was to reduce system inefficiencies. The transmission network was now separated from generation and treated as a regulated monopoly. The responsibilities of the three new TOs were detailed in the NETS SQSS, and the fulfilment of these responsibilities would at times require network investment. The companies were entitled to recoup the costs of this investment through charges levied on the users of its network – the TNUoS charges discussed in the previous section. However, the appropriateness and efficiency of its investments were to be kept in check through regular 5-yearly Transmission Price Control Reviews (TPCRs) undertaken by the regulator (OFFER, later Ofgem). TPCRs employed the formula 'RPI-X' to identify the extent to which transmission charges would be allowed to rise (as discussed in Section 3.3).

Thus the Transmission Price Control Reviews were focussed on driving efficiencies within the standards of the NETS SQSS, within relatively near-term 5-year time periods. When new network investment was required, this would be signalled through changes in the calculated TNUoS charges, and via the Balancing Service Incentive Scheme (BSIS) which provides incentives for the transmission owners to limit congestion costs (Baldick et al., 2011).

In March 2008, Ofgem launched a review of the TCPR process entitled 'RPI-X@20' – reflecting the almost twenty-year time period for which RPI-x had been used as the price control formula. The RPI-x@20 review highlighted the challenges that faced energy networks in the future. These included: drivers for decarbonisation of electricity supply; electrification in heat and transport; smart grids; interactions of renewables and nuclear; increase in local generation. Further, all of these challenges would take place against a background of ageing network assets due for renewal. By contrast the period for which the efficiency focussed RPI-x formula had been in place, had been one in which Transmission Owners had been able to manage existing assets with little need for significant new investment (Helm, 2003; 2009). It was concluded that RPI-x was not the appropriate model to meet these challenges (Ofgem, 2010c).

There was a notable shift in perception of the role of networks. The review began to reflect an acknowledgement that networks could no longer be treated as passive systems to be regulated deterministically under static security conditions – rather networks were now being presented as active enablers for delivery of policy objectives. Just as the role of Ofgem was at this time being enlarged through addition of broader policy goals to its principal objective (Section 3.5), now the network companies were to receive an enlarged remit. The aims of the new price control approach were now to include that of encouraging energy network companies to 'play a full role in the delivery of a sustainable energy sector', as well as, perhaps more conventionally, to 'deliver long-term value for money network services for existing and future customers' (Ofgem, 2010c).

The new model was christened RIIO, for 'Revenue set to deliver strong Incentives, Innovation and Outputs' (Ofgem, 2010c). RIIO utilises many of the same structures and processes as its predecessor. However, there are a number of key aspects of the RIIO model which differentiate it from RPI-X.

First, there is a broader definition of the kinds of activities for which network companies can justifiably seek to raise revenue. Rather than only seeking to maintain the NETS SQSS, network investments can qualify under six categories of output: customer satisfaction, reliability and availability, conditions for connection (which broadly cover traditional aspects of network performance and security of supply); environmental impact (which includes the carbon footprint of networks as well as their role in facilitating long term decarbonisation); social obligations, safety (which cover compliance with HSE legislation).

Second, RIIO encourages a longer-term outlook on network investment. This is in part due to the extension of the price control period from 5 to 8 years. Perhaps more significant, however, is that the measurable outputs of the six categories described above can be classed either as primary outputs, if the output is expected to be fully delivered within the price control period; or as secondary outputs, if the output is in itself a milestone or contribution towards a longer term objective which spans several price control periods. The inclusion of secondary outputs is thus intended to guard against short-termism and invite companies to plan investments on the timescales equivalent to those of broader policy objectives, such as the 2050 carbon targets. Companies are required to 'consider the costs of reinforcing the network in the context of a twenty-five year asset management plan, rather than in the context of what is needed for the price control period itself' ((Ofgem, 2010a), p. 50). Given the uncertainties which play out over such time periods, companies are required to take a view of future demand which is 'underpinned by a range of potential scenarios' (ibid).

Third, RIIO aims to encourage and reward innovation. This is partly achieved by allowing innovation development activities to qualify as secondary outputs in the business plan, but also through a separate innovation stimulus package, built on the Low Carbon Networks fund model, which provides 'discretionary rewards for commercial innovation' (Ofgem, 2010c).

Fourth, in assessing the needs for the various outputs under each category, network companies are encouraged to 'engage' with consumers of their services, and 'work with others' in the industry or in other sectors 'to identify potential joint solutions that may provide long-term value for money' (Ofgem, 2010a).

Under RIIO, Ofgem's assessment of the companies' required outputs and the associated revenue to which they are entitled, is made in response to business plans put forward by the companies at the start of the price control review. 'The onus is on network companies to justify their view of required expenditure' ((Ofgem, 2010a), p. 47). Companies should set out 'what they will deliver and how', with a 'key focus on primary outputs linked to objectives' and a 'transparent link between primary outputs and delivery costs'. Companies should also provide 'clear evidence of long-term value for money' and evidence that the activity is 'is likely to facilitate longer term efficient delivery'. The last of these may be supported by showing that the company has considered 'a range of options', considered 'the longer term' including the 'context around cost numbers' and has engaged with stakeholders ((Ofgem, 2010a), Figure 18 p. 47).

Incentives are provided to companies in a number of ways. The possibility of qualifying for 'fast-track' approval of the business plan, is intended as an incentive to produce a detailed and robust business plan in the first instance. There are also a number of financial reward and penalty mechanisms which can be implemented according to the performance of the company in delivering its outputs (Ofgem, 2010a). Late on in the development process, Ofgem further introduced an Environmental Discretionary Reward – a financial prize awarded annually to Transmission Companies according to how well they performed against a 'scorecard' of six indicators: strategic understanding of and commitment to low carbon objectives; involvement in whole electricity system planning for low carbon future; approach take to connections for low carbon generators; quality of innovation; approaches to demand side response; and direct environmental impact (Ofgem, 2012b).

RIIO was first implemented in the 5th TPCR beginning in April 2013. Prior to this transmission companies had submitted their initial business plans in August 2011. The initial assessment of these business plans was published in October, including the decision to retain SPT and SHETL in the fast-tracking process. The final decision to fast-track SPT and SHETL was announced in January 2012, and the final proposals for SPT and SHETL were published by Ofgem in April 2012. After further iteration final proposals for NG were published in December 2012.

Much of the discussion around National Grid's business plan related to their costing methodologies, including the costs of line upgrades, and the sums which could be claimed for improving the visual amenity of existing lines in environmentally sensitive areas. Ofgem drew on scaled comparisons of costs incurred in TPCR4, as well as by those provided in the business plans of the two Scottish network owners, to make their case that National Grid's costs were inflated (Ofgem, 2012f).

More generally in relation to their outlook on network investment in the context of wider low carbon policy, all three of the final published business plans took a comparable approach. A 'best view' expectation of the new generation they would need to connect over the period was based on National Grid's 'Gone Green' scenario (National Grid, 2013c). However, this total investment level was split between 'baseline' activities which would definitely go ahead, and the remainder which would be part of 'uncertainty' mechanisms, triggered by certain volumes of generation connections.

RIIO represents a shift in approach to managing expenditure on the transmission network, from one where network owners are passive recipients of load and generation, and must simply respond to this within the security bounds set by NETS SQSS requirements and the price cap set by RPI-X, to one where network owners are expected, on top of these requirements, to act as active leaders in the transition to a low carbon system.

The business plans generated by RIIO tread a balance between a strategic, anticipatory approach to facilitating the connection of large amounts of low carbon generation, using the 'Gone Green' scenario as a basis for these assumptions, and a more risk averse view of network investment, shown by the uncertainty mechanisms. Ofgem's own guidance also reflects these different priorities. A variety of different mechanisms in the process encourage 'strategic understanding of and commitment to low carbon objectives' (Ofgem, 2012b) and consideration of 'the longer term' (Ofgem, 2010a). However, despite the apparent prominence of the Gone Green scenario in forming such longer term views, companies are also required to take a view that is 'underpinned by a range of potential scenarios' (2010a, p.50). Further, Ofgem emphasises that 'the RIIO framework provides the flexibility to assess the case for network investment when there is sufficient certainty for a project to be brought forward and therefore to ensure that the most efficient cost solution is adopted' (Ofgem, 2012e).

What the appropriate level of strategic, forward planning activity in support of a low carbon transition should be does not have a precise answer. Though Ofgem's guidance emphasises that the plans will be judged in terms of long term value, exactly what constitutes long-term value may be hard to demonstrate precisely and may therefore be contentious. The review of the companies' business plans has shown that Ofgem can engage in relatively precise and empirical debates around issues such as the cost of specific network upgrades, the correct implementation of financial instruments, the appropriate balance between debt and equity funding. However, there remain fundamental decisions in the business plan – what level of low carbon generation connection to plan for, what to consider baseline investment and what to retain as an option – the merits of which cannot be precisely and objectively evaluated, because the level of future low carbon generation is itself considered an external uncertain factor. Yet these questions are at the crux of whether the TOs are playing a 'full role in the delivery of a sustainable energy sector' (Ofgem, 2010c). These questions are largely about judgement, and about the kind of 'values' that underlie Ofgem's review process – precisely, on the balance Ofgem wishes TOs to take between being the active progenitors of a low carbon transition, and being the reactive respondents to the moves of other system actors.

The TOs are in some ways and from some quarters being viewed as 'prime movers' of the low carbon transition – the expectation is present by implication in some of the criteria set for them in the RIIO process, as well as in more explicit statements of key stakeholders, for example as garnered by National Grid during its consultation process. The company reports from stakeholder workshops that 'Several stakeholders called for an integrated strategic view of the future of energy'; that 'there was strong widespread agreement that to inject speed into strategic network development requires two broad elements: 1) a stable strategic plan for the energy network system, allowing a strategic approach to the development of the network 2) anticipatory investment that ensures grid connections are in place ahead of demand'; and quoting one stakeholder directly, ' "National Grid needs to take the leadership role on strategic development of the grid" ' (National Grid, 2012d). SPT also appear to assert a leading-edge role for transmission network companies in the introduction to their business plan: 'Key to [delivering UK energy policy] will be transmission as by its very nature it has to lead the way and underpin energy policy by being ahead of the generation curve' (SP Transmission, 2012). However, it is also evident that none of the TOs see themselves entirely as having the ability or the remit to be the ultimate driving forces of the transition. For most anticipatory network investments, the long-term value of the decision depends at least in part on activities of actors whom the network companies are unable to influence directly (e.g. generation companies). Despite the more active enabling role that RIIO expects the TOs to take, it is clear that each is also looking to external sources to be the final arbiter on 'the direction of travel'. This is clear from the TOs' reliance on the Gone Green scenario as an external bench mark for their plans. SPT also used their business plan to make a direct appeal to Ofgem to ensure that 'as well as protecting the consumer in terms of cost, they send out a strong signal that they support the blueprint laid out by the Government in July for Renewables and the required infrastructure to support this development' (SP Transmission, 2012). Again, the question of whether Ofgem is the right actor – or indeed whether the appropriate actor currently exists – to send out that kind of strong signal, is a critical one.

4.4.2 Offshore transmission investment process

In March 2007 Government announced that the framework for offshore transmission would be a 'competitive, asset-based regulatory regime'. Under this regime, licenses to build, own and operate offshore transmission are issued through a competitive bidding process run by Ofgem. The companies compete in terms of the 20-year revenue stream they require to carry out these activities. Generators may either request an Offshore Transmission Owner (OFTO) to be selected to build the assets for them ('OFTO build'), or they may build the assets themselves ('Generator build') and transfer them to an OFTO upon completion (Ofgem and DECC, 2012).

This approach ensures that the separation between generation and transmission ownership is maintained in offshore networks – this is a principle of the GB onshore system and is also required by the EU's Third Energy Package. However, the 'generator build' option is felt to offer flexibility and to help ensure timely connection. In contrast to the regulated monopoly approach used for the onshore networks, a further potential advantage of the approach is that it avoids the need for regular price control reviews, as, in theory, efficient revenue prices are set up front through the competitive tender process.

Possible disadvantages to this approach relate to questions of whether it would impede the co-ordinated development of the offshore network, which may be more cost-effective in the long term than an incremental, piece-by-piece approach. When bidding in a competitive, price-based tender process to provide the infrastructure for a certain offshore asset, it is not clear what incentive a potential OFTO would have to over-size the infrastructure it installs for the benefit of possible future wind farm developments, even though such anticipatory investment might be optimal in the long term.

Reports commissioned by the Government have indicated potential benefits of a co-ordinated approach to offshore infrastructure planning (Redpoint, 2011a, TNEI and PPA, 2011). The Government is therefore continuing to investigate how co-ordination in offshore planning can be achieved in tandem with the existing regulatory regime. Ofgem's ITPR project has also been launched to consider the potential interactions between onshore, offshore and interconnection regimes, and whether more deliberate coordination between these regimes is required (Ofgem, 2012d).

4.5 Discussion

This chapter has discussed the policies and institutions which govern the relationship between generation owners and transmission owners within the GB electricity system. At the heart of this relationship is the trade-off between the benefits of building more transmission, which facilitates greater access to the system by more generators, and the costs that such new transmission investment entails. The policies and institutions discussed are designed to strike a balance in this trade-off. Traditionally, the potential benefits of increasing transmission capacity were increased security of supply, and reduced system costs as a result of increasing access to the network of the most efficient generators. There is now a third major policy objective in the electricity sector, which is decarbonisation. The question of whether and to what extent the policies and institutions governing transmission-generation interactions should be adapted in view of low carbon objectives, is a recurring theme within transmission network policy. In this chapter's discussion of the current policy regime, this can be summarised in two questions:

- Should locational signals in transmission charging be maintained, in view of the fact low carbon generators, especially renewables, would frequently experience high locational charges?

- Should the approach to network investment become more anticipatory or strategic, in view of the significant changes to the generation mix pending as a result of low carbon policies?

4.5.1 Locational signals of network use

In the current system, locational signals are provided to generators as part of the TNUoS charge. However, the current 'connect-and-manage' regime, 'shallow' targeting of connection costs, derogation from SQSS requirements in Scotland, and the fact that constraint costs are socialised across all users via BSUoS, means that the locational signal provided to generators is not as strong as it could be. Newbery (2011) is blunt about this, arguing that 'the present system over-rewards costly distant locations and over-rewards renewables in favoured (e.g. windy) locations, rather than minimising consumer costs and making electricity more affordable' (Newbery, 2011).

There are a number of aspects to this. The first is how the network costs arising from a new generator are targeted. A 'shallow' connection charging approach targets only the costs of local network connections at the new generator; wider network reinforcements are considered a shared responsibility arising from the activity of all generators, and are therefore socialised. A 'deep' connection charging approach considers the new entrant fully responsible for both local and wider network upgrades that may be required by its new injections – the full responsibility for a network upgrade is targeted at the 'marginal' generator.

Newbery (2011) argues for a 'deep' connection charging approach in which the cost of network upgrades are targeted on new entrants who cause the need for the upgrade by their location decision. A possible objection to such an approach concerns the 'lumpiness' of transmission investment. There may be many generators connecting to a section of network with spare capacity, who thereby avoid the deep connection charges. However, it is the marginal generator whose added entry capacity, however small, triggers the eventual upgrade, and bears all the costs.

In the current arrangements, new generators pay for only the 'shallow' connection costs. The deeper connection costs are recaptured via the TNUoS charge which is designed to smooth out this 'lumpiness' and spread it across all generators. It is thus 'ultra-long run' (Bell et al, 2011). However TNUoS charges can vary for generators, depending on the changing pattern of generation and demand. This means that an incumbent generator who made an investment decision based on low TNUoS charges in a particular region, may find that TNUoS charges in that region rise if more generators subsequently connect. Baldick et al (2011) hold as a principle that sunk costs should not be subject to this kind of variation.

The TNUoS charge then from one perspective may be argued to be too variable to provide the correct cost recovery method for sunk network costs. However, from a different perspective it may be argued to insufficiently variable to achieve other kinds of objectives. As noted by Bell et al. (2011), the locational element of the charge is based on the calculated marginal increase in power flows in MWkms from an additional MW in a given location at system peak, but this does not factor in what the network capacity is in each region, so that it does not reflect actual costs and constraints in the different parts of the network. Further, it does not reflect the variation in actual constraints which may occur on the network at different times and under different conditions – for example as a result of the varying output of renewables.

Thus, the outcome of the combined effect of locational TNUoS and socialised BSUoS is that a locational long-run marginal cost signal is provided to generators, which influences their decisions on an investment time scale, although this signal has the potential to change during the lifetime of the investment, due to other system changes; however there is no locational signal provided to generators' decisions on the operational dispatch time scale.

Some commentators do favour the inclusion of a locational element in the real-time costs experienced by generators, which would affect their dispatch decisions. This would provide generators with an incentive, where possible, to avoid using the network at times of high congestion, and to plan their output for times of lower network congestion – a more efficient outcome for the network. For commentators such as Newbery (2011) Baldick et al. (2011) and Green (2010) the desirable way of achieving this would be the full locational pricing of energy through Locational Marginal Pricing or Locational Nodal Pricing. Locational Marginal Pricing operates in the PJM market in eastern United States, as well as other networks in the US. Under LMP the price at each node reflects the marginal cost of the most expensive generator still having access to that node within the available transmission capacity. The variations in nodal prices therefore incorporate the limitations on power flows placed by the available transmission network capacity. As well as influencing short-term dispatch decisions, persistent high or low LMPs also provide long term investment signals to generators and transmission owners (see Appendix B.4 for further discussion).

The debate around how far and in what way to signal locational elements of network costs to generators is given another angle by the broader policy goal of decarbonisation. This policy involves the direct promotion of renewable generation sources, which have strongly locational characteristics – all else being equal, it is clearly most preferable for developers of wind farms to locate in the windiest areas, for developers of wave farms to locate where the waves are strongest, etc. However, these areas are also geographically distant from the average demand 'centre of gravity' of the system, and, for various historical reasons as discussed in Chapter 3, are not strongly interconnected with southern demand centres. If charging arrangements are such that the locational signals are very strong, this could inhibit the commercial viability of renewable generation, which is constrained in terms of where it can locate, and thus potentially frustrate a primary energy policy objective.

However, Newbery and others argue that environmental objectives are most efficiently met by incentives which target exactly what is wanted, not indirectly by trying to remove barriers which are not exclusive to the favoured technology (i.e. coal plants in Scotland would benefit from socialisation of transmission charges as much as renewables would). The correct approach, Newbery argues, is not to price the network incorrectly, but to set the low carbon strike price sufficiently high to overcome the network cost specifically for the favoured technologies (Newbery, 2011). Baldick et al. (2011) also argue that 'environmental objectives are most efficiently pursued through mechanisms that directly address those objectives'.

4.5.2 Strategic coordination and anticipatory investment

As discussed in Chapter 3, tolerance of centralised planning and control of the system has shifted throughout its history. It is noteworthy however that the shape of the current transmission network was very largely established during periods of planned strategic expansion of the network by a centralised agency, on the basis of predictions of the major future load and generation centres. Equally noteworthy is the dominance since the 1990s across the political spectrum of a value set which considers State-led centralised decision making to be inefficient, and to involve risk of sub-optimal outcomes compared to market-led activity. The dominance of this value set has meant that the arrangements for identifying the appropriate level of transmission investment have had to evolve into a regulated process through which transmission and generation provide signals to each other: broadly, generation receives signals through TNUoS charges, and the signal for new transmission investment is largely read from the levels of constraint costs imposed by the activities of generators.

The current network was planned for a coal-intensive system. The system is now in the process of an attempted major transition to a low carbon system. This potentially raised the question of whether the network should be re-planned according to the expectation of a low carbon generation mix, just as the expectation of future large coal stations influenced its planning the in the 1950s and 1960s; or whether, the existing network being what it is, for whatever historical reason, efforts should be made to fit the new generation mix as far as possible into the existing network design, with major new expansions to be avoided until their need is beyond doubt, to avoid wasting money in stranded assets.

Each of the academic commentators on Ofgem's project Transmit referred positively to the notion of centralised coordination of transmission network planning. In Baldick et al's preferred proposal, 'a rational planning process would be undertaken in which transmission reinforcements are made that are anticipated to yield the lowest overall expected system-wide cost of generation and transmission, subject to environmental and security constraints' (Baldick et al, 2011). Newbery (2011) also considers the potential merits of a 'Transmission System Planning Authority' as a 'guiding intelligence' behind a strategic, cost-minimising approach to transmission investment. Evidently, such anticipatory investment in the network entails risk due to uncertainties of trying to predict where future generation will locate such that the 'system-wide cost of generation and transmission' can be minimised. Bell et al. (2011) observe that 'the 'correct' amount of transmission is difficult to identify when there is uncertainty about which generators holding future access rights will exercise them, many industry stakeholders having in the past been particularly concerned about the risk of 'stranded assets' consequential to over-building of transmission. Nonetheless, given the long lead times… and the 'lumpiness'… many others (including Bell (2002) and Baldick (2011) have argued that consumers' long-term interests would be best served by at least some degree of 'strategic' or 'anticipatory' investment in transmission'.

As observed in this chapter, the new RIIO framework for governing transmission investments makes considerably greater allowance for longer term thinking and strategic investment with the goal of delivering on low carbon targets in mind. The framework even encourages TOs to be at the forefront of the transition. National Grid's stakeholder consultation also appeared to reveal a more general appetite for TOs to 'take a leadership role on strategic development of the grid' (National Grid, 2012c). However, as Bell et al (2011) observe, the activity of the TOs is itself affected by significant uncertainties around what will in fact be the activities of generators following any investments that they make – uncertainties over which the TOs themselves evidently have no direct control. A notable feature of the regulatory reforms which have emerged since the rise of decarbonisation on the political agenda, is the gradual increase of responsibility for considering long term decarbonisation included in the remits of key actors, notably Ofgem and the TOs. However, the fundamental structure of the actor-institution network has not changed, and the system remains one in which, formally, no single actor has direct responsibility or remit for taking a strategic leadership role for the transition as a whole. There remains then a question about whether there is a gap in the actor-institution network for what Helm (2003) has called an 'energy agency', with responsibility for translating government targets into a more concrete plan.

4.5.3 The intersection of locational pricing and strategic planning in the current policy mix

Questions around the balance between fully locational pricing of network costs and socialisation of costs for wider policy reasons; and between strategic, anticipatory planning of the network, and a network responsive to generation developments, are an ongoing balancing act in UK transmission policy. ***Figure 21*** shows these two value systems as an intersecting grid. Along each of the axes have been placed elements of transmission policy, according to which of the values or principles they favour. As the diagram shows, the UK has a number of different components to its transmission regulation policy, leaning in different directions within this spectrum of values.

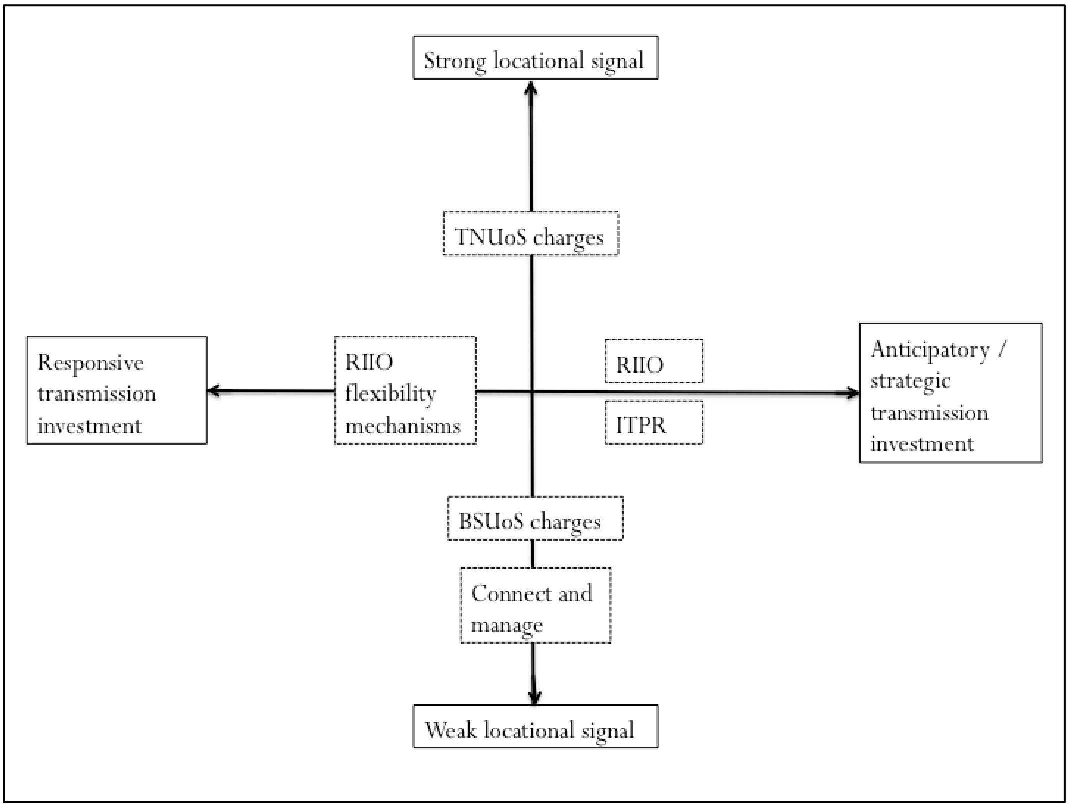


Figure 21: *2x2 grid of values affecting UK transmission network policies, and location of specific policies and frameworks along each axis*

Some of the elements of this policy mix – TNUoS and BSUoS – have been present since privatisation. Others – connect and manage, RIIO – have emerged in response to system challenges and requirements since then. A question this poses is whether this resulting mix of policies, different elements of which lean in different directions of the axes, is something which is inefficient and contradictory, and which should be reformed so that all elements consistently point in the same direction for each axis- in other words, that all policy elements can be placed within one quadrant. A notable feature of academic perspectives on this balance is a tendency to favour an overall approach located in the top right-hand quadrant. Academic commentators such as Newbery (2011), Baldick et al (2011) and Green (2010) favour strong locational signals which operate both on long-term investment and short-term dispatch decisions of generators, with the preferred means of achieving this typically involving locational marginal pricing. At the same time, academic views are also typically supportive of a strongly anticipatory and coordinated approach to network management, often involving some kind of energy agency, planner or ISO (Newbery, 2011, Baldick et al., 2011, Bell et al., 2011). Baldick et al. (2011) summarise the intersection of these two axes, describing their preferred approach as ' "generation follows transmission" or "plan and then price"… Under this approach, a rational planning process would be undertaken in which transmission reinforcements are made that are anticipated to yield the lowest overall expected system-wide cost of generation and transmission, subject to environmental and security constraints… Generators would not be subject to locationally differentiated fixed annual charges for sunk transmission costs… Instead, projections of locational energy prices would incent siting of generation in the most economically efficient locations'.

4.5.4 Relationship of the transmission policy values grid to wider energy policy values and paradigms

Alternative decisions about where to locate GB electricity transmission policy on each of the two axes shown in ***Figure 21*** are underlain by alternative value systems about what the priorities and objectives for electricity transmission networks should be, and the best way to achieve these. These value systems have clear correspondences with the values systems which compete in the wider energy system, discussed in Chapter 3. The prominent underlying issue of principle in the broader energy area – the question of the relative roles of state coordination and market activity – echoes through both of the two axes identified in this specific policy area.

However, it is also worth acknowledging that how this general issue of principle translates into a specific policy area such as transmission, creates particular and technical questions specific to that area. The two axes are transmission policy interpretations of the broader state versus markets question – the translation may reveal different specific issues if applied to other sectors such as electricity generation, transport or domestic building efficiency.

The two axes are also each slightly different versions of the state versus markets question, one considering the role of the state as a designer, the other the value of a technology-blind mechanism for increasing market efficiency. Though it might be possible to combine these variables into a single axis – with state design and no locational market signals opposing no state design and strong market signals – on further reflection it becomes evident that these are in fact two independent variables. For example, the high state role in terms of design could be combined with strong locational market mechanisms – indeed, as noted, this is the combination favoured by several academic commentators.

This discussion shows that, while considering the effect of values on policy making is important, it is rarely so simple as to imagine that all policy options within a policy area will align with high consistency on the same side of a binary division. The same goes for the relationship between policies within a given area (such as transmission policy) and policies within a broader related area (such as energy policy in general). Though they are clearly related, and value shifts in the broader area are likely to infuse debates within the specific area, it is possible for one to move at a different speed, or even in a different direction, to the other. For example, it is possible to imagine the continuation of a technology neutral, market-led paradigm on generation incentive policy, at the same time as increasing co-ordination and anticipatory planning in transmission networks; as well as a lurch to highly technology-directive approach on generation combined with a decentralised and responsive approach on transmission policy. Such perturbations and inconsistencies within the ideological fabric are, in Hall's terminology (Hall, 1993), accommodations made for anomalies within the prevailing paradigm. With the mix of value systems evident in current transmission policy, and the mixture of value systems suggested by broader energy policy – for example in the question of technology specific or technology neutral generation incentives – it is far from evident that developments in all areas should simultaneously move in an ideologically unified fashion. For this reason it seems prudent to regard values in the specific area of transmission policy, and values in broader energy policy as related but not strongly coupled. As such, from a scenario structure point of view, transmission policy and wider energy policy have to be considered as independent variables. How this conclusion affects the structure, scope and boundaries of the scenario system under study will be discussed in Section 7.3.1.1.

4.6 Conclusions

An analysis of the current policy mix which governs the relationship between generation and transmission shows how actors and institutions established at privatisation with the aim of achieving an economically efficient trade-off of the costs and benefits of transmission investment, have become increasingly overlaid with adjustments made in response to system challenges that have arisen since then. Key challenges have included the non-compliance in Scotland arising from its unification with the England & Wales system under BETTA, the growth of renewables driven by the decarbonisation agenda, and the further even greater changes to the system expected in line with low carbon targets over the next few decades. The resulting mix of policies has been analysed in terms of two dimensions: the degree of locational signal provided to generators; and the extent of anticipatory or strategic planning involved in network investment. Each of these dimensions has strong resonances with one of the key value spectrums identified in the historical analysis in Chapter 3, around the relative merits of market-based private sector delivery and state-led strategic coordination. However, at the same time each of the two dimensions is a different version of the market-state question of Chapter 3, and indeed they are sufficiently different to be considered independent variables, as depicted by their representation as 2x2 matrix. As a result of the various objectives and stresses it has responded to since privatisation, the current policy mix contains a mixture of elements tending in each direction of both axes. This opens the question of whether a more efficient mix would more consistently commit to one of the four quadrants.

5 Current actor perspectives on network management

In order to explore further the issues uncovered in the policy analysis reported in Chapter 4, semistructured interviews were undertaken with a number of key system actors. The individuals interviewed were all senior-level representatives of organisations directly involved as actors within the system under study. The interviewees covered representatives of energy companies, transmission owners, the system operator and the regulator. Interviews were undertaken on the basis of the Chatham House Rule – as a result, the views quoted in this chapter are not attributed to individuals or organisations. The intention of the interviews was to make a connection between the broader value trends identified as applying to the UK energy system in Chapter 3, and the specific policy choices identified in Chapter 4. The interviews were intended to explore participants' views on specific transmission policy options, and to situate these views within the context of broader narratives and paradigms uncovered in Chapter 3. There were also opportunities for the experts being interviewed to raise additional areas of interest and concern which may not have already been identified by the literature review, thus adding further insight to the policy analysis of the thesis.

The structure of the interview was directly derived from the policy analysis reported in Chapter 4, with the diagram (***Figure 21***) representing the intersection of the two key policy variables – locational signal and strategic-anticipatory approach – used as visual aid to discussions. The interview guide is reproduced in Appendix C.

5.1 Current context

5.1.1 Where are we on the axes?

The interview was begun by presenting the 2x2 matrix shown in ***Figure 21***. Interviewees were invited to indicate where on this axis they would locate the current GB transmission regime, and also to highlight issues of importance to transmission not covered by the two axes.

Views on the current location of the GB regime suggested that it was not perceived as being ideologically at the extremes of either axis, but also suggested reasons why the system could move along either dimension, not least of which was EU energy policy.

> We're coming from somewhere in the middle, maybe marginally more locational than the rest of Europe, but we're coming from somewhere that's fairly responsive, reactive, and there's a number of initiatives that might move us in a different direction, but none of them have moved yet.

Another comment suggested it was not the intention to be at the extreme ends:

> In terms of the overall pattern of charges, there is no clear indication that Britain wants to be at the extreme ends of either of these axes, for example strongly locational or strongly anticipatory. The mix of policies hasn't been devised with this kind of framework in mind.

5.1.2 The EU context

One interviewee viewed the locational axis in terms of significant fluctuations in direction over recent years, with further changes possible as a result of the EU context.

> A lot of where we are, or might be moving to, is being driven by third package and European network codes… Five or six years ago the drivers would have been more towards the locational with a stronger commitment towards markets leading decision making in networks… [However, subsequently] the UK probably was moving more towards the weak locational signal, if you look at what Transmit was doing and what

they discussed, it was generally around trying to dilute the locational signal. Europe's not pro-locational signals, but things like capacity allocation and congestion management network code, market coupling, the target model, all this kind of stuff, subtly points towards the importance of locational signals. I find that this axis is confused in terms of where we end up moving to.

5.1.3 The recent background – BETTA, the GB queue, TIRG, Connect and manage

The diagram also raised some discussion around the broader context and background behind the current mix of policies it depicts, and the balance between them. A key issue here was the transition from NETA to BETTA in 2005, one of the results of which was a large queue of generation projects with applications to connect in Scotland.

> Prior to BETTA, the boundary capacity between Scotland and England was regulated, and agreed as part of… the British Grid System Agreement (BGSA) … The capacity on the interconnectors was handed out between the two Scottish companies and EDF… As part of the BETTA decision in 2004, they said if you apply for connection prior to BETTA go live, you won't secure the wider works associated with connection to achieve compliance between Scotland and England. So everyone who was thinking about building a wind farm in Scotland put it in an application – resulting in a large queue. Because securities are a very material cost.

The result was a large queue of projects, totalling about 9 GW. The Transmission Investment for Renewable Generation (TIRG) scheme provided for uprating, reconductoring and substation rebuilds, and in 2012 following ENSG the work, the TOs received agreement for series compensation and the Western Link. By 2016 it is anticipated that the England-Scotland boundary will be close to compliant.

> Connect and manage was brought in [in 2010] to relieve the pressure in the queue… if you've got a whole load of projects waiting in Scotland, they've all got dates. But with connect and manage you can offer all of them the earliest date, socialise that risk. You've got potential for congestion – but what actually happens is some projects go away, some connect a bit earlier, some a bit later. For every MW of connect and manage you offer, you typically only get 0.2 MW actually connecting, and you generally are maintaining either your level of compliance or non compliance. What it's really doing is giving you a way to manage the future queue of connections in a way that socialises risk. What it also does, is it doesn't provide a short term locational signal once they're connected because we don't have locational BSUOS. But doing locational BSUOS with an intrinsic net non-compliance on the Scottish boundary would have effectively undone that policy decision from 2005, which would have been politically very difficult.

It was estimated that the non-compliance resulting from the pre-BETTA decision caused "an underlying level of congestion of somewhere between £100-200m per year", with connect and manage adding "about £30m per year on top of the non-compliance costs". Connect-and-manage was described as accepting and socialising the risk of having constraints, in order to manage the risk of having to make transmission investments in advance against a queue of uncertain projects.

> So you actually only invest at a time when you're much more certain about what's really going to connect. And instead of queuing up likely projects behind unlikely projects, you allow stuff to come forward when it's ready, and improve clarity about what will connect and bring forward the drivers for investment… One of the outcomes is that that risk is socialised so you don't get locational signals – but you've got to put it in that policy context, back from 2005.

Thus previous policy decisions, in this case relating to the decision to join up the markets of two previously separate systems connected by limited and regulated interconnector capacities, create important context to the mix of policy frameworks at work in the present system.

5.2 Locational signals

5.2.1 The principle of locational transmission network charging

The principle of locational signals is to expose generators to at least some of the network costs of their activities, to enable an efficient choice to be made which balances the benefits they experience in marginal generation cost advantage of different locations, against the cost that generation in that location may impose upon the network. The majority of interviewees were broadly in support of this principle. Referring to Project Transmit and its consideration of alternative charging models including the 'postage stamp' socialised transmission charging model, one interviewee commented:

> We thought that the right answer was cost-reflective charging because that will deliver benefits, ultimately, to consumers.

The importance of achieving energy policy goals in the most economically efficient way possible was an important priority for many, and using market signals was generally argued to be a more effective way of delivering this objective than a command-control approach.

> Correct network pricing can bring efficiency to the overall goal that you have in mind, so if the goal is a certain amount of renewables by 2020, you want to do that in the most efficient way possible, and if you have postage stamp approach to transmission, what behaviour does that engender? … It's important to know what's the efficient thing to do and to incentivise that appropriately. Otherwise government becomes the central purchaser for everything… are they best placed to know that? … I'd be certain there's a lot more intelligence in the market as to what the most efficient thing

to do is, and having efficient transmission signals can help bring out that market intelligence.

Economic efficiency was also argued to be a critical criterion for the long-term sustainability of any strategy in view of public and political acceptance.

> You don't want to see five years go by and the rules change again… Stable and enduring solutions are needed, and the only way to get an enduring solution is to get the fair and balanced solution that meets the needs of consumers.

In discussions the proposition was made to interviewees that the requirements of carbon budgets and renewable energy targets created a different context – that given the tendency of the best renewable resources to be located in northern areas distant from southern load centres, locational pricing works against a higher order government policy objective. For those in favour of locational pricing, the responses to this proposition most frequently drew on the principle of not mixing up different objectives between policy mechanisms.

> We don't see transmission charging as a lever to deliver other policies. If as a result of cost-reflective transmission charging you have to pull another lever to deliver on policies, then so be it. They have the appropriate lever, in this case the strike price given for low carbon technologies.

> You should keep your objectives separate – if you want to subsidise technologies you should keep that separate from distorting the way that networks develop.

> If you start tampering with network charges and reducing social welfare and increasing consumer costs through different network charging, that's effectively an additional subsidy for renewables on top of the structural measures they're also getting…. The best way to do this is to understand the trade off on wind speed… and… network costs, and for people to pick their own balance between the two… To do anything else would reduce transparency around the total cost of subsidy.

However, others argued that key elements of energy policy – notably low carbon and renewables targets – as well as the methods chosen to deliver these – contracts for difference and capacity mechanisms – were making locational transmission charging less valid.

> It's highly questionable the way things are going at the moment that it's still relevant. When you look at the degree of state involvement in decision making with CfDs, flexibility and system services contracts, and the capacity mechanism, we're moving towards a three layer market of energy, capacity and flexibility and services… It seems counterintuitive to be introducing pricing signals when it's no longer simply a case of energy production from the best generating technology located in the best place. With low carbon there are other drivers for location which are far more important, and less flexible about location than would have been the case in a purely CCGT world. Where you've got the wind regime saying we are going to invest in the north of Scotland, it's pointless having a transmission charging regime which says you

> shouldn't build it there, you should build it in the centre of London. Equally with offshore, the transmission charging arrangements should reflect the fact that that's where it's going to be, not imposing a counter-intuitive pricing signal on it.

It was also argued that the costs of transmission were small compared to generation investment costs, which should affect the view of where to find savings.

> If you try and optimise things for transmission, you might find a 10% saving in transmission, but that's within a cost element which is only 5-10% of what it would be in generation. You'd only need a couple of percent increase in generation cost to outweigh the benefit of the transmission saving… For example accessing higher load factor renewables offers a much greater cost reduction in the overall provision, than the optimisation of the transmission network alone would necessarily reflect.

5.2.2 On TNUoS and the current arrangements

In the current arrangements the TNUoS charge is levied on the right of generators to access the transmission network on the basis of their declared Transmission Entry Capacity (TEC), and a calculation of the impact of an additional MW at that location on the overall system power flow at system peak. Thus TNUoS has a locational element. It is recalculated annually, and thus can in theory change each year if there are changes in the relative location of supply and demand on the system. The BSUoS charge is levied on actual energy generated and recoups the costs of balancing services including congestion management. Its per unit energy charge does not vary between location, thus the locational element of congestion is socialised.

Discussions took place around the current arrangements. A point of discussion around the TNUoS charge was the relative advantage of a capacity based charge which is stable compared to one which is variable; additionally there were slightly different perceptions around whether TNUoS is broadly speaking stable or variable.

One area of discussion was the differentiation between short and long term signals, "whether you are influencing dispatch or investment decisions – which is an important aspect of what you look for in a locational signal."

To influence investment signals, an important feature would be long term stability, which some interviewees felt the TNUoS charge achieved well.

> If you have a stable enduring TNUoS charge, that gives a fairly long term signal that affects where you locate your plant. You have reasonable visibility of what the charges will be over the lifetime of the plant… To reverse transmission flows from being predominantly north to south would be a very long term process, involving a very large amount of generation locating in the south. So it's sending in that sense an appropriate large scale signal that where you have the choice you should put your plant in the south.

Other network signals created by shorter-term dynamics and fluctuations, it was argued, should not be locationally targeted, as is the case in the current system with the BSUoS charge.

> Other charges that are more constraint related and prone to shorter term investments that alleviate or create constraints, are not sending that signal – it's a signal you can't respond to. That's an important dimension – is the locational signal part of an enduring regime and relatively predictable over the life of the plant, as opposed to something short term and which generators had no way of predicting in their investment decisions? TNUoS is relatively predictable. With BSUoS you socialise the costs because they're unpredictable and not useful as a locational investment signal… You dispatch yourself on your own short run marginal costs, and transmission system investment is driven by constraint costs. So everyone is getting their correct revenue for the efficiency of their plant, and what is being generated is a constraint cost which is socialised among generators and provides a signal to grid to invest to bring down the constraint. The constraint cost provides the justification for grid investment.

In other discussions however, both the rationale for having long-term stability in locational network charging, and the proposition that the TNUoS charge even as currently designed was inherently stable, were challenged.

> TNUoS is thinking about two things. It's thinking about the long run marginal cost of the asset you're building, and it's thinking about how far on average the power is travelling, how much network it's using. The centre of gravity of the system has been moving south at about 10 miles per year over the last 10-15 years. Gradually the distance travelled is going up, and the LRMC is gradually going up as well. But if you get a significant change in the generators connected to the system, that can affect it as well. So you're not getting a sunk cost, a flat charge – you're getting what is meant to be a marginal signal for the cost of the next MW. So it does move around.

Given this potential for variability, alternative models which fixed the transmission charge based on the parameters of the original investment, were discussed, which would have the benefit of providing investors with greater certainty.

> One of which would be to sink all the existing costs and charge that out based on the original investment parameters – where was the centre of gravity on the system when you started building that, what did you expect it to deliver; and then you get the question of do you charge that only to existing generators or to new connectees also? If you charge sunk to existing and marginal to new you get differential locational signals for different parties.

However,

> In terms of the most efficient outcome it's much more efficient to charge everyone the marginal. You don't want to have incredibly expensive connection rates for new connectees, and yet have an old generator sitting there with no incentive to close because its being charged sunk costs, which over fifty years would disappear to almost zero. What you want is that generator to be exposed to the marginal costs and close,

> while a similarly old generator [in a less network constrained location] can stay open instead. Then new generation can connect using the existing network at a much lower overall cost. That captures the most social welfare.

However, it was acknowledged that varying charges levied on sunk investments were "tough for those that are exposed to it." Alternative compromise models were to find means of reflecting the long term trend in long run marginal costs, whilst dampening the exposure to variability:

> For example could you do what business rates used to do slug, dampen change, over seven years. Not do an annual LRMC, but smooth it over seven years, or only start to change it once it's been sustained for a number of years in a row, rather than moving it up and down all the time… But that is a big regulatory policy decision whether to expose people equally to marginal costs and deliver the best lowest network costs, or slug or smooth or socialise those costs and provide greater certainty which you hope will reduce barriers to entry and therefore drive greater investment and social welfare than minimising network costs.

> The test for creating a new overhead line should be very high, so you should always assess the drivers for that at marginal cost. However, those are very long term decisions so I also think it's very fair that in areas of the network that are very mixed you should be looking to slug the year on year variation to reflect longer term trends. Having a charge that bounces up and down every year feels less appropriate than having one that is averaged over seven years, or is based on the last five years and on an industry agreed scenario for the next five years, or something else.

The potential for changes in the power flow on the system were increasing. The current system sees relatively stable overall power flows and therefore TNUoS charges, largely due to the similar locations of coal and gas plant, which reduces the power flow impact of any switch between them, and the reasonable spread of nuclear plants around the country. However,

> The potential within the framework is there for large variation. For example if we see big swings in solar PV, if we get 10 GW PV south of Birmingham, that will have tremendous impact on flows day to day, so the commodity within the network charge will change significantly. It won't affect the peak charge because it's a darkness peak. But all these things have an effect.

5.2.3 Future developments

5.2.3.1 The effect of EU policy on locational signals in GB

Several interviewees emphasised the importance of EU energy policy, in particular the Third Energy Package and the 'Target Model' for electricity markets (Ofgem, 2012c), on the issues being discussed. In several discussions the potential for this to drive stronger locational signals within GB were highlighted. A key concept here was ‘market splitting’, which refers to an existing market with a single price being split into different zones, which are allowed to have different prices from each other. The difference between prices in the different zones would reflect the balance of supply and demand within each zone, and would also be affected by the amount of transmission connection capacity between each zone – high levels of interconnection would tend to facilitate inter-zonal trade and thus reduce price differences between zones. The related concept of ‘market coupling’ refers to two or more existing markets being joined up to become different price zones within a single market.

> If you take the Nordic market as being the blueprint for the target model, they have market splitting, they have much stronger signals for operation of the market in the short term, and potentially for transmission signals in the longer term…. Actually for us the potential is that market splitting could bring forward much stronger locational signals which could be used for investment not just in the shorter term.

> The European network codes may change some of what is done here. It could be in terms of locational charging. An extreme example is that one of the codes contemplates market splitting as well as market coupling… As more interconnection is built, that will affect charges, and market splitting also could affect charges and other costs.

> As part of the third package, [market splitting is] one of the options, under the codes. If you build the assumption that people are going to run to network capability into your model, suddenly you don’t need to build so much network… It places the short run costs of congestion onto generators, and further hedges transmission investment – so you’d only be building [transmission network] once you could prove a long term systemic problem.

If market splitting were implemented, interviewees considered that it could create two or possibly three separate zones within the GB system. A clear potential boundary would be between Scotland and England, with some suggesting another could emerge separating the south-east corner of England, which would become part of a zone with northern France.

But other comments highlighted EU developments that could work against a locational signal.

> The worry from our point of view is that there are a number of tools and regulations that will be binding on us, including tariff structures and the level of generation charges you are entitled to impose. Ultimately if Europe decides that generation charges should be capped, that may impact upon on GB charging and affect how strong the locational signal can be.

5.2.3.2 Locational Marginal Pricing (LMP)

Going further than the zonal prices which would occur as a result of market splitting would be to allow prices to vary at each transmission node, or locational marginal pricing (LMP). The majority of interviewees did not raise this spontaneously, though one discussed possible reasons for a reluctance to pursue this option in GB.

> I haven't come across a reason why we couldn't do it [LMP], but the main reason I've come across as to why there's nervousness around it is how much it would cost and how disruptive it is to set up a new market. If you look at the transition from the pool to NETA you get some idea. Everybody needs to reform their trading systems, you'd need to go back to the pool. LMP is complex compared to NETA. You'd need to be sure that it is going to drive efficiencies, I don't think anyone's bold enough to say that. It's not going to be driven by the efficient transmission argument – it's difficult to use LMP on its own to get all of the signals you need to drive investment, it doesn't happen automatically.

While EU codes were broadly considered to have potential to bring about market splitting, it was less clear that they could be interpreted as calling for LMP.

> You've got to think about how compatible it is with Europe – the main priority is to ensure we are not going to infringe what comes out of Europe. This is not really pushing towards LMP.

The possibility of market splitting and zonal splitting leading towards LMP was ambiguous.

> In US regions, several have begun with zonal pricing, the zones got smaller until they gradually worked towards LMP, although this didn't happen in Norway. With most transitions you have zones gradually moving to LMP. But Europe's not there yet. The pressure to comply with European legislation would mean market splitting at most, at the moment.

5.2.3.3 Wind variability and locational BSUoS

The variable output of renewables will be a key factor in future system regulation. It was a major subject of the discussions in Project Transmit, which proposed a charge which differentiated annual from peak contribution, allowing renewables to pay the charge at a level which more closely reflected their actual use of the network. There was in general broad support for this conclusion of Transmit.

> If you have a lot of wind running, you may well not have the fossil plant running at the same time. Transmission owners understand this and will invest accordingly. To charge renewables and fossil the same amount, double what they should be paying, is therefore clearly wrong. So we support the work done under Transmit.

Though Transmit proposes to acknowledge the lower peak network utilisation of renewables, it does so still on a standing capacity basis and does not respond to real-time network conditions.

> There is medium term debate about whether to have locational BSUoS. One of the challenges is that there is a cost to operating the network without much thermal in

> Scotland, because the wind isn't always blowing. The real tough limit on Scotland is importing power into Scotland- it's difficult to get power all the way up to the North of Scotland, because there's a whole lot of network and if you haven't got anything connected to it the volts just rise up and up… There are older thermal stations up here, which, in an ideal world [would run] off-peak, off the wind, when the wind's not blowing.

This would allow the network to be sized "to take the wind *or* the thermal plant", if appropriate incentives could be found to encourage flexible plants to limit their utilisation of the network to low-wind and therefore less congested times.

A key challenge of greater penetrations of variable renewables is that

> … things will start to move more in the short term. We already see significant variation GB-continent based on renewable output on the continent, and significant variation between Scotland and England, based on renewable output in Scotland, so there will be benefits in having a charging regime which reflects that, in the mid-term. But again, as with TNUoS, you have to think hard about the trade off between long-term certainty vs. short term marginal signals.

Locational BSUoS was seen as "potentially a very useful tool with greater penetration of renewable generation, variable generation and interconnectors as well." However, one interviewee felt that if real-time locational signals do develop "it'll probably happen through market splitting."

5.3 Co-ordination, anticipatory planning

There was wide support for some kind of strategic approach to network planning, though differences in views of the degree to which this should extend. During discussion two interpretations of "strategic" emerged, which had overlapping elements but also slightly separate emphases. The first interpretation encompassed anticipatory investment – building transmission network in advance of the commissioning of generation assets, in the expectation that these generation assets will be built at some point in the future. The second was concerned with the coordination between different transmission regimes, notably onshore, offshore and interconnectors.

There was a common understanding of the main driver behind strategic network planning, which was the significant system changes required by the decarbonisation transition.

> There's a pending step change in the energy system… a paradigm shift that's moving towards a future where the tradition of generation follows demand no longer works… If you were going to prepare the networks of the future now, you probably wouldn't start with what we've got. This says to me there needs to be a step change… if you want to make a paradigm shift, someone has to be visionary, companies have to make a step change.

For some there was a clear justification for anticipatory investment, based on the rapid deployment trajectory implied by decarbonisation on the generation side, and the fact that much of generation has shorter lead times than transmission, such if that if transmission is not anticipatory, the result will be delays and / or constraint costs.

> Unfortunately the development times for transmission are longer than for the generation it's connecting up. In some ways this suggests that a central planning route is the way to go –you have to think ahead about what you are trying to create in terms of a generation portfolio, to feed that in early enough to have everything coming in at the right time… At the moment we are suffering not from over-investment in generation but underinvestment in transmission. We're recognising the longer lead times for network infrastructure. That can only be addressed with a much clearer idea of where we're going, so that the network can be put in place in time. Otherwise you'll be in a world of catch up – there's an awful lot of generation going to be built, and if all the transmission is coming after that, then the constraints issues are going to be significant.

This view tended to be supported by the argument that the location of much of the generation could be established with high certainty.

> Regardless of whether its renewables, unabated gas, abated gas – it's almost an ideal situation for putting together a scenario to allow transmission planners to draw lines on the map.

Linked to this was a perception amongst several interviewees that the EMR programme is highly interventionist and amounts to a commissioning programme of set quantities of particular generation types. Some suggested that the government had a clear view on how much of different generation types it wanted to commission, which it was expressing through EMR and the strike prices, and that as a result having a blueprint and making it public so that network companies could plan accordingly, was merely a matter of making explicit something which was already decided *de facto* and was implicit in existing policies.

> At the moment we have this pretence that we have a free generation market, but it's hard to see what generation investments are going to be made without some form of contractual relationship – new build gas will be done that way, CCS, nuclear, renewables. Actually we should say at least we know what we're going to do in generation and feed that into the transmission process. Otherwise we'll slow the process down because we won't know what generation to build because we're not feeding that information in early enough or in a detailed enough way.
>
> [Predicting future generation mixes is something] the government is doing a large amount of, through the EMR. From the fact that the strike prices vary for different technologies, there is an intention to acquire different quantities of each, and that has to be a key input.

As a result,

They [the TOs] should be able to say, this is what we are going to design the system on, and here are the implications for transmission. The generators can all see that and make decisions appropriately… You could match the transmission plan to the levy control framework, this gives much greater clarity to the market about what the transmission element of all the variables looks like. So you set down the plan on transmission, and invite generators to apply and put money down on that basis, and say that Ofgem will allow the companies to get on and build this network.

Others however laid greater emphasis on the uncertainties which could prevail around the precise generation mix, despite the effect of EMR, and stressed that the government did not want to take such a command control approach.

I've heard the… view [that EMR is] basically a massive procurement exercise to get nuclear and certain other technologies done. However that's not quite right, as they are hoping ultimately to move to an auctioning process which would be more technology agnostic. The hypothesis that you could make significant savings on transmission by having the certainty of what was going to deploy, I think is right, as long as the right incentives were on TOs to deliver it efficiently. But it doesn't feel to me like there is appetite for that kind of command and control, centrally dictated energy mix – even though you could definitely argue that the EMR looks quite a lot like that in its first incarnation.

We don't know for sure the government's direction of travel post 2020 – if there's no subsequent renewables target for 2030, the rate could slow. On the other hand, if you did change the regime, you might make it more cost effective to deploy offshore wind, so the rate could increase… if you built and socialised the costs of building transmission to renewable rich areas, then it's more likely generation would get built there, because the connection costs would be low. However, [it's not right to take] those risks on behalf of consumers. Which is how you end up with connect and manage.

A number of interviewees saw the benefits of an anticipatory approach in principle, but also identified risks, and thus argued for a more cautious approach to it.

The benefit of anticipatory investment is that it can be more efficient, by linking schemes up and getting one suitably sized pipe rather than a series of incremental upgrades, but it will lead potentially to stranded assets, and that's where the cost reflective pricing breaks down – if you have assets that are not what are needed, it's impossible to charge for them appropriately, and that's the socialised cost which dilutes the locational signals. You're looking for it to be done, but done very well – which is not straightforward. Which is why most investment has tended to be responsive – it's a safer way to proceed. You'd be really looking for some strong evidence that it's justified.

Getting the right transmission investment is difficult. There's a trade off between under-investing and holding back generation projects, and over-investing and having stranded assets. There's a number of actors in that piece. Some of the recent developments have been helpful, other aspects remain which make it difficult for generators to make investments. It is complex, there are a lot of actors and large sums

> of money involved. Most of their interests ultimately are aligned, but they all have their own slightly different interests.
>
> A lot of commentators… have this view that transmission networks should be like motorways, and you should build to the islands, and once the connection's there, everyone will turn up… We don't take that view…

Some interviewees also qualified the argument that anticipatory network investment was required to avoid constraints in a fast decarbonising generation mix, where the lead times of the generators were shorter than those of the transmission companies, observing that there are different lead times associated with different technologies.

> It also depends on who's connecting. The nukes are easy because it takes them longer to connect than it takes… to build overhead lines… Likewise, offshore wind tends to be a 5-7 year timeframe. There are lots of them and it's not clear how many of them will go ahead, so there's a sizing uncertainty, but you can certainly build out in roughly the timescale that they're going to be doing it. The real challenges … are CCGTs – because you can go from final investment decision to operation in under two years, or more typically 2.5 -3. And onshore wind which can go from final investment decision to operation in less than 18 months, and you've got thousands of parties in Scotland. So things can move very quickly, and that's the bit that's hard for network companies.
>
> One of the advantages of nuclear is that it is relatively well-matched with transmission in terms of timescales and location. Some of the examples in Scotland where renewables can come on relatively quickly, some of those projects are not always aligned with transmission timescales, which means the generation projects can be held back. Nuclear is also a very concentrated energy source which again fits well with the transmission system.

Interviewees also discussed various hedging measures in which sufficient anticipatory network investment could take place, without the need to attempt to undertake full predictions of the entire future generation mix. The balance to be struck was between spending as late as possible to maximise certainty about the generation side, and spending early enough to avoiding delay and meet generators' connection dates. Where there are single parties with large generation projects, it's easier to offset the risk of transmission investment by holding securities, however

> Where you've got multiple parties its much harder and you need to try and take some judgement, but on the other hand that diversity also brings diversity of risk. [It's possible to] look at a range of scenarios for potential future networks and connections, and look at the least regret investment options driven by those scenarios… That gives… a strategic enough driver to invest or not invest.

It is also possible to undertake "low cost interim options",

> which might cost a little bit more per unit for a couple of years, but may avoid a significant commitment being made earlier than is absolutely necessary. And that's

really important because… if you're prepared to take congestion costs, or put in a temporary way of running the network for a few years, then that gives time for the real network need to become much clearer.

Again, connect-and-manage was seen as an important tool to hedge uncertainty around specific generation projects and get clearer view of the genuine network need.

The great thing about connect and manage is you don't have to build all of the network in advance, you can build the network on a slight lagging curve to the generation build out. And that again further de-risks your investment. Taking £20-30m congestion risk for 2-3 years whilst you build your £1bn undersea link, doesn't seem like a bad trade off, given that link's going to be there for 25 years… If you think about trying to make a decision 5 or 6 years out, when no one's had to put any money in, compared to trying to make a decision 2 or 3 years out when people are close to final investment, you've already seen others come through – it's a much clearer position to be in… So it's a really useful tool in the long term wherever you've got significant growth, significant uncertainty.

Also, it was emphasised that the cost commitment on a new transmission line is "a curve over time". On a new overhead line,

… your cost commitment builds up gradually from four to five years out through to total cost committed probably 2 years out. There's not one decision to build an overhead line, it's a gradually accumulating cost commitment.

Thus, network owners can

… bring forward the low cost element of the start of the projects as early as possible to understand the implications. The planning element is often the biggest challenge. As much of that as can be brought forward is useful.

Put together, the combination of these various hedging strategies adds up to "an effective way of managing exposure".

As well as the question of anticipatory network investment, a slightly different emphasis on the idea of strategic network planning was discussed by a number of interviewees, which was the possible requirement for coordination between the various actors and regimes involved in the system.

You need to create a structure which will encourage the economies of scale which can be achieved by creating a network. This requires a different type of thought process, rather than sending one signal to one generator in isolation.

A key issue was coordination between onshore, offshore networks and interconnections.

> At the moment, they're different programmes. There's a different regime for offshore, onshore and cross-border. There's an absence of mechanisms that would allow more anticipatory work to be done offshore and cross-border. They're all things that should be considered part of an overall mix rather than pursued individually. Interconnection is competing, loosely, with flexible generation, demand side response and storage. There probably shouldn't be a separate programme for interconnection. It comes back to locational signals and allowing the market to come forward. If you build a lot of interconnection you're destroying the business case for storage and demand side response. The same for the generation mixes onshore and offshore, if you prioritise one over the other that means that government and policy is taking the decision as to what you want. You shouldn't be pursuing those things separately – how do you stop doing this? A greater commitment to locational signals and market derived decision making. That doesn't have to mean just letting the market get on with it. It can look more like a Norwegian example where the market gives you the transparency of what needs to happen and then you have an overlay of decision makers that come in. They're pointing to what the prices say, it allows the market to respond to a certain extent but then you have a bit more justification for what you're doing in the anticipatory and strategic world because it allows you to make trade-offs against different places, particularly in transmission network.

Some interviewees emphasised the potential savings that could be made through multi-purpose projects which combine the connection of offshore zones with the creation of additional power flow corridors for the GB system as a whole.

> [There are] options to oversize some of the offshore networks and to couple up some of the offshore networks

Some emphasised that despite these benefits there could be practical problems with achieving them due to the numerous actors involved with different projects and priorities.

> If there is a sharing case to be made… the TOs have to give a quotation based on the share, but you can't force conjoined application and financial decision on the individual power plants. Instead of a simple point to point link which might take a year you could be waiting three or four years for a wider network upgrade, because that's all you can get a quote for due to the other projects that are hovering around. Or it could work the other way, in that because there is a coordinated network approach you get a lower cost connection. But unlocking the key to getting those joint decisions is quite hard.

Interconnection was seen as significant area in which a greater strategic view would be needed.

> Europe have a view on interconnection, GB has historically had a view; the two are not aligned. Government has put out its policy view on interconnection which gives benefits of anywhere between 9 and -9 GW. Is there any leadership in this space? It wouldn't matter if it wasn't material, but it is. It is an important part of this jigsaw. A lot of people just see us in isolation, but I think this is quite a big piece.

> Interconnection is a nice example where you are not clear at all where it lies along the anticipatory-responsive axis, Eleclink being an example of a merchant led, responsive project, Nemo as an example of a more strategic, regulatory project. There is no clear policy which says we prefer this or that kind of model.
>
> The interesting thing is whenever anyone talks about network planning they talk about new connections… In the longer term you have to look more broadly around trends: demand, active and reactive power, generation closures, interconnection – all come strongly into play.

The discussions around the potential future benefits of increased coordination between regimes, and the challenges to achieving this within the current system, led to discussions around the possible need for institutional change in order to address the issues which will come into play. Several of the interviewees contemplated that the creation of a body with oversight of all three transmission regimes, the ability to join them up and to set the direction of travel, could be beneficial.

> You could argue for that. In some ways National Grid is moving in that way. Because of its commercial interests it's not yet able to join up all the thinking that would be necessary. You would probably get National Grid to divest itself of its commercial interests and then do that. It's already doing the capacity work, the low carbon work, the system planning. Where it gets into a problem is the TO part.

As in the above quote, the possibility of system change was mostly explored in terms of evolving the available existing actors and institutions, rather than root-and-branch reform. The issue of resolving conflicts of interest, if this kind of change was to be achieved, was mentioned by several interviewees.

> The SO also has some conflict of interest – if the SO is incentivised to achieve certain things, it may make a decision which improves its incentive payments, but is not the right decision for the system as a whole. But these are incentives that have been created by regulatory tools, so could be taken away.
>
> We have certainly supported the idea of National Grid taking a greater role. Whether that goes as far as a design authority depends what you mean by that. But in terms of planning, particularly with things like the offshore investments, the interplay with interconnectors, the interplay with the Scottish TOs – National Grid as system operator have a very light touch role, but ultimately will get landed with the system that they've got to operate. It seems odd to us that when you're responsible for operating the system you don't have a greater say in how it's planned… The challenge in solving this problem is that the SO is not entirely independent… as SO they are incentivised to operate the system efficiently. You need someone to balance the investment cost decisions against the system operational cost decisions. All these things are manageable through correct incentives – but it's not straightforward… our view is there could be a stronger co-ordinating role that will help get further down that route, though it clearly won't be perfect.

Other interviewees were wary of the perils of institutional reform.

> I would be wary of saying… that there's a silver bullet of a central design authority or that we need to DECC to step up and do something. I don't think as a nation we can deal with that, that's not the way we've done things historically – I think there are examples where working collaboratively can also achieve something in a relatively short time line. Whereas doing institutional reform to get a central design authority or an independent system operator would take a decade.

Some picked up on the theme of the requirement for coordination between the various actors and regimes, but explored the possibility of achieving this through improving collaboration and cooperation between them, rather than establishing a body with the power to enforce collaboration between the other players.

> You want to make sure that you have the right frameworks, mechanisms in place, and the right stakeholders engaged, to get a balance…. You're never going to get the right answer if you're completely responsive to just the next generator coming online. Equally, if you have a blueprint it's almost certain to be wrong. What you need is some mix in the middle… It needs some kind of central collaboration of the key players, who are enabled and incentivised to participate, and enabled and incentivised to actually do something about it as well. And maybe one of the challenges that we have at the moment… is that actually the right players don't have the right level of responsibility… no combination of these parties now has a legal mandate to care about what happens in terms of cross border infrastructure. It doesn't have to be a central system planner, but… if everyone had just a little more responsibility then maybe something could happen.

The ENSG process was cited as an example of this.

> There's no doubt about the effectiveness of ENSG in releasing forward looking transmission investment of the scale and size required for this step change. £4.5bn was identified in this needs case that was developed collaboratively. No one single party is responsible, which maybe isn't a brilliant thing, but actually to make a step forward, maybe no one single party was responsible, but everyone was responsible, and something actually happened. Where we are at the moment, for coordinated infrastructure that goes beyond our shoreline, nobody's responsible for that, and why does nothing happen, why are we stuck in this reactive world? Because there isn't that formula where everyone leans on each other. It helps you to get a bit more of that happy case in the middle. If you look at what has come out of ENSG, Western Link is now under construction. There's been a lot of rigorous assessment trying to drive out efficiencies in procurement and design, there has been a lot of regulatory scrutiny. It hasn't just progressed blindly, at every stage there has been scrutiny.

However, the lack of formal clarification of the role and remit of the ENSG in relation to government policy, left others with a sense of confusion and lack of clarity around the precise location of responsibility for establishing a needs case for the transmission network.

> There's obviously the ENSG work which is being continually refreshed, and to some extent that gives you a strategic plan for large scale investment. One of the challenges

> though is that at the same time you've got government policy, in terms of what investments in generation it wants, and that does have a big impact in terms of what transmission investments you might therefore need. The ENSG gives you something to look at and to a certain extent some certainty, but you've got all these things going on on the side, which may mean we don't need some particular investment after all. So the network companies are left in the middle, trying to develop these projects, and Ofgem is there signing off the needs case. Ofgem is not responsible for government policy, but they've got to make sure the investment is signed off in a timely way, so they put pressure on the network companies to say whether it's justified. The network companies can say that they have certain connection requests, but actually it depends on what the strike prices might be. So the ENSG work is helpful, but there's still quite a lot of uncertainty around it, and our impression is that Ofgem are finding it difficult to sign off some of the needs case, which delays things.

5.4 Conclusions

Interviews with key system actors based around the key policy value dimensions identified in Chapter 4, have helped to situate the current transmission policy options within a context of broader values and paradigms concerning energy system governance. The interviews also allowed the experts to bring up important insights and concerns about issues that had been less strongly identified – including the importance of the transition from NETA to BETTA in 2005, and the potentially growing future importance of coordination between onshore, offshore and interconnection regimes.

The interviews revealed some differences in perceptions, as well as some areas of higher agreement. The increased level of state involvement in the electricity system in view of carbon and security objectives was noted by several interviewees who perceived the EMR programme as representing an increasingly interventionist stance of the government. For some this perceived interventionist approach on the generation side was considered to undermine and render irrelevant the aims to use market-based locational signals for transmission network use. Others however viewed the areas as separate, with locational signals providing the means by which government targets could be met efficiently.

A majority of interviewees expressed broad general support for the principle of locational signals, and some were broadly supportive of the current approach where locational signals are provided on a fixed capacity basis through TNUoS, whereas variable constraint costs are socialised through BSUoS. Several interviewees were of the view that any increase in the strength of locational signals would be most likely to come as a result of EU network codes promoting market splitting. There was some discussion of the change in network power flows, including intra-annual variability caused by increasing renewable capacities, and the prospects for the annually fixed TNUoS charge in this context. The possibility of a locational BSUoS charge to reflect greater short-term variability was discussed. However, there was no strong advocacy for a more root and branch reform towards an LMP model, with one comment perceiving the political risk greater than the certainty of the benefits.

There was wide support for some kind of more strategic, anticipatory or coordinated approach to transmission network planning, though to different extents. Some emphasised the possibility of having a very clear idea of the required generation mix implied by the government's renewable and low-carbon targets, and CfD strike prices, and of building out the transmission network on the expectation of this mix. Others emphasised the remaining room for variability in the precise mix which could meet the government's targets, and the resulting risk of stranded assets. Most acknowledged the need for some level of anticipatory build out, particularly in view of the multiple and modular nature of renewables projects, but conceived of more graduated approach using hedging mechanisms such as least regret analysis, accepting moderate constraint costs through connect and manage, and bringing forward early low cost work on transmission upgrades whilst keeping the whole project under review.

A key unresolved issue mentioned by several interviewees was the coordination between onshore, offshore and interconnection regimes. Several cited potential benefits from coordination of these regimes, as well as risks from lack of coordination.

Institutionally, several contemplated the creation of an independent agency with a mandate to undertake these coordination issues, usually suggesting that this could be achieved by the complete separation of the SO part of National Grid, and some clarification of its incentives. Others favoured preserving the existing structure, due to the transitional costs of significant institutional change, but of finding ways to encourage and facilitate coordinated thinking. The ENSG approach was cited as an example of how this can be achieved, however there were also concerns about the lack of formal remit for ENSG and its status in relation to government targets. However, similarly to the locational issue, there was no strong advocate for a radical institutional reorganisation of the system.

6 The technological configuration – modelling the system

Chapters 3, 4 and 5 used historical analysis, policy analysis and key actor interviews to explore the actors, institutions, policy frameworks and value-sets which contribute to the system under study, and are critical to considering its evolution forward in time. Equally critical for the representation of the system under study in this thesis, is a representation of the physical technologies and infrastructures associated with the system. This chapter summarises the process of data collection and model development undertaken in order to achieve a coherent but sufficiently detailed representation of the technological layer of the system under study.

6.1 The system under study – the GB transmission network

The GB transmission network is defined as the circuits operating at 400 kV and 275 kV, with the addition of the 132 kV circuits in Scotland. Figure 22 illustrates the configuration of the transmission network on a map of Great Britain.

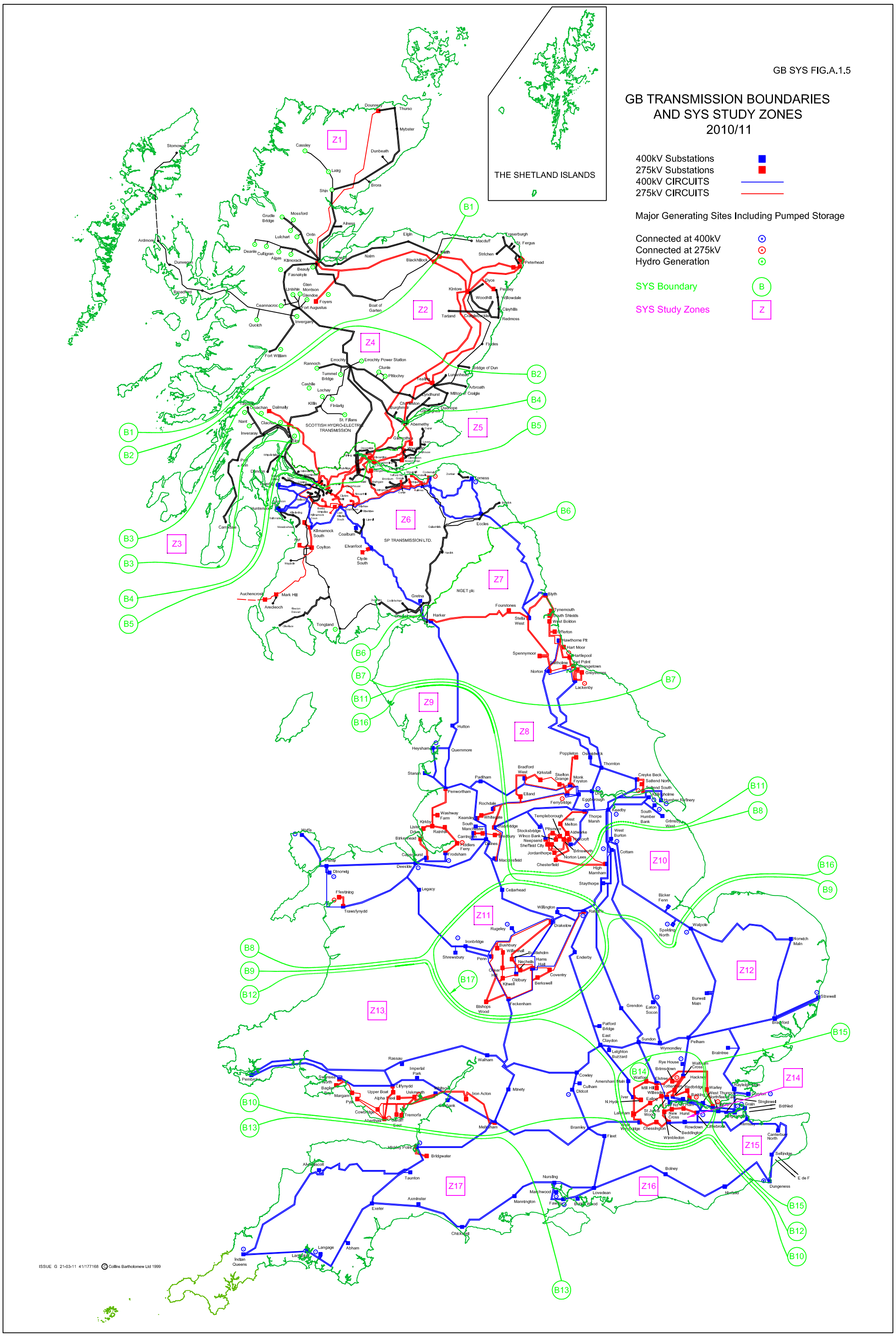


Figure 22: *GB electricity transmission network ((National Grid, 2011b)*

Simulation of power flows across this network could be achieved at different levels of granularity. Barnacle et al (2013) make full use of available GB network data from National Grid (National Grid, 2011b) to produce a model which specifies the network in full detail, with 813 buses and 1204 lines. Gerber et al (2012) by contrast represent the GB network in a greatly simplified load flow model consisting of 16 busbars connected by 15 branches. This allows a consideration of power transfer over the key regional boundaries, but aggregates over the detail of power flow through more specific sections and corridors of the network.

In the current project a level of spatial disaggregation somewhere in between these two studies was sought. The model had to be sufficiently simple to make the production of a large number of runs emanating from multiple scenarios and multiple system conditions, a relatively tractable prospect. On the other hand, it required sufficient granularity to show the effect of particular system upgrades on particular network corridors, and to have the flexibility to represent differently evolving system architectures. A heuristic process was undertaken to establish the appropriate level of detail, beginning with a comparatively simple 17 zone representation of the GB network, and gradually adding greater network detail and spatial resolution, undertaking analyses of 'strawman' scenarios at each stage to test the performance of the model in relation to the requirements of the project. This heuristic process and the associated strawman scenario outputs are reported in Appendix D. The outcome of the process was to settle on a system representation consisting of 50 onshore nodes, with additional offshore nodes and interconnector points depending on the scenario.

The parameterisation of this approximated network is now described in terms node and branch data, demand data and generator data.

6.2 Branch paramaterisation – selection of nodes and use of real line and equivalent line data

Developing an approximated network model first required decisions about amalgamation of multiple nodes. The amalgamated nodes used to represent the real network were selected by referring to the National Grid's map of the GB transmission network (reproduced here as Figure 22). Where possible, simplifications were made by combining closely neighbouring nodes into single bus bars. Nodes were chosen in order to ensure that the model would have sufficient granularity to capture:

- Key branching points and alternative corridors within the network
- The location of large generators, or large clusters of generator types

- The potential for new extensions to the network, e.g. offshore networks or sub-sea interconnectors

- Significant demand sites such as large cities or industrial areas

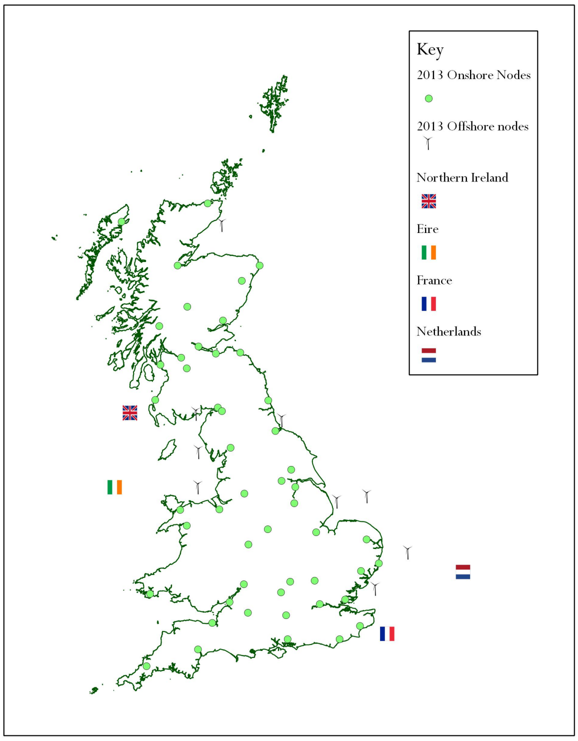


Figure 23: *Location of nodes for simplified network representation, 2013 system*

Figure 23 shows the locations of the nodes selected for a simplified representation of the 2013 network. As well as onshore generation hubs, load centres and network junctions, it includes the main offshore hubs and the connection points for current interconnections with other systems. There are a total of 50 onshore nodes, 9 offshore nodes, and four interconnection points. The location of a number of possible future nodes, which may be required to represent the addition to the network of future offshore development sites, connection of Scottish islands and international interconnections, according to different scenario developments, were also noted at this point.

Having identified the locations of the nodes to be used to represent the current system, the next stage was to parameterise the branches which connect them. The main reference source for the data was Appendix B of National Grid's Seven Year Statement (National Grid, 2011b). This appendix provides detailed line parameters for every section of the GB transmission network. In each case, the key data provided are the identities of the two nodes connected, the length and voltage of the line, the line parameters of resistance (R), reactance (X) and susceptance (B), and the seasonal thermal rated capacity of the line. Some of the amalgamated model nodes are close enough to real SYS nodes that connections between them can be paramaterised using the real line data given for the branches connecting those SYS nodes. In other cases amalgams of two or more lines are made by summing their rated capacities, and calculating their combined parallel impedances using the formula,

Equation 1

$$\frac{1}{Z_{eq}} = \frac{1}{Z_1} + \frac{1}{Z_2} + \cdots + \frac{1}{Z_n}$$

which states that the inverse of the total impedance (Z_{eq}) is equal to the sum of the inverse component impedances ($Z_1 \ldots Z_n$). In other cases a line which finishes at a certain SYS node for which there is no direct model equivalent may be extended to the nearest model node by calculating the RXB /km values for the real line, and multiplying this by the required remaining distance.

An impression of the degree of aggregation from SYS real system data to model representation can be attained by comparing Figure 24, a close up of Zones 6 and 7 from the map of the system provided in the SYS, with Figure 25, a close up of the same region showing the nodes and branches represented in the model.

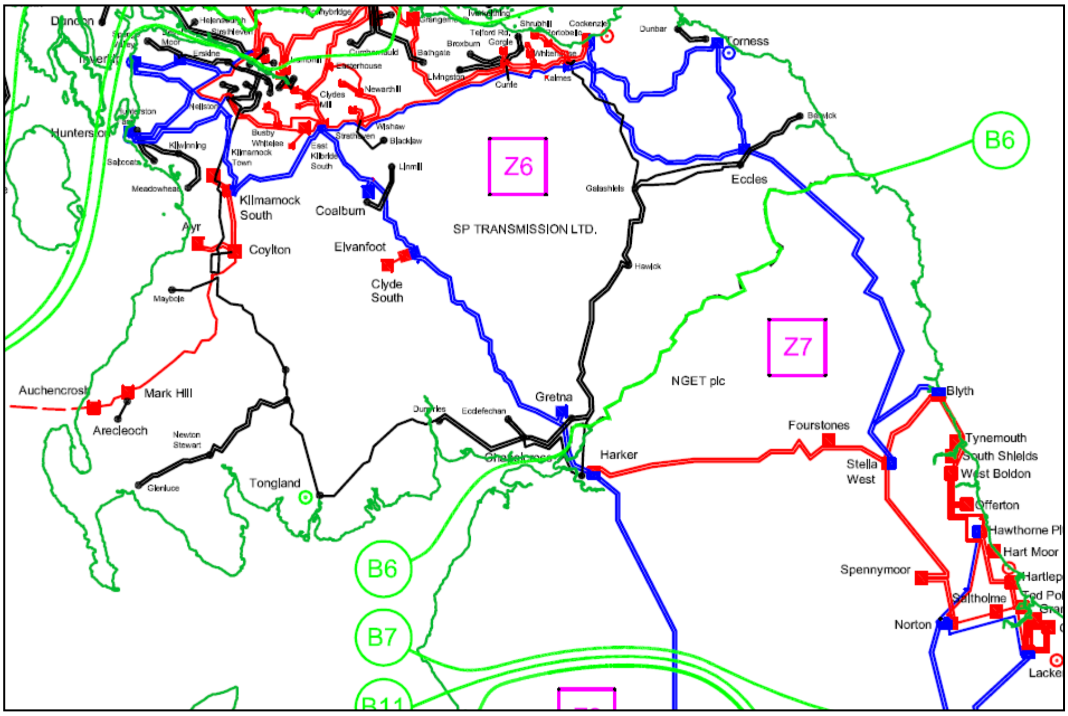


Figure 24: *GB Transmission network SYS Zones 6 and 7 (National Grid, 2011b)*

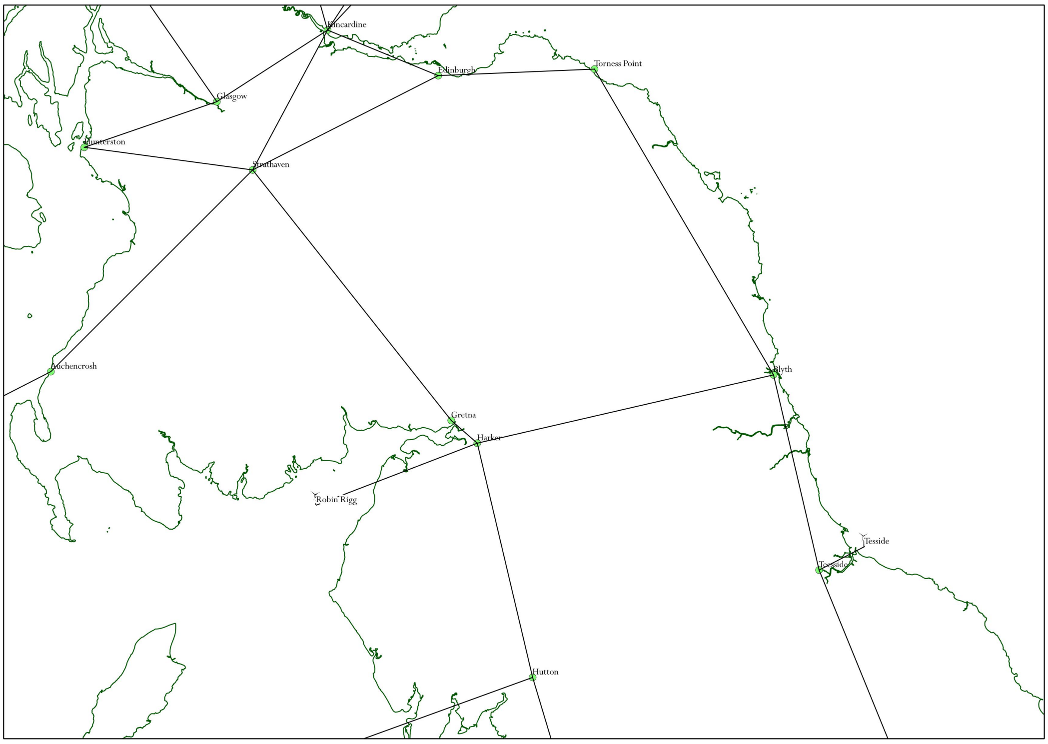


Figure 25: *Simplified model representation of GB transmission network SYS zones 6 and 7*

The resulting map of branches across the whole system is provided in Figure 26. By comparing this map with Figure 22, it can be seen that the equivalent network representation greatly simplifies the local arrangement of the shortest sections of line, whilst preserving the overall shape of the system including the broad arrangement of the key long-distance transmission corridors.

As well as the key parameters of resistance (R), reactance (X) and susceptance (B), each line is parameterised with a seasonal loading limit. The SYS (National Grid, 2011b) provides thermal loading limits for each of the system branches. These are further modified to allow for voltage and stability limits, as described in Appendix E.1.

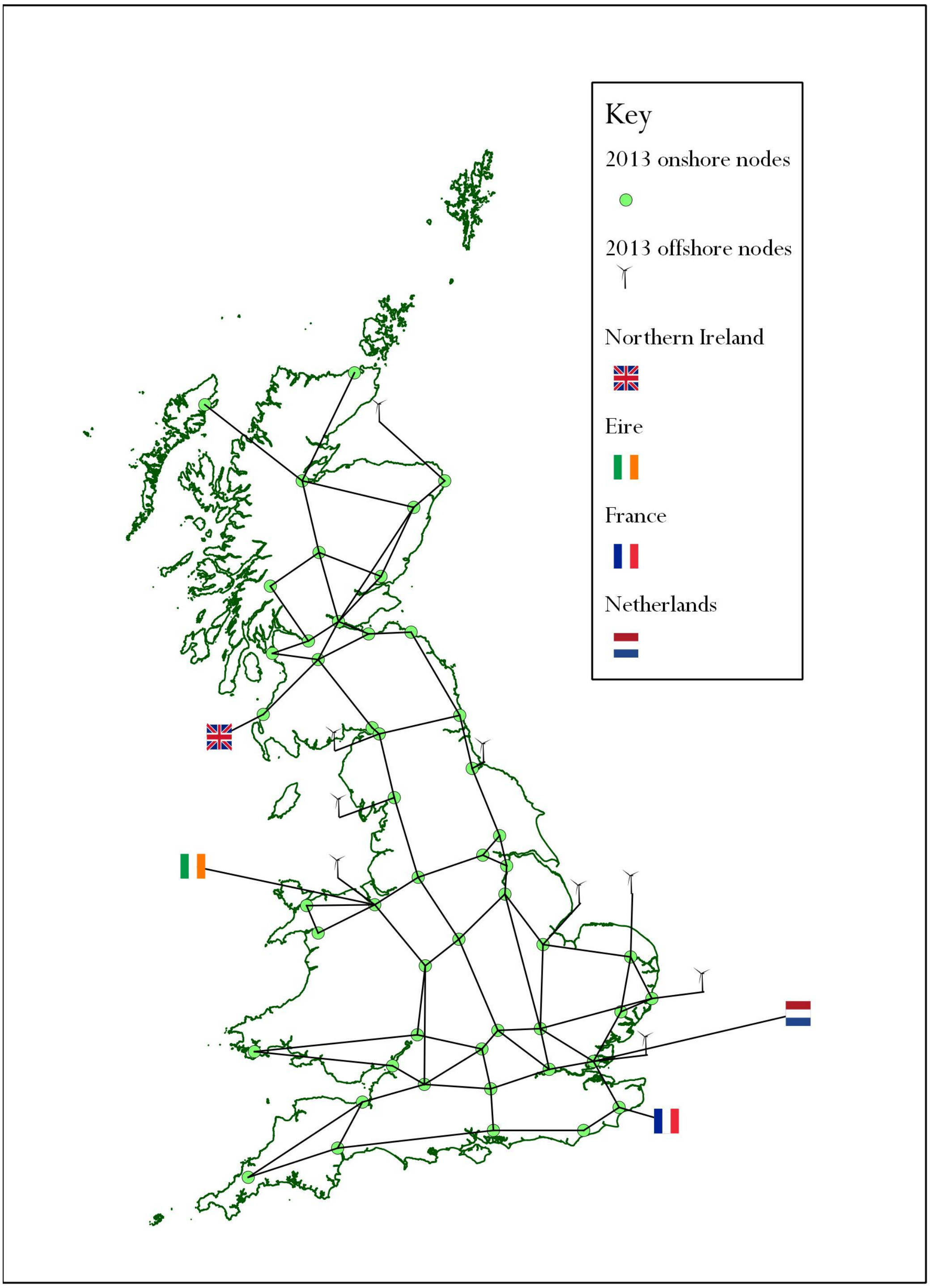


Figure 26: *Approximated network map - nodes and branches 2013*

6.3 Demand side

6.3.1 Total GB system demand at seasonal peaks

Traditionally, analyses of system adequacy have focussed on the winter peak – the point of the year at which the overall demand on the system is greatest (National Grid, 2011b, National Grid, 2012a, Gerber et al., 2012). The justification for this is that if the network is sufficient to safely carry generation to load at the highest demand point of the year, it will, *a fortiori,* be sufficient for all other times of the year. This reasoning is acceptable for a system dominated by dispatchable generators whose outputs will directly follow the contours of the load. It may not hold so well, however, for a renewable dominated system, in which the outputs of plant are not correlated to load. For example, a low demand condition could also place strain on the network if it coincided with a high wind condition, resulting in the need to export greater amounts of renewable generated power from low-load areas across the network.

For the current project therefore, there is interest in testing the network under different demand conditions. Historical data on total system electricity demand for each half-hour period between 2006-2012 was analysed. Electricity demand profiles have seasonal patterns, with winter, summer and intermediate (spring and autumn) months all exhibiting different patterns. ***Figure 27***, ***Figure 28*** and ***Figure 29*** show the 24-hour demand patterns of days in April, July and December from 2006-2012.

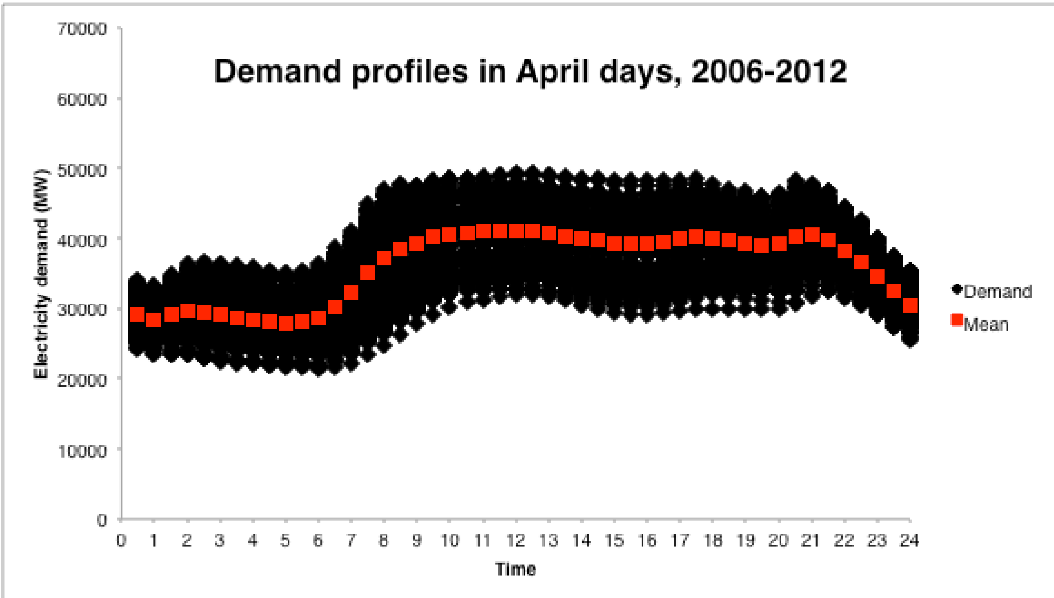


Figure 27: *Demand profiles in April days, 2006-2012*

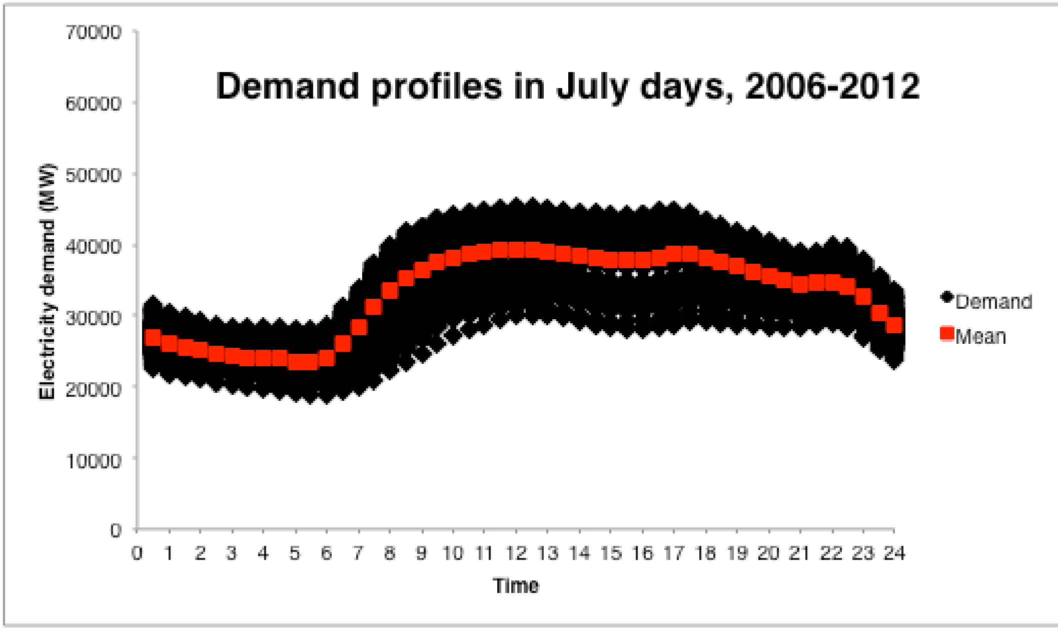


Figure 28: *Demand profiles in July days, 2006-2012*

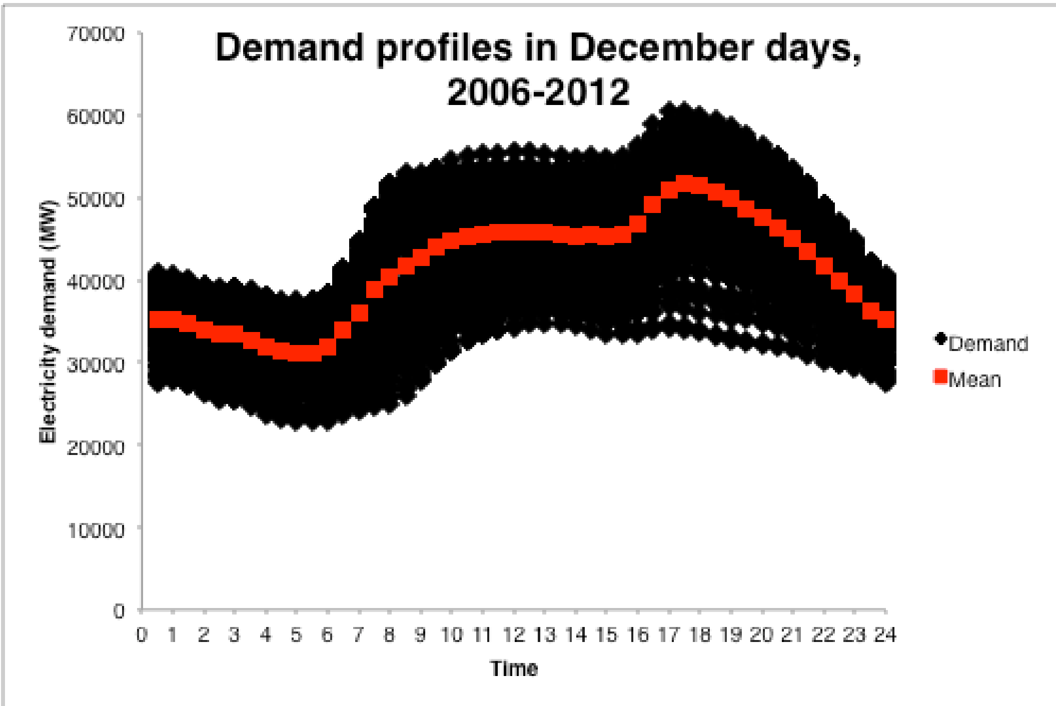


Figure 29: *Demand profiles in December days, 2006-2012*

As can be observed in the above figures, on winter days peak demand typically occurs between 5 and 6pm, and reaches a maximum of 60 GW. In spring and summer the profile is much flatter, with a broader daytime shoulder; however in both spring and summer the highest demand is typically found between 12 and 1pm. In spring the highest peak is around 50 GW, in summer 45 GW.

This provides the three seasonal system conditions which will be analysed in the load flows:

- April, 12-1pm. Total system demand in 2013: 50 GW
- July-August, 12-1pm. Total system demand in 2013: 45 GW
- December-January, 5-6pm. Total system demand in 2013: 60 GW

6.3.2 Splitting total GB system demand amongst model nodes

Having established total system demand for each of the three given seasonal condition, a further requirement is to divide this total demand between the various system nodes, in order to represent the distribution of demand across the country. DECC provides the annual electricity consumption of the UK by regional and local authority, for 2011, disaggregated by domestic and industrial consumption (DECC, 2011). By overlaying the map of the 74 nodes on the map of UK counties and unitary authorities, it was possible to 'allocate' the demands of each of the local authority areas to the closest of the 74 nodes (***Figure 30***).

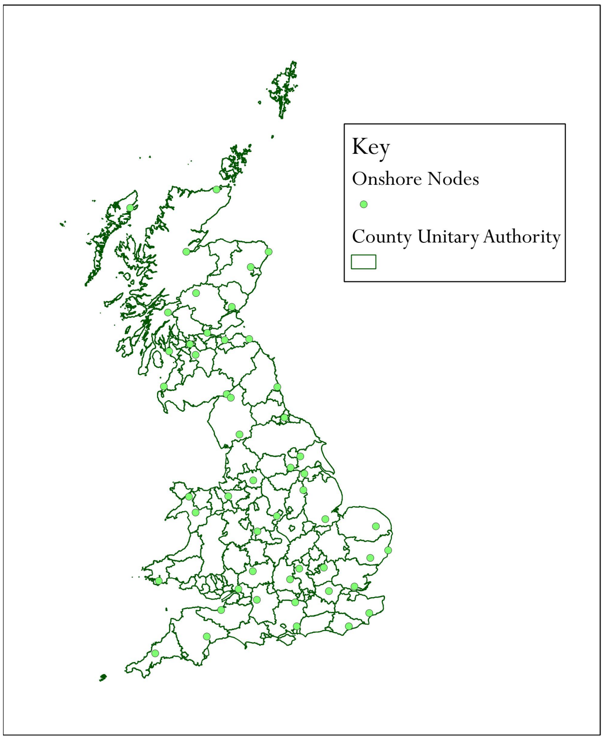


Figure 30: *GB unitary authorities and system nodes*

The percentage of total annual demand accruing at each model node was calculated. Further analysis showed that the percentage contributions to annual energy demand of a region are a reasonable proxy for that region's percentage contribution to system peak (as reported in Appendix E.2). Hence these regional demand proportions were used as fixed percentages to divide up the total system power demand between each of the nodes for any condition modelled.

6.3.3 Evolution of demand through time

The previous two sections showed how the total system power demand in the current system at three different seasonal conditions was identified, and how that power demand was shared between the system nodes. This section explains how changes to the overall power system demand through time are calculated for the purposes of the scenarios.

The evolution of electricity demand over the next few decades is an area of significant uncertainty. Overall demand for electricity will be affected by:

- Growth in use of electrical appliances
- Growth in industrial demand

- Effects of energy saving and energy efficiency measures

- Growth in demand from new sources such as vehicles and domestic heating systems

Further, the power demand at any given point in time (as opposed to the overall energy demand across the year) will be influenced by patterns of use. For example, whether all future electric cars are re-charged in the early evenings has a significant impact on how large the increase on winter peak will be.

A demand profile has been constructed, drawing key assumptions from National Grid's Gone Green Scenario (National Grid, 2013c) and the Digest of UK Energy Statistics (DECC, 2013a). Although the scenarios in this study will run to 2033, the demand profile is extended to 2048, in order to represent a trajectory towards a highly decarbonised energy system by mid-century. The key assumptions of the profile are as follows:

- Domestic lighting, appliances and resistive heating, and overall commercial sector demand, all decrease as a result of efficiency improvements

- Domestic heat pumps grow strongly, accounting for 95 TWh of annual demand in 2048

- Industrial demand increases from 98 TWh in 2012 to 124 TWh in 2048, reflecting growth in the sector

- Electrification of trains continues at historical rates, electric vehicles grow strongly, reaching 90 TWh of annual demand in 2048

- Electric vehicle charging patterns are spread, reflecting smart meter incentives. The percentage of the daily charge coinciding with the winter, spring summer peaks are 4%, 2% and 2% respectively.

The resulting profile of annual electricity demand change is illustrated in ***Figure 31***. More detail on working assumptions is presented in Appendix E.3.

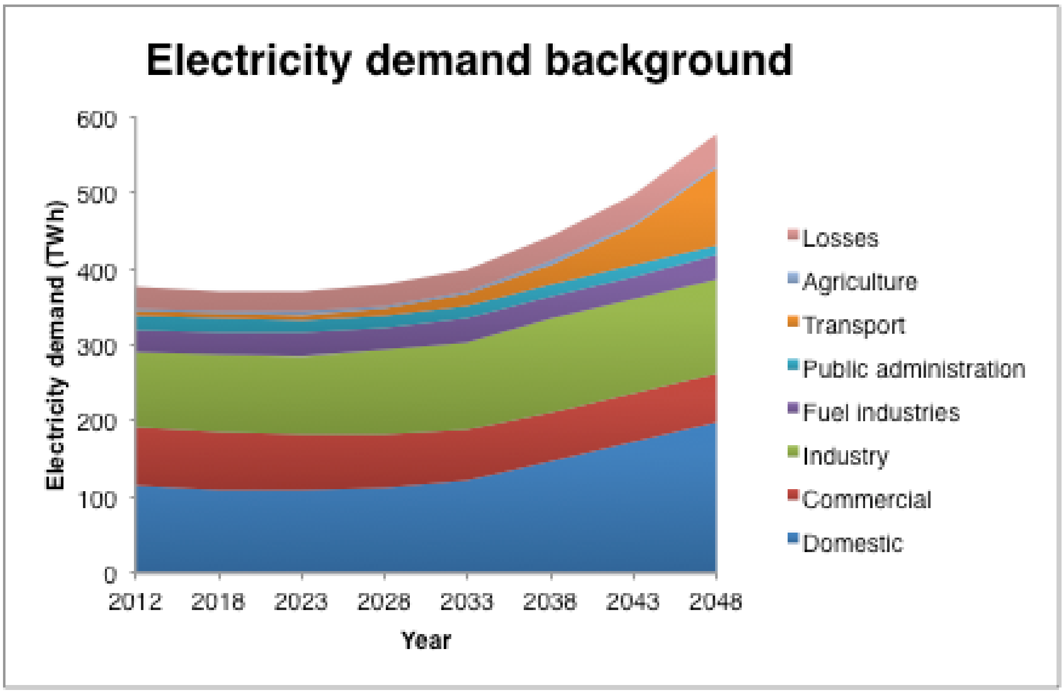


Figure 31: *Annual electricity demand background for scenarios*

According to these assumptions, annual electricity demand in 2048 stands at 578 TWh, an increase of just over 50% from 2012 levels. Though this is steep, it is not extraordinary by historical standards. It compares more with the modest rate of growth between 1981 and 2003, which saw a 36% increase over 22 years (***Figure*** *17*), than the more rapid growth periods, such as the five-fold increase in demand in just over 20 years between 1951 and 1973 (***Figure*** *15*). This level of electricity demand by mid-century is also consistent with MARKAL runs operating under stringent decarbonisation targets (Ekins et al., 2013).

The 2012 ratio of annual demand to system peaks in winter, spring and summer, were calculated and applied to all annual demands except that from electric vehicles, to derive the peak contribution. This assumes that patterns of use in these sectors will remain the same. Electric vehicles were treated separately, enabling the assumptions about the percentage of daily charging occurring at each time to be factored in (further variations around charging pattern assumptions will be discussed under 'non-actor-contingent' elements). The resulting evolution of winter, spring and summer peak demands is illustrated in ***Figure*** *32*. Further detail on working is provided in Appendix E.3.

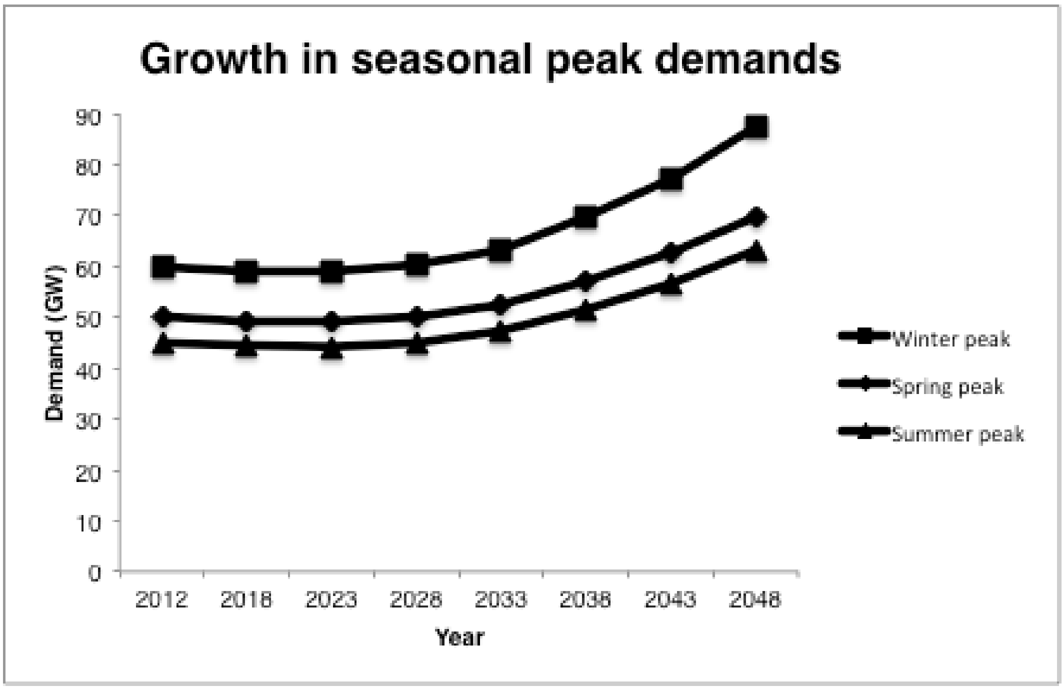


Figure 32: *Growth in seasonal peak demands for scenarios*

6.4 Generator data

6.4.1 Installed capacities of generators by node

The third key component of the technological configuration is the mix of different types of generation plant and their locations. For calibration to the base year of 2013, SYS (National Grid, 2011b) projected data for the year 2012/13 was used. Data on renewables was also double checked against the most up to date sources provided by RenewableUK's Wind Energy Database (RenewableUK, 2013b), and by checking the status of projects on individual project websites. The effect of closures, including due to the large combustion plant directive, on capacities of conventional plant since the publication of the SYS in 2011, was also factored in. Each individual generator was then associated to one of the established onshore or offshore nodes shown in Figure 23. An aggregated table of installed capacity split into nine GB regions (the regions are indicated in ***Figure 34***) is presented in Table 5. Further detail and data sources are contained within Appendix E.4. Figure 33 represents the amounts of installed capacity of fossil generators at system nodes.

Table 5: *Installed capacities by generation type and region*

Region	Region name	Offshore wind	Onshore wind	Other renewables	Nuclear	Thermal	Storage	Total
1	Northern isles	0	363.8	0	0	0	0	363.8
2	N.W. Scotland	0	862.6	1022.8	0	52	740	2677.4
3	N.E. Scotland	10	213	61.2	0	412	0	696.2
4	Borders West	787.2	1862.65	33	3482	449	0	6613.9
5	Borders East	65.9	573.5	0	2422	4937	0	7998.4
6	Mid-West	240	0	0	490	6884	2004	9618
7	Mid-East	841.2	0	0	0	24853	0	25694.2
8	South-West	0	299	0	1261	8054	0	9614
9	South-East	1708.8	0	0	2288	12626.9	0	16623.7
Total		**3653.1**	**4174.55**	**1117**	**9943**	**58267.9**	**2744**	**79899.6**

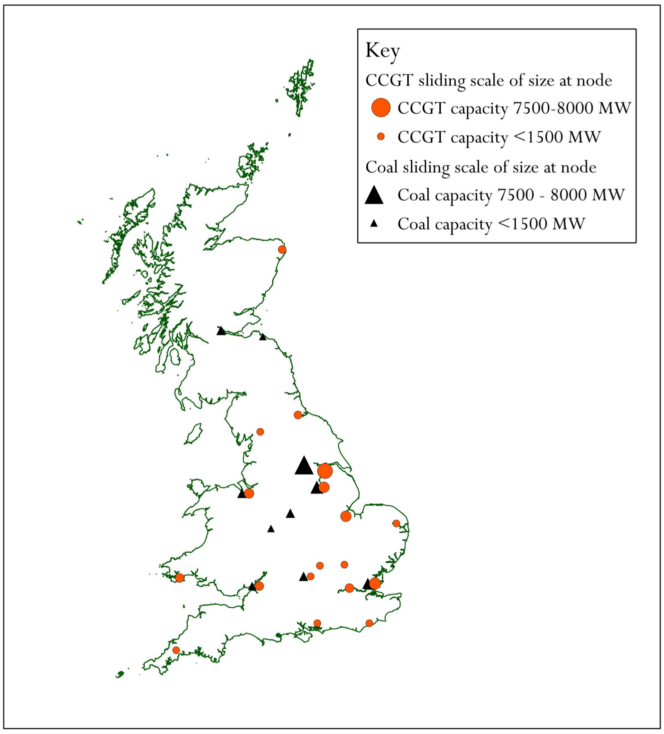


Figure 33: *The distribution of coal and CCGT plants by system node, GB, 2013*

These installed capacities represent the starting point of each scenario. As the scenarios are developed, capacity is added or subtracted depending on investment decisions hypothesised within each scenario. This process is described further in Chapter 7.

6.4.2 Technical availability of generators

In order to model a power flow at a given point in time, the total installed capacity of a generation type at a given node must be modified by an availability factor (AF) – the percentage of the generator's total installed capacity which is technically available for dispatch at the time of the condition being modelled.

6.4.2.1 Availability of fossil fuel and nuclear generators

In energy system modelling studies, fossil, other thermal and nuclear plants are typically applied an annual AF of 0.9 (90%) (e.g. Kannan et al, (2007)). This annual AF reflects time during the year that plant may be unavailable due to maintenance, and is chosen to reflect the amount of energy available from the pant over the course of the year. For a load flow simulation of a particular system condition, this smoothed 90% factor is not meaningful – plant will either be 100% available, or considerably less than 100% due to maintenance. By 'availability' is meant technical availability, not the level of generation a particular plant may choose to sell into the market in a particular half-hour. Hence in this study, the AF of conventional plant is 1, or 100%.

6.4.2.2 Availability of wind

For wind farms, the availability factor will vary by location, season and time of day, according to the weather conditions which provide the energy for their output. The difference between wind conditions in different parts of the country at is an important factor for the power flow – for example higher winds in the North would create higher power output from renewables in the North, adding to the north-south power flow.

The seasons and times to be analysed in each scenario time-step were defined to capture a range of demand profiles (6.3.1). In order to explore the contribution of wind at these times, it was necessary to access historic data for wind conditions for each of these seasons and hours of the year, simultaneously in the different regions in the country to be modelled. Grünewald (2012) and Green and Staffell (2012) both in different ways explore the effect of geographic diversity on wind output diversity. Both find that, because of the high correlation between nearby regions, and the relatively small size of the UK as a whole, dividing the UK into four regions is sufficient to capture the essence of the diversity.

Therefore in this study the division of Britain into nine regions, shown in *Figure 34* was deemed sufficient for the purposes of geographic diversity. Using the UK

Meteorological Office MIDAS database (UK Meteorological Office, 2012), nine weather stations were selected and wind speed data extracted for the years 2002-2012. Stations were selected based on the following criteria:

- Geographically dispersed locations
- Good availability of 10m wind speed data for the duration of the time period being studied
- Open and relatively rural locations (checked using Google Earth)

The nine selected sites and associated regions are illustrated in ***Figure 34***. The wind speeds recorded at these stations were taken as proxies for describing wind speeds throughout the nine wind-speed areas, as indicated on the map. Each of the onshore and offshore system nodes was enclosed within one of the nine wind speed areas.

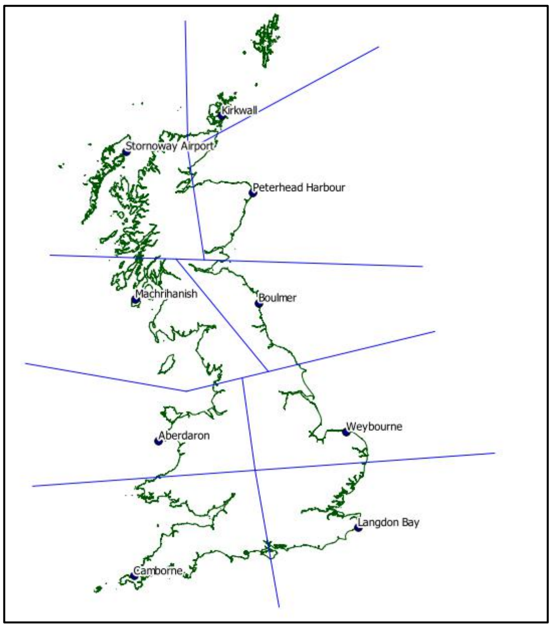


Figure 34: *Nine selected wind monitoring sites and associated regions*

A possible approach to managing this wind speed data would be to calculate average wind speeds for each of the required time periods at each of the nine locations. What this could potentially confuse, however, is the degree of spatial interdependence between locations, which is also important for a network study. The approach taken, therefore, was to identify a range of days and times during the period 2002-2012 whose actual wind conditions across the country would collectively span a good range of possibilities. The data used for this study is therefore real historical data, selected for its representative characteristics, rather than statistically generated or simulated data.

There were three seasonal time periods selected for modelling on the basis of their demand characteristics (as discussed in Section 6.3.1). These were:

- Winter peak (December-January, 5-6pm)
- Summer peak (July-August, 12-1pm)
- Spring peak (April, 12-1pm).

Thus, the wind speed data for the hours of 5-6pm every day in December and January, 12-1pm in July and August, and 12-1pm in April, from the years 2002-2012, were isolated to produce three data sets of wind conditions coinciding with winter peak, summer peak and spring peak. Each of these seasonal data-sets was then examined for the following candidates:

- High overall wind speed – the day on which the mean of the wind speeds at each location is highest
- Low overall wind speed – the day on which the mean of the wind speeds at each location is lowest
- North-South gradient (NS) – the day on which the difference between the mean of the northern sites and the mean of the southern sites is greatest, in favour of the north.
- South-North gradient (SN) – the day on which the difference between the mean of the northern sites and the mean of the southern sites is greatest, in favour of the south.
- "Average" – the day which combines being closest to the overall average wind speed, and the closest fit to the most typical north-south gradient, for that time and season over the whole period.

This produced 5 individual historical wind days for each of the three seasonal times. Each of these days consisted of real data for each of the nine sites.

Following this, some simple conversions were made on the data to deliver onshore and offshore availability factors for renewable technologies. First the 10m wind speed was converted to the wind speed at a hub height of 80m using the formula provided by Best et al (2008). Then offshore wind speeds were derived from these onshore speeds using the method provided by Hsu (1988). Finally, the wind speeds were converted to an AF using a power curve for a Siemens SWT 2.3 provided by Staffell (2012). The full data and working are provided in Appendix E.5.1.

6.4.2.3 Availability of other renewable technologies

Wave output is strongly correlated to wind, as wave energy is derived from wind. The key difference is that the energy in waves may take longer to peak under a given wind condition, and does not drop off as quickly following a drop in wind. The assumption is made that the AF for wave energy in each seasonal and weather condition is the same as that for wind. The potential for inaccuracy is that for high wind conditions, if the condition had recently started the waves would not yet be at their full height, hence the wind output factor would overestimate the wave output factor; and correspondingly for low wind conditions, had the wind only recently dropped, the waves would still be carrying more of their energy, hence the wind output factor would underestimate the wave output factor. However, these variations are relatively minor and would cancel out.

Tidal energy is uncorrelated to wind. The tides follow lunar cycles and shift by half an hour each day. This means that although high and low tides can be accurately predicted, the time of day at which they occur on *any given day* is constantly shifting, moving half an hour forward every day. This means that for any given time of day – say 5 to 6pm – the tidal conditions and resulting output from tidal turbines would be different each successive day. Therefore, although it would be possible to predict the tidal output for a given installed capacity at a *specific* day and time in the future, it is not possible to match a particular tidal output to the more generic time descriptions used in this project – for example the winter peak being modelled in the project is 5 to 6pm on *any day* in December or January. As a result it is necessary to apply a fixed availability factor to all tidal sites. A standard availability factor of 0.7 was selected as being the highest output that could simultaneously occur at opposite ends of Britain. The working for this is given in Appendix E.5.2.

For hydro, the maximum quarterly average load factor for hydro in the last three years (0.54, reported in (DECC, 2014b)), has been scaled against the ten year mean rainfall for the months of January, April and August weighted by UK hydro resource (DECC, 2014c), to produce availability factors of 0.54, 0.25 and 0.38 for the winter, spring and summer conditions respectively. These factors themselves average to 0.39, close to the typical 40% average load factor reported for hydro (DECC, 2013a). Further detail on the working is in Appendix E.5.3.

Solar PV may potentially play a role in the future electricity mix, either in highly distributed residential-scale installations, or in more commercial scale ground mounted arrays. However, it makes no contribution to the winter peak, hence any scenario including PV would not displace any low carbon generation assuming that the intention was to meet winter peak with largely low carbon generators. It is possible that with breakthroughs in storage that PV could contribute to winter peak. However, such a storage breakthrough is considered to have significant uncertainty and therefore not included as a basic scenario assumption. As a result PV is not considered as an option within the initial scenarios, but the effect of adding PV output in summer peak in each of the scenarios is explored as a sensitivity in the 'non-actor-contingent' element analysis (Section 8.6.8.3).

6.5 Merit order dispatch

In order to represent the system condition at a particular point in time, the correct amount of generation must be dispatched from the available generation potential at the given season and wind condition, to meet the overall system demand corresponding to that time.

This is achieved via an Excel tool which ensures that total system generation equals demand via a merit order dispatch by generation type. According to the time of year and wind condition selected, the tool calculates the proportion of the total installed capacity which is available to dispatch, based on the relevant availability factors. The next step is to dispatch from this available generation capacity that amount of power which is in fact required – that is, the amount which is equal to the total system demand. This is achieved using a simple merit order approach. The merit order used is based on that employed by the ENSG study (2009) and is shown in ***Table 6***.

Table 6: *Merit order used for dispatch*

Merit Order	
1	Interconnectors
2	Offshore wind
3	Tidal
4	Wave
5	Hydro
6	Onshore wind
7	Nuclear
8	CCS
9	Biomass
10	CHP
11	Fossil
12	Fossil peaking
13	Storage

The above table represents a reasonable expectation of marginal dispatch costs, and assumes that under low carbon policies, low carbon generators would tend to have dispatch priority over higher carbon generators. The clustering by ENSG of coal and CCGT into one 'fossil' category is followed in this approach. This reflects the fact that predicting which of these at any given time will be higher in the merit order is highly uncertain. Additionally, the change in network flows caused by a switch between coal and gas as marginal generator is not great, as suggested by the fairly strong locational correlation of the two generating types (***Figure 33***), as well as being confirmed from experience as reported in key actor interviews (Section 5.2.2).

The merit order is applied using an Excel-based algorithm. The model dispatches in order of technology type, without preference for locational node. It considers each technology type in order of merit. If the total available power from all nodes within a given class of technology is less than the remaining total system demand (RTSD), it dispatches all available power for that technology at each node, and proceeds to the next technology type in the merit order. Eventually the model reaches a technology from which the total available power is more than the RTSD, due to the technologies already dispatched. At this point, available power at each node of this marginal technology is reduced in proportion to the ratio of RTSD to the total available power for that technology, so that the RTSD is met exactly. Any subsequent technologies in the merit order deliver no output.

6.6 Load flow

The previous sections describe the process of assembling three kinds data: branch parameters; generation at each node; demand at each node. These three data sets define a system condition under which power will flow through the branches of the network to meet demand at every point. In order to simulate how the power would flow through the network in that condition, a load flow analysis is undertaken. A load flow is an analysis of the power flows across a network at a point in time, demonstrating how power divides across the various junctions within a network. This is dictated by the arrangement of load and generation around the network, as well as by the relative impedences of the various sections of circuit. When presented with two parallel lines, current divides between them in inverse proportion to their impedances. This follows Ohm's law (Equation 4, Appendix A.1.1), which shows that current is inversely proportional to resistance (or impedance in AC circuits).

Load flows can be simulated of both AC and DC systems. AC simulations record reactive power, losses and voltage drops, and are required for sufficiently accurate simulations of distribution networks. DC load flows have the advantage of being computationally simpler, and with a faster simulation time. They treat the network as if it were DC, and although this simplification is not appropriate for distribution networks, DC load flows can simulate high voltage transmission networks with a high degree of accuracy (Gerber et al., 2012). Although they do not account for resistive losses, this simplification is considered acceptable for high voltage networks, where losses are significantly lower than on distribution networks. On the GB transmission networks, losses are typically 2% of generation (Elexon, 2013). The DC load flow tool provided by the open source programme MATPOWER, provided as a plug-in to the MATLAB software (Zimmerman et al., 2011), is used for this analysis.

However, because the generation dispatch described above is driven solely by the merit order, and does not consider the location of the generators, it is a dispatch which is not limited by transmission constraints. The purpose of the load flow is to identify whether the power flow brought about by this non-locational merit order dispatch would result in overloads, and thus whether constraints would need to be applied to the generation mix as a result of network limitations. If power flowing down any line is in exceedence of the rated capacity of that line, the system operator would have to adjust the output of generators either side of the constraint by trading in the balancing mechanism, until the overload has been removed. In the scenario development process, the operation of the balancing mechanism is not simulated, but the level of line exceedences is taken as an indication of the level of constraints which would be experienced on the system under the given condition. The power flows are also represented visually using the Quantum GIS (QGIS) open source geographical information systems package, in combination GIS data from Ordnance Survey Open Data[2]. The information on power flows and line exceedences is used to influence decisions on generation and transmission investment in the subsequent time-stage of the scenario, as will be discussed in the next chapter.

6.7 Conclusions

This chapter has summarised the process of data collection and model development undertaken to support the representation of the technological layer of the system under study. It has described the development of a simplified representation of the GB transmission network using equivalent line data; the development of seasonal demands and their projection through the time period of the scenarios; the assembling of data on installed capacities of transmission connected generators for the base year, and on seasonal and temporal availability due to weather and other variations; the operation of a merit-order dispatch algorithm; and the combination of all this data to run a DC load flow, and represent using GIS software. The next chapter describes how this technological framework interacts with the other two system layers – values, and actors / institutions – in the scenario development process.

7 Application of the scenario development process

Chapter 2 proposed a scenario process based around a system characterisation involving three levels: values, actors and institutions, and technologies. Subsequent chapters provided the information required to characterise the system within each of these three levels. The current chapter explains how each of these elements will be integrated in order to deliver an integrated iterative scenario process, as set out in Section 2.6. The resulting scenarios will be narrated in Chapter 8.

7.1 The structure of the system – values, actors and the technological system

Socio-technical systems involve co-evolutionary dynamics between technological artefacts and infrastructures, and actors and institutions (Berkhout et al., 2004, Geels, 2002, Freeman and Louça, 2001, Hughes, 1983, Hannah, 1979), as large technological systems are 'both socially constructed and society shaping' (Hughes, 1987).

Figure 35 summarises the interactions between actors, institutions and technologies in the system under study. The technological level of the system under study is the generation mix and transmission network installed to meet a given system demand. This system configuration produces system conditions of power flows, and sometimes constraints, during real time operation. The combination of the system configuration and its conditions during operation have effects on future investment decisions both on the generation and transmission side, which are communicated through the institutional structures which pertain to them.

On the generation side, the system configuration and system conditions give rise to network charges – TNUoS and BSUoS, as discussed in Chapter 4 – which are paid by generators. The level of locational signal in network charging may influence generation investment plans of the generating companies, along with other government generation focussed policies, and ultimately affect generation investment.

On the transmission side, the system condition, and in particular any significant constraints that may arise from it, may also contribute to a case for new transmission investment. This investment case may also be bolstered by industry expectations of future generation investments, which themselves are informed by generators' investment plans insofar as they are known, and long term government targets. The investment case is adopted by transmission companies in presenting their investment plans in the RIIO price control process, which is monitored by Ofgem, and at the conclusion of which transmission investments can be made.

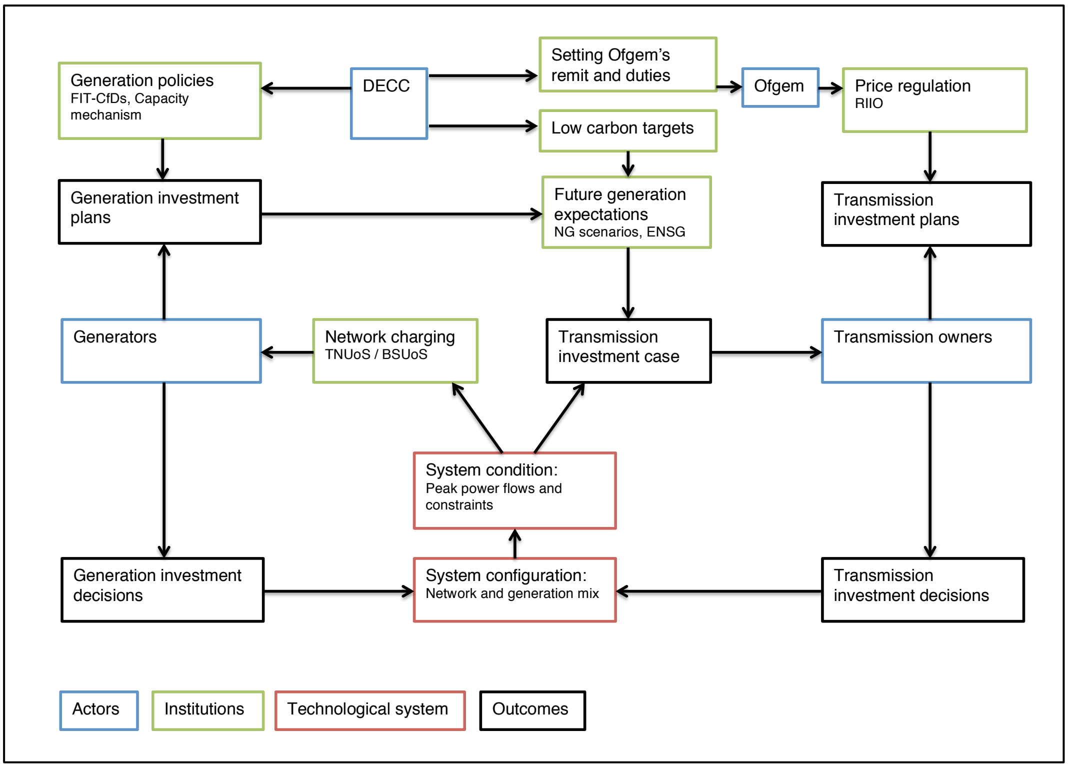


Figure 35: *Conceptual map of the system under study, showing interactions of actors, institutions and technologies and infrastructure*

The picture presented is therefore of a dynamic feedback process where the technical outcomes of operating the existing system, and expectations about the possible future system, combine to contribute to future investment decisions in respect of both generation and transmission assets. The actual path which the system takes however is dependent on the tuning of the policies and institutional arrangements which mediate the system, and the relative balance they strike between affecting the generation or the transmission side. In respect of this balance, the key questions which emerge are:

- What level of locational signal is provided to generation to influence future siting decisions, and operational decisions?

- What level of anticipatory or strategic thought is present in transmission planning?

Making a judgement about which balance to strike is not a straightforward empirical question – in large technological systems with long lead times on investments and high levels of technological lock-in, there is no luxury of counter-factual. These are ultimately political judgements, taken of necessity from within a value system, which suggests both a preferable type of solution or approach to a problem, and a desirable end state which is aimed for (Leach et al., 2010, Clapp and Dauvergne, 2005, Sunderlin, 2003). Section 4.5.3 described the intersection of the two value spectrums associated with the questions of locational pricing and strategic-anticipatory investment, in the context of the current GB policy arrangements and debates about their future. ***Figure 36*** now reprises that intersection, drawing attention to the four policy value-set combinations which arise from it.

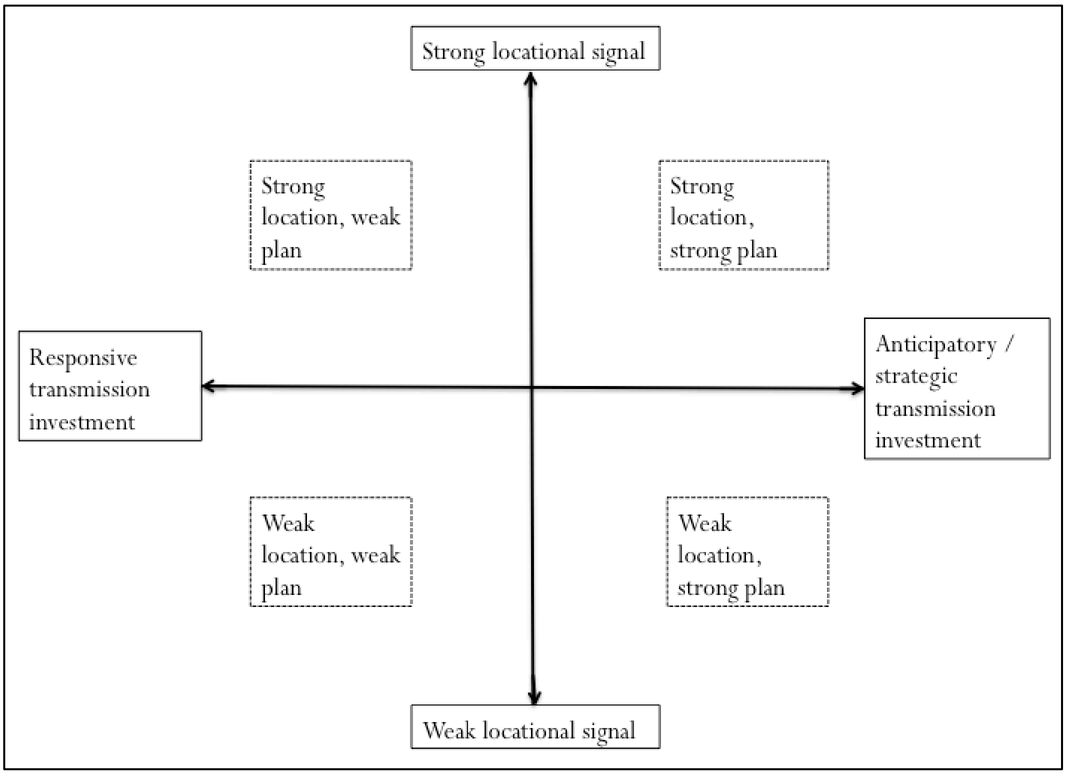


Figure 36*: The intersection of planning and locational pricing values spectrums*

These four contrasting combinations suggest alternative value-sets which could underlie the motivations and decisions of policy-making actors. These alternative decisions would create different institutional frameworks, prompting different actor actions and subsequent reactions within the actor-institution network, causing different investments to be made within the technological configuration. In other words, these contrasting value-sets are the starting point for the alternative dynamics which cascade down to the other two levels, ultimately resulting in alternative evolutionary scenario pathways. As shown in **Error! Reference source not found.**, which illustrated the historical case study of the GB electricity system, this flow of influence from values through actions and technological configurations, can also be followed by flows back up through the levels. For example if technological realities throw up problems or contradictions which challenge or force reappraisal of the dominating value-set.

7.2 The scenario development process

The scenario development process then is one of joining up the various tools and analytical stages described in the previous chapters, in order to achieve a fluid movement through the tree levels of values, actors and institutions, and technologies. *Figure 37* illustrates the scenario process, showing the links between the various tools and approaches.

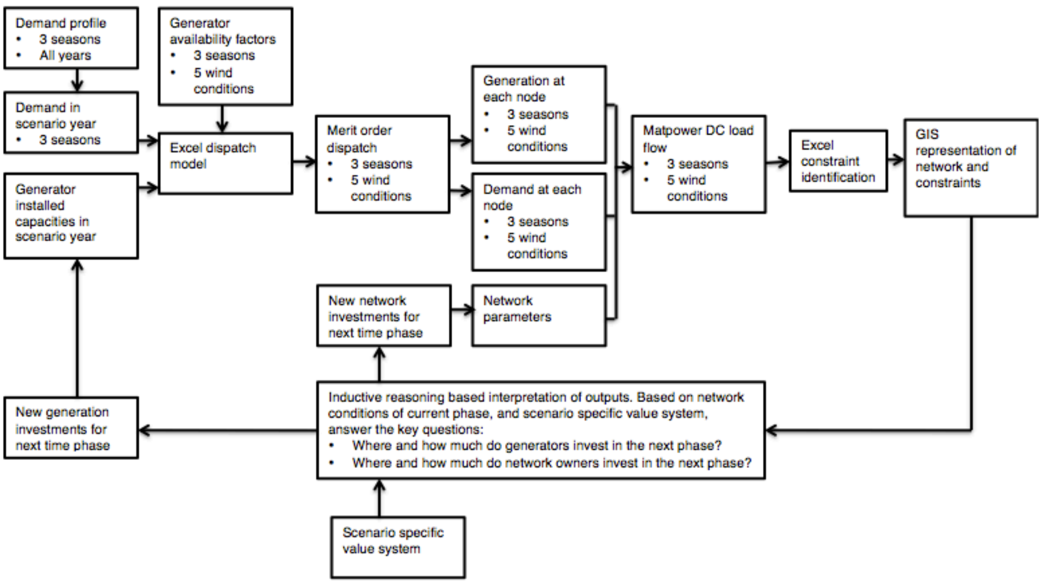


Figure 37: *Flow diagram of scenario process*

The first step is to establish the demand profile for the given scenario year, from the overall system demand profile for the scenario period, the working for which is given in Section 6.3. This is combined with the generation mix which in the first year is taken from 2013 data, and which in subsequent years is added to according to the requirements of each scenario; along with data on seasonal availability factors which include wind output in different wind conditions, as described in Section 6.4. These datasets allow the Excel dispatch model, described in Section 6.5, to run a generation dispatch according to its merit order, for each of the three seasons and five wind conditions as described in section 6.4.2.2. The demand and generation data per node for each season and condition, are combined with the data on transmission network parameters – in the first year these are taken from 2013 data, as described in section 6.2, in subsequent years added to according to the requirements of the scenario. These three datasets – nodal demand, nodal generation and network parameters – allow a load flow to be undertaken for each of the system conditions, using the MATPOWER load flow tool. The power flows along each branch are fed back into the Excel model to compare power flows against capacity ratings, and identify constraints. The constraint patterns are also then represented in the GIS, in order to interpret the results visually.

The above steps represent one complete iteration of the process for the generation mix and network configuration in a given scenario year. The crucial next stage is the feedback of the outputs of this process, via the mediative effect of the value-set under which the particular scenario operates, to create the portfolio of new generation and transmission investments which are to take place during the next scenario time-stage.

The quantitative and visual outputs are analysed to understand the system performance – where and under what conditions system constraints are occurring. These outputs must then be interpreted in the context of the scenario specific value system. By considering the available data in the context of the value system for that scenario, two sets of decisions must be made: where and how much do generators invest in the next phase; where and how much do network owners invest in the next phase?

The effect of the four different value systems on these decision points can be demonstrated by summarising the decision rules which each scenario would apply to these questions. The following paragraphs set out the overall guiding value-set of each scenario, as defined by the intersection of the value-axes shown in ***Figure 36***, and explain how this translates into decision rules which guide the development of new transmission and generation investments in each scenario time-stage.

7.2.1 Strong location, strong plan (SLSP)

Strong Location Strong Plan (SLSP) is guided by a policy value-set which espouses the benefits of trying to organise regulated markets to accurately reflect all costs in order to deliver the most efficient solution within whatever constraints are imposed upon them. For transmission networks this means that strong locational signals are sent to generators in order that they make an efficient trade off between costs of generation and the costs to network of their locational choice. However, due to the scale and lumpiness of transmission investment there is also a belief that while locational signals are important to influence the use of the existing network, some element of strategic planning is still required to coordinate network expansion, given the significant structural changes expected in the system under the decarbonisation programme.

The decision-making approach for scenario development within this framework therefore involves attempting to maximise network utilisation but also being open to opportunities for significant strategic network upgrade decisions. In any time-stage the first step is to examine the power flows and constraints of the previous time stage and identify the network capacity availability in the different regions of the network. Low carbon technologies which are available to be deployed in regions with available network capacity will be deployed as a first order priority, moving into constrained regions only if more deployment is needed to remain on track for the decarbonisation target. In this way network upgrades are minimised. If however the triggering of network upgrades becomes unavoidable then network upgrades can be taken in any given time-stage with a strategic anticipatory mind-set – that is, building out beyond the immediate needs of that time-stage in expectation of future deployment in the region in question.

The precise policies which achieve the locational signal are not specified in the scenario – although potential policy options are discussed across all scenarios in the analysis undertaken in Chapter 9. However, an important assumption about the targeting of the policies is that they deliver a locational signal which influences not only investment decisions, but also real time operational decisions – this would mean that generators and interconnector operators have an incentive to respond to real-time locational network conditions in their operational patterns. In order to reflect this, this scenario allows modelling interventions on the Excel dispatch model. The dispatch algorithm by default dispatches by technology type in merit order, but with no preference for location. However, in this scenario interventions are made to directly alter the output of flexible plant in constrained areas, typically turning down northern fossil plant in high wind conditions. Output of fossil plant can be reduced on a regional basis, or by specific plant. Regular candidates for this treatment are Peterhead (node 8) and Longannet (node 13). This treatment reduces fossil output during high wind conditions, and returning fossil to normal output during low wind conditions, effectively mimicking a network sharing arrangement. The outputs of the interconnectors are also manually controlled in response to the locational network conditions in any given power flow.

7.2.2 Strong location weak plan (SLWP)

Strong Location Weak Plan (SLWP) is also guided by a policy value-set which espouses the benefits of sending strong locational signals to generators in order that they make an efficient trade off between costs of generation and the costs to network of their locational choice. Unlike SLSP however, there is no appetite for a forward looking anticipatory, or coordinated approach to network development. The belief is that with the correct locational signals and generation targeted low carbon policies, the efficient balance between network expansion and generation location will be found. There are no anticipatory network investments in this scenario – upgrades only respond to visible and committed generation projects within each time-stage.

The decision-making approach for scenario development within this framework therefore involves attempting to maximise network utilisation and avoiding network decisions which go beyond the visible requirements of the current time-stage. As in SLSP, in any time-stage the first step is to examine the power flows and constraints of the previous time stage and identify the network capacity availability in the different regions of the network. Low carbon technologies which are available to be deployed in regions with available network capacity will be deployed as a first order priority, moving into constrained regions only if more deployment is needed to remain on track for the decarbonisation target. In this way network upgrades are minimised. Unlike in SLSP, network upgrades are only triggered on an incremental basis, and building out beyond the immediate needs of the current time-stage in expectation of future deployment, does not occur.

As in SLSP, it is assumed that the locational signal influences not only investment decisions, but also real time operational decisions, creating incentives for generators and interconnector operators to respond to real-time locational network conditions in their operational patterns. Therefore, interventions on the Excel dispatch model are made to alter the output of flexible plant and interconnectors during different wind conditions. As in SLSP, this treatment reduces fossil output during high wind conditions, and returning fossil to normal output during low wind conditions, effectively mimicking a network sharing arrangement. The outputs of the interconnectors are also manually controlled in response to the locational network conditions in any given power flow.

7.2.3 Weak location, strong plan (WLSP)

Weak location strong plan (WLSP) is guided by a value-set which perceives that the targeting of locational costs on generators does not improve the efficiency with which the system meets its required targets, but rather acts as an obstacle to the successful attainment of those targets. Locational signals are viewed as a lower order priority compared to that of achieving carbon targets, and thus have greatly reduced relevance in a system undergoing a major low carbon transition. Generators are therefore not provided with strong locational signals, and therefore have no incentive to incorporate network conditions into their planning or operating decisions. The value-set of this scenario also espouses the benefit of making anticipatory and strategic transmission network investment planning decisions, rather than responding only to the incremental upgrade needs of firm generation projects.

The decision-making approach for scenario development within this framework therefore involves the deployment of low carbon technologies without regard for constraints imposed by existing networks, but with a strategic and anticipatory approach to network upgrades in respect of future generation deployment. In any time-stage generation investment decisions will be taken across a balanced portfolio of technologies according to the technology specific locational advantages, but without considering what constraint may have occurred in the previous phase. Transmission network investments in any time stage are made to bring the system as close to compliance as possible – this involves considering areas of emerging network constraint in the previous time-stage alongside the implications of the next set of generation investment decisions, and with an anticipatory view of likely requirements in future stages. There is no intervention upon the dispatch patterns generated by the Excel algorithm in response to the operational network constraints emerging in different conditions.

7.2.4 Weak location weak plan (WLWP)

Weak location weak plan (WLWP) is guided by a value-set which perceives that the targeting of locational costs on generators does not improve the efficiency with which the system meets its required targets, but rather acts as an obstacle to the successful attainment of those targets. Locational signals are viewed as a lower order priority compared to that of achieving carbon targets, and thus have greatly reduced relevance in a system undergoing a major low carbon transition. Generators are therefore not provided with strong locational signals, and therefore have no incentive to incorporate network conditions into their planning or operating decisions. However, it also maintains an ambivalence towards centralised planning, coordination or attempts to develop long-term blueprints of system development, and so resists the development of institutions which have any tendency towards interventionist or centralised planning approaches. Network development remains mostly reactive, and there are no anticipatory network investments in this scenario – upgrades only respond to visible and committed generation projects within each time-stage.

The decision-making approach for scenario development within this framework therefore involves the deployment of low carbon technologies without regard for constraints imposed by existing networks, but with a responsive approach to network upgrades. In any time-stage generation investment decisions will be taken across a balanced portfolio of technologies according to the technology specific locational advantages, but without considering what constraint may have occurred in the previous phase. The rate of generation investment may be slowed due to lack of available network, but the locational choice is not affected. Transmission network investments in any time stage are made to bring the system as close to compliance as possible – this involves considering areas of emerging network constraint in the previous time-stage alongside the implications of the next set of generation investment decisions. However, there is no anticipatory view of likely requirements in future stages. There is no intervention upon the dispatch patterns generated by the Excel algorithm in response to the operational network constraints emerging in different conditions.

7.2.5 Reflections on the epistemology of the scenario development process

The scenario development process as described follows a movement between the three levels, at each stage considering how value systems, actor-institutional relationships and technological system realities combine to inform the decisions taken by actors in the next time-stage. This involves the integration of diverse kinds of information, and inferring from it plausible resulting strategies from the perspective of different system actors. As shown in the flow diagram of ***Figure 37***, this involves an inductive rather than deductive approach to reasoning. In philosophy, a deductively reasoned argument is one in which the conclusions necessarily follow from the premisses. An inductively reasoned argument is one in which the premisses give strong evidence for, but do not logically entail or guarantee the conclusions. Thus while deductive arguments can only be valid or invalid, inductive arguments have relative degrees of strength (Copi et al., 2006, IEP, 2014). The logical dependence of deductive reasoning on the truth of its premises ultimately requires the acceptance of some starting axioms, or else no knowledge at all can be established. Attempting to reason without accepting either starting axioms or induction is problematic. Hume's refusal to tolerate any form of inductive reasoning led him to an extreme sceptic position which rejected the validity of scientific enquiry. In his discussion of Hume, Russell concludes 'that induction is an independent logical principle… and that without this principle science is impossible' (Russell, 1947).

The principles of deductive and inductive reasoning can also be applied in a comparison of alternative approaches to future scenarios and modelling. The output of a linear-programmed optimisation model is effectively a complex deductive argument – given the premisses of the argument (the costs and performance characteristics of the technologies) the conclusion (the cost-optimal mix of technologies for the system as it is defined in the model) is logically valid – the conclusion is logically guaranteed by the premisses. Evidently, as with any deductive argument, the argument itself does not establish whether the premisses are true. In fact, the premisses in this case are subject to considerable variation and uncertainty, and this is precisely the main challenge with how to interpret the multiple possible outputs of such models. By contrast, the scenario process developed in this thesis, proceeds inductively. It uses a combination of premisses which are contrasting types of data, both qualitative and quantitative, and which as a result cannot logically be combined to produce a deductive argument. However, they can be combined inductively to produce strong evidence for the postulated outcome.

The deductive modelling approach though 'valid' in the strict logical sense, is entirely dependent upon a vast number of premisses whose truth is impossible to verify – specifically, the costs and other quantified parameters of energy technologies, fuels, demand elasticities etc, for many years into the future. The inductive scenario approach requires reasoning which cannot be shown to be logically valid in the same way, as it involves making mental linkages between logically contrasting (quantitative and qualitative) datasets. However, its premisses can be clearly understood, and though they are not strictly amenable to being proved as true or false, they can be seen as plausible, and likely outcomes from them can be strongly reasoned by anyone with an empathic understanding of how humans might behave in certain situations. Thus the scenario approach is built on relatively strong inductive arguments of the type: *if I were a generation investor with a range of technology options, in a system with some congested and some uncongested areas, and which gave strong locational signals, I would be likely to invest in the uncongested area*.

Thus inductively reasoned scenarios avoid producing an output which can only be said to be 'valid' based on a large number of highly uncertain individual premisses to the argument, and instead produce an output which can be said to be 'strongly reasoned' based on a much more limited set of conditions, incorporating technical conditions as well as actor perceptions of these in the context of a hypothesised policy value set.

These are in no sense 'optimised' pathways. However, again it must be remembered that for an optimisation model the optimisation is based on inputs which are highly uncertain, and within a system that has major structural differences to any real energy system, notably perfect information and perfect foresight. The scenario approach by contrast produces plausible pathways which emerge from the aggregated activities of system actors with separate perspectives, limited information and limited foresight. The characteristics of the process therefore usefully reflect uncertainties and information limitations which exist in real systems.

7.3 The structure of variability in the scenarios

Chapter 2 argued that the effectiveness of scenarios is greatly assisted by clearly categorising the future variability of the system. This section clarifies which elements of the future scenarios will be considered fixed, and sets out how variation between the scenarios will be considered.

7.3.1 Fixed system elements

A large technological system is highly complex and has a very large number of potentially variable elements. Nonetheless, a large number of internal system elements in a scenario will be treated as fixed or 'pre-determined'. This may be because there are elements of the system which there are good reasons to consider highly certain and predictable – thus their consistent treatment within all scenarios reflects the high level of certainty connected with them. Other elements may be treated as fixed, not because their invariability is certain, but because exploring their variability is beyond the immediate scope of the process, because they are considered to be less fundamentally connected with the concern of the focal question. For practical reasons there must be a hierarchy of elements whose variation is explored – all other elements should for consistency be held as fixed across all scenarios. The key fixed elements are now discussed, including whether they are fixed because they are considered pre-determined, or their variability is beyond the scope of the question.

7.3.1.1 Low carbon policy

The focal question sets the role of the transmission network within a specific low carbon context, defined as a requirement to meet a target of $50gCO_2/kWh$ by the early 2030s (CCC, 2010b, CCC, 2013a). This means that in all scenarios low carbon policy is a fixed element – the background assumption of the level of commitment to achieving this target through supporting and incentivising low carbon generation technologies does not vary. This fixed background assumption on decarbonisation is not intended to suggest that such a policy background is a foregone conclusion. Rather it is a question of scope of the focal question, according to which the research is not concerned with what the role of the transmission network would be in a system in which decarbonisation was completely off the agenda. The trajectory towards the $50gCO_2/kWh$ target is measured at each time stage in each scenario, by calculating the total annual contribution to electricity supply of the installed capacities of generators, based on average annual load factors (given in Appendix E.5.4), and assuming that low carbon generators are higher merit-order than high-carbon generators.

The precise policies which would be required to incentivise the building of low carbon generation plant sufficient to meet this target, are not specified in the scenarios. However, it is assumed that all available technologies are given comparable incentives, sufficient for each to be competitive, and there is no explicit preference for one technology over another. Depending on the scenario and its transmission charging policy approach, some technologies may have locational advantages – however this would arise from the effect of the transmission charging policy, not from the generation incentive. This assumption of technology neutrality in generation incentives involves the assumption that, at least as far policy on incentivising low carbon generation is concerned, the existing market-led, technology neutral paradigm – what Mitchell has described as the Regulatory State Paradigm (RSP) – remains in place, and that there is no shift in any of the scenarios to, for example, a more directed state intervention on the generation mix in favour of a particular technology type.

This freezing of the conditions of the broader energy policy value set or paradigm, even while the scenarios explore changing value sets associated with the specific area of transmission policy, might be criticised from the point of view of the broader internal consistency of the scenarios. For example, in scenarios which are predicated on more anticipatory and strategic planning in transmission, the validity of a continuing assumption that no comparable strategic planning approach takes place on the generation side might be questioned, on the basis that the internal consistency of scenarios requires that the same value-system should inform all areas of policy which fall within them.

The requirement for internal consistency is something strongly argued for by proponents of the intuitive logic school of scenario thought (Van Der Heijden, 2004). This can be interpreted to mean that any policy or actor decision in the scenario must conform to the values which characterise the scenario – the values attain a global currency. However, critics have pointed out that this extreme homogeneity is in fact highly unrealistic – the world is much more typically heterogeneous and replete with tensions and disagreements (Anderson et al., 2005). Unless there is a strong reason why policies are yolked together under the same value system, there is no reason to assume that they would be. It is necessary to look at the real world system that the scenario is representing and ask whether or not consistency of values between given policy areas is guaranteed by inherent links between those areas, or whether they are insufficiently strongly linked to guarantee that a policy change in one area entails a similar policy change in the other.

As will be set out in Section 7.4.1, the scenarios in this thesis focus on electricity transmission policy choices, and the intended 'scenario users' are transmission policy makers. The values grid depicted in ***Figure 21*** creates four scenario spaces specifically referring to alternative approaches within transmission policy. The question is, should the values suggested by these alternative spaces be translated and extended to other, wider energy policy areas? Is there an inherent link between transmission policy and other energy policy areas, meaning that approaches in transmission policy will be mirrored in other areas?

Transmission policy and other energy policy areas – particularly generation incentives – are different areas involving different types of technologies and different sets of actors. They are affected by different policy levers (TNUoS, BSUoS, RIIO etc for transmission; FITs and CM for generation incentives) which are pulled by different sets of people within Ofgem and DECC. The expressions of equivalent values in terms of specific policies in the two areas, could also mean quite different things. Attempting to pick a winning generation technology is a different kind of risk from being anticipatory about future network needs; though the latter involves a degree of technological expectation, it is less specific and allows for a greater amount of hedging. The anticipatory transmission approach as understood in this thesis, is by no means inconsistent with a technology neutral generation incentive approach. There is no inherent reason why policy levers in these two areas should necessarily be pulled at the same time and in the same direction.

Given that it cannot be conclusively shown that contrasting values in transmission and the broader energy system policy cannot co-exist, these have to be treated as independent variables. The scenarios are about informing transmission policy, which means they must clearly show the possible effects that decisions which could be taken within that sphere, by the intended scenario users (transmission policy makers), might have on the system. Unless a variable can be shown to be absolutely coupled to one of the key variables under study, it should not be simultaneously varied as this would obfuscate what the effect of the transmission policy choice had been. The holding constant of independent variables other than those directly under study is a matter of upholding the clarity of the outputs. This relates to the point of principle developed during the discussions in Chapter 2 and proposed in Section 2.6.2.

The co-existence of apparently contrasting value-sets within different areas of energy policy is moreover by no means an unexpected phenomenon. As discussed in Chapters 3 and 4 it is precisely such a mix which is characteristic of energy policy generally and transmission policy specifically, at the present time. Hall's analysis of policy paradigms suggests that it is highly possible that values affecting different policy choices could shift in different ways and at different times within the fabric of the policy mix, as the overall policy paradigm 'stretches' to accommodate an 'anomaly'. Where, in scenarios presented in this thesis, shifting transmission policy values contrast with the frozen wider energy system policy values, it is this 'stretch' condition that is being represented. Hall notes that an accumulation of these stretches can result in the paradigm being ultimately discredited and replaced – the appearance of stretches and the tensions which may be caused by them are highlighted in the scenarios and discussed as part of the analysis, including observing examples in which the tension may be accumulating to such an extent that there could be a possibility of broader paradigm shift (for example in Section 9.2.8). This approach allows the scenarios to convey a more realistic depiction of policy in which multiple policy areas are not inevitably closely aligned and locked together. It also allows analysis of where wider regime tensions may arise through increasing anomalies in the paradigm. Such an analysis is not achieved in scenarios which smooth such tensions away by pre-supposing unrealistic levels of cross-regime ideological harmony.

7.3.1.2 System security

It is also a requirement that the generation mixes achieve an acceptable level of system security, bearing in mind the increased proportion of variable generation sources. Although there is potential for storage, demand side management and interconnectors to mitigate the effect of supply side variation, a more conventional response would be to ensure that there is sufficient thermal capacity to back up the variable renewables. In the scenarios, a relatively conservative approach is taken of using the derating factors applied by Ofgem in their 2013 Capacity Margin Assessment (Ofgem, 2013), to calculate the derated capacity margin of the generation mix against the peak demand in the scenario year. These derating factors (***Table 7***) are Ofgem's statistical assessment of the proportion of installed capacity of each generation type which can be reliably expected to be available at the time of winter peak. They are therefore different from, and serve a different purpose to both the seasonal availability factors discussed in Section 6.4.2, and the average annual load factors reported in Appendix E.5.4.

In each scenario year, the generation mix is required to achieve at least a positive capacity margin, through the addition where necessary of firm thermal capacity in addition to the low carbon capacity which may have been added in order to maintain the decarbonisation trajectory. The requirement for only a positive capacity margin is in conventional terms minimal, as currently derated capacity margins less than 5% would be considered risky. However the requirement for only a positive capacity margin includes an assumption that with a large penetration of renewables some other measures – such as demand side response, storage or interconnection – might well become available to add to system security.

The precise policy measures which would be required to ensure that the investment required to maintain a positive capacity margin actually takes place, are not specifically detailed in the scenarios. For plant whose output would ideally be required on an increasingly intermittent basis, as greater quantities of renewables are installed, there are essentially two options. One is that if prices are allowed to rise as high as they naturally would at a point of supply scarcity, such as a low wind condition, that high price, even though only occasionally received, would be sufficient to provide overall annual reward for the plant. However, political sensitivity to high prices, even if occurring very seldom, often means that in practice such prices are prevented from occurring. If this occurs, this creates a 'missing money' problem, and means that peaking plant must be given other incentives to operate, such as the capacity mechanism, which pays plant a fixed retainer to be available at peak times if needed (Royal Academy of Engineering, 2013). The inclusion of a capacity mechanism within the EMR package suggests that this latter approach is the one that is favoured for the time being.

Table 7: *Derating factors by technology for capacity margin calculations, used in Ofgem's capacity assessment (Ofgem, 2013)*

Fuel Type	Availability (%)
Coal / Biomass	88
Gas CCGT / Gas CHP	85
OCGT	92
Oil	82
Nuclear	81
Hydro	84
Pumped storage	96
Wind	17-24

7.3.1.3 Interconnectors

The existing interconnectors have default settings in the modelling when their behaviour is not affected by specific scenario dynamics. They are all on export, with the Moyle and Eire interconnectors each set at 500 MW export, reflecting typical conditions. The IFA and Britned interconnectors are set at a nominal 50 MW export – effectively therefore the default assumption is that they are net neutral. These central assumptions follow those used by ENSG (2012). However the behaviour of these and additional interconnectors is varied in scenarios where the policy and operational conditions deem it appropriate, as is described in the scenarios.

7.3.1.4 Demand profile

Section 6.3 described the process by which system demands for each of the three seasons, disaggregated spatially by model node and projected forward through the scenario period, were developed. As described in Section 7.2 these nodal demand profiles are key inputs to the scenario generation process. Evidently, these input data are based on a single projection of the possible evolution of overall system demand. This projection is strongly informed by the National Grid's Future Energy Scenarios report (National Grid, 2013c), and includes assumptions of the general increase in existing energy system demands, as well as additional new energy service demands arising from the electrification of heat and transport as part of the energy system-wide low carbon transition, as described in Section 6.3.3. The proportions by which the overall system demand is allocated to nodes remains fixed, as described in Section 6.3.2.

However, it is evidently possible that significant variations from this demand profile could in fact occur. The overall growth in electricity demand could be curbed by even greater uptake of energy efficient technologies than is assumed in the profile, or by profound cultural and lifestyle changes. The mass electrification of heat and transport may not occur even assuming the low carbon transition as a fixed element, as alternative decarbonisation vectors may be identified for these services. Demographic shifts may run counter to the assumption that the locational distribution of energy demands remains similar to day, for example if there is a significant change to the concentration of population in the south-east of England. All of these things are possible, but the inclusion of multiple demand profiles against which to test the scenarios would have expanded the number of variables being dealt with by the scenarios beyond manageability. The alternative of running each of the scenarios against a different demand profile would have significantly reduced the comparability of the scenarios, making analysis relating to the focal question of transmission networks extremely difficult. It would also not have had a logical justification – the variation between the scenarios is specifically about transmission network policy, and there is no clear reason why this should have a direct effect on demand. Thus, a single demand profile, broadly compatible with the background assumption of overall system decarbonisation, was developed and applied uniformly to all scenarios.

7.3.1.5 Transmission network investments

Evidently the starting point for all scenarios must be the base year of 2013, hence all scenarios have in common the existing transmission network infrastructure of that base year, as described in Section 6.2. Each of the scenarios makes different additions to this starting network, as the scenarios diverge over successive time periods. However, a small number of transmission network upgrade projects were committed and underway in 2013, and are thus incorporated as fixed and pre-determined elements in each of the scenarios. ***Table 8*** lists these projects, all of which are included in each scenario in the 2018 scenario year. Data sources for this information are the Transmission Owner Major Project Update Table, June 2013 (available at (ENSG, 2013)), checked against projections for boundary capabilities in (ENSG, 2012) and (National Grid, 2012a).

Table 8: *Committed transmission network upgrade projects to appear in all scenarios by year 2018*

Transmission owner	**Project summary**	**Increase in transfer capacity or generation accommodated (MW)**	**Action taken in model**
SHE Transmission	Beauly-Denny 400kV line	850 over B1, 1200 over B4	Beauly-Denny 132kV line (132 MW) replaced by one 400kV line (2780 MW) and on 275kV line (1090 MW), nodes 5-10-13
SHE Transmission	Beauly-Blackhillock-Kintore 275kV reconductoring	300	Line 5-7 uprated by 800; with 0.38 derating this gives 300
SHE Transmission	Hunterston-Kintyre 240 MVA AC subsea link	350 MW additional generation	Added as two 500 MW lines with 0.35 derate, nodes 9-16
SHE Transmission	Caithness-Moray HVDC Reinforcement	600	Added as one line from 3 to 6, to add to the exitsing 6 to 7 line
SPT	Incremental Reinforcement: (a) Series Compensation (b)) East-West 400kV Upgrade	1100 (B6)	a) the 1100 B6 increase achieved by changing B6 ratio; and b) theeast-west upgrade by uprating strathaven-smeaton to double 400kv line
SPT	Western HVDC link	2200 (B6)	Western HVDC added, nodes 16-33
SPT	East Coast 400kV Upgrade	1700 (B5)	East coast upgrade added - uprate to 400kv line between nodes 13-18 (and 7-13?)
NGET	Scotland-England Reinforcement (Harker-Hutton reconductoring)	1400	Increased capacity of Harker Hutton (22-31) line. This delivers approx 1400 extra as stated in this list, btu note difference in B7 caps between ENSG 2012 and ETYS 2012, and relative timing of measures
NGET	North Wales (Reconductor Trawsfynydd –	1500	Uprated using example lines - actually adds 2000

	Treuddyn)		to capacity after derating
NGET	East Anglia (i) Reconductoring Bramford-Norwich + (ii) Bramford Substation Reconfiguration	1100	Norwich to Sizewell now with 'turn in' at Bramford. Both lines uprated

7.3.1.6 Generation investments

As with the transmission system, the common starting point for all scenarios is the existing generation mix in the base year of 2013, as described in Section 6.4. In addition, there are two conventional generation projects which, though not operational in 2013, are sufficiently advanced to be considered as fixed, pre-determined elements in all scenarios. The Carrington 800 MW CCGT plant is currently under construction near Manchester, and is assumed to appear in all scenarios in 2018. The Hinkley Point C nuclear station is assumed to be online in all scenarios by the year 2023.

The majority of onshore wind additions in the year 2018 are common to all scenarios. These total 2671 MW and constitute the majority of the added capacity between 2012/13 and 2017/18 in the 2011 Seven Year Statement. This gives a baseline capacity of 6846 MW in all scenarios (the SYS lists only transmission connected wind). SLWP meets only this baseline, whereas the other scenarios include more of the total SYS 2017/18 listing of 7864 MW, due to different assumptions about connections to remote regions and islands.

Offshore wind sites currently with consent, totalling 2746 MW, and those under construction, totalling 1401 MW, are treated as fixed elements and appear in all scenarios in 2018 as a minimum baseline (see Appendix E.4 for further detail).

7.3.1.7 Generation retirements

There are a number of known factors which will cause the closure of large quantities of currently existing conventional plant within the time frame of the scenarios. The most significant factors are the age of the plant, the impact of EU regulations such as the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED), and domestic low-carbon policies. Precisely how these factors will interact, and what will be the exact pattern of closures as a result cannot be predicted with certainty. Assumptions on generation retirements are therefore, for the most part, not proposed as pre-determined elements, but, in the same manner as the demand assumptions, constitute a reasonable trajectory taking into account the above factors, which is held constant across all scenarios to assist comparability.

Table 9 shows the programme of plant closures applying in each scenario. The closures listed to take place by the year 2018 are all committed as of 2013, due to a mixture of commercial decisions and the effect of the LCPD, and are thus 'pre-determined'. The closures listed in subsequent years are more speculative. An influential factor in the mid 2020s will be the Industrial Emissions Directive. Ratcliffe-on-Soar is the only plant at the time of writing to be fully opted into the IED. It is likely that the IED will cause some significant plant closures in the mid 2020s, and those selected for closure in the scenarios in 2023 have been done so on the basis of the tone of recent announcements by the relevant companies. In 2028 the remaining coal plants except for Ratcliffe-on-Soar are closed – this is due to an assumption that with an increasingly strong low carbon policy agenda it will be increasingly hard for them to operate. In 2033 a large number of CCGT plants, and Ratcliffe-on-Soar, are closed due to reaching the end of their expected operational life – the IEA estimates the technical lifetime of a CCGT plant at 30 years (Seebregts, 2010).

Table 9: *List of plant closures and retirements by scenario year*

Scenario year	Plant name	Node	Plant type	Capacity	Reason for closure
2018	Teesside	25	CCGT	1875	Uneconomic
	Roosecote	31	CCGT	229	Uneconomic
	Wylfa	34	Nuclear	490	End of life
	Kings Lynn A	42	CCGT	340	Uneconomic
	Ironbridge	45	Coal	964	LCPD
	Uskmouth	57	Coal	363	Uneconomic
	Tilbury Stage 1	59	Coal	1131	LCPD
2023	Hartlepool	25	Nuclear	1207	End of life
	Eggborough	27	Coal	1940	End of life / IED
	Ferrybridge	27	Coal	1014	End of life / IED
	Heysham 1	32	Nuclear	1160	End of life
	West Burton (half)	41	Coal	1000	End of life / IED
	Didcot B	56	CCGT	1550	End of life / IED
	Aberthaw	57	Coal	1665	End of life / IED
	Dungeness B	61	Nuclear	1081	End of life
2028	Longannet	13	Coal	2284	End of life / low carbon
	Hunterston	16	Nuclear	1074	End of life
	Torness	19	Nuclear	1215	End of life
	Lynemouth	23	Coal	420	End of life / low carbon
	Drax	27	Coal	3906	End of life / low carbon
	Heysham 2	32	Nuclear	1248	End of life
	Fiddler's Ferry	33	Coal	1987	End of life / low carbon
	Cottam	41	Coal	2000	End of life / low carbon
	West Burton (remainder)	41	Coal	987	End of life / low carbon
	Rugely	45	Coal	1018	End of life / low carbon
	Hinkley B	71	Nuclear	1261	End of life
2033	Peterhead	8	CCGT	1180	End of life
	Brigg	28	CCGT	260	End of life
	Killingholme	28	CCGT	900	End of life
	Killingholme 2	28	CCGT	665	End of life
	Keadby	28	CCGT	735	End of life
	Deeside	33	CCGT	515	End of life
	Connahs Quay	33	CCGT	1380	End of life
	Rocksavage	33	CCGT	810	End of life
	CDCL	41	CCGT	395	End of life
	Peterborough	42	CCGT	405	End of life
	Ratcliffe on Soar	44	Coal	2021	End of life
	Corby	46	CCGT	401	End of life
	Little Barford	47	CCGT	665	End of life
	Barry	57	CCGT	245	End of life
	Rye House	58	CCGT	715	End of life
	Barking	58	CCGT	1000	End of life
	Medway	59	CCGT	700	End of life
	Damhead Creek	59	CCGT	805	End of life

7.3.1.8 Other elements out of system scope

As defined by the focal question, the system under study for the scenarios is the transmission network and the actors and policy values directly linked to this. Developments at the distribution network level cannot be considered in detail by the scenarios. Distributed generation technologies which would connect directly to the distribution networks are not part of the initial storyline development – however a possible expansion in solar PV is considered as a non-actor-contingent element.

The scenarios primarily focus on known and demonstrated technologies. They have not included carbon capture and storage (CCS) technology as an option, and biomass for electricity generation is also limited to the relatively small capacities listed by 2017/18 in the SYS. Large scale expansion of biomass power generation is considered too uncertain in the light of sustainability concerns.

Public objections to a major expansion in transmission networks could constitute a major part of the story transmission development, as there exist significant public concerns around transmission line and pylon construction (Devine-Wright et al., 2010). It is beyond the scope of the scenarios to represent alternative levels of public support for or objection to transmission lines as an additional scenario variable. However, the contrasting network architectures delivered by the scenarios may be evaluated in terms of the level of investment required and the potential challenges this could present in terms of public acceptability.

Despite the removal of or freezing of assumptions around elements which are not directly within the system under study, some of the aspects may have significant impacts. A selection of them are analysed via ex-post sensitivity analyses as non-actor-contingent elements as discussed in Section 7.3.2.

7.3.2 Categorising future variation: 'actor-contingent' and 'non-actor-contingent' elements

The previous section described various elements of the system which are treated as fixed, either because they are considered as pre-determined or because their variation is beyond the scope of the work. This section summarises the approach to the scenario elements which are considered subject to potential variation, recalling the distinction drawn in Section 2.3.2 between 'actor-contingent' and 'non-actor-contingent' elements. This distinction is useful to clarify the different kinds of decision making to which the various future elements could be applied. Actor-contingent elements suggest options policy makers could take which could have a material effect on the evolution of the system (proactive decision making). Non-actor-contingent elements are outside of the control of policy makers, and the exploration of such elements gives policy makers the chance to consider how robust their decisions would be under different uncontrollable aspects of the future (protective decision making). In combination, the scenario analysis that this structure promotes may yield insights that contribute towards agreed paths forward (consensus building).

7.3.2.1 Actor-contingent elements

Actor contingent elements are the elements which are within the control of key internal system actors to influence. Scenarios which emerge from the active and conscious choices of certain key prime mover actors, are ‘actor-contingent scenarios’ – contingent upon key choices made by these prime mover actors. In these scenarios, these key choices are policy choices which affect the regulation of the transmission system. These policy choices are based on alternative value sets as illustrated in ***Figure 36***. The effects of these choices are the impacts they have on decision making processes of other actors who choose to invest in transmission or generation technologies. The reasoning behind these investment decisions in each scenario is represented by the developed by the inductive application of the decision rules explained in Section 7.2.

The transmission and generation investment decisions within each scenario are also guided by certain parameters and boundaries. On the generation side, there is an impetus that investment decisions as a whole should ensure the system remains on track to hit 50gCO_2/kWh by 2033, and retain a positive capacity margin, as described in Sections 7.3.1.1 and 7.3.1.2. In addition, technology specific investment decisions are bound by locational specific bounds on maximum deployment potential, and by maximum build rates. These data are provided at Appendix E.4.

On the transmission side, network investment choices can occur in three ways. First, where an existing line is low capacity compared to the highest capacity lines on the network as defined in the original SYS data (National Grid, 2011b), it is considered to have potential for an uprate, which would be achieved by replacement of the line with a new higher capacity material, whilst using the existing towers and line route. In this case the line parameters of the existing line – thermal capacity and impedance – are exchanged for the line parameters of the new higher rated line (based on the parameters of another higher rated real line in the SYS data). Second, onshore capacity can be added through the building of new overhead lines. In this case line parameters are copied from existing lines, multiplied by the distance and the impedances combined using Equation 1. Third, HVDC subsea offshore cables can be added. Paramaters for these are based on those suggested by Sarkar (2012). Uprates and new overhead lines remain subject to the derating factors as discussed in Section E.1, which account for voltage and stability limits. Sub-sea HVDC cables bypass these limits and can add capacity at 100% of their rating.

7.3.2.2 Non-actor-contingent elements

Non-actor-contingent elements are those which are uncertain, which could have a significant impact upon the system, but which cannot be controlled or are not related to the decisions of any identifiable internal system actor. This could be because they originate from outside the system, as defined by the focal question, or because the nature of their uncertainty is such that they are not easily connected with known possible actor decisions. Although system actors cannot control these elements of the future, they may wish to consider how robust the decisions they can make will remain under such conditions. As the non-actor-contingent elements are unconnected to the decision making process which defines the actor-contingent scenarios, they could, logically, be elements experienced by any of the scenarios. The non-actor-contingent elements are therefore used as stress tests to consider the relative robustness of each of the emergent systems to these different aspects.

Thus following the development of the actor-contingent scenarios using the process described in the previous sections, each of the scenarios will be tested against the following non-actor contingent variable elements:

- Growth in solar PV – this would be seen by the transmission network as suppressed demand during sunny periods.
- Alternative EV charging patterns – including greater or lesser peak avoidance, locational signals
- Development of grid scale storage
- Public objections to transmission network expansion

7.4 Summary of scenario process

Section 2.6 developed a scenario development process which clarifies the boundaries of the process and draws apart the different kinds of fixed and variable future elements of which the future scenarios are comprised. As emphasised in that section, the process in practice is not linear. However, with all elements now in place, it is appropriate to briefly reprise that process and indicate how the various elements discussed fall in to it.

7.4.1 Define the question and objective type, and identify the scenario user or users

The focal question for the scenarios is:

- How can transmission network policy choices affect the role that the transmission network plays in helping to deliver a low-carbon electricity system by the early 2030s?

The focal question clarifies that the primary scenario users are UK actors with the ability to influence electricity transmission network policy. The objective of the scenario process is primarily proactive – it aims to inform policy decisions that could be made in the near-term by actors who have the agency to make such decisions. The key 'prime movers' in this regard are DECC and Ofgem. However, multiple actors in the system, including generation and transmission companies have the potential to influence the design of these policies. Hence the scenarios may also have the potential to serve as tools towards consensus building between these various actors. Finally, the scenarios will be tested against non-actor-contingent events – the relative robustness of the scenarios to these will inform protective decision making.

7.4.2 Scope and define the system in terms of visions and values, actor networks and technological configurations

The focal question defines the system as the technologies, policies and actors with a direct relationship to the electricity transmission network. Through the discussion in Chapters 3 to 6 this system has been characterised across these three levels, and Section 7.2 described how the movement and iteration between these three levels, as called for in Section 2.5, is achieved in practice.

7.4.3 Identify pre-determined or immobile elements

Identified pre-determined elements are the generation and transmission investments considered committed at the time of writing, as set out in Sections 7.3.1.5 and 7.3.1.6. Other elements, though potentially variable, are treated as fixed due to the scope of the focal question. These are: low carbon policy; requirement for conventional plant due to capacity margin; demand profile; generation retirements. Elements which are out of system scope are: distribution network activity including distributed generation; major demand side changes; unknown or uncertain technologies; and public objections. However some of these elements are subsequently explored as non-actor-contingent elements.

7.4.4 Identify actor-contingent elements

The actor-contingent elements which provide the basis through which the scenarios diverge from each other, are the policy decisions which could be made around the signalling of locational network requirements to generators, and the level of strategic or anticipatory planning in network development. These options are organised within four distinct value-set frameworks (*Figure 36*) which are hypothesised as being the prevalent value-sets within which policy choices are made in each scenario.

7.4.5 Describe system evolution via branching points along alternative pathways

Using these policy-guiding value-sets as the internal motors of the decision making process in each scenario, the evolution of four distinct scenarios is traced forward from the identical starting point of the present system, based on how the alternative value-sets interact with the interpretation of the system condition and how this informs subsequent network and generation investment decisions. This requires an iterative process as set out in Section 7.2.

7.4.6 Assess actor contingent scenarios against non-actor contingent uncertainties

Having developed scenarios based on the active decisions of internal system actors, these 'actor-contingent' scenarios can now be tested against non-actor-contingent uncertainties (listed in Section 7.3.2.2), which whilst being beyond the scope of the system as defined by the focal question, could occur against the background of any of the scenarios.

7.5 Conclusions

A scenario process based on inductive reasoning from multiple contrasting data sources can make a useful contribution to energy system policy analysis. It is a process capable of integrating contrasting but relevant types of information, exploring the perspectives of system actors in conditions of imperfect information and limited foresight, as would be the case in the real system. Rather than producing numerous optimal solutions based on uncertain inputs, it produces plausibly reasoned pathways differentiated by the alternative policy value-sets which guide them.

This chapter has also set out the practical approach for creating scenarios which iterate between the three system levels, and identified boundaries, fixed and variable elements. It has also shown how the information assembled in Chapters 3-6 fits into the outline scenario process set out in Chapter 2, and in so doing has: clarified the focal question, objective type and scenario users; identified the values, actors and technological configurations relevant to the system under study; and identified the different kinds of fixed and variable elements which will affect the development of the scenarios. In the next chapter the scenarios will be described.

8 Low carbon transmission network scenarios

This chapter presents narrative descriptions of four scenarios of the development of the GB transmission network in the context of the overall decarbonisation of the electricity system, developed using the method previously described. This chapter begins by presenting the power flow modelling outputs relating to the system in the base year 2013, and then proceeds by describing in turn each of the evolutionary paths taken by each scenario from this starting system state. The alternative scenarios are presented in turn. Each scenario description begins with a short overview of the whole scenario period, after which the five-year time stages are presented in succession. Each time-stage description describes the changes to the generation mix and the new transmission investments which occur in the scenario time-stage, and the power flows and exceedences which arise from these generation and transmission investments against the set demand background. The emergence of constraints on the network in one time-stage provides information which feeds forward to the investment decisions taken in the next time stage.

The scenarios are described in this chapter using a combination of qualitative narrative, quantitative data and visual representation of the network.

8.1 2013: the present system

8.1.1 2013 Generation mix

Figure 38 summarises the generation mix in the current system.

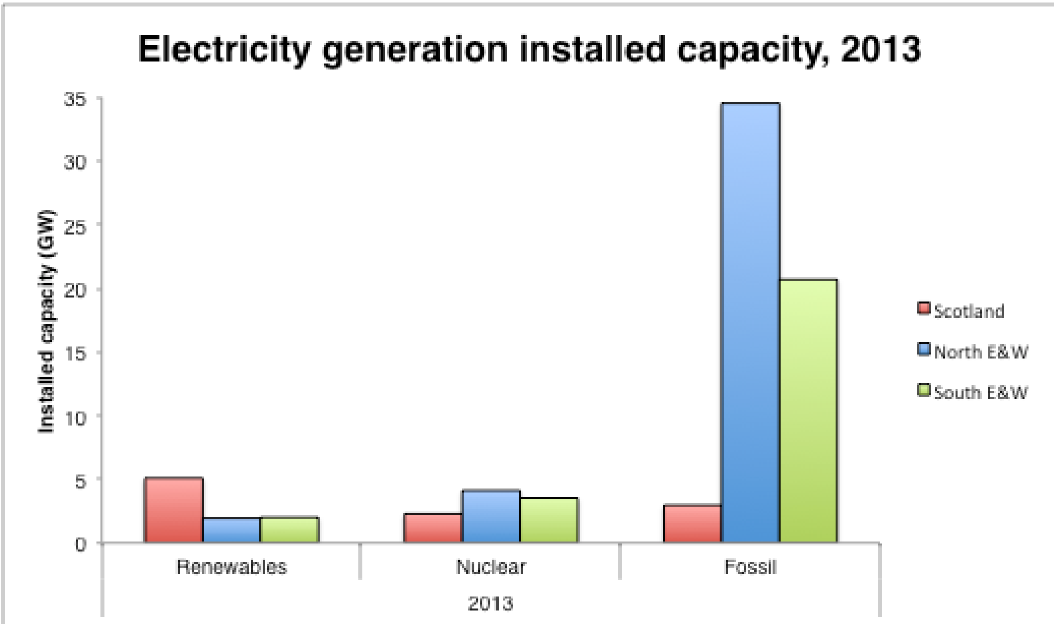


Figure 38: *Electricity generation installed capacity, 2013*

This generation mix gives the following system indicators in 2013 (*Table 10*).

Table 10: *2013 System indicators*

System derated capacity margin (%)	4.7
Proportion of annual electricity demand met by (%):	
Renewables	8
Nuclear	19
Other	73
Carbon intensity of electricity (g/KWh)	432

As discussed in Section 6.4.1 the generator mix for the base year of 2013 was based on the 2012/13 projection from the 2011 National Grid Seven Year Statement (SYS) (National Grid, 2011b). The SYS had to be used as it provides a detailed breakdown of each transmission connected generator by its location on the grid, by specifying its grid access point, whereas the Digest of UK Energy Statistics (DUKES) (DECC, 2013a, DECC, 2014a) does not provide this locational information. The 2011 edition of the SYS was the last to be published – the document was subsequently merged with various other National Grid publications to become the Ten Year Statement, first published in 2012 (National Grid, 2012a). This new document however did not provide the detailed breakdown of plants by locational grid access point in its appendices, as the SYS had previously done. Hence the most recent available data for the base year with the required locational detail were the 2012/13 projections from the 2011 SYS.

The use of projected data from 2011 means that there is a possibility of some small discrepancies between what was projected by National Grid in 2011 and what actually turned out. In assembling scenario base year data, in some cases adjustments were made to the 2012/13 SYS projected data in order to account for updated information on commercial decisions of operators, which differed from the TEC applications they had submitted at the time of the 2011 SYS. A more detailed discussion of generator installed capacity assumptions, their adaptation from SYS data and related working, is provided in Appendix E.4.

Table 11 compares the installed capacities in general technology types for 2013 as projected in SYS 2011 data and used in the scenarios, with the actual recorded installed capacities for the year 2013 as reported in DUKES 2014 (DECC, 2014a). In categories such as offshore wind, nuclear, wave and tidal and fossil, the difference between the values is small, and can be attributed to minor differences between National Grid's 2011 projections, and the actual out-turn. However, more substantial differences are found in the categories of onshore wind, solar, biomass and waste, and to a lesser extent hydro. These differences reflect the fact that the SYS data only captures transmission connected generators. However, a substantial amount of the current renewable installed capacity is at lower voltage networks - DUKES captures generation installed at both transmission and distribution levels, hence the higher figures in some cases.

Table 11: *Comparison of scenario base year installed capacity assumptions with 2013 reported data from DUKES. Source: (DECC, 2014a), table 5.6 (nuclear and fossil data) and table 6.4 (renewables data)*

Technology type	DUKES 2014 Capacity (MW)	Scenario base year data (based on SYS 2011) Capacity (MW)
Onshore wind	7513	4175
Offshore wind	3696	3653
Nuclear	9906	9943
Hydro	1693	1117
Wave and tidal	7	0
Bioenergy and wastes	4002	97
Fossil	61,764	55931

Data from DUKES 2014 (DECC, 2014a) indicates that the amount of electricity produced from nuclear closely matches the levels generated by the assumptions in the base year modelling: table 5.1 from DUKES 2014 reports 70.6 TWh from nuclear in 2013, which was 19.8% of the total electricity supply of 356.3 TWh (DECC, 2014a); the scenario base year data has 72.3 TWh from nuclear, which is 19.2% of the total electricity supply of 376.2 TWh. This close match in energy terms for nuclear reflects the similarity of the installed capacity figures (as shown in ***Table 11***, above), which in turn reflects the fact that all nuclear is transmission connected. However, the total production from renewables in 2013 recorded by DUKES amounted to 53.7 TWh, or almost 15% of total electricity supplied (DECC, 2014a), whereas the scenario base year data generates 30.1 TWh which amounts to only 8% of total supply. This significant difference is due to the issue, noted above, of a significant quantity of renewable power being generated on distribution networks, and not recorded by the SYS, and hence not included in the base-year installed capacity assumptions for these scenarios.

The focus on transmission connected generation in these scenarios, and the decision not to enumerate and locate all of the existing distribution connected renewables to add to the base year generation mix, is justified by the fact that the scope and focus of the scenarios and the related power flow modelling is on the transmission network. From the perspective of the transmission network, embedded generation on the distribution networks is indistinguishable from a reduction in demand. Detailed modelling of power flows on the distribution network is out of scope for the current project. The decision to restrict the scope of this project to the transmission network was considered necessary for the purposes of bounding the work and making it tractable. Nonetheless the potentially significant future role of distribution connected renewables, and the possibility that large quantities of embedded generation could begin to have quite significant interactions with transmission networks, means that a valid criticism could be made that growth in distributed generation was not considered as an internal variable within each of the scenarios. In order to partially address this potential criticism, one of the 'non-actor-contingent' variants applied to each of the scenarios, is a condition in which large scale penetration of a distributed energy technology – solar PV – does occur, and the effects of this on the transmission network are explored (8.6.8.3).

8.1.2 Resultant power flow

The modelling of power flows illustrates the present state of the system. Although installed capacities of renewables are currently low relative to longer-term ambitions, these technologies are having an impact on the pattern of constraints, as shown by the generally higher level of line exceedences (which would require constraining actions) when the power flow is run for high wind conditions.

The winter high-wind condition (***Figure 39***) sees high exceedences between the highlands of Scotland and the central belt, over the Cheviot boundary and in the north-west of England, as high renewable output in northern GB is exported south. There is also a constraint between south Yorkshire and the east Midlands due to high fossil output in this region. In the winter low wind condition (***Figure 40***) constraints in Scotland and northern England are almost entirely removed, but there are still some constraints in the Midlands and the south-west due to the activity of conventional plant. The relatively small quantities of renewables, and their concentration in northern Britain means that in the other conditions, NS produces a similar constraint pattern to high wind, and SN and average conditions produce a similar constraint pattern to low wind.

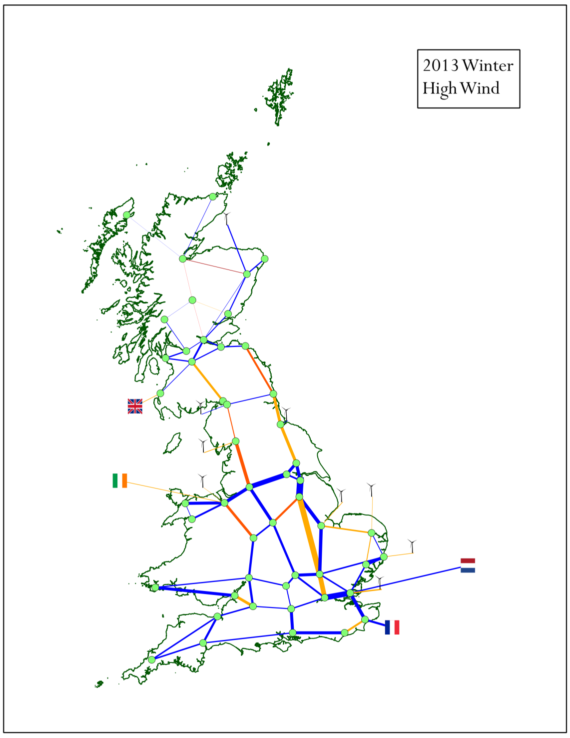


Figure 39: *2013 Winter High Wind power flow*

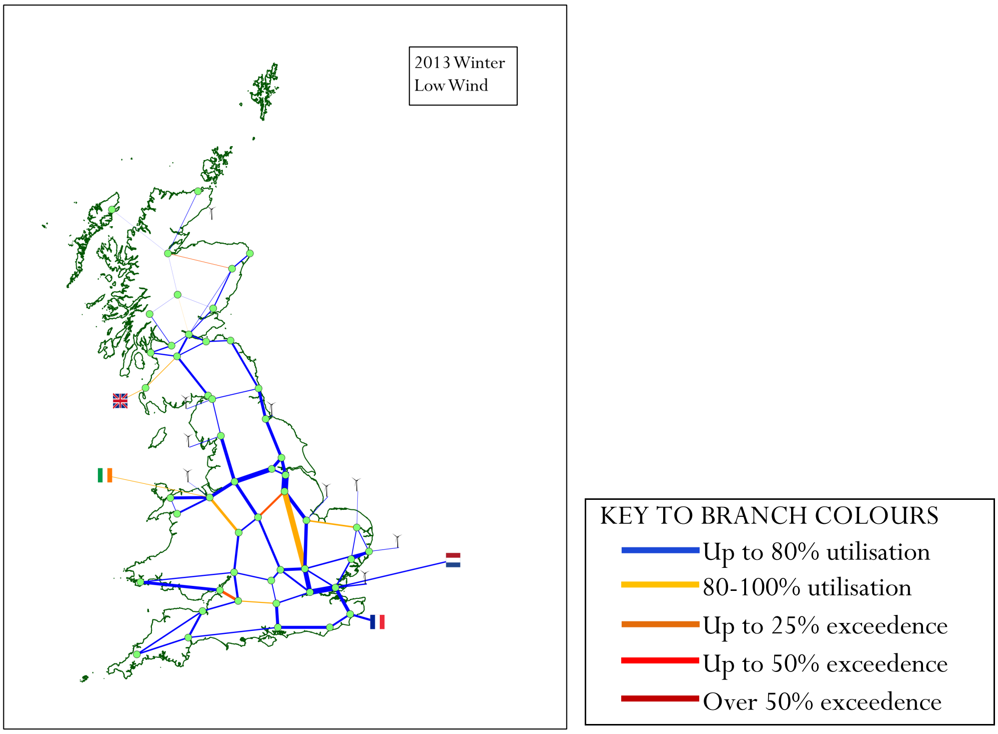


Figure 40: *2013 Winter Low Wind power flow*

The Spring high wind (***Figure 41***), North-South, South-North and average (***Figure 42***) wind conditions have significantly higher exceedences in Scotland than in the equivalent winter conditions, but lower or zero exceedences in the midlands and south-west from conventional plant. This is due to the fact that spring time can still produce high winds, comparable to winter time, and combined with significantly lower demand this creates a greater export flow from the northern renewable areas. The high wind with lower demand also reduces requirements from conventional plant which is why constraints in the midlands and southern England are reduced. The spring low wind condition produces no exceedences.

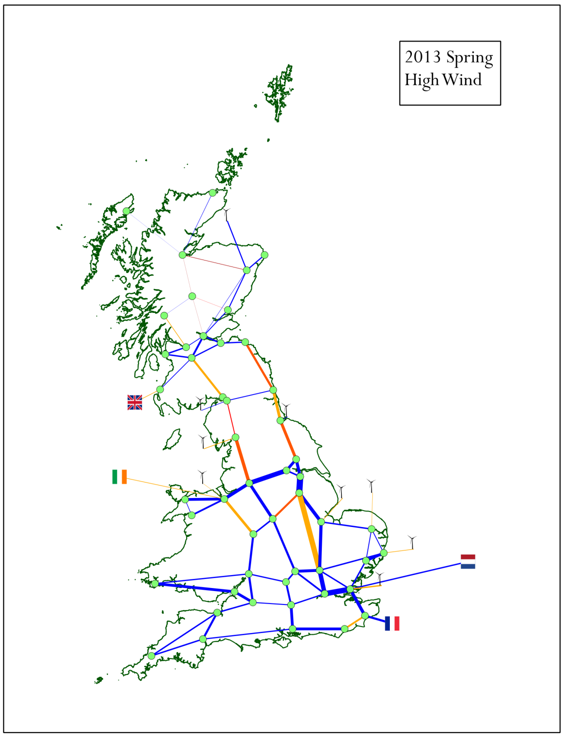


Figure 41: *2013 Spring High Wind power flow*

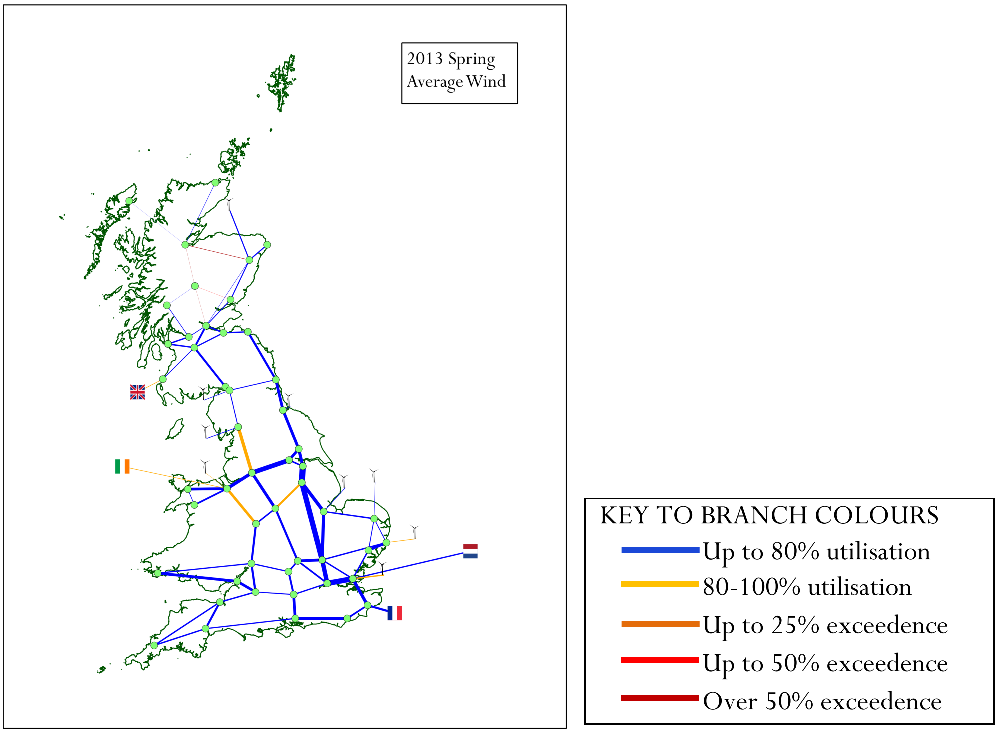


Figure 42: *2013 Spring Average Wind power flow*

In the summer conditions the constraints are persistent in the north of GB, as the lower demand again creates greater export requirement from northern renewables, but less stress on the networks in the rest of the country. The summer high wind condition (***Figure 43***) has higher northern exceedences than the winter high wind condition (although not as high as the spring high wind condition) due to the lower demand causing more north-south export than in the winter case. The low, NS and average (***Figure 44***) conditions also have constraints in Scotland but none in England, and the SN condition, with its particularly low northern output, is free of constraints.

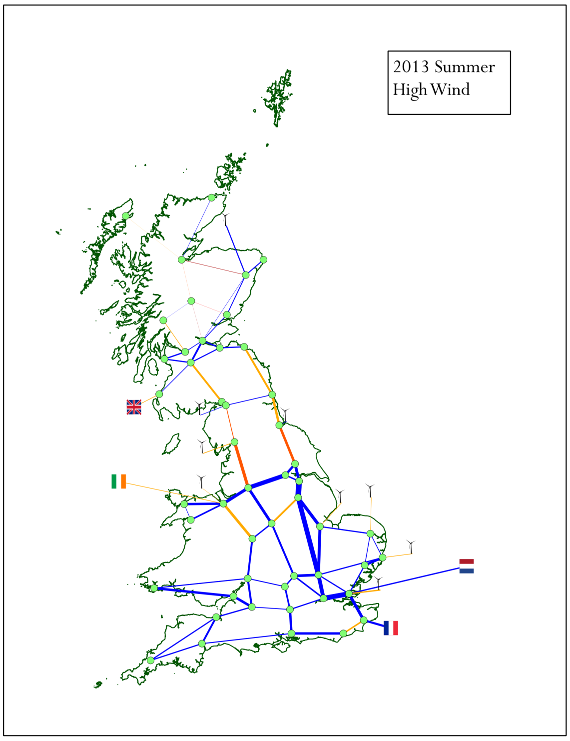
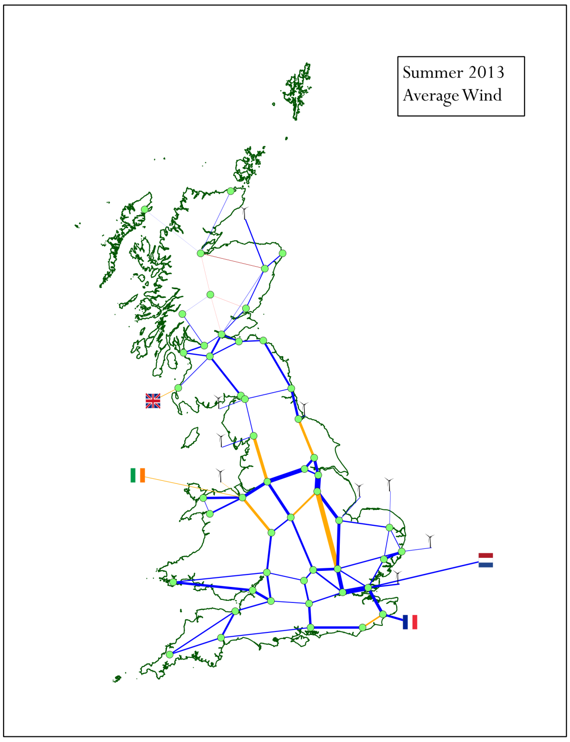


Figure 43: *2013 Summer High Wind power flow*



KEY TO BRANCH COLOURS
- Up to 80% utilisation
- 80-100% utilisation
- Up to 25% exceedence
- Up to 50% exceedence
- Over 50% exceedence

Figure 44: *2013 Summer Average Wind power flow*

These results show that the combined effect of wind conditions and the pattern and level of power demand combine to affect the level of constraints required on the system. High wind and low demand in exporting areas contribute to highest constraint levels, as lower load close to renewables means that more power has to flow elsewhere across the network (generally, south). Constraints are persistently found in Scotland in all seasons, in most wind conditions, except those with particularly low wind in the north of GB.

8.2 Strong location strong plan (SLSP)

8.2.1 Overview of whole scenario

In this scenario there is a clear commitment to use network charging as a means of creating locational signals of network conditions, to influence the siting and operational decisions of generators. Whilst the specific policy frameworks are not detailed in the scenario, it is assumed that the frameworks have the ability to affect operational decisions, to help with network congestion in real time, as well as investment decisions. However, in addition to the strong locational signals provided by the network charging policies, there is also a preparedness to take a long term anticipatory approach to network investment – when new investments pass the locational threshold and trigger new network investments, these network investments are undertaken not on a piecemeal basis but with a long term anticipation of future investments in the region. As a result, this scenario sees a relatively limited expansion of the existing network in the first decade of the scenario period, as new low carbon generation investment is concentrated on making best use of existing network capacity. However, as the potential for the existing network to support additional renewables saturates, new network investments are undertaken in a strategic anticipatory manner. First, the area in the Scottish North Sea is developed into an offshore grid combined with export capacity to Norway as well as England, which allows for smoothing of the overall output and interconnection flows. Similarly, in the final part of the period, an offshore network develops in the English North Sea, combined with export capacity to Denmark. The resulting picture in 2033 is of a highly interconnected system, but with different regions of GB interacting differently with their European interconnections, due to locationally differentiated price signals. This allows a high development of renewables, with networks fairly well utilised and sized to transmit a relatively smoothed overall power flow between regions. The resulting network permits the development of 68 GW of renewables by 2033. However, due to the low load factors of renewables nuclear also plays a significant role in meeting overall electricity demand with low carbon sources, reaching 17 GW in 2033. Due to the retirement of all but one of the existing nuclear fleet by this point, this involves the construction of five new stations over the whole time period. Despite this heavily decarbonised mix, 37 GW of fossil thermal plant is maintained online to meet demand during very low wind conditions.

8.2.2 2013 - 2018

8.2.2.1 Overview of period

In 2013 the most significant network concern is the export of power between Scotland and England. This relates to the integration of Scottish and English systems under BETTA, and is being added to by increasing development of renewables in the north of GB. There are plans to invest in the network to bring the Scotland-England boundary into compliance. Notably, these include reconductoring and other works on the existing border circuits, and the construction of the new HVDC offshore link between Hunterston and Deeside (***Table 8***).

The EMR package has come into effect which it is hoped will provide sufficient incentive for low carbon generation to meet EU 2020 targets and the CCC carbon budgets.

The key changes during this period therefore are the significant upgrade of the Scotland-England boundary, and a development of renewable resources in line with available network capacity. The philosophy of this scenario means that the primary aim is to meet low carbon and renewable targets in a way which balances the preferences of generators to locate in certain regions, with the costs that such locational choices may impose on the network.

8.2.2.2 Generation mix

Onshore wind is deployed in accordance with applications existing in 2013, with the exception of applications in mid-Wales, Shetland and the Orkneys, as the costs of securing new network upgrades deter developers. High wind speeds in the Western Isles however encourage more development here, and the strategic development of the HVDC western link further boosts development. Offshore wind is deployed in accordance with planned and under construction sites as of 2013, in addition to 2400 MW at Dogger Bank. The final reactor at the Wylfa nuclear site is closed, and a number of closures of coal and oil plants occur under the Large Combustion Plant Directive. The locational signal, which has an effect at the operational as well as the investment timeframe, encourages fossil generators co-located with wind to turn down during windy periods, effectively sharing network capacity. ***Figure 45*** shows the effect of these generation investment decisions on the total installed capacity during the period.

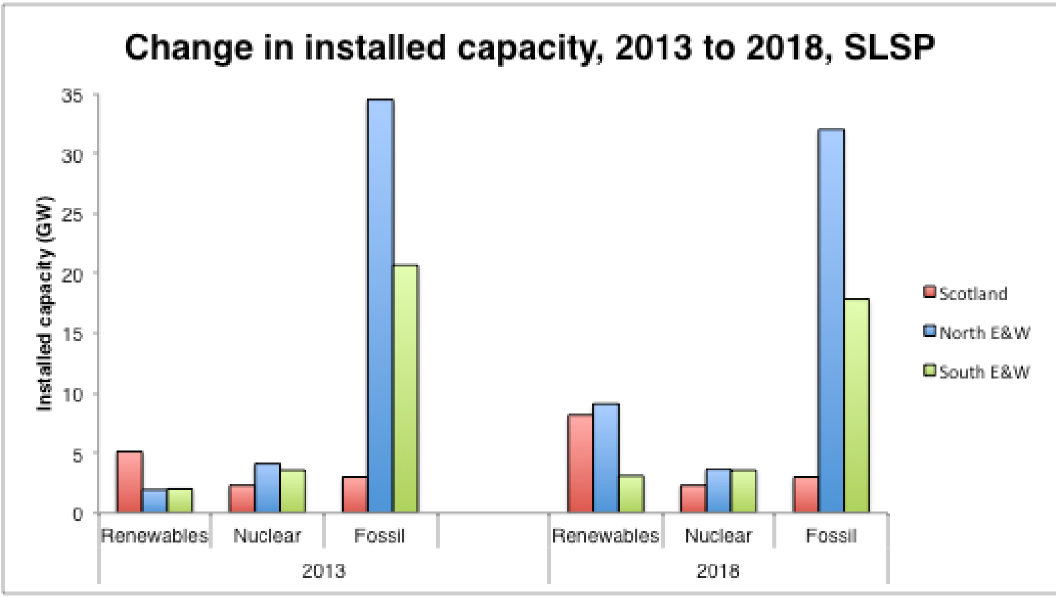


Figure 45: *Change in installed capacity, 2013 to 2018, SLSP*

This generation mix gives the following system indicators in 2018 (***Table 12***).

Table 12: *SLSP 2018 system indicators*

System derated capacity margin (%)	3.8
Proportion of annual electricity demand met by (%):	
Renewables	21
Nuclear	19
Other	61
Carbon intensity of electricity (g/KWh)	358

8.2.2.3 Network investment

Confirmed network upgrades as of 2013, as detailed in ***Table 8*** (Chapter 7) are included in this scenario, most significant of which are the upgrades over the Scotland-England boundary, including the HVDC western link between Hunterston and Deeside. Beyond these, an HVDC connection from Beauly to Stornoway is also made, in anticipation of renewable development in the Hebrides. The geographical arrangement of the upgrades is indicated in ***Figure 46***.

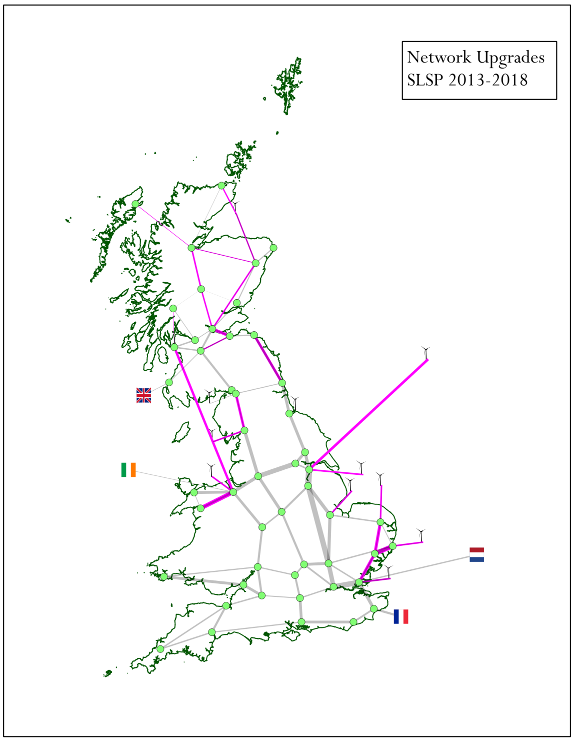


Figure 46: *Network upgrades SLSP 2013-2018*

8.2.2.4 Resultant power flow

This scenario finds that due to the upgrades over the Cheviot boundary, this boundary is now largely compliant. By contrast, increased constraints are found in northern England, as the increased renewable output from Scotland combines with the still considerable thermal capacity in Yorkshire and Lancashire. Typical constraint corridors are from the Humber through Lincolnshire towards the East Midlands and London; and between Deeside and the West Midlands. These constraint corridors reflect patterns of existing large scale generation in relation to large load centres. However the constraints are also exacerbated by the output of Scottish wind power, which although it now bypasses the major constraint area of 2013, the Cheviot boundary, adds to the output of thermal stations to produce constraints in northern England. This is particularly the case for the lines running south from Deeside, which now also take the power from the landing of the HVDC western link. The effect of increased Scottish wind on these corridors can be seen by comparing a high wind condition at winter peak with a low wind condition (***Figure** 47* and ***Figure** 48*). In the low wind condition, constraints are less in these northern England corridors, although new constraints emerge in lines running from western England towards London, as the lower wind output requires increased output from thermal stations in southern Wales and western England.

In summary, in 2018 this scenario sees a network in which growing output from renewables is continuing to have some impact upon constraints; however, due to significant network investments since 2013, these are not occurring in Scotland but in northern England; and the activity of large clusters of fossil generators in northern England and the midlands is at least as significant as the wind output in affecting the constraint patterns.

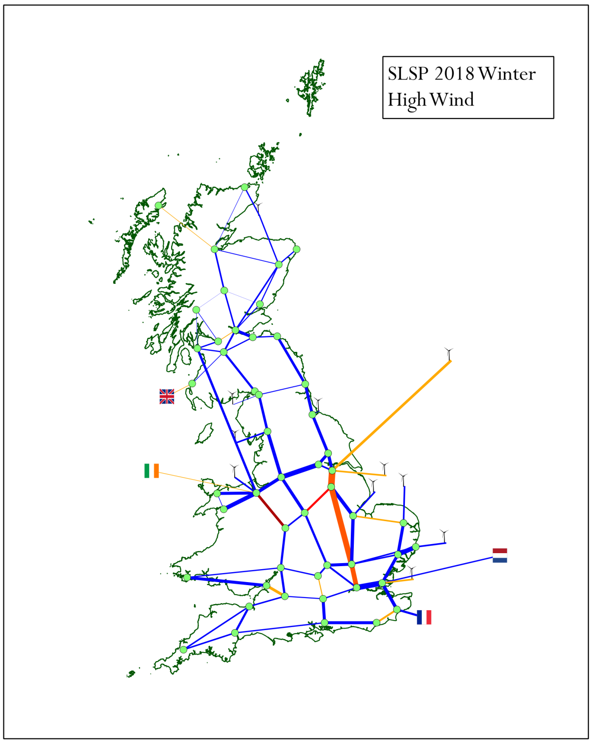


Figure 47: *SLSP 2018 Winter High Wind power flow*

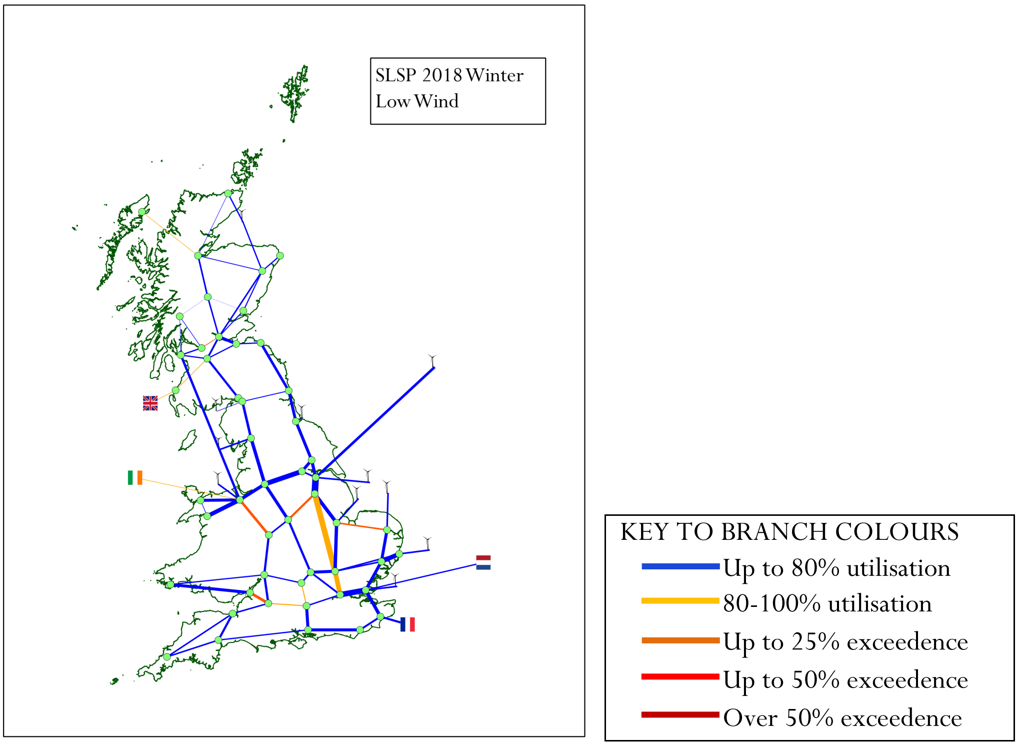


Figure 48: *SLSP 2018 Winter Low Wind power flow*

8.2.3 2018 - 2023

8.2.3.1 Overview of period

The installed capacities of onshore and offshore wind in 2018 were similar to the central range of DECC's renewable energy roadmap (DECC, 2011c), which is constructed with reference to the UK's EU 2020 renewables targets. In this next period, the bedding-in of the EMR and the successful administration of the feed-in tariffs, within the pressure of the CCC's carbon budget which expects deep power sector decarbonisation through the 2020s, pushes forward a continued growth in low carbon generation. However this occurs within a framework which gives clear incentives to utilise the existing onshore network efficiently, in preference to triggering new onshore upgrades. The development of offshore wind in the southern North Sea is undertaken alongside a coordinated approach to offshore transmission infrastructure which takes account of onshore network capacity in its landing points. Marine technologies become commercially available and are developed in the south-west, reflecting available network capacity here.

8.2.3.2 Generation

There is a modest increase of 1 GW in onshore wind in Scotland – although this is the most cost effective renewable technology it is locationally disadvantaged. This increase is permitted by a network charging policy which includes measures to encourage thermal generators in Scotland to reduce output during windy conditions, allowing some sharing of network capacity. This increase is limited by the available existing network capacity, allowing for network sharing with conventional generation.

Larger developments in offshore wind are possible, connected by project specific radial lines to bring power from the projects ashore. However due to the transmission charging regime, there is a greater incentive for projects to connect in the south of England than in northern England and Scotland. As a result significant development occurs in Dogger with a further 4.8 GW, plus 3 GW at Hornsea. The East Anglia zone begins its development with 1.2 GW, and the very southerly zones Rampion and Navitus are developed to their full available potential of 0.7 and 1.1 GW respectively.

Locational charging also encourages tidal and wave technologies, which are approaching commercialisation, to locate in southerly locations. Tidal stream is installed, 400 MW in waters off the north Devon coast, and 200 MW in the Solent. A 500 MW wave power project is installed off the north Cornish coast. A further important new addition in this period is the new nuclear station at Hinkley Point.

Also significant in this period are plant closures. The effect of the EU's Industrial Emissions Directive is felt, with a number of the older coal and gas plants opting out and closing by 2023. In addition, around 3.5 GW of nuclear plant closes due to its age. 800 MW new CCGT is sufficient to maintain a positive capacity margin. This is sited in Yorkshire where there is network capacity available due to the closure of Eggborough and Ferrybridge.

Figure 49 gives the overall impression of the change in plant mix in this period.

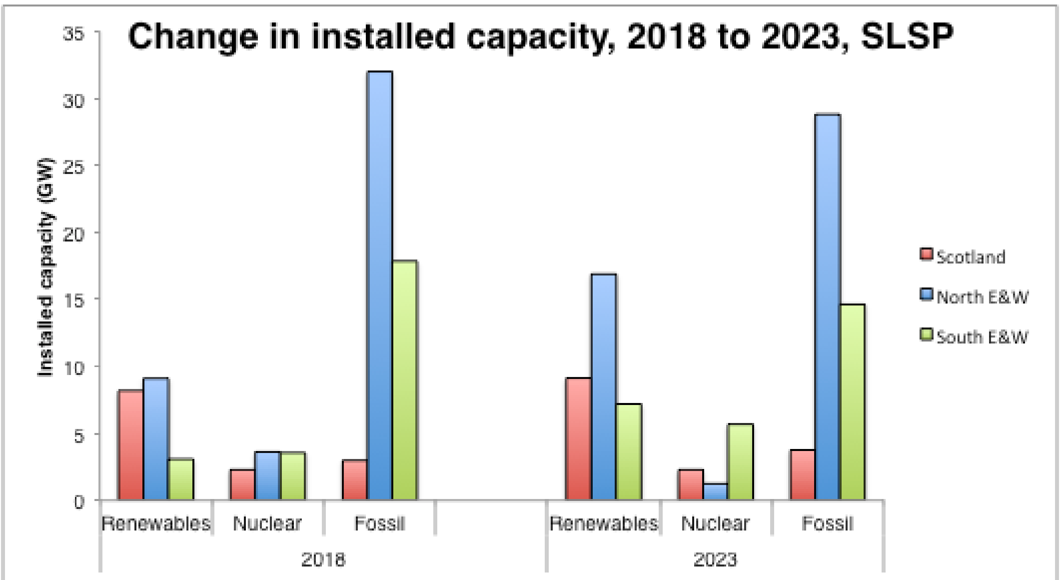


Figure 49: *Change in installed capacity, 2018 to 2023, SLSP*

This generation mix gives the following system indicators in 2023 (***Table 13***).

Table 13: *SLSP 2023 system indicators*

System derated capacity margin (%)	1.1
Proportion of annual electricity demand met by (%):	
Renewables	33
Nuclear	18
Other	49
Carbon intensity of electricity (g/KWh)	271

Renewables have made considerable advances over the period, however the contribution of nuclear remains similar to 2018, as the opening of Hinkley Point C compensates for the closures of older stations. The resulting reduction in output from fossil stations contributes to a reduction in the carbon intensity of electricity, though with still some way to go to the 50g / kWh target.

8.2.3.3 Network

Due to the locational effects of charging policy, new generation is located such that it causes little requirement for major onshore upgrades. A new 400kV line from Hinkley Point to Seabank is constructed to carry power from the new nuclear station. The main new offshore infrastructure upgrades are the radial connections to the various new offshore sites. In addition Dogger and Hornsea wind farm are connected to each other by two 2.4 GW HVDC cables. These allow transport between the wind farms and also provide an additional corridor for power to flow from north to south, allowing some of the offshore wind output to bypass the congested Yorkshire-Lincolnshire routes. The geographical arrangement of the upgrades is indicated in ***Figure 50***.

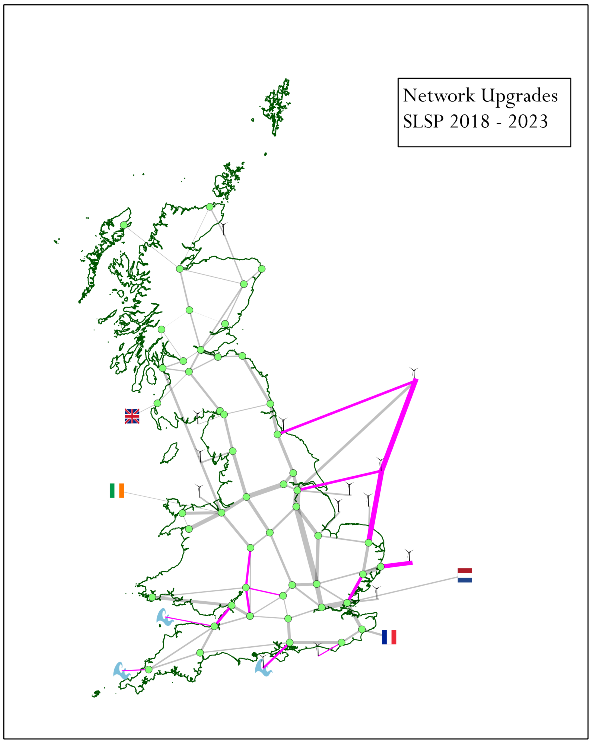


Figure 50: *Network upgrades SLSP 2018 - 2023*

8.2.3.4 Resultant power flow

In general similar patterns of constraint can be observed to those found in 2018 – in particular running south from Humber, south from Deeside, and east from Bristol. However, the levels of constraint are in general lower than in 2018. This is due to the increased renewable output pulling down fossil output in these areas. In Winter high wind (***Figure 51***), Scotland remains compliant, and the key exceedences are felt in Humber to the Midlands, where remaining fossil generators are added to by injection from Dogger and Hornsea offshore wind farms. North Wales to west Midlands also experiences constraints due to the injection from the western link. Further, the connection of the Dogger-Hornsea offshore link introduces significantly increased power flows in the East Anglia and Essex areas as power is drawn towards the load centre of London. The winter NS condition avoids constraints in the East of the country because of the lower output from the North Sea wind farms, however constraints are higher in the west of the country as comparatively more of the Scottish wind output is transferred to North West England via the western Link. The largest single constraint in the winter conditions is found in the SN condition, from Humber to east Yorkshire. This can be attributed to the very low output in

Scottish onshore wind in this condition, meaning that comparatively little power is flowing down the western HVDC link to reach the western parts of England. This means that power is being pulled from Humber westwards, through this now important corridor. A similar dynamic is found in the summer SN condition.

Otherwise the Spring and Summer conditions exhibit similar patterns to the winter conditions. The highest summer constraints are found in the NS condition, due to a combination of lower overall supply but higher output in Scotland, causing both significant North-South export, and high output from southern fossil stations.

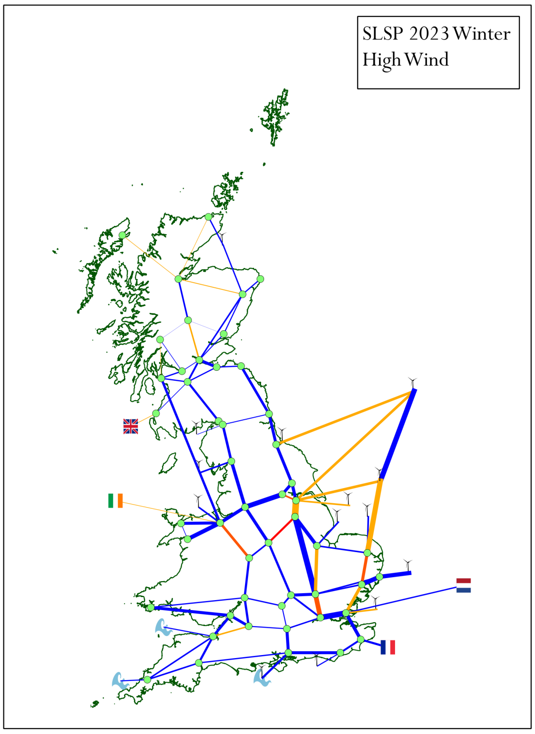


Figure 51: *SLSP 2023 Winter High Wind power flow*

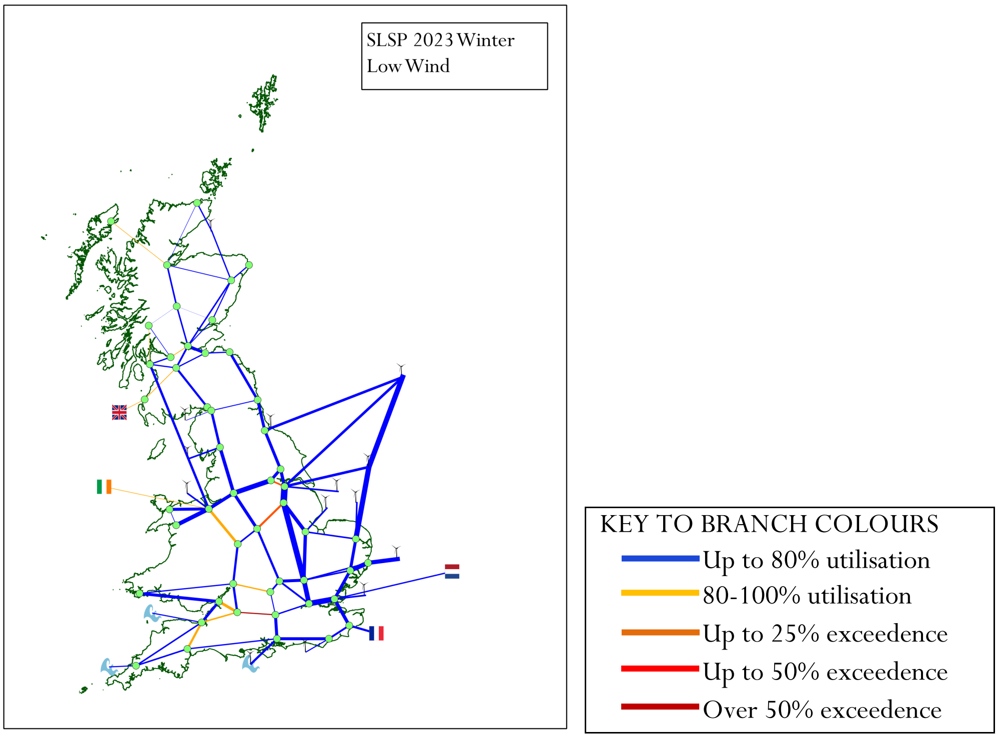


Figure 52: *SLSP 2023 Winter Low Wind power flow*

8.2.4 2023 - 2028

8.2.4.1 Overview of period

By 2023, the contribution of renewables to overall electricity generation reached 33%. However, with the carbon intensity of electricity in 2023 at 198 g/kWh, there is still a steep climb to reach the CCC's target of 50 g/kWh by 2030. Due to high wind speeds, companies are increasingly keen to develop the Scottish North Sea, despite higher transmission costs for the power when it reaches the mainland. The development of the Scottish North Sea goes alongside the strategic development of an offshore grid in the area, linking the Shetland and Orkneys with offshore sites. The use of locational pricing sees increasingly different prices occurring in Scotland and England due to their different generation portfolios. This creates a case for interconnection between Scotland and Norway, as the potentially high renewable output from Scotland can be traded with the more dispatchable hydro output in Norway. Therefore, an interconnector between Scotland and Norway is integrated into the strategic Scottish offshore network development.

8.2.4.2 Generation

The strategic approach to the Scottish east coast offshore grid, along with the Norwegian interconnection capability, releases the potential for significant expansion in all forms of renewables in Scotland. There are 500 MW of new onshore wind in both Shetland and Orkney. The potential to develop Moray and Forth offshore zones is now realised, with 1.5 and 2 GW constructed in these zones respectively. Wave and tidal resources can also be developed in Scotland, and there are 500 MW of wave devices in the waters of both Shetland and Orkney, as well as 300 MW tidal stream amongst each island group. The Pentland Firth is also developed with 500 MW tidal stream. Scottish hydro, having been limited in its development, now acquires an additional 300 MW.

In England, Dogger and Hornsea offshore wind zones increase by 800 MW each, and East Anglia by 1 GW. A further 500 MW of wave power is added off both the Devon and Cornwall coasts.

As in 2023, a significant factor affecting the generation mix is the effect of plant closures. Nuclear stations at Hinkley Point B, Hunterston B, Heysham 2 and Torness all close due to age. One new plant at Wylfa comes online. A number of coal plants close due to a combination of the IED and age, capacity totalling 13.6 GW. In order to maintain a positive capacity margin, around 12.5 GW of new CCGT opens. Locational signals encourage most of these to locate south of the midlands.

Figure 53 shows the effect of these changes on installed capacity during this period.

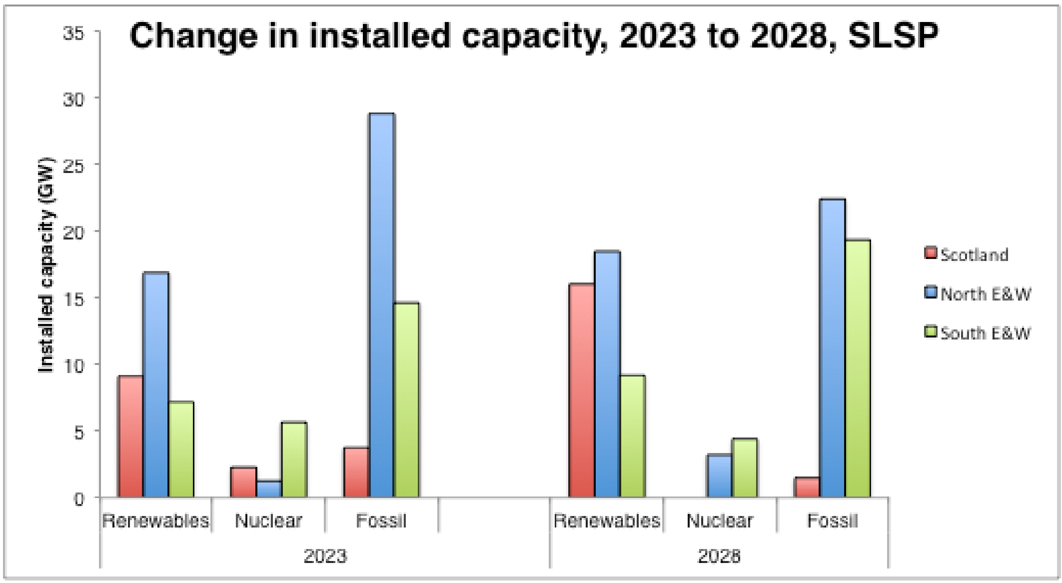


Figure 53: *Change in installed capacity, 2023 to 2028, SLSP*

This generation mix gives the following system indicators in 2028.

Table 14: *SLSP 2028 system indicators*

System derated capacity margin (%)	0.3
Proportion of annual electricity demand met by (%):	
Renewables	41
Nuclear	15
Other	45
Carbon intensity of electricity (g/KWh)	189

Renewables are making a large contribution of over 40%, however due to various nuclear closures and only one new plant, the relative and absolute contribution of nuclear has declined since 2023. A significant contribution is still required from fossil thermal generators – coal plants that closed in the period have been replaced by a similar capacity of new CCGTs in order to protect the capacity margin.

8.2.4.3 Network

The Scottish North Sea offshore network expands in a coordinated manner to combine outputs from Shetland, the Orkneys, Moray and Forth, as well as providing export capacity to England and Norway. ***Table 15*** summarises the upgrades and new lines which constitute this offshore network.

Table 15: *List of upgrades constituting the Scottish North Sea offshore grid, SLSP, 2028*

Course of line	Capacity (GW)
Orkney to Caithness	1.2
Shetland to Orkney	1.2
Shetland to Moray Firth offshore hub	1.2
Caithness to Moray Firth offshore hub	2.4 (upgraded from 1.2)
Moray Firth offshore hub to Peterhead	2.4
Shetland to North sea hub	1.2
Moray Firth offshore hub to North Sea hub	1.2
Peterhead to Firth of Forth offshore hub	2.4
Firth of Forth offshore hub to North Sea hub	1.2
Firth of Forth offshore hub to Torness	1.2
Firth of Forth offshore hub to Blyth	2.4
North Sea hub to Norway	4.8

Figure 54 shows the geographical arrangement of this North Sea offshore grid.

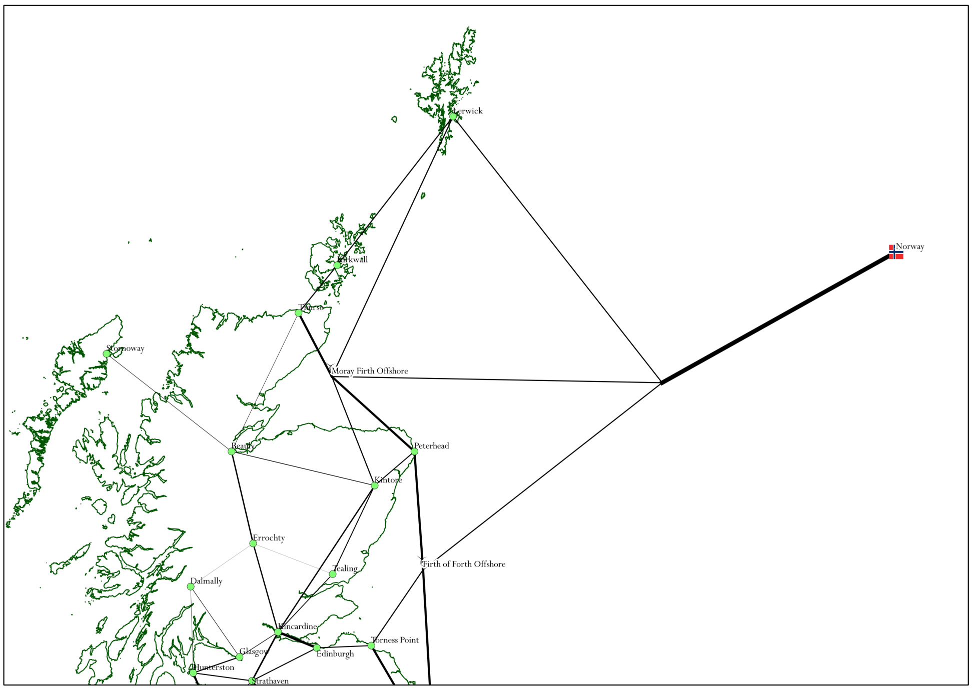


Figure 54: *SLSP 2028 close up of Scottish North Sea offshore network*

In addition the English North Sea offshore spine, from Dogger to Hornsea and Hornsea to Spalding is uprated from 4.8 to 7.2 GW. This is both to manage increased output from Dogger and Hornsea but also oversized in anticipation of a future interconnector to Denmark.

Significant onshore network upgrades are also made in England and Wales. The connections of Dogger and Hornsea zones at Humber require upgrades in lines running out of this area. In particular the line between Humber and Sheffield is doubled, allowing greater East-West transport, and the lines between Cottam and the East midlands are uprated. New lines, and uprates of existing lines are undertaken in North Wales owing to the output from Wylfa nuclear, and in anticipation of future offshore wind from the Irish sea zone. There are also significant uprates and additions of new double circuits in the network between East Anglia, Suffolk and London, to manage the growth in output from southern North Sea wind farms. The geographical arrangement of all network upgrades in this period is indicated in ***Figure 55***.

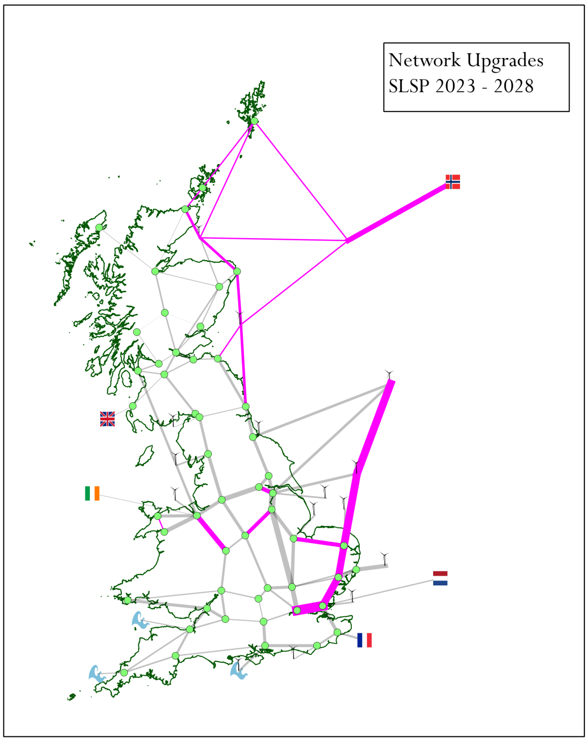


Figure 55: *Network upgrades SLSP 2023- 2028*

8.2.4.4 Resultant power flow

In this scenario the Norwegian interconnector alternates between import and export depending on the wind conditions in Scotland. In High wind conditions the interconnector is exporting excess wind from Scotland to Norway. In low wind conditions the interconnector is importing power from Norwegian hydro to the Scottish offshore network. A key assumption therefore is of a high degree of complementarity between Scottish and Norwegian renewable resources, owing to the use of storage reservoirs in the Norwegian hydro system. Under this assumption, the result is a fairly consistent bi-directional use of the Norway – Scotland interconnector, and a consistent, single directional flow of power on the circuits, including both the east and west bootstraps, exporting power from Scotland to England.

The southern North Sea offshore network continues to provide significant amounts of power for load centres in the south east.

As shown in ***Figure 56***, ***Figure 57*** and ***Figure 58*** the combination of interconnection and offshore grids provides a fairly stable power flow pattern between large renewable sites and large load centres, with comparatively low constraints overall.

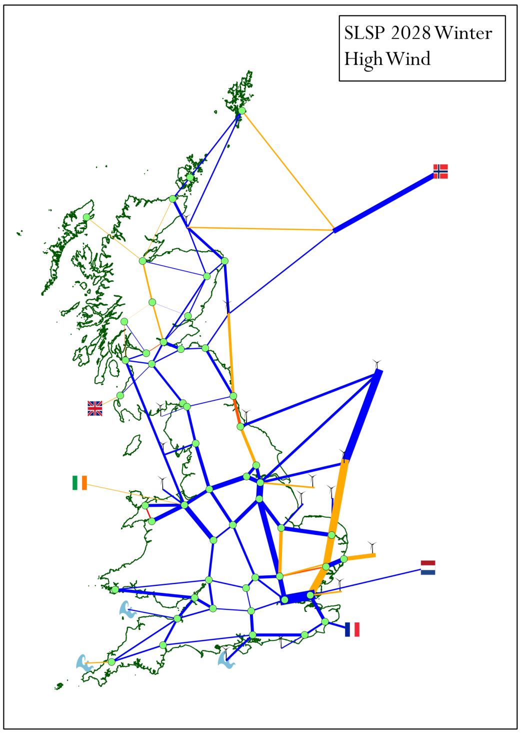


Figure 56: *SLSP 2028 Winter High Wind power flow*

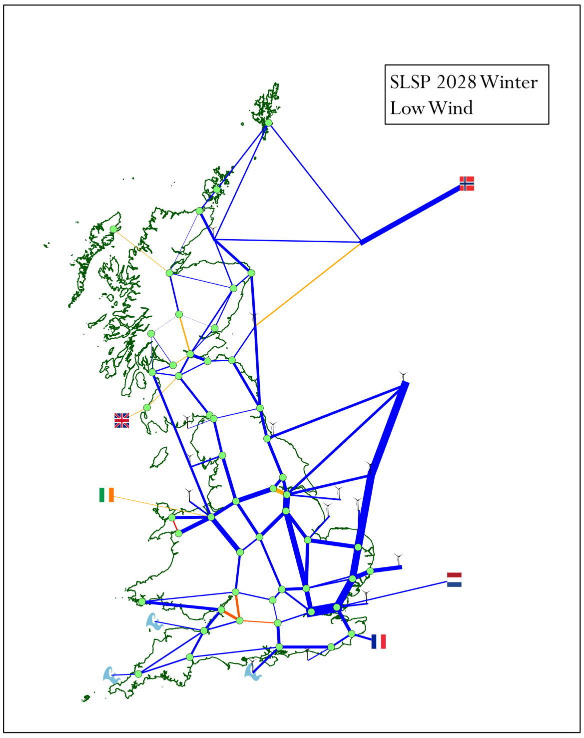


Figure 57: *SLSP 2028 Winter Low Wind power flow*

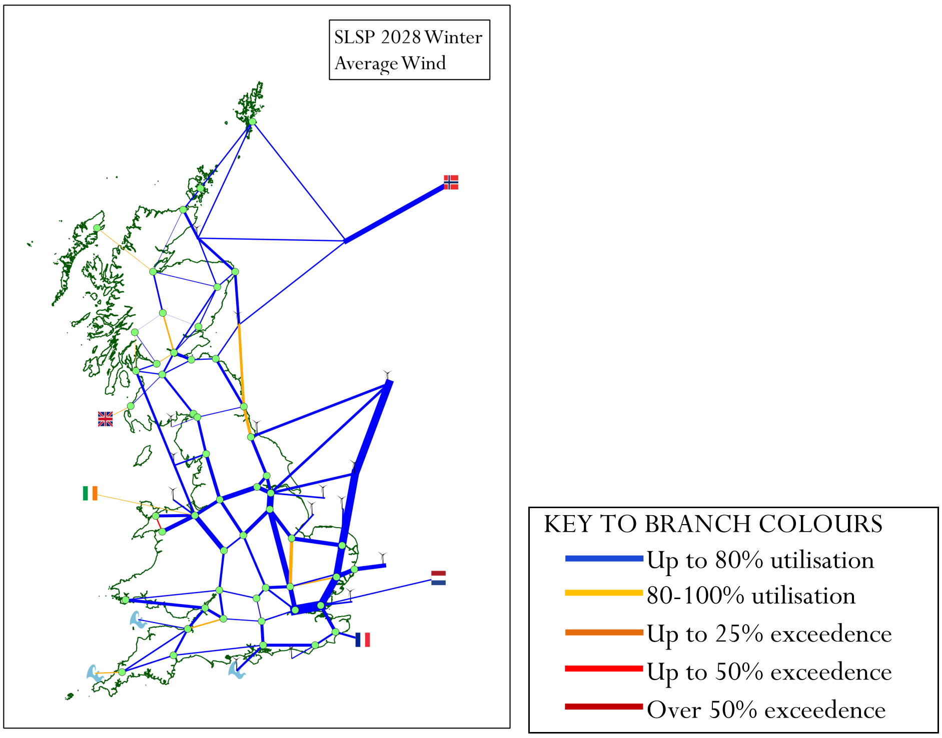


Figure 58: *SLSP 2028 Winter Average Wind power flow*

8.2.5 2028 – 2033

8.2.5.1 Overview of period

A continued expansion of renewable and nuclear generation allows this scenario to hit the target of 50g CO_2/kWh by 2033. Locational signals continue to encourage location of both nuclear and renewables in areas of the network which as far as possible make use of existing network capacity. However, the growth in generation capacity continues to stimulate more network expansion, particularly along the English east coast where large amounts of power from offshore wind join the network during high wind conditions, and in Wales due to the expansion of wind power in the Irish Sea, and onshore wind in central Wales. Locational signals operating across the network see different signals emerging at different times in different parts of GB. This drives the construction of more interconnector capacity with Europe and Ireland. Interconnectors become crucial to the operation of the system with areas of highly variable output. By 2033 the picture is of a system with highly developed offshore networks and bootstraps, high levels of interconnection with neighbouring systems, but having avoided major upgrades and new lines across substantial areas of the onshore GB network.

8.2.5.2 Generation

Offshore wind expands to the full capacity of Round 3, adding 1500 MW at Forth, 1000 MW at Dogger, 200 MW at Hornsea, and 5000 MW at East Anglia. The Irish Sea Zone is developed for the first time, with 4200 MW.

The closure of a further 14 GW of ageing fossil plant opens up connection opportunities in the north of England and Midlands, and 2 GW of onshore wind connects in northern England. The wind potential of mid-Wales is accessed with a new strategic network investment, and 2 GW connect here.

The locational charges favour the development of large scale tidal barrage at a number of locations, as these can be spread around the country – Solway Firth, Deeside, Humber, Severn and Thames. There are further major developments of wave power in the largely uncongested south-west, as well as a small additional development of wave power off the Western Isles in Scotland, making use of available capacity on the existing offshore radial connection built in a previous period.

Despite the significant strategic development of integrated offshore networks, the network capacity is still not sufficient to carry enough power to reach the 50g/kWh target with renewables alone. This scenario also requires three more new nuclear plants, whose locations can be chosen to reflect available network capacity – the chosen locations are Heysham, Bradwell and Sizewell. The already existing Sizewell B is now the oldest member of the fleet. Its scheduled decommissioning year is 2035.

Maintaining a positive capacity margin also requires the opening of 5 GW of fossil thermal plant. This plant is distributed across suitable locations across England, most of it south of the Midlands. However, this plant operates very intermittently, responding flexibly to requirements in low wind conditions.

Figure 59 shows the effect of these changes on installed capacity during this period.

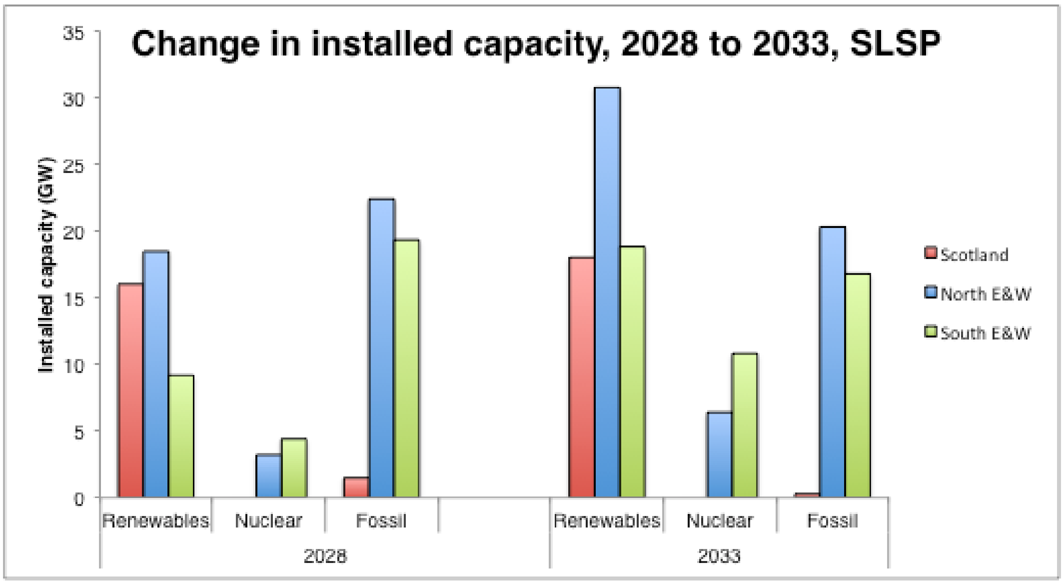


Figure 59: *Change in installed capacity, 2028 to 2033, SLSP*

This generation mix gives the following system indicators in 2033 (***Table 16***).

Table 16: *SLSP 2033 system indicators*

System derated capacity margin (%)	2.8
Proportion of annual electricity demand met by (%):	
Renewables	57
Nuclear	31
Other	11
Carbon intensity of electricity (g/KWh)	46

8.2.5.3 Network

New offshore renewable developments trigger a number of upgrades to radial connections. In addition, the East Anglia zone is connected via the Thames Array to Sellindge, where it meets the France interconnector.

In Scotland the connection between Argyll and Hunterston is upgraded to allow for the increase in wave power in the Western Isles. In Wales, a strategic upgrade of the network connects central Wales to Ffestiniog and Ironbridge. A new sub-sea bootstrap of 2.2 GW is built between Wylfa in north Wales and Pembroke in south Wales.

The now significant zonal variation in generation output across the country has encouraged the development of interconnectors. The connection to France is increased by a further 2 GW with a new connection running through the Channel Tunnel, and there is a new sub-sea connection from Dogger, connecting the English North Sea offshore grid with Denmark. The new Irish Sea zone, as well as connecting to Wylfa, also connects to the Eire network. Each of these interconnectors exploits low prices in the GB zone to which they connect during times of high wind output, exporting power to the neighbouring market.

In the North Sea, the connection between Forth and Blyth receives another cable, raising its capacity to 3.6 GW. There is an addition of a subsea direct link between Blyth and Humber. Onshore upgrades are made on the East-West lines between Northumberland and Cumbria, and the lines running south from Cumbria into Lancashire. There are also further significant upgrades in the East Anglian network, owing to the increased output from the East Anglia offshore zone, and the new Sizewell nuclear station. A new line directly connects Sizewell to Grain on the Thames estuary. The geographical arrangement of the network upgrades in this period is shown in ***Figure 60***.

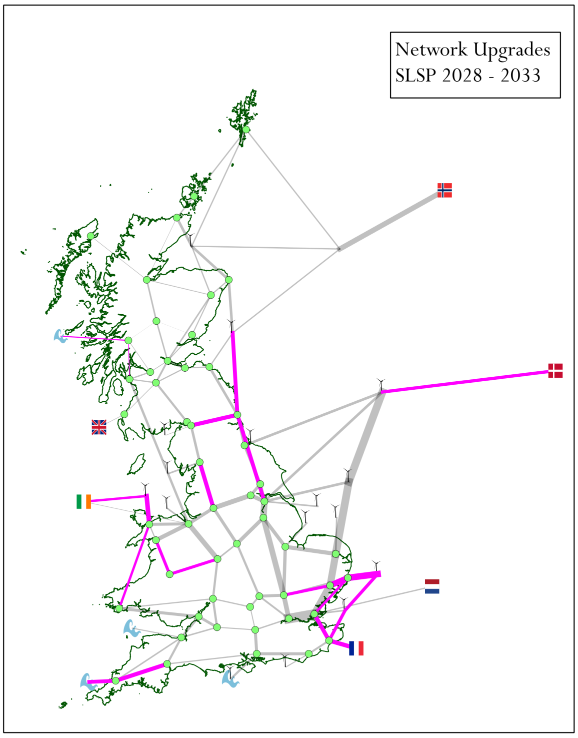


Figure 60: *Network upgrades SLSP 2028 - 2033*

8.2.5.4 Resultant power flow

Under high wind conditions the network succeeds in avoiding excessive constraints largely due to the activity of the interconnectors in spilling available power from high-generating zones, eastern Scotland, eastern England and north-west Wales

(*Figure 61*). However, in the high wind winter condition, despite full export through interconnectors the full output of nuclear stations cannot be used. By contrast, under low wind conditions, standby fossil plant are called on to meet demand, even with full import from interconnectors. As can be seen in *Figure 62*, due to the arrangement of fossil plant and interconnectors, this condition results in slightly higher constraints than the high wind condition in certain corridors, notably in the south east between the French and Netherlands interconnectors, and London. When wind output is skewed to the north, more constraints emerge in the main corridors transmitting power from north to south, notably, in *Figure 63*, in north Wales. This condition also experiences constraints in the areas between the south-eastern interconnectors and London, due to high interconnector import resulting from low wind generation in the southern regions. The potential variability in output amongst different zones from different weather conditions presents challenges to designing a network which remains compliant under all conditions. Nonetheless, the development of interconnectors between GB zones and from GB zones to other European systems, enables a high degree of smoothing of each zone's output, keeping congestion relatively low. As shown in *Figure 64*, the winter peak during an average wind condition is almost entirely compliant.

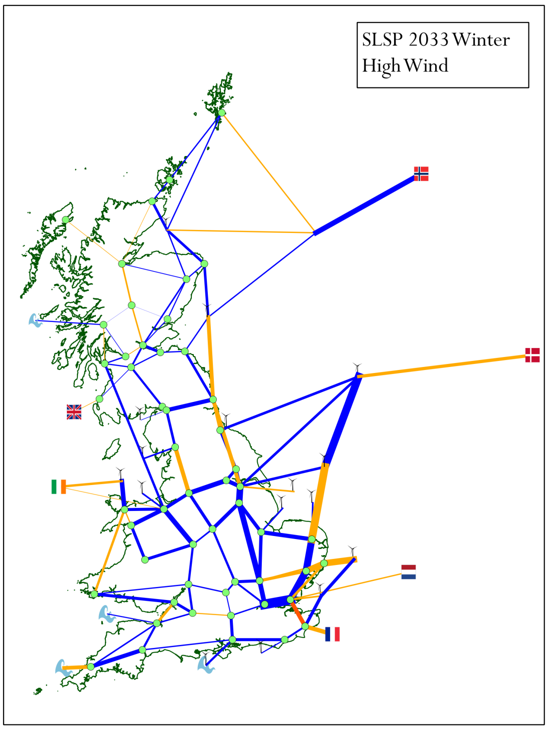


Figure 61: *SLSP 2033 Winter High Wind power flow*

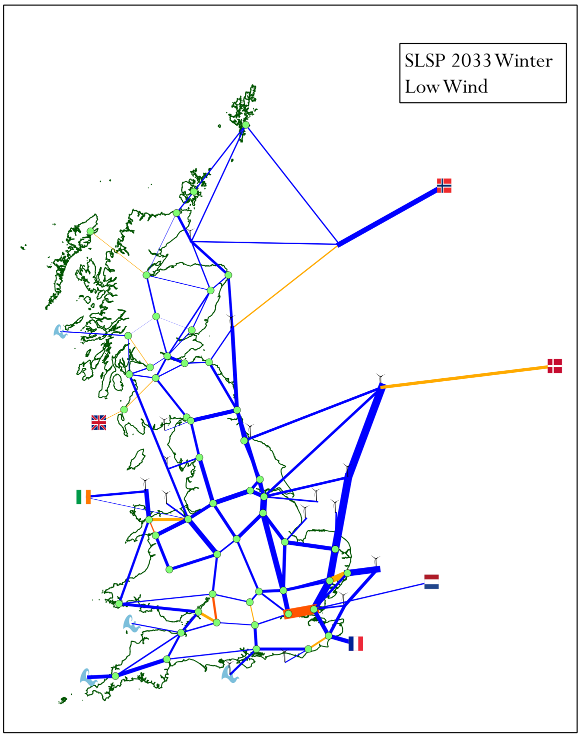


Figure 62: *SLSP 2033 Winter Low Wind power flow*

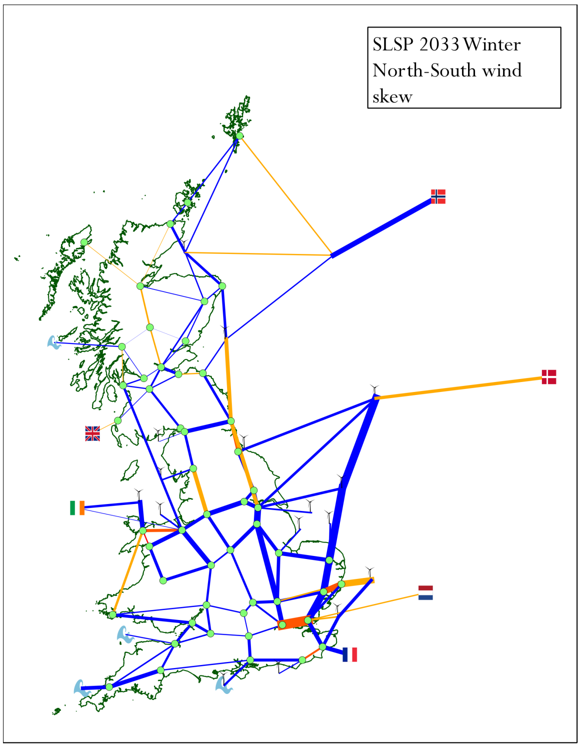


Figure 63: *SLSP 2033 Winter North to South skew power flow*

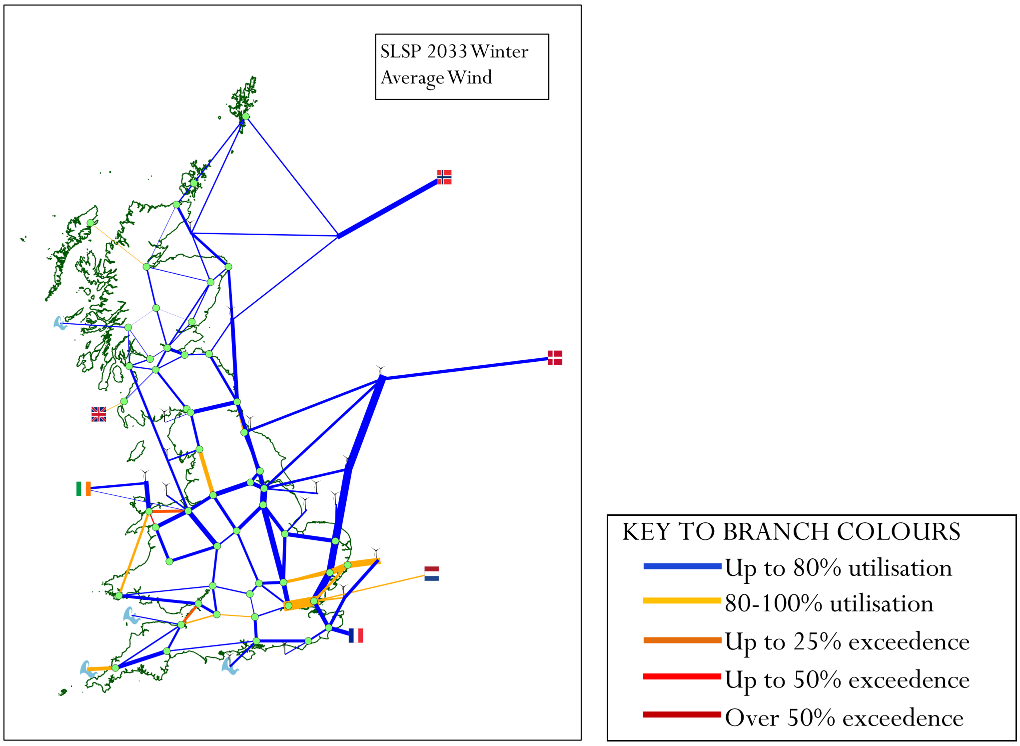


Figure 64: *SLSP 2033 Winter Average Wind power flow*

8.3 Strong location weak plan (SLWP)

8.3.1 Overview of whole scenario

In this scenario there is a clear commitment to use network charging as a means of creating locational signals of network conditions, to influence the siting and operational decisions of generators. Whilst the specific policy frameworks are not detailed in the scenario, it is assumed that the frameworks have the ability to affect operational decisions, to help with network congestion in real time, as well as investment decisions. However, in contrast to SLSP, there is little appetite on the part of network owners to take forward looking anticipatory network investment decisions, and major network upgrades are undertaken only in response to firm commitments from generators for substantial numbers of MWs. In broad terms, the guiding philosophy is that network investments should be entirely neutral about generation technology choice – networks should not be planned in advance with the goal of facilitating the connection of a particular technology with particular locational characteristics. Rather the generators' choice of technology and location should include exposure to the costs that their connection implies for the network. As a result, in the early years of the scenario, there is a modest development of renewables in areas where there is available network capacity. There is some development of offshore wind, but this is focussed in the zones connecting in the southern parts of GB. In the middle and later periods, low carbon technology choice increasingly favours technologies with flexibility around location, which benefit from lower locational charges. This results in a significant growth in tidal barrage, and a major expansion in nuclear, with by 2033 all eight designated nuclear sites operating with 3.2 GW nuclear power stations. The picture in 2033 is therefore of a nuclear dominated system, with contributions from on- and offshore wind, tidal barrage and a small amount of wave power in southern locations. There are 27 GW nuclear installed, 44 GW of renewables, and 35 GW of fossil thermal maintained for flexibility in low wind conditions. This scenario achieves the required carbon intensity of electricity of 50g/kWh with comparatively few additional network upgrades beyond those already scheduled in 2013.

8.3.2 2013 – 2018

8.3.2.1 Overview of period

In 2013 the most significant network concern is the export of power between Scotland and England. This relates to the integration of Scottish and English systems under BETTA, and is being added to by increasing development of renewables in the north of GB. There are plans to invest in the network to bring the Scotland-England boundary into compliance. Notably, these include reconductoring and other works on the existing border circuits, and the construction of the new HVDC offshore link between Hunterston and Deeside (***Table 8***, Chapter 7).

The EMR package has come into effect which it is hoped will provide sufficient incentive for low carbon generation to meet EU 2020 targets and the CCC carbon budgets.

The key changes during this period therefore are the significant upgrade of the Scotland-England boundary, and a modest development of renewable resources in line with available network capacity. The philosophy of this scenario means that the primary aim is to meet low carbon and renewable targets in a way which balances the preferences of generators to locate in certain regions, with the costs that such locational choices may impose on the network.

8.3.2.2 Generation mix

Onshore wind is deployed in accordance with applications existing in 2013, as discussed in Section 7.3.1.6. There is no strategic anticipatory development of island links to Shetland, the Orkneys or the Western Isles, or high voltage connection of mid-Wales, as the costs of securing new network upgrades deter developers. Offshore wind is deployed in accordance with consented and under construction sites as of 2013 (as discussed in Section 7.3.1.6), in addition to 2400 MW at Dogger Bank. The final reactor at the Wylfa nuclear site is closed, and a number of closures of coal and oil plants occur under the Large Combustion Plant Directive. The locational signal, which has an effect at the operational as well as the investment timeframe, encourages fossil generators co-located with wind to turn down during windy periods, effectively sharing network capacity. ***Figure 65*** shows the effect of these generation investment decisions on the total installed capacity during the period.

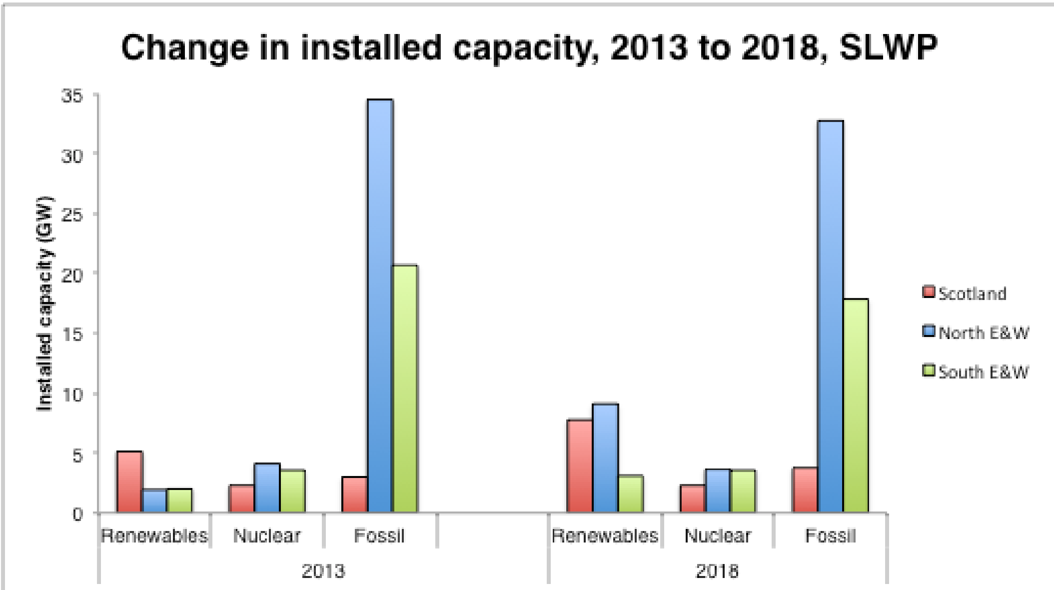


Figure 65: *Change in installed capacity, 2013 to 2018, SLWP*

This generation mix gives the following system indicators in 2018 (***Table 17***).

Table 17: *SLWP 2018 system indicators*

System derated capacity margin (%)	5.9
Proportion of annual electricity demand met by (%):	
Renewables	20
Nuclear	19
Other	61
Carbon intensity of electricity (g/KWh)	356

Not building the Western Isles HVDC link means around 500 MW less of onshore wind than in SLSP in Scotland, which has a small effect on the overall annual contribution of renewables and the carbon intensity of electricity. Other than this the generation mix in this scenario is identical to SLSP in the same year.

8.3.2.3 Network investment

Confirmed network upgrades as of 2013 are included in this scenario (***Table 8***, Chapter 7), most significant of which are the upgrades over the Scotland-England boundary, including the HVDC western link between Hunterston and Deeside. Beyond these, no further network upgrades are made. The geographical arrangement of the network upgrades in this period is shown in ***Figure 66***.

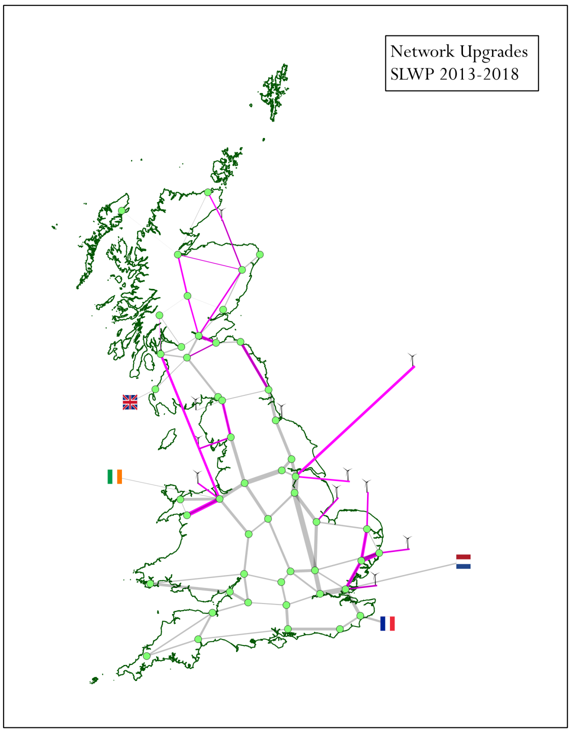


Figure 66: *Network upgrades SLWP 2013-2018*

8.3.2.4 Resultant power flow

As in SLSP 2018, the upgrades over the Cheviot boundary have made this boundary now largely compliant, but increased constraints are found in northern England, as the increased renewable output from Scotland combines with the still considerable thermal capacity in Yorkshire and Lancashire. As would be expected given the very similar plant mix, the same key constraint corridors emerge as in SLSP, namely from the Humber through Lincolnshire towards the East Midlands and London; between Deeside and the West Midlands. The effect of increased Scottish wind, which although it can now pass the Cheviot boundary nonetheless meets constraints in the Midlands, can be seen in a similar way to SLSP by comparing a high wind condition at winter peak with a low wind condition

(*Figure 67* and *Figure 68*). In the low wind condition, constraints are lower in these northern England corridors, although new constraints emerge in lines running from western England towards London, as the lower wind output requires increased output from thermal stations in southern Wales and western England.

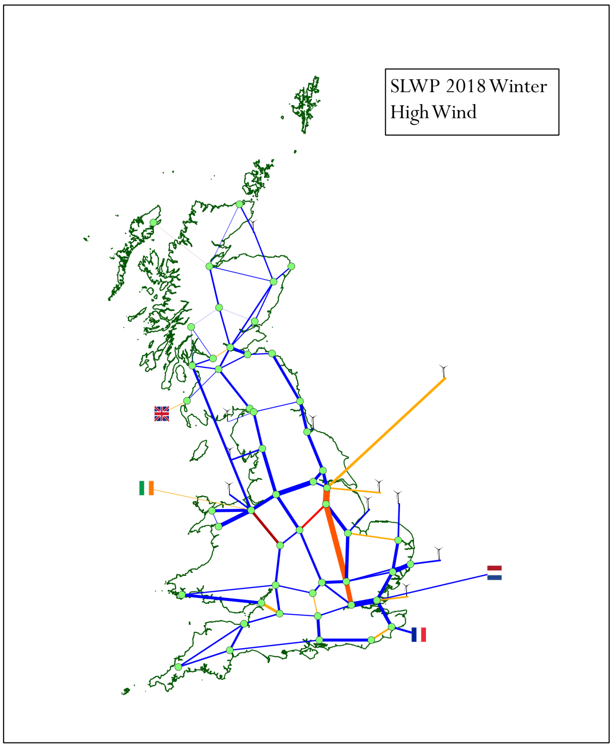


Figure 67: *SLWP 2018 Winter High Wind power flow*

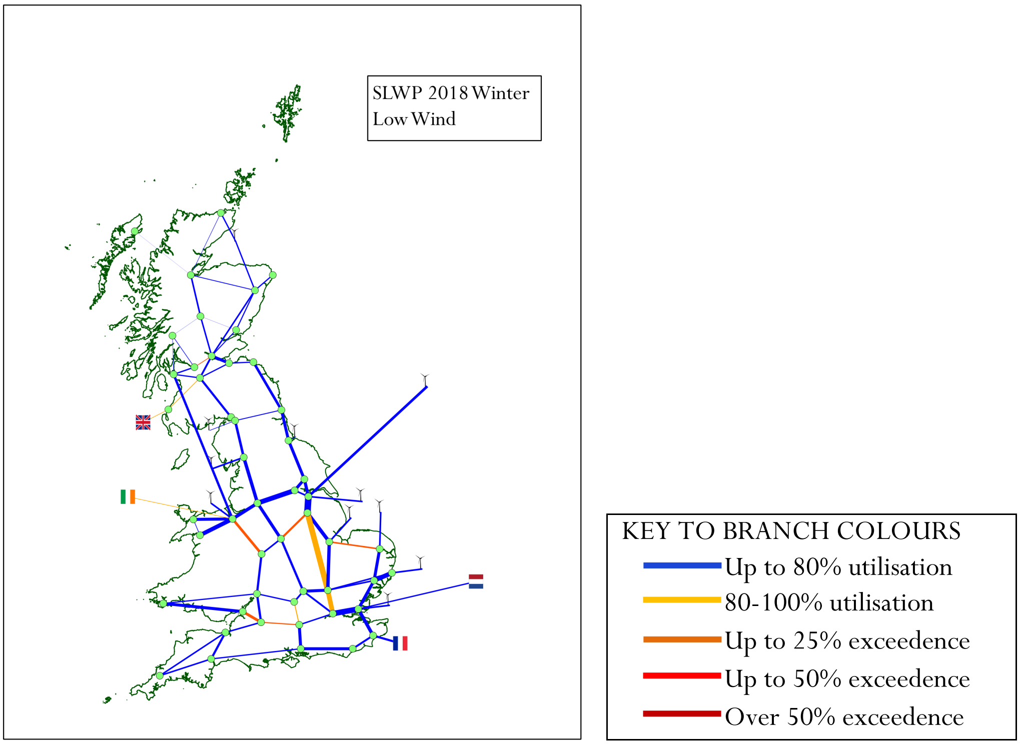


Figure 68: *SLWP 2018 Winter Low Wind power flow*

Spring and Summer in general have lower constraints than winter, as the large quantities of fossil plant respond flexibly to changes in demand.

In summary, in 2018 this scenario sees a network in which growing output from renewables is continuing to have some impact upon constraints; however, due to significant network investments since 2013, these are not occurring in Scotland but in northern England; and the activity of large clusters of fossil generators in northern England and the midlands is at least as significant as the wind output in affecting the constraint patterns.

8.3.3 2018 – 2023

8.3.3.1 Overview of period

The installed capacities of onshore and offshore wind in 2018 were similar to the central range of DECC's renewable energy roadmap (DECC, 2011c), which is constructed with reference to the UK's EU 2020 renewables targets. In this next period, the bedding-in of the EMR and the successful administration of the feed-in tariffs, within the pressure of the CCC's carbon budget which expects deep power sector decarbonisation through the 2020s, pushes forward a continued growth in low carbon generation. However this occurs within a framework which gives clear incentives to utilise the existing onshore network efficiently, in preference to triggering new onshore upgrades. There is some development of offshore wind and marine technologies which become commercially available during the period, focussed on the southern North Sea, south coast and south-west coast. There is no coordinated or anticipatory approach to offshore transmission infrastructure, and so offshore projects are developed on an individual basis with radial connections. The conditions are most favourable for low carbon generation technologies which can be flexible about location. As a result, several new nuclear stations are planned but only Hinkley Point C comes online by 2023.

8.3.3.2 Generation mix

As in SLSP, there is a modest increase of 1 GW in onshore wind in Scotland – although this is the most cost effective renewable technology it is locationally disadvantaged. This increase is permitted by a network charging policy which includes measures to encourage thermal generators in Scotland to reduce their output during windy conditions, allowing some sharing of network capacity. This increase is limited by the available existing network capacity, allowing for network sharing with conventional generation.

Some further developments in offshore wind are possible, connected by project specific radial lines to bring power from the projects ashore. However due to the transmission charging regime, there is a greater incentive for projects to connect in the south of England than in northern England and Scotland. The lack of strategic anticipatory approach to offshore grids means that projects connect radially to the closest onshore connection point. Hornsea is able to add 1.2 GW to its existing capacity, but there is no further development at Dogger due to network constraints around the North-East and Humber. The East Anglia zone begins its development with 1.2 GW, and the very southerly zones Rampion and Navitus are developed to their full available potential of 0.7 and 1.1 GW respectively.

Locational charging also encourages tidal and wave technologies, which are approaching commercialisation, to locate in southerly locations. Tidal stream is installed, 400 MW in waters off the north Devon coast, and 200 MW in the Solent. A 500 MW wave power project is installed off the north Cornish coast. A further important new addition in this period is the new nuclear station at Hinkley Point.

Also significant in this period are plant closures. The effect of the EU's Industrial Emissions Directive is felt, with a number of the older coal and gas plants opting out and closing by 2023. In addition, around 3.5 GW of nuclear plant closes due to its age. New CCGT plants opening at Thorpe Marsh (960 MW) and Drakelow (1320 MW) contribute to maintaining a positive capacity margin.

Figure 69 gives the overall impression of the change in plant mix in this period.

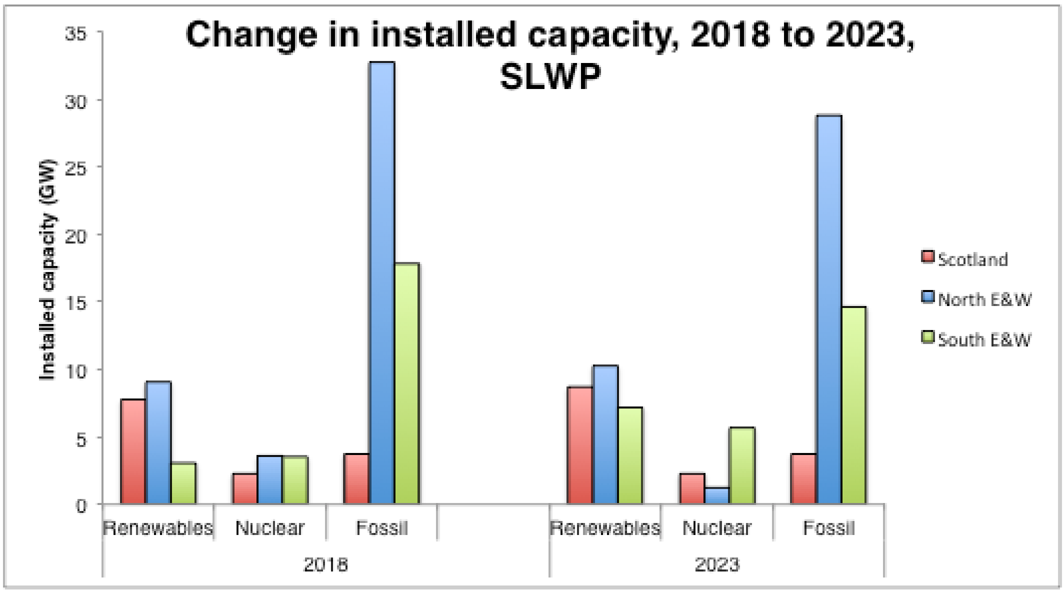


Figure 69: *Change in installed capacity, 2018 to 2023, SLWP*

This generation mix gives the following system indicators in 2023.

Table 18: *SLWP 2023 system indicators*

System derated capacity margin (%)	0.9
Proportion of annual electricity demand met by (%):	
Renewables	26
Nuclear	18
Other	56
Carbon intensity of electricity (g/KWh)	305

Renewables have increased substantially, however the locational signal combined with the lack of anticipatory network investment has limited the expansion of the network and contained the level of renewables deployment. The approach has stimulated interest in low carbon sources with greater locational freedom, however in the case of wave and tidal these have only recently commercialised and roll out remains slow. In the case of nuclear, the planning horizon is such that still only Hinkley Point C has come online, although other plants are in planning.

8.3.3.3 Network investment

Due to the locational effects of charging policy, new generation is located such that it causes little requirement for major onshore upgrades. A new 400kV line from Hinkley Point to Seabank is constructed to carry power from the new nuclear station. The main new offshore infrastructure upgrades are the radial connections to the various new offshore sites. The geographical arrangement of the network upgrades in this period are shown in ***Figure 70***.

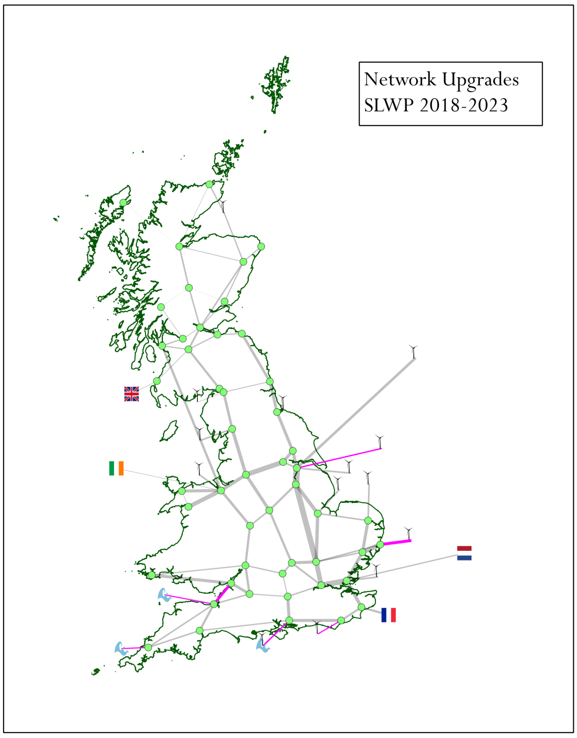


Figure 70: *Network upgrades SLWP 2018 - 2023*

8.3.3.4 Resultant power flow

At the winter peak, in all wind conditions there are moderate constraints in three important corridors: from Humber into Sheffield constraints are found as power from Hornsea and Dogger wind farm zones, as well as fossil generators in the area, is exported west; from Cottam to East midlands, as power from the same areas is exported into the Midlands load centres; and from Merseyside to West Midlands as power from the North, including outflow of the western HVDC link, flows south.

In addition high constraints are found in all conditions on the line flowing east from Melksham to Bramley, carrying power from the south-west towards London. Constraints on this line are a result of a number of factors. First the addition of Hinkley Point C, with Hinkley Point B still operational, significantly increases available power in the south-west. Second, there are also significant quantities of thermal plant around the Severn and south-wales. As these outputs are less during high wind periods, the constraints on the Melksham – Bramley line are less in high wind conditions (***Figure 71***). The winter low wind condition sees constraints and high line utilisation in the south west, due to a combination of new nuclear and renewables, plus existing fossil in the region (***Figure** 72*).

In spring, similar constraint corridors are found but in general Midlands constraints are lower than in winter. But in high wind conditions (High, NS and Average) more constraints are found in Scotland due to the lower demand here causing higher export. Melksham – Bramley again sees high constraints, again somewhat correlated with low wind.

The summer conditions have generally lower constraints, with the exception of NS, but again Melksham – Bramley stands out with very high constraints.

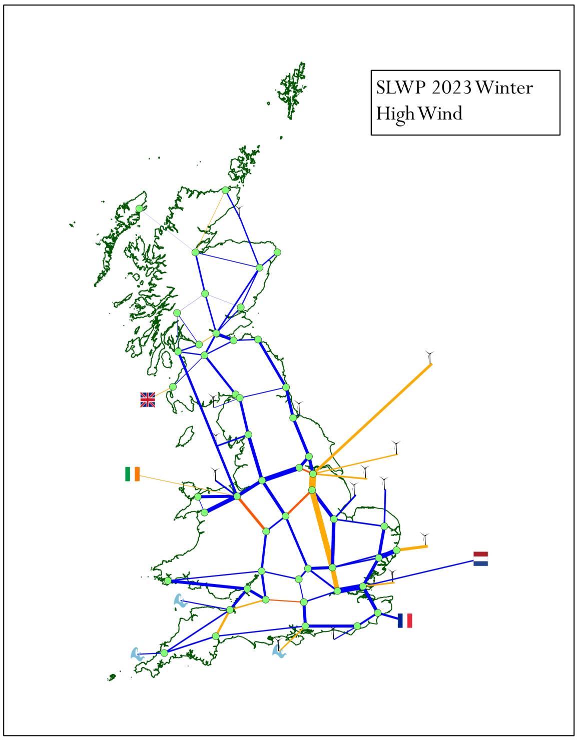


Figure 71: *SLWP 2023 Winter High Wind power flow*

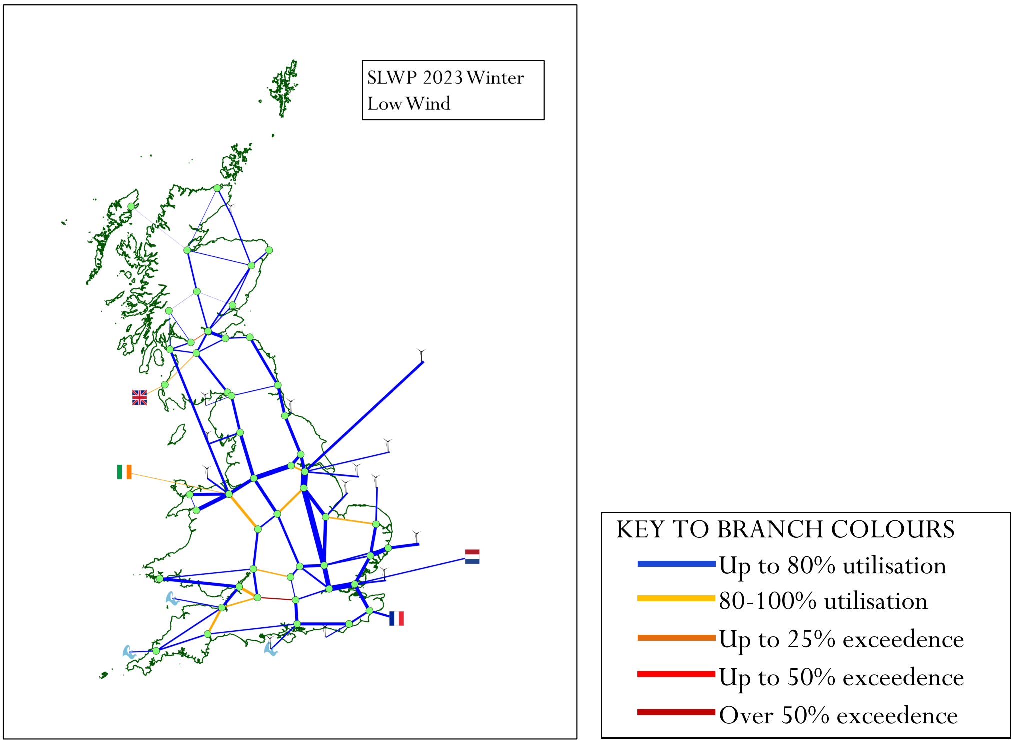


Figure 72: *SLWP 2023 Winter Low Wind power flow*

8.3.4 2023 – 2028

8.3.4.1 Overview of period

Remaining within the CCC's carbon budgets, and remaining on track to hit the electricity carbon intensity target of $50gCO_2/kWh$ by 2030, is a key priority for this period. The strong locational signal and lack of strategic anticipatory network development means that during this period low carbon generation with the ability to locate in the south of the network is favoured. In Scotland the existing portfolio of renewables already meets the available export capacity, and so no further development of renewables occurs. There is some additional expansion in southern offshore wind, wave and tidal, and two new nuclear power stations are commissioned.

8.3.4.2 Generation mix

Moderate expansion of southern North Sea offshore wind sites is permitted along with a programme of selected onshore network upgrades in the Midlands and East Coast. Thus, Dogger expands by 1.2 GW with a new connection to Teesside, Hornsea by

1.8 GW and East Anglia by 1.2 GW. A further 500 MW is added to the Cornish wave hub, and a new 1 GW wave installation connects to the coast of North Devon. Two new nuclear stations open, Sizewell C and Wylfa.

As in all scenarios, this period also sees a significant number of fossil and nuclear plant retirement, owing to age and the effect of the Industrial Emissions Directive (IED). 4.8 GW of nuclear plant and 12.6 GW of coal plant close. In addition to the 6.4 GW of new nuclear plant, a further 12.7 GW of new CCGT plant is required to maintain a positive capacity margin.

Figure 73 gives the overall impression of the change in plant mix in this period.

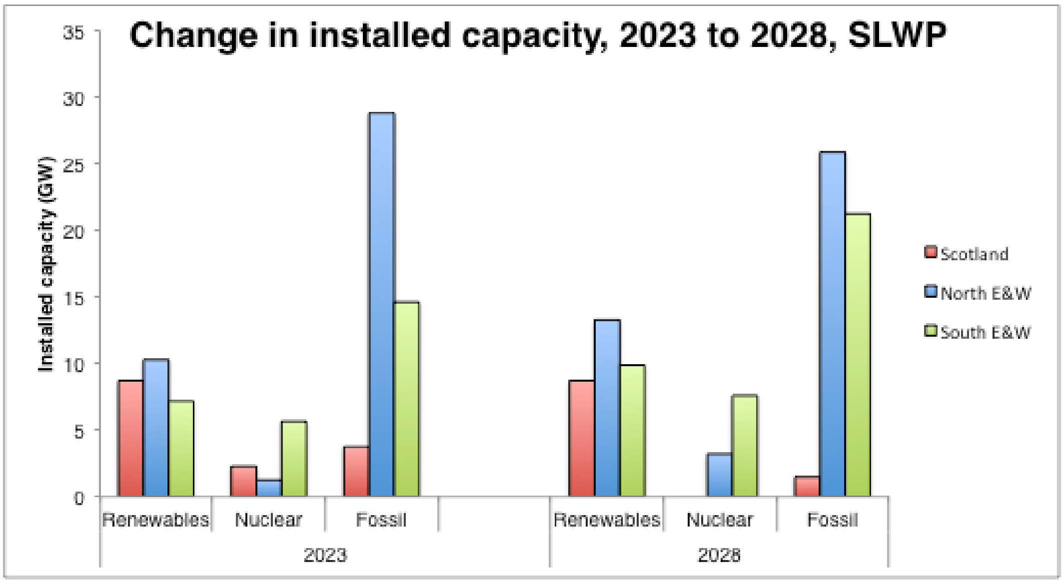


Figure 73: *Change in installed capacity, 2023 to 2028, SLWP*

This generation mix gives the following system indicators in 2028.

Table 19: *SLWP 2028 system indicators*

System derated capacity margin (%)	2.7
Proportion of annual electricity demand met by (%):	
Renewables	30
Nuclear	21
Other	49
Carbon intensity of electricity (g/KWh)	206

8.3.4.3 Network investment

Additions to the radial connection lines are required to connect the new offshore sites, and a new line connecting Dogger with Teesside is constructed. In addition a number of onshore network upgrades are made. The existing double circuit running west from Humber to Yorkshire is uprated; in North Wales the single circuit running from Wylfa to Trawsfynnyd is doubled; the Deeside to West midlands circuit is uprated; in the West country circuits between Melksham, Bramley and Cowley are uprated; and an additional circuit is added between Sizewell and Bramford. The geographical arrangement of the network upgrades in this period are shown in ***Figure 74***.

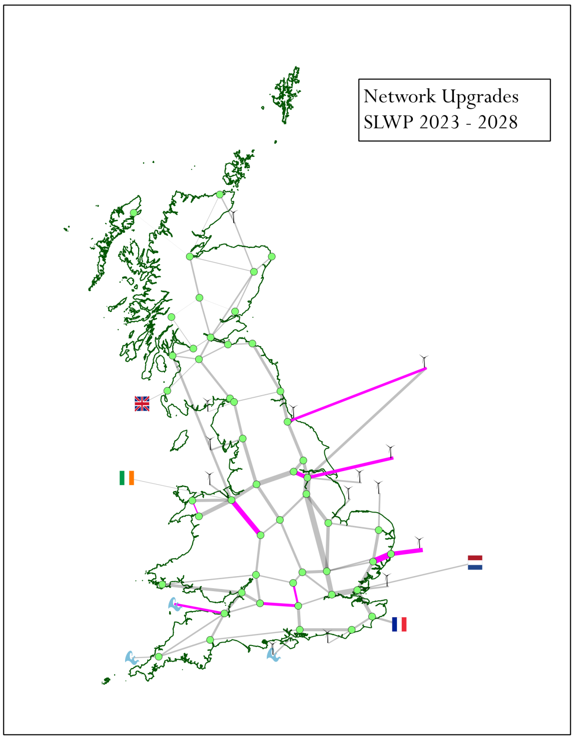


Figure 74: *Network upgrades SLWP 2023 - 2028*

8.3.4.4 Resultant power flow

The average wind condition at winter peak is virtually entirely compliant, with only a small constraint. However this is contrasted by a wide range of different kinds of constraints in different places, in the other conditions. The high wind condition sees moderate constraints in Scotland and in Suffolk, as combined output from the Sizewell nuclear stations and the East Anglia offshore zone runs westwards (***Figure 75***). The low wind condition finds south western areas constrained due to the added contribution from fossil plant in Somerset and South Wales, as well as a constraint between Grain and London (***Figure 76***). The NS condition has constraints in the north of Scotland but nowhere else, as the high northern wind output supresses the output of southern fossil plants, at the same time as southern renewable output is low. The largest constraints are found in SN, as a low overall wind output causing higher fossil output, is combined with a disproportionately high output from southern renewables, causing constraints across the south-east and south-west. It is also noticeable that the power flow is south to north in this condition, as low northern wind output sees northern GB importing from the south. The highest constraint is found between Humber and Yorkshire, as output of the southern north sea renewables and Humber fossil plant is exported west and northwards (***Figure 77***).

The spring patterns are similar to those found in winter, although with some differences in constraint levels due to the different balance between available output and demand. The average condition has moderate constraints as lower demand in key areas – north Scotland and East Anglia, require greater export. Constraints are much lower in the SN condition compared to Winter, and the north-south power flow is preserved.

Summer conditions are similar but in some cases constraints are bigger than in spring. For example, in summer high wind, and SN, both of which have notably high constraints between Sizewell and Bramford, as high wind output relative to the lower demand in the region causes more export. The power flow in SN is again south to north, though less extreme than winter.

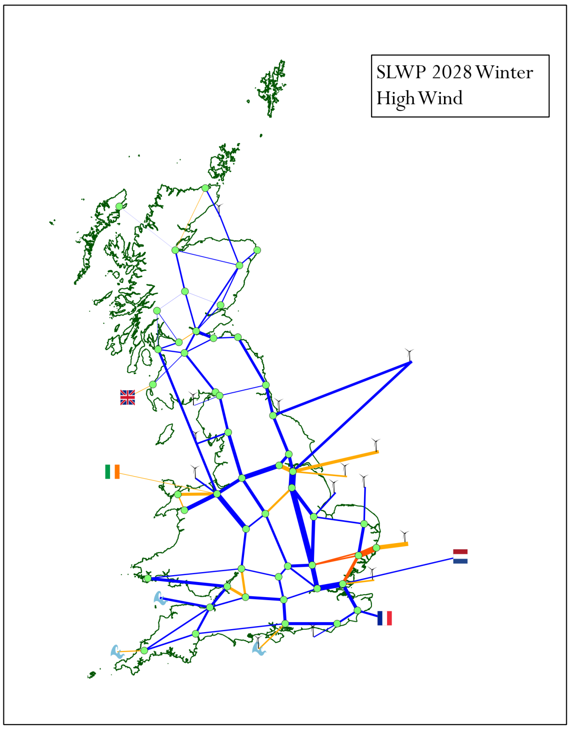


Figure 75: *SLWP 2028 Winter High Wind power flow*

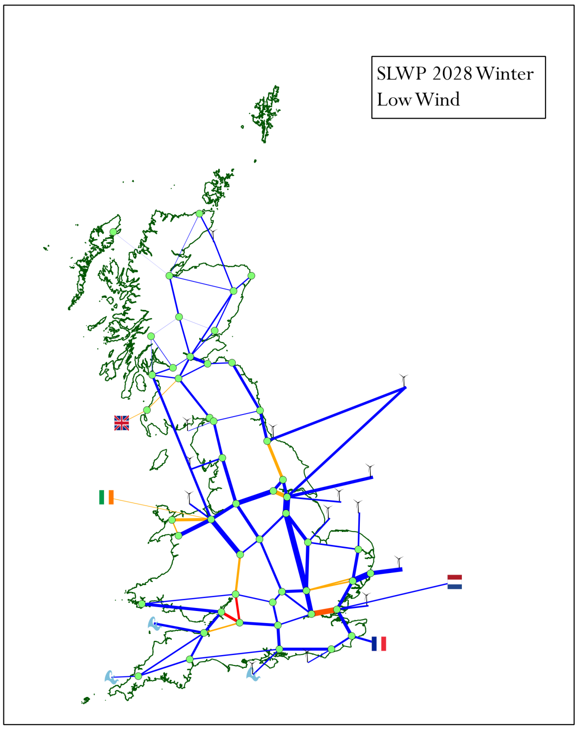


Figure 76: *SLWP 2028 Winter Low Wind power flow*

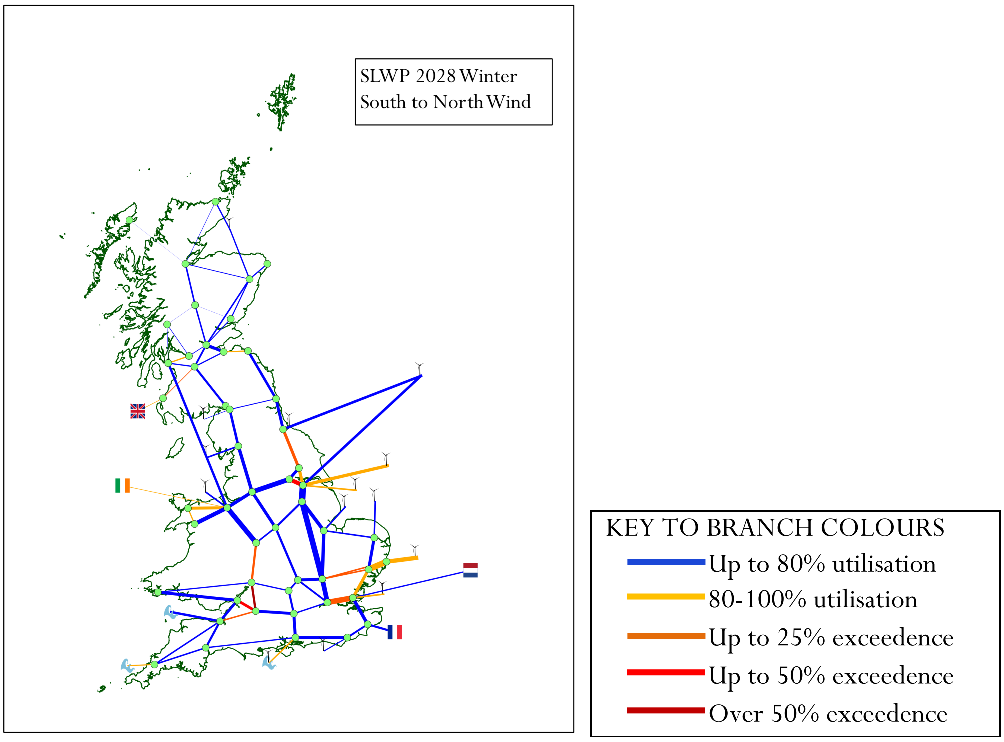


Figure 77: *SLWP 2028 Winter South to North Wind power flow*

8.3.5 2028 – 2033

8.3.5.1 Overview of period

The consistent policy approach of promoting low carbon technologies with a strong locational network signal but no anticipatory network investment has provided a conducive environment for nuclear generation. In this period a number of planning applications for new stations reach completion and there is a major expansion in nuclear power. These stations are spread around the country and are largely able to utilise network capacity that has been made available by a further tranche of fossil plant retirements. A comparatively moderate expansion in renewable capacity also takes place, in locations where network capacity is still available, largely south of the Humber, although the retirement of Peterhead allows an expansion of the Moray Firth offshore zone. While there have been some sizeable onshore upgrades of areas of network surrounding the large new nuclear stations, the general picture in 2033 is of a network very similar in structure to 2018, following the western HVDC link, with the most notable additions being radial connections from offshore sites, the majority of which connect in southern locations.

8.3.5.2 Generation mix

This period sees the construction of five new nuclear stations, which take up each of the remaining available designated nuclear sites: Sellafield, Hartlepool, Heysham, Oldbury and Bradwell. This constitutes 16 GW in five years, or an average of 3.2 GW per year. This is a fast build rate, but comparable to build rates found in other scenarios and in historical examples (DECC, 2010a).

There is a further 13.8 GW of fossil retirement due to the age of the plant. Offshore wind expands with 1000 MW at Moray Firth, Hornsea and East Anglia adding 1000 MW, and there are new developments of 1000 MW and 1200 MW in the Irish Sea and Bristol Channel zones respectively.

Wave power again pushes forward in southerly zones, with 1000 MW added in waters off the Devon, Cornwall and Pembrokeshire coasts. Large tidal barrages are also built in southerly areas – Severn, Thames, and the Wash – and a new tidal stream project is developed at Alderney.

Despite the large amounts of fossil retirement, no new fossil needs to be built to maintain a positive capacity margin.

Figure 78 gives the overall impression of the change in plant mix in this period.

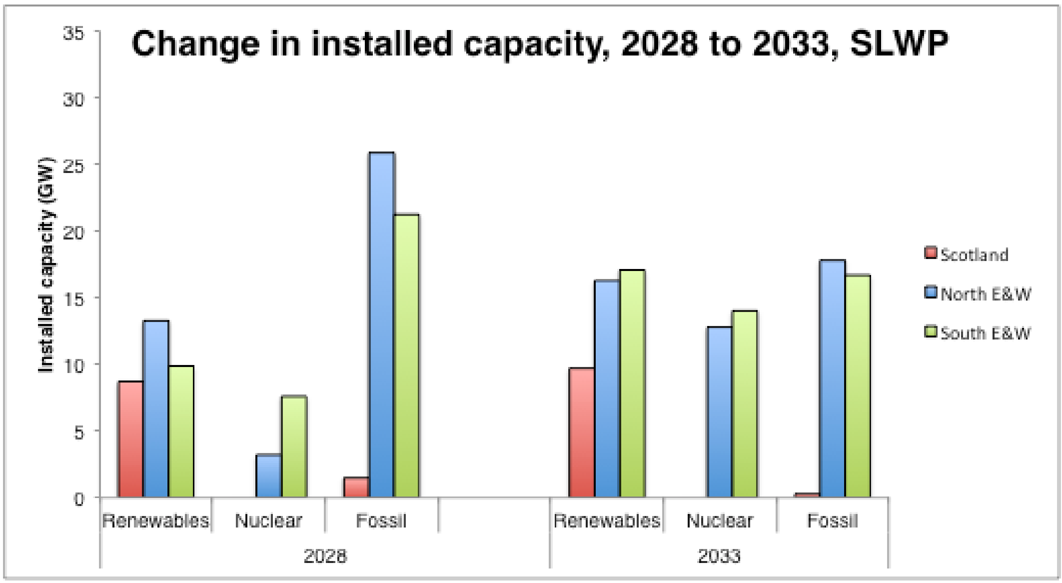


Figure 78: *Change in installed capacity, 2028 to 2033, SLWP*

This generation mix gives the following system indicators in 2033.

Table 20: *SLWP 2033 system indicators*

System derated capacity margin (%)	4.0
Proportion of annual electricity demand met by (%):	
Renewables	38
Nuclear	49
Other	13
Carbon intensity of electricity (g/KWh)	53

Despite the larger installed capacities of renewables, nuclear meets the greatest proportion of electrical energy demand due to its higher load factor.

8.3.5.3 Network investment

Due to the locational spread of the new generation projects, this scenario again avoids the construction of major bootstraps or boundary upgrades, nonetheless there are a number of important and in some cases substantial network upgrades to be made.

The new offshore projects require radial connections, notably the new Alderney tidal development. In addition, significant onshore upgrades occur in some key network corridors. Line uprates are required in the north of England around the new nuclear stations at Sellafield and Hartlepool, and an additional single circuit is added to the double circuit between Harker and Hutton. In the west of England the addition of Oldbury requires an uprate on the Seabank to Melksham line, an uprate of the Bramley to Cowley line plus new additional double circuits on the route from Melksham through Bramley to London. The Hinkley Point to Melksham line is uprated. In the east of England, Sizewell to Bramford and Grain to Sellindge are uprated, and Bramford to Eaton Socon receives another double circuit. Grain to London, Exeter to Lovedean, and Wylfa to Deeside are also uprated.

The geographical arrangement of the network upgrades in this period is shown in ***Figure*** *79*.

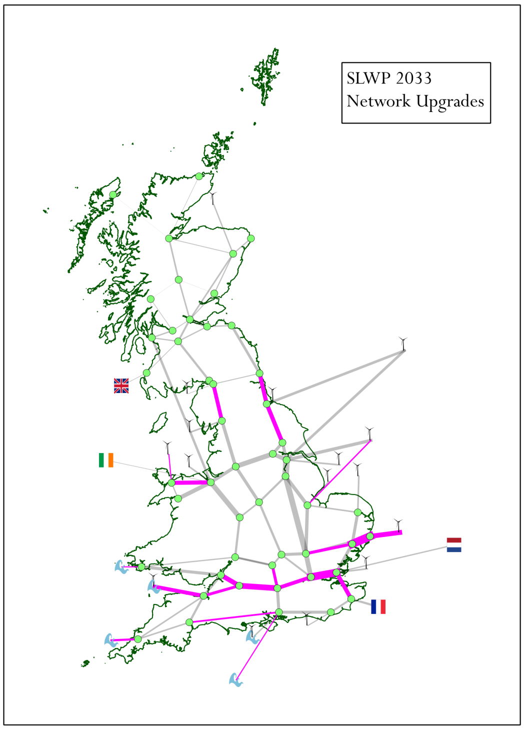


Figure 79: *Network upgrades SLWP 2028 - 2033*

8.3.5.4 Resultant power flow

In winter, as in 2028, the average wind condition is almost completely compliant, however there are significant variations from this created by the effect of the different wind conditions (***Figure** 80*). The high wind condition sees some relatively minor constraints in the north but is also mainly completely compliant (***Figure** 81*), and the low wind condition also sees only minor constraints. The NS condition sees a slightly larger constraint between Blyth and Durham, with higher wind output combining with output from Hartlepool nuclear station. The highest constraints are found in the SN condition, notably on the corridor from Melksham to Bramley to Cowley, and between Pembroke and Walham as power is exported from the high producing south west. There is also a strong south to north power flow in this condition, with exceedences over the Cheviot boundary due to power flowing into Scotland (***Figure** 82*). In the high wind condition the interconnectors were used on full export in order to avoid nuclear ramp down.

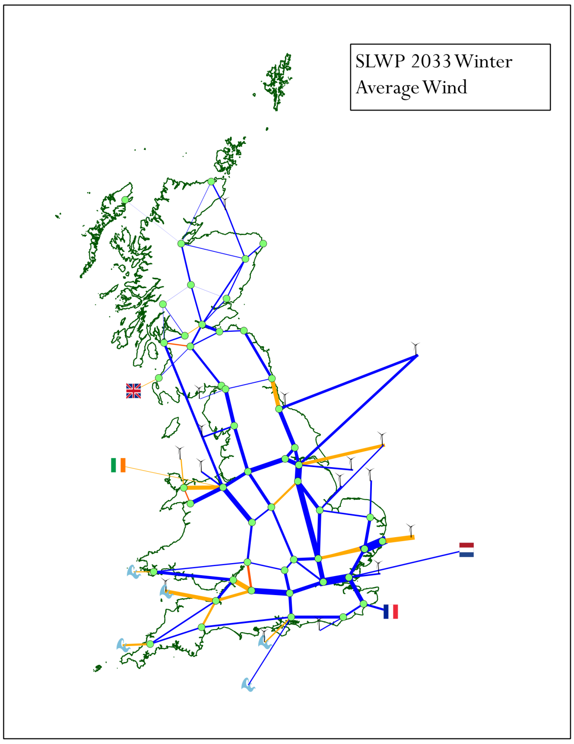


Figure 80: *SLWP 2033 Winter Average Wind power flow*

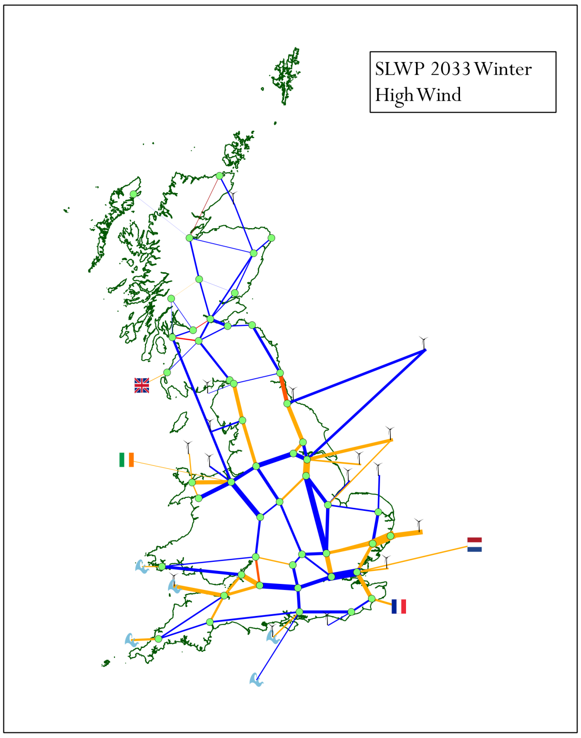


Figure 81: *SLWP 2033 Winter High Wind power flow*

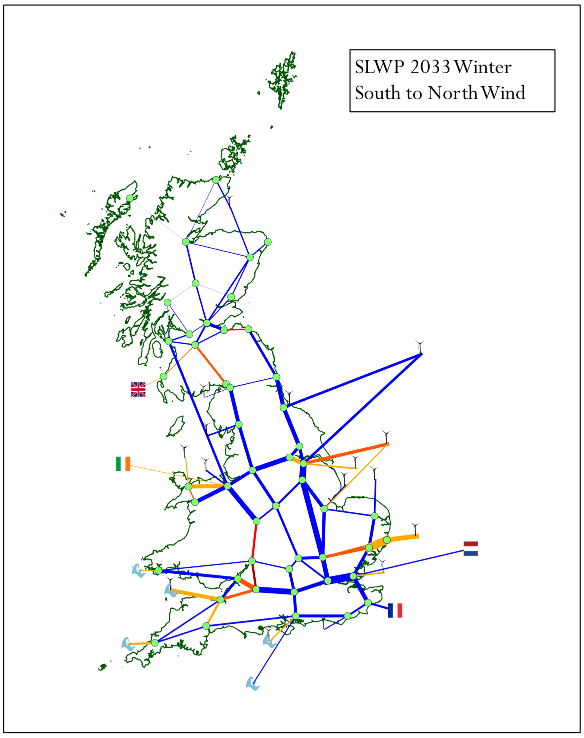


Figure 82: *SLWP 2033 Winter South to North Wind power flow*

In spring, the average wind condition is similarly compliant, though with some constraints in Scotland due to lower demand. The situation is very similar for the high wind condition and for NS. In low wind there is constraint from Torness to Edinburgh as power flow is flowing south to north into Scotland, and also constraints from the west country into London. Notably SN has no constraints at all. For Hi and SN conditions, interconnectors are on full export but there is still required some ramp down of nuclear.

In Summer, the average, high and low wind conditions all have very low constraints. NS sees some constraints on north-south export corridors, particularly Durham to York. SN has very minor constraints in the east of England. For Hi and SN conditions, interconnectors are on full export but there is still required some ramp down of nuclear (though only 800 MW per plant for SN).

8.4 Weak location strong plan (WLSP)

8.4.1 Overview of whole scenario

In this scenario the overriding network philosophy is that networks should be at the service of the higher order aim of decarbonisation. The premise is that renewables should play a significant role in the decarbonisation process, that locational network charging is something which runs counter to this higher priority government objective and is thus no longer useful or relevant. This results in a rapid expansion of renewables in the early years of the scenario, with a strong focus on northern areas of GB including the Scottish islands. This requires substantial network upgrades which are undertaken as far as possible on an anticipatory basis, and which service a system with very high levels of power export from the north to the south of the country. Interconnector projects occur in later years as the potential for spill from renewable output becomes greater, though the precise locations of these connections are not influenced by locational pricing. By 2033 the picture is of a system with high levels of interconnection to neighbouring systems, and high capacity transmission corridors both offshore and onshore which are required to distribute the high levels of peak production across the country, on a predominantly north-south gradient. The system supports 75 GW of renewables and 14 GW of nuclear generation. 39 GW of fossil thermal remains online for balancing during low wind conditions. Although the system achieves compliance during the winter peak high wind condition, the sheer variety of variable output across the system makes it hard to plan the system to be compliant in all weather and demand conditions, and curtailment of renewables may be a frequent occurrence.

8.4.2 2013 – 2018

8.4.2.1 Overview of period

In 2013 the most significant network concern is the export of power between Scotland and England. This relates to the integration of Scottish and English systems under BETTA, and is being added to by increasing development of renewables in the north of GB. There are plans to invest in the network to bring the Scotland-England boundary into compliance. Notably, these include reconductoring and other works on the existing border circuits, and the construction of the new HVDC offshore link between Hunterston and Deeside (***Table 8***, Chapter 7).

The EMR package has come into effect which, it is hoped, will provide sufficient incentive for low carbon generation to meet EU 2020 targets and the CCC carbon budgets.

However, as well as the planned upgrades required to achieve compliance of the Scotland-England boundary based on generation expected in 2013, transmission planning in this scenario goes significantly further to extend to previously unconnected areas of the grid and unlock renewable potential in these regions.

8.4.2.2 Generation mix

Onshore wind is deployed according to the base assumptions in all scenarios, with the addition of wind projects in mid-Wales, wind projects and a and a 20 MW wave demonstration in the Hebrides, and a 100 MW tidal project in the Orkneys which are supported by new strategic network upgrades.

Offshore wind sees all consented and under construction projects in 2013 move to completion, with the further addition of the first 2.4 GW project at Dogger.

The final reactor at the Wylfa nuclear site is closed, and a number of closures of coal and oil plants occur under the Large Combustion Plant Directive. ***Figure 83*** shows the effect of these generation investment decisions on the total installed capacity during the period.

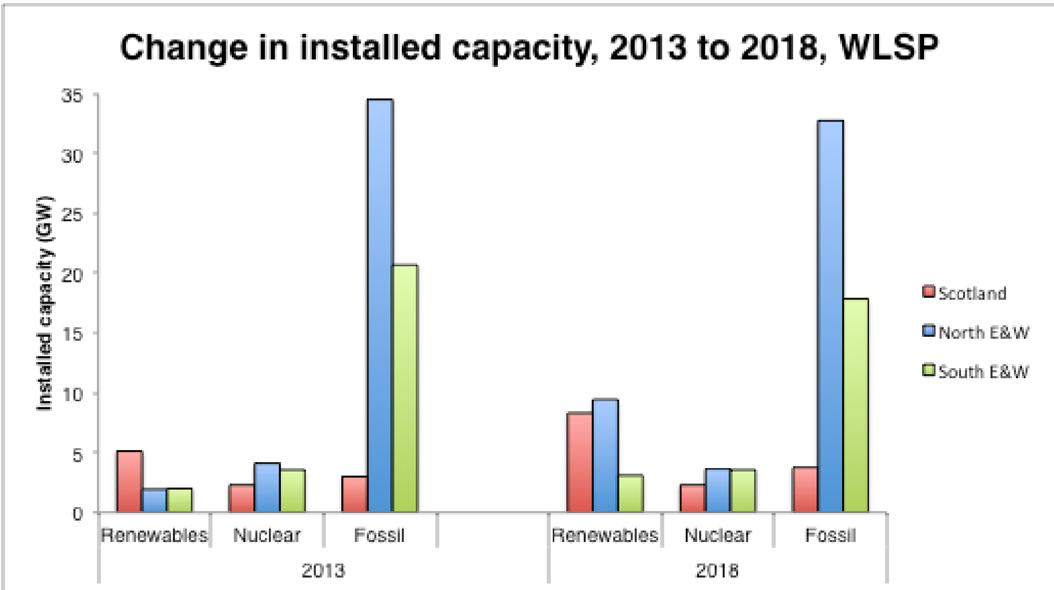


Figure 83: *Change in installed capacity, 2013 to 2018, WLSP*

This generation mix gives the following system indicators in 2018.

Table 21: *WLSP 2018 system indicators*

System derated capacity margin (%)	6.2
Proportion of annual electricity demand met by (%):	
Renewables	21
Nuclear	19
Other	60
Carbon intensity of electricity (g/KWh)	352

This scenario provides the highest renewable contribution in 2018 with a further 360 MW of onshore wind in Mid-Wales, in addition to the Hebrides additions, and contribution from tidal in the Orkneys (100 MW). These additional contributions have a small effect on the carbon intensity of electricity compared to the other scenarios.

8.4.2.3 Network investment

Confirmed network upgrades as of 2013 are included in this scenario, most significant of which are the upgrades over the Scotland-England boundary, including the HVDC western link between Hunterston and Deeside (***Table 8***, Chapter 7). In addition to these, this scenario also sees island connections to the Western Isles (HVDC link) and Orkneys, and a new transmission line to Mid-Wales, connecting with the East Midlands. The geographical arrangement of the network upgrades in this period is shown in ***Figure 84***.

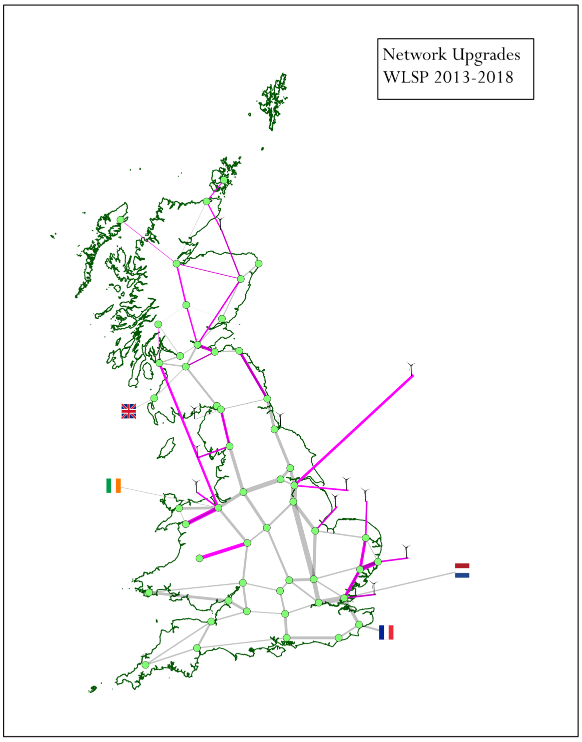


Figure 84: *Network upgrades WLSP 2013-2018*

8.4.2.4 Resultant power flow

In Winter the effect of the investments in renewables in Scotland, and the lack of locational signal to affect the operation of fossil plants in Scotland and northern England during times of high congestion, results in clear constraint patterns running from north Scotland as far as London. The high wind condition finds constraints in the central belt of Scotland and at the English border. Particularly high constraints can be found between Humber and Cottam, relating to the output of Dogger wind farm as well as regional fossil plants; and from Deeside, where the HVDC western link now lands, running south. Constraints continue on the corridor from the east Midlands to the major load centre of London (***Figure** 85*). Constraints are substantially lower in the low wind (***Figure** 86*) as well as in SN conditions. NS has in general lower constraints, although the constraint between Deeside and the west Midlands is still high, owing to the large throughput from the western link. The average wind condition shows a similar pattern to the high wind condition, though without constraints in Scotland (***Figure** 87*).

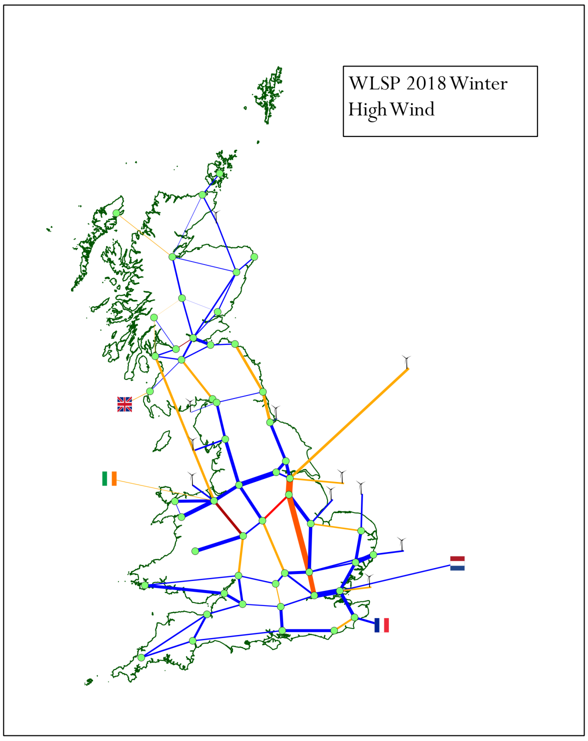


Figure 85: *WLSP 2018 Winter High Wind power flow*

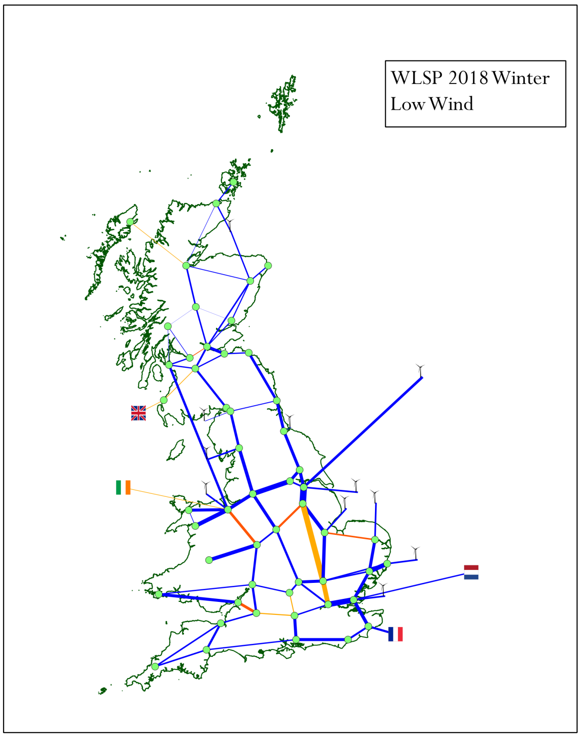


Figure 86: *WLSP 2018 Winter Low Wind power flow*

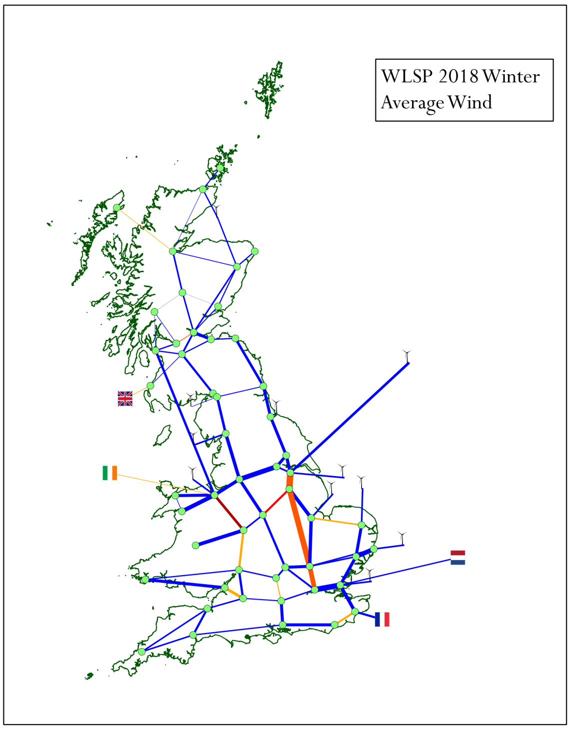


Figure 87: *WLSP 2018 Winter Average Wind power flow*

Similar patterns and constrain corridors are observable in Spring and Summer. Although in general lower demand and lower wind conditions lead to lower constraints, there are variations. For instance while the combination of low demand and low wind leads to low constraints in the summer low wind condition (***Figure** 88*), the higher northerly output in spring NS leads to relatively high constraints (***Figure** 89*).

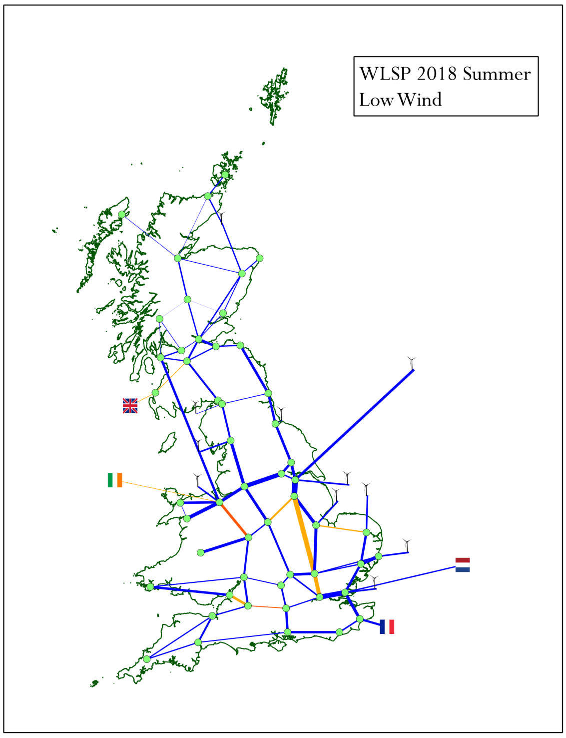


Figure 88: *WLSP 2018 Summer Low Wind power flow*

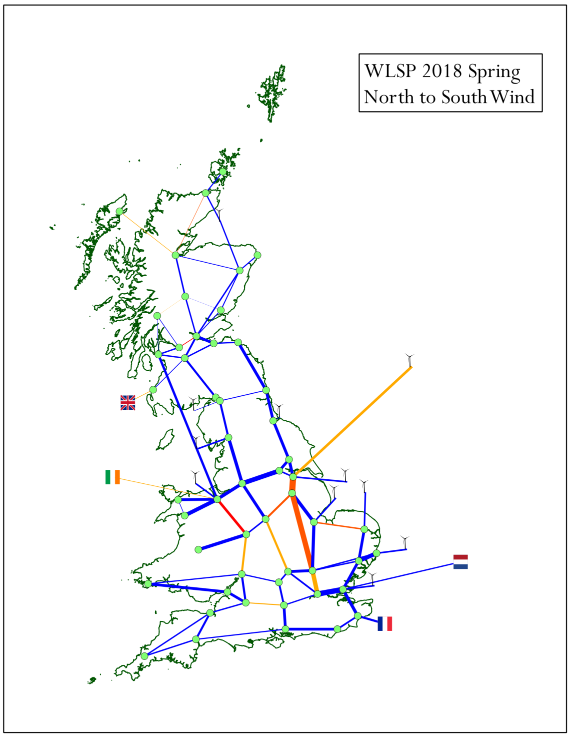


Figure 89: *WLSP 2018 Spring North to South Wind power flow*

8.4.3 2018 – 2023

8.4.3.1 Overview of period

In the context of the continued push towards staying on track for the CCC's target of 50gCO_2/kWh in 2030, locational signals continue to be smoothed, and significant on- and offshore network upgrades take place in anticipation of the rapid growth in renewables.

8.4.3.2 Generation mix

The prime technology choice and location under this scenario is onshore wind in Scotland, which increases by 3 GW during the period. 500 MW are installed on Orkney and 1 GW in mid-Wales. Hydro also receives a boost in this period and additional 300 MW is added in Scotland. Offshore wind development takes place at all available locations: Moray Firth (1500 MW), Forth (1050 MW), Dogger-Teesside (2400 MW), Hornsea (1200 MW) Irish Sea (2200 MW), East Anglia (1200 MW), Rampion (700 MW) and Navitus (1100 MW).

Tidal stream is developed at Orkney (300 MW), Pentland Firth (500 MW), Solent (200 MW), Western Isles (500 MW) and Bristol Channel (400 MW). Wave power is also commercialised in this year, and 500 MW are installed at each of Orkney, Hebrides, Western Isles, Devon and Cornwall.

Hinkley Point C nuclear power station also comes online during this period.

Figure 90 shows the effect of these generation investment decisions on the total installed capacity during the period.

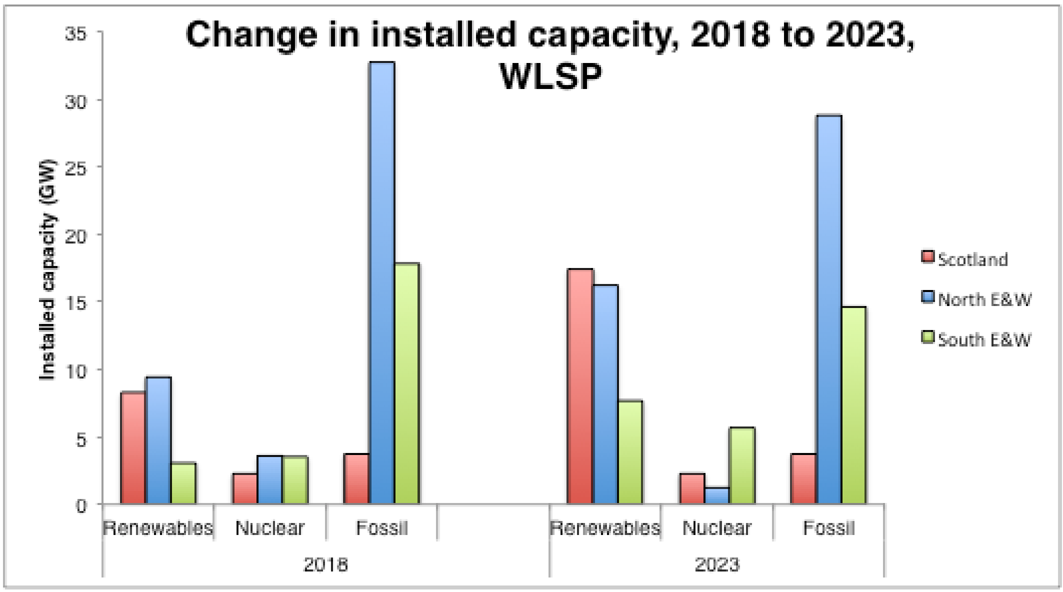


Figure 90: *Change in installed capacity, 2018 to 2023, WLSP*

This generation mix gives the following system indicators in 2023.

Table 22: *WLSP 2023 system indicators*

System derated capacity margin (%)	3.0
Proportion of annual electricity demand met by (%):	
Renewables	39
Nuclear	18
Other	43
Carbon intensity of electricity (g/KWh)	238

8.4.3.3 Network upgrades

Very substantial network upgrades are implemented in line with the aggressive development of renewables across the country. Required island connections are made and uprated, and radial connections of offshore zones. In addition, the new Hinkley Point C link and upgrades of networks in Scotland, the Cheviot boundary and the North-East of England are undertaken. New HVDC bootstraps are also required, between Peterhead and Blyth (4.4 GW), Durham and Norwich (2.2 GW), Wylfa and Pembroke (2.5 GW), and Torness and Lackenby (2.2 GW). In addition another cable is added to the existing HVDC link from Hunterston to Deeside HVDC link, raising its total capacity to 4.4 GW.

The network upgrades for this period are represented geographically in ***Figure 91***.

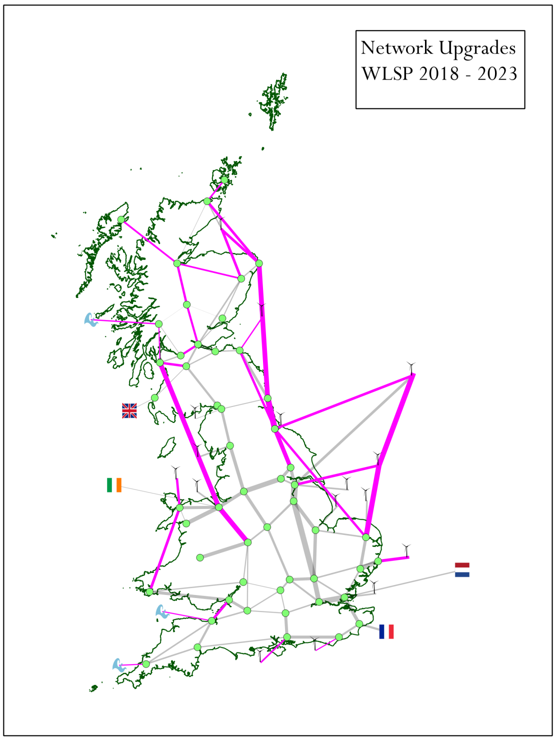


Figure 91: *Location of network upgrades, WLSP 2018 - 2023*

8.4.3.4 Resultant power flow

In winter the most common constraint, which occurs in all conditions, is on the line between Melksham and Cowley, owing to the high production in the south-west, emanating from Hinkley Point B and C, in combination with a number of wave and tidal installations in the south-west. Aside from this, constraints occur on different parts of the east coast network, depending on the different relative outputs from northern Scottish renewables, and north sea offshore zones. In the high wind condition, constraints are experienced between Durham and Yorkshire, as high output from Dogger finds its way south, and Norwich and Bramford as the high output from Dogger and Hornsea lands in East Anglia (***Figure 92***); in the NS condition constraints occur between Blyth and Durham due to the high output through the east coast bootstrap, and between Walham and Cowley, as high northerly output transmitted through west-coast bootstraps and onshore upgrades is pulled in towards London (***Figure 93***).

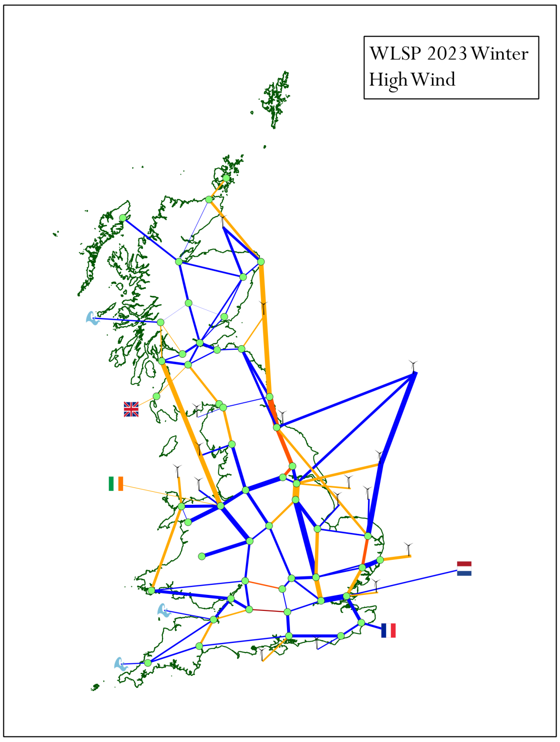


Figure 92: *WLSP 2023 Winter High Wind power flow*

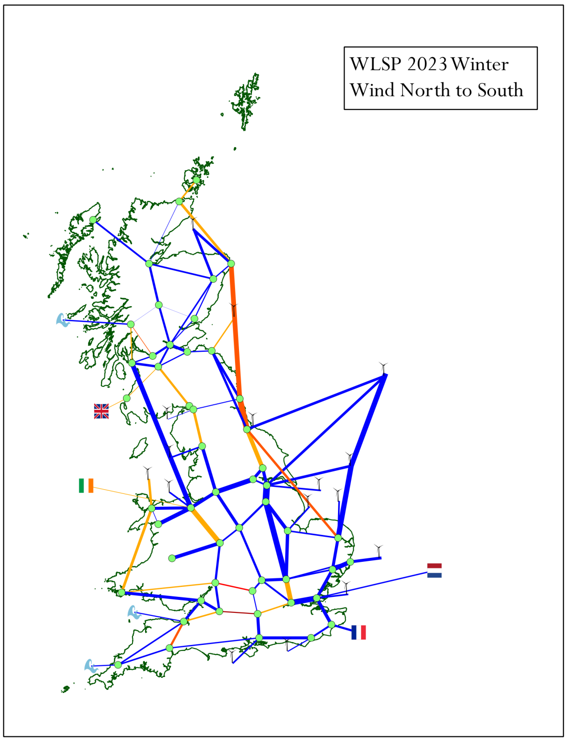


Figure 93: *WLSP 2023 Winter North to South power flow*

Similar patterns are observable in Spring, with Melksham to Cowley again being constrained in all conditions. The high wind condition sees the highest constraints elsewhere, on both the west coast between Harker and Hutton, and on the east coast from Teesside through to Yorkshire (***Figure 94***). The average wind condition also sees constraints between Walham and Cowley (***Figure 95***).

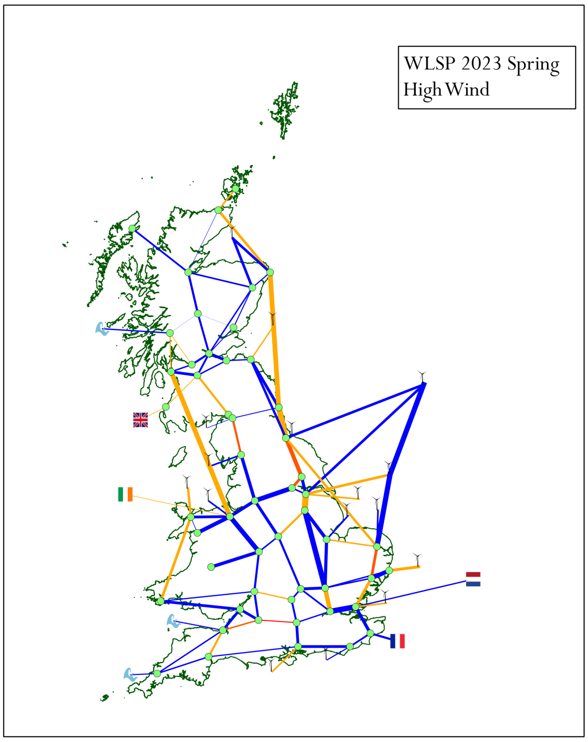


Figure 94: *WLSP 2023 Spring High Wind power flow*

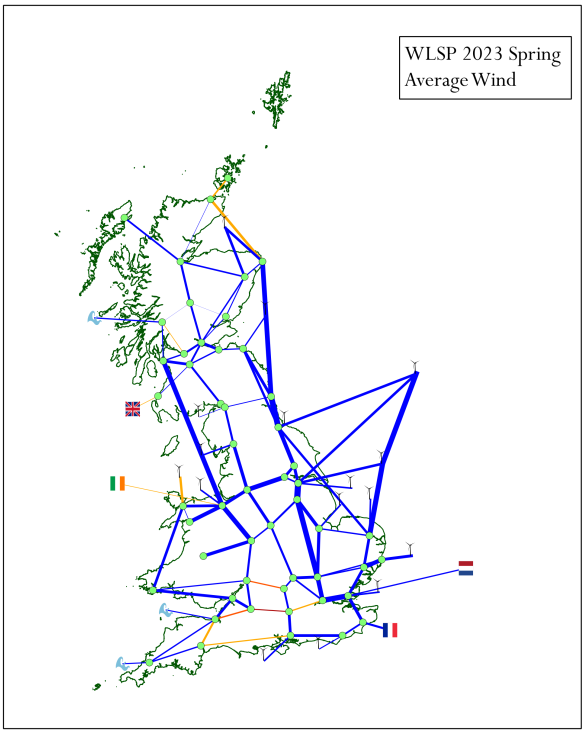


Figure 95: *WLSP 2023 Spring Average Wind power flow*

In summer constraints are lower overall but again high constraints occur between Melksham and Cowley due to the south western output. Highest constraints elsewhere are found in the NS condition (***Figure 96***).

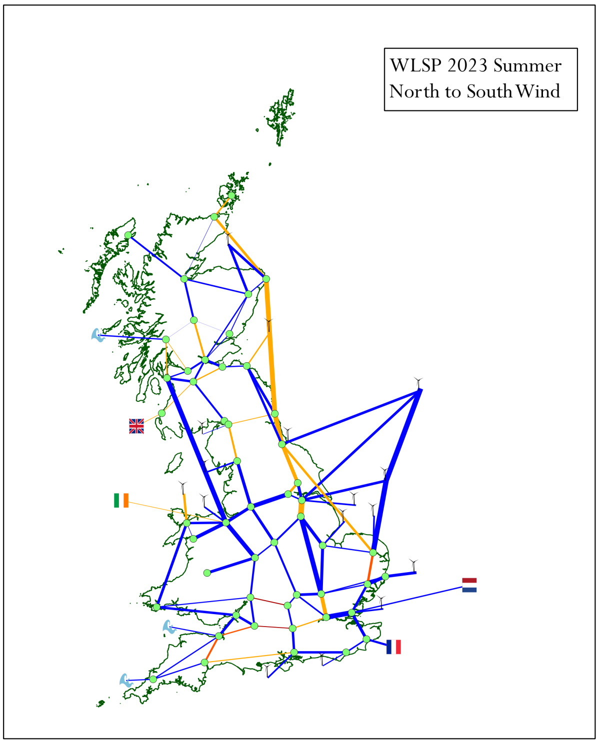


Figure 96: *WLSP 2023 Summer North to South Wind power flow*

8.4.4 2023 – 2028

8.4.4.1 Overview of period

The generation mix in 2023 represented good progress towards the target of 50gCO_2/kWh by 2030, but with some way still to go. This period sees a concerted push towards that target, again with low carbon generation connecting throughout the country, and with network investment having to move quickly to keep up and minimise constraints. The rapid growth in renewables creates huge amounts of variability in the patterns of output, which result in variable power flow patterns depending on the weather conditions. The variability of output also creates commercial opportunities for interconnectors, however the location and operation of these interconnectors is not influenced by locational signals.

8.4.4.2 Generation mix

Onshore wind continues to expand with a further 3 GW in Scotland mainland and a further 500 MW in Shetland and Orkney. Mid Wales also sees a further expansion of

1 GW. Wave power is developed in Shetland, Orkney, the Hebrides, the Western Isles, Devon and Cornwall, and tidal stream is developed in the Pentland Firth.

In addition a number of tidal barrage schemes are opened, in the Solway Firth, Deeside, the Wash and Bristol channel.

As in all scenarios, this period also sees a significant number of fossil and nuclear plant retirement, owing to age and the effect of the Industrial Emissions Directive (IED). 4.8 GW of nuclear plant and 13.6 GW of coal plant close. Two new nuclear plants are opened at Sellafield and Sizewell. However, owing to the large numbers of renewable installations, a comparably small amount of new CCGT is required to come online in order to maintain a positive capacity margin, with around 5.3 GW commissioning by 2028.

Figure 97 shows the effect of these generation investment decisions on the total installed capacity during the period.

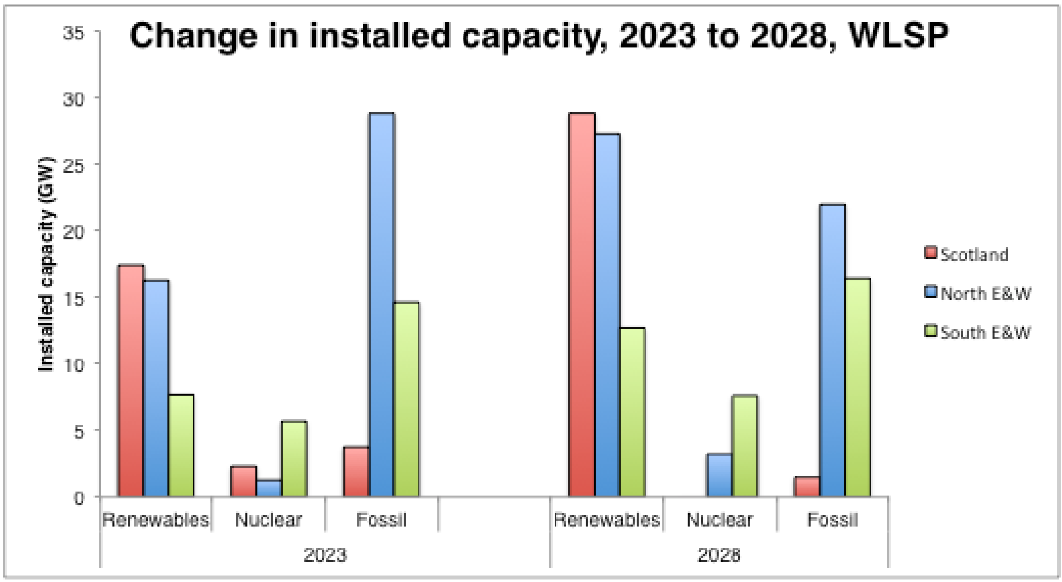


Figure 97: *Change in installed capacity, 2023 to 2028, WLSP*

This generation mix gives the following system indicators in 2028.

Table 23: *WLSP 2028 system indicators*

System derated capacity margin (%)	2.9
Proportion of annual electricity demand met by (%):	
Renewables	60
Nuclear	21
Other	19
Carbon intensity of electricity (g/KWh)	81

There is now a very large contribution from renewables, and the carbon intensity of electricity is close to the required 50g / kWh.

8.4.4.3 Network upgrades

In addition to the required upgrades to radial links, major upgrades are again made to the network of offshore bootstraps, required to transport the large volumes of power from north to south. New lines are added to the bootstrap routes along the east coast, and onshore upgrades made in East Anglia where the power reaches land and heads toward London. Along the west coat, a new series of bootstraps head from Thurso to Stornoway and down through Inverary to Hunterston where it joins the Western HVDC link, which itself receives a further upgrade. Onshore upgrades occur in lines between Teesside and Yorkshire, and in Cumbria. The Wlyfa-Pembroke HVDC also receives an upgrade, and there is a new direct link from Norwich to Sellindge where the French interconnectors are met. The geographical arrangement of the network upgrades in this period is shown in ***Figure 98***.

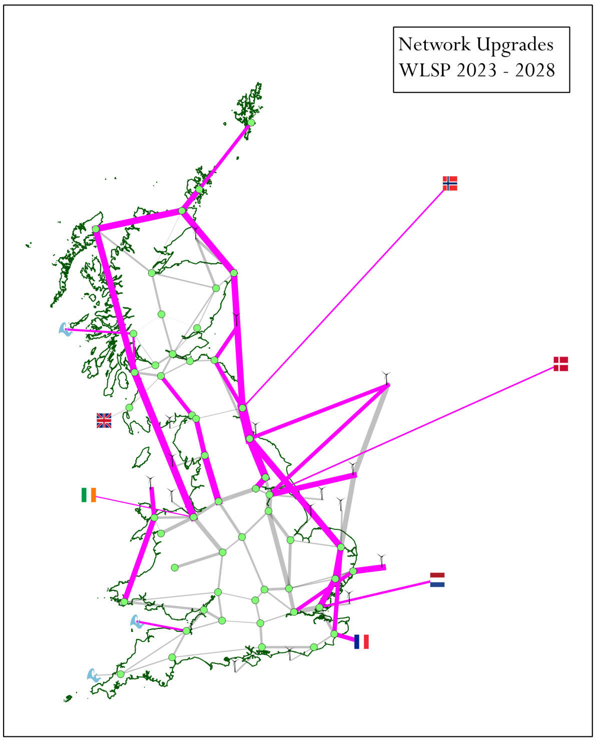


Figure 98*: Network upgrades WLSP 2023 - 2028*

8.4.4.4 Resultant power flow

Massive upgrades have been required to keep the system broadly compliant. Even so all conditions have constraints, many significant, and there is a high level of variation as to where these occur, as the combination of swings in renewable generation and interconnector activity create dramatic changes in flows. Interconnectors are active in exporting power during high wind conditions and importing power during low wind conditions. Without the activity of interconnectors, in high wind conditions wind or nuclear output would have to be curtailed, and in low wind conditions fossil plant would be called on to generate.

In winter, the high (***Figure** 99*) and NS conditions have significant constraints in southern Scotland and the cheviot border; the low wind condition has isolated constraints in the south east due to imports from the interconnectors (***Figure** 100*); SN and the average wind condition have a few constraints in southern Scotland and northern England (***Figure** 101*). Notably there are lower constraints between the south-west and London than in previous years, due to lower output from fossil plants as a result of the higher overall renewable output.

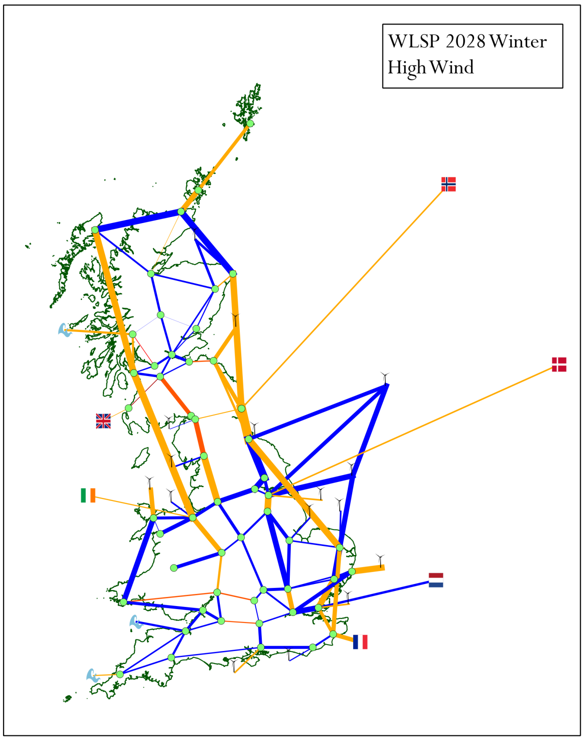


Figure 99: *WLSP 2028 Winter High Wind power flow*

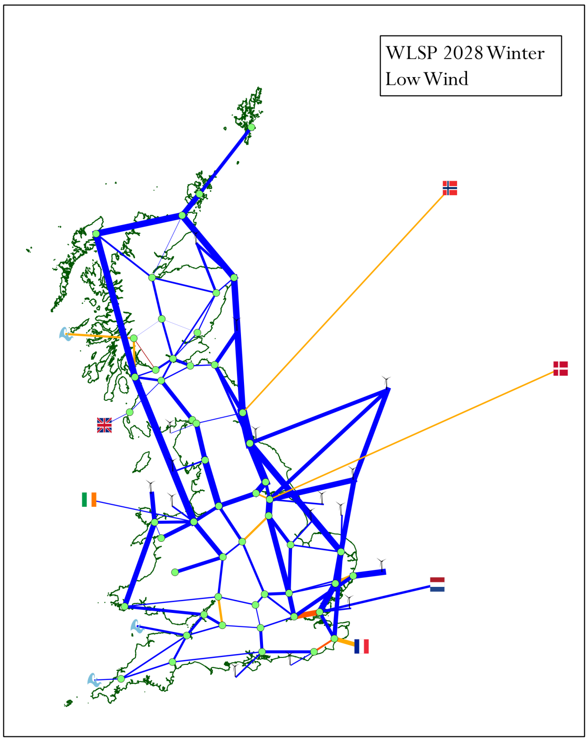


Figure 100: *WLSP 2028 Winter Low Wind power flow*

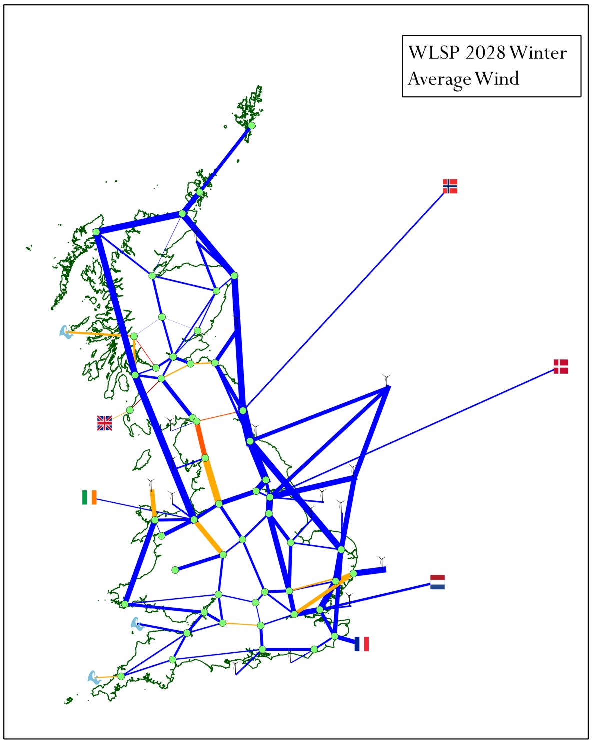


Figure 101: *WLSP 2028 Winter Average Wind power flow*

In spring, constraints vary considerably depending on the balance between local demands which are lower than in winter, and wind conditions, which can in some instances be almost as high as winter. In the high wind condition constraints are only found in northern Britain, and in the low wind condition there are isolated constraints in the midlands and south. The NS condition has significant constraints in northern England and isolated in constraints in the south (***Figure 102***); and in SN the constraints are relatively smaller but clustered around the cheviots. It is the average condition in which constraints are spread most widely around the country, in Scotland, northern England and the south (***Figure 103***).

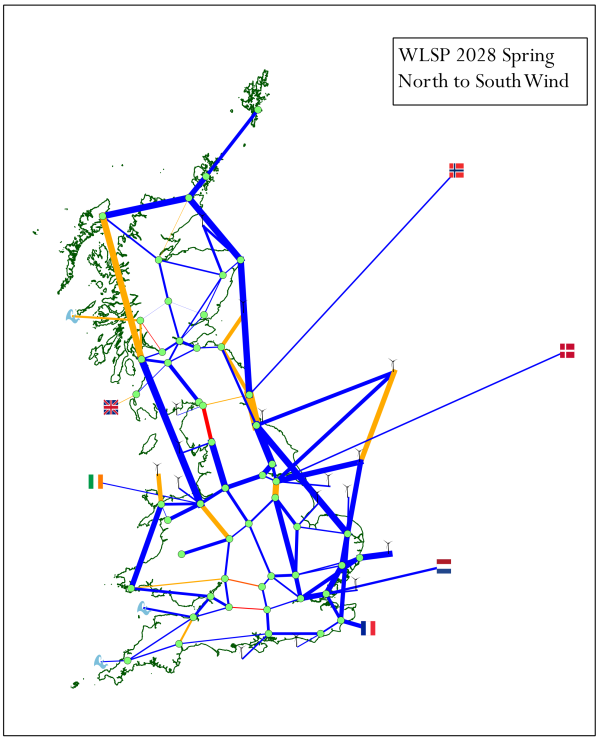


Figure 102: *WLSP 2028 Spring North to South Wind*

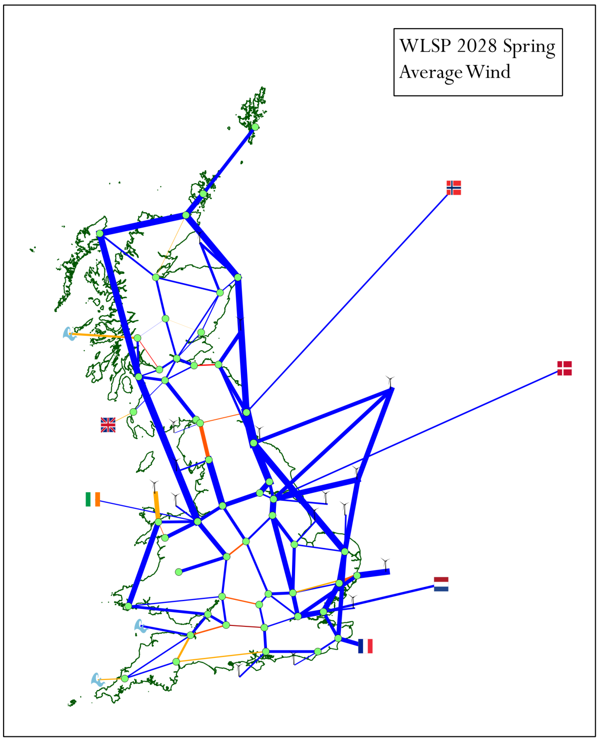


Figure 103: *WLSP 2028 Spring Average Wind power flow*

In summer constraints are in some cases higher than in winter and spring, due to a still high renewable output but matched to a lower demand level, causing more export of power from high generating areas. In the high wind condition, constraints are high in the Cheviots, western England and Norfolk (***Figure 104***); in the low wind condition the constraints are focussed in the south, around the interconnectors; in NS constraints are focussed in northern England, and western England; in SN, in northern England and Norfolk; and in the average wind condition, in Scotland, northern England, and western England (***Figure 105***).

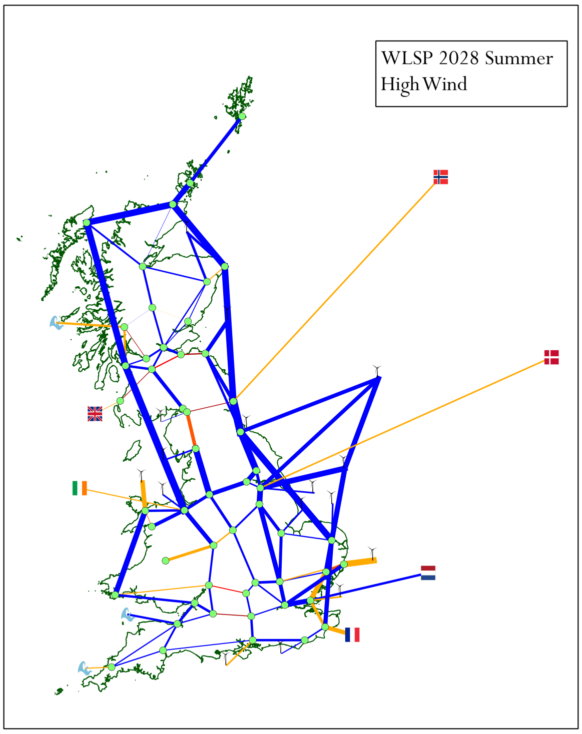


Figure 104: *WLSP 2028 Summer High Wind power flow*

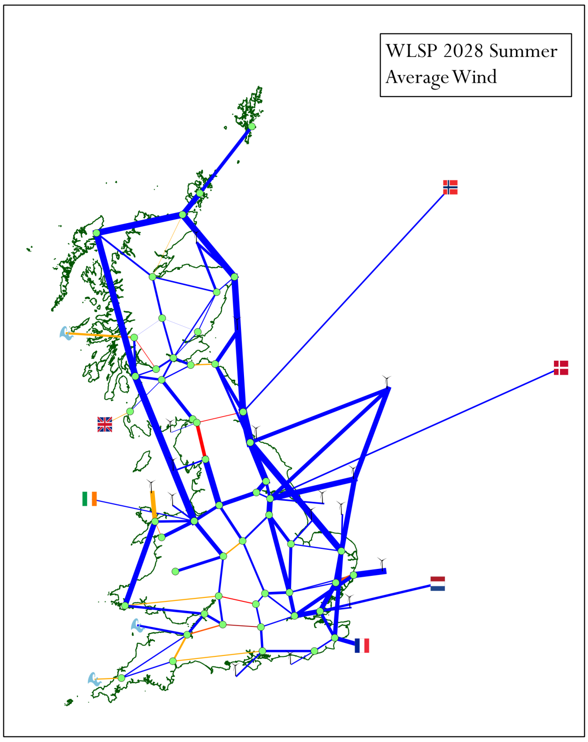


Figure 105: *WLSP 2028 Summer Average Wind power flow*

8.4.5 2028 – 2033

8.4.5.1 Overview of period

The major expansion of the previous decade allows for a comparatively lower rate of generation build out than in the previous decade of this scenario, but network upgrades continue to be made in order to achieve compliance across as much of the network as possible.

8.4.5.2 Generation mix

The remaining available space at Round 3 offshore wind zones is used, adding 1800 MW to Dogger and 3000 MW to East Anglia. 500 MW of wave are added at Orkney and Hebrides. A new nuclear power station is added at Wylfa.

There is a further 13.8 GW of fossil retirement due to the age of the plant. Due to the comparatively small number of low carbon openings, maintaining a positive capacity margin requires that 13 GW of new fossil plant is commissioned during the period.

Figure 106 shows the effect of these generation investment decisions on the total installed capacity during the period.

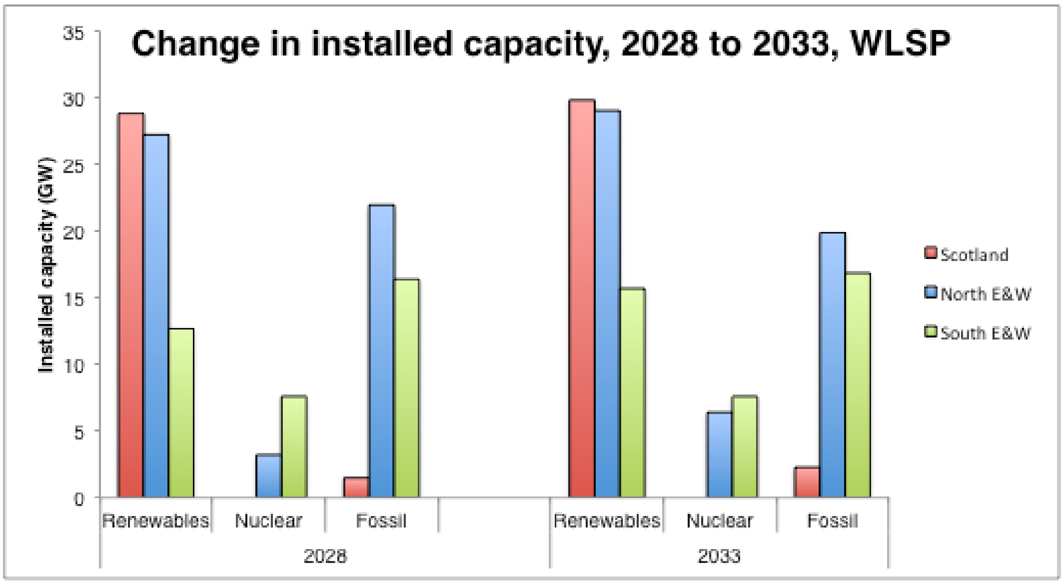


Figure 106: *Change in installed capacity, 2028 to 2033, WLSP*

This generation mix gives the following system indicators in 2033.

Table 24: *WLSP 2033 system indicators*

System derated capacity margin (%)	3.3
Proportion of annual electricity demand met by (%):	
Renewables	62
Nuclear	26
Other	12
Carbon intensity of electricity (g/KWh)	49

8.4.5.3 Network upgrades

Upgrades are undertaken in the west of Scotland and north-west England. The line from Auchencrosh to Windyhill is upgraded to a double, and the western corridor from Windyhill, through Gretna and Harker to Hutton has another single line added to the existing double circuits. The geographical arrangement of the network upgrades in this period is shown in *Figure 107*.

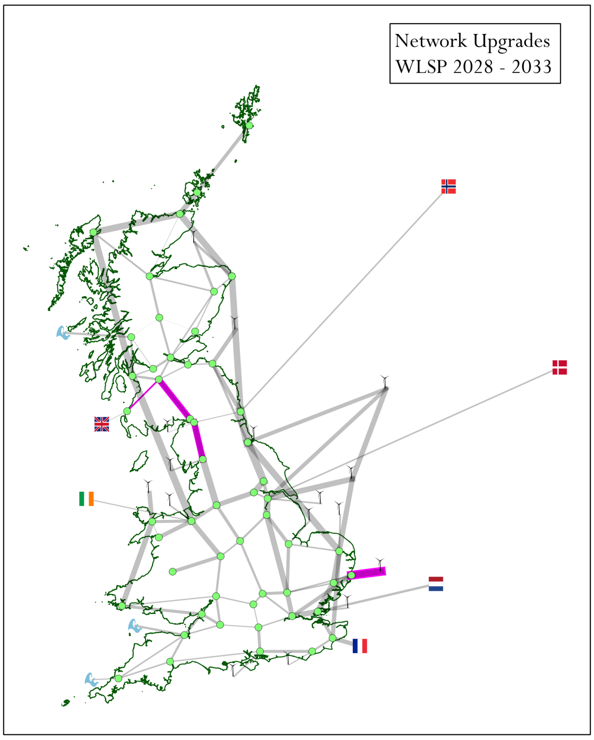


Figure 107: *Network upgrades WLSP 2028 - 2033*

8.4.5.4 Resultant power flow

The power flows arising from this generation mix again show significant within-season variation depending on the weather conditions. Reinforcements undertaken on the network within the last decade of the scenario are such that the winter high wind condition is almost entirely compliant (***Figure** 108*). However the low wind condition has more constraints, although lower utilisation overall, as can be seen in the diagram), particularly in the south-east due to imports from interconnectors (***Figure** 109*). A comparison of these two figures also indicates that the low wind condition has lower utilisation overall – the high wind condition achieves a more even spread of power, with low wind having more concentrated point sources, notably the interconnectors. The NS condition finds constraints particularly in Scotland and north-west England, as well as in the south-east from Sizewell and the East Anglia offshore wind zone (***Figure** 110*). The SN condition has fewer northerly constraints but more in the west of England and Wales and in particular a very large constraint on the lines running west from Sizewell, due to combined nuclear and offshore wind output (***Figure** 111*). The average condition sees constraints throughout the network with again particularly high constraints running west from Sizewell (***Figure** 112*).

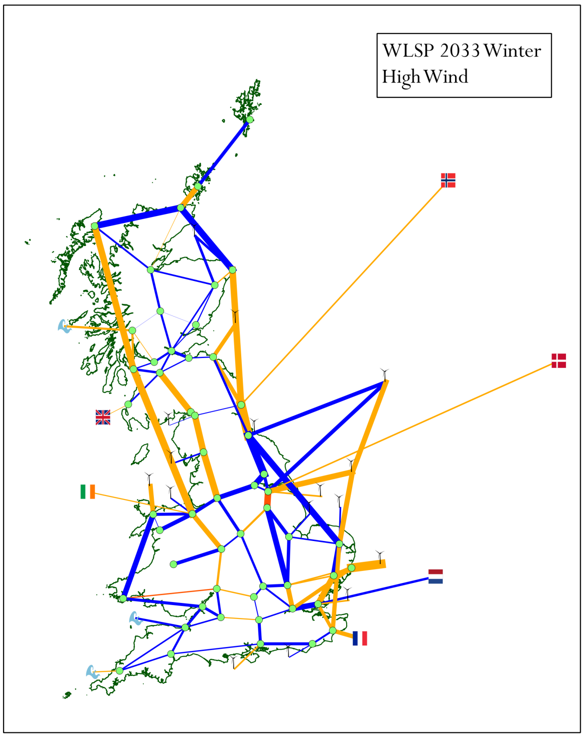


Figure 108: *WLSP 2033 Winter High Wind power flow*

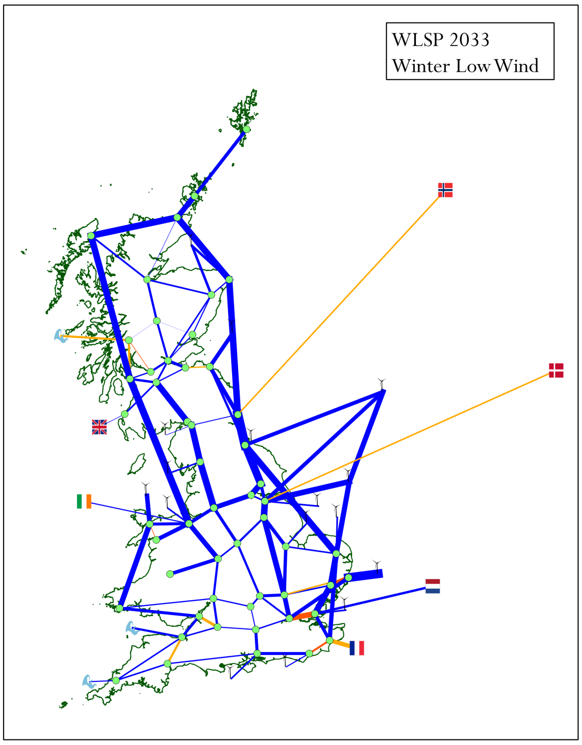


Figure 109: *WLSP 2033 Winter Low Wind power flow*

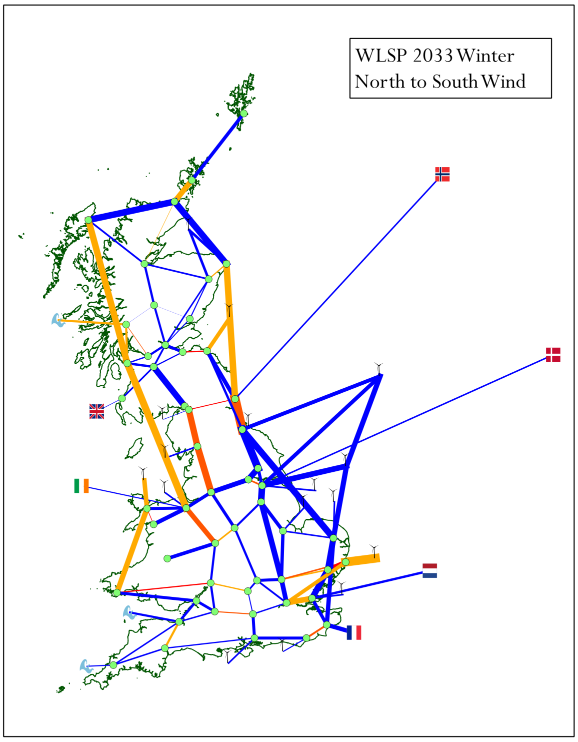


Figure 110: *WLSP 2033 Winter North to South Wind power flow*

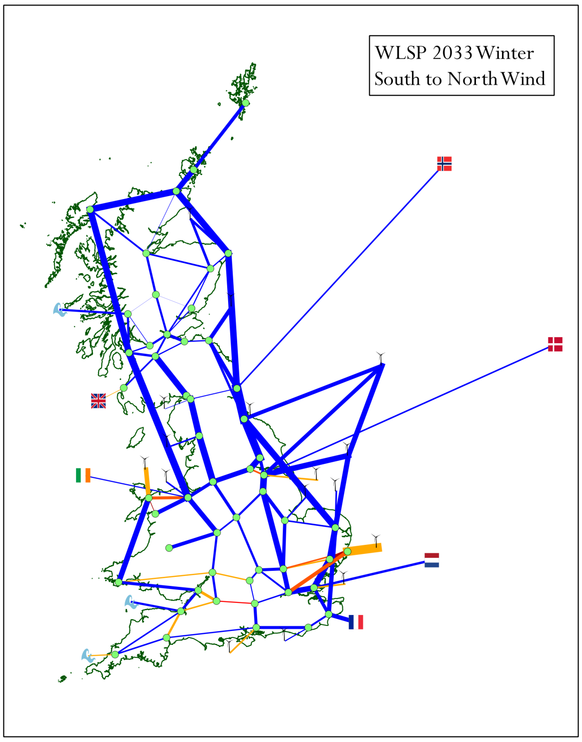


Figure 111: *WLSP 2033 Winter South to North Wind power flow*

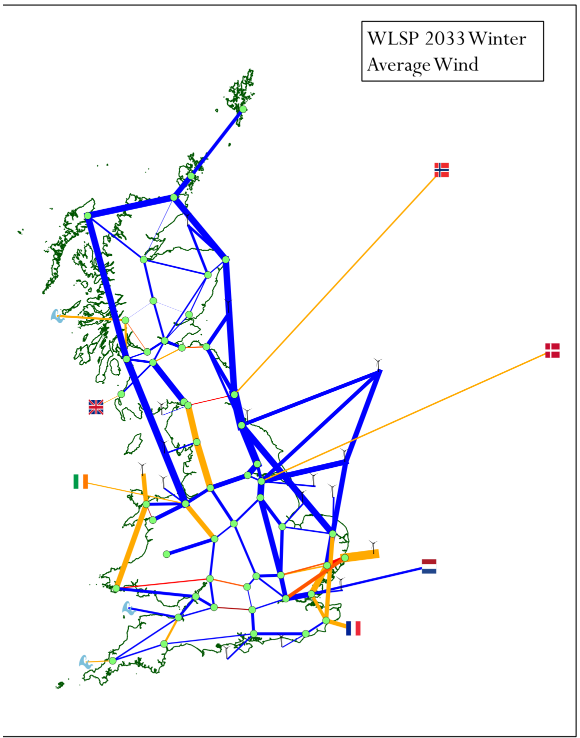


Figure 112: *WLSP 2033 Winter Average Wind power flow*

In Spring, the high wind (***Figure 113***), SN and average conditions all have zero constraints. By contrast the NS condition has high constraints exporting south (***Figure 114***), and the average condition has very high constraints in the south east.

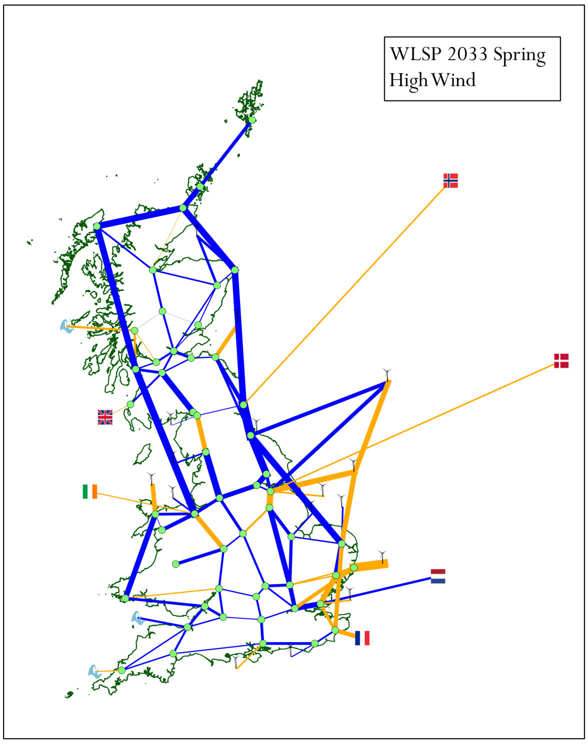


Figure 113: *WLSP 2033 Spring High Wind power flow*

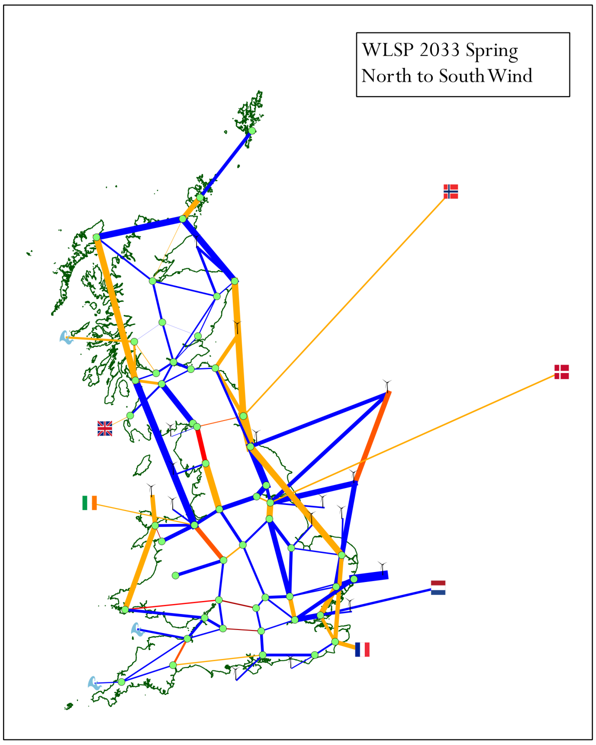


Figure 114: *WLSP 2033 Spring North to South Wind power flow*

In Summer, constraint problems occur in all conditions as the low demand requires greater export in the highest producing regions. High wind (***Figure 115***) sees constraints in Scotland and in southern exporting corridors, as well as in the circuits west of Sizewell. Low, NS and SN all have a range of constraints spread across the network, and the average condition (***Figure 116***) has high constraints across the network.

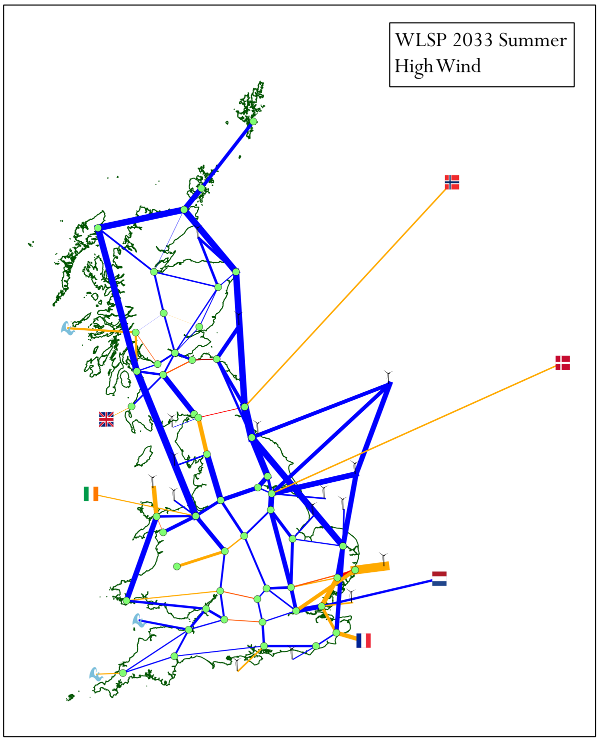


Figure 115: *WLSP 2033 Summer High Wind power flow*

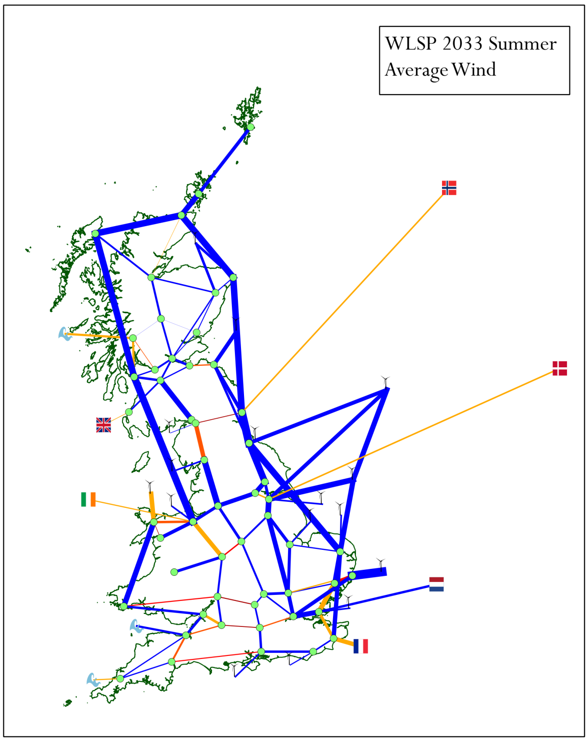


Figure 116: *WLSP 2033 Summer Average Wind power flow*

8.5 Weak location, weak plan (WLWP)

8.5.1 Overview of whole scenario

In this scenario the overriding network philosophy is that networks should be at the service of the higher order aim of decarbonisation. The premise is that locational network charging is something which runs counter to this higher priority government objective and is thus no longer useful or relevant. However, there are also remains a reluctance to engage in significant anticipatory forward planning of network requirements, on the basis that the precise generation mix of the future cannot be known, neither is there any wish to attempt to impose a blueprint on the industry. The role of networks is therefore to follow the pattern of generation investments as far as possible as they occur.

This results in a spread portfolio of renewables and nuclear in locations across the country, though with a less rapid expansion of in the early years of the scenario than in WLSP, as behind the curve network investments put a slight break on the pace of generation investment. By the mid-2020s new renewable investments in the north of GB are such that substantial onshore network upgrades are required along north-south corridors, along with both east and west offshore bootstraps. However, the level of offshore investment is significantly less than in WLSP due to the higher capital cost and greater forward commitment this requires, an approach which is not favoured in this scenario. By the late 2020s a network is emerging which is highly compliant in low wind conditions, but with high constraints in high wind conditions, as reactive network investment struggles to keep pace with generation investments uninfluenced by network constraints. This situation is further exacerbated in 2033 with the addition of sufficient low carbon generation to meet the carbon intensity target – largely compliant low and SN conditions contrast with extremely high constraints in high wind or NS power flows. The final generation mix is of 58 GW renewables, 20 GW nuclear and 37 GW fossil. However, the high constraints with which the system is operating creates serious questions about whether such a system would be in practice feasible, given potentially very high constraint payments made to renewable generators in Scotland. This issue could cause a reappraisal of the value system (with either a move towards more locational control or influence on generation investment, or a more strategic anticipatory approach to network investment). Alternatively, it may cause a political and public reaction against renewables, the apparent source of the problem, that causes low carbon targets to be missed.

8.5.2 2013 – 2018

8.5.2.1 Overview of period

In 2013 the most significant network concern is the export of power between Scotland and England. This relates to the integration of Scottish and English systems under BETTA, and is being added to by increasing development of renewables in the north of GB. There are plans to invest in the network to bring the Scotland-England boundary into compliance. Notably, these include reconductoring and other works on the existing border circuits, and the construction of the new HVDC offshore link between Hunterston and Deeside (***Table 8***, Chapter 7).

The EMR package has come into effect which, it is hoped, will provide sufficient incentive for low carbon generation to meet EU 2020 targets and the CCC carbon budgets.

Transmission investment in this scenario does not extend significantly beyond planned 2013 upgrades, and generation investments proceed largely as in the other scenarios.

8.5.2.2 Generation mix

In addition to the standard additions detailed in Section 7.3.1.6, this scenario includes more development in the Western Isles (Stornoway). The lack of strong locational signal has encouraged proposed projects in these areas, with the addition of new wind and a 20 MW wave demonstration in the Hebrides, causing the HVDC link to be built reactively within the time frame. Developments in the Orkneys and mid-Wales however do not occur due to the continued lack of connection to the main network. Offshore wind sees all planned projects in 2013 move to completion, with the further addition of the first 2.4 GW project at Dogger.

The final reactor at the Wylfa nuclear site is closed, and a number of closures of coal and oil plants occur under the Large Combustion Plant Directive. ***Figure 117*** shows the effect of these generation investment decisions on the total installed capacity during the period.

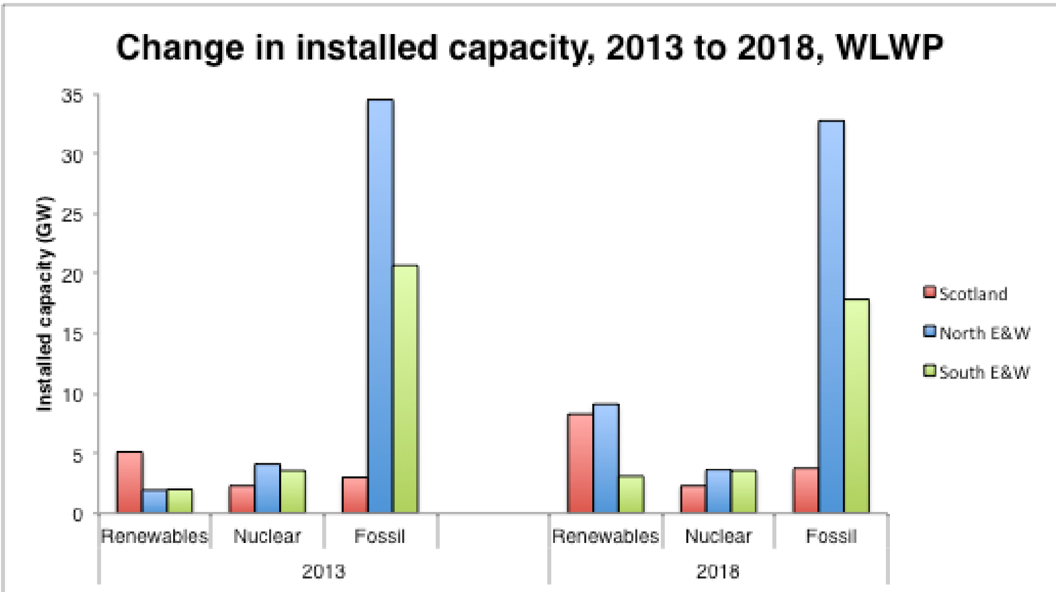


Figure 117: *Change in installed capacity, 2013 to 2018, WLWP*

This generation mix gives the following system indicators in 2018.

Table 25: *WLWP 2018 system indicators*

System derated capacity margin (%)	6.0
Proportion of annual electricity demand met by (%):	
Renewables	20
Nuclear	19
Other	61
Carbon intensity of electricity (g/KWh)	354

8.5.2.3 Network investment

Confirmed network upgrades as of 2013 are included in this scenario, most significant of which are the upgrades over the Scotland-England boundary, including the HVDC western link between Hunterston and Deeside (as described in ***Table 8***, Chapter 7). In addition to these, this scenario sees the HVDC island connection to Stornoway in the Hebrides.

Figure 118 illustrates the network upgrades in this period.

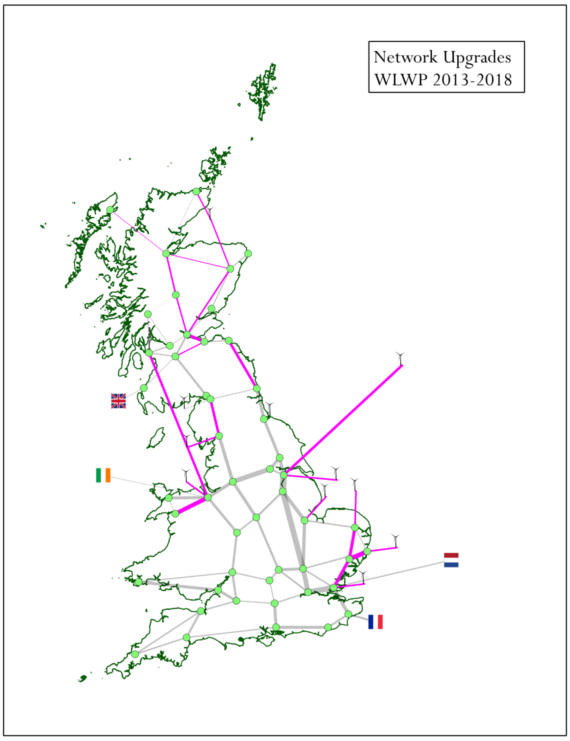


Figure 118: *WLWP network upgrades 2013-2018*

8.5.2.4 Resultant power flow

In winter the effect of the investments in renewables in Scotland, and the lack of locational signal to affect the operation of fossil plants in Scotland and northern England during times of high congestion, results in clear constraint patterns running from north Scotland as far as London. The effect of transmission investments can be seen by the reduction of constraints in northern Scotland – however the generation investments contribute to contribute to increased constraints further south. The winter high wind condition has high constraints in the central belt of Scotland, south of the Beauly-Denny line, and constraints persist over the England-Scotland border. Very high constraints are now observable south of Deeside, as the operation of existing north western fossil and nuclear plants is now added to by the output of the 2.2 GW HVDC line. In addition a line of constraints can be found from the Humber towards London, as the Humber region contains a large amount of fossil generators and now also receives input from Dogger and other east coast wind farms. Similar constraint patterns are found in the NS and average conditions, as these include moderate to high wind output in Scotland, which is exported south causing constraints in similar areas. However these conditions have lower constraints between Humber and London due to lower output from southern north sea zones. In the SN and low wind conditions the significantly lower northern wind conditions results in recognisably lower constraints over the network – however lower north to south power transfer results in the south east pulling more power in from the west, and as a result both of these conditions cause a constraint on the line from Bristol to Melksham, as power flows west to east.

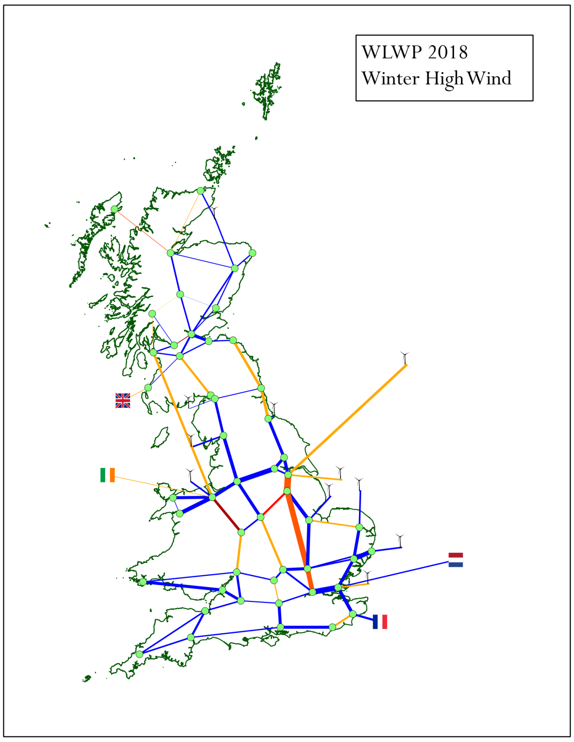


Figure 119: *WLWP 2018 Winter High Wind power flow*

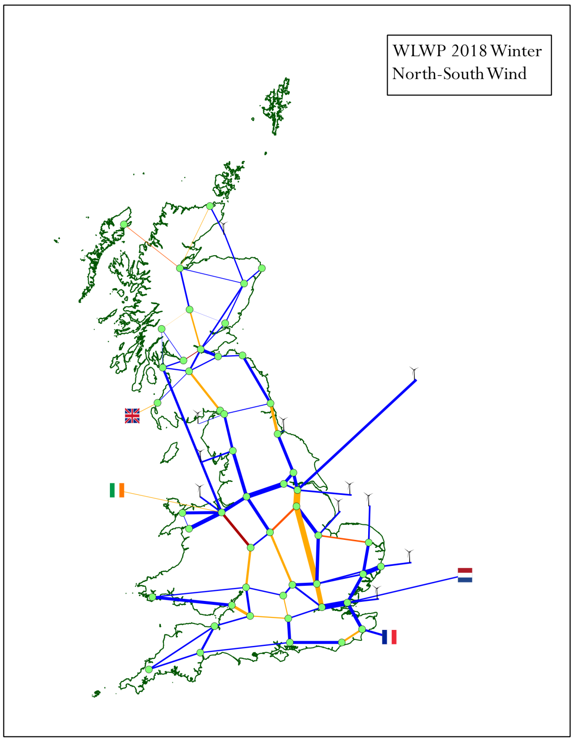


Figure 120: *WLWP 2018 Winter North to South Wind power flow*

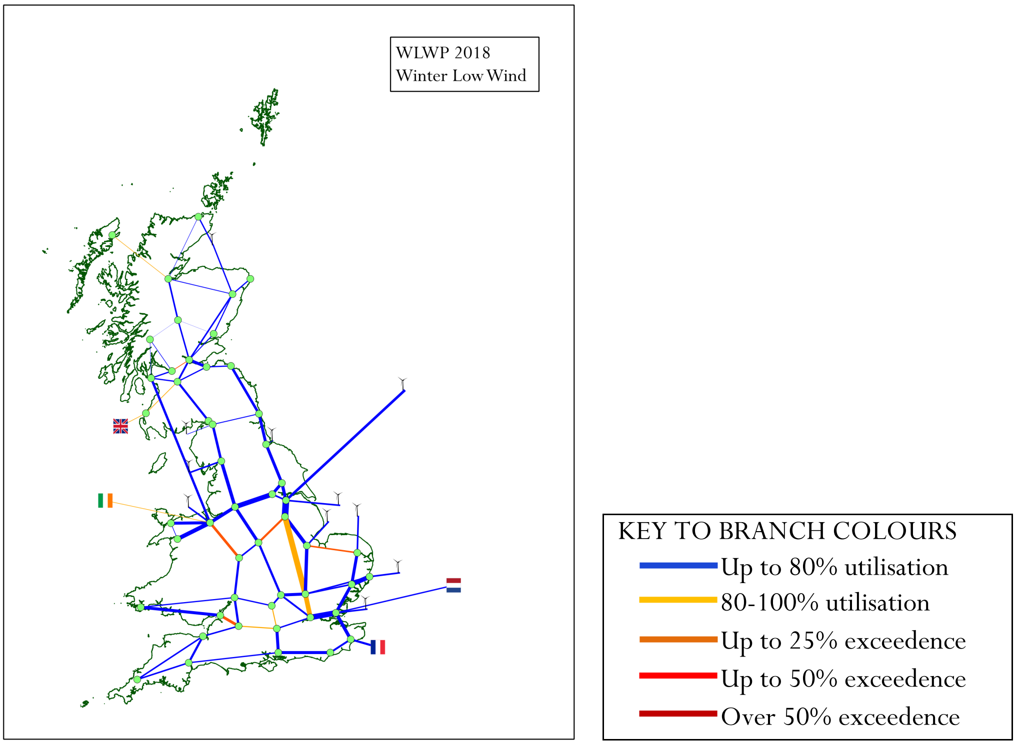


Figure 121: *WLWP 2018 Winter Low Wind power flow*

Spring patterns are very similar, with the primary driver of north-south constraints, and constraints between Humber and London, being the north-south pattern of wind output. Due to the lower demand, constraints are lower on the south west- south east corridors in low wind conditions. Constraints are also high in summer conditions, as the low demand causes greater export from high power producing regions – moderate constraints are spread throughout the network in the summer NS condition.

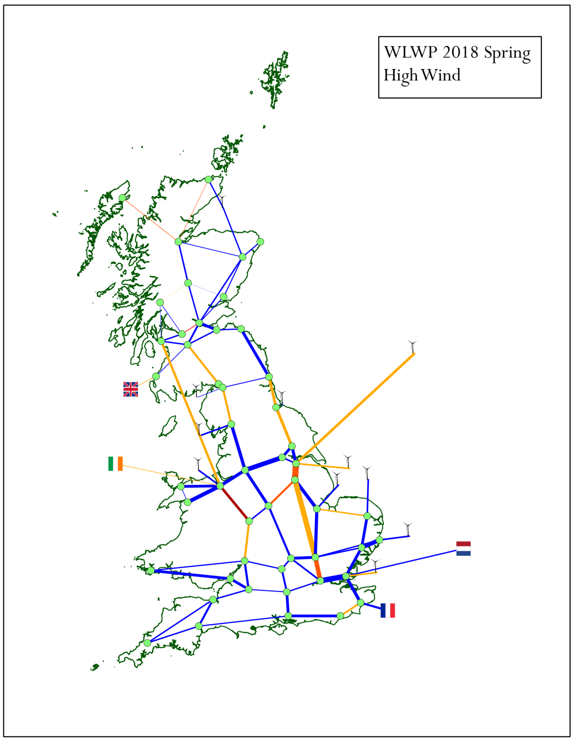


Figure 122: *WLWP 2018 Spring High Wind power flow*

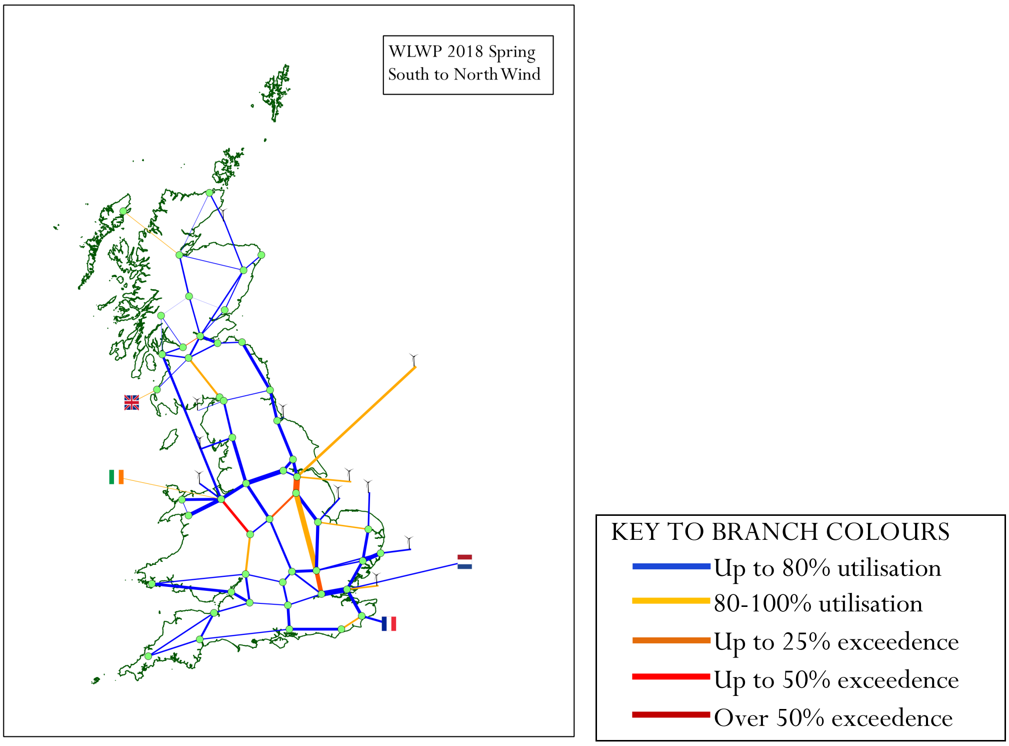


Figure 123: *WLWP 2018 Spring South to North Wind power flow*

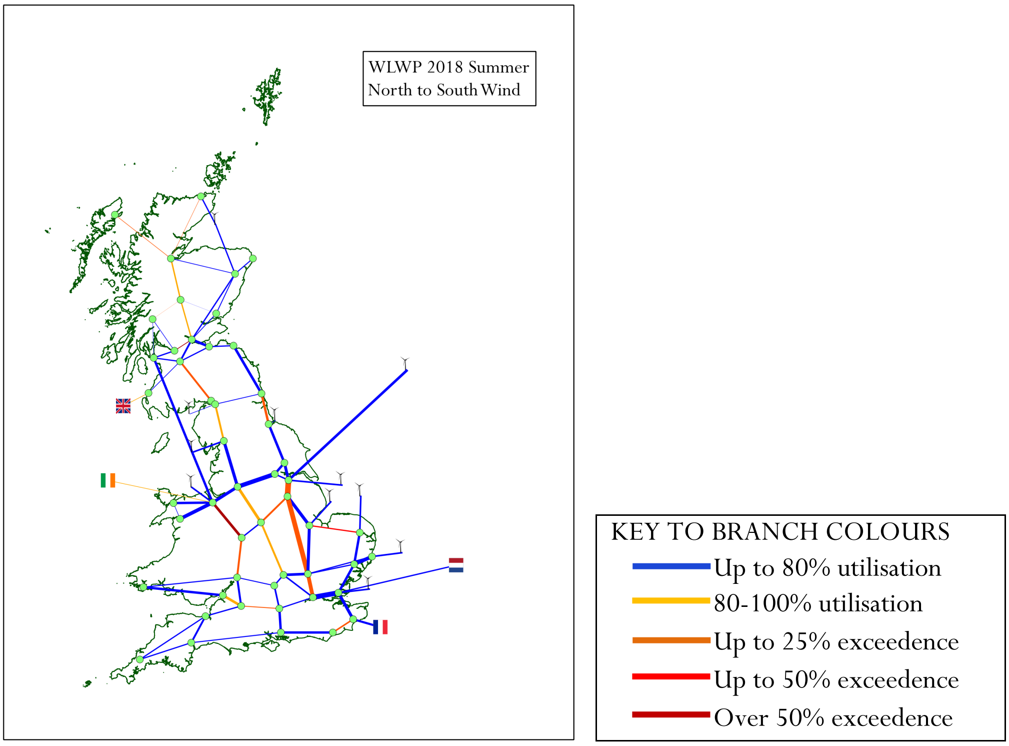


Figure 124: *WLWP 2018 Summer North to South Wind power flow*

8.5.3 2018 – 2023

8.5.3.1 Overview of period

In the context of the continued push towards staying on track for the CCC's target of 50gCO_2/kWh in 2030, locational signals continue to be smoothed. Transmission planning continues to operate primarily in responsive mode, and lags the development of renewables. Significant constraints continue to be experienced and the growth in renewables is less rapid than in WLSP.

8.5.3.2 Generation mix

There is a continued strong development of renewables in particular in the north of the system, as weak locational signals apply. However, the lagging development of the network in practice puts a break on the development of renewables by comparison to WLSP. There is just under 750 MW additional onshore wind on mainland Scotland and less than 100 MW additional hydro.

Offshore wind development takes place at all available locations: Moray Firth (1500 MW), Forth (1050 MW), Dogger-Teesside (1200 MW), Hornsea (1200 MW) Irish Sea (2200 MW), East Anglia (1200 MW), Rampion (700 MW) and Navitus (1100 MW).

Tidal stream is developed at Pentland Firth (125 MW), Solent (200 MW), Western Isles (500 MW) and Bristol Channel (400 MW). Wave power is also commercialised in this year, and 125 MW are installed at Hebrides, and 500 MW at Islay, Devon and Cornwall.

Hinkley Point C comes online, while Harltepool, Heysham 1 and Dungeness B close. Fossil retirements are as the standard background for this year (***Table 9***, Chapter 7). ***Figure 125*** shows the effect of these generation investment decisions on the total installed capacity during the period.

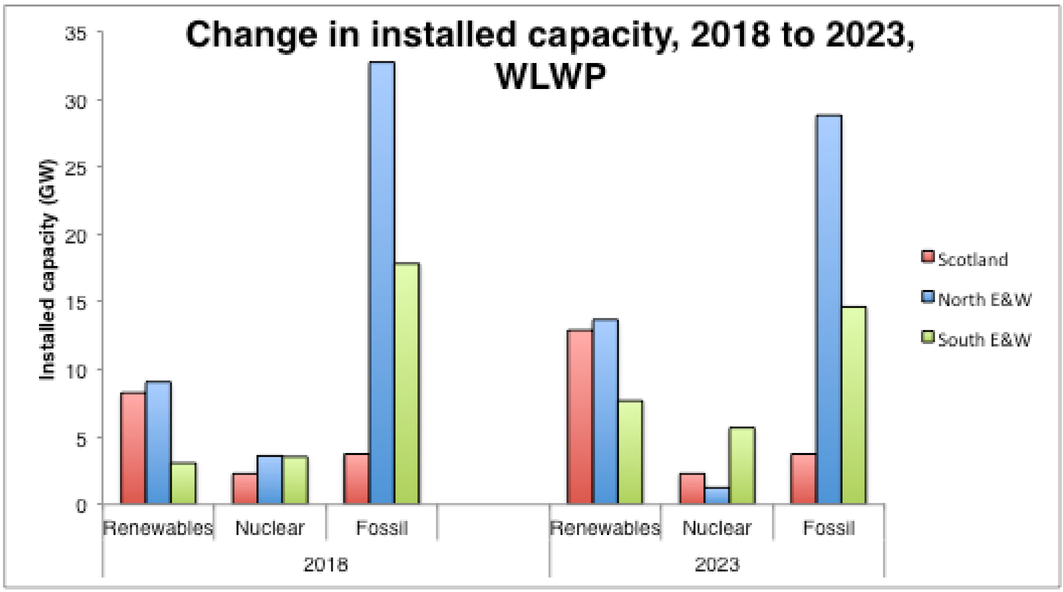


Figure 125: *Change in installed capacity, 2018 to 2023, WLWP*

This generation mix gives the following system indicators in 2023.

Table 26: *WLWP 2023 system indicators*

System derated capacity margin (%)	0.4
Proportion of annual electricity demand met by (%):	
Renewables	33
Nuclear	18
Other	49
Carbon intensity of electricity (g/KWh)	269

8.5.3.3 Network upgrades

In addition to new offshore radial lines connecting new offshore renewable projects, a number of upgrades are made to network transfer capability, in view of the constraint issues found in the previous time stage. Upgrades are made to lines from the north-south of Scotland, including on the Beauly-Denny corridor, to which a second circuit is added, and on the Kintyre-Hunterston subsea cable. The eastern HVDC 'bootstrap', from Peterhead to Blyth, is completed. Further uprates and added lines add capacity to both the east and west coast corridors from the Scottish central belt to the Midlands, including an uprate of the line running south of Deeside, which was heavily constrained in the previous time-stage due to the infeed from the HVCD western link. As in all scenarios a new line is added in the south-west to accommodate output from the new Hinkley Point C nuclear station.

The geographical arrangement of the network upgrades in this period is shown in ***Figure 126***.

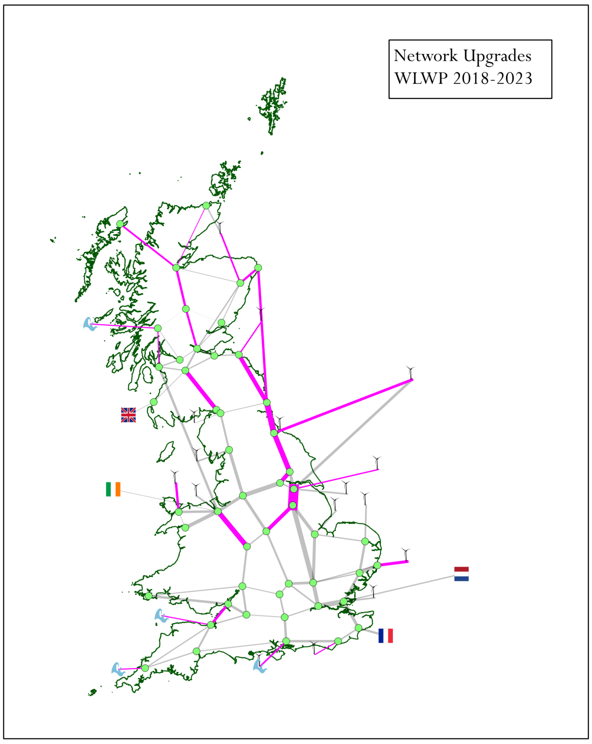


Figure 126: *Network upgrades WLWP 2018 - 2023*

8.5.3.4 Resultant power flow

Transmission investments in this period mean that the winter high wind (***Figure 127***) condition sees a significant improvement in many of the key constraint corridors identified in the previous time stage. However, the growth in renewables in Scotland, though more modest than WLSP, still causes constraints in this condition in the highlands of Scotland, and between Beauly and Kintore as power is drawn eastwards by the new HVDC bootstrap. Constraints remain on the east and west coasts of northern England, and new constraints have emerged in north-west Wales, due to infeed from the Irish Sea wind farm zone, and in the south west due to infeed from wave and tidal installations in Cornwall and the Bristol Channel. NS has similar constraint patterns to high wind. The lower wind conditions, low wind and average (***Figure 128***) see reduced constraints across northern Britain, however the west-east line between Melksham and Bramley is consistently constrained owing to south-west marine installations, Hinkley Point C as well as remaining fossil plants in the region.

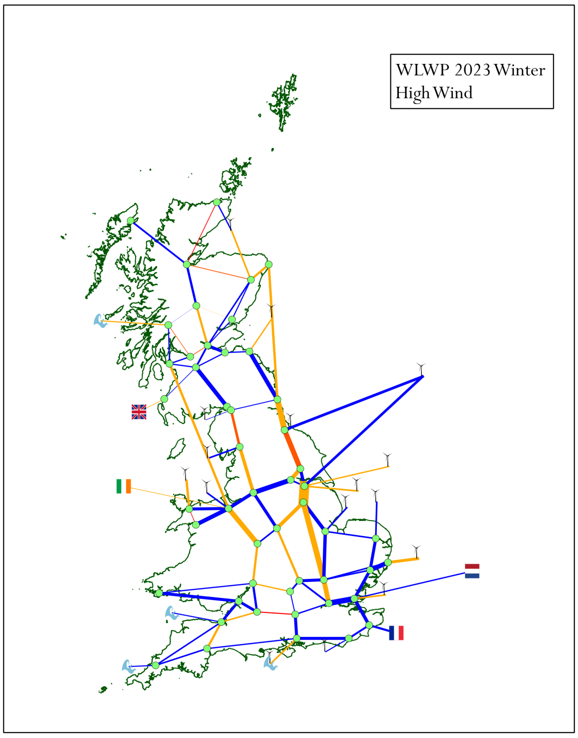


Figure 127: *WLWP 2023 Winter High Wind power flow*

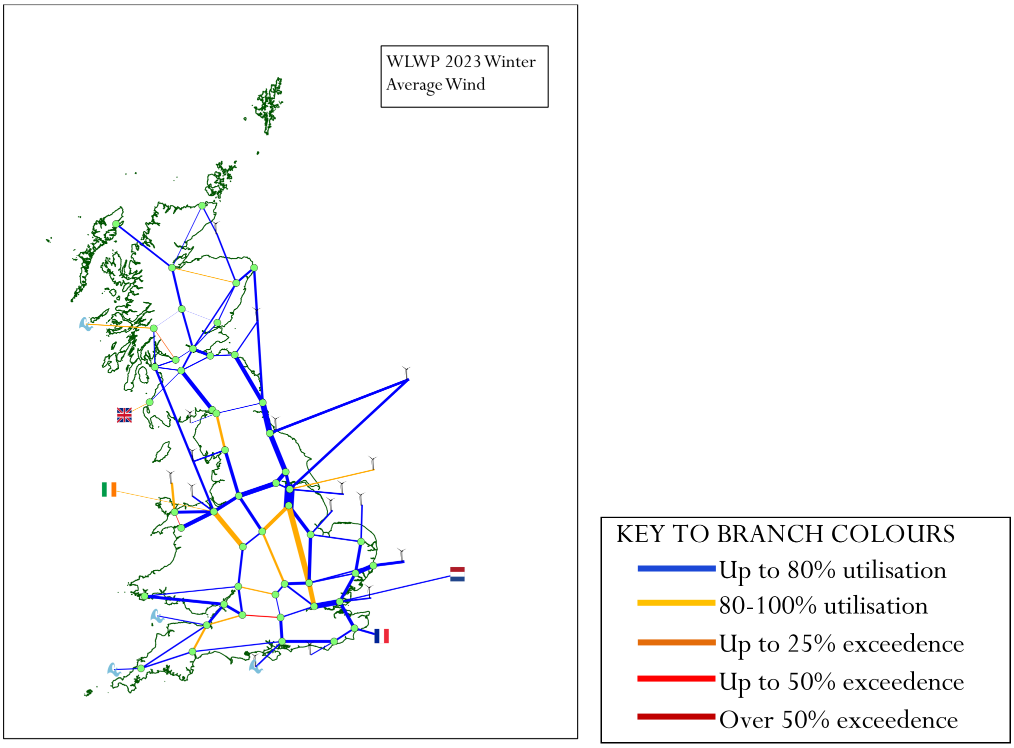


Figure 128: *WLWP 2023 Winter Average Wind power flow*

The Spring high wind condition (***Figure 129***) however sees the return of very high exceedences, as the combination of high spring winds with lower demand produces a greater north-south export. High constraints are found again in northern Scotland and also on key corridors in northern England, between Harker and Hutton on the west and Teesside to north Yorkshire on the east coast. The latter constraint also relates to the new connection of Dogger to Teesside as well as Humberside. As in winter high wind, constraints are also found in north Wales and Wiltshire, contributed to by western offshore renewables. The NS condition has a similar constraint pattern to high wind. Low wind, SN (***Figure 130***) and average conditions all have greatly reduced constraints in northern GB than high wind, but continue to have constraints in the west, notably north Wales and Wiltshire / Somerset, due the increase in renewable output in these areas.

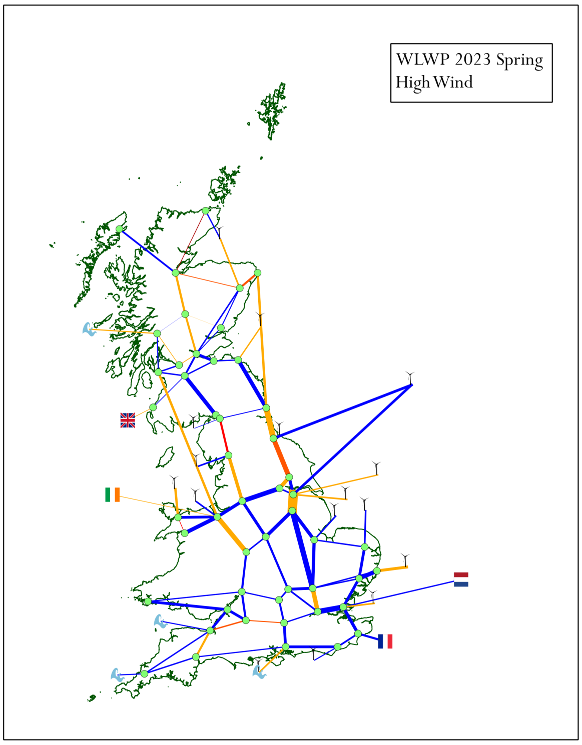


Figure 129: *WLWP 2023 Spring High Wind*

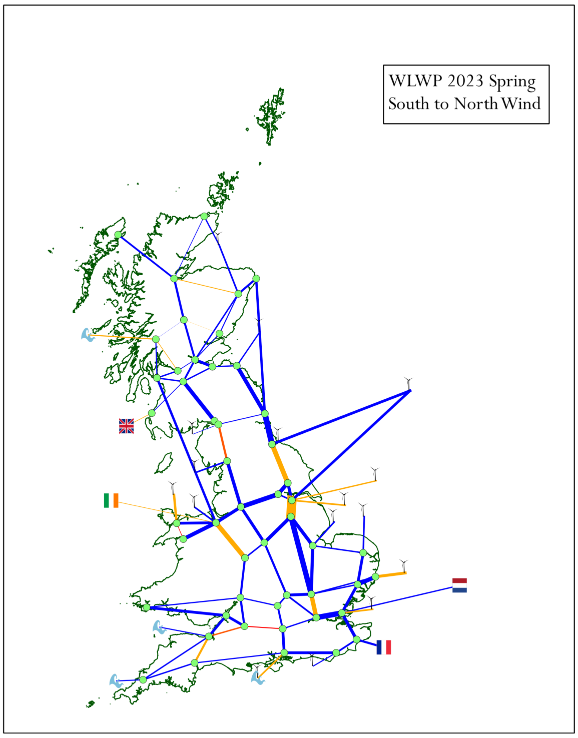


Figure 130: *WLWP 2023 Spring South to North Wind power flow*

In summer constraints largely follow the same pattern as the other two seasons, but with noticeably lower constraints as the lower demand in general means lower stress on the network. The exception is the NS condition (***Figure 131***), where the combination of the comparatively high northerly wind condition with an overall low demand sees high constraints in northern Scotland, as well as other constraints throughout the network as excess available power is shifted through low demand regions towards the south east.

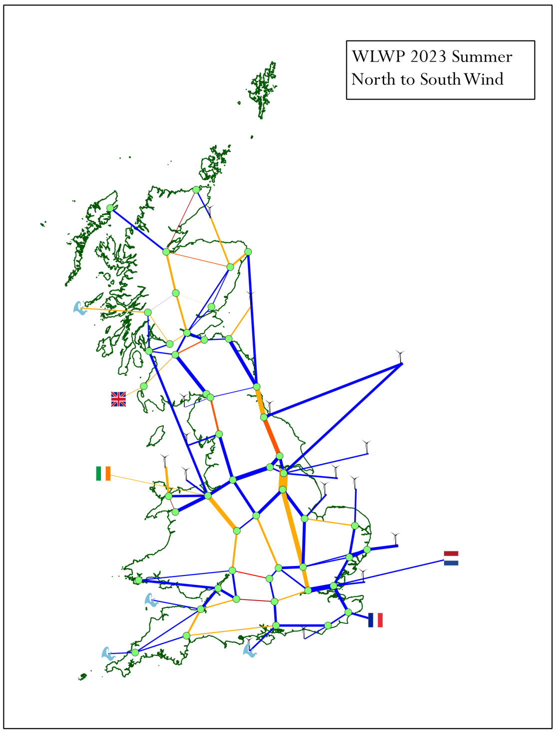


Figure 131: *WLWP 2023 Summer North to South Wind power flow*

8.5.4 2023 – 2028

8.5.4.1 Overview of period

Transmission investments in this time-stage respond directly to the key recurring constraint corridors in the previous time-stage. At the same time ongoing generation investments see a growth in all forms of low carbon generation. The growth in renewables in northern GB is slower than in WLSP, and there are two new nuclear stations. By 2028 system power flows show significant variation between high compliance with areas of under utilisation in some conditions, and very high constraints in other conditions.

8.5.4.2 Generation mix

The lack of locational signal presents no disincentive to invest in northern Britain and other network constrained areas. However, the lack of forward network build out under these conditions creates potential for high constraint costs. This slows investment in renewables in the northern parts of GB by comparison to WLSP.

Onshore wind in Scotland increases by a total of 1500 MW, a tidal stream installation of 500 MW is commissioned in the Pentland Firth and 200 MW of wave projects brought online in Hebrides and Islay. 200 MW wave farms also commission in Devon and Cornwall. Offshore wind increases by 1000 MW in each of Forth, Dogger, Hornsea, East Anglia and Irish Sea. Two new nuclear stations are commissioned, at Sellafield and Sizewell. According to the standard background assumptions for this scenario year there are 4978 MW of nuclear closures and 12602 MW of fossil closures. Maintaining a positive capacity margin requires commissioning of 10 GW new fossil plant, which is assumed to be distributed across the network, at the following former station sites: Longannet, Drax, Fiddler's Ferry, West Burton and Rugely.

Figure 132 shows the effect of these generation investment decisions on the total installed capacity during the period.

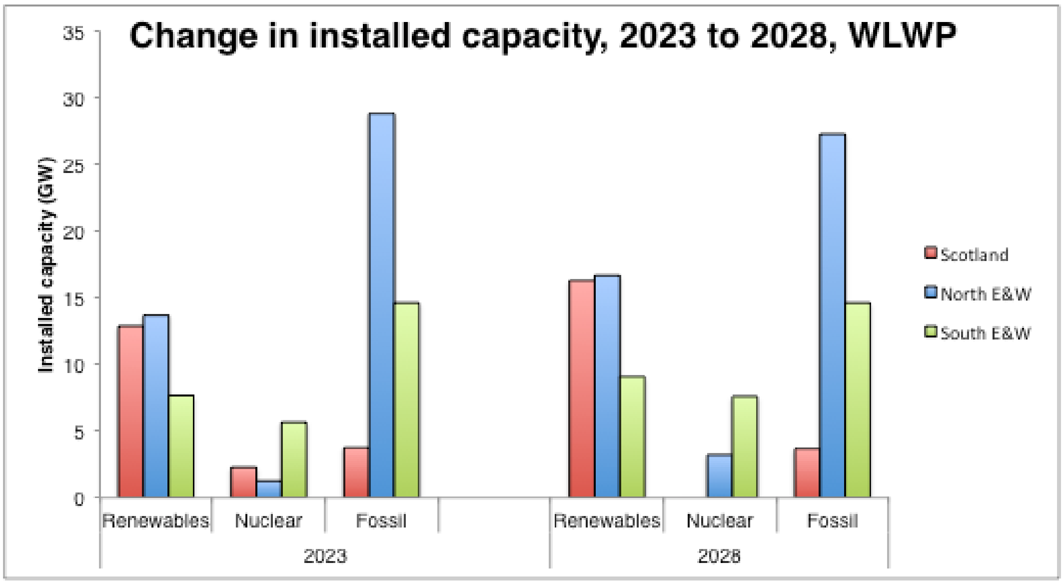


Figure 132: *Change in installed capacity, 2023 to 2028, WLWP*

This generation mix gives the following system indicators in 2028.

Table 27: *WLWP 2028 system indicators*

System derated capacity margin (%)	0.5
Proportion of annual electricity demand met by (%):	
Renewables	39
Nuclear	21
Other	40
Carbon intensity of electricity (g/KWh)	170

8.5.4.3 Network upgrades

Network upgrades in this period are focussed on resolving the main recurring constraint areas in the previous time-stage. Thus, further reinforcements are made in northern Scotland and from Beauly to Kintore, allowing power to transfer to the eastern HVDC link. The corridor from the southern western isles link with Islay to the central belt is also reinforcements. Reinforcements take place on both the east and west coast of northern England, the east coast particular due to the added infeed form the eastern HVDC. Infeed from the Irish Sea and North Sea renewables causes reinforcements in North Sea and Humberside. There is also strengthening of the west-east corridors from Somerset and Wiltshire towards London, and considerable strengthening of the eastern England network owing to infeed from the East Anglia wind farm.

Upgrades in the north-west and south-east of England also relate to the commissioning of Heysham and Sizewell nuclear plants in this period. Though this scenario is not anticipatory in network development, the long lead time and large single source power output of nuclear plants mean that even in a non-anticipatory regime, networks can be strengthened in time with nuclear builds.

The geographical arrangement of the network upgrades in this period is shown in ***Figure 133***.

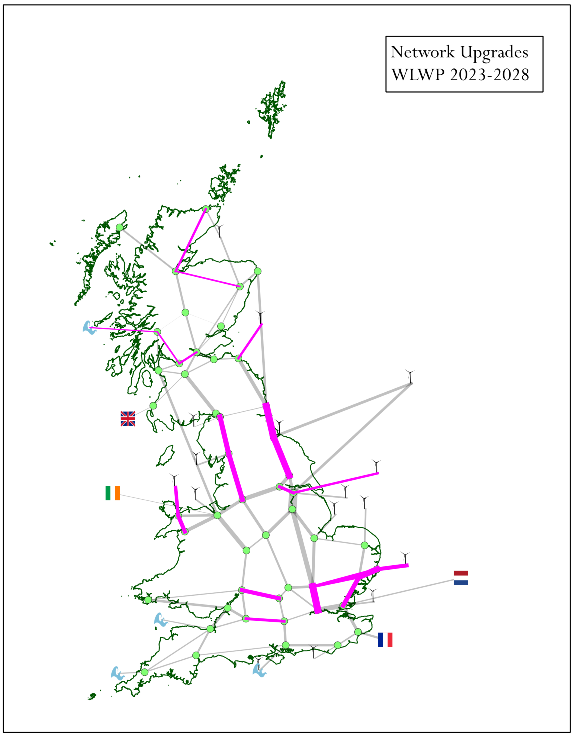


Figure 133: *Network upgrades WLWP 2023 - 2028*

8.5.4.4 Resultant power flow

The power flows arising from this generation mix show the successful resolution of several of the key constraint areas from the previous time-stage. However the continued increase in generation investment means that there already strong north-south power flow in high wind conditions has increased further, with high constraints persisting on the main north-south transit routes. These high wind, high constraint conditions are contrasted with very low constraint power flows during low wind conditions.

Winter high wind (***Figure** 134*) shows Scotland now largely compliant though with a constraint on the southern section of the Beauly-Denny corridor. High constraints however persist down the west coast as Scottish and Atlantic renewables are exported south. There also remains a constraint between Teesside and Humberside due to renewable infeed from the North Sea and the eastern HVDC link, despite onshore reinforcements having taken place in this area during the period. NS shows a similar pattern, although without east coast constraints due to lower southern North Sea output (***Figure** 135*). Low wind and average wind are both free of constraints, as the spread of relatively low output renewables around the country results in no stressed export areas. SN is similarly free of constraints, except for the corridor between Humber and central Yorkshire, as high southern North Sea output is drawn westwards (***Figure** 136*).

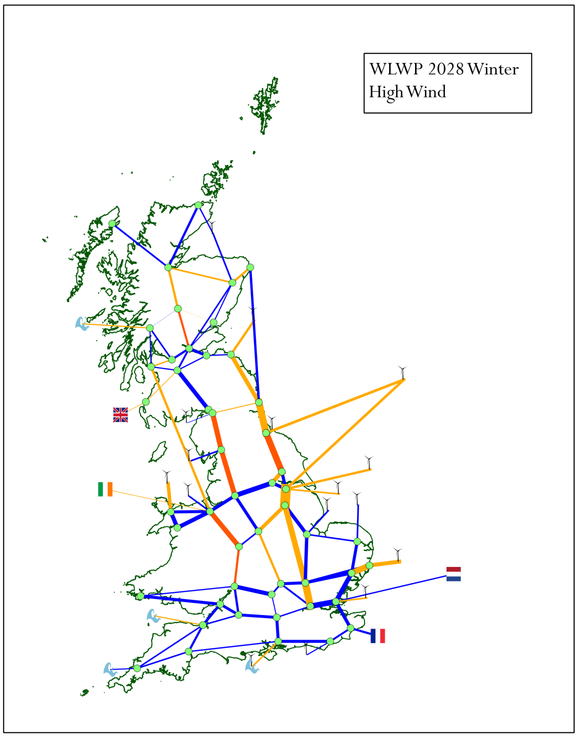


Figure 134: *WLWP 2028 Winter High Wind power flow*

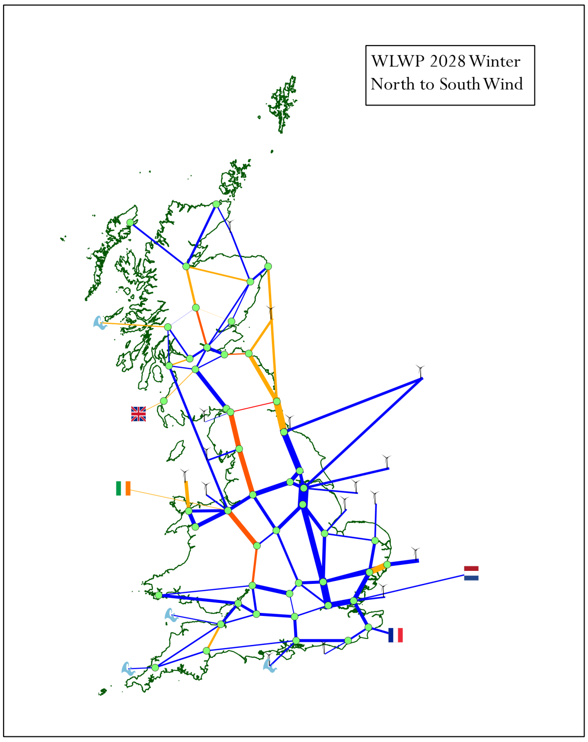


Figure 135: *WLWP 2028 Winter North to South Wind power flow*

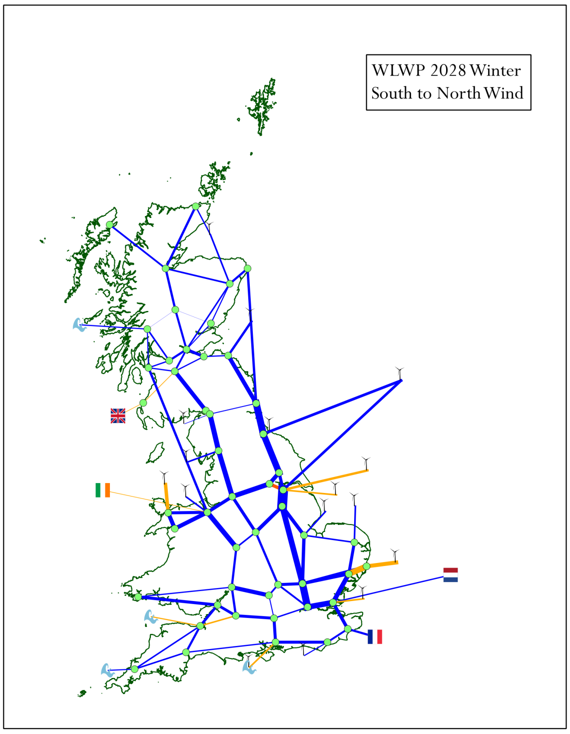


Figure 136: *WLWP 2028 Winter South to North Wind power flow*

Spring high wind exhibits a similar pattern to winter high wind, with relatively small constraints in Scotland, but high constraints moving down the west coast of England as lower demand causes larger transfers. There is also a noticeable constraint corridor between Humber and central Yorkshire as north sea offshore wind feeds into the system (***Figure 137***). In NS constraints are focussed on the west coast of England. Low wind and average are again free of constraints (***Figure 138***), and SN largely free except for the Harker-Hutton line in north-west England.

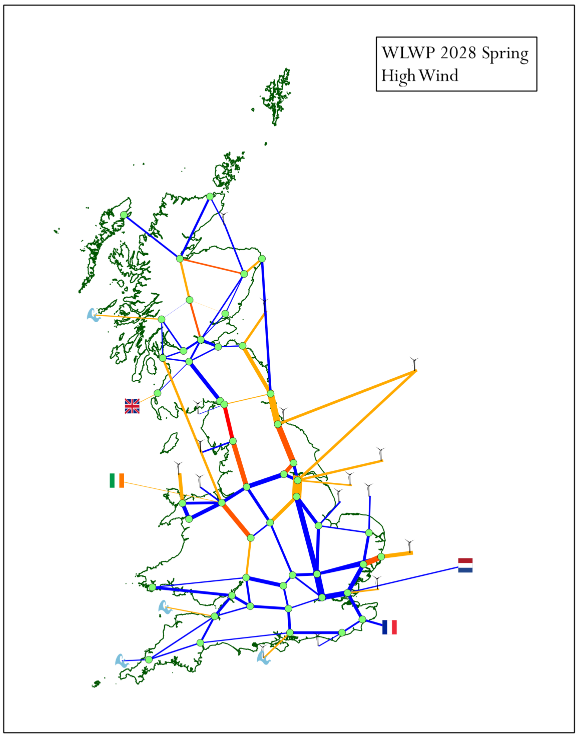


Figure 137: *WLWP 2028 Spring High Wind power flow*

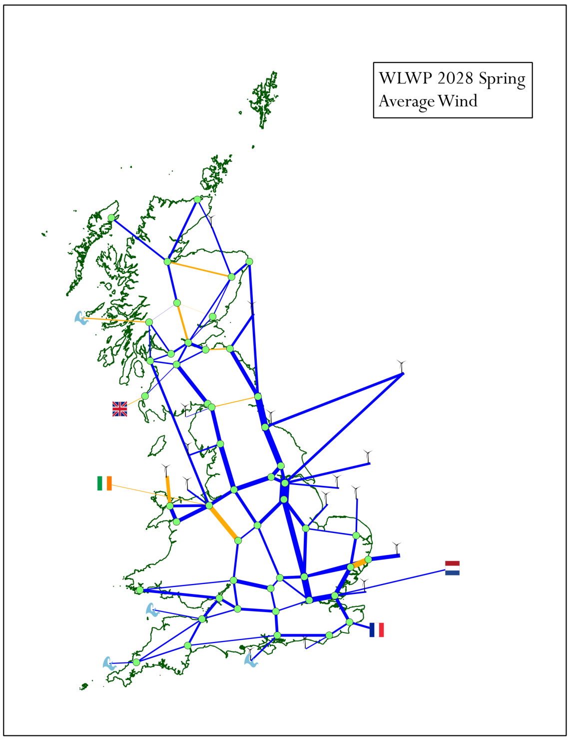


Figure 138: *WLWP 2028 Spring Average Wind power flow*

In Summer, the NS condition exhibits a similar pattern to previously discussed conditions with high constraints in central Scotland and down the west coast of England (***Figure 139***). High wind also has similar but lower constraints in Scotland and north-west England. However, in addition a significant constraint is now found between Sizewell and Bramford as power from the East Anglia wind farm is transferred towards London. Average and low wind are again largely constraint free. SN is constraint free except for another large constraint between Sizewell and Bramford, relating to East Anglia wind output (***Figure 140***).

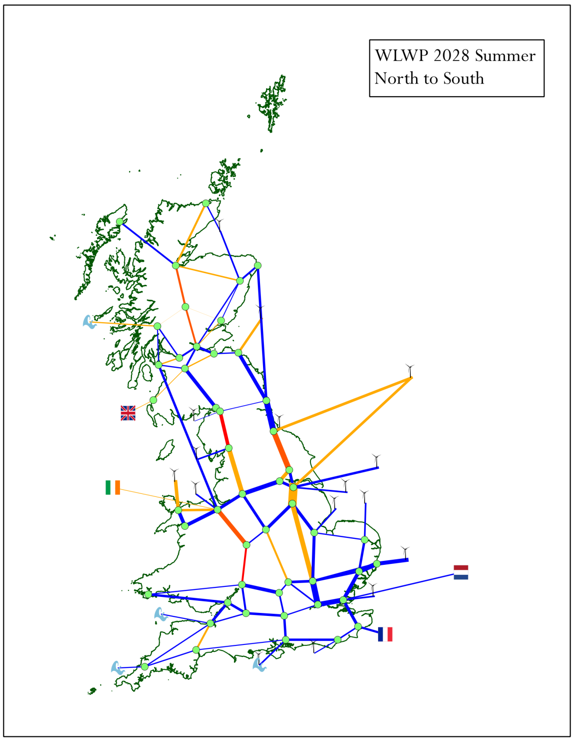


Figure 139: *WLWP 2028 Summer North to South Wind power flow*

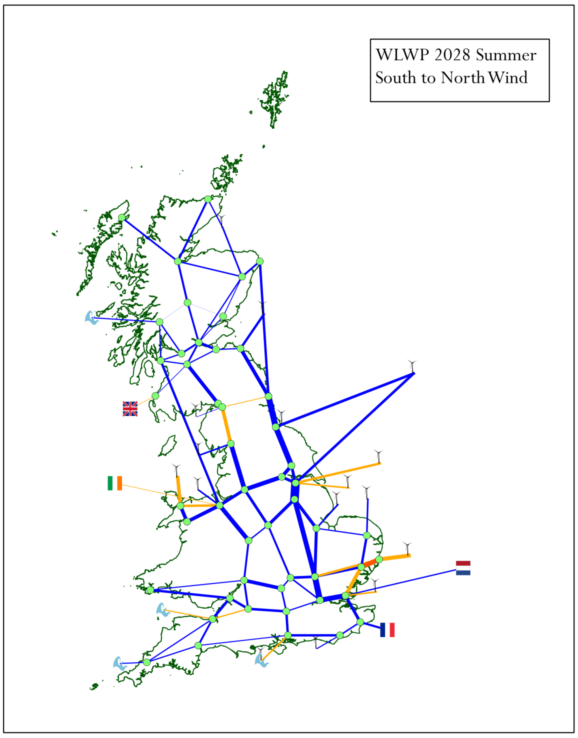


Figure 140: *WLWP 2028 Summer South to North Wind power flow*

8.5.5 2028 – 2033

8.5.5.1 Overview of period

A continued steady growth in renewables continues during this period in the most resource rich areas of the country. However, transmission capacity ultimately places a limit on northern renewables' growth as constraint costs rise. As a consequence three new nuclear plants make a required contribution towards meeting the 50gCO_2/kWh target by 2033. Transmission investments again respond to constraint issues in the previous section, but are behind the curve of the still rapid growth in renewable capacity over this period. By 2033 then the system continues to experience high constraint costs during high wind conditions, and isolated constraints as well as under-utilisation in low wind conditions.

8.5.5.2 Generation mix

Scottish onshore wind adds a further 2 GW, creating a total of 11 GW, and further 1.5 GW of tidal stream capacity is added at the Pentland Firth. Wave power continues to expand with 800 MW added at Hebrides, Islay, Devon and Cornwall. Offshore wind is expanded in Forth (1000 MW), Dogger (3500 MW), Hornsea (800 MW), Irish Sea (1000 MW) and East Anglia (3200 MW). Three new nuclear plants are commissioned during the period, at Heysham, Wylfa and Bradwell. As in all scenarios in this time-stage, a further 13.8 GW of fossil plant retires. In this scenario 5 GW of new fossil plant opens in order to maintain a positive capacity margin – 2 GW at Peterhead and Deesside / Connah's Quay, and 1 GW at Keadby.

Figure 141 shows the effect of these generation investment decisions on the total installed capacity during the period.

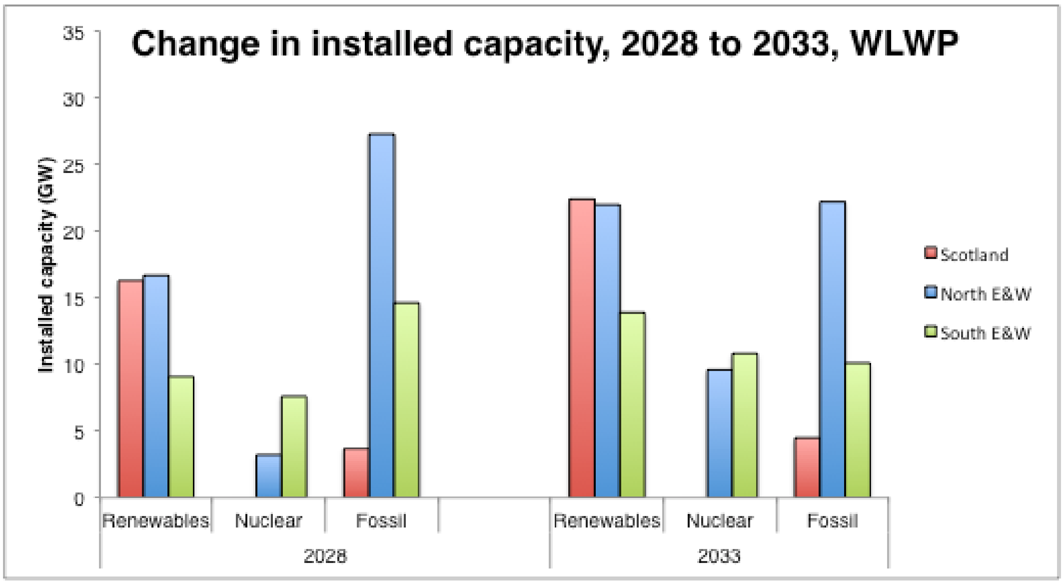


Figure 141: *Change in installed capacity, 2028 to 2033, WLWP*

This generation mix gives the following system indicators in 2033.

Table 28: *WLWP 2033 system indicators*

System derated capacity margin (%)	1.8
Proportion of annual electricity demand met by (%):	
Renewables	50
Nuclear	37
Other	13
Carbon intensity of electricity (g/KWh)	50

8.5.5.3 Network upgrades

This time-stage continues with the ongoing upgrade of offshore networks, primarily relating to facilitating peak north-south transfer. In Scotland, additional capacity is added on the Western Isles link to the Hebrides, and a third circuit on the southern section of the Beauly-Denny corridor. In England new circuits are added along the west coast transmission corridors, and on the east coast south of Teesside, and re-conductoring adds east-west transfer capacity between Harker and Blyth. Another circuit is also added between Sizewell and Bramford in the south-east.

The geographical arrangement of the network upgrades in this period is shown in ***Figure 142***.

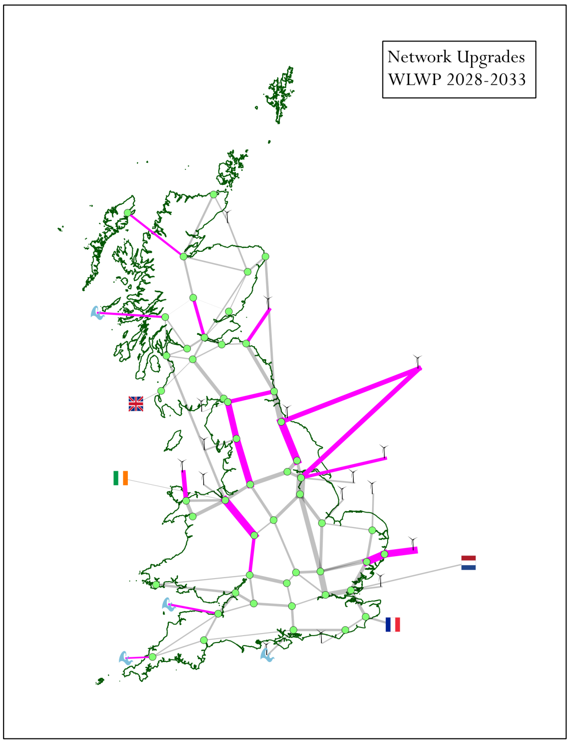


Figure 142: *Network upgrades WLWP 2028 - 2033*

8.5.5.4 Resultant power flow

The pressure of meeting the 50gCO_2/kWh target by the end of this time stage means that the pace of installation of renewable technologies has significantly outstripped the installation of transmission capacity in this scenario. High wind conditions have widespread high constraints relating to a significant north-south power flow which exceeds available transfer capacity. Lower wind conditions in general have much lower utilisation but still produce high, albeit more isolated constraints.

The winter high wind condition (***Figure 143***) produces extremely high constraints throughout Scotland and across the Cheviot boundary, and along the west coast of northern England and north Wales. Particularly high constraints are also found along the east coast of northern England, due to infeed from the Eastern bootstrap combined with a major increase in capacity increase in offshore wind in the southern North Sea. The NS condition is similar although with lower constraints along the east coast due to lower output from southern North Sea renewables. A similar pattern but with lower overall constraints is also observable in the average condition. In the low wind condition (***Figure 144***), the output of Scottish wind in combination with Pentland Firth tidal capacity (obviously unaffected by low winds) and by fossil plants at Peterhead and Longannet, called into operation due to low overall winds, is sufficient to cause constraints in Scotland. However, in the rest of the country there are no constraints. The SN condition by contrast (***Figure 145***) is free of constraints in the north of GB, however isolated constraints occur in England and Wales relating to high output from major clusters of renewables – in north Wales due to the Irish Sea zone, and in East England due to the East Anglia zone.

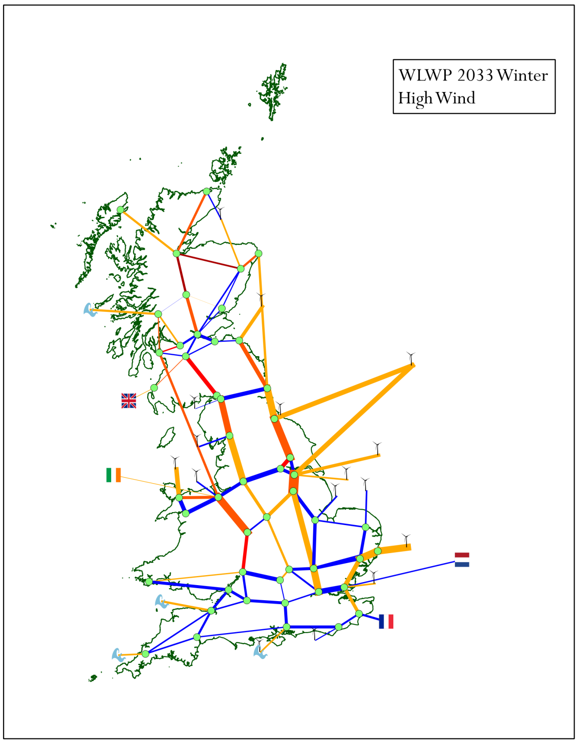


Figure 143: *WLWP 2033 Winter High Wind power flow*

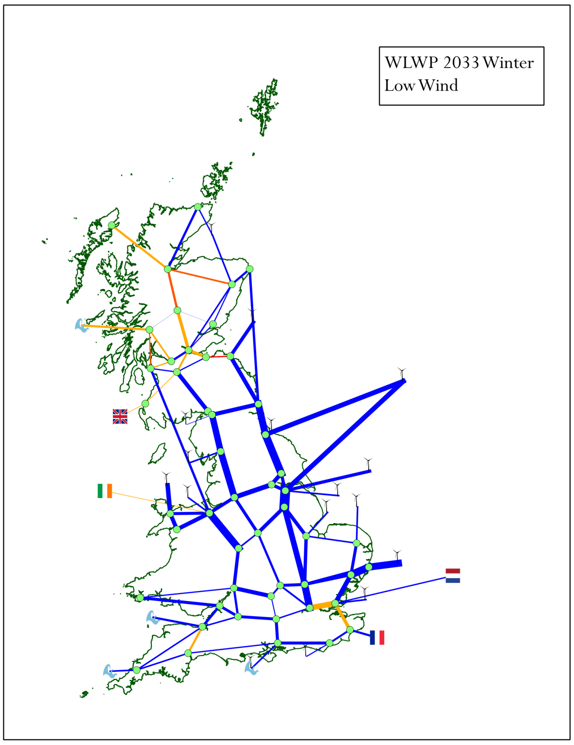


Figure 144: *WLWP 2033 Winter Low Wind power flow*

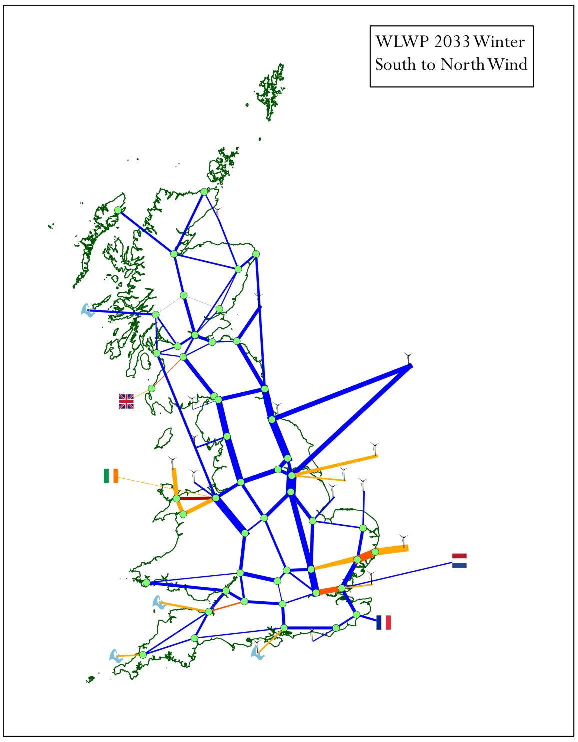


Figure 145: *WLWP 2033 Winter South to North Wind power flow*

In Spring the high wind condition (***Figure 146***) has a very similar constraint pattern to the winter high wind condition. The NS condition is also similar to its equivalent winter condition although it has higher constraints on the east coast, as the output from Dogger is greater. SN also has constraints in Scotland and northern England. The average condition (***Figure 147***) has some high constraints in Scotland, otherwise England is almost entirely unconstrained except for two key corridors which again relate to high offshore output – from the Irish Sea zone in North Wales, and from East Anglia in East England. The low wind condition however is entirely unconstrained.

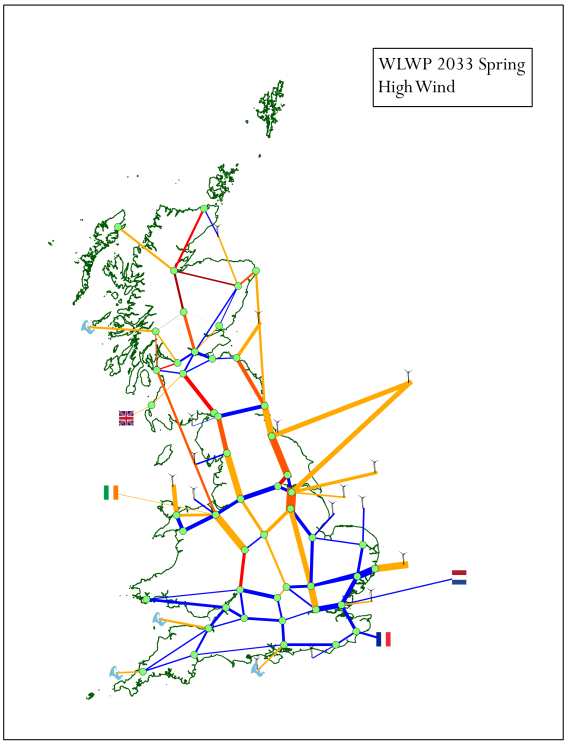


Figure 146: *WLWP 2033 Spring High Wind power flow*

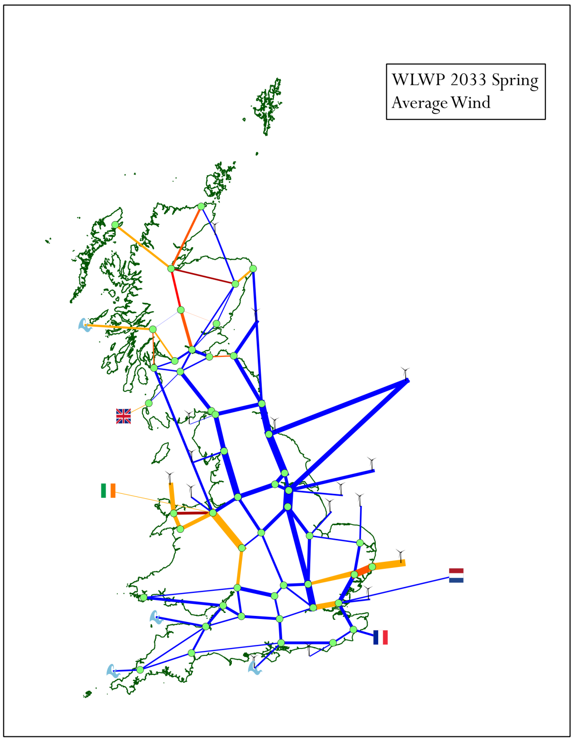


Figure 147: *WLWP 2033 Spring Average Wind power flow*

The summer conditions show similar patterns. The high and NS (***Figure 148***) conditions show widely pervasive and high constraints relating to a strong overall north-south power flow. The low, SN (***Figure 149***) and average conditions are free of constraints through the majority of the network, but have isolated high constraints in key corridors relating to the infeed from high producing renewable sites, typically the Irish Sea and East Anglia zones.

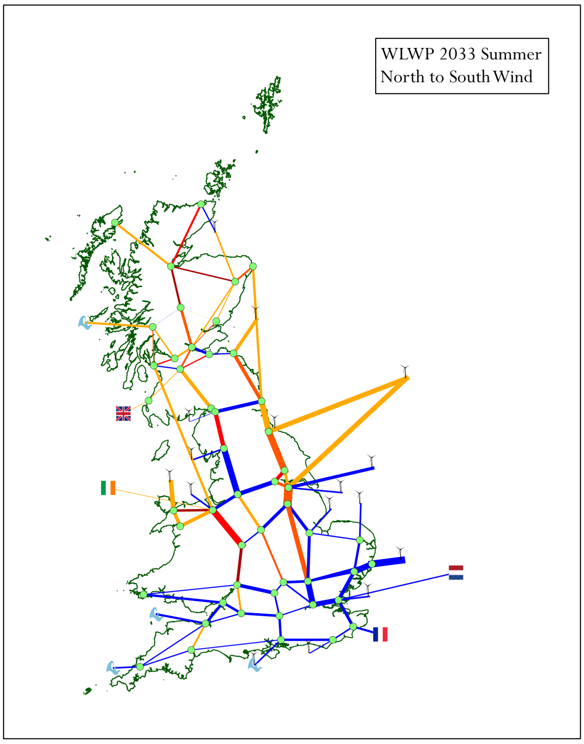


Figure 148: *WLWP 2033 Summer North to South Wind power flow*

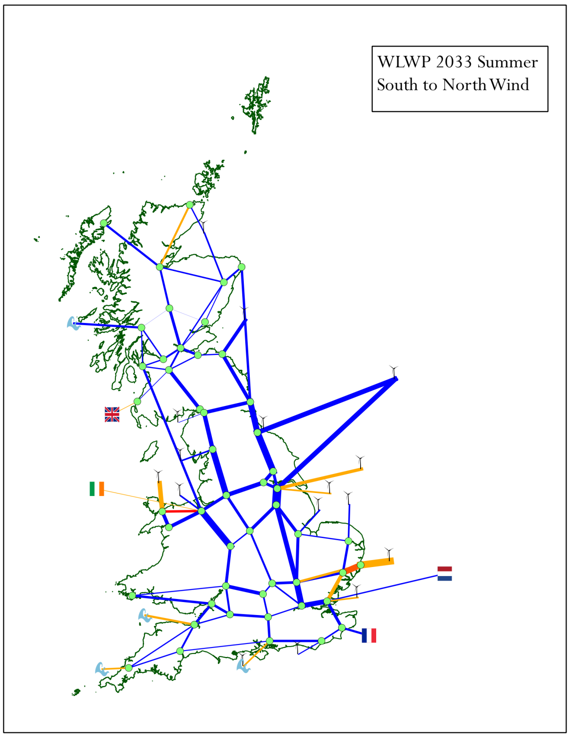


Figure 149: *WLWP 2033 Summer South to North Wind power flow*

8.6 Scenario comparisons and sensitivities

The scenarios described in the previous sections explore how different approaches to the utilisation and expansion of transmission networks could affect and interact with the trajectory taken by the system towards a carbon intensity target of 50gCO_2/kWh by the early 2030s. The following section makes some comparisons of key system indicators across the scenarios, and explores the effects of some additional uncertainties upon the network configurations described by the scenarios.

8.6.1 Comparison of final networks

Figure 150 compares the network configuration of the four scenarios in the year 2033, and the power flows they experience at the winter high wind condition.

SLSP has achieved targeted strategic network upgrades in specific renewable rich areas – mid-Wales, Scottish and English North Sea regions – and avoided major onshore reinforcements. It uses bootstraps between England and Scotland on both west and east coasts, and from north to south Wales. High capacity interconnectors to Denmark and Norway are integrated with offshore networks and respond to locationally specific signals to affect their operation. This means that at various different network conditions power transfers between regions within GB are smoothed, and the utilisation level of the networks kept relatively consistent. At the winter high wind the system trades strongly with neighbouring systems through interconnectors, which has the overall effect of avoiding constraints on the system despite relatively low investment in onshore network strengthening.

SLWP has made onshore network investments in certain key corridors, however it has not made bold anticipatory investments to exploit areas such as mid-Wales, the Scottish North Sea and the Scottish islands. It has also avoided the need for any further bootstrapping between Scotland and England, beyond the western HVDC link. The strong locational signal has limited the development of renewables in Scotland, but it has encouraged the development of southern renewables, particularly marine and tidal barrage, offshore wind in the southern North Sea, and nuclear – all of which can find connection points in relatively uncongested areas of the network. The lower output volatility caused by the lower renewable content of this scenario has meant a reduced incentive for interconnectors, so the system is less interconnected than in SLSP. Nonetheless, due to the spread of generation capacity around the network the winter high condition is met whilst almost entirely avoiding constraints.

WLSP has avoided signalling locational network constraints to generators. This has provided strong incentives for generators to invest in a portfolio of technologies across the network, including extensive development of renewables in the resource-rich northerly areas. In order to keep pace with the rapid deployment of generation capacity including in previously weakly connected network areas, an extensive programme of anticipatory network investment is undertaken. This includes high capacity HVDC interconnectors from the north of Scotland down the length of the east coast to Suffolk, and down the length of the west coast to south Wales. The output volatility created by the large renewable capacity creates incentives for interconnectors to trade power with neighbouring systems at times of high and low renewable output; however the lack of locational signal means that the operation of these interconnectors responds to overall GB system balance, without taking into account network conditions in the particular connecting zone. This means that interconnector activity can at times add to network transfer requirements, rather than reducing them as in SLSP. The high level of GB network investments in this scenario however mean that the high wind winter condition, despite very large power transfers, is almost entirely compliant.

WLWP has also avoided giving strong locational signals to generators, and has thereby encouraged development in renewable-resource-rich but weakly connected northern areas of GB. However, its approach to network investment has not been anticipatory but responsive to the development of generation as it has been committed. For nuclear power, due to the length of time between when a project is considered committed and when it is finally commissioned, responsive network investment can deliver required upgrades in time for the first day of the project's operation. For renewables however, the number of different projects and the speed with which they can move from planning to commissioning means that a responsive transmission approach can result in transmission investment lagging generation. In this scenario the result is high constraints, especially in high wind conditions, as transmission investment struggles to keep pace with the generation investments made within each time stage. With little additional strategic network investments beyond the east and west HVDC bootstraps, the scenario proceeds with successive incremental reinforcements of sections of the onshore network, as more renewable capacity is added. This results in a network whose overall shape is similar to the present one, but with greatly increased capacity in key onshore north-south corridors. Nonetheless, the lack of anticipatory network investment puts a practical brake on the pace of renewable investment, and this scenario relies on a greater quantity of nuclear power than WLSP, in order to meet the 50gCO_2/kWh target. In 2033 the winter high wind condition experiences high levels of constraint throughout Scotland, northern England and the Midlands, as the high output from northern renewables is transferred south through a network whose investment levels are still lagging those of the generation portfolio.

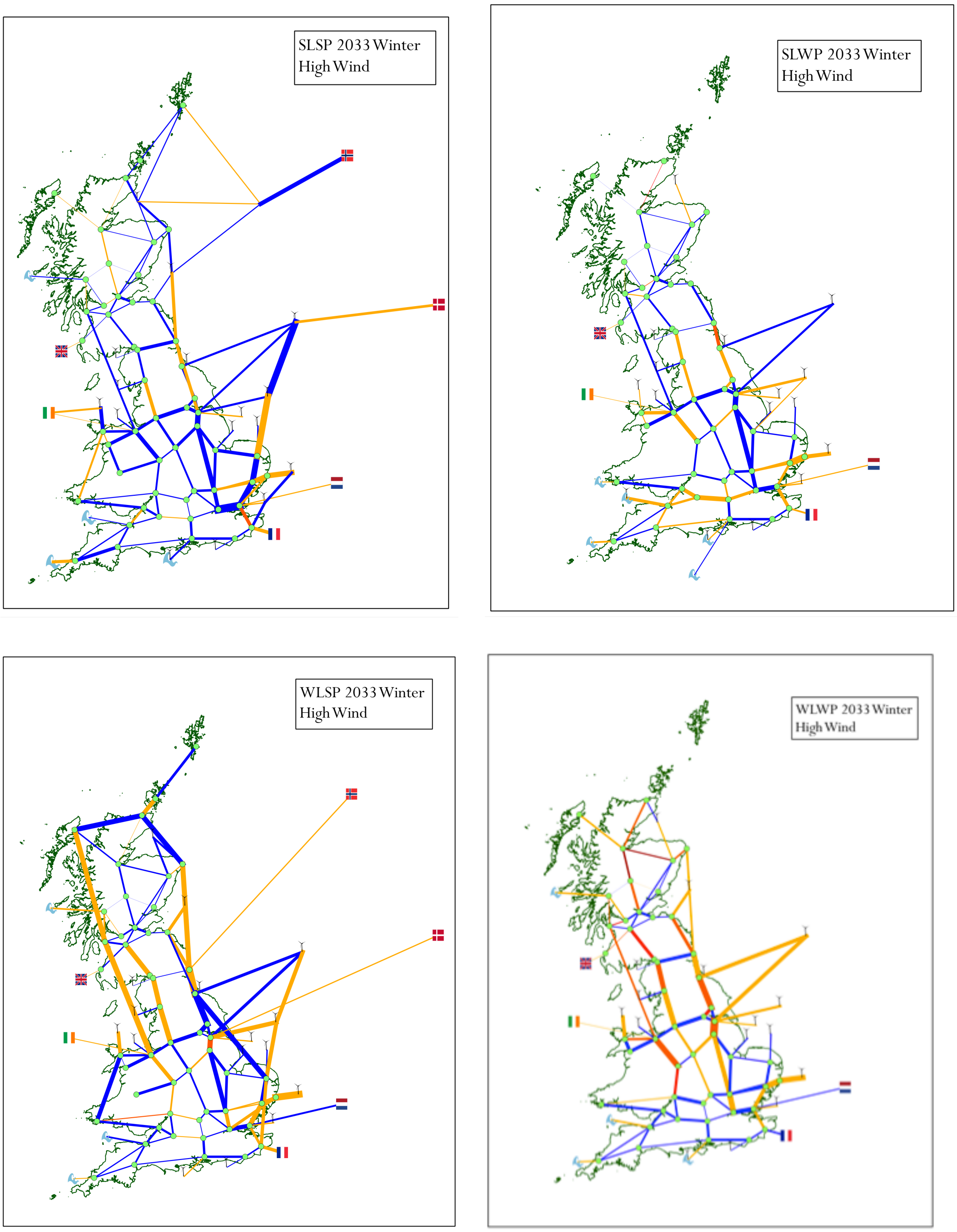


Figure 150: *Comparison of four scenarios in year 2033, winter, high wind*

8.6.2 Trajectory of decarbonisation

Figure 151 shows the change in carbon intensity of supplied electricity in g/kWh, by scenario and scenario year.

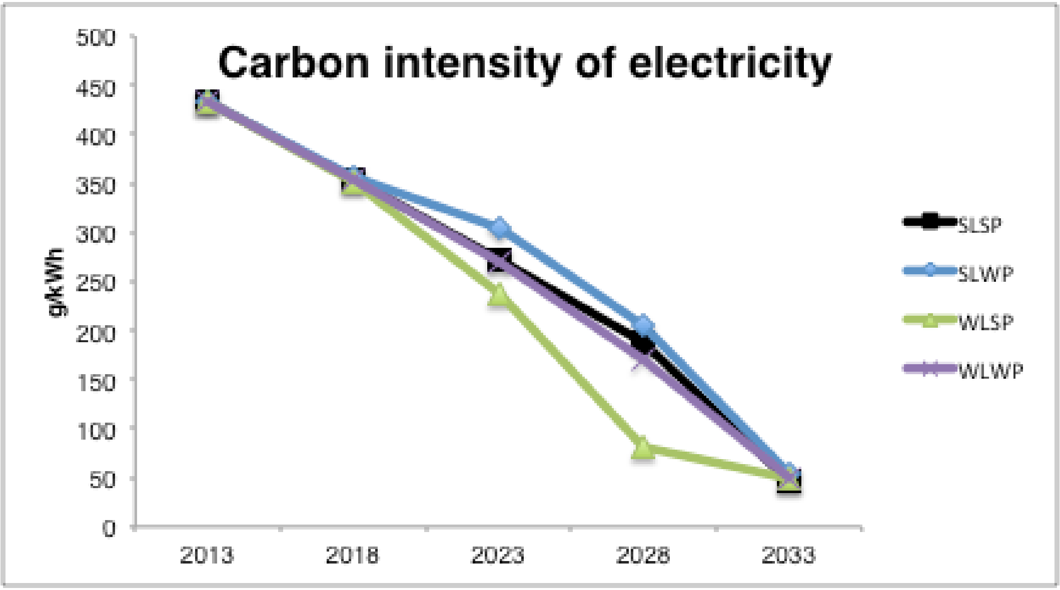


Figure 151: *Change in carbon intensity of electricity by scenario and scenario year*

The figure shows that WLSP follows a concave trajectory with strong early action, whereas SLWP follows a convex trajectory, leaving a steep reduction in carbon intensity to the end of the period. SLSP's trajectory is slightly convex, and WLWP is almost straight-line. The intensive build-out of renewables with accompanying rapid expansion of network capacity seen in the early and middle periods of WLSP is the main factor behind its concave decarbonisation trajectory. The convex trajectory of SLWP reflects its slower early deployment of renewables and reliance on a more extensive nuclear programme, which comes to fruition later in the period. In SLSP expansion of renewables is enabled, but waits for strategic anticipatory network expansions before these are considered viable. This results also in a later action trajectory, though for different reasons than SLWP, as the final period sees a rapid growth in renewables, due to available infrastructure, as well as some new nuclear. WLWP's trajectory can be contrasted with WLSP, indicating that the absence of forward infrastructure planning, in a weak locational policy context, slows the trajectory of renewable deployment. The limits on renewable deployment means that nuclear is important to maintain the course of the trajectory in the later stages of the scenario.

8.6.3 Contribution of renewables

***Figure** 152* shows the annual output from renewable sources by scenario and scenario year, and ***Figure** 153* shows the percentage contribution this makes in each case to overall electricity supply.

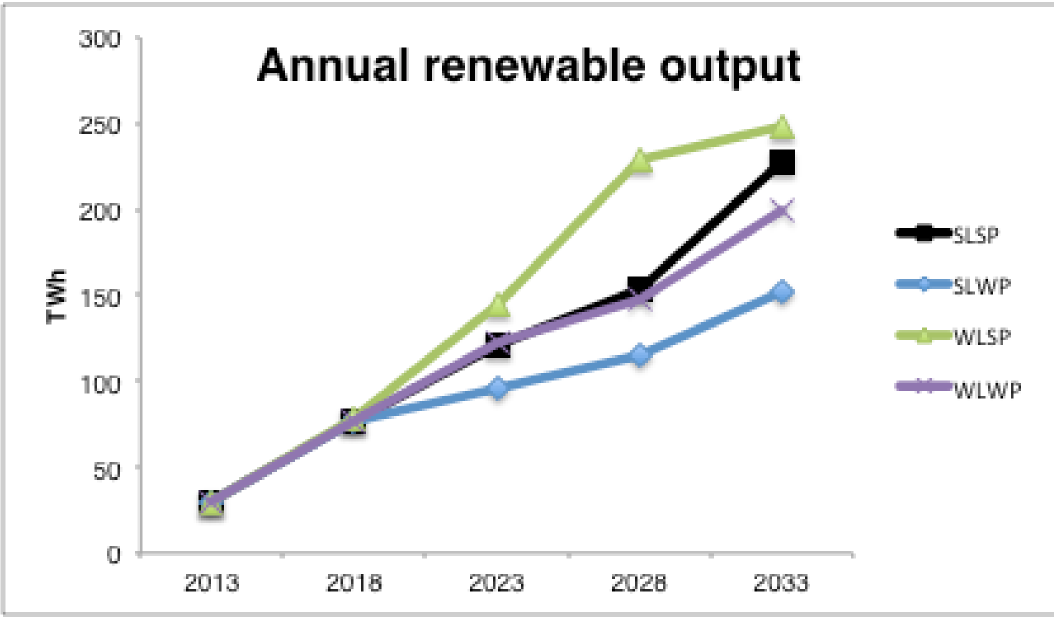


Figure 152: *Annual renewable output by scenario and scenario year*

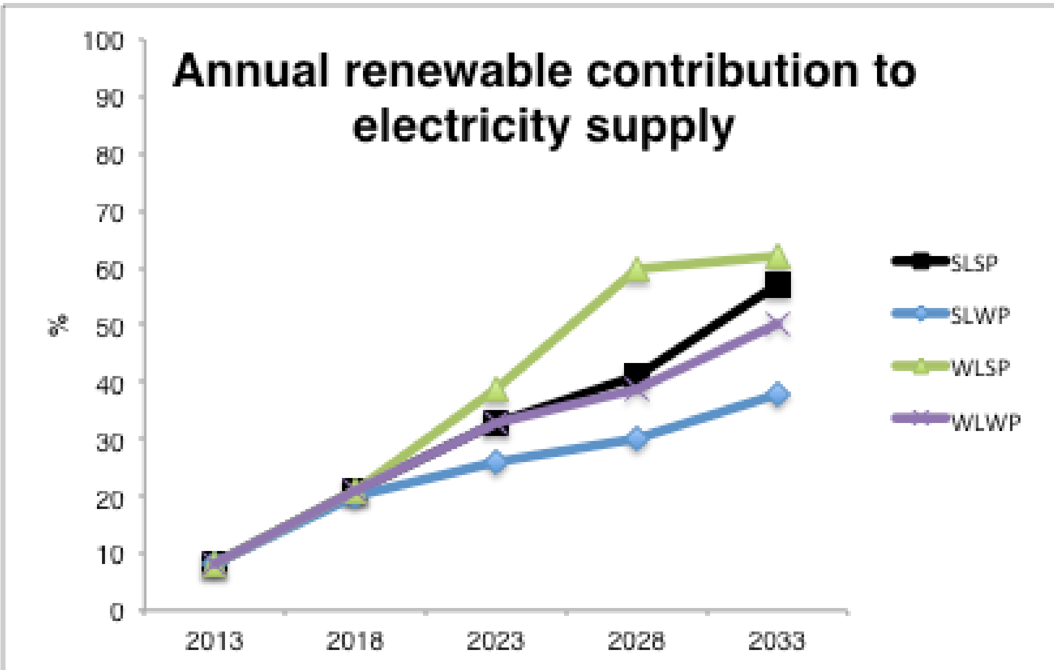


Figure 153: *Annual renewable contribution to electricity supply by scenario and scenario year*

Comparing WLSP and SLSP again highlights the early- and late-action characteristics of these scenarios, with WLSP making its push for renewables early on in the period, and with renewable expansion happening later in SLSP following the strategic build out of the network. Despite their different trajectories however, the two scenarios finish up with similar levels of renewable generation, with WLSP producing 248 TWh and

62% of its supply from renewable sources, and SLSP producing 228 TWh and 57% of its supply from renewables. WLWP maintains a steady growth in renewables, but is overall less steep than WLSP due to the infrastructure limitations. Renewable growth in SLWP is the least steep of all scenarios. As a result this scenario has the largest contribution of the three from nuclear, which comes online in significant quantities in the later periods of the scenario.

8.6.4 Final generation mix

Figure 154 shows the final generation mix in the four scenarios.

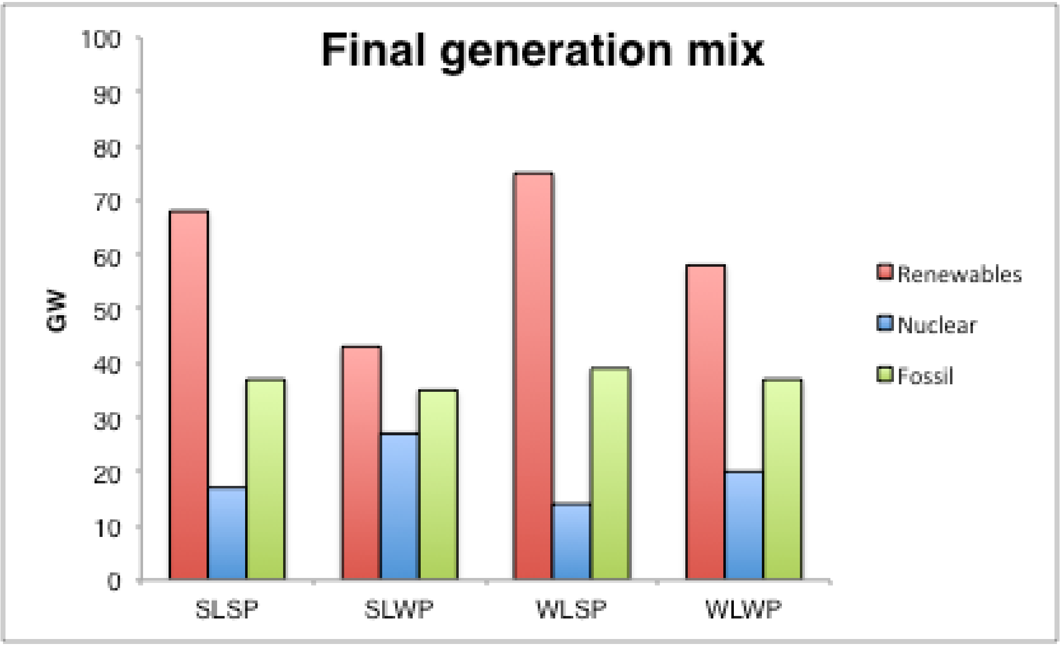


Figure 154: *Final generation mix of scenarios*

All four scenarios employ large quantities of all three broad generation types. Even though SLWP has maximised the use of nuclear by developing all eight available sites, it still requires a not insubstantial 44 GW of renewables to achieve a sufficiently decarbonised supply. Conversely, although WLSP has expanded its networks considerably to enable the development of 75 GW renewables, it still relies upon a significant fleet of nuclear stations amounting to 14 GW. SLSP and WLWP also, whilst having large renewables portfolios of 68 and 58 GW respectively, also require substantial nuclear portfolios of 17 and 20 GW respectively – which are critical to meeting the target due to their higher load factors. The locations and network implications of renewable build out in these scenarios were already challenging, and the implications of attempting to meet the target without a nuclear contribution, were stretching plausibility. All three scenarios also maintain very similar levels of fossil plant of 35-40 GW to maintain the security of the capacity margin.

Similarities and correspondences between the generation mixes of the different scenarios belie differences in the network configurations the scenarios build to get there. In particular, the final installed capacities of SLSP and WLSP turn out to be quite similar in terms of the three broad categories of technology types – however the network architectures they have built to support this are very different, as discussed in the following section.

8.6.5 Quantities of network upgrade

Figure 155 compares the lengths of lines receiving different kinds of network upgrades, and ***Figure 156*** combines this with the level of capacity upgrade to provide the overall quantity of upgraded network in GWkm (quantity of upgrade in GW * length of upgrade in km).

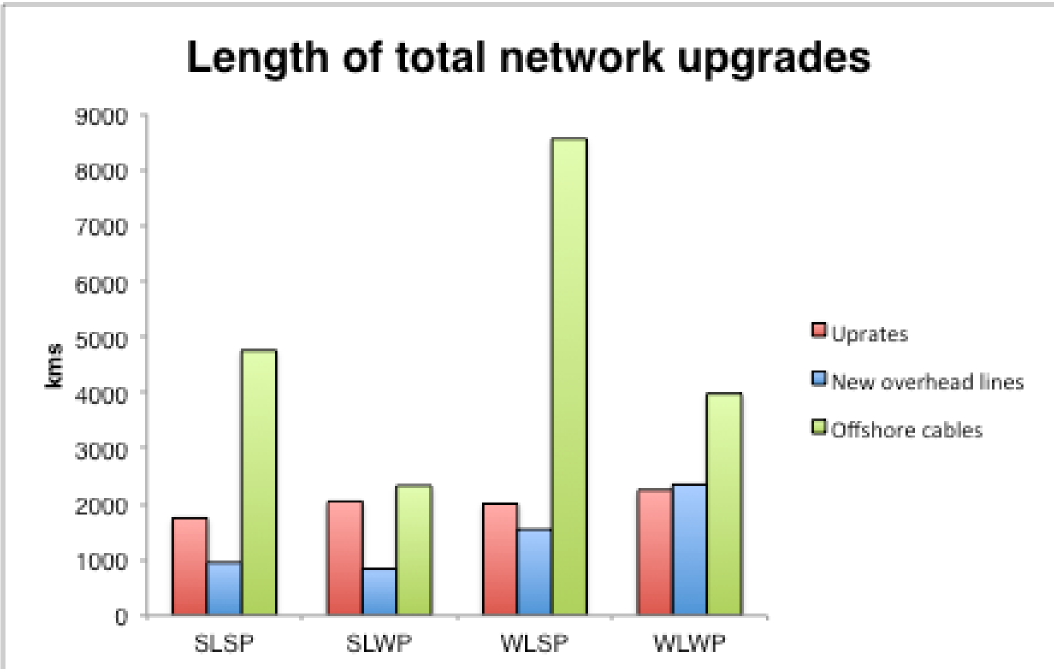


Figure 155: *Length of total network upgrades by scenario and type of upgrade*

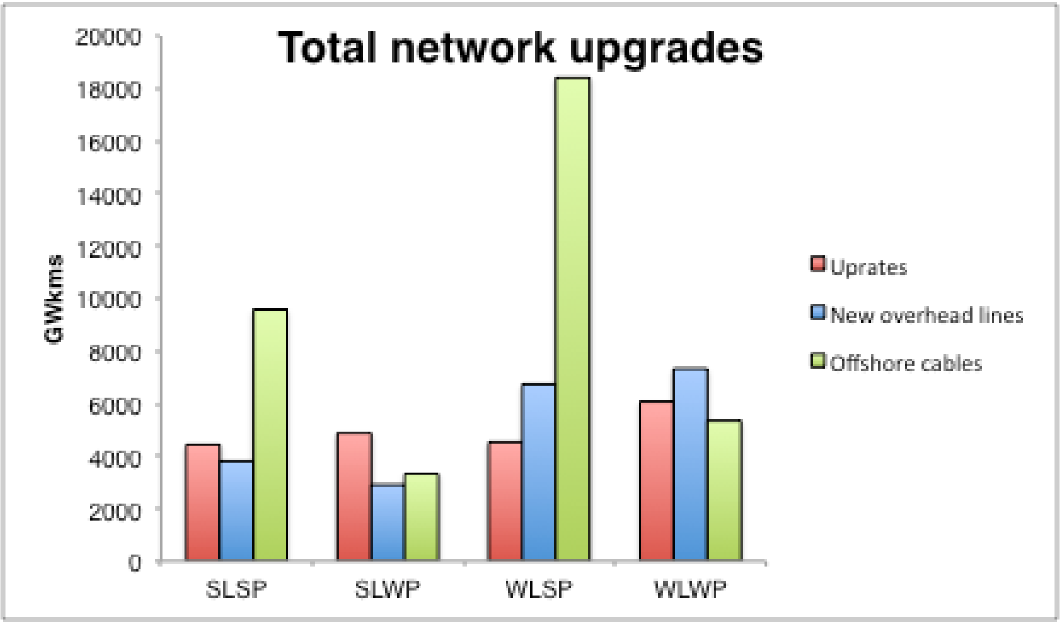


Figure 156: *Quantities of total network upgrades by scenario and type of upgrade, in GWkms*

WLSP has the largest levels of network expansion, with a particularly large offshore expansion due to the large numbers of bootstrapping offshore cables required to convey high peak output renewables and interconnector output from north to south. It also has a high onshore impact, with upgrades of new onshore lines around double that in SLWP and SLSP. SLWP has the lowest upgrade requirements. A key difference between SLWP and SLSP is that whereas SLWP's expansion is spread between uprating of existing lines, new onshore lines and offshore lines, SLSP uses offshore lines not just as radial connections to offshore sites, but as bootstraps and networked meshed connections which enable the conveyance of power across the system with a relatively low onshore upgrade requirement. The scenario with the largest levels of onshore upgrades – both line uprates and new overhead lines – is WLWP. This is due to the scenario's high peak output requirement, combined with its lack of investment in strategic offshore upgrades, as can be seen by its much lower investment in this category compared to WLSP.

8.6.6 Costs of network upgrades and comparisons with other scenarios and projections

Projections of future costs are subject to uncertainties, however based on available estimates of the costs per km of the different types of upgrade, estimates of the total costs of new transmission investments (above like-for-like renewal) for each scenario can be produced, for any point in each scenario trajectory. This section reports on estimated transmission network investment costs for the scenarios, in the medium-term and the longer-term. Details of the cost estimation methodology are provided in Appendix F.

In order to provide some context to these costs, as well as presenting estimated medium-term and long-term network investment costs for the scenarios developed in the current thesis, this section also compares these cost estimates to similar available estimates on possible future transmission network requirements, as well as broader energy system cost projections and the expected costs of other major infrastructure projects that may take place in the future.

8.6.6.1 Medium term investment costs

Section 1.2.1 discussed a number of studies which have in different ways considered the future prospects for electricity networks under a decarbonising electricity supply mix. Two of these – ENSG (ENSG, 2009, ENSG, 2012) and Barnacle et al (2013) – include estimates of the total investment costs of delivering the strategic network upgrades required under their specific low carbon scenarios out to 2020. Clearly the cost estimates in these reports, corresponding to their respective partially decarbonised 2020 scenarios, are not comparable to the final cumulative network costs of the scenarios developed in this thesis, which extend to a heavily decarbonised system in 2033 – these final costs will be discussed in the next section. However, it is nonetheless informative to compare the network costs estimates of ENSG (2012) and Barnacle et al (2013) to the cumulative costs at a comparable intermediate point in the trajectory of the scenarios developed in this thesis. It is also possible to compare the geographical architecture of the transmission networks described in the scenarios at such a comparable intermediate point, with the 2020 transmission architecture proposed in ENSG (2012). Barnacle et al (2013) do not make explicit the geographical arrangement of their proposed upgrades, so such a comparison is not possible in this case.

In order to establish a meaningful comparison it is necessary to choose an appropriate intermediate scenario year, the conditions of which compare adequately with the 2020 scenarios used by ENSG (2012) and Barnacle et al (2013) – 'Gone Green' and 'Market Rules' respectively.

As shown in ***Table 29*** and ***Table 30***, the generation mixes of all four scenarios for both of the years 2018 and 2023, and the outputs for Market Rules and Gone Green for the year 2020, all have certain broad similarities especially around the capacities of fossil plant (coal, gas and oil), and nuclear. This reflects the long lead-times for plant construction in the case of nuclear, such that there is little flexibility for considering a mass rollout over the next ten years; and in the case of fossil-fuel powered plant, that a similar amount of capacity continues to be required in the medium term for capacity margins, such that expected closures are assumed to be replaced across all scenarios. However, greater divergences are found in the scenarios' assumptions on deployment of renewables. The key difference between Gone Green and Market Rules is in their deployment of offshore wind – Gone Green installs 16.6 GW, Market Rules only 7 GW. As ***Table 29*** and ***Table 30*** show, this means that Market Rules is more comparable to the 2018 outputs for the scenarios developed in this thesis; Gone Green on the other hand is more comparable to the 2023 outputs.

Table 29: *Comparison of installed capacities (GW) of scenarios for year 2018, with 'Market Rules' for year 2020. 'Market Rules' data from Barnacle et al (2013), Table 6*

Installed Capacity (GW)	SLSP 2018	SLWP 2018	WLSP 2018	WLWP 2018	Market Rules 2020
Offshore wind	9.9	9.9	9.9	9.9	7
Onshore wind	7.2	6.8	7.6	7.3	9.4
Other renewables	3.2	3.2	3.3	3.2	5.2
Nuclear	9.5	9.5	9.5	9.5	10.7
Fossil	52.1	52.1	52.1	52.1	54.5[3]
Other	2.2	2.2	2.2	2.2	9

Table 30: *Comparison of installed capacities (GW) of scenarios for year 2023, with 'Gone Green' for year 2020[4]. Gone Green data from ENSG (2012), Figure 3*

Installed Capacity (GW)	SLSP 2023	SLWP 2023	WLSP 2023	WLWP 2023	Gone Green 2020
Offshore wind	20.7	14.1	21.2	20.0	16.6
Onshore wind	8.2	7.8	12.1	8.1	9.1
Other renewables	4.3	4.3	8.0	6.1	3.1
Nuclear	9.2	9.2	9.2	9.2	12.3
Fossil	45.7	47.2	44.9	44.9	50.0
Other	2.2	2.2	2.2	2.2	9.3

In both Barnacle et al (2013) and ENSG (2012), the cost estimates do not appear to have been adjusted by a discount rate. In order to aid comparison with these reports therefore, the undiscounted cumulative costs of investment in onshore upgrades and HVDC links, but not including radial connections to offshore renewables, are reported for all scenarios. Scenario cumulative costs for the year 2018 are reported for comparison

[3] 'Market Rules' fossil includes 2.3 GW Coal CCS
[4] 'Gone Green' figures are transmission connected only

with Barnacle et al (2013), and costs for 2023 are reported for comparison with ENSG (2012).

Barnacle et al (2013) produce a range of costs, as the genetic algorithm approach used in the paper to define networks for the generation mix scenarios produces a range of solutions. In ***Table 31*** the range of the results quoted in Barnacle et al for 'Market Rules' in 2020 is compared to the cumulative costs for the scenarios in this thesis, for the year 2018.

Table 31: *Undiscounted cumulative costs (£bn) of network investment in the four scenarios in 2018, compared with the 'Market Rules' 2020 scenario, as reported by Barnacle et al (2013)*

	SLSP 2018	SLWP 2018	WLSP 2018	WLWP 2018	Market Rules 2020 (Barnacle et al., 2013)
Network costs (£bn)	8.1	6.6	8.8	8.1	0.3 – 0.8

The upper end of the range of costs in Barnacle et al (2013) is an order of magnitude lower than the cost estimates for the scenarios in this thesis in the comparable year (in terms of generation capacity) of 2018. In considering this difference, it can be observed that the Barnacle et al cost ranges appear low even compared to the projected costs of projects currently known to be proceeding, such as the Beauly-Denny line (estimated cost £600m, (BBC, 2013a)) and the Western Link (estimated cost £1bn, (National Grid and Scottish Power, 2015)). Though a detailed description of what upgrades are made to accommodate the Market Rules scenario is not provided, Barnacle et al do note in relation to the network plan which provides the lowest investment of their overall range, that 'this minimal cost is however understandable as the overloads under this line loading condition, and under this 2020 scenario, occur at lines of small distance and capacity. The largest line capacity for an addition of a line, for this plan, is only 132 MVA, and the largest route length is only 85.5 km'. These levels of network reinforcement on a 2020 scenario are aptly described as 'minimal' when compared to the scenarios developed in this thesis, as well as to the ENSG analysis (described further below). The explanation for the comparatively low level of network investments found by Barnacle et al is likely to reside in a combination of the assumptions taken by the authors for the geographical distribution of the Market Rules generation mix, and their assumptions about the output of the various generators, especially the renewables, (high, low or average) at the point of the power flow being analysed. Comparisons of the various scenarios and power flow conditions explored in this thesis have shown that these two variables can have a considerable impact on the requirements of the transmission network (as discussed in detail in Sections 8.2 to 8.5). However, the assumptions about geographical distribution and temporal variation of output are not made clear by Barnacle et al (2013).

ENSG also calculate the total costs of the network investments they consider necessary to accommodate the Gone Green 2020 scenario. These investment costs are compared in ***Table 32*** to the network investment costs of the four scenarios developed in this thesis, in their 2023 reporting years.

Table 32: *Undiscounted cumulative costs (£bn) of network investment in the four scenarios, compared with the Gone Green 2020 scenario, as reported in ENSG (2009, 2012)*

	SLSP 2023	**SLWP 2023**	**WLSP 2023**	**WLWP 2023**	**Gone Green 2020 (ENSG, 2009)**	**Gone Green 2020 (ENSG, 2012)**
Network costs (£bn)	9.2	6.7	18.9	8.9	4.7	8.8

The network investment costs for 2023 for the scenarios developed in this thesis, are much closer to the ENSG calculations (2009, 2012) than the 2018 costs were to those reported in Barnacle et al (2013), being broadly within the same order of magnitude, and in some cases very similar. The difference between the cost estimates in ENSG (2009) and (2012) is in large part due to the greater inclusion of offshore HVDC links in the later report, including links to Scottish islands (ENSG, 2012). As can be seen from the table, in the 2023 scenario year, investment costs in SLSP and WLWP are very close to the estimate for Gone Green 2020 given in ENSG (2012). SLWP requires a little less – around 75% of the Gone Green investment quoted in ENSG (2012). WLSP is the clear outlier, with more than double the investment costs of the others. A comparison of the network investment maps for the scenarios in 2023 (***Figure 157***) with the equivalent map of the required network for Gone Green provided by ENSG (2012) sheds some light on the differences in investment costs.

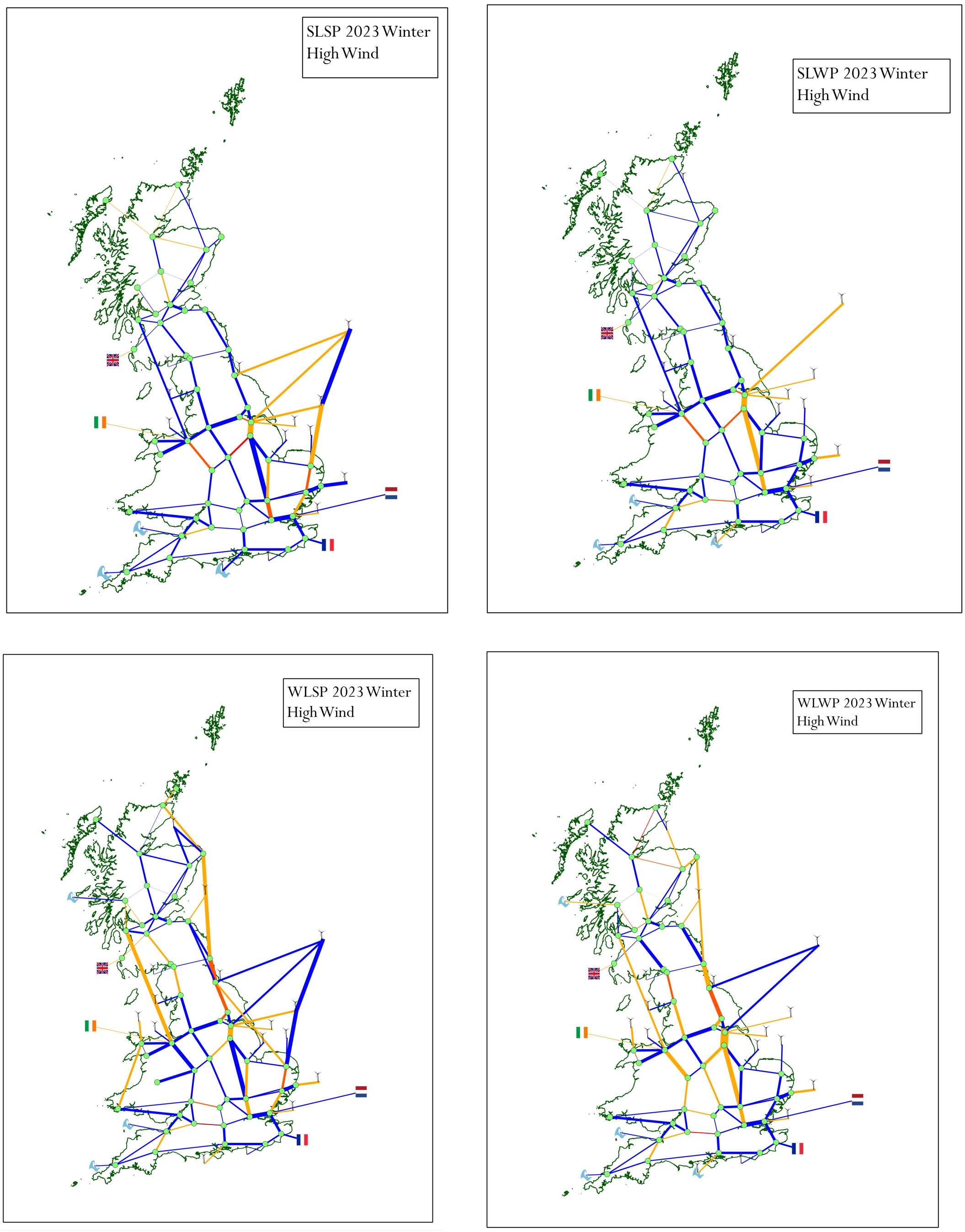


Figure 157: *Comparison of networks of the four scenarios at 2023, Winter High Wind*

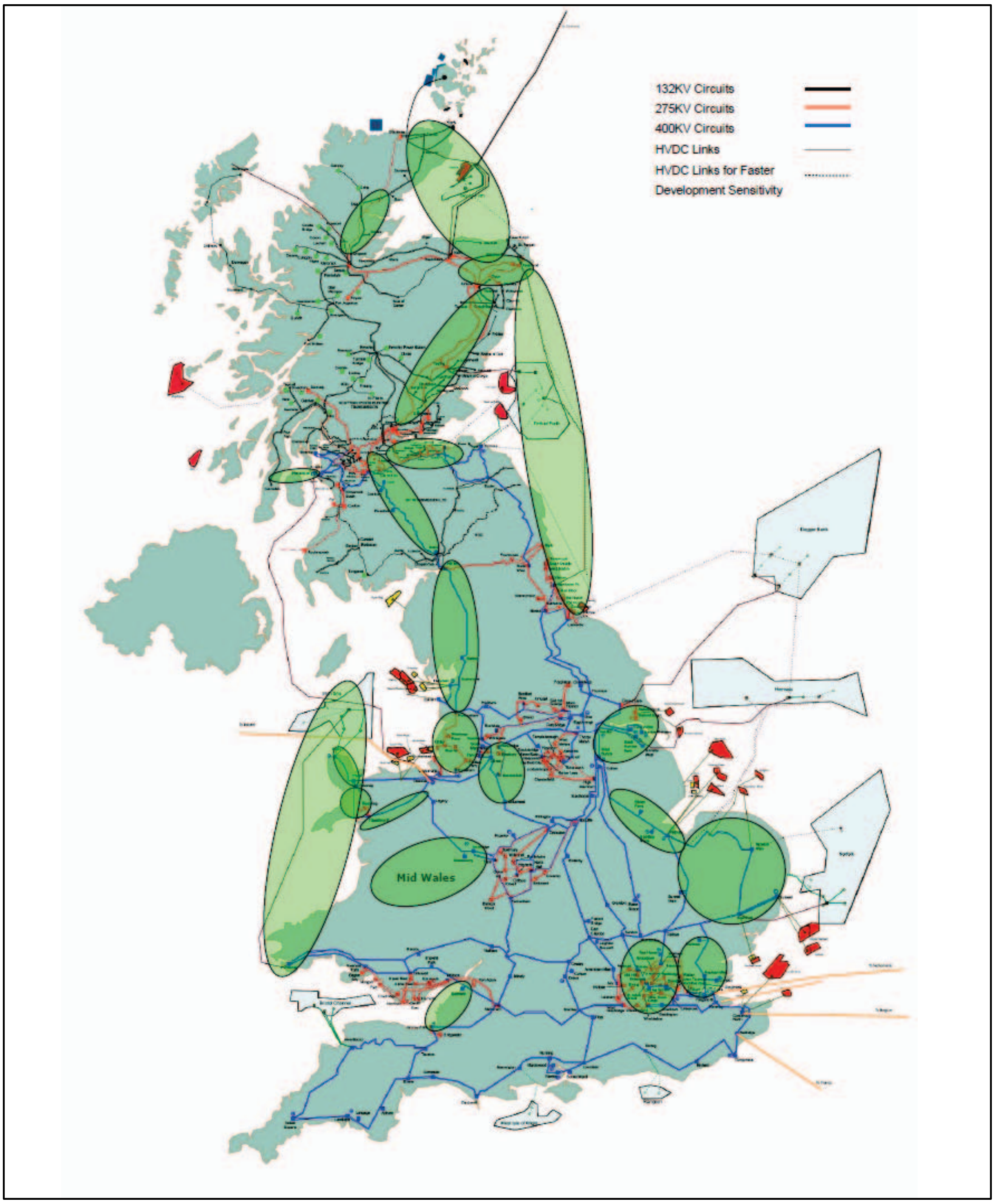


Figure 158: *Map of potential network reinforcements identified by ENSG (2012) based on Gone Green 2020*

As shown in ***Figure 158***, the ENSG analysis based on Gone Green 2020, suggests a number of major reinforcements, including offshore interconnectors across the Moray Firth, between Scotland and England along the east and west coasts (the Western Link is present but not highlighted in the ENSG map (***Figure 158***) as it was considered a firm project by the time of the 2012 report), from north to south Wales, as well as numerous onshore upgrades, especially in critical north-south corridors. By comparing ***Figure 158*** with

Figure 157, it is possible to compare the ENSG's network for Gone Green 2020 with the networks built by the scenarios presented in this thesis up to the year 2023 (the most comparable scenario year in terms of generation mix to Gone Green 2020). Although none of the four 2023 networks provide an exact match to the ENSG Gone Green network, arguably the most similar is WLWP 2023. Like the ENSG network, WLWP has built by 2023 both the eastern and western offshore 'bootstrap', as well as the Moray Firth interconnection, and substantially strengthened other key onshore corridors. SLSP and SLWP both avoid the need to build the eastern bootstrap, however SLSP has made substantial onshore investment which puts its costs closer to Gone Green, whereas SLWP has even avoided most of these onshore upgrades, allowing it to achieve costs significantly lower than Gone Green. Although WLSP in 2023 has some similarities to the ENSG's Gone Green network which the other 2023 scenarios do not, namely the addition of the north-south Wales offshore bootstrap, and the new mid-Wales connection, it also has many substantially greater upgrades than found in other scenarios, such as a doubling of the eastern and western bootstraps, further addition of bootstraps down the east coast as far as Norwich, and other substantial onshore upgrades. These constitute a very much greater level of network investment than in the other 2023 scenarios, and the ENSG's Gone Green network, which explain the very noticeable difference in investment cost.

The drivers for the different levels of investment in transmission relate primarily to the location of the generation plant and the degree of operational flexibility within the system. These drivers and their effect on specific transmission investment choices, and resulting overall pattern of investment, have been discussed in greater detail earlier in this chapter during the exposition of the scenarios themselves, and further policy implications from these issues will be discussed in the remainder of the thesis. However, at the high level, the comparison of the scenarios developed in this thesis and the resulting network investment cost calculations, with similar calculations undertaken by ENSG, indicate that for a broadly similar kind of network the method developed in this thesis calculates a similar investment cost to that provided by ENSG. In the scenarios where the investment costs are significantly lower or higher than the ENSG analysis, clear reasons can be identified in terms of the physical characteristics of the networks, for why this should be so.

8.6.6.2 Long term investment costs

For the longer term investment costs, all transmission upgrades including radial offshore connections are included. This is because in scenarios with a more strategic approach, offshore networks emerge in which lines are serving wider network purposes as well as the conveyance of power from particular individual wind farms, so the distinction is harder to maintain. In any case, consumers will have to pay for the costs of all of these one way or another. The investment costs are discounted using the annual discount rate of 3.5% recommended by the Green Book. Details on cost assumptions are in Appendix F

The total undiscounted and discounted investment costs for each scenario are presented in ***Table 33***.

Table 33: *Total undiscounted and discounted cost of network investment in each scenario*

Scenario	Undiscounted cost (£bn)	Discounted cost (£bn)
SLSP	49.1	32.1
SLWP	25.2	17.8
WLSP	87.6	58.6
WLWP	43.9	29.9

For comparison, a high level estimate of onshore, offshore and interconnection investment requirements in scenarios out to 2030 was made by Pollitt et al (2013). Their range was from £22bn-£52bn (though it is unclear whether these totals are discounted). The total undiscounted network investment costs for three of the scenarios fit comfortably within this range. WLSP is noticeably outlying beyond the high end of Pollitt et al's range, however as in the earlier discussion of medium-term investment costs, there are clear reasons, relating to the significantly greater level of physical network investment in this scenario, for understanding why this should be so.

In considering the relative magnitude of these network investment cost ranges, a comparison can be made to estimated generation investment costs over a similar period. The Carbon Plan estimates the net present cost of low carbon policies affecting the electricity sector as £62.3 bn until the end of the third carbon budget period (2022). In the Electricity Market Reform consultation document it was estimated that £70-75bn of investment was required in electricity generation by 2020. Moving beyond the early 2020s, significant additional generation investment would be required. The CCC estimate that the total investment costs in electricity generation for scenarios reaching a carbon intensity of electricity of 50gCO_2/kwh by 2030 would be up to £200bn between 2014 and 2030 (CCC, 2013b). The distribution of these generation investment costs for one such scenario is shown in ***Figure 159***.

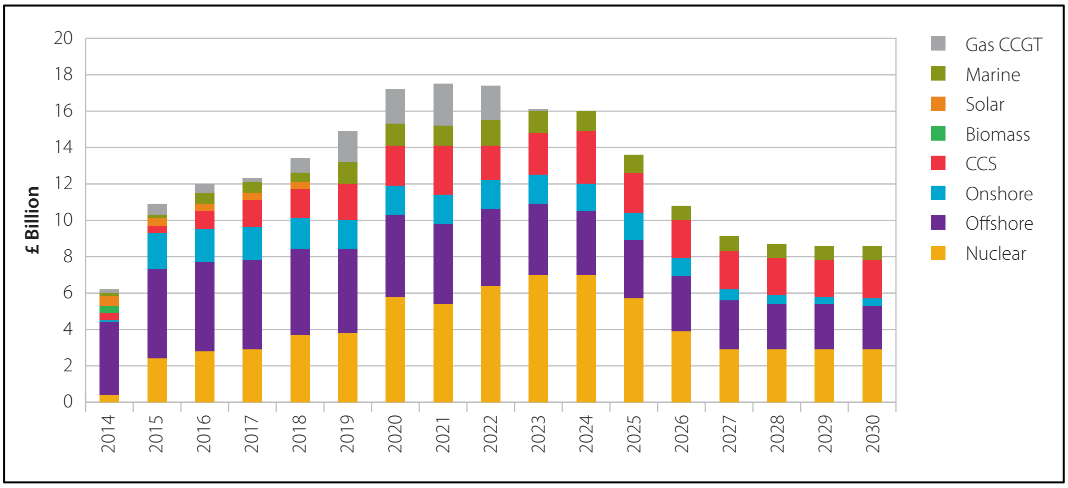


Figure 159: *Capital expenditure on low-carbon technologies in CCC 'Higher Energy Efficiency' scenario reaching 50gCO2/kwh by 2030. CCC calculations based on Poyry and Redpoint modelling. Appears as Figure 2.6 in CCC (2013b), p. 46*

It should be recognised of course, that these total investment costs are based on projections of expected future costs for individual technology types, which are themselves subject to considerable uncertainty, as made clear within the CCC's analysis on the power sector (Chapter 2 of CCC (2013b)). This root uncertainty necessarily implies uncertainty around the overall £200bn figure – nonetheless it is based on robust analysis and thus, in spite of the uncertainty, may be considered a reasonable guide to the region of generation investment costs that may be expected.

The comparison of this projected £200bn figure for generation investment with the range of costs for new transmission investment projected by the scenarios in this thesis, strongly suggests that the costs of transmission will be substantially less than the costs of generation – however, not necessarily a negligible amount. In interviews for this thesis, it was suggested that costs of transmission investment were historically in the region of 5-10% of the cost of generation (see section 5.2.1), and thus should be considered of a much lower priority to optimise, compared to optimising generation costs. However, comparing the undiscounted total transmission investment costs for the scenarios developed in this thesis to the CCC's estimate of £200bn in electricity generation for highly decarbonised scenarios over a similar time-period, suggests that the cost of transmission investment could range from just over 10% to about 40% of the total cost of generation investment. The wide range of network costs suggested by the scenarios, and the particularly substantial costs at the high end of the range, suggest there are strong reasons to think about network management policy as a means of minimising network investment costs within a low-carbon transition, rather than assuming that network costs will always be negligible in relation to generation costs, and consequently adopting an approach which assume transmission costs are not worth optimising.

The overall costs of any electricity system will of course be a combination of generation and network costs. In the scenarios developed for this thesis, the scenario with the lowest network investment cost is SLWP. This scenario also has the highest installed capacity of nuclear. This is due to the relative locational flexibility, including availability in the south, of nuclear, meaning that it has an advantage in a scenario where the network policy is based on strong locational signals and the avoidance of large-scale anticipatory network projects in the context of uncertainty. For similar reasons, non-wind renewables such as wave and tidal power, which have relatively good locational diversity, are also strongly represented in this scenario. This supports the conclusion that the greater the locational flexibility of the technology, the greater the potential to reduce network costs. It does not however support the conclusion that a nuclear scenario would necessarily be lower cost overall. Establishing such a conclusion would require comparing generation investment costs as well as network costs, and there remain very considerable uncertainties around future generation investment costs, as discussed by the CCC (2013b), and as indicated by ongoing uncertainties about the final cost of the proposed new nuclear plant at Hinkley Point C (Macalister, 2015). Such a combined analysis of generation and network costs, including uncertainties about future generation costs, is beyond the scope of this thesis.

What is within the scope is a cross-comparison of the network investment costs of the scenarios, which includes some consideration of both the similarities and differences of the generation mixes achieved in each one. As noted above, the relative locational flexibility of technologies such as nuclear, wave and tidal are significant drivers of the relatively low transmission investment requirement in SLWP. However, it is also interesting to note that although the network investment costs of SLSP and WLSP are quite different, with the cumulative figure for WLSP almost double that of SLSP, the broad generation mixes for each scenario are quite similar. As shown in ***Figure 154***, the installed capacities of renewables in the two scenarios are within 7 GW of each other, and for nuclear the difference is 3 GW, or one nuclear power station. The difference in network requirements and resulting investment cost is a result partly of different choices about where to locate these capacities, but also to do with the operational incentives of the regime which rewards flexibility in plant for which this is an option. The lower cost is thus achieved by locational decisions but also by operational incentives.

Considering the possible evolution of the real electricity system, it is clear that the precise future generation mix that emerges is an area of major uncertainty, not least because of the uncertainties around the future costs of the various generation technologies. It is inevitable that the precise mixture of generation technologies will affect the overall network configuration and its costs, and network planning has to some extent to be responsive to this. However, an important message from comparing the scenarios developed in this thesis is that for any given generation mix, the policies which govern the relationship between transmission network investment, generation investment, and system operation, can make a significant difference in whether the total cost of the transmission network is small (albeit not negligible) in relation to the cost of generation; or whether it becomes a significant proportion of the overall system costs, and of a magnitude that threatens the economic viability of the system.

Transmission system costs might also be compared to other major infrastructure investment projects. ***Table 34*** compares some of these. They suggest that at the lower end of the scenarios' range, the transmission network costs are of an order which is comparable to other major infrastructure projects, which, though controversial because of their cost as well as other issues, have received significant political backing as being in the long-term public interest. This suggests that a political argument could be made for a transmission investment project in this range. At the higher end of the range – WLSP's £88bn (undiscounted) – it becomes harder to envisage strong political support, and such a programme would be more vulnerable to being abandoned once the costs became apparent. This further emphasises the real long-term value in paying attention to a network investment and management regime which is able to deliver flexibility but also cost-effectiveness in responding to whatever emerges on the generation side.

Table 34*: Comparative costs of other major infrastructure projects*

Project	Expected cost (£bn)	Reference
HS2 High Speed Rail Link	50	(Lords Select Committee, 2015)
Trident replacement	15-20	(BBC, 2013b)
Crossrail	14.8	(Crossrail, 2015)
Hinkley Point C	24.5	(Macalister, 2015)

8.6.7 Network utilisation

Figure 160 shows the average network utilisation in 2033 for the five wind conditions under each scenario. The two 'weak location' scenarios have a more volatile network utilisation level in different wind conditions. WLSP and WLWP produce the greatest variation, with significantly less well-utilised networks than the other two scenarios in low and SN wind conditions. SLSP achieves the most consistent level of utilisation across all conditions, as the location of its plant and the operation of its interconnectors contribute to smoothing the variability of renewable generators. WLWP achieves the highest utilisation level at NS and average conditions – however it does this at the expense of major constraints in overloaded lines, as highlighted in the discussion of this scenario in Section 8.5.

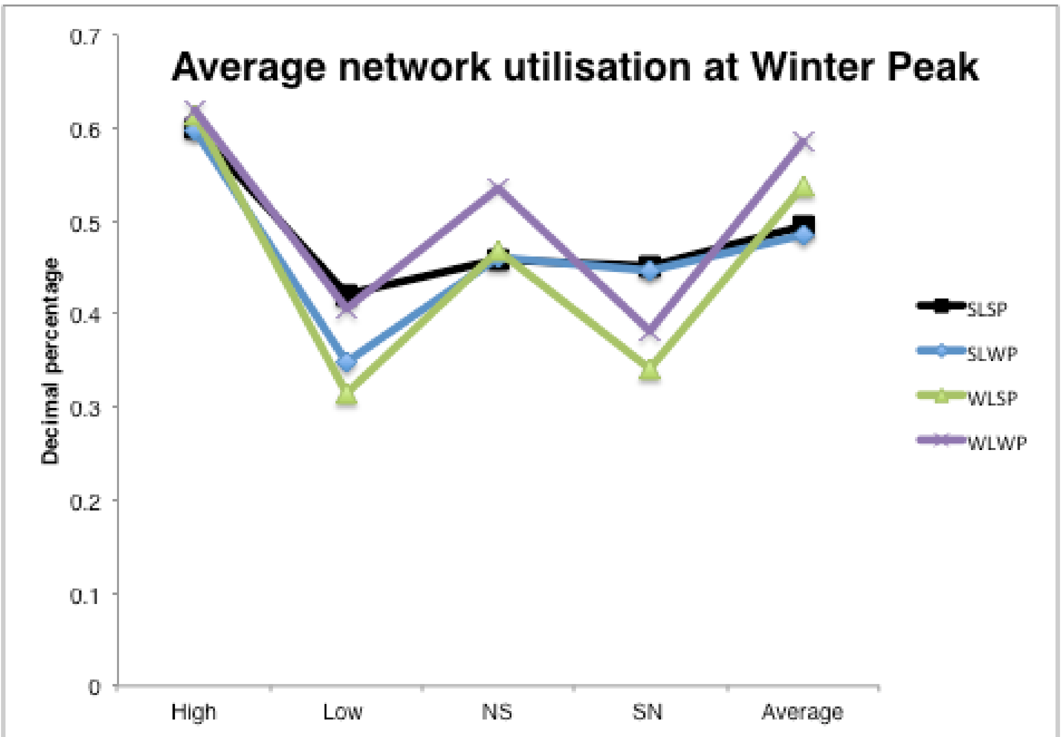


Figure 160: *Average network utilisation at winter peak*

8.6.8 Non-actor-contingent elements

The scenarios have been developed based around policy strategies which could be pursued by policy makers, and the possible effects of these on other system actors have been explored. These strategies are by definition within the control of policy makers and are thus considered 'actor-contingent' elements. However, in addition there are also possible future elements which are less directly controllable by policy makers, but which could have significant and important effects upon the development of the system. These are 'non-actor-contingent' elements, and a selection of these will now be discussed in terms of their possible effects on each of the scenarios.

8.6.8.1 Electric vehicle charging patterns

Is discussed in Section 6.3.3 and Appendix E.3, a fixed assumption of an exponential growth pattern for electric vehicles, culminating in close to 100% of passenger transport kilometres met by electric vehicles in 2048, forms the background for each scenario. The trajectory of the growth curve means that by 2033 electric vehicles are accounting for around 9% of total passenger vehicle transport demand, equivalent to about 9 TWh. This is combined with assumptions from the National Grid Future Energy Scenarios on re-charging patterns, which assume a relatively spread overnight re-charging pattern, with the result that 4% of the total daily charging requirement takes place within the winter peak hour of 5-6 pm. By 2033 this only adds 1 GW on to winter peak.

However these fixed assumptions are subject to various uncertainties. A faster uptake in electric vehicles would increase the power demand by 2033. Additionally, charging patterns other than those hypothesised by National Grid, could see greater demand clustered around winter peak, and technological changes such as the development of vehicles with the ability to fast-charge could also increase the risk of peak demand clustering.

The effect of changing the proportion of daily demand assumed to be charging over the winter peak from 4% to 50% was explored. The impact is the addition of almost 12 GW of peak demand above the 1 GW added from EV charging in the standard scenarios. This kind of clustering could occur with faster charging technologies, and no behavioural incentives to stagger recharging. However, a similar kind of increment could also have been the result of similar spread-charging behaviours to the National Grid hypotheses, but with an increased rate of diffusion of electric vehicles leading to a larger number of vehicles by 2033. The additional demand is spread amongst the demand nodes using the same proportions calculated to allocate the other demands.

In SLSP the effect of this added peak is noticeable in mostly moderate but occasionally large increases in constraints on certain lines – however these remain mostly isolated, and reflect the same pattern of constraints found in the equivalent original scenarios. ***Figure 161*** compares the winter NS condition with and without the additional electric vehicle charging. It can be seen that the pattern of constraints is almost identical, although the constraints in the EV variant are usually higher, and there are some significant additional constraints on lines not constrained in the original pattern – notably an 800 MW constraint running from Grain into London.

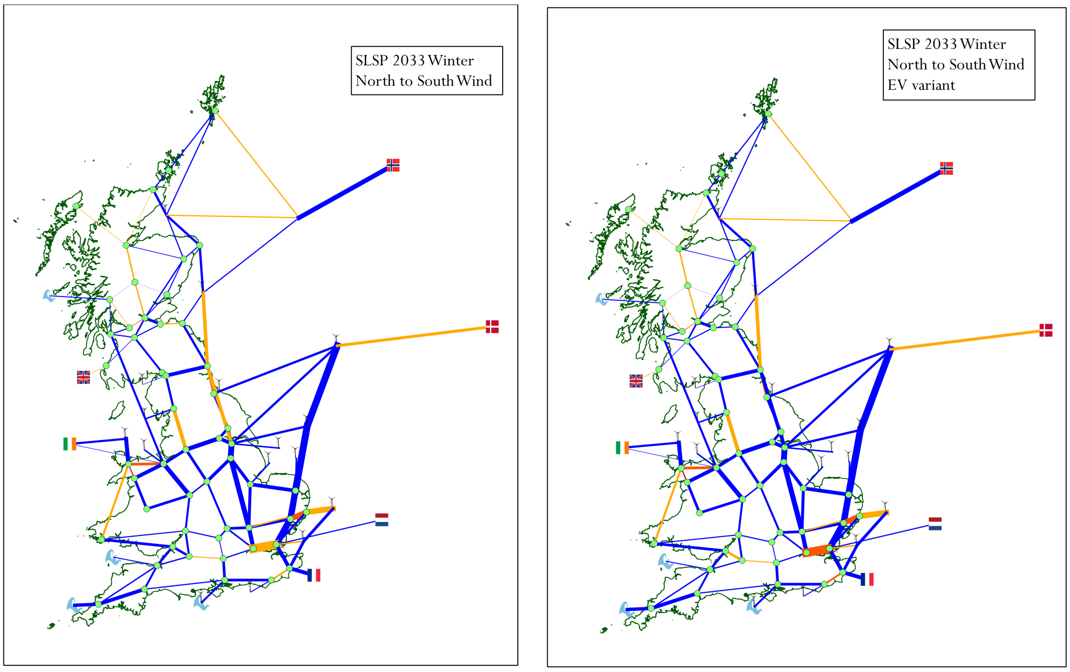


Figure 161: *SLSP Winter North to South Wind power flow, standard and EV variant*

A similar effect is found in SLWP – comparing the winter high wind conditions with and without the added EV charging sees some increased constraints in the north of GB, though maintaining the same broad constraint pattern, and some increased constraints in the south-west and south-east leading into London (***Figure 162***). There is some reduction of constraint on the line north of Teesside.

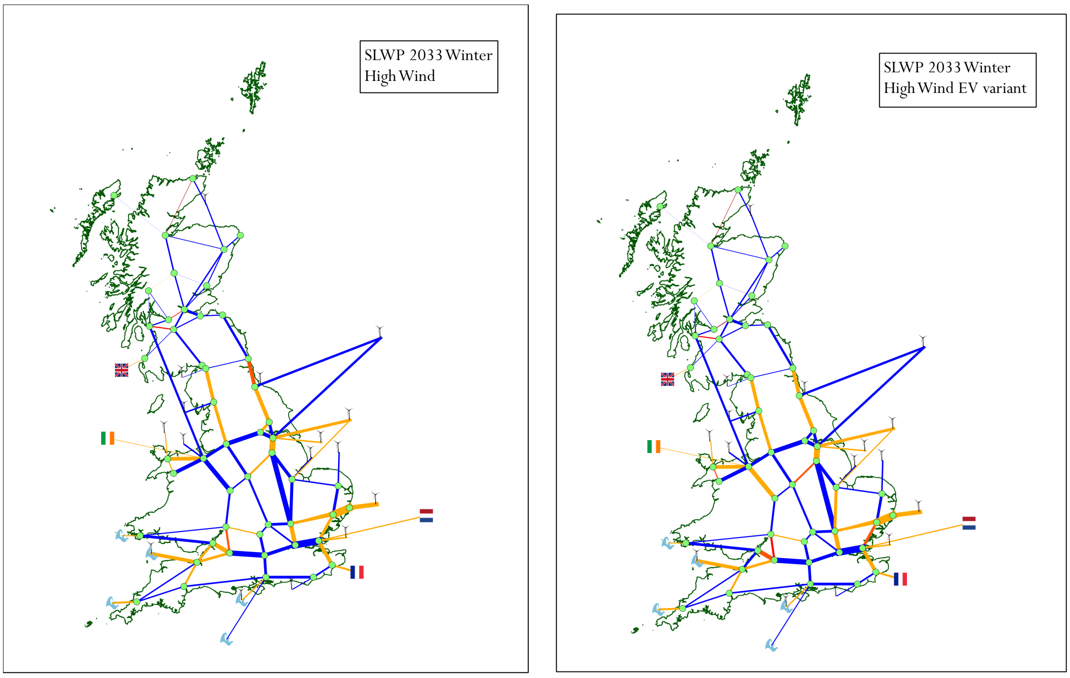


Figure 162: *SLWP Winter High Wind power flow, standard and EV variant*

A greater effect is found in WLSP, with the addition of the increased EV peak causing increased constraints through the network including key north-south export corridors, and in southern and central England as shown in ***Figure 163***. The same type of effect is found in WLWP winter high wind – moderate increases in constraints are found in the areas of the north of GB which were originally already highly constrained, but the noticeable increases in constraints are in the south of England (***Figure 164***).

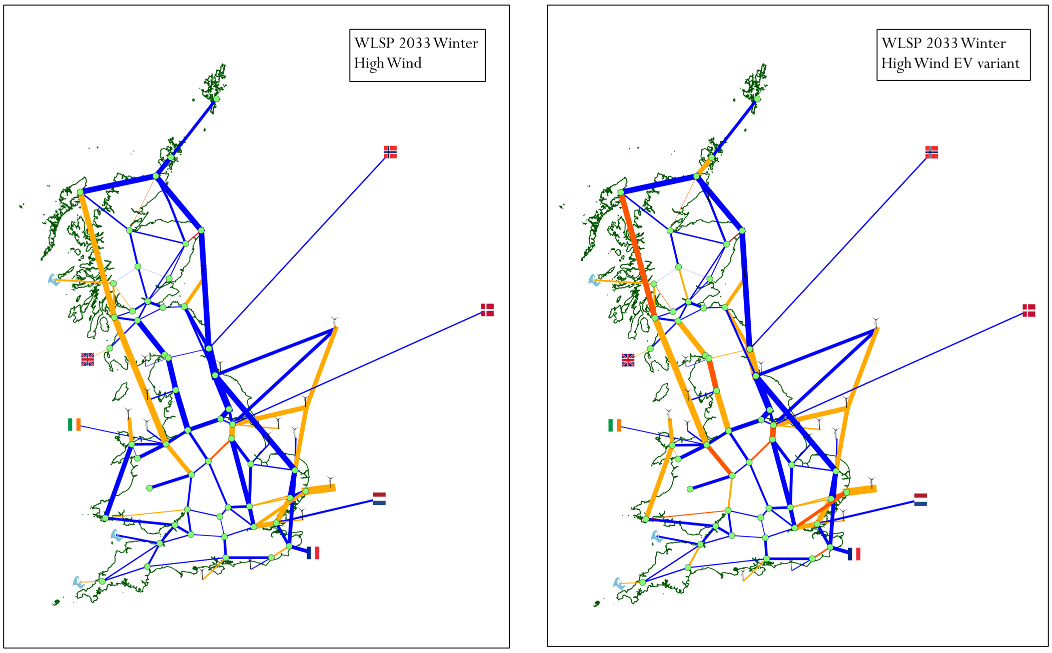


Figure 163: *WLSP 2033 Winter High Wind power flow, standard and EV variant*

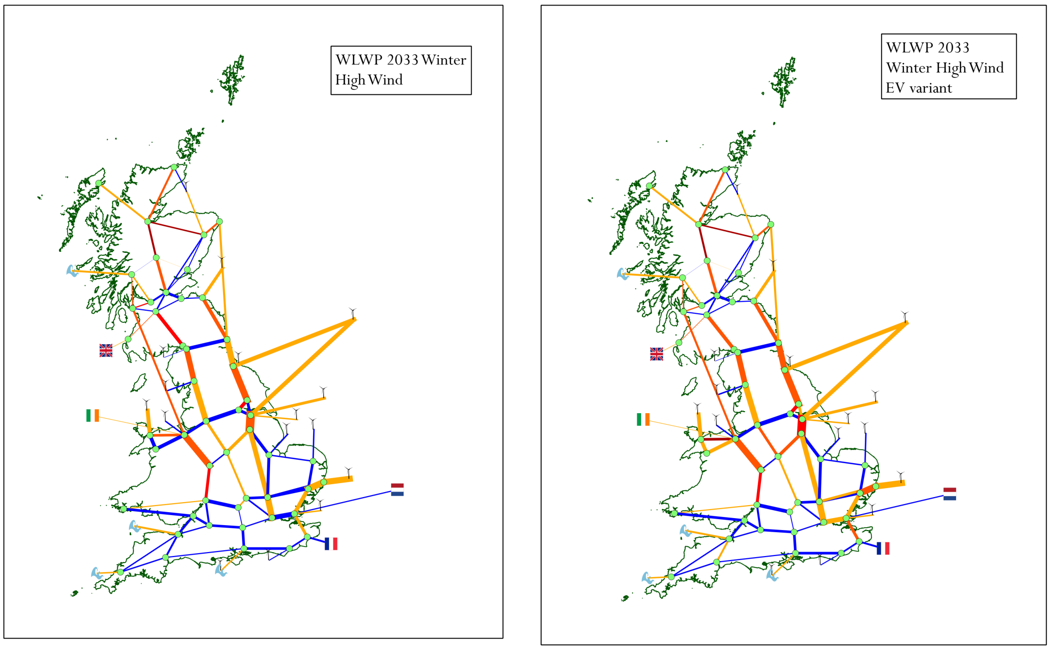


Figure 164: *WLWP 2033 Winter High Wind power flow, standard and EV variant*

Overall the increase in constraints from the added EV peak was more noticeable in the weak location scenarios, as the existing strong north-south power flow in these scenarios is made more acute by the increase in southern demands. Across the scenarios the more noticeable effect of an increased EV peak tends to be in southern areas of the network, where high constraints can occur on previously unconstrained lines. In the north of the network however the impact is more muted (and reduces constraints on certain lines). This different effect of EV charging in different regions can be attributed to the fact that the cost or benefit of added demand on the network depends on other overall network conditions. In most scenarios the conditions see only slight increases in constraints in northern areas because the additional network transfer requirements caused by the overall demand increase is mitigated by the fact that increased demands in exporting areas brings export power flows down and thus reduces constraints. In the south which is in general an importing region the effect of added demand tends to be to increase constraints. The reverse is true in scenarios where there is an overall south-to-north power flow, such as SLWP SN. In this condition the constraints in Scotland are much more noticeably increased by the EV peak – this is due to the fact that in this particular condition Scotland is already an importing zone, and thus the increased EV demand in Scotland exacerbates rather than mitigates this situation ***Figure 165***.

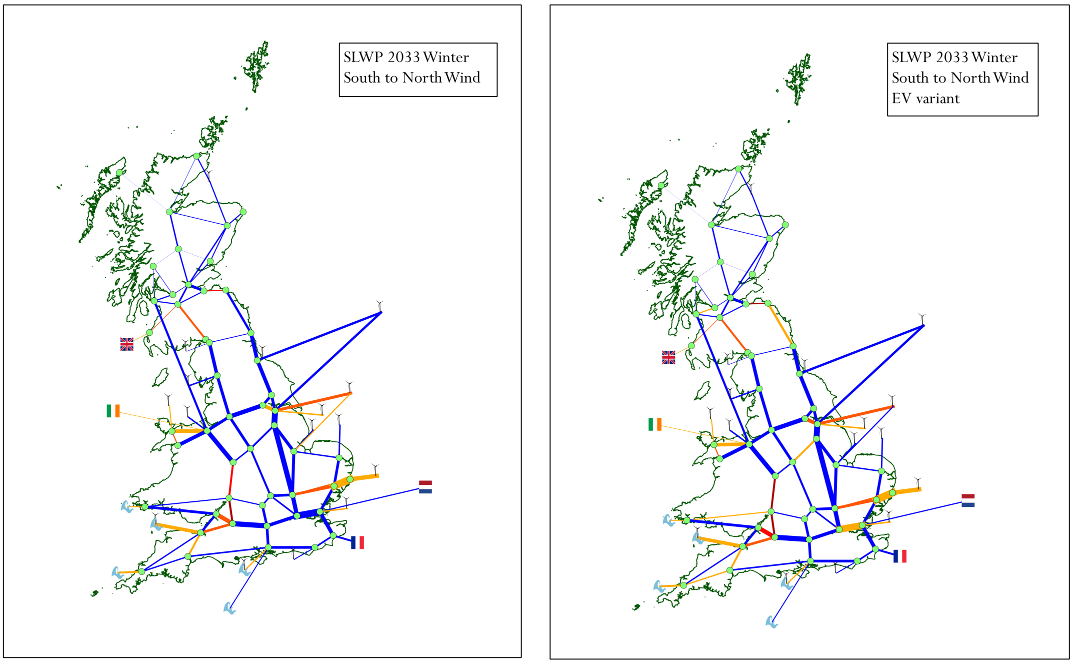


Figure 165: *SLWP 2033 Winter South to North Wind power flow, standard and EV variant*

This being the case, the ability to control and alter demands in different regions in response to network conditions may be of some value. A further sensitivity was applied to the highly constrained WLWP high wind EV condition, which was to increase demand from all nodes north of the Mersey and Humber by 20%, and reduce the demand of all other nodes by 20%. This produces a condition with lower constraints than both the EV condition without demand response, and the original WLWP high wind condition, as the additional northern demand soaks up power and reduces export requirement, whereas the reduced southern demand reduces import requirement (***Figure 166***).

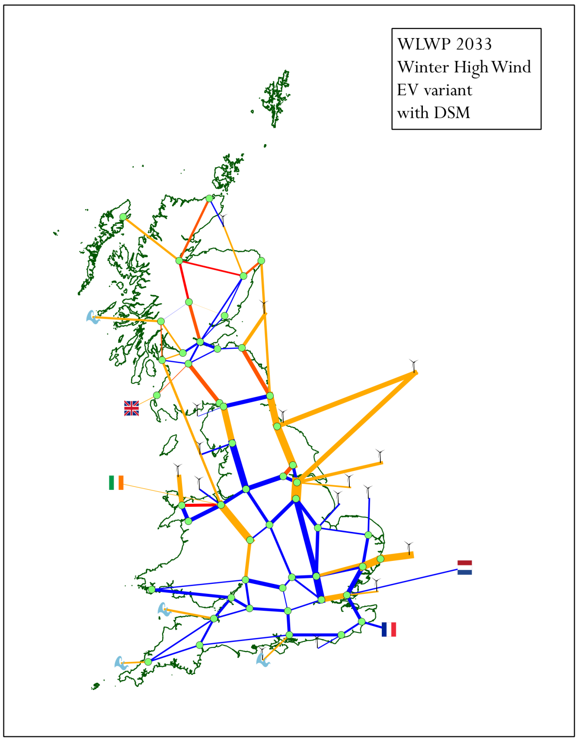


Figure 166: *WLWP 2033 Winter High Wind power flow, EV variant with DSM*

This suggests that the increase in electricity demands from technologies including electric vehicles, as well as potentially increasing stress on the network could also create opportunities if their demand can be influenced in a way that reflects locational network conditions as well as time of use.

8.6.8.2 Grid-scale storage

In order to see the possible effect of storage a sensitivity was run in which the availability factor at dispatch for each renewable technology was set equal to its average annual capacity factor – offshore wind at 40%, tidal at 30%, etc. This represented the smoothing effect of widely applied grid scale storage, absorbing power during high output periods and feeding power back on to the grid during low output periods, achieving an overall smooth output.

The sensitivity considers a technology breakthrough in grid scale storage from the mid 2020s. The alternative storage pathway begins at the 2023 scenario year. The generation investment decisions for the final two time stages are held constant, but with the smoothed load factors applied to the variable renewable technologies. This alters the decision making on required network investment for the final two stages. The comparison of the alternative storage pathway over the final two time stages with the original scenario, suggests the effects that storage could have on required network investment in the final two time stages.

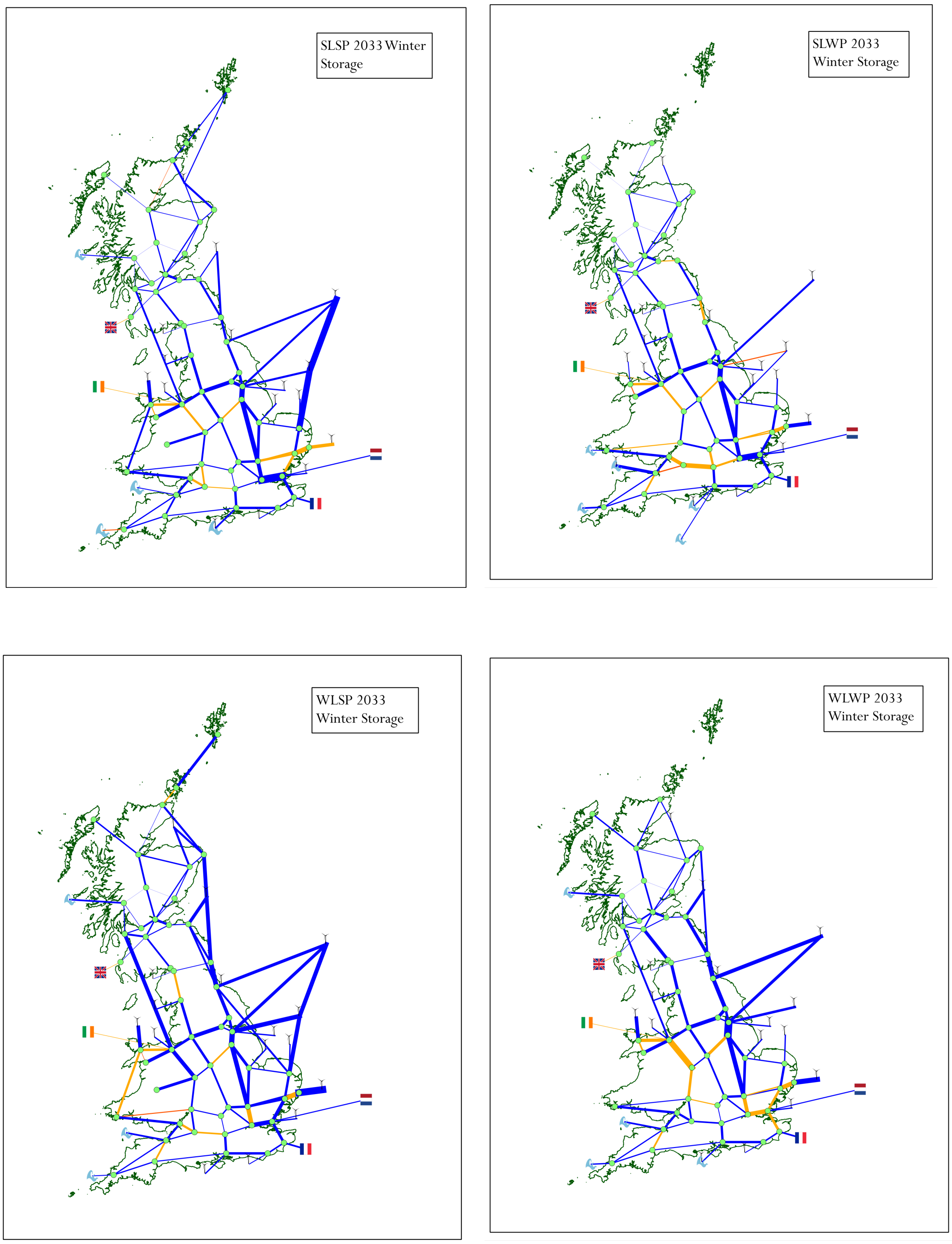


Figure 167: *All scenarios Winter 2033 power flows, storage variants*

Figure 167 compares the 2033 network configurations of the four scenarios, and their power flows at winter peak. A comparison with *Figure 150* shows at a glance some significant reductions in network investments. WLWP also shows a noticeable change from being highly constrained to largely compliant at the winter high wind condition. ***Figure 168*** compares the lengths of network investment in all scenarios with and without storage. The lengths of avoided network upgrades in kms, and quantities of avoided network upgrades in GWkms, are presented in ***Figure 169*** and ***Figure 170*** respectively. The most dramatic savings are made in WLSP, followed by SLSP, both of which avoid significant quantities of offshore HVDC connections – in particular WLSP which has been sized for a peak renewable output considerably higher than the average output. In SLSP interconnectors meshed into offshore grids are an important means of smoothing renewable output. However the smoothing assumed from grid-scale storage from 2023 onwards reduces the case for interconnection in this scenario variant. Reductions in SLWP are less dramatic due to the lower quantities of renewables in this scenario, and the way in which they are spread around the system, which avoided the network having to deal with major exporting regions. Due to the significant reduction in peak flows in WLWP, the size of required network upgrades is reduced which means that more of them can be addressed through line uprates, rather than new lines. As shown in ***Figure 169*** this actually results in a slight increase in the length of lines uprated in the storage variant compared to the original scenario, but with clear benefits in terms of avoided new onshore lines.

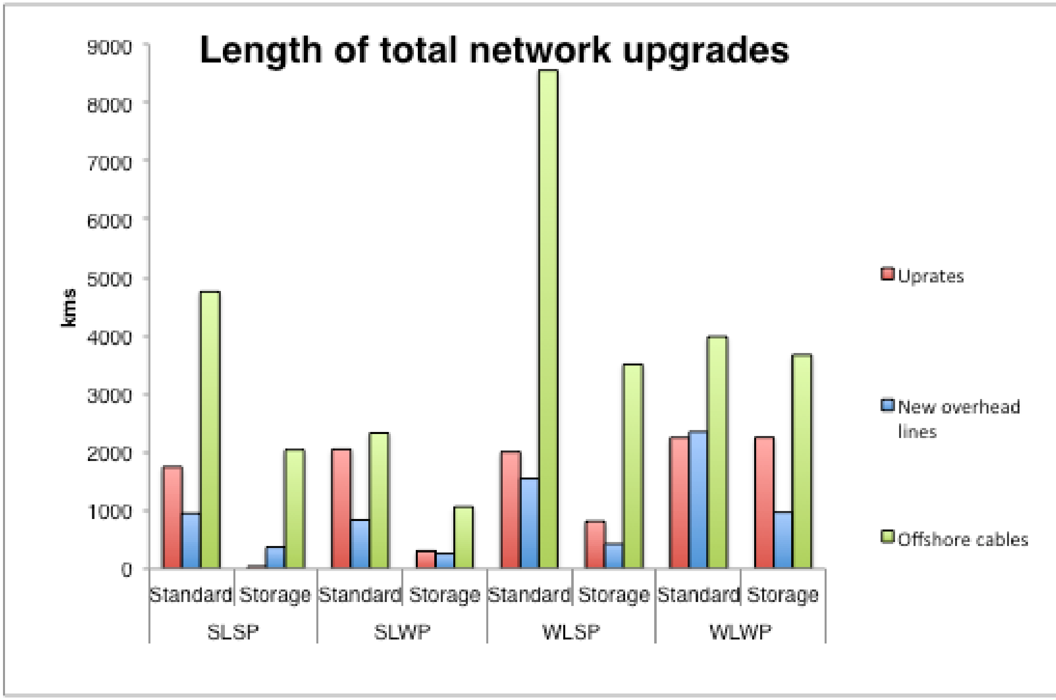


Figure 168: *Length of total network upgrades in all scenarios, standard and storage variants*

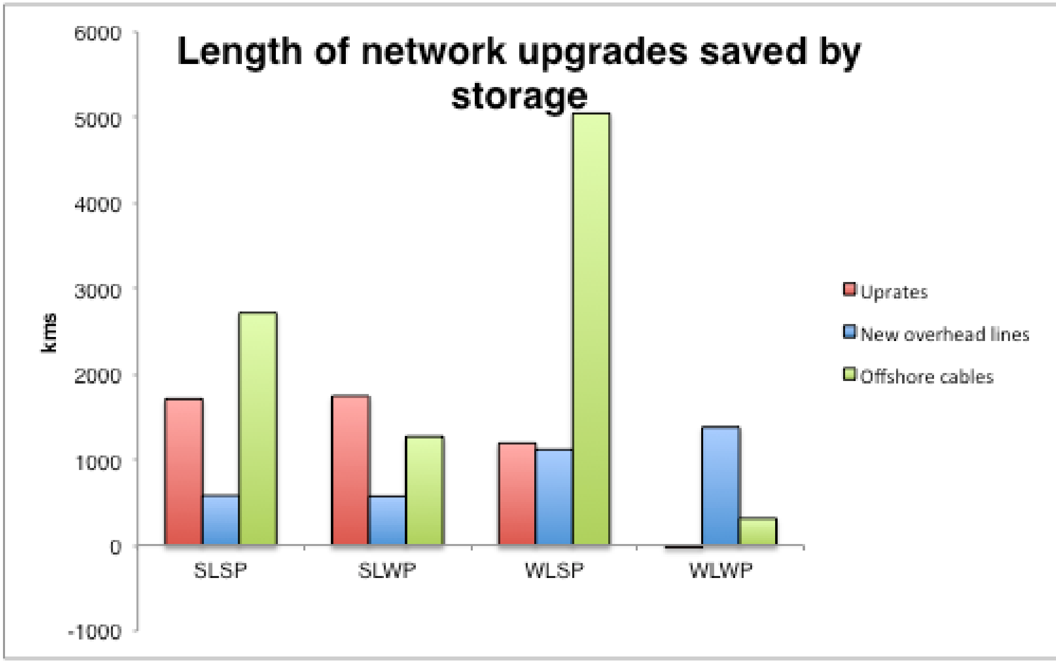


Figure 169: *Length of network upgrades saved by storage*

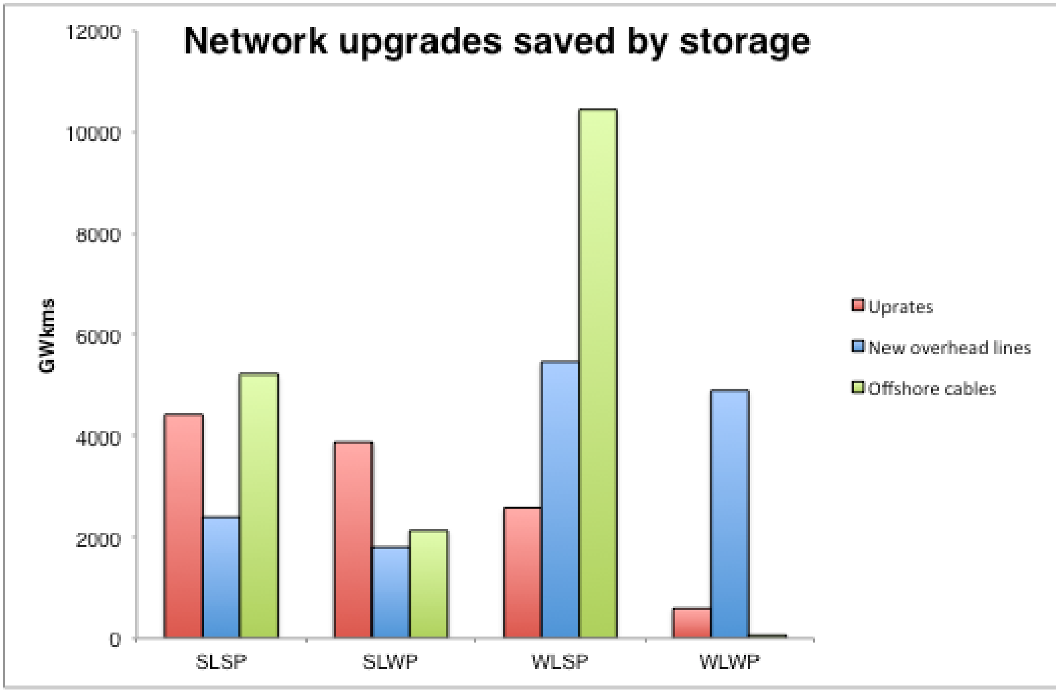


Figure 170: *Quantity of network upgrades saved by storage*

Large grid-scale storage could therefore address one of the major drivers behind the very significant expansions in network capacity which occur across the scenarios. The high estimated costs associated with these expansions shown in ***Table 33*** suggest that there may be significant value to the system of the development of grid-scale storage, in terms of avoided network investment. If the operation of storage could be influenced by locational network constraints, as well as by the overall system supply-demand balance, it could have a critical effect in delaying or avoiding the need for expensive transmission system upgrades.

8.6.8.3 Solar PV

The future level of deployment of solar PV is another factor which was beyond the scope of the study to include as an internal system variable, but which could nonetheless have significant impacts on power flows at the transmission level. Large-scale ground mounted PV installations of sufficient size to connect directly to the transmission network are conceivable. However, distribution connected PV could also have impacts on transmission flows by reducing the demand at the nearest transmission entry point, or if installed in large numbers by actually causing power to flow up voltage levels from the distribution network to cause an export on to the transmission network. There are numerous technical challenges associated with these different possibilities. However, for the purposes of this study, which uses a nodal model of the transmission network, each has the same effect – an increase or decrease in the net load or generation at a node, has the same effect in the load flow whether it is thought of as being caused by an increase in transmission connected generation, a spill over of distribution connected generation onto the transmission network, or a reduction in load at the transmission entry node.

The modelling approach selected was to add solar PV as a technology category at the top of the merit order. Installed capacities were added to reflect an even scaling up of the current distribution of all large and small scale PV units. There is currently a clear pattern in PV installations with a concentration band stretching from south-west England to East Anglia. This distribution is maintained and the locational installed capacities scaled up by the same factor to deliver an overall increase from today's levels of 2.8 GW to 10 GW by 2033. ***Figure 171*** compares the regional distribution of current PV with the 2033 scenario assumptions.

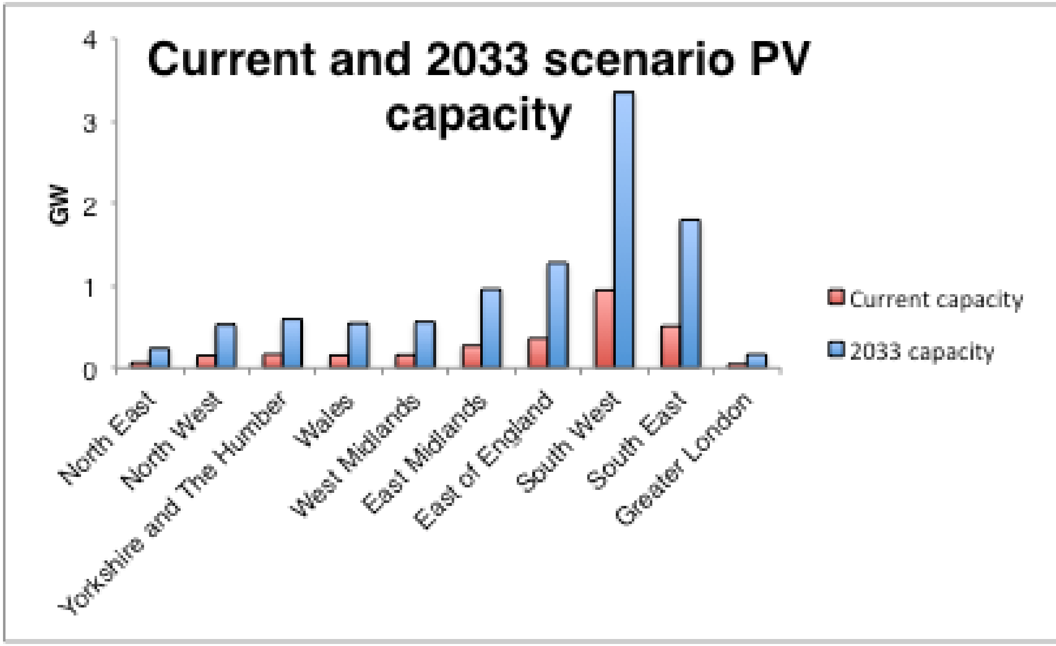


Figure 171: *Current and 2033 scenario PV installed capacity by region. Current figures from Westacott (2014)*

The regional distributions of PV capacity under the 2033 assumptions were shared equally amongst all nodes within that region. The scenarios were run for the summer condition – 12-1 pm in July / August – with a simplified assumption of all units operating at 100% load factor. Evidently the winter peak condition of 5-6 pm in December / January would receive no contribution from solar PV.

In the SLSP conditions the effect of the added solar PV is generally to create a slight shift in the locations of constraints, though without significantly altering the overall pattern and overall levels of constraint. The comparison of SLSP summer high wind with and without the solar PV additions demonstrates this – the occurrences of constraints shift on to different lines, with a slight shift of southerly constraints from the south-east to the south-west (***Figure 172***).

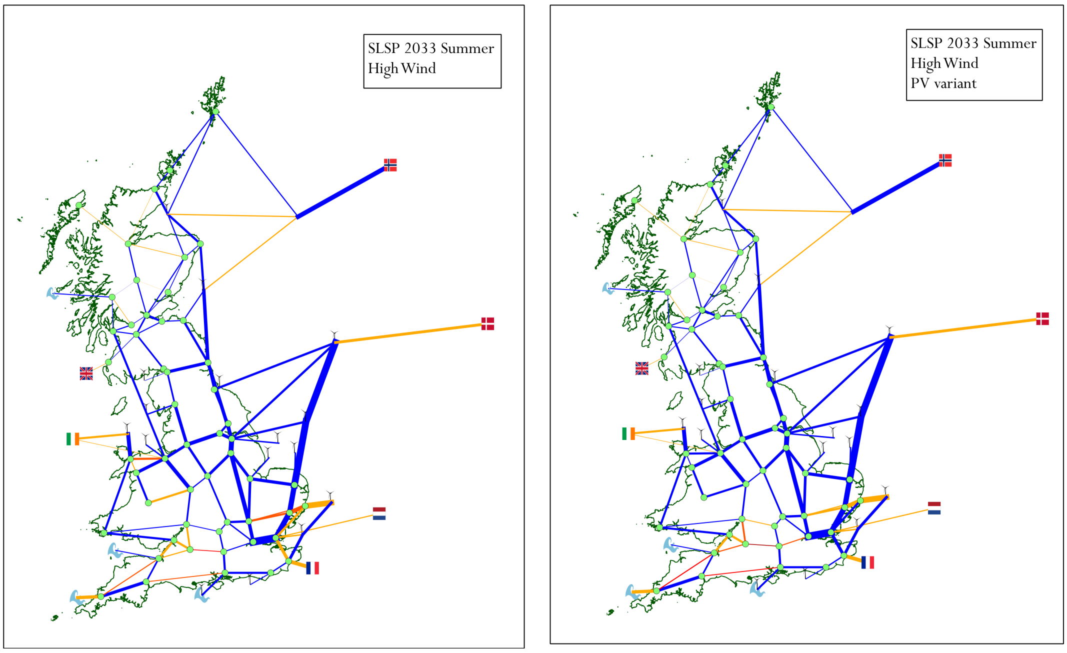


Figure 172: *SLSP 2033 Summer High Wind power flow, standard and PV variant*

In SLWP the effects of the added solar PV are more noticeable. Southern constraints are tangibly increased, particularly on corridors between the south west, with its high concentration of solar, and London, as can be seen from comparing the summer high wind conditions with and without solar (***Figure 173***). In the NS condition on the other hand, the addition of solar noticeably reduces constraints by balancing out the north-south gradient (***Figure 174***).

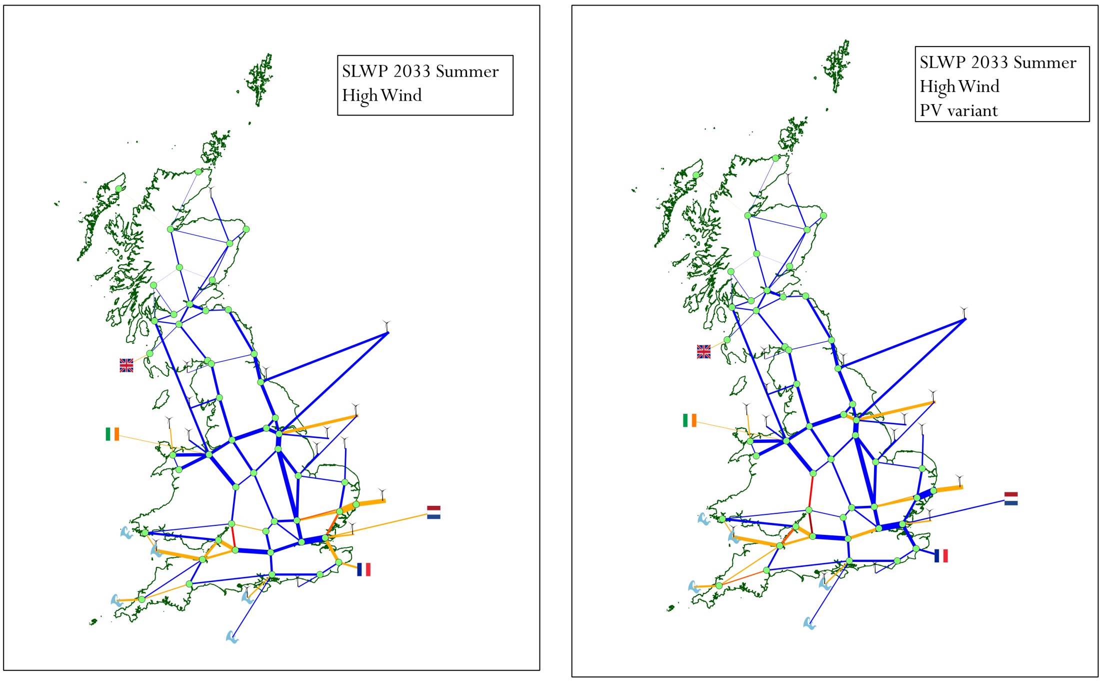


Figure 173: *SLWP 2033 Summer High Wind power flow, standard and PV variant*

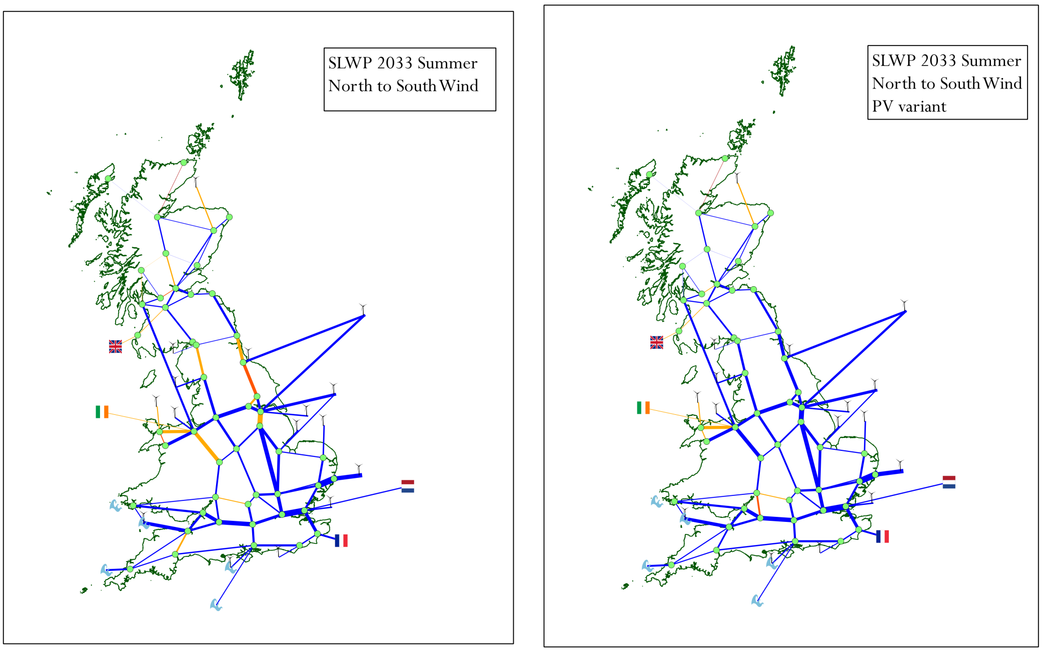


Figure 174: *SLWP 2033 Summer North to South power flow, standard and PV variant*

In WLSP the effect of adding PV in the summer condition tends to be positive as it reduces the north-south power flow and thus reduces north-south export constraints. This is particularly noticeable on the NS condition.

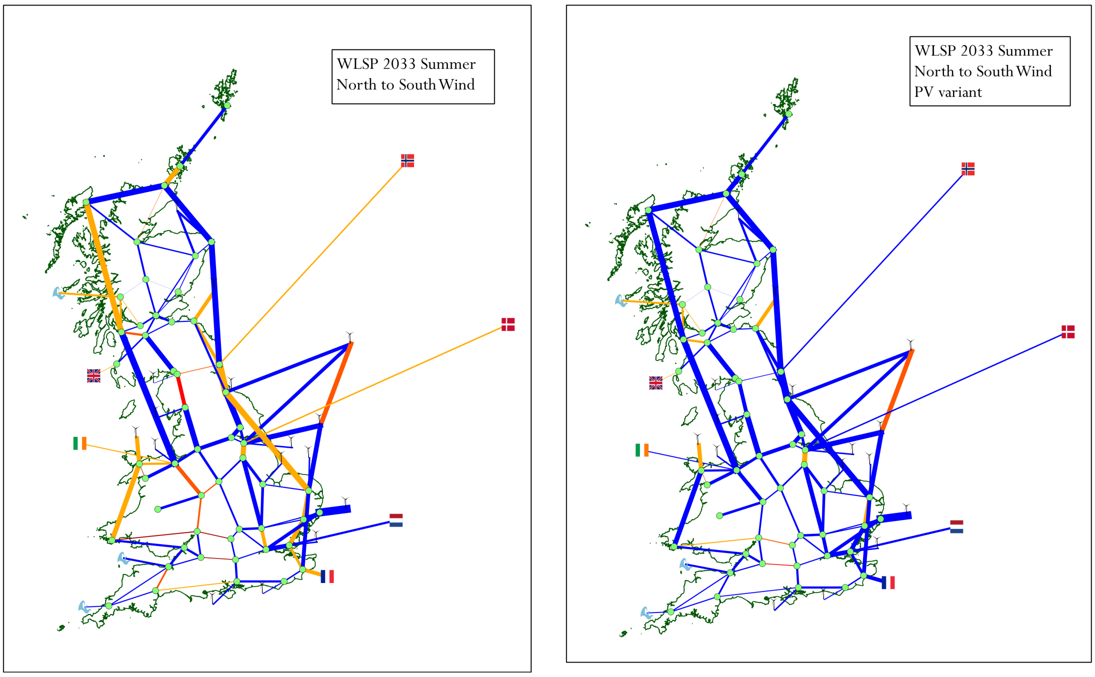
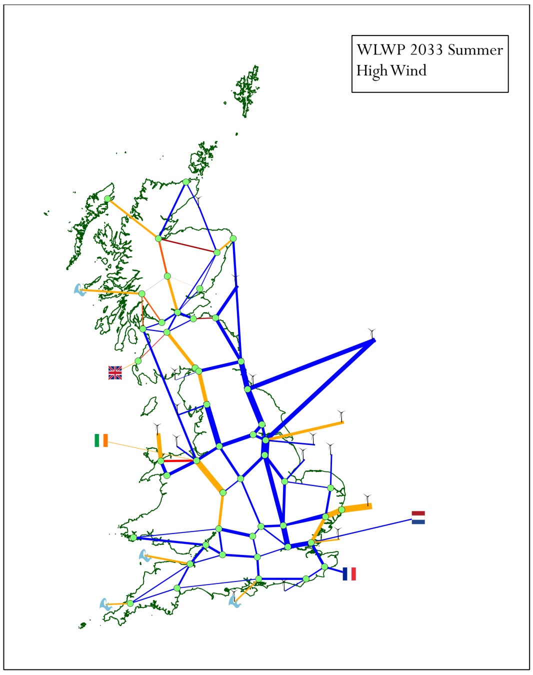


Figure 175: *WLSP 2033 Summer North to South Wind power flow, standard and PV variant*

A similar positive effect is found in the WLWP summer high wind condition. This scenario has a strong north-south power flow from renewables investments, but a much lower capacity network than WLSP. The original high wind condition sees high constraints in Scotland and northern England. The addition of solar very significantly reduces the overload on north-south corridors by reducing the demand in the south. In other conditions in this scenario a similar, although less dramatic effect can be seen.



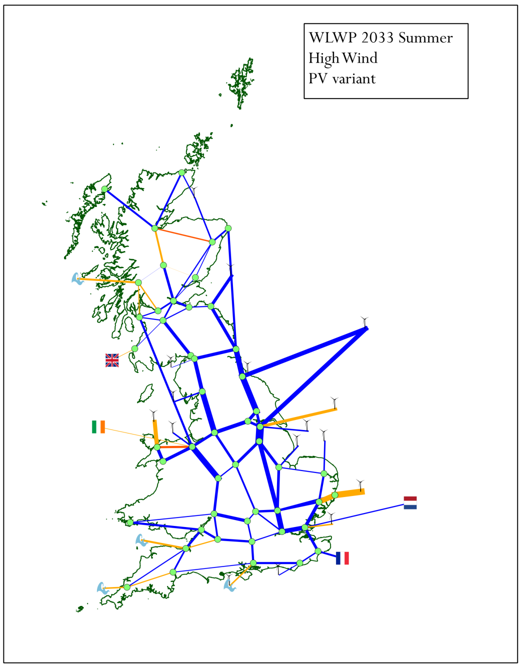


Figure 176: *WLWP 2033 Summer High Wind power flow, standard and PV variant*

In general the runs show the potential benefit, from the transmission network perspective, of complementary sitings of renewables. In scenarios where the generation mix has already been spread in response to locational signals, the benefits are in general reduced and constraints increased as a result of adding PV in southern areas, because there is already comparatively high infeed onto these areas. Exceptions may be found in the NS conditions of these scenarios (***Figure** 174*). However, the weak location scenarios have a strong northern renewable concentration and thus a more consistently strong north to south power flow. The addition of solar – predominantly in the south under the assumptions of this variant – is largely quite beneficial in such scenarios as it reduces this north-south export flow by suppressing southern demand.

An additional question raised by all of these scenarios however relates to the flexibility of nuclear. In several of these low demand summer conditions, with the addition of solar PV, the penetration of renewables is such that the required nuclear output in some wind conditions is reduced to very low levels, whilst still being required in substantial quantities in other conditions. It would be more manageable if a low output for nuclear could consistently be expected at certain times of year, so that plant could be scheduled in advance. However, strong variation in nuclear requirement occurs in relation to different wind conditions which – as shown by the MET Office data used to generate the conditions – could occur at the same time of year. In all of the summer peak conditions modelled, there are major variations. SLSP with solar sees a swing between 13% and 49% capacity output required from nuclear plants between the high to low wind condition. SLWP with solar, despite its lower renewable content sees nuclear output swing from 25% to 100%

between high and low wind conditions; in WLSP with solar, nuclear requirements swing from zero to 86%; and in WLWP with solar from zero to 100%.

8.6.8.4 Public acceptability of future systems

It was beyond the scope of the scenarios to include public attitudes towards generation technologies as internal variables within the scenarios – for example assuming that in some scenarios public attitudes were more tolerant towards certain technologies or infrastructures than others. However, taking the overview of the scenarios presented in the preceding sections it is possible to consider implications and trade-offs which are of relevance to the public acceptability of the overall transition.

Nuclear is a technology which remains perennially controversial (Corner et al., 2011, Poortinga et al., 2013). In this context, a noticeable feature of the scenarios is that they all deploy nuclear in significant quantities, though with a large range between the highest and lowest deployment level. The requirement for nuclear in all scenarios arises from the boundaries set by the scenario assumptions for maximum deployment levels of other key technologies – for example offshore wind, the outer boundary for which is guided by the projected capacities of the Round 3 sites. Further exploration of sites for fixed turbines, or the development of floating turbines could dramatically increase the outer potential of offshore wind. Equally the inclusion of CCS and large scale biomass to electricity generation could have contributed to a no-nuclear scenario – however these technologies were excluded due to remaining technological and supply chain uncertainties. Thus, an outcome of the analysis is the proposition that under reasonable assumptions limited to existing demonstrated technologies, a scenario which meets the required carbon targets must include some nuclear. Scenarios which met the target without nuclear could be developed, but the level of technological uncertainty involved in the assumptions about the remaining generation technologies would be significantly increased.

All of the scenarios involve significant network upgrades, with estimated investment costs that would represent a non-negligible part of the overall costs of a low-carbon transition. New transmission lines can cause controversy, especially in environmentally sensitive areas (Devine-Wright et al., 2010). The scenarios suggest that both the costs and the visual impact of new transmission network upgrades could become major issues in the public debate around the low carbon transition. If it is considered an important priority to minimise transmission investment, a strong locational signal combined with a responsive approach to network investment is capable of delivering a system which successfully meets the target with comparatively low network investments (although in the real world with the absence of counter-factuals, the SLWP investment programme would still likely be perceived as quite substantial). However, the trade-off of this approach is the reduction in investment in onshore wind and northern offshore wind, and the increased investment in nuclear and tidal barrage, each of which may entail controversies (Corner et al., 2011, Poortinga et al., 2013, Devine-Wright, 2011). In SLWP, nuclear in particular is deployed with 3.2 GW stations at each of the 8 potential locations listed by DECC.

The strong planning scenarios SLSP and WLSP deliver substantial additional network capacity through offshore meshed networks and bootstraps, which as well as linking offshore renewables provide additional transit capacity for power flows across the system. This reduces the visual impact of new onshore lines and pylons, but at a substantially increased cost – investment costs for HVDC subsea cable are estimated to be close to ten times the cost of a standard transmission line upgrade (Appendix F). Both visual impact of transmission lines and costs of network upgrades as translated onto consumer bills are areas of potentially significant public controversy, and attempt to reduce one may have the effect of increasing the other. Survey work by Devine-Wright et al (2010) appeared to uncover a public preference for putting transmission lines 'out of sight', regardless of the cost. However, as explored by Hobman and Frederiks (2014) there may be a gap between expressed attitudes and actual willingness to pay in the context of low carbon energy systems. The scenarios SLSP and WLSP also build high levels of on and offshore wind, technologies which also have issues with public acceptance (Haggett, 2011, O'Keeffe and Haggett, 2012, Jones and Eiser, 2009).

Equally, the cost implications of high constraint levels could become highly controversial, particularly if understood through media commentary and public and political debate in terms of renewable generators being paid large sums not to produce energy (Mendick, 2015). The constraint levels that emerge from WLWP – where there is no locational signal and no anticipatory investment – imply levels of constraint costs which may not be politically and publically feasible to maintain. Such a scenario would likely either be forced to change its value system – to adopt locational signals, or a more anticipatory transmission investment programme – or to abandon the low carbon trajectory. Alternatively it could be rescued by a technological breakthrough that resolves the deadlock, for example grid-scale storage, as explored in Section 8.6.8.2.

There are clearly challenging issues involving public acceptance for any kind of large infrastructure programme, and new transmission investment is no different. More subtly however, transmission infrastructures are closely bound up with developments on the generation side. Parkhill et al (2013) have explored public acceptance of whole energy systems, considering supply and demand issues. A logical next step for this kind of whole-system public engagement research is to include the costs and benefits of transmission infrastructure, and its trade-offs against electricity generation technology preferences, within the discussion.

8.7 Post 2033

Though all scenarios have reached the 50g/kWh target, there remain considerable ongoing challenges. Notably, if the electrification of passenger vehicle transport was to continue, and at the same time the carbon intensity of power generation was to be maintained at close to 50g/kWh, this would require maintaining a strong pace of investment in low carbon generation, and corresponding transmission investments. The demand assumptions developed for the scenarios see overall demand rising from 376 TWh in 2013 to 399 TWh in 2033 – an increase of only 6%, as modest demand increases in demand electric heat and vehicles are largely offset by efficiency improvements in appliances and other end use technologies. As previously noted, electric vehicles are only adding 1 GW to winter peak demand in 2033, under the spread charging assumptions which are used in the standard scenarios. The post 2033 trajectory sees a take-off in electric vehicles as passenger transport is electrified. Along with increasing demands in other sectors, the electrification of passenger transport contributes to a 45% increase in overall electricity demand, from 399 TWh in 2033 to 578 TWh in 2048. Under the same spread-charging assumptions used in the standard scenarios, this increase adds 9.8 GW at winter peak. If each of the scenarios from 2033 was to maintain a carbon intensity of 50g/kWh with this level of increased demand, they would require investments equivalent to 21 GW of nuclear, or 44 GW of offshore wind. The prospect of this additional level of investment beyond 2033 would present challenges in each of the scenarios. Thus in the longer term the level of demand that may be expected from electric vehicles is a question with significant implications for network planning.

8.8 Conclusions

Using a three-level system representation consisting of policy value-sets, actor networks and technological configurations, four contrasting scenarios were created which explored the iterative effects of transmission and generation investments within different policy contexts. The structure of the scenario process differentiated actor-contingent elements, which are potentially within the control of 'prime-mover' system actors, from non-actor-contingent elements, which are less controllable. This structure is useful for differentiating between proactive, protective and consensus building policy-related insights which emerge from the scenarios. In the following chapter, the scenarios will be compared, analysed, and policy recommendations drawn.

9 Implications and analysis

This chapter discusses implications from the scenario and sensitivity analysis reported in Chapter 8. The first section briefly summarises the high level implications from undertaking low carbon transmission network scenarios, drawing insights from the process as a whole and high level comparisons between the scenarios. The second section analyses in more detail specific challenges thrown up by the scenarios, and what these might suggest about potential challenges in the real system. The third section draws on both of these sections in order to consider the policy options available to policy makers with respect to the system under study.

9.1 High level implications – the role of transmission networks in a decarbonising electricity system

An important high-level conclusion from the scenarios is that there is an important role for transmission networks in a decarbonising electricity system. The scenarios explore alternative pathways towards the same decarbonisation target, through different combinations of low carbon generation technologies, and within different transmission network policy regimes. In each of the scenarios a significant expansion of the transmission network architecture takes place, over and above the like-for-like renewal of existing assets. The scenarios suggest that it is not possible to fit a sufficiently low carbon generation mix into the existing network infrastructure design, due to the lack of correlation between the potential locations and capacity sizes of new low carbon technologies, with those of the existing generation mix. Without new investment, therefore, transmission network capacity will be a significant barrier to decarbonisation. This makes the requirement for careful attention to design and investment in new transmission architectures of some kind, a strong conclusion from the scenarios.

However, the scenarios also show considerable differences in the levels and locations of new transmission investment required – there is more than one possible network configuration and associated generation mix which would succeed in delivering the target of 50g/kWh carbon intensity of electricity by around 2030. The scenarios indicate contrasting possible trajectories for the coevolution of the electricity generation and transmission system, and the final design of the transmission networks in each case reflects this co-evolutionary development of the generation and transmission mix through the scenario period. This means that the appropriate network design is strongly interrelated with investment decisions on the generation side, and the complete adherence to a single blueprint of the future transmission network based on particular assumptions around generation investments, would risk some level of redundancy or inadequacy if for any number of reasons a different generation mix emerged.

Thus transmission network planning requires both a forward looking approach, and flexibility. A lack of forward thinking in relation to the evolution of transmission and generation investment creates a risk that insufficient or inappropriate transmission investment becomes a barrier to the successful decarbonisation of the system. However, as there is not one single network design which will be optimal for any and all generation mixes, flexibility is also a key requirement to allow generation and transmission to co-evolve in a coherent manner.

9.2 Challenges

The scenarios highlight different challenges for transmission network planning and operation. This section highlights the main challenges, comparing across scenarios for the different ways they emerge and the different levels of robustness each scenario has to them.

9.2.1 Generation location and network utilisation – investment time scale

The current configuration of the transmission network reflects its historic development, notably with strategic decisions taken to improve connection between areas with high generation output, such as the coalfields of northern England, with high load centres such as London. Political decisions, such as the separation of the southern Scotland area from the England and Wales system, have also had their impact. Historically, the network was developed on a 'generation-led' basis, designed primarily to accommodate the output of coal stations. If the network were being designed from scratch at the present time with the next forty years in mind, it would undoubtedly take a somewhat different shape to the one which we have inherited. There is a certain logic to the proposition therefore that if previous generations planned their transmission network according to the requirements of their anticipated supply portfolio, we should do the same and plan the network to meet the generation mix of tomorrow, not accept the design of yesterday.

Conversely however, there is an argument that the reality of the physical infrastructures that exist cannot be wished away and it makes sense to make best use of these wherever possible, before expanding the network. Further the sheer distance of some of the potential sources of renewable energy do present serious challenges in terms of the amount of network investment that would be required to connect them to load centres.

The policy approaches followed in the different scenarios create different conditions that affect how this challenge is experienced. The weak location scenarios do not provide locational network signals, with the result that renewable generators are strongly incentivised to locate in the north of GB where the greater renewable resources are located. This creates a strong location bias of generation in the north of GB, resulting in a large north-south power flow in typical conditions, in particular in high wind or high northern wind conditions (e.g. ***Figure 108***, ***Figure 110*** and ***Figure 143***). The network configuration of WLSP indicates the requirements in network terms of meeting the peak output of this kind of generation mix. WLWP has a more responsive network investment approach, accepting interim congestion costs. Its winter high wind power flow however indicates the high level of congestion that could ensue in certain wind conditions, from not building to meet peak output (***Figure 150***).

The strong location scenarios provide locational signals to generators, which encourage a more spread generation mix around the network. This results in a dramatic decrease in required network investment compared to WLSP. As shown in ***Figure 156*** SLWP's total network investment amounts to 11,138 GWkm, a little more than a third of that required in WLSP (29,692 GWkm). SLSP takes a more strategic approach to facilitating deployment of northern renewables. This increases its network investment levels in relation to SLWP (*Figure 156*), but at 17,830 it is still only slightly over half of that required in WLSP – a notable saving given that its total deployment of renewables is only slightly behind that of WLSP (*Figure 154*). In SLWP then the reduced network investment is primarily achieved by spreading the generation mix around the network and thus avoiding major export requirements from particularly high generation zones to load centres. In SLSP the same effect on locational investment occurs, but greater penetration of renewables than in SLWP is enabled largely due to the greater development of interconnectors, and the fact that their location as well as operational characteristics are affected by locational network signals. Thus there are two important kinds of locational signal. The first effect takes place at the investment timeframe, assisting with a general spread of projects around the network avoiding severe generation-supply gradients in terms of installed capacity. The second effect takes place at the operational timeframe, and concerns the responsiveness of technologies to variation in network availability as a result of the dispatch. In conventional systems accounting for the first effect largely covers the operational timeframe too, due to the similar operational characteristics of conventional plant. In a high-renewable system however, operational characteristics become a significant additional variable which incentives targeted at the investment time frame can only partially address.

9.2.2 Build rates, lead times and pathway issues – managing the transition

As discussed above, network investment strategies are highly interrelated with generation investment strategies. However, the question of how anticipatory or responsive the network strategy is, in relation to existing and possible future generation investments, affects what kind of network will be built.

An important factor in relation to the coordination of generation and transmission investments is the relative size and lead-times of the investments. Nuclear power stations are high capacity and have long development lead times. As such these can be anticipated by transmission. Renewable projects are generally considerably smaller and more numerous, owned by a number of different companies. They can in some cases proceed from planning to commissioning more quickly than transmission line projects can be planned and built. This makes it harder for transmission to build in step with renewable deployment – it must either attempt to anticipate the trajectory of renewable deployment, or respond to it on a lagging curve. The latter approach is broadly the one currently favoured by the connect and manage regime. There is much to be said for this approach in that it hedges the risk of which specific projects will actually come through, and builds out when there is greater certainty, accepting some small constraint costs. The hedging strategy of connect and manage, followed by responsive transmission investment, has been appropriate to the historical rates of project completion compared to the number of projects that sought connections particularly in the pre-BETTA rush in 2005. However, challenges to this approach may emerge from the early 2020s on. If carbon budgets are to be met, the deployment rates of renewables during this period must increase dramatically by historical standards, as shown by the deployment rates of renewables in the four scenarios, illustrated in ***Figure 177***.

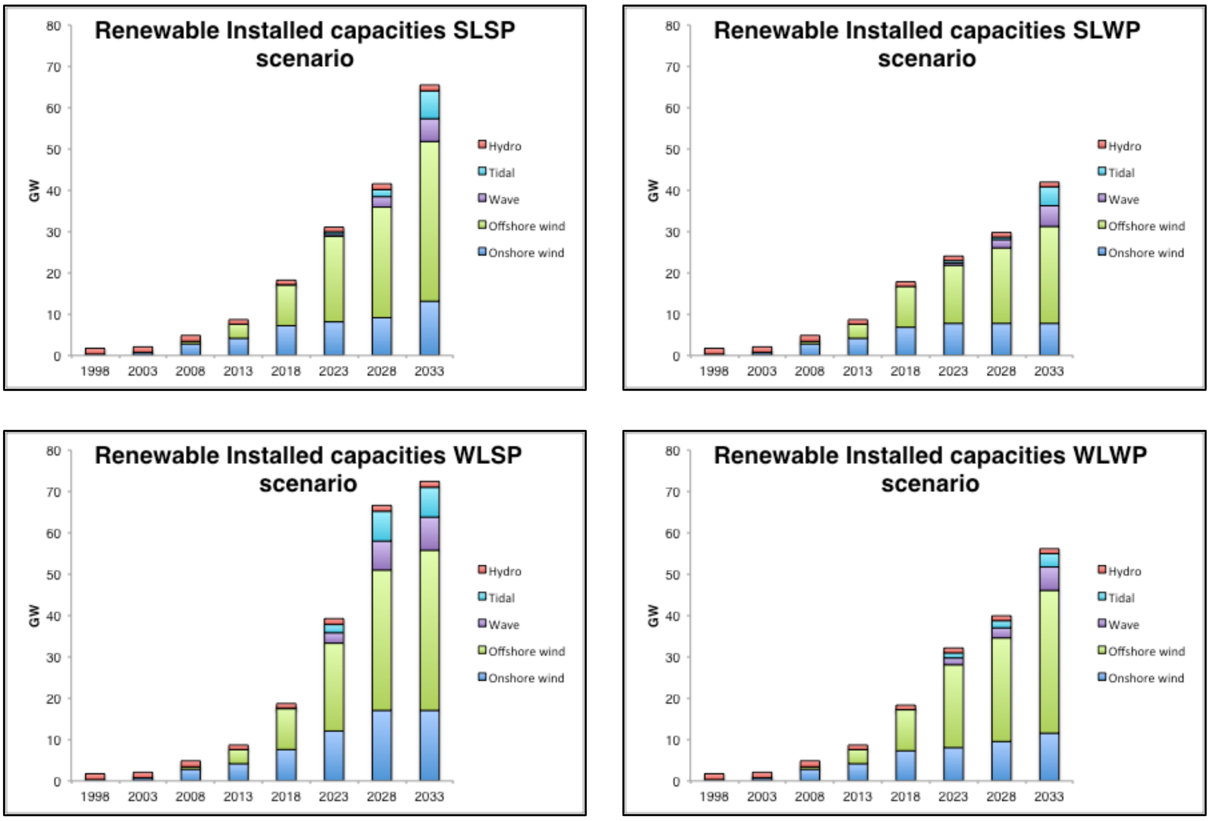


Figure 177: *Installed capacities of non-thermal renewables. Historic data (1998-2008) from DUKES Table 6.4 (DECC, 2013a). 2013-2033 data from scenarios.*

The deployment rates for renewables appear steep by historic standards in all scenarios, particularly in SLSP and SLWP in the mid- to late-2020s. The most moderate deployment rate is found in SLWP which leads to the lowest renewable capacity of the scenarios, in combination with the highest nuclear capacity. Chapter 8 discussed in detail the network upgrades which occur in tandem with these generation deployments. SLSP and SLWP each follow an anticipatory approach with bold network investments including deployment of HVDC offshore links, in order to reduce constraints. WLWP does not keep pace with renewable deployment and as such experiences high constraints throughout the scenario period.

The decarbonisation trajectory recommended by the CCC implies very significant generation investments through the 2020s. The scenarios make clear that these will need to be coordinated with significant network investments, which must be timely if they are not to delay achieving that target. At the same time this must be balanced against the risk of making transmission investments which turn out to be surplus to requirements due to different generation outturns.

At the time of writing the near-term network challenges are focussed on bringing the Cheviot boundary into compliance. All scenarios show that the currently planned network upgrades listed in ***Table 8*** will broadly deliver this compliance. However, all scenarios also indicate that in the medium term of 2018-2023 the follow on from this will be increased constraints in the north and midlands of England, when power flowing south from Scotland in high wind conditions meets the still high output from coal and gas generation in the north of England. This could present a transitional challenge as to whether to invest further to bypass these constraints, or wait for this plant to retire during the 2020s.

The mid-2020s presents a significant branching point in terms of potential major renewal of the generation mix. In particular, there could be a significant number of retirements clustered around the mid- to late-2020s, as existing fossil plant, many of which were built during the 'dash for gas' in the 1990s, reach retirement age, at the same time as the IED could force the closure of coal and other non-compliant fossil plant, and all but one of the currently existing nuclear stations reach the end of their scheduled operational lives.

At this period in the transition it is unlikely that a fully functioning low carbon generation mix will be established, meaning that there will be a very strong impetus for the commissioning of new fossil plant. At this point, new gas plant would contribute to reducing emissions if it displaced coal, and in all scenarios in this medium term period a significant amount of the decarbonisation is done by the switch from coal to gas in the generation mix. The continuing commissioning of new gas plant into the mid-2020s then does appear to be likely under reasonable expectations of progress in renewable deployment up to that point. There are a number of risks associated with this prospect. A key risk is that if these new gas plants are commissioned under a regime which gives them the expectation of running in the long term as baseload and without incentives for flexible operation, this could create a carbon lock-in for the electricity system. However, it should also be noted that each of the scenarios maintains substantial capacities of fossil plant on the system by 2033, ranging from 30 to 40 GW. This is due to the requirement of all scenarios in all years to achieve at minimum a positive de-rated capacity margin, using Ofgem's derating factors. In a decarbonised mix it seems likely that these plant would still be required, but would be operated on an increasingly intermittent basis. Thus, approaching the 2020s it will be important to provide the correct incentives to encourage these plant to be built, but if their commissioning is to be compatible with a low carbon system, structures will need to be in place to reward their increasingly intermittent and flexible operation, in response to the variable output of renewables.

9.2.3 Variability of output and its effects on power flow – operational time scale

Renewable generators typically have an average output of 30-40% of their full rated capacity (Appendix E.5.4). This presents a question for network sizing of whether to attempt to meet the full or only the average output of the generator. The situation becomes more complex with multiple generators situated in various parts of the network, when the swings between an under-utilised and a heavily constrained network depending on renewable output, can be considerable.

The concept of 'Capacity Factor' (CF) is sometimes used to consider the extent to which renewables can provide firm capacity which allows the displacement of conventional plant. This factor is calculated based on a probabilistic assessment of the likelihood of renewable generation not being available when required, and thus requiring conventional back-up. The CF of a renewable technology would tend to decline the higher the overall installed capacity of renewables, because although higher renewable capacity results in more delivered energy, it also results in greater risks in significant drops in renewable power output at particular times, which means each added unit of renewable capacity has the ability to displace incrementally less conventional back-up capacity, whilst maintaining an acceptable level of system security. However this calculation is not used in the scenario analysis for this thesis, because the method in this thesis does not involve probabilistic calculations of renewable availability – instead, as discussed in Section 6.4.2 and Appendix E.5 it collects historic weather data at specific times of day and year, and analyses the impact on the system of specific conditions chosen as representative of the spread of conditions for that time of day and year. Hence the technology 'availability factors' discussed in Section 6.4.2 and Appendix E.5, are different from CFs, and the latter are not used in this analysis. As discussed in Section 7.3.1.2 the issue of system security with increasing deployments of renewables is addressed through the method of calculating the de-rated capacity margin of the system.

Section 9.2.1 compared the locational signal across scenarios in terms of its effect on investment decisions. It discussed the effect in terms of avoided network investments of having a locationally spread generation mix, rather than one with output clusters distant from load centres. However, a characteristic of high-renewables systems in contrast to conventional systems, is that as well as the impact on system power flows and constraints caused by long term investment decisions, for any given generation mix a similar level of power flow variation could be created by variations in weather conditions.

Weather-related variation in constraints and power flows can already be identified in the 2013 conditions (comparing ***Figure 39*** and ***Figure 40***). In the 2018 scenario year, although the Scottish borders are largely compliant, significant constraints have passed down to northern England and the Midlands, which are again wind-related (for example comparing ***Figure 47*** and ***Figure 48***).

In these early stages, although constraint impacts of renewables can be felt, they remain confined to reasonably predictable corridors. In later stages though as more renewables connect in more locations, a greater diversity of power flows and constraint patterns emerges in response to different weather conditions, creating different constraint corridors in each case. This natural power flow variation arising from the locational variation of weather conditions across the country at any given time makes the identification of constraint corridors and the justification of network upgrades more complicated.

In a conventional system, the greatest constraints would generally be expected at the time of peak system utilisation, or winter peak. For this reason, network adequacy studies by national grid have traditionally been focussed on studying power flows at winter peak (National Grid, 2011b). However, in a system with growing proportions of variable renewables, constraints will occur at a greater variety of demand times depending on the overall balance between supply and demand. In 2028 and 2033 SLWP and WLSP find higher constraints in summer conditions than in winter or spring, when patches of high renewable output coincide with low local demand to contribute to high inter-regional transfer.

Even at similar annual demand times (e.g. the winter peak) contrasting generation output patterns, and contrasting network power flows may be experienced on different days, despite a very similar demand pattern. Each of the scenarios sees considerable variation in the level and pattern of constraints across different wind conditions in their final years. SLWP and WLSP see considerable variation of power flow and constraints at the same demand time but with different wind conditions, as can be seen by comparing SLWP 2033 Winter average wind (***Figure 80***) with SN(***Figure 82***), and in WLSP 2033 Winter, the high wind condition (***Figure 108***) with SN (***Figure 111***) and NS (***Figure 114***). SLSP has less variation than the other scenarios between different wind conditions (e.g. ***Figure 61*** and ***Figure 64***). This is due to the effect of the interconnectors which in this scenario operate in a manner responsive to the conditions of the area of the network to which they connect, not just to the overall system balance. In the case of the Norway interconnector this allows the smoothing of export from Scotland and the Scottish North Sea, so that there is a relatively stable flow of power southwards; a similar effect is achieved by the Danish interconnector in respect of the English North Sea zones.

Overall most scenarios and conditions continue to show a strong north-south power flow across the network, as in all scenarios the capacity of renewables installed in Scotland is sufficient to create a significant export flow south at the windiest times. However, certain wind conditions produce a very substantial reversal in this flow direction. Notably, in SLWP, with its nuclear dominated England and wind dominated Scotland, the Winter 2033 SN condition sees a substantial export from England to Scotland (***Figure 82***). Other examples of non-standard conditions are the level of east-west transfer required in different wind conditions, with some conditions seeing high constraints on the east-west link between Humber, Yorkshire and Lancashire (e.g. SLWP 2028, Winter SN, ***Figure*** 77), if low output in Scotland pulls power from the north sea across the network. Lines running west-east from south Wales and the west country, and east-west from East Anglia, into load centres in central England and London, also experience variable constraint levels across the scenarios. In general these lines have greater congestion when a low overall renewable output condition maximises output from southern nuclear power stations – these conditions are exacerbated when combined with a high southern renewable output at the same time as a low northern output (e.g. SLWP 2033 Winter SN (***Figure 82***); WLSP 2033 Winter SN (***Figure 111***) and Average(***Figure 112***)). The high wind conditions however tend to reduce constraints on these corridors – reflecting that the high wind condition typically has a prominent north-south gradient, and it is for this gradient that the networks have been primarily adapted. Constraints can also be found in low demand conditions, if they coincide with high wind output, particularly in the north – for example WLSP 2033 Summer high and average wind conditions (***Figure 115*** and ***Figure 116***).

In general then, the scenarios suggest that power system adequacy will no longer be able to be planned against a standard assumption of the system condition at winter peak, but will have to take account of the interaction of both demand and output across a range of system demand and weather conditions. This variation can lead to significant alterations in the overall gradient of the power flow, with the traditionally expected north-south gradient changing in some conditions for a south-north gradient, and other conditions having significant east-west and west-east flows in certain regions. It also leads to considerable variations in the constraint experienced in particular regions or power flow corridors, which in some conditions may be constrained, in others under-utilised. The increased power flow variability may be a source of increased network expenditure due to the need to invest above the average utilisation level in a number of network locations – rather than being able to expect a relatively consistent power flow pattern with 'typical' high power flow corridors – in order to avoid constraints across the network. This kind of power flow variability adds complication to the process of planning and justifying network upgrades. It also raises questions about the appropriate design of policy instruments for giving locational signals to generators which reflect actual network conditions at any given time. The existing TNUoS charge is based on annual calculation of the 'centre of gravity' of the system at winter peak, and reflects the distance of the generator from the point in the network to which power is on average pulled. Although this currently is a reasonable proxy for costs imposed by generators on the network, the scenario analysis indicates that the range of system conditions that could be experienced across different demand conditions as a result of the variability of renewable output, could make the TNUoS charge, both because of its methodology and its annualised nature, increasingly less appropriate.

9.2.4 System responsiveness to variable output – what helps or hinders, and its effect on network investment

The locational signals in the strong location scenarios are assumed to provide a signal at the operational, as well as the investment time frame. This begins to show a benefit from the early stages of the strong locational scenarios by allowing for fossil plant to respond flexibly to renewable output in the same region of the network. Up to 2023, both SLSP and SLWP achieve sustained investment in renewables in northern GB without incurring major constraints (as in WLWP) or triggering major early upgrades (as in WLSP), beyond those already scheduled in all scenarios in the first time stage. This is achieved as a result of fossil plant in Scotland and northern England turning down their output to avoid congestion during times of high renewable output. This kind of dynamic is useful to those scenarios in the short to medium term, effectively providing a delay option on transmission investment, whilst still avoiding major constraints in the near term. As noted in Section 9.2.2, the rewarding of flexible responsive fossil plant becomes an increasingly important issue in view of the new plant which will be commissioned in the mid-2020s.

The weak location scenarios by contrast have to deal with significant constraints during the transitional period of the 2020s as a result of the combination of growing renewable output as well as significant persisting fossil output. For example, in WLSP in 2023 many of the constraints are related to the still high output from fossil generators in northern England and the Midlands under certain conditions – though the constraint is also caused by high renewable output flowing north to south, the still high fossil output is adding to this (***Figure 93*** and ***Figure 94***). In other words, this scenario suggests a period in the mid- 2020s when the system could be experiencing the 'worst of both worlds' in terms of constraints – a large north-south power flow from high renewables outputs combined with a still high midlands fossil output. The situation is further exacerbated in this scenario due to the lack of locational signal to influence the operational regime of fossil plant. However, this situation is in part resolved from 2028 when greater output from higher merit order renewables and nuclear reduces the fossil output in northern England and the Midlands, which actually relieves the constraints in these areas. In such cases, it is possible to see that the case for or against transmission investment could usefully be informed by a reasonable expectation of what the future might hold for fossil plant, as their declining output might serve to resolve constraint problems without further network investment. The utility of this longer term view may be a seen as a justification for an arms length system planning body. On the other hand, the pattern of fossil retirements will be affected by commercial considerations which would not be predictable or influenceable by such a body, which points to the advantage of a more flexible reactive approach. It is also noteworthy that a clear locational signal affecting both investment and operational decisions, as exists in the strong location scenarios, would help to resolve these issues and possibly reduce the need for intervention from a formally established strategic planner.

By the final two time stages however, there are increasing examples of conditions in all scenarios in which none of the remaining fossil plant is dispatched due to the quantity of higher merit order low carbon plant on the system. There are examples of nuclear being the marginal generator, with the nuclear plants operating at less than full output. In later periods, constraints are much less frequently found in the northern England and Midlands areas typical of early periods, which were due to the combination of high output fossil plants with renewable output flowing south. Instead constraints are more related to areas in which nuclear outputs combine with outputs from large renewable zones. For example SLSP Winter 2033 high wind is largely unconstrained, as the networks are of sufficient capacity to manage an overall high renewable output spread across the network (***Figure 61***). The overall wind output in this condition is such that nuclear stations are slightly ramped down. However the low wind condition has constraints in lines coming out of Sizewell and Wylfa (***Figure 62***). This is due to the fact that the overall low wind has required full output from nuclear stations, at the same time as pockets of reasonably high wind output in the southern North Sea and Irish Sea. Similarly, SLWP 2033 Winter SN shows a situation in which high southern renewable output combines with output from nuclear stations at Hinkley and Oldbury to create constraints in the south-west. These conditions suggest that in addition to incentivising flexibility in fossil generators there would be significant value attached to any flexibility that was achievable in a non-wind based low carbon technology – whether this was nuclear, CCS, biomass or tidal barrage with reservoir storage. This is both in view of conditions where overall renewable output makes nuclear the marginal technology, and of examples where the ability to flex down in favour of renewables would avoid a constraint.

The level of interconnection between GB and neighbouring systems is likely to increase over the coming decades. There are a number of factors influencing this. First the EU target model envisages greater unification of markets, which will promote opportunities for physical interconnection. Second, a GB supply mix dominated by wind and nuclear could provide strong commercial incentives for interconnection, as oversupply of energy at high wind times would create low GB prices, and under supply at low wind times would create high GB prices, in both cases potentially providing arbitrage opportunities with neighbouring systems, depending on conditions in those systems. While interconnections are generally argued to be positive for security of supply and overall system balancing, their impact on network planning and constraints depends on the level of locational signal influencing their design and operation.

In both SLSP and WLSP new interconnector projects are commissioned from 2028, the point at which the combination of nuclear and renewables begins to mean that high wind conditions will produce an excess supply of power. The effect that such new interconnections could have on the GB network depends on the extent to which their location and operation responds to GB network conditions. In SLSP, the entry point of two key interconnectors, with Norway and Denmark, via large offshore hubs, is influenced by the location of large renewable areas, and the operation of the interconnectors is driven by conditions on the GB system, such that at high wind times (***Figure 61***), excess power is spilled from the offshore grids through these interconnectors, and at low wind times power is exported onto the spare available network capacity (***Figure 62***). This reduces the variation of power flows experienced through the onshore network, which creates better network utilisation and reduces the need for onshore upgrades. In WLSP the interconnectors connect directly to the mainland at points which have less consideration of network conditions, and they are operated in response to overall system prices but not local conditions. For example, in WLSP 2033 Winter NS (***Figure 110***), the Norway interconnector imports into Blyth, due to the less than maximum overall wind output and therefore potentially higher GB prices available. However, because there is still high wind in the north, there is still a large power flow through the Eastern HVDC link, which also terminates at Blyth. Thus in this example even though the overall system balance may encourage import through the interconnectors, the additional power is unhelpful to the region of the network to which the interconnector is feeding in. Whereas in SLSP the Norwegian interconnector connects directly into a Scottish North Sea offshore grid allowing a direct integration with the output of that zone, in WLSP, without a strong locational signal, it connects at Blyth in Northumberland. This means that in WLSP the variability of Scottish output must still be accommodated in added network capacity down the length of east Scotland and north-east England before the power can be exported. The effect of this in terms of network investment can be seen by comparing the additional bootstrapping required in north-eastern part of the network in WLSP, as well as south of Blyth, compared to SLSP (***Figure 150***). In SLSP the Danish interconnector connects via the southern north sea offshore grid which means that when output from this offshore region is surplus to capacity on the east coast, it can be exported directly to Denmark. In WLSP the connection of the Danish interconnector directly onshore at Humber feeds and extracts power directly to and from the eastern onshore network. This misses the chance for direct interaction with the southern North Sea wind farms, and means that greater upgrades are required between East Anglia and London to accept the full output of the southern North Sea zones (***Figure 150***). The locationally responsive smoothing effect of interconnector operation in SLSP allows the scenario to achieve a relatively stable utilisation factor across different weather conditions. The utilisation factor of WLSP is more variable, and drops significantly during low wind conditions, as a result of the network's requirement to invest in sufficient capacity to manage a peak output which is significantly greater than average utilisation (***Figure 160***).

A technological uncertainty of potentially major significance is the possible development of economic large-scale electrical storage. The potential benefit of storage in temporal supply-demand balancing has been discussed (Grünewald, 2012), however its potential impact on avoided network expansion has been less emphasised. The storage sensitivities show very high levels of avoided network compared to the original scenario. The storage variant of SLSP, SLWP and WLSP each reduces network investment by a similar proportion of between 60 and 70% of the original. In real network size terms, these are evidently greater the higher the network investment in the original scenario, so that WLSP has the highest network investment reduction between the standard and storage variant (***Figure 170***). The value of these network investments may be seen as one measure of the value of storage, or possibly the regret associated with investing in peak-sized network and then large-scale storage being deployed – particular when considered in the context of the range of network investment costs estimated in ***Table 33***. In WLWP the under-invested network in the standard scenario is closer to being the perfect size in the storage network, and it has a comparatively smaller reduction of 30% between the standard scenario and storage variant. The more noticeable effect of storage in WLWP is the eradication of the major constraints in this scenario.

If electric vehicles are deployed in large numbers, then the extent to which the charging patterns of the vehicles can be influenced according to system and network conditions will be significant in affecting whether their effect is beneficial or not. The EV sensitivity analyses explored an increased charging intensity of electric vehicles over the winter peak, and found in all cases some increased stress on certain sections of the network in response to this. However, the effects were more marked in the weak locational scenarios, as the particularly strong north-south power flow in these scenarios is further exacerbated by the greater increase in southern demands (***Figure 163*** and ***Figure 164***) In the strong locational scenarios the added constraint from the EV variant was less definitive – although there were some shifting of constraints onto different lines in southern areas, the overall pattern was not greatly altered, and there are some constraint reductions in northern areas (***Figure 161*** and ***Figure 162***). This suggests that the greater spread of generation around the network achieved in the strong locational scenarios makes them more robust to higher demand peaks. A further sensitivity on WLWP 2033 Winter High Wind EV deployed a simplified example of locationally differentiated demand side response, increasing demands north of Mersey and Humber by 20%, and reducing all other demands by 20%. This resulted in lower constraints than both the EV variant and the original version of the condition, suggesting that locational demand side response may assist transmission network management (***Figure 166***). Growth of EVs then potentially poses challenges to the transmission network, but also opportunities. Overall these sensitivities indicate that the long term influence of locational signals on transmission and generation investment are beneficial in reducing the impact of added peaks from demands such as EVs. They also suggest that on the operational time scale locational signals may also be useful in helping EVs to become an opportunity for increasing the efficiency of network operation. However, it is also important to recognise that this study has not modelled the distribution network, and developments in demand that are beneficial to the transmission system may have the opposite effect at distribution level.

A major roll-out of solar PV could also have very noticeable impacts on power flows. In scenarios and conditions characterised by an existing strong north-south power flow, the addition of predominantly southerly-sited PV helps to reduce the gradient of this power flow and thus reduce overall constraints. Thus the weak location scenarios see the greatest benefit from the addition of southern PV across conditions (***Figure 175*** and ***Figure 176***), although strong locational scenarios also see constraint reduction when the output pattern creates a north-south power flow, as in the SLWP NS condition (***Figure 174***). These sensitivities again indicate the added value of generation the location of which complements existing generation – the weak location scenarios seeing the greater benefit from the addition because their networks had been lacking this complementarity. However, an important issue here is that if much of the PV is in fact connected to distribution networks, its location would not be affected by transmission network policy, despite the fact that at the levels explored in this scenario it could have a material impact on transmission power flows.

9.2.5 Public acceptability of transmission in an energy system context

Section 8.6.8.4 highlighted some of the different public acceptability issues that could emerge from each of the scenarios. It is beyond the scope of the current study to undertake a full investigation of the relative public acceptability of each of the scenarios. All scenarios involve high deployments of technologies which have the potential to raise public objections, such as nuclear, onshore and offshore wind, and tidal barrage. Any ranking of scenarios by public acceptability would involve judgements about the relative preferability of such technologies. For example, SLWP might *prima facie* appear to entail public acceptability challenges due to its high nuclear deployment, however this would be based on a subjective assumption that nuclear is generally considered less desirable than offshore wind – clearly for anyone who had the opposite perception, SLWP would be more appealing. Detailed investigations into the trade-offs individuals would make between alternative energy futures have been undertaken by Parkhill et al (2013).

As a general observation however, it is possible to say that the different scenarios present very varied transmission architectures both in terms of physical deployment (***Figure 150***) and cost (***Table 33***). Because the scenarios have been premised on alternative policy value systems, they suggest that there are policy choices which can be made to direct the system towards one kind of future network or another. If the impact of transmission is of sufficiently high order amongst public acceptance concerns, then these concerns could be taken into account to optimise the impact of transmission network according to public concerns. However, the trade off is that a less extensive network inevitably reduces the choice in available generation technologies, particularly in view of the high onshore, offshore and marine resources potentially available in Scotland and northern Britain. This in turn implies that as the carbon constraint gets tighter, with fewer technologies to choose from, there would be a greater risk that technologies with greater potential for public controversy may be required. The scenarios thus indicate that in developing constructive public engagement on future energy systems the role of and required investment in transmission is an important variable to consider in comparing different generation portfolios and energy system choices.

9.2.6 Technological uncertainties

As noted, the scenarios were quite tightly bounded in terms of technology availability, with technologies over which there is some significant technological or supply chain doubt, excluded. This was to avoid the proliferation within the scenarios of uncertain elements not within the control of the key prime mover system actors. Nonetheless it must also be acknowledged that there are still levels of uncertainty around the low carbon technology types that were included. Onshore wind is perhaps the least uncertain of the low carbon technologies, being mature and with few major technological challenges. Offshore wind is technologically well-understood and with high levels of commercial deployment, however there remain considerable uncertainties about its future costs (Heptonstall et al., 2012). Wave and tidal stream are not technologically complex however their development remains in a pre-commercialisation phase (RenewableUK, 2011). Tidal barrage has been demonstrated at scale, for example at La Rance in France, which has a peak output of 240 MW. However the projects included as options within this scenario approach are typically three to four times the size of this (Appendix E.4.3.3). Nuclear is of course mature in the sense that nuclear stations have existed since the 1950s, however the European Pressurised Reactor (EPR) type being planned at Hinkley Point C is a new design, an example of which is not yet in operation (although EPR stations are currently under construction in Finland, France and China). Thus the levels of nuclear deployment in all of the scenarios, but particularly SLWP, may be considered subject to the uncertainties surrounding the successful completion and economic operation of the new generation of EPRs. As already noted, each of these technologies may experience limits on expansion due to public objections, as can the transmission network itself.

Each of the scenarios is at or very close to the outer limit of total available capacity (defined in Appendix E.4) for at least one of onshore wind, offshore wind or nuclear, as well as having to use significant quantities of tidal and wave power. There would not be a large amount of room for manoeuvre if any of the assumptions on available capacity of particular technologies proved to be too optimistic.

On the other hand, key technologies not included in this analysis due to uncertainties are large scale biomass electricity generation, and CCS, which if successfully developed and deployed at scale could widen the options and reduce pressure on other technologies. ***Figure 178*** shows potential geological storage sites, and thus suggests that if CCS were successfully developed, favourable locations could be in the north-east of Scotland near Peterhead, in the east of England near the Humber, or around the Mersey close to the Irish sea. In each case the location is very close to areas of the network which could be experiencing high infeeds from offshore wind zones. At the time of writing the two projects that have received funding under the UK CCS competition to undertake front end engineering and design studies are based on potential projects at Peterhead, Aberdeenshire and Drax, North Yorkshire (DECC, 2014d).

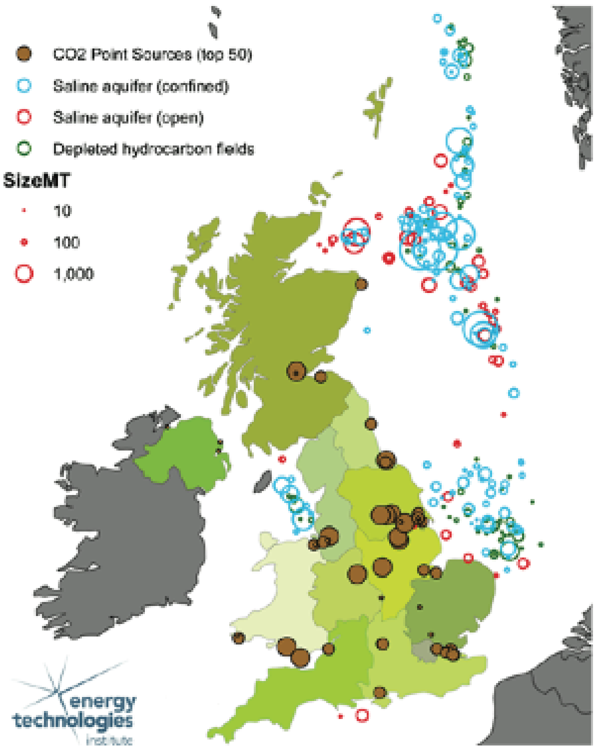


Figure 178: *Proximity of the UK's largest emitters to CO2 storage sites in the North and Irish Seas. Map provided by the Energy Technologies Institute, source:*

Biomass has potentially greater locational flexibility. The location of existing thermal power plants (particularly coal) may gives some indication as they tend to be linked to ports via railway lines.

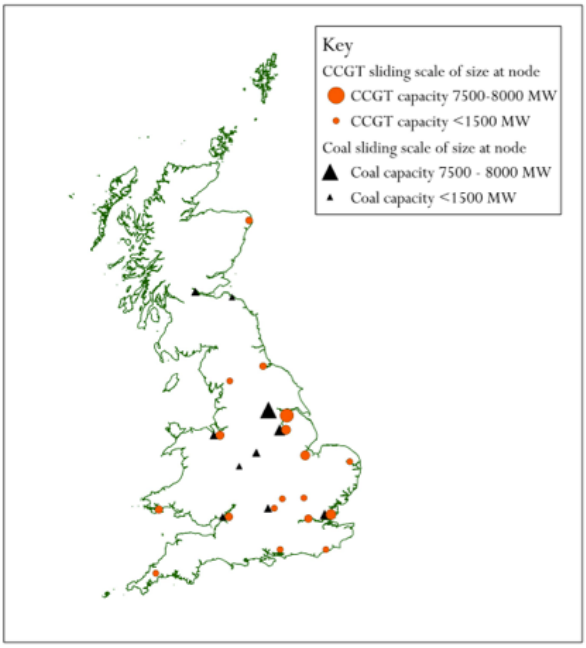


Figure 179: *Location and size of CCGT and coal plants*

The potential locations of biomass and CCS may therefore have significant transmission network implications, as they are likely to feed in to areas of the network into which large renewable zones will also feed. As previously noted, whether CCS or biomass can be demonstrated and deployed at scale, a particularly valuable characteristic of a non-weather related low carbon generator will be flexibility, both for avoidance of local network constraints when output and location coincides with output from large renewable zones, and for overall system balancing.

9.2.7 The effect transmission policy on the emerging generation mix

As discussed throughout the thesis, the policy value systems which govern the different scenarios apply specifically to the area of transmission policy, with other policy areas, including policies on generation incentives, held constant. This is justified first by arguing that there is no inherent reason to view transmission policy and generation policy as strongly coupled (7.3.1.1), and second by drawing on the scientific principle that independent variables should not be simultaneously allowed to vary, without generating additional scenarios (Section 2.6.2). The clarity that this provides is that any differences between the scenarios can be traced to choices in the transmission policy area, with no other variables interfering.

An interesting outcome in the scenarios is the different generation mix which is delivered by each one, despite a uniform assumption of technology neutrality in generation incentives across each scenario. The contrasting generation mixes do not mean that despite intentions to the contrary there were in fact implicit generation biases acting on the scenarios. Rather, this outcome is evidence of the important interactions between generation and transmission. In which direction the influence is strongest – whether transmission leads generation, or generation leads transmission – depends on the transmission policy regime, and how it manages this interaction. How the transmission policy regime manages this interaction has significant impacts on the evolving generation mix.

The critical variable is the locational signal. Scenarios with a strong locational signal favour technologies with greater locational flexibility, such as nuclear, wave and tidal. This is simply because in a situation where a particular area of the grid is becoming constrained and thus more costly for generators to connect to, technologies with the flexibility to locate in other areas of the grid will be able to continue to deploy whilst incurring lower transmission costs. By contrast, based on assumptions about the optimal locations for onshore wind, and locations of proposed large offshore wind zones, locational options for wind are more limited. This means that options for deploying wind can become limited by transmission constraints more quickly than other technologies, in scenarios with a strong locational signal. In scenarios with a weak locational signal, options for wind are never closed down, regardless of any transmission constraints that are being created. In each case, the anticipatory planning dimension operates to dampen or exacerbate the effect. In the strong location scenarios, the weak planning aspect in SLWP effectively confirms the limitations placed upon locationally challenging technologies by being conservative about network expansion; the strong planning approach in SLSP by contrast periodically re-opens up areas of the network which had been partially lost to high transmission charges, by taking anticipatory investment decisions. In the weak location scenarios, the strong planning approach in WLSP becomes the strategy for responding to the demands of generation unencumbered by locational signals – a generation leads transmission situation; by contrast, the weak planning approach in WLWP does not affect the generation choices created by the weak locational signal, but does ensure that the system experiences high constraints as a result of the combination of 'unhelpful' locational choices of generators, and an un-anticipatory transmission investment regime.

Thus the four scenarios deliver different generation mixes as well as different transmission configurations. However, because of the tightly defined system boundary used in the scenarios, which focussed on transmission policy and treated generation policy as an external, frozen variable, it is possible to identify these changes in both generation and transmission as being related to choices made specifically within transmission policy, rather than from an unclear mix of multiple simultaneously varied policy variables.

9.2.8 Contradictions and tensions emerging from the scenarios

The scenarios were defined as combinations of two possible policy variables within the area of transmission policy. As argued in Section 4.5, though both are related to the broader state vs markets questions which frequently recur within energy policy, they are different versions of this question operating in slightly different areas of the transmission policy space. They were thus treated as independent internal variables, policy choices which could be made independently and simultaneously. The fact that these policy choices could be made independently does not necessarily entail however that the result of doing so would always be harmonious and free of problems or tensions. Unlike trend based scenarios which treat a value system as a homogenous end point (Section 2.4.1), the scenario method developed in this thesis is designed to follow through the outcomes of particular value driven choices without pre-judging whether the outcomes will be successful and harmonious, or problematic and contradictory. The resulting scenarios illustrate this point well.

As described in the commentaries to the scenarios in Chapter 8, and as also emerges in the discussion in Section 9.2.7, three of the scenarios have policy value combinations which manage to address the challenge of a rapidly decarbonising electricity supply mix with more-or-less success. A critical factor is having a strong locational signal (i.e. SLWP) to utilise network effectively – if a strong anticipatory planning approach is added (SLSP) this increases the available technology options which will be successful within the locational framework. A weak locational signal can be made to work, but increasingly drives a strong and of necessity anticipatory approach to transmission planning (WLSP) in order to accommodate the new generators whilst avoiding excessive constraints.

Thus three of the scenarios (SLSP, SLWP, WLSP) are operating with a policy combination which, in different ways, could successfully interact with new generation to build a system that works. The fourth however (WLWP), as noted in the discussion in Chapter 8, seems to have a strategy that will be hard to sustain in the face of the challenges of the decarbonising mix. As constraints rise from generation that is being fed no locational information, and a network without an anticipatory strategic planning approach, the system looks increasingly less viable, and it seems increasingly likely that something will be forced to change. This could either be that a) a locational pricing strategy is reverted to (so that the scenario becomes something much like SLWP), or that b) an anticipatory planning strategy is reverted to (so that the scenario becomes something much like WLSP), or that c) neither the policy on location or planning changes, but the carbon target is abandoned.

It would have been possible to revise the scenario along one of these lines, instead of persisting with a scenario whose feasibility was becoming increasingly questionable. However, it is argued that a useful part of a scenarios process is the generation of infeasibilities, contradictions or 'failures', as these can be as informative as the harmonious successes. Therefore rather than trying to smooth away the tension which builds up in the scenario, the decision was made to follow through the logic of premises, drawing attention to and highlighting the tensions and possibilities of failure, and to treat such tensions as useful outputs of the process, and part of the analysis.

9.3 Policy options

The scenarios are framed around different policy options, themselves informed by different value systems. The framing of the scenarios allowed the exploration of the interaction of two policy spectrums – locational signals and anticipatory investment / coordination. This section draws together the implications for policy of the scenario work, within each of these two areas individually and in terms of how they interact together.

9.3.1 Locational signals in the transmission network

Locational signals in transmission networks are intended to indicate to users the relative benefits or disbenefits of activities which take place at different areas of the network. The principle is that users whose locational choices are of benefit to the network should be rewarded relative to users who impose costs on the network by their locational decisions.

The scenarios suggest potentially strong benefits of using locational signals to influence long-term investment choices. Scenarios with a portfolio of generation technologies spread across the network achieve a lower level of network investment (comparing SLSP and WLSP), or lower constraints (comparing SLWP and WLWP). They appear to be more robust to growth in peaks, for example from electric vehicles. Additionally the effect on interconnector investment decisions is more likely to create benefit for the network (comparing SLSP with WLSP).

However, the scenarios also suggest that a locational signal acting only on long-term investment decisions, and not on real-time operational decisions, will be increasingly unsatisfactory. In the present GB system the main locational signal is provided through the TNUoS charge, which is levied on capacity, and recalculated annually using a methodology which estimates the change in power flow arising from the hypothetical addition of another MW at each location in the system. Locational signals are not fed back to users in real time on the basis of dispatch operations, as GB system prices do not change by location, and constraint costs are socialised amongst users through the BSUoS charge.

This approach is predicated on a system in which power flows are reasonably consistent in direction and quantity, with the result that the constraints which arise are reasonably predictable in terms of where and at what time of the day and year they occur. In such a system, a fixed annual charge can be a reasonable proxy for representing the network conditions that are actually experienced at various times through the year.

The scenarios indicate that a future low carbon system is likely to exhibit significantly greater variation in power flows, due to the variability of renewable generators which could be located in various regions of the system, causing a greater variability in the relative utilisation of the network in its various regions at different times. The outcome of this is that the relative benefit or disbenefit to the system of an additional MW of generation in a particular location, is something which could change on a daily or even hourly basis, even given similar demand conditions, given the wide potential variability in output patterns. In this context, an annually fixed capacity based signal would be less appropriate than it currently is.

Locational network signals affecting real-time operation could usefully influence the behaviour of a range of existing and potential new system actors. They have the potential both to stimulate network-efficient utilisation of known and existing technologies and practices, and to create market niches for new technologies and practices which could be of benefit to the network.

There are a number of characteristics and innovations which could create system benefit, and which could be incentivised by locational signals:

Flexibility of fossil plant – in the near and medium term the flexibility and responsiveness of fossil plant in the context of rising renewable contributions will be increasingly valuable. In the transitional period of the 2020s it will extend the potential for coexistence of fossil plants and renewable generators within existing network limitations, offering a delay option on major transmission investment whilst there is still significant fossil on the system, and the precise configuration of renewable generation is to be decided. In the longer term flexibility of fossil plant is likely to remain a critical part of overall system balancing.

Co-location of complementary generators – although renewable generators are mostly non-dispatchable, the natural output cycles of different kinds of renewable resources have greater or lesser degrees of correlation. In the longer term, this could be increasingly relevant as a wider technology portfolio of renewables emerges. An incentive to site renewables in locations where the existing renewable resource would be less correlated to the cycles of the new generator, would improve network utilisation.

Interconnection – interconnection has the potential to assist the management of variability but also to add constraints. If the operation of the interconnectors responds to signals which take account of regional network availability as well as the overall system supply-demand balance, this would encourage the use of interconnectors in a manner that ameliorated rather than exacerbated network constraints.

Demand side response – the ability to shift demand in response to network constraints could also provide a useful solution to variability within network capacity limitations, potentially reducing constraints and delaying the need for network upgrades. In terms of network utilisation and managing power flows, demand side response has equal per-MW value to generation response, and should be rewarded as such. Roll out of electric vehicles may provide significant challenges but also opportunities in providing additional demand side response. Consistent locational signals would in the longer term create incentives for innovative business models for example aggregating the demand response of a number of consumers.

Storage – a significant driver of the high network investment requirements of a scenario such as WLSP is the gap between average and peak utilisation entailed by the natural output cycles of most renewables. A breakthrough in grid-scale storage could have significant impacts in reducing the investment required to achieve compliance for a given low carbon portfolio. A key problem with incentivising storage lies in establishing structures which convey a reasonable proportion of its system value to the storage operator (Grünewald, 2012). Real-time locational network signals, incentivising both generation and demand in the right locations, could create a strong value proposition for storage.

Flexibility of low carbon technologies – as well as the already growing importance of flexibility in fossil generators, in the longer term flexibility in low carbon technologies will be an increasingly attractive characteristic from a network and system management point of view. Establishing a signal which consistently rewards this is of great value for long term innovation, as development work on emerging technologies such as CCS, biomass generation, as well as new nuclear designs and tidal lagoons, can be given a clear signal about the value of flexibility.

These examples indicate the benefit of introducing the locational network signal soon. First, because in the short and medium term there are significant benefits to be derived in terms of efficient network utilisation and retaining network investment options, whilst significant quantities of fossil plant continue to coexist on the network with a fast growing portfolio of renewable generators. Second because in the longer term there are major benefits to be won from the new technologies and behaviours described above and explored through the scenarios. Encouraging the innovation to deliver these when they are critically needed requires the creation of niche opportunities to which these innovations can respond. This requires a persistent signal about the kind of characteristics that will be valued. It is not clear whether one of these particular solutions will become dominant, or whether a portfolio will emerge. There may be competitive dynamics between them, as for example early success in storage might reduce the business case for interconnection or demand side response. However, a locational network signal has the potential to provide a technology neutral driver to which all have the possibility to respond.

The scenarios did not specify the precise policy mechanisms by which real-time locational network signals were assumed to be provided. The range of options will now be discussed.

The approach favoured by many academic commentators is locational marginal pricing, according to which prices of energy vary by location according to the generation, demand and import and export capacity available. It is argued that this provides a long term signal, in that observers can identify regions in which prices are consistently high and infer that this would be a good place to make a new investment; but it also provides a short term signal which participants follow in order to guide their operational behaviour in real time.

Despite the highly consistent academic view on this issue (Newbery, 2011, Baldick et al., 2011, Green, 2010), the GB system has not taken steps towards the LMP model, and there are strong reasons for thinking it unlikely that this will happen in the near future. Interviewees (Chapter 5) commented that the transition to an LMP system is inhibited by the institutional inertia and transitional costs of doing so, with one commenting that it would be politically a bold move to bet that the transitional costs would be outweighed by the benefit of the new model. Recent years have seen very significant levels of effort expended in reforming institutions within the current electricity regime, through EMR, Project Transmit, and the RPI-x / RIIO reform. These reforms represent considerable institutional investment in the incumbent regime, which would be a form of policy stranded investment if the system was completely overhauled.

These within-regime reforms inevitably generated uncertainty, which it was reported was inhibiting investment (Royal Academy of Engineering, 2013). The uncertainty created by a major industry restructure would be greater and unlikely to be politically realistic at a time when both capacity constraints (Royal Academy of Engineering, 2013) and decarbonisation targets (CCC, 2014) remain pressing concerns and prominent political issues.

The historic analysis traced the sharp change of direction from a centrally controlled to a market-led system in the 1990s. It also showed how, almost as soon as that market transformation had been completed, the intervention and coordination of the state and its arms lengths bodies began to be drawn back in to the process. As observed by several interviewees in Chapter 5, we are now in a mixed period, where principles of private investment and market based system operation, sit alongside very high levels of strategic state intervention, in particular through the setting of feed-in-tariffs and the growth in importance of capacity auctions for security of supply. Thus it is also unclear in terms of the currently dominating political value-set how plausible a return to the kind of purer market system in which LMP could operate would be.

Interviewees observed that it could be that EU developments, rather than internal reforms, move the GB system towards zonal pricing. The EU Third Energy Package, it has been observed, aims for regional market splitting as part of overall EU market integration, and its 'target model' is akin to the Nordic markets which employ Locational Nodal Pricing. Whilst this is a possibility it is not inevitable, and is also a development which is less within the control of UK policy makers. As such there is a strong argument that other means should be found of signalling real-time network constraints and availability, in order to capture the benefits listed above.

There is the possibility of reflecting real time locational network conditions using existing institutions. One of the interviewees considered that the possibility of locational BSUoS was a debate worth having. Unlike a locational energy price, locational BSUoS would be a retrospective charge, but if skewed to be higher per MWh for generators in the areas of the network where constraints occurred, it would provide an incentive for generators where possible to control their output in view of network constraints. It could also send negative price signals to areas where generation would relieve constraints, and in theory both signals could incentivise the corresponding opposite behaviour on the demand side. It would thus help to create potential market niches on the demand side for innovators such as demand side response aggregators and storage providers.

If neither LMP or locational BSUoS were pursued it would be possible to deliver some of the effects achieved in the strong-locational scenarios through a more coordinated and strategically managed approach. For example, if the System Operator, transmission owners, offshore developers and potential future interconnector investors were to come together to negotiate an agreed plan on offshore networks and interconnection. To encourage the development of storage, capacity payments for storage units in particular locations of system value could be offered. However such approaches are likely be somewhat inflexible, entail policy risk, and be less sensitive to real-time operating conditions. It is also noteworthy that they would involve the state being further drawn in to an even more interventionist position in respect of the system.

9.3.2 The need for coordination

The appropriate level of centralised intervention and coordination in the electricity industry is an issue which has repeatedly resurfaced in policy debates throughout the history of the industry. On the one hand the argument goes that private actors acting independently without centralised coordination will deliver better technological innovation and a more efficient system overall. On the other hand arguments have been made that the public service nature of the industry, and its inherently networked structure mean that centralised coordination interventions are frequently required in order to achieve efficient system outcomes. In the current UK policy context, the higher watermark of the non-intervention approach in the mid-1990s has since been receding in the light of new public policy concerns relating to the electricity industry, as well as of the possibility of significant new network requirements. Views from the interviewees on this issue were mixed, with some highly sympathetic to the development of a strategic long-term blueprint or plan for electricity networks; others less convinced of the utility of this.

From a historical perspective it would seem to be a relevant observation that the major expansions of transmission networks in the UK have all been achieved under centrally coordinated programmes. At the same time, however, it must also be acknowledged that these expansions took place during periods of growing demand, and during most of which there was only one significant large-scale generation technology – coal – which gave some certainty to the question of the relative location of load and generation, and to the prospect of the future utilisation of these networks. The current context is of a system which it is expected will undergo significant changes in generation mix, with potentially also significant growth in demand. However, the precise trajectory of demand growth is much less clear than, for example, in the post-war years. Furthermore, there is larger diversity of generation technology options, each with different locational characteristics, and with considerable uncertainty about their relative future costs and operational characteristics.

Nonetheless, if targets are to be met this entails a rapid growth in installed capacities of some combination of low carbon sources. One important consideration is the relative lead times of generation technologies and transmission infrastructure. As noted by one of the interviewees, transmission build lead times are comparable to those of nuclear power stations, hence network upgrades specifically responding to new nuclear power stations can be built responsively, in 'lock-step' with the nuclear build programme. The SLWP scenario describes a largely responsive transmission build programme which primarily follows the commissioning of nuclear stations. For renewables however the situation is more complex, as projects can move from planning to commissioning more quickly than the typical lead times for transmission infrastructure. Further, there are multiple parties involved, the sum total of which might be sufficient to trigger an upgrade, but which as individual projects would not do so. An argument could therefore be made that if there is a policy priority to bring on large amounts of renewables quickly, to avoid delays judgements should be taken about the likely areas for these, and appropriately sized networks built out in advance. WLSP describes a scenario in which an aggressive deployment of renewables is pursued, with transmission networks as far as possible laid down in advance of this. WLWP does not have such a forward edge on transmission and thus experiences delays, and greatly increased constraints. Thus, one potential argument in favour of a strategic coordinated approach is the avoidance of delays and constraint costs while transmission catches up with generation.

Another argument concerns the potential difference of a strategic approach compared to a non-coordinated approach in terms of achieving synergies and economies of scale in network planning. It is easy to conceive of relatively small and dispersed renewable energy hubs connecting to the network in a radial fashion without there being much added value in a strategic coordinated plan for how these individual farms connect up. However in the longer term large amounts of renewable generation capacity are required to meet the targets, even in scenarios with large nuclear fleets. In relation to the large round 3 offshore wind zones, significant bottlenecks emerge without coordination. For example, the ability of SLSP to connect all of the Round 3 potential, is strongly assisted by the development of strategic meshed offshore networks particularly off the east coast of Scotland and in the southern North Sea. SLWP by contrast, with its radial connection approach, meets onshore constraints much earlier. The issue may be particularly pertinent for the large offshore zones, particular those which infeed into high nuclear areas. Another key point is that SLSP has more offshore network and therefore gets away with less onshore network, compared to SLWP.

The key argument against a strategic blueprint approach points to the numerous uncertain and uncontrollable factors which pertain to the future system, especially its future generation mix, and the degree of impact these uncertainties could have on the characteristics of the system and its power flows. Significant uncertainties were uncovered both by the internal variation of the scenarios, and by the non-actor-contingent uncertainties applied across all of them. First, against identical demand backgrounds, the scenarios developed quite contrasting power flows and resulting network requirements, entirely due to the variation of the different combinations of nuclear and renewables developed in each. It might be argued that we can anticipate broadly the most favourable areas for renewables – the north of the country – and that transmission infrastructure should be built out in expectation of the development of these areas. However, such a broad characterisation is unlikely to be sufficient to justify a real transmission link of a particular capacity in a particular location. Each of the scenarios shows major upgrades, though due to the variations in precise locations and quantities within the generation mix, there many differences between them. The non-actor-contingent elements suggest further uncertainties – the roll out and charging patterns of electric vehicles, a breakthrough in storage and the mass deployment of PV all have effects on the power flows. In addition it would be possible to list a number of other possible developments which, it would be reasonable to surmise, would also have impacts on the system – development of CCS, due to the specific locational requirements of CCS plant; the use of hydrogen or biofuels for transport, due to the resulting impact on electricity demand.

As shown in the comparisons of the network investment levels and costs in Sections 8.6.5 and 8.6.6, the magnitude of investment in all scenarios is considerable, and the difference between the scenarios also great. The costs of transmission investment are not likely to be negligible but will form a considerable proportion of the total costs of the transition. In this context oversizing simply for the sake of erring on the side of caution is unlikely to be an acceptable strategy. Thus for reasons of maintaining societal support for the transition, as well as purely financial constraints, it is still beneficial to use transmission network efficiently and avoid their expansion to levels significantly greater than required.

On balance the degree of variation between the networks developed within each of the scenarios does not suggest a strong case for fully comprehensive network expansion blueprint. The range of potential sources of variation which could affect network requirements is such that predicting an optimal network decades in advance is too risky. A level of flexibility and periodic review in responding to actual generation outturns and other technological and system developments, as is contained within the RIIO process, is likely to remain sensible for the forseeable future. However, it also emerges that given certain conditions of developments to high levels in certain areas, some degree of forward thinking about the development trajectories of particular zones in the network, with a view to joining up and coordinating network solutions, could be rational and beneficial. Candidate areas for such treatment include:

Scotland and its east coast offshore region, and its interface with England and potentially Norway

The large potential for renewable resources in Scotland raises questions about the sizing of interconnector capacity. Interactions with Norway could help to smooth the export south and is a factor worth considering in the expansion of the Scottish offshore network and connections to England

The English east coast offshore zones

The English North Sea contains a number of very high capacity offshore wind zones. Radial connections could contribute to very high constraints in the onshore network around the East Midlands and East Anglia. The development of a north sea offshore grid with numerous connections to different locations along the east coast, as well as potentially more interconnectors to Europe, could add benefit when the North Sea zones are generating very large amounts of power. The English east coast zones could also experience high infeeds from eastern Scotland if high capacity interconnectors, and particularly east coast offshore bootstraps, are constructed.

Irish Sea and Wales / north-west England

This area could experience a number of very significant infeeds. The HVDC western bootstrap is under construction. If it is joined by the Wylfa nuclear plant and a fully developed Irish Sea zone, there could be considerable combined infeed into this area, particularly at high wind times. The benefits of Irish interconnection, and a Wales HVDC should be monitored in respect of this area.

A further issue which has been suggested by some of this analysis, is the question of the relative benefit of different developments to the transmission network, compared to the distribution network. In particular, the effect of developments at the distribution network of growing electric vehicle demand and growing distributed generation, were explored in terms of their impact on the transmission network. It was found that there could be situations in which the alteration of demands on the transmission network caused by these distribution network activities, may have beneficial effects for the transmission network. Key examples of this were the increase in demand in northern Britain relative to a decrease in southern Britain using demand responsive EV charging, reducing the north-south power flow gradient and thus reducing constraints; and similarly an increase in southern PV output also reducing the north-south power flow gradient. However, in both cases these power flows would have had very significant impacts on distribution networks, not all of which may have been positive. The challenges of such dynamics to the distribution networks were noted by interviewees. However, if such developments scale up they may also create implications for the transmission network. This suggests that another potentially valuable area for forward planning and coordination may be conversations between TNOs and DNOs about the increasing possibility of interaction between different voltage levels, and how beneficial effects can be captured, and negative impacts mitigated.

9.3.3 The balance between locational signals and coordination

This section explores how the two key policy variables of locational signals and coordination can be brought together in a coherent policy framework.

A strong conclusion from this work is that a locational signal is increasingly important in a low carbon system to promote efficient network utilisation and to maintain options on transmission network investment in the face of uncertainty around precise future generation mixes. It will be increasingly important that this signal affects real time operational decisions as well as investment locational decisions. This implies a move away from, or some kind of addition to, the current form of the TNUoS which is the only way in which locational signals are currently conveyed to transmission system users.

In theoretical terms the neatest solution to this would be to establish a market based on locational marginal pricing, as this would provide all of the above signals and allow the relevant actors to respond and make their decisions in an autonomous and decentralised way. It is possible that such a market could eventually develop in the UK, and currently the thing looking most likely to drive it is the EU Third Package.

However, the specific project of reorganising the market along these lines is one which involves numerous obstacles. The transitional costs of market reorganisation would be high, and the inertia from the various existing actors who are accustomed to the functioning of the existing market could work against the process, particularly given the significant amount of investment that has recently been undertaken in upgrading components that still fit within the incumbent policy regime.

Furthermore, the components which have been added through EMR have moved the system more towards a mixed system with an underlying market structure combined with strong intervention. These developments have significantly pulled the system away from a pure unimpeded market pricing approach. The reality of this policy value drift has to be acknowledged in order to produce policy recommendations that are tractable.

It has been suggested in Section 9.3.1 that creating a locational BSUoS charge is a step which could exist within the incumbent regime and also produce something close to the desired effect. Failing this, the implication of keeping on track with decarbonisation trajectory recommended by the CCC is either very high network investment (as in WLSP) or very high constraint levels (WLWP), either of which could create significant public and political tension and endanger the successful achievement of the targets. It is possible that in such a situation the problem of variable power flow and network utilisation would draw in increasingly high centralised coordination, for example using capacity mechanisms to commission flexible generation or storage in specific areas, or with the state becoming increasingly involved in interconnection projects. Such an increase in interventionist solutions may create an increasingly stronger rationale for the creation of an independent syste operator (ISO) or other kind of central coordinating body, to coordinate the allocation of contracts for difference and capacity payments in a way that was also rational from the point of view of the network.

Thus it is possible to see how a weaker overall locational signal could eventually require higher levels of coordination in order to make interventions to resolve issues arising from it. However, the variables also have some independence, and there have also been areas identified where some forward planning and coordination may be useful in addition to a locational signal.

The question arises because of the multi-actor nature of the system on the generation side, compared with the monopolistic characteristics of the transmission network. The network provider can provide information to each of the various actors about network conditions at any given time; however, the robustness of decisions taken on this information will also be affected by subsequent decisions taken by other actors, to which they are not party. Equally the network provider cannot predict in advance how each of the other actors will respond. Without coordination the only option is for each actor including the network operator to act in response to each actor step. However, this can lead to a solution which is someway below optimal at the system level. In order to get a better outcome, there is an argument for the sharing of information on intended actions, such that the network operator can plan for the activity of multiple actors several stages ahead, not just one step ahead. For example, multiple actors may each receive a signal which encourages them to invest in offshore wind in the southern north sea. Taking each of those planned projects as individual projects the network owner may rationally offer radial connections to each to a similar point on the grid, as the marginal impact of each is low. However, taking a slightly longer term view and taking the projects as a portfolio may lead to the identification of more strategic links with longer connections to other parts of the network. The ability to do this requires giving the network owner the ability to make advanced investments with some of that cost paid by near term projects, but with the possibility to recoup costs against future, less firm projects, when they arise. Though carrying some element of risk, the future potential payoff may justify this.

Thus even in a market with strong locational signals there may still be relevant opportunities for coordination between the multiple actors involved, when it comes to network investment. Locational signals and strategic anticipatory network planning are not mutually exclusive – even in a system with perfect locational signals some strategic planning of network is likely to improve the efficiency of outcomes. However, the weaker the locational signals, the more that coordinated intervention may become necessary to attempt to achieve an efficient utilisation of the network, given the increasing challenges with variation in network usage and power flows which could be faced in a decarbonising system.

9.3.4 Institutional arrangements

This section discusses the extent to which new institutional arrangements may be required in relation to the different options. The key policy requirements highlighted by the analysis are the need for a means of reflecting real time locational signals to generators as well as only long term signals; and an institutional arrangement which facilitates the identification of beneficial opportunities for strategic coordination between various actors and regimes, without attempting to implement a fixed blueprint.

The creation of an LMP market would require substantial reorganisation of the market, including the creation of an ISO (or TSO) with responsibility for calculating the energy price at each node. In a discussion paper Pollitt et al (2013), outline this model and stress its benefits, but acknowledge the substantial reorganisation it implies. The inclusion of a locational element in the BSUoS charge on the other hand, which while it may be a theoretically less elegant solution from an academic standpoint, could be achieved with no major institutional changes, being a modest adaption of an existing mechanism. This is not to say however that such a move would be straightforward, as it would inevitably create winners and losers against the status quo. As has been seen with Project Transmit, such reforms can result in a very long discussion process.

However, as noted above, both of the above approaches to locational incentivisation would also benefit from some level of strategic foresight on network planning, due to the potential benefits of identifying synergies in network connection strategies in view of the multiple generator actors involved in the system. There have been calls (including in interviews for this thesis) to establish an independent system planner, or system architect, whose role would be to set the direction of travel for the system and to authorise the strategic build out of the network for this purpose. On the basis of the scenario analysis carried out in this thesis it is not possible to go so far as to recommend this, due to the range of different network designs which may be compatible with a low carbon system, and the technological uncertainties associated with them. However, the analysis has identified that there could be genuine benefit from creating institutional capacity to keep a watching brief on developments in generation investment, to highlight how more strategic and anticipatory approaches to network investment in particular zones may be of long term benefit.

It is useful to break down the different elements of what would be required in such institutional capacity. The first requirement is for some kind of independent and unbiased strategic oversight which can look across regimes and identify potentially beneficial opportunities. The second requirement is that those who would actually build the assets have the freedom and remit within the price control structure to undertake anticipatory and coordinated investments. The third requirement is that there is scrutiny that any proposed multi-purpose project does indeed represent a value for money contribution to government strategic objectives.

On the second point, in fact there appears to be sufficient provision within the RIIO framework to encourage and allow this. The RIIO framework is designed to encourage network companies to 'play a full role in the delivery of a sustainable energy sector', (Ofgem, 2010c) and in so doing they are permitted to take longer term view on investment, considering 'the costs of reinforcing the network in the context of a twenty-five year asset management plan, rather than in the context of what is needed for the price control period itself' ((Ofgem, 2010a), p. 50). Companies are also encouraged to 'work with others' in the industry or in other sectors 'to identify potential joint solutions that may provide long-term value for money' (Ofgem, 2010a) and to be involved in whole-system planning for a low carbon future (Ofgem, 2012b).

On the third point, scrutiny of investment proposals is something which most clearly falls within Ofgem's remit. Pollitt et al (2013) discuss the possible requirements for new bodies to undertake the scrutiny of future transmission investments, arguing that Ofgem suffers from a lack of capacity to do this effectively. However, if Ofgem's capacity is as limited as Pollitt et al suggest, this primarily suggests an argument for Ofgem to ensure their capacity is sufficient in this regard, rather than creating a new scrutiny body and confusing Ofgem's purpose and remit.

It is in relation to the first point that there may be an argument for some institutional development. There is currently no organisation with the remit and responsibility to look across transmission regimes in the context of a rapidly changing generation mix, and identify opportunities for synergies and network coordination. This would not entail a one-off future forecast and resulting system blueprint. Rather, the body would have to periodically re-examine opportunities in the context of the evolving generation mix. Any coordination opportunities it identified could then be incorporated as evidence supporting the needs case for a multi-purpose project in transmission company plans within the RIIO process, and would thus ultimately remain subject to scrutiny from Ofgem through existing processes. Equally, if this strategic body identified particularly beneficial coordination opportunities which were not being pursued by companies, Ofgem's scrutiny within the terms of RIIO could conceivably include requiring the companies to coordinate with each other and give greater consideration to such plans.

The role of such a body would be comparable to the recent role played by ENSG, where their work on transmission requirements out to 2020 was much cited by Transmission Companies in justifying the needs cases for their plans, and also directly gave rise to a major strategic project – the western HVDC link – which was a joint venture between two companies, National Grid and Scottish Power Transmission.

As such, the new body discussed in this section could simply be an evolution from the ENSG. To ensure its long-term robustness however, there would be a need to ensure its independence from the commercial interests of any of the existing actors, and that it could transparently demonstrate this. It would also need to develop a transparent and robust approach to considering future scenarios, and be able to demonstrate what expectations about the future were underlying the needs cases it developed.

A potential advantage of such an approach is the minimal institutional upheaval it requires, and the fact that the activity already undertaken by the ENSG provides a test case for how it could work. The role of Ofgem in scrutinising any emerging plans would remain crucial, and it is therefore important that Ofgem has sufficient capacity to undertake such scrutiny.

9.3.5 Conclusions – policy recommendations

The previous discussions give rise to the following policy recommendations.

The first recommendation is that the move from a locational signal which influences investment only to one which influences real-time operation primarily, and investment by extension, will be of significant importance and value to the decarbonising electricity system. Bearing in mind the existing set of policy commitments within the electricity system and the direction of travel, it is judged that the most tractable way of achieving this will be to work towards a locational BSUoS charge, targeted equally at generation and demand, and with the potential for negative prices to provide incentives for generation that helps the network, as well as penalties for generation that does not help it.

The second recommendation is that even with locational signals indicating the costs and benefits to generators of network connection in different areas, there is still benefit in some level of strategic anticipatory consideration of future network needs. It requires modest institutional change, namely the creation of an organisation with independence from the TOs, the SO and Ofgem. The new organisation would not have the power to launch projects itself, but its recommendations could be referred to as evidence for a joint-needs case between TOs and other merchant actors as appropriate, for review in the normal manner by Ofgem. It may be sufficient to deliver this body by making minor amendments to the ENSG, improving the transparency of its processes and clarifying its scope and remit.

10 Conclusions

This chapter summarises the conclusions of the thesis. It first considers the scenario method developed for application in this research, identifies its novelty, and reflects upon the usefulness of this approach in considering future policy problems. It then summarises the conclusions specifically relating to the policy area under discussion, the role of the transmission networks in a decarbonising electricity system. It highlights the technical challenges revealed by the scenario process, and recalls the key policy recommendations arising from the analysis. Finally some suggestions are made for future research.

10.1 Conclusions on the scenario method

10.1.1 The role and purpose of scenarios

The use of scenarios to consider possible future situations to aid near-term decision-making is an intuitive human activity practised at every scale from the individual considering personal plans, to the more formalised and corporatised procedures undertaken by large organisations. The range of tools and methodologies which have been applied to producing scenarios is vast, as might be expected given the range of sectors in which scenario analysis has been applied. To the heart of every scenario process however runs Pierre Wack's challenge: 'Do they lead to action? If scenarios do not push managers to do something other than indicated by past experience, they are nothing more than interesting speculation' (Wack, 1985a). Volkery and Ribeiro make the same challenge to public policy scenarios, affirming that 'having an impact on the design and choice of policies remains a litmus test for the relevance of scenario planning' (Volkery and Ribeiro, 2009). The prevailing existence of uncertainty about the future is not in any sense an argument against the utility of doing scenarios. Scenarios are not intended to remove or wish away uncertainty, but to provide a logical framework for analysing the possible effects of decisions within that context of uncertainty. 'The future is an emerging landscape with unknown contours; the constraint is that despite the unknown horizons, we have to take decisions today that commit us for the future. Even if the information is degraded we have to place our bets now, to create the future rather than submit to it' (Godet, 1987). Successful scenarios should not be expected to eliminate uncertainty entirely, but should be expected to help to improve decisions that must be made in respect of the future, within that context of uncertainty.

10.1.2 Limitations of public policy and low carbon scenarios

Scenarios should help to inform and improve decision making in the context of future uncertainty. However, the success of public policy scenarios, including low carbon scenarios, according to this criterion has in fact been mixed. Volkery and Ribeiro report that scenarios are more often used in the early phases of the policy cycle, for 'indirect forms of decision support' such as 'awareness-raising' and 'issue-framing' but that more progress needs to be made with incorporating scenario planning into 'processes of policy design, choice and implementation', noting that 'the role and purpose [of scenarios] within the decision-making process is not always clear' (Volkery and Ribeiro, 2009).

Hughes and Strachan (2010) criticised low carbon scenarios for failing to represent the role of human actors in the transition process, and for the separation of technological systems from human systems which failed to represent the co-evolution of a socio-technical system. They argued that this results in a lack of tractability in the policy space, as the underlying structure of the scenarios is not conducive to allowing policy makers to trace the role of their own decision making within the alternative futures presented. In the case of 'trend based' scenario methods, the futures are a complex blend of different kinds of political, social and technological drivers, often at regional, national global scales, which present vivid storylines but with such compounded uncertainty that the scope for impacting on the future seems non-existent. In the case of 'technical feasibility' or 'modelling' based scenarios, the description is of an energy system as a purely technical model whose operation can be guided through the pulling of constraints and levers that have at best only a passing resemblance to the way that actual policies impact upon real system actors and their choices.

10.1.3 The contribution of the scenario method developed in this thesis

The scenario method developed for this thesis addresses this deficit in two ways. The first is by developing a conceptual model of the system which draws on three different approaches scenario methods have taken to representing the system under study, to produce a three-level model of the system, representing the constant interaction between political values, actor strategies and decisions, and technological system outcomes. The model understands policy choices as emanating from politics, itself subject to the influence of prevailing systems of values or ideology. It considers the impact of these policy trajectories upon the strategies and choices of system actors, and the effects of these choices upon the technological system, as well as the effect that technological system conditions have upon system actors. The model requires an iterative movement between these three levels, calling for a cross-disciplinary approach which brings together qualitative data on interpreting political values and actor strategies, with quantitative data on system performance.

The second important aspect is the development of a scenario process based on tightly defining the key focal question and the system under study, and systematically categorising different kinds of future element. Elements which are considered 'pre-determined' are separated from those which are contingent upon decisions which could be made by prime-mover system actors, or 'actor-contingent', and from those which are less easily attributable to the decisions of identifiable system actors, and thus more profoundly uncertain, or 'non-actor-contingent'. The actor-contingent elements are the policy approaches encapsulated by the value sets which are the starting hypotheses for each scenario within the three level model. Thus the scenarios are fundamentally defined and differentiated through alternative policy approaches which could be taken by prime-mover system actors. This puts the perspective of the policy maker, and their agency within the system, at the centre of the scenario process, which is thereby rendered more likely to deliver tractable policy relevant recommendations.

10.1.4 Reflections on strengths and weaknesses of the new scenario method

10.1.4.1 The tightly-defined system boundary

Critical to the clarity offered by this approach is the very clear focus on a specific policy question, alternative responses to which are varied as the key 'actor-contingent' elements which differentiate the scenarios. The system boundary is set such that the number of independent internal system variables, or actor contingent elements, is small enough that they can each be systematically varied within a manageable number of scenarios. In the current study there were two independent variables (locational signal and anticipatory planning) each with two levels (strong or weak). The combination of these variables at each of their possible levels yields four possible scenarios. Had there been an additional variable with two levels, this would have implied a total of eight scenarios – already stretching the bounds of manageability. When the manageable limit of the number of scenarios is reached, the system boundary has to be drawn around the independent variables that have generated these scenarios, with all other potential variables set as external to the system. This means that they have to be treated as 'extraneous variables' and held constant during the actor-contingent scenario development part of the process, though they can form part of a selective 'stress test' in the non-actor-contingent part of the process.

The strength of this method, as argued in Section 2.6.2, is the greater clarity it allows in perceiving the effect of the independent variables of interest without interference from extraneous variables, as opposed to approaches which produce scenarios from a mixture of many different independent variables at various different levels, making the effects of any particular variable hard to attribute. This principle is strongly related to the well established principles of experimental design in behavioural, psychological and physical sciences, which require the holding constant of extraneous variables in order to see the effect of an independent variable of interest. In other words, the method is arguing that scenarios should be conducted with comparable design rigour to controlled scientific experiments, conducted in order to rigorously test the effect of identified variables of interest. It is this design rigour which assists in producing scenarios which can make strategically effective contributions to policy making, by highlighting the impacts of identifiable actor choices.

The trade-off to this focal clarity is that significant parts of the energy system which do not fall within the system under study as defined by the focal question, are held as constant, with a handful of non-actor-contingent elements identified to test the robustness of the actor-contingent scenarios. Significant elements not internally varied by the scenarios in this study included alternative demand profiles, alternative approaches to generation, and the possible breakthrough of major but technologically uncertain technologies such as CCS. The scenarios also limit their focus to the transmission network, meaning that distribution level activities are out of scope and for the most part not considered, with the exception of the non-actor-contingent element of a large growth in solar PV, much of which can be assumed to be distribution connected. This means that the scenarios have considerably fewer elements being simultaneously varied than is typically found in energy scenarios, which typically aim to 'cover the waterfront' of possibilities across multiple criteria, using just a handful of scenarios. In particularly, other recent electricity system focussed scenarios such as those associated with the LENS and Transition Pathways projects (Ault et al., 2008, Foxon, 2013), reviewed in Section 1.2.1, have included more radical visions of the future, including highly decentralised electricity systems. The current scenarios, due to the limitation of their focus on the transmission network, are inherently precluded from exploring such futures.

The broad, multi-variable approach to energy scenarios has clear attractions given the multi-sectoral and interlinked qualities of energy systems, the fact that they are embedded in social processes, and that long-term technological transitions can be powerfully understood as complex processes involving integrated changes in technology, society, economics and culture. It could be argued that the tightly focussed approach developed in this thesis, for all its focus on experimental clarity, misses out on these cross-sectoral dynamics which are characteristic of real transitions. Conversely, the disadvantage of the broad multi-variable approach is a lack of clarity about what question the scenarios are trying to answer, and what specific policy decisions they are to be related to. The fundamental argument for the tightly bounded scenario development process developed in this thesis is that it is better to have a clear answer to very specific question, than a vague answer to a very big question.

A potential area of interest for future research in energy scenarios will be on how to bring together the strengths of these contrasting approaches. This thesis continues to propose that scenario processes should always aim to deliver practical and usable insights to their users, and rigorous and controlled design of the process is argued to be critical to this. However, if this design rigour can be combined with a broader multi-sectoral scope then this could increase the richness of scenario storylines, allowing for a broader range of potentially significant drivers to be included in the analysis, and potentially increasing their interest and uptake amongst a wider range of stakeholders. Ultimately, however, researchers will always have to confront a trade-off between the breadth and scope of what is considered, and the precision and depth with which it can be considered.

10.1.4.2 Value systems, tensions and contradictions

The process of making political value systems the starting hypothesis for the scenarios, in addition to clarifying the elements of the system which can be related to proactive choices, may also assist policy makers in seeing their decisions in the context of the values that may be informing them. Value systems are a constant and natural part of human decision making processes – in a highly complex world, without making some judgements about what we expect to the world to be like, it would be hard to make any decisions at all (Forrester, 1971). However, the risk is that value systems can become implicit and cease to be questioned. An important role of scenarios is to make such value-sets or world views explicit and consider how they could influence decision making (Wack, 1985a, Wack, 1985b). By making explicit the value-sets which are affecting decision making, policy makers can consider if there is benefit in changing them. If they choose not to, they can focus on the scenario that most closely reflects their value system and consider their options within it.

The three-level system concept used in the scenario approach can also have the effect of testing the consistency of value-sets against emerging technical realities. For example, WLWP produced a technical system exhibiting considerable stresses, which would be likely to force a change in the guiding value set. As discussed in Section 9.2.8, the internal stresses implied by the scenario suggest that a relaxation or abandonment of either the 'weak location' or 'weak planning' principles, or of the underlying decarbonisation trajectory, would be the eventual likely outcome Just as in past examples (as shown in **Error! Reference source not found.**) technological system stresses have forced value shifts, the three-level scenario approach provides the opportunity to consider similar future interactions. It might be argued that a scenario approach which is capable of generating contradictions and inconsistencies is in some sense flawed. On the contrary, the analysis in this thesis has illustrated the usefulness of using scenarios to explore how certain combinations of choices which are possible for policy makers to take, can lead to tensions and contradictions. It is far more interesting and informative to discover through scenarios the possible problems and failures which could result from certain policy-choice combinations, than to produce a set of scenarios in which harmonious success is a pre-determined assumption.

10.1.4.3 The mixed-method approach: integration of quantitative and qualitative approaches

The process involves inductive reasoning to integrate both quantitative and qualitative information from each of the three levels at each time stage, and to infer likely decisions of system actors in response to this. This is clearly a process which does not produce optimal outcomes according to an objective function, and which employs human judgement to integrate qualitative and quantitative inputs, rather than purely deterministic calculations from purely quantitative inputs. There is a potential weakness here, in that throughout the scenario process choices and judgements which would in reality be taken by many different actors with access to detailed commercial information, are taken in the scenario by the individual researcher, with much less quantitative detail and some degree of subjectivity. On the other hand, the commercial information that would be available to an energy company in the year 2033 is no more available to a purely quantitative modeller in the present time than a qualitative analyst. The modeller will still at some point have to make a subjective judgement as to what the quantitative input data should be, even if on the basis of the input data it receives, the quantitative model can then proceed to make a watertight 'deductive' argument (see Section 7.2.5). Thus subjective judgement about future conditions is essentially common to all modelling and scenario approaches – the key difference is that the approach used in this thesis merely misses out a line of calculation compared to modelling approaches. For example, in the case of a scenario with a strong locational signal, the economic model argument would run, 'let's assume that the transmission charge at this location is £x/MW, and that this is sufficient to discourage investment in relation to other available areas', whereas the approach in this thesis would be, 'let's assume that *whatever the transmission charge at this location*, it is sufficient to discourage investment in relation to other available areas'. In either case you have an outcome which is dependent on subjective assumptions. Whilst the model may provide the analyst with a number, it is a number to which subjective assumptions are attached; it doesn't remove the subjectivity from the entire process.

Another frequent feature of quantitative economic models is the production of optimal solutions – based on a set of input criteria and a clearly defined objective function. The current approach clearly does not produce optimal outcomes according to any objective function. It does however produce narratives through which the perspective of actors making judgements in a multi-actor system with limited foresight and imperfect information can be explored. That the outcomes of these narratives are in no sense optimal, that some indeed are highly problematic, is not in itself a weakness. The consideration of scenarios that create problems – for example when actors are motivated to make decisions which are not system optimal; or of scenarios which come close to failure – for example when the value-set of the scenario seems to be increasingly incompatible with a key system objective; is just as useful as considering scenarios which succeed. The key point is that comparing scenarios which have different kinds of problems, or indeed 'sub-optimalities', which arise from different combinations of decisions which could be taken by identifiable prime-mover system actors, is more informative from a policy making perspective than the comparison of multiple 'optimal' solutions, whose differences are generated by the varying of uncertain assumptions which have no clearly identifiable link to the decisions of system actors.

Nonetheless the approach set out in this thesis is intended to be flexible, and to be capable of incorporating inputs and insights from a range of quantitative and qualitative tools, as appropriate to the focal question. Further quantitative detail in the analysis, notwithstanding the qualifications noted above regarding the inevitable subjectivity relating to assumptions about future quantitative data, could add detail and insight, for example on the trade-offs between different technologies with different investment costs, and the relative costs of deploying these in different areas of the network. Whereas the scenarios in this thesis were undertaken using a spreadsheet to list the assumptions made about generation investment, the incorporation of generation and transmission costs within different areas of the network within an energy system model could produce additional insight, provided the time-staged iteration within prevailing value systems could be maintained.

10.2 The role of the electricity transmission network in a decarbonising electricity system – technical insights and policy recommendations

The scenario process summarised in the previous section was applied to the key focal question:

- How can transmission network policy choices affect the role that the transmission network plays in helping to deliver a low-carbon electricity system by the early 2030s?

This section summarises the technical insights and policy recommendations that emerged from the analysis.

10.2.1 Significant expansion in transmission network capacities is required to facilitate a low carbon transition

The scenarios explore alternative pathways towards the same target of 50gCO_2/kWh carbon intensity of electricity generation, guided by alternative policy approaches to transmission regulation and planning. They employ different combinations of generation technologies and transmission network designs to reach the target. In each of the scenarios a significant expansion of the transmission architecture takes place, over and above the like-for-like renewal of existing assets. This is due to the lack of correlation between the potential location and capacity sizes of future low carbon generators, and those of existing conventional generators. Thus, a strong conclusion is that transmission networks will be required to play an important role in the low carbon transition, through their expansion to accommodate new forms of generation.

10.2.2 The level and location of required transmission network expansion varies substantially in response to different possible low carbon generation mixes and policy strategies

Although increase in network capacity is a common factor in all scenarios, the scenarios also show considerable differences in the levels and locations of new transmission investment required – there is more than one possible network configuration and associated generation mix which would succeed in delivering the target of 50g/kWh carbon intensity of electricity by the early 2030s. The variations in the networks developed emerge as a result of the alternative policy strategies pursued in each scenario, and of the resulting interactions between transmission network capacity and generation investment decisions. Further variations in network requirements were suggested by sensitivity analyses of 'non-actor-contingent' elements, which considered alternative electric vehicle charging patterns, the growth of solar PV and the development of grid-scale storage. Thus, while policy choices around transmission planning and regulation will substantially influence the way the network develops, the pathway taken will also be strongly interrelated to investment decisions on the generation side, and demand-side changes. The resulting potential for variation in network requirements makes it hard to identify a comprehensive future network 'blueprint' which could appropriately and efficiently apply to the range of all plausible future scenarios. Thus transmission network planning requires forward thinking, to ensure that insufficient or inappropriate transmission investment does not become a barrier to decarbonisation, but also flexibility, to allow generation and transmission to co-evolve in a coherent manner.

10.2.3 Challenges and opportunities for transmission networks in a decarbonising electricity system

The scenarios suggest a number of challenges and opportunities that will be faced in the planning and operation of the transmission network over the coming decades.

Several inherent characteristics of low carbon technologies present direct network challenges. Renewable resources are in many cases located distantly from high load centres and will require network upgrades. In many cases the speed with which they can be built will outpace that with which transmission lines can be built, presenting a coordination challenge, particularly in the 2020s when the pace of decarbonisation must be rapid.

The transitional period of the 2020s could see challenges as the combination of growing renewables alongside still high fossil output creates risk of high exceedences. This period will also be likely to require new CCGT investment, which must be operated intermittently otherwise there is a risk of fossil lock in.

There will be considerably greater variation in power flow patterns and constraints in different seasons, and under different wind conditions within the same seasons – this creates challenges for how much to size the network, as well as network management issues. Flexible and responsive fossil as well as low carbon plant, will be of increasing value.

Storage, electric vehicles with load shifting, and distributed generation all have the potential to make significant impacts on transmission constraints and investment requirements, both positive and negative. At the same time these technologies would also impact on the distribution network, though there may be situations in which a beneficial outcome for the transmission network is the opposite for some distribution networks, and vice versa.

Interconnection also has the potential to balance renewable variation and help to avoid constraints and onshore network investment – however if it is not responsive to regional network conditions it may increase constraints. Large offshore zones may also contribute to significant onshore constraints, but if coordinated could assist with relieving GB system constraints

Overall the physical size and costs of the required transmission network are potentially very large, as is the difference in size and cost between the alternative systems presented in the scenarios. Networks are not a marginal part of the cost and impact of the overall low carbon transition.

10.2.4 Policy recommendations

10.2.4.1 Primary policy recommendations

There are two primary policy recommendations arising from this analysis. The first is to establish a locational signal at the operational, as well as investment timescale. This would

- incentivise existing fossil generators to avoid using the network at high wind times
- encourage the co-location of renewables with complementary output patterns
- provide stronger signals for the siting and operation of interconnectors, helping to ensure that they relieve congestion and avoid onshore network upgrades, rather than add to them
- provide the appropriate innovation signal for developing technologies such as CCS, storage and electric vehicles, and for socio-technical innovations such as demand response aggregation – that flexible response is something that is valued and will be rewarded on the system

There are different options for how the locational signal can be provided. Given the realities of the current regime and policy value-set, the approach most likely to achieve results is to include a locational element within BSUoS.

The second primary recommendation is to create a body with a remit to oversee strategic interactions between the various actors and regimes of the electricity system, and to identify potentially beneficial opportunities for strategic coordination between them. There are potentially significant benefits to be obtained from joining up thinking between onshore, offshore and interconnections. There will also be increasing interactions between transmission and distribution networks. The new body would provide evidence for a needs case which could be taken up in transmission companies network development plans, and subsequently scrutinised by Ofgem. This may be a natural evolution from the existing ENSG, but would need to be transparently independent from commercial interests of system actors, and to have a transparent approach to assessing future uncertainties in the context of government targets.

10.2.4.2 Interactions between locational signals and strategic coordination

There are clear interactions between the locational and the coordination dimensions. Not least, the weaker the locational signal, the stronger the case will become for coordination and intervention, for example to direct interconnector connections, or commission plant in specific locations for network balancing reasons. However, more positively the locational signal potentially works well alongside a coordinated approach. As noted above, transmission network planning requires forward thinking, to ensure that insufficient or inappropriate transmission investment does not become a barrier to decarbonisation, but also flexibility, to allow generation and transmission to co-evolve in a coherent manner. The key to this balance is a locational signal. A locational signal is of potentially great value to an anticipatory or coordinated scheme, as it provides the transparent information required to justify the benefits of the scheme. Additionally, once projects have been built, the locational signal (especially if it operates at the operational timescale) encourages the efficient utilisation of the network that has been built, maximising the investment and avoiding further investments.

10.2.4.3 Additional policy suggestions

The scenarios show very high levels of variation in power flows within years, due to a combination both of different demand profiles, but also very substantial in response to different weather conditions. This suggests that for all kinds of network analyses, the traditional approach of analysing the winter peak as the time of greatest network stress, will no longer be sufficient. Rather, a range of system conditions, affected by both demand and locational renewable output, will need to be analysed.

Finally, the scenarios show that transmission networks will constitute a significant part of the overall costs and impacts of the transition. The public consent for the transition as a whole is vital. Whilst studies have explored public acceptance of transmission architecture, and of generation technologies, given the interactions between these as shown in the scenarios, it will be of increasing value to have public conversations about these in which the interactions and trade offs between generation and transmission are made explicit.

10.3 Suggestions for future work

This thesis concludes with some suggestions for areas of future research.

10.3.1 More detailed policy analysis on locational BSUoS or alternatives

A key recommendation was creating a locational signal on dispatch via locational BSUoS. Given the potential for controversy and extended debate in any change to system codes which creates winners and losers, more research is required into the specific advantages, disadvantages and institutional challenges of creating a locational BSUoS charge. It would also need to be established that the incentives it creates could also be accessed by demand side participants. If the challenges are too great, then alternative means of creating a locational dispatch signal need to be suggested.

10.3.2 Identification of the precise institutional requirements for a strategic coordinating body

The research proposes an independent body tasked with overviewing system developments and identifying beneficial opportunities for coordination between actors and regimes. Further research could define more precisely how the remit and structure of the body could be arranged such that it had industry authority as well as independence from commercial interests, and whether it could be established through an evolution of the ENSG.

10.3.3 Integration of transmission issues into conversations around public acceptability of energy system transitions

The generation mix and the transmission network are integrated, co-evolving elements of the same system. Different generation mixes have different implications for transmission, and limitations on transmission can also imply limitations on generation choices. Important work on public acceptability of whole system energy transitions has been undertaken by Parkhill et al (2013). An important next step for the public conversation is the integration of transmission networks into this whole system picture, and integrated generation-transmission scenarios could be an important tool to assist in this.

10.3.4 Scenario method refinements

A number of refinements and improvements to elements of the scenario method developed in this thesis could be undertaken in future research. A key area is the representation of different wind conditions, in a way which incorporates a more developed statistical understanding of the likelihood of different conditions, without smoothing the outputs entirely to averages and thereby ignoring the significant effects of gradients across the system at specific times.

Another potential avenue is to enhance the generation system representation by soft-linking the approach to an energy system model (ESM). This would require not running the ESM in standard full-optimisation mode, but rather in a staged or 'myopic' optimisation mode, allowing iteration with the power flow, values and actor analysis of the scenario approach.

10.3.5 Broader applications

The scenario method developed in this thesis has been applied to a specific question of transmission network policy. However, the method could also be applied to other questions of sociotechnical transition, in which there is deep uncertainty, but where the role of policy in affecting the direction of system evolution can nonetheless be significant. A key feature of the scenario approach developed in this thesis is the tightly-constrained system scope, which is intended to ensure clarity in the analysis of the effects of the independent variables of interest, whilst holding other variables constant. However, as noted, the tightly-defined system scope recommended in this method may be considered at odds with the range and depth of system transformation that could be envisaged in the context of a low carbon transition. A challenge for future research is whether it is possible to maintain the rigorous approach to system scope and independent variables recommended in this thesis, with a more holistic view of the wide ranging challenges and potential transformations which may be faced by a decarbonising energy system.

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Appendix A: Power system basics

A.1 Electricity networks

Electricity systems are connected through networks of electrical circuits. In countries with large interconnected electricity systems, bulk, long-distance transfer of electrical energy is usually achieved on high voltage circuits strung on steel pylons. At the local scale, smaller quantities of power are delivered to final end-users on low voltage circuits, which often disappear beneath the roads once they have entered towns and cities.

A.1.1 Voltage and losses

Losses of electrical power occurring due to resistance[5] within a conductor are given by:

Equation 2

$$P_{loss} = I^2 R,$$

where P_{loss}=power losses, I=current and R=resistance. Thus, for a given resistance, power losses are proportional to the square of the current. Further, because:

Equation 3

$$P = VI,$$

where P=power, V=voltage and I=current, an increase in voltage proportionally reduces the current for a given power flow. Thus increasing the voltage reduces resistive losses in proportion to the square of the voltage change. High voltage networks therefore have significantly lower resistive power losses than low voltage networks. Because resistance in a conductor increases in proportion to its length, high voltage networks are preferred for the transfer of power across long distances.

[5] Resistance is a concept which applies to direct current (DC) systems. The analogous concept in alternating current (AC) systems is impedance. For simplicity, these fundamentals are set out here using the concept of resistance, as for DC systems. However, the fundamental principles are transferrable via the concept of impedance to AC systems.

A.1.2 Loading limits of electrical circuits

The amount of power that can be safely transferred across electrical circuits is limited by three considerations: thermal limits, voltage drop limits, and stability limits.

Thermal limits occur as greater power increases current (Equation 3), which in turn increases power losses (Equation 2) resulting in a greater amount of energy being dissipated in the wires as heat. The increased temperature in the wires causes sagging, increasing the proximity of adjacent wires to each other as well as to other external objects, which can create a risk of power arcs and short circuits.

Transmission of power over long distances also results in a reduction of voltage at the receiving end of the line. The voltage drop occurring within a resistor (such as a transmission line) can be calculated by Ohm's law:

Equation 4

$$V = IR,$$

which shows that voltage drop is proportional to resistance, which itself increases with distance. Thus long distance transmission lines are susceptible to significant voltage drops. Voltage drops must be minimised in order to preserve system efficiency and ensure correct operation of electrical equipment. Voltage drops can be controlled by limiting the loading on vulnerable line sections, however, reactive power provided by shunt capacitors and reactor compensations can also be used to control voltage levels.

Power system stability is defined by Kundur et al (2004) as 'the ability of an electric power system, for a given operational condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact'. The type of stability being considered can be subdivided according to whether the disturbance is small and the time frame gradual, which can include the normal load changes during everyday operation – often referred to as 'steady state stability'; or whether the disturbance is large and sudden, such as a loss of generation or line fault, often referred to as 'transient stability' (Glover et al., 2008). Kundur et al (2004) further define stability types according to the mechanical issue of concern in each case. Voltage stability is concerned with maintaining steady voltages at all system buses, and avoiding voltage drops, as discussed above. Rotor angle stability 'refers to the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance' (Kundur et al., 2004). The rotor angle, or power angle, is the phase difference between the voltage waveforms of generators at either end of a transmission line. The power transmitted across the line is proportional to the cosine of the power angle – hence a power angle of 90° would achieve maximum power transfer. However, exceeding a power angle of 90° has non-linear effects as generators become increasingly out of synchronism, risking reversal of power flows with cascading destabilising impacts on the rest of the system. Operators therefore limit power angles considerably below 90° to avoid this risk following an unexpected disturbance. This can place a limit on the acceptable power transfer capability of a line which is some way below its maximum thermal loading level. A third type of stability is frequency stability. The GB system operates at a frequency of 50 Hz, and the nominal frequency is maintained as long as load and generation are in balance. Sudden losses of loads in parts of the system can lead to frequency swings which in turn can lead to further tripping of generating units and loads. An interconnected network can mitigate against this risk by ensuring that load can be maintained even in the case of an unexpected fault or line-outage – however maintaining this responsive capacity may again require limiting the loading of transmission lines below their theoretical thermal maximum.

Appendix B: Additional policy detail

B.1 The British Electricity Trading and Transmission Arrangements

The production and consumption of electricity in Great Britain takes place in a market governed by the various codes and standards known collectively as the British Electricity Trading and Transmission Arrangements (BETTA). The bulk of electricity trades within BETTA are bilateral – the result of contracts between electricity generators and electricity retailers, who in turn then sell electricity to consumers. Some large consumers also buy energy wholesale direct from generators under bilateral contracts. Bilateral trading ends one hour before real time (called 'gate closure'), after which point only the system operator (SO) National Grid may undertake further trades (Green, 2010).

During trading, participating companies will have provided National Grid with indicative information about their trades, in order to assist the SO with its network planning. At gate closure, companies notify National Grid of their final intended contractual positions (the energy they have agreed to buy or sell as a result of bilateral trading) and their intended physical positions (the energy they actually expect to supply or consume, which may be different from the contractual position due to unexpected events).

From gate closure to real time, the SO can make further trades through the Balancing Mechanism (BM). The role of the SO at this point is to ensure that supply and demand are balanced, while respecting transmission network constraints. The SO may need to buy or sell in order to balance energy shortfalls or over-supply resulting from differences in contracted and physical positions of market participants – for example a generator may be short of power due to an unexpected plant outage, or a retailer may require more power due to incorrectly forecast demand. In addition, even when supply and demand are matched on aggregate, the SO may have to trade to re-arrange the geographical provision of supply in relation to demand, due to transmission constraints. In such a case, the SO 'sells' energy back to a generator on the exporting side of the constraint (reducing the overall generation behind the constraint), and must then 'buy' the resulting shortfall back from another generator on the importing side of the constraint. The level of trading which must be undertaken by the SO in the BM is therefore partly related to the level of congestion on the grid.

Participants in the BM submit 'bids' to buy power (for a generator this means buying back power they have already sold, or in other words reducing their output; for a large consumer this means increasing consumption); as well as 'offers' to sell power (for a generator this means increasing generation, for a consumer reducing demand). In the case of 'offers' the potential for profit for a generator is straightforwardly that of the additional reward for producing more power. In the case of bids, the profit margin occurs because the generator will bid to 'buy' back their own power (turning down their generator and saving fuel) for less than the price at which they previously sold it. Successful participants in the BM require a high level of flexibility in their operation patterns; hence nuclear and renewable generators find it difficult if not impossible to participate in the BM.

In a situation where more power is required at a given location, the SO will require to buy more power and will therefore look for offers from suitably placed generators. In the situation where less power is required, the SO will need to sell excess power back, and will therefore be looking for bids from suitably placed generators. The total cost of these exchanges to the SO will be the money spent in accepting offers, minus the money recuperated from accepted bids. ***Figure 180*** illustrates this graphically, in a situation where both bids and offers, in different locations, are required to resolve a transmission constraint.

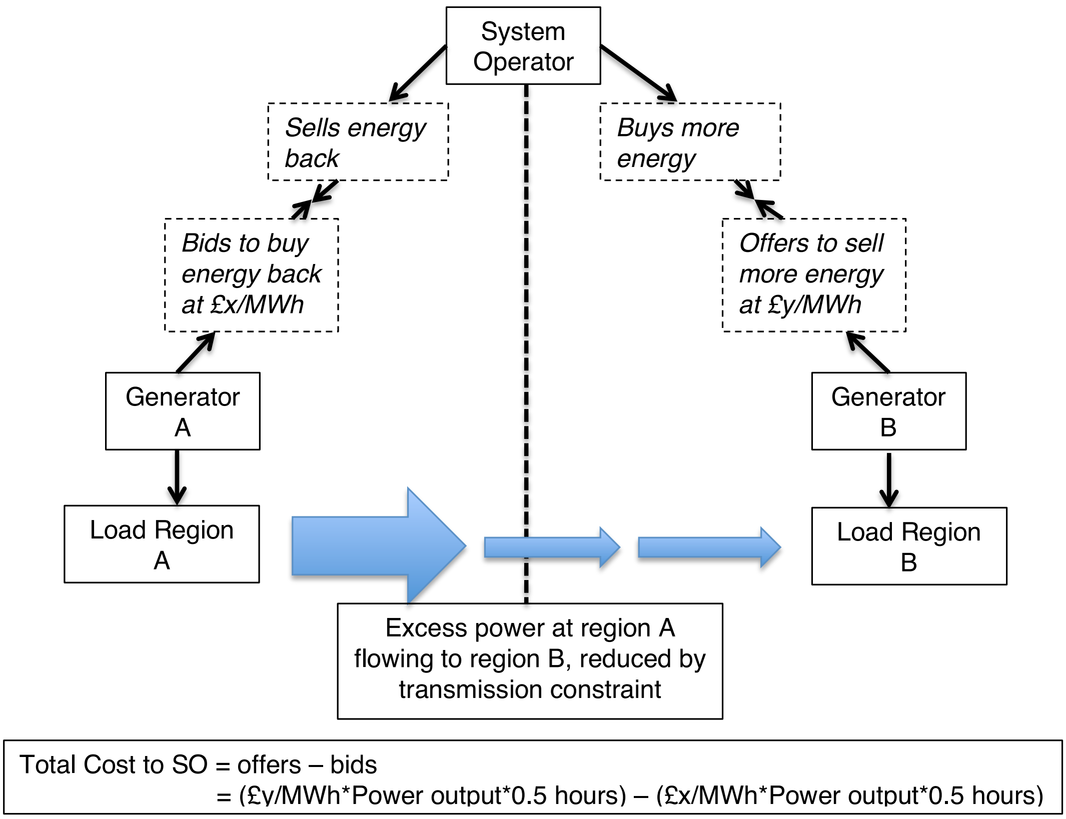

Figure 180: *Illustration of the balancing mechanism*

The prices at which companies make bids and offers for the BM are indicative of their propensity and willingness to participate. The figure below shows average bid and offer prices for the BM, compared to the market index price, for the year 2008/09.

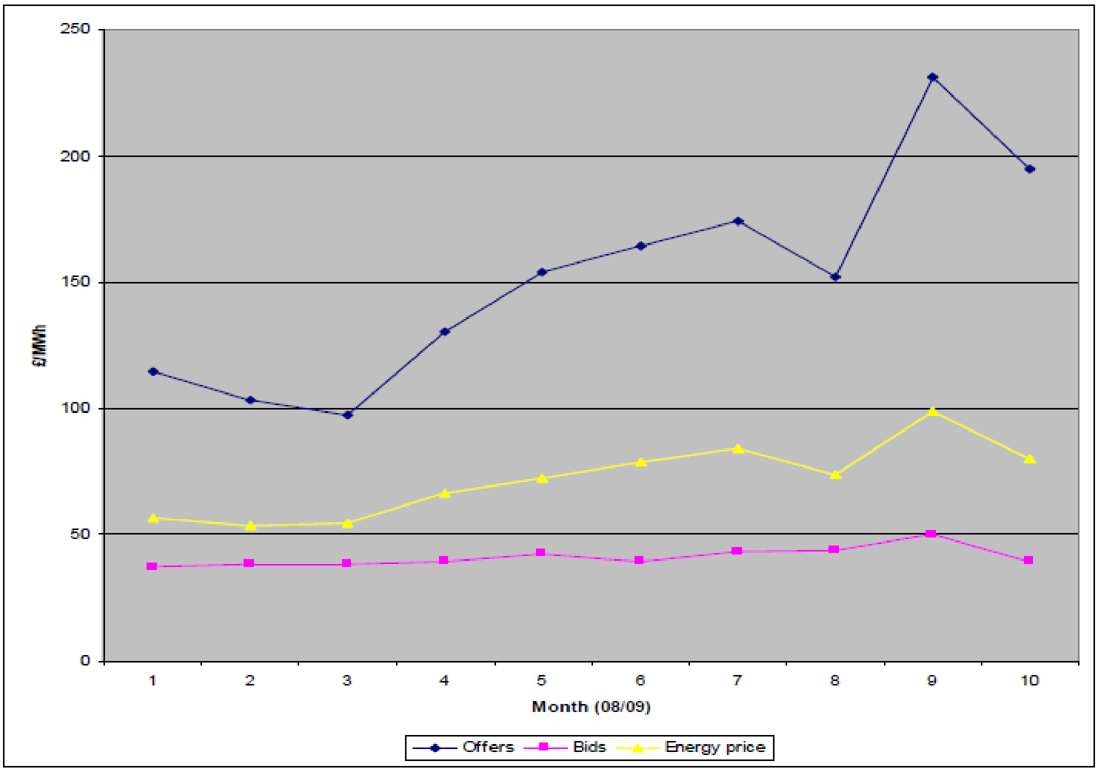

Figure 181: *Balancing mechanism bids and offers compared with market index price, 2008/09 (Baker et al., 2010)*

The table below presents the bid / offer assumptions used in modelling of transmission access options by Redpoint for DECC, in terms of their deviation from the market price. The data are derived from historical observation. For example, using these assumptions, for a market price of £50/MWh, Coal would submit a bid of £45/MWh and offer at £85/MWh. The cost incurred by the system operator if were able to select this technology both for constraining on and off, would be the difference between the actual bid and offer prices (or the sum of the discount and the premium) – in this case £40/MWh.

Table 35: *Assumed deviations from short-run marginal costs in the balancing mechanism used in Redpoint modelling (Redpoint, 2010)*

Plant type	Bid discount	Offer premium
Coal	5	35
Coal LCPD opt out	8	90
CCGT	10	50
OCGT	10	70
Oil	10	300
Hydro	20	20
Offshore Wind	80	10000
Onshore Wind	40	10000
Biomass regular	40	10000
Biomass energy crop	80	10000
Marine	120	10000
Nuclear	150	10000

The very low bid prices submitted by renewable generators reflect the fact that if they do not generate they will not qualify for ROCs – thus the margin between the price at which they sold the energy and that at which they bid to buy it back, must at least compensate them for the loss of the ROC. The implication of the discount level used by Redpoint for offshore wind and marine would be a negative bid price in most circumstances – that is they would receive a payment not to generate. Similarly, nuclear plants would typically submit negative bids due to the cost of flexing down a nuclear plant at short notice.

At the other end of the scale, the extremely high offer prices submitted by most renewables and nuclear indicate that they do not wish to be asked to increase generation. For renewables this is due to the fact that they would be physically unable to increase their output beyond what was available from their renewable energy source; for nuclear it reflects the fact that if running, the plant would be running at full available output, without the ability to flexible ramp up at short notice.

The BM is not the only mechanism available to the system operator for the balancing of supply and demand, or resolution of transmission constraints at or close to real time. Through the Short-term operating reserve (STOR) the system operator pays rent to participants to keep spare generation on standby at specified times. Triads are a means of triggering industrial demand side response. The Capacity Mechanism, one of the reforms to be introduced as a result of the forthcoming Energy Bill, would further increase this type of strategic reserve available to the system operator.

At the end of each half hour trading periods, the trades made by the SO within the BM are summed. If the SO had to accept more offers than bids (or buy more energy than it had to sell), then overall there was a shortage of generation and the system as a whole was 'short'. This triggers a 'system buy price' (SBP) to be calculated from the average of a representative sample of the SO's purchases, excluding those made for system reasons such as resolving transmission constraints or running spinning reserve. Participants who were short of power in a short system are then made to pay the SBP, effectively paying the SO for the purchases it made on their behalf in the BM. Participants who had excess power in a short system receive payments for their excess based on the price of recent trades.

If the SO had to accept more bids than offers (or sell more energy than it had to buy), then overall there was an excess of generation and the system as a whole was 'long'. This triggers a 'system sell price' (SSP) to be calculated.

B.2 The TNUoS calculation method

In the GB system the standard charge for access to the network for both generators and consumers is known as the Transmission Network Use of System (TNUoS) charge. The current method for setting TNUoS charging tariffs is based on a calculation of the notional increase in network costs associated with any incremental change in generation at each location on the network. It is known as 'investment cost related pricing'.

The model begins from the assumption that the time of system peak demand is the point against which the security of the network, and choices about investment in new network, must be defined. The method scales total transmission entry capacity (TEC) by a uniform factor so that over the whole network, total generation = total demand. A load flow model calculates the power flowing down each branch under this system condition, and multiplies this by the length of the branch to give a network usage indicator, in MWKm. The sum of MWKms on each branch yields a total MWkm figure for the network. Generation is then increased at one node, and the calculation performed again. The difference between the MWKm figure now calculated, and the original base case MWKm, is the nodal incremental MWkm figure, which will be positive or negative, depending on whether the additional MW of generation increased or decreased power flows. The incremental MWKm figure is then multiplied by an 'expansion factor' representing the different costs of different line types, and by a global locational security factor, which allows for the additional security standards of a secured network according to the GB SQSS. This yields a cost increment (or decrement) resulting from increasing generation at one node. By repeating the calculation for each node, a set of incremental costs per additional MW are calculated. Nodes with similar costs are then grouped together into zones, and an average cost per MW calculated for each zone. This produces an unadjusted zonal tariff in £/kW. This tariff is adjusted by a constant, c, so that the revenue recovery is 73% from demand and 27% from generation. (This split was defined at privatisation and appears to be entirely arbitrary (Bell et al, 2011)). Local charges are then computed using the same method as for the wider tariff. Finally a fixed residual non-locational component is added to the charge to make up the full cost-recovery requirements for maintaining the network and building new capacity, as the locational component recovers only about 20% of 'Total Allowed Revenue' allocated by the regulator to the transmission companies (Bell et al., 2011, Kirk-Wilson, 2010)

B.3 NETS SQSS

Transmission network investment levels are subject to different pressures. The transmission network is required to convey power between generation and load centres. In order for this to be achieved with an acceptable level of security of supply, standards are defined to which the network must conform. Changes in generation and demand patterns may increase or change the stresses placed on the network, which may in turn create the need for new network investment. On the other hand an objective to deliver an acceptable level of service at the minimum possible cost has a constraining effect on levels of network investment.

Since the 1970s, transmission network planning has been undertaken primarily through analyses of its required performance at the time of the highest demand on the system, or 'system peak' (Bell et al., 2011). As well as managing power transfers at system peak, the system must be resilient to an additional set of stress factors coinciding with the peak. These are defined in the document known as the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS). The system must be planned such that for any of the following events: a fault outage of a single circuit (N-1), a double circuit over head line on the 'supergrid' (400kv) (N-d), a double circuit line in SHETL or NGET's region, a section of busbar, or a fault outage following a prior outage if both are within NGET's network (N-2); the following will not occur: loss of supply capacity, unacceptable overloading of primary transmission equipment, unacceptable voltage conditions or system instability (National Grid, 2012b).

In the operational timescale, the standards are slightly more flexible. The N-1 standard remains binding, though the system does not have to be secured against loss of supply capacity less than 1500 MW for a double circuit fault; and for the loss of double circuits on the Supergrid unacceptable voltage and circuit overloading must be avoided although no avoidance of loss of supply is mentioned. No mention is made either of N-2 requirements (National Grid, 2012b).

B.4 Locational Marginal Pricing (LMP)

Under locational marginal pricing, a market clearing price is calculated for every location in the network, based on the marginal costs of the plants available to supply the load to that specific location at that specific time. Transmission constraints are reflected in these prices, as locations unable to access generation from the cheapest plant due to lack of transmission capacity, will be given a price which reflects the marginal cost of the plant that is available to them. Thus, generators will receive a lower price if they are located in an area of the network which already has high availability of low cost generators sufficient to meet local demand, and where additional generation is likely to cause export; conversely generators located in areas where load is exceeding local generation, or where local generators have higher marginal costs and import capacity is limited, will receive a higher price. The PJM operates with a day-ahead market and a real-time market. The day-ahead market calculates hourly LMPs for the following day, based on submitted generation offers, demand bids, and scheduled bilateral trades. The real time market is a spot market with LMPs calculated every five minutes based on the actual operation of the system (PJM website). ***Figure 182***, ***Figure 183*** and ***Figure 184*** illustrate the variability of prices by location and time in the PJM. At 7:10am on a weekday morning, there are relatively low prices across the network, but the higher prices are clustered around the areas where load is highest – cities and conurbations like Washington, Ohio and Chicago. At 7:20am, prices across the whole network have increased, probably reflecting a spike in demand as the working day begins. By 7:30am, prices have been suppressed, probably reflecting the activity of generators in ramping up to meet demand. The picture looks similar to how it was at 7:30, though with slightly different gradients, probably reflecting the availability to different locations of generation to meet demands. These prices are therefore signals which influence real time operational decisions. Further, by observing their patterns over the longer term, generators would also be able to consider their potential new investments in different areas of the network according to the revenue they might expect to receive there. Additionally, the prices can serve as signals for independent transmission owners to make new transmission investments between regions where the price differential is persistently large. Locational Nodal Pricing is a variant on LMP which is used in the Nordpool, a market including a number of northern European countries. It is based on a similar principle but with the locational energy prices clustered into larger regions, rather than being provided at every individual network entry point.

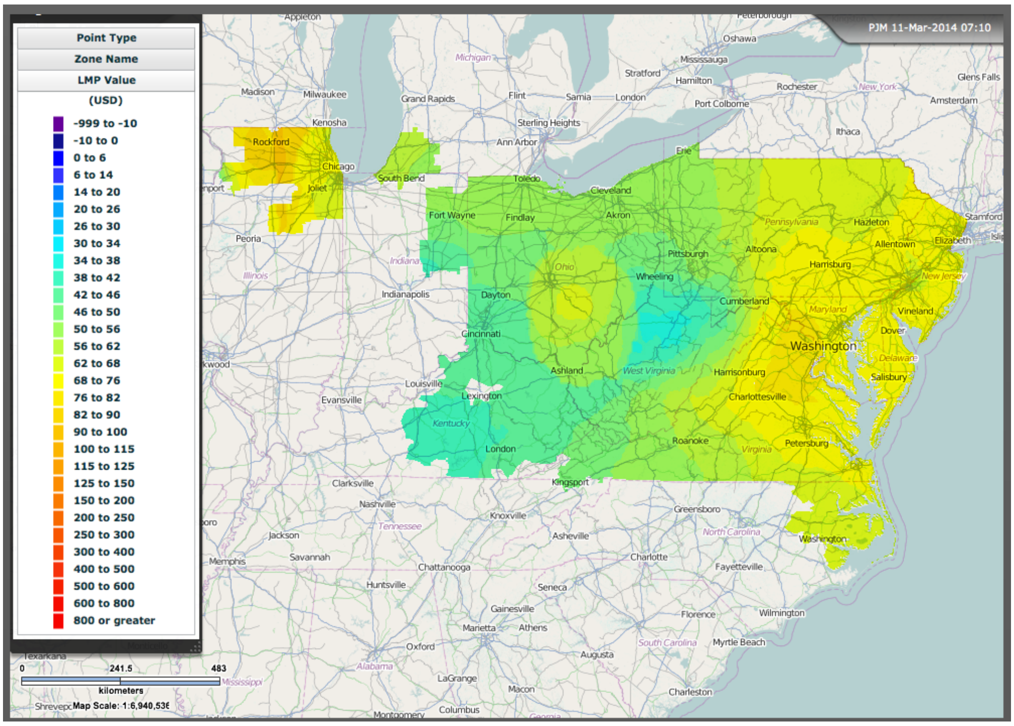

Figure 182: *Contour map showing price variation across PJM market, Tuesday 11th March, 7:10 am, Eastern Daylight Time. Source: PJM*

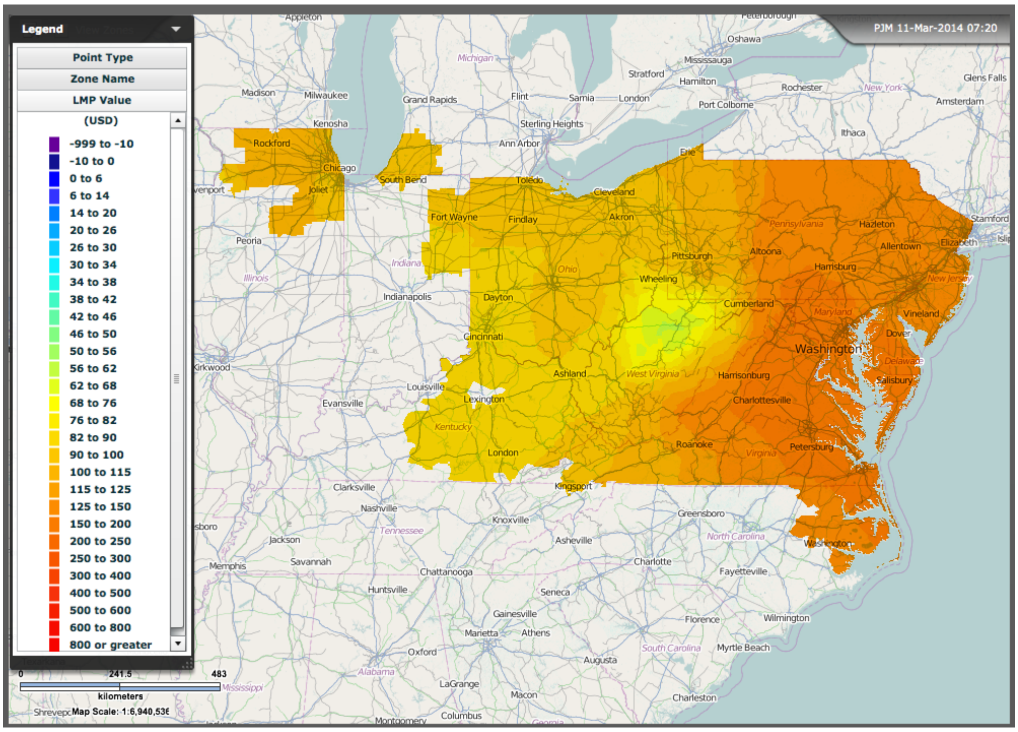

Figure 183: *Contour map showing price variation across PJM market, Tuesday 11th March 2014, 7:20 am, Eastern Daylight Time. Source: PJM*

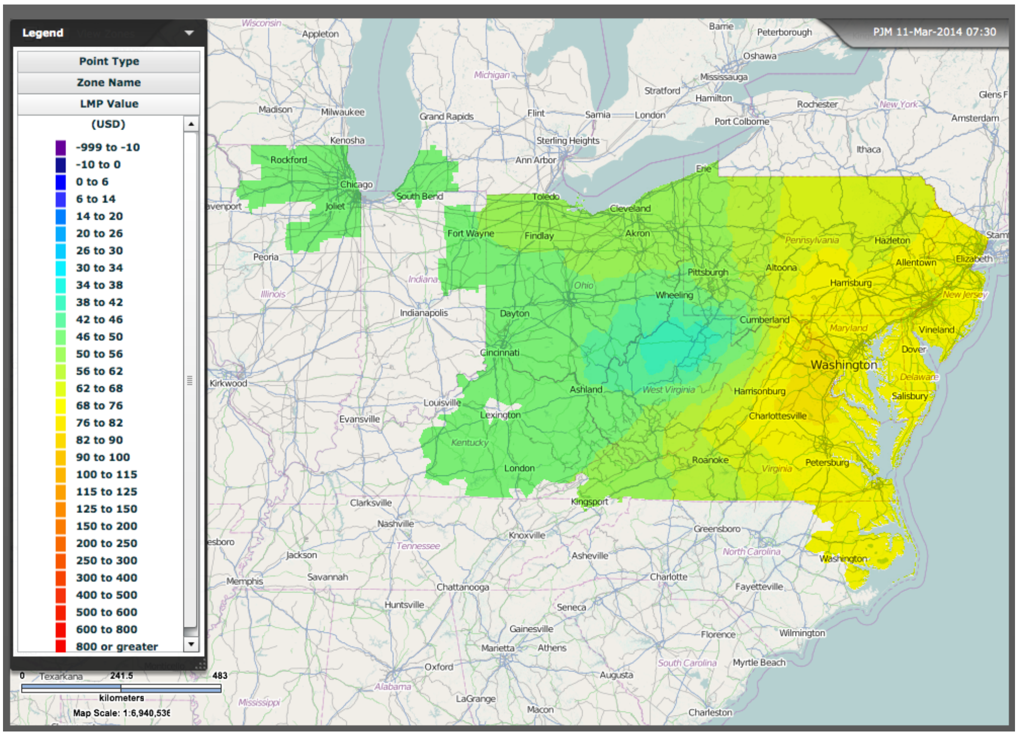

Figure 184: *Contour map showing price variation across PJM market, Tuesday 11th March 2014, 7:30 am, Eastern Daylight Time. Source: PJM*

Appendix C: Semi-structured interviews

Semi-structured interviews were carried out with seven senior-level stakeholders in organisations involved in the GB electricity system. The stakeholders spanned:

- Energy companies
- Transmission owners
- The System Operator
- The Regulator

The interviews were carried out on the basis of the Chatham House Rule – views would be cited but not attributed to individual or organisation. The interviews were recorded, transcribed and analysed for cross-cutting themes. The resulting analysis is presented in Chapter 5.

C.1 Interview structure

The following structure was observed for all interviews.

C.1.1 Introduction – the basis of the research

The aim of the research was introduced: to investigate the role of the transmission network in a decarbonising electricity system. In particular, it considers the interaction between transmission and generation policies and investment decisions in the development of a low carbon electricity system.

C.1.2 Part 1: the 2x2 axis

The 2x2 axis developed from the policy analysis presented in Chapter 4 was presented to the interviewee (***Figure 185***).

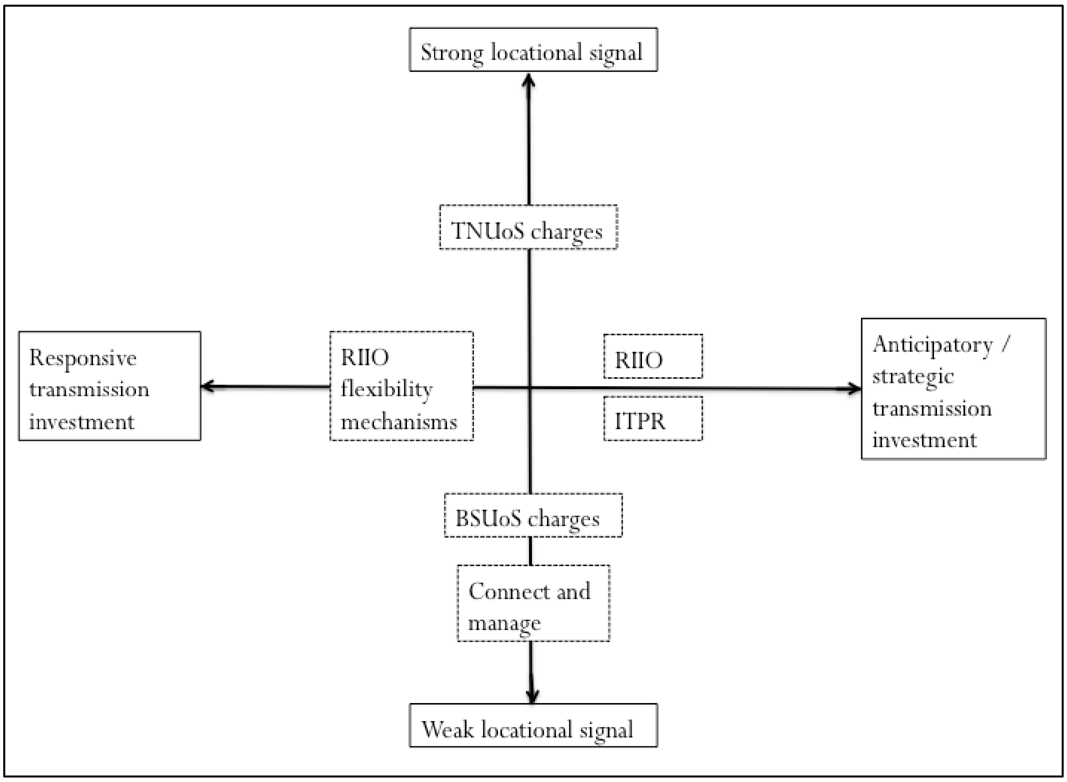

Figure 185: *Intersection of two policy variables - strength of locational signal and level of strategic approach ot transmission investment*

This graphically lays out the two policy areas which are the focus of this research, represented as intersecting axes: the level of locational signal provided for generators; the degree of strategic or anticipatory decision making in transmission investment. It also places aspects of the current policy mix along each axis, showing that different aspects of the current policy mix have a different emphasis.

- Q1. Bringing together the cumulative effect of these various policy elements, where would you currently position us on this grid?
- Q2. Where do you think we should be?
- Q3. Are there important variables not covered by these axes?

C.1.3 Part 2: locational signals

- Q4. Should generators be exposed to full ('deep') connection costs and locational transmission charges? Or should network costs be a socialised cost, so as not to disadvantage any generator whose location may be determined by resource availability?

C.1.4 Part 3: strategic planning

- Q5: Should we have a strategic plan for network development? Or is this too interventionist?

C.1.5 Part 4: other issues

- Q6. Is there a requirement for institutional change?

- Q7. Are there other important issues which relate to the development of the transmission network within the context of an increasingly low carbon generation mix, which have not been mentioned here?

Appendix D: Heuristic model development

D.1 General approach

Any model of a technological system employs some simplifications of the real world system. Judging what simplifications can reasonably be made within the model in order to make the process workable, whilst maintaining sufficient technical detail to enable analysis of key questions, is an important part of model development. A useful heuristic in guiding the balance between simplification and complexity is the principle known as 'Ockham's razor' or *lex parsimoniae* (the law of parsimony). Though it has been applied widely and restated in many forms, its original formulation appears to be:

> Plurality must never be posited without necessity (William of Ockham)

Applying the principle to the process of constructing a model suggests that a model should be as complex as necessary to answer the question being asked of it, and no more complex than this. In relation to the above research question, the requirement is for a model that has enough detail to represent the effects of specific actor investment decisions and policies relating to the UK electricity transmission network, and to demonstrate how, in the long term, these decisions are more or less favourable to the deployment of low carbon generation technologies. There is less requirement, in the context of this research question, for a model capable of analysing near term operational issues, relating to voltage drops, transient stability, faults and outages.

D.2 National grid boundaries

In the 2011 Seven Year Statement (SYS), National Grid divides the GB transmission network into 17 study zones, divided by 17 boundaries, for the purposes of analysing power flows across key points of interest in the network. The location of the boundaries and study zones in relation to the main interconnected transmission system is shown in Figure 22. Each boundary divides the entire network into two sections, so that the number of zones on one side of the boundary added to the number of zones on the other side of the boundary is always 17. The 2011 SYS provides indicative generation and load figures for each study zone for the anticipated Winter Peaks of the years 2011/12 to 2017/18 (National Grid, 2011b). This data provided a useful starting point for model development.

D.3 Heuristic model development approach

D.3.1 Boundary analysis

Given locational load and generation data, it is possible to calculate the power flow across any boundary which divides a power system into two parts, using a simple arithmetical process, without recourse to the power flow equations of a load flow model. Neglecting losses, within any network where total generation = total demand, when split into two parts by a single boundary, the power flow across that boundary can simply be calculated by subtracting load from generation on either side of the boundary. A negative figure indicates the importing side of the boundary, a positive figure indicates the exporting side. This process is set out in Table 36 for the generation and load data provided in the SYS for the year 2011/12. The discrepancy between the power flow values on either side of each boundary are due to the fact that there is a discrepancy in the data of 7MW between total system load and generation.

Table 36: *Generation, load and power flows across 17 SYS boundaries at Winter Peak, 2011/12*

Boundary	Load North (LN)	Load South (LS)	Gen North (GN)	Gen South (GS)	Power flow from North (GN-LN)	Power flow from South (GS-LS)
1	511	58323	915	57926	404	-397
2	1120	57714	1905	56936	785	-778
3	65	58769	273	58568	208	-201
4	1702	57132	2634	56207	932	-925
5	2895	55939	4792	54049	1897	-1890
6	6025	52809	8734	50107	2709	-2702
7	8886	49948	11704	47137	2818	-2811
8	21434	37400	29198	29643	7764	-7757
9	29832	29002	39226	19615	9394	-9387
10	51451	7383	55796	3045	4345	-4338
11	14177	44657	21841	37000	7664	-7657
12	46230	12604	49963	8878	3733	-3726
13	55884	2950	57055	1786	1171	-1164
14	49330	9504	57091	1750	7761	-7754
15	56684	2150	53627	5214	-3057	3064
16	15134	43700	28383	30458	13249	-13242
17	51393	7441	55355	3486	3962	-3955

Would such a boundary analysis be sufficient for the current research? A boundary flow analysis can deal only with one section of the network at a time, and aggregates a broad range of assumptions around what is happening across the rest of the system, in terms of load, generation and network. For example, a boundary analysis of SYS

Boundary 6, which runs along the border between Scotland and England, would not distinguish amongst the power flow across that boundary between particular onshore upgrades, or the proposed DC offshore cables. It would not see how actions taken to relieve pressure on this boundary would affect other areas of the network, as the analysis effectively assumes that all other areas of the network are balanced. Therefore, a boundary analysis could be a useful tool to generate quickly a large number of scenarios, if the interest is in examining one area of the network in particular, or one at a time. The boundary analysis is less suitable for assessing interconnected network development effects, such as corridors of power flow, and the effects of developments in one area upon another. The controversies around renewable generation installations and transmission line upgrades occur in specific locations, and may involve interrelated impacts across the network, and potentially trade offs between investment decisions in different areas. The aim of this research is to set such controversies in the context of different evolving system options. Future networks, having undergone different levels of investment may also have different capacity and bottleneck issues to the present one, for which the existing SYS boundaries have been drawn up. Thus, a simple boundary analysis is not sufficiently fine-grained or flexible for the purposes of this research.

D.3.2 17 node load flow with generic branch data

Initial load flows were conducted using a 17 node representation of the GB transmission network. This was convenient due to the fact that aggregated generation and demand data is available for the Winter Peak for 17 study zones in the National Grid's Seven Year Statement (SYS) (National Grid, 2011b) for the years 2011/12 to 2017/18.

A means of representing the connections between these regions was sought which provided greater spatial detail than the boundary analysis, but which was still high-level enough to be sufficiently manageable and flexible within the broader scenario method employed in this project. Detailed line parameters for every section of the GB transmission network are available in Appendix B of the 2011 SYS (National Grid, 2011b). In each case, the key data provided are the identities of the two nodes connected, the length and voltage of the line, and the line parameters of resistance (R), reactance (X) and susceptance (B), and the thermal capacity rating of the line in MW. For the purposes of this initial simplified model, the parameters for three sections of real lines were selected, to be representative of short, medium and long distance transmission line sections in the model. Table 37 provides the relevant parameters of these line sections.

Table 37: *Parameters of three indicative line types*

Line Type	From Node	To Node	Length (km)	R (% on 100 MVA)	X (% on 100 MVA)	B (% on 100 MVA)	Winter Rating (MVA)
Long	Cottam	Eaton Socon	135.23	0.15	2.35	89.14	2780
Medium	Norton	Osbaldwick	83.84	0.11	1.59	51.05	2009
Short	Cottam	Keadby	34.63	0.06	0.67	20.61	2102

By examining the distances between the centres of each pair of connecting SYS zones, the choice of whether to apply the short, medium or long line data to connect the corresponding nodes was taken. Where zones were connected by more than one transmission line, the number of lines connecting the corresponding nodes was doubled, tripled or quadrupled as appropriate. For example, Figure 186 shows that Zone 6 and Zone 7 are separated by Boundary 6, and that the principal lines which cross this boundary are two 400 kV double circuits – one from Strathaven to Harker, the other from Eccles to Stella West. The distance between these centres was judged to be 'medium'. Thus four individual lines of line type 'medium' (representing two double circuits) connect Node 6 to Node 7 in the model. Figure 187 is a representation of the simplified approach to representing this section. The same process was repeated to produce a branch matrix providing an approximate version of the GB transmission network, consisting of 17 nodes which correspond to the 17 SYS study zones.

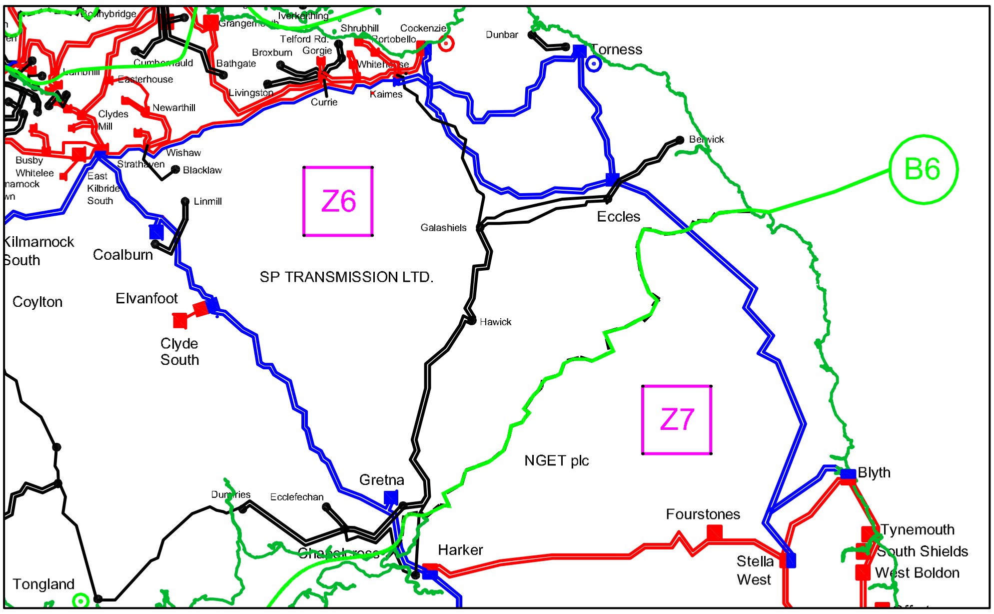

Figure 186: *GB transmission network, boundary 6*

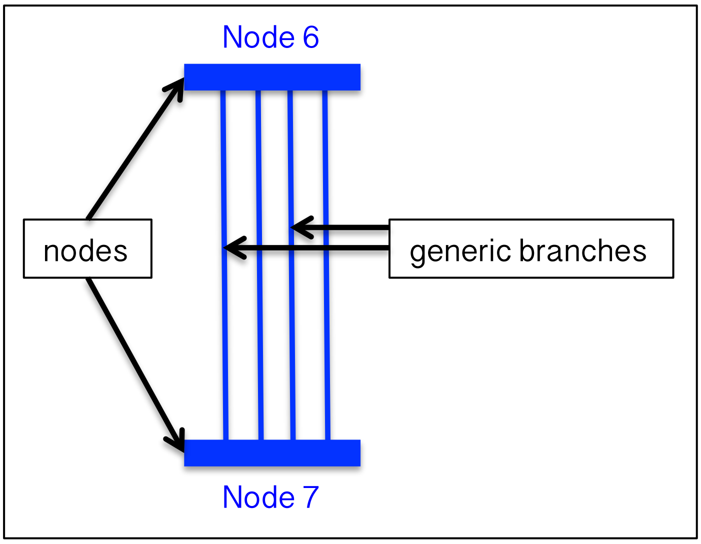

Figure 187: *Approach to simplified network representation with generic branches*

D.3.2.1 Testing through reproducing SYS flows, and strawman scenarios

As a means of model validation, the power flows through relevant branches were summed to reproduce the power flows across each of the SYS boundaries, and compared to the boundary transfers identified in the SYS. The model was also run with a selection of 'strawman' scenarios, showing high development of renewables in the north, in order to further verify the model's output.

Load flows for the Winter Peaks of years 2011/12 to 2017/18 were carried out in the model described above, using the SYS load and generation data reported in (National Grid, 2011b). This produced power flows through each of the lines specified in the model. By adding together the power flows through relevant lines it was possible to reconstruct the power flows across the 17 SYS boundaries. ***Table 38*** compares the modelled boundary flows (LF) with those stated by the SYS, for the Winter Peaks of each of the years 2011/12 to 2017/18. It also compares the differences between the totals of load and generation in all zones stated by the SYS.

Table 38: *Comparison of modelled load flows (LF) with SYS boundary flows (SYS) based on SYS load and generation winter peak projections*

	2011/12		2012/13		2013/14		2014/15		2015/16		2016/17		2017/18	
Boundary	LF	SYS	LF	SYS	LF	SYS	LF	SYS	LF	SYS	LF	SYS	LF	SYS
1	397	404	470	477	572	580	1158	1166	1116	1148	1139	1140	1130	1132
2	778	785	844	851	975	983	1826	1834	1946	1978	2173	2174	2296	2298
3	208	208	233	233	266	266	259	259	254	254	246	246	110	110
4	925	932	1010	1017	1163	1171	2019	2027	2730	2762	2921	2922	2836	2838
5	1890	2134	1991	1961	1907	1992	2799	2989	3470	3695	3864	4178	3956	4025
6	2700	2882	3141	2984	3188	3034	4269	3962	4502	4764	4845	5228	5998	5999
7	2811	2812	3138	3138	3097	3098	4372	4372	4857	4855	4642	4642	5179	5178
8	7757	7758	7997	7997	8004	8005	8531	8531	8546	8545	7957	7958	7858	7857
9	9387	9387	9570	9570	9601	9600	10191	10191	10444	10443	8757	8757	7398	7397
10	4338	4339	4555	4555	4748	4748	4813	4813	4836	4836	4104	4104	3415	3415
11	7657	7658	7587	7587	7226	7227	8180	8180	8498	8497	7926	7927	7965	7964
12	3726	3727	3676	3676	3555	3555	4503	4503	5322	5322	4322	4321	3441	3440
13	1164	1164	1184	1184	1189	1190	1231	1231	1243	1243	620	620	29	29
14	7754	7755	8067	8067	8366	8366	8373	8373	8351	8351	8266	8267	8213	8214
15	3064	3065	3130	3130	3234	3235	2996	2997	2847	2848	2800	2800	2668	2669
16	13242	13243	13249	13249	13017	13018	13975	13975	14419	14418	13194	13194	12471	12469
17	3955	3955	4089	4089	4194	4195	4135	4135	4023	4023	4468	4469	4966	4966
Total Load (MW)	58834		59010		59188		59447		59713		59972		60229	
Total Gen (MW)	58841		59017		59196		59455		59745		59973		60231	
Gen-Load(MW)	7		7		8		8		32		1		2	

Most of the modelled boundary flows (column LF) confirm those stated in the SYS exactly, or within 1 MW, a difference which can be attributed to rounding. Where there are greater discrepancies, some (highlighted in yellow) can be explained by the fact that the total generation and demand figures given in the SYS for all zones do not match (as shown in the final three rows of the table). Matpower's 'slack bus' (node 1 in this case) compensates by adjusting its generation output. This means that the northern side of all boundaries is producing less in the Matpower model than stated in the SYS, by the amount given in the final row of the table, which is also the amount of the discrepancy between SYS and modelled boundary flows in the cases highlighted in yellow. Other larger discrepancies, highlighted in red, cannot be explained. However, as previously noted the expected boundary flow across any boundary which divides a network in two can be calculated simply by subtracting total generation from total demand on either side of the boundary. This simple calculation confirms the modelled boundary flows as accurate (as shown in ***Table 36*** for the year 2011/12), and suggests either errors or unexplained working in the SYS data and calculations.

The 17 node model with generic line parameters was also used to test two ‘strawman’ scenarios in order to see how the model would reflect growing penetrations of different technology types in different areas. They are both scenarios for the year 2018, under the assumption that low carbon policies stimulate strong investment in renewable generation technologies. In Scenario A the developments are locationally unconstrained and are thus strong in areas of high wind potential; in Scenario B the investments are spread across the network more evenly, as for example might be expected if locational pricing signals across the network were stronger.

In both Scenarios, A and B, the nodal demands are as given in the SYS for the year 2017/18, as shown in ***Table 36***. The installed capacities by technology type and zone for Scenario A are shown in Table 39. These figures have been aggregated from the data given in the SYS 2011 Appendix F (Table F.11) (National Grid, 2011b) for the year 2018. This SYS list of generation capacity includes plants under construction, consented, as well as those which have only been proposed. It is therefore unlikely that all of the plant included in Table 6 will be built. However the figures serve as a useful starting point for testing a scenario with high penetrations of renewables.

Table 39: *Installed capacity (MW) by technology type, Scenario A, 2018*

Zone	Onshore wind	Offshore wind	Wave	Tidal	Hydro	Nuclear	Fossil / Thermal	Peaking	Total
1	2528	2220	0	0	577	0	0	300	5625
2	113	0	0	0	18	0	1192	0	1323
3	234	0	0	10	230	0	0	0	474
4	393	1075	0	0	259	0	0	0	1727
5	148	2275	0	0	0	0	2475	440	5338
6	3784	0	0	0	33	2289	185	0	6291
7	0	0	0	0	0	1207	4003	0	5210
8	0	2395	0	0	0	0	14542	0	16937
9	184	1421	0	0	0	4078	8965	2004	16652
10	0	0	0	0	0	0	9172	0	9172
11	0	0	0	0	0	0	4587	0	4587
12	0	5985	0	0	0	1207	4031	0	11223
13	475	1515	0	0	0	0	9944	0	11934
14	0	0	0	0	0	0	2737	0	2737
15	0	1201	0	0	0	1081	6090	0	8372
16	0	0	0	0	0	0	1673	0	1673
17	0	0	0	100	0	2931	1045	0	4076
Total	7859	18087	0	110	1117	12793	70641	2744	113351

The installed capacities by technology type and zone for Scenario B are shown in Table 40. These figures have been produced by revising downwards the penetration of onshore and offshore wind in the network constrained Scottish zones (Zones 1-6), and increasing the penetration of onshore and offshore wind in less constrained English zones. The total penetration of wind in Scenario B is 20,263 MW, slightly less than the 25,946 MW in Scenario A.

Table 40: *Installed capacity (MW) by technology type, Scenario B, 2018*

Zone	Onshore wind	Offshore wind	Wave	Tidal	Hydro	Nuclear	Fossil / Thermal	Peaking	Total
1	1000	0	0	0	577	0	0	300	1877
2	113	0	0	0	18	0	1192	0	1323
3	234	0	0	10	230	0	0	0	474
4	393	0	0	0	259	0	0	0	652
5	148	0	0	0	0	0	2475	440	3063
6	2000	0	0	0	33	2289	185	0	4507
7	0	0	0	0	0	1207	4003	0	5210
8	0	4000	0	0	0	0	14542	0	18542
9	184	2000	0	0	0	4078	8965	2004	17231
10	0	0	0	0	0	0	9172	0	9172
11	0	0	0	0	0	0	4587	0	4587
12	0	7000	0	0	0	1207	4031	0	12238
13	475	1515	0	0	0	0	9944	0	11934
14	0	0	0	0	0	0	2737	0	2737
15	0	1201	0	0	0	1081	6090	0	8372
16	0	0	0	0	0	0	1673	0	1673
17	0	0	0	100	0	2931	1045	0	4076
Total	4547	15716	0	110	1117	12793	70641	2744	107668

To produce generation output figures for the condition to be modelled, assumptions must first be made as to the availability factor of the total installed capacity per technology type. For both scenarios the AF of conventional technologies was set at 90%. Each scenario was modelled with high (90% AF) and low (30% AF) output from renewable technologies.

Multiplying the installed capacity by the AF gives a total dispatchable potential for each technology. This potential is dispatched according to a simple merit order, until demand is met. In these scenarios the merit order is the order of the arrangement from left to right of the technology type columns in Table 39 and Table 40. After some experimentation it was decided not to differentiate between coal and gas but rather to have a catch-all 'fossil / thermal' category. It was decided that a detailed treatment of the uncertainties around relative future prices of coal and gas was beyond the scope of this thesis, hence the technologies are not differentiated. Renewable technologies, on the other hand, are differentiated. This is not due to greater certainty around their future costs but because of the significance of the locations, and on the intermittency characteristics of different types of renewables on the network.

In each case the resulting power flows between the nodes were compared with the maximum boundary capabilities noted in the SYS Chapter 8 (National Grid, 2011b). Where a power flow between nodes was greater than the relevant boundary capability this was considered a boundary overload.

As shown in Figure 188, Scenario A with high wind assumptions produces significant boundary overloads across boundaries 1, 2, 4, 5, 6, and 7. Boundaries 8, 11,14 and 17 also have smaller overloads. Thus, the greatest boundary exceedences are experienced in the North of GB, particularly Scotland, as a result of high installed capacities of both onshore and offshore wind, and the limited transfer capabilities in these zones, in comparison to other areas of the UK.

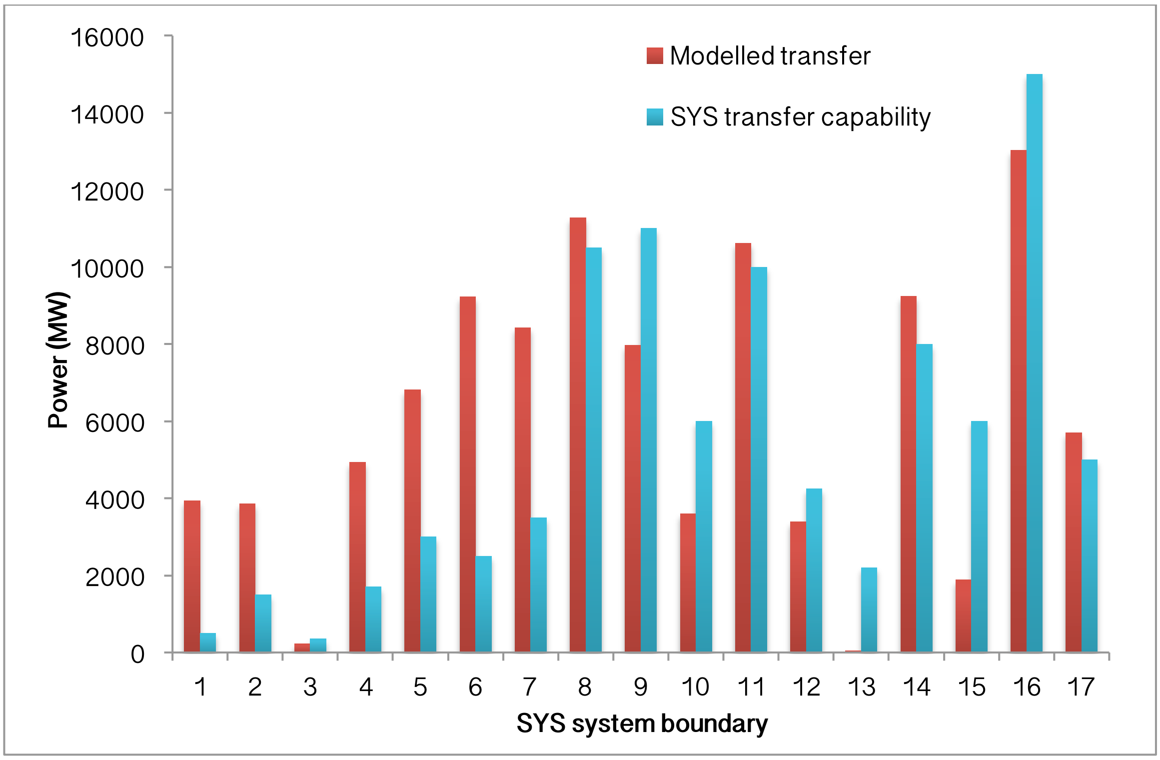

Figure 188: *Boundary transfers, Scenario A, high wind*

Figure 189 shows the effect of assuming a low wind condition for Scenario A. Almost all boundary exceedences are removed.

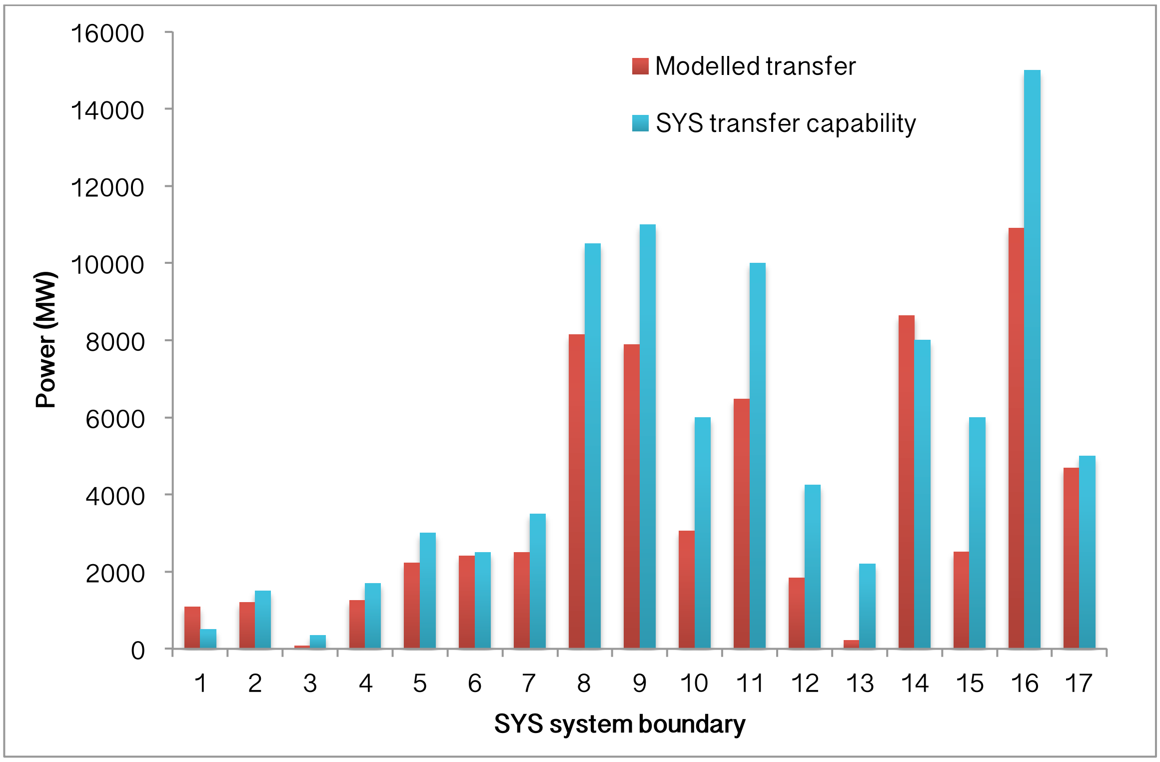

Figure 189: *Boundary transfers, Scenario A, low wind*

Scenario B represented a mix of installed capacity with renewables spread more evenly throughout GB, rather than concentrated in Scotland, as is the case in Scenario A. The effect of this is that even in a high wind condition, boundary pressures are significantly less in the north of the network, as shown in Figure 190.

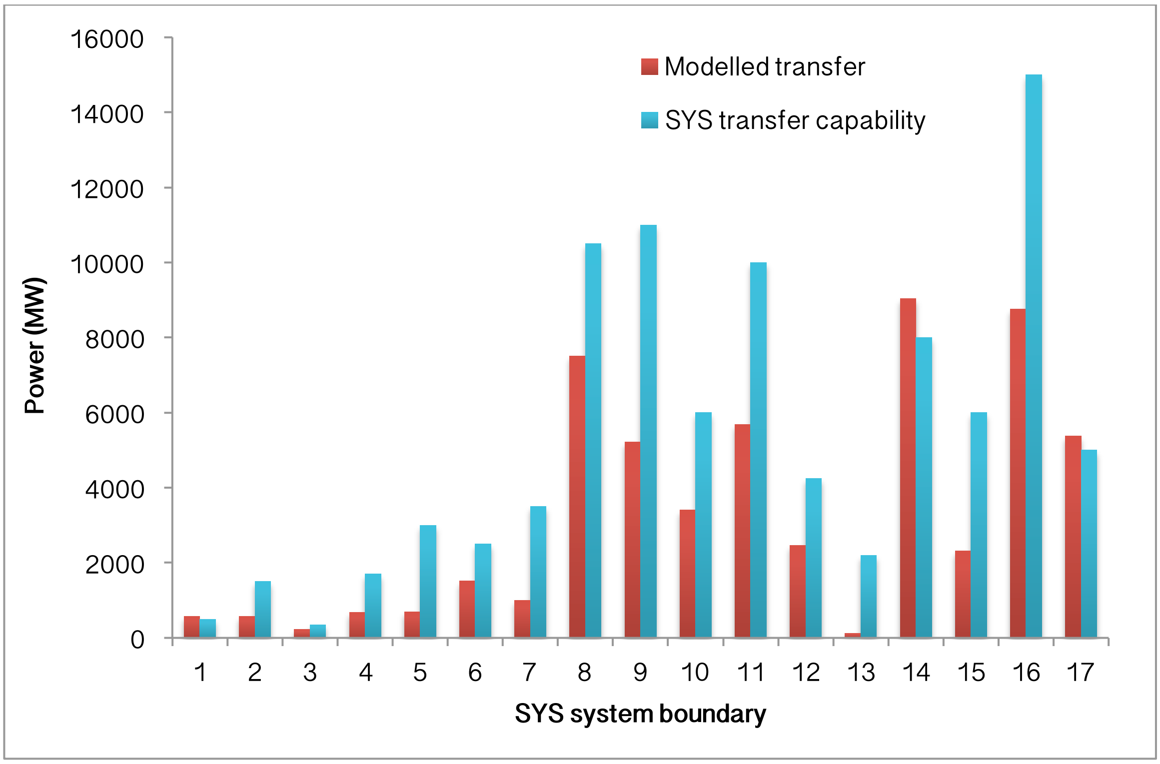

Figure 190: *Boundary transfers, Scenario B, high wind*

Under a low wind condition, Scenario B experiences still lower boundary pressures (Figure 191).

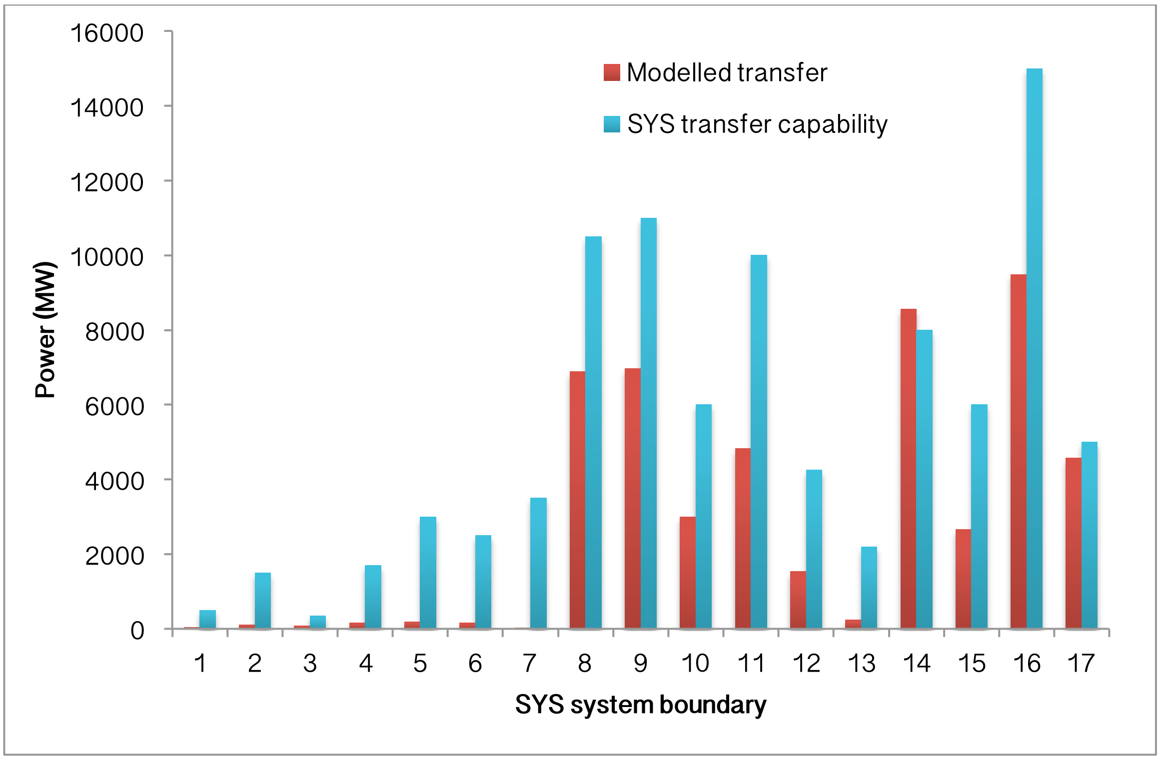

Figure 191: *Boundary transfers, Scenario B, low wind*

As well of the effects of wind in the North, it is also noticeable that boundary 14 is exceeded in all scenarios, and boundary 17 in all except Scenario B, low wind. These boundaries encircle the cities of London and Birmingham respectively, and the exceedences are thus understandable as being related to the high levels of demand at these nodes.

Although the results of these initial runs validated the model and showed that it could be used to simulate broad power flows in high-renewable scenarios, it quickly became clear that the use of generic line data meant that the approach was revealing little more than could have been achieved by a boundary analysis. The use of identical line data to describe for example lines classified of length 'medium' meant that current would divide equally down each, whereas in reality the lines were of different impedances which would cause a different current division for each one.

D.3.3 17 node load flow with real line data

A second version of the model attempted to increase line detail without increasing the number of system nodes. This required representing nodes as 'bus bars' – points at the end of the more accurately characterised lines would be represented in the model as the same node, as if they were connected by a zero-impedance bus bar. This allowed the possibility of a model which described more detailed power flows across specific identifiable lines, whilst avoiding the increased data requirements of defining generation and load at a larger number of nodes.

For example, Node 6 was now connected to Node 7 using the following approach. Node 6 was defined as a bus bar joining Cockenzie and Strathaven. Node 7 was defined as a bus bar joining Stella West and Harker. The connections between Node 6 and 7 were defined using the real line parameters for the two separate double lines, from Cockenzie to Stella West, and from Strathaven to Harker. It would thus be possible to analyse in a load flow analysis the power flow across this border through both of these separate sections of line. The approach is illustrated in Figure 192.

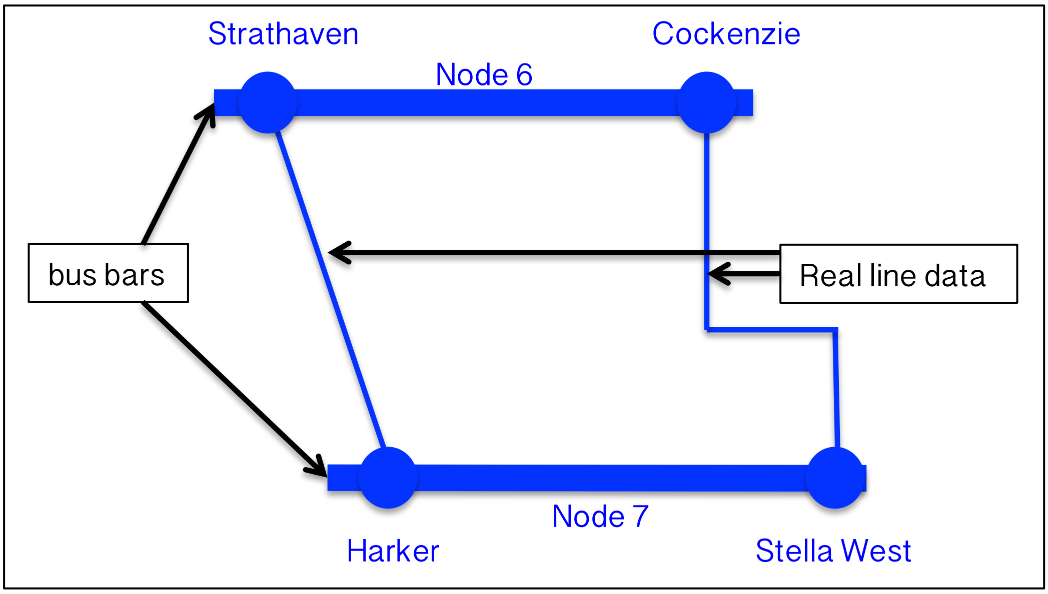

Figure 192: *Bus bar and real line data approach to representing networks*

It was found that the bus-bar approach is a useful means of short cutting around the representation of relatively complex but minor and local sections of network, which would otherwise require significant time to parameterise in full. However, problems are encountered when the distances between sections of network represented as connected on a bus-bar are of a similar size as, or are even greater than, the distances of the sections of the network which are actually parameterised. In an extreme example, the connections between Zones 5 and 6 (across Boundary 5) were defined with a high level of line detail, but still with only one bus-bar node for each zone. The result was a misleading comparison between levels of impedance in each line. The longest line connecting these two nodes was the line between Longannet and East Kilbride, which is 60km long. The shortest was Lambhill to West George Street at only 4km. The shorter line is parameterised with much smaller RXB values simply because of its real length. However, the model sees West

George Street and East Kilbride as being the same point, Node 5, and the Lambhill to West George Street section therefore as a low impedance short cut. Hence, it experiences greater power flows and appears to experience constant thermal overloads.

Clearly this is an extreme example, as the inclusion of the Lambhill – West George Street section was almost certainly over-specific. Nonetheless, it is useful as a vivid example of a problem which may be more subtly present in approximated network modelling where bus bars approach a size comparable with the length of parameterised lines. Future work could attempt to define the maximum allowable ratio between bus-bar size and parameterised line length, before spatial distortions become too great.

A further, related concern was the effect of amalgamating different large generation types at opposite ends of an SYS zone, into one nodal generation output, particularly when there are clear alternative 'corridors' of transmission lines running through zones. For example, in Figure 186, Zones 6 and 7 are shown as having two clear East and West corridors of 400kV transmission lines. With limited interconnection between them, output from Hunterston and other large stations on the West coast would largely flow down the western corridor, and output from Torness and for example large offshore wind farms in the North Sea, would flow predominantly down the East. However, if there is only one node per zone, this kind of corridor analysis cannot be undertaken meaningfully, even if both the East and West line sections are defined in full using real data. As both East and West power output are lumped together, the power will simply be divided between the two corridors according to Ohm's Law.

Finally, it should also be noted that the 17 SYS zones are drawn up to represent the system boundaries of greatest significance for power flow analysis at the time of publication of the SYS. Looking forward decades into the future, the anticipated changing balance of the generation mix will cause different power flows across the network, which could significantly alter the location of where such boundaries would be drawn in the future. Maintaining such boundaries as fixed points in a scenario analysis looking forward decades may become increasingly inappropriate therefore.

A key conclusion therefore was that the greater degree of line specificity demand by the research question was driving a need for a greater number of nodes than 17. This led to the development of the 50 node model, as described in Chapter 6.

Appendix E: The 50-node model: further detail and assumptions

Appendix D described the heuristic process by which the appropriate resolution for the network representation was established. This led to the development of a model based on 50 onshore nodes, plus additional offshore nodes. This model is described in Chapter 6, and forms the basis for the outputs in the rest of the thesis. This appendix provides further detail on working and assumptions underlying this final model.

E.1 Defining line loading limits

Under any given system condition, the flow of power through different branches of the network is dictated by the overall balance of load and generation at each of the system nodes, and by the relative impedances of the lines. However, transmission lines have loading limits which must be respected. If the loading of any line on the network threatens to be in breach of its limits, the System Operator must take actions to reduce generation output on the exporting side of the line, and increase generation output on the importing end of the line, in order to reduce power transfer across the line.

Line loadings are limited by three factors: thermal limits, avoidance of excessive voltage drops, and preservation of system stability (Appendix A.1.2). Appendix B of the SYS (National Grid, 2011b), which provides parameters for all GB system lines, indicates the maximum thermal rating of all lines. However, the additional constraints placed by voltage and stability considerations can often mean that the upper limit of allowable line loading is lower than the thermal rating (National Grid, 2011b, National Grid, 2012a).

It is important that the analysis compares simulated power flows against a realistic approximation of line loadings – using thermal ratings alone would be an unrealistically high loading, which would never be allowed to occur in reality.

The National Grid Ten Year Statement (National Grid, 2012a) provides a boundary commentary, which assesses the transfer capability of the 17 system boundaries depicted in Figure 22, accounting for whichever is the lower constraint between thermal, voltage and stability limits. The total thermal transfer capability of each boundary which would be represented by the equivalent network model, can be established by summing the listed thermal capacities of each section of line crossing a boundary. These total thermal capacities can be compared to the actual transfer capability stated in the Ten Year Statement. This comparison is shown in Table 41.

Table 41: *Comparison of total thermal rating with actual transfer capability at 17 system boundaries*

Boundary	Total thermal winter rating (MW)	Actual transfer limit (MW)	Ratio – actual:thermal rating	Notes
1	1314	500	0.38	Reinforcements from capacity additions
2	3304	1600	0.48	Reinforcements from capacity additions
3	792	350	0.44	Reinforcements from capacity additions
4	5198	1860	0.35	Reinforcements from capacity additions
5	5285	3660	0.68	Thermal limit
6	8800	3300	0.38	Voltage and stability limit. Addition of series capacitors and some uprating can raise to a limit of 4400 MW (ratio 0.5)
7	11634	3600	0.31	Taken from ENSG (2012) – a thermal limit
8	18974	11300	0.60	Voltage limitation
9	24421	12600	0.52	Thermal and voltage limit
10	16975	6000	0.35	
11	22909	9200	0.40	Voltage limitation
12	20030	5900	0.29	
13	9474	2000	0.21	Transient voltage stability limit
14	6591	9750	0.36	
15	15614	8000	0.51	
16	33490	15000	0.45	
17	21050	6000	0.29	Reactive compensation support could raise capability by 1GW

The ratio of the actual permitted transfer capability to the total thermal winter rating at each boundary, provides a 'derating factor' which must be applied to the total thermal transfer capability of each boundary in order to arrive at its actual transfer capability. In order to reflect the additional constraints of voltage and stability, each line will be derated from its total thermal capacity by the relevant derating factor of the main boundary it crosses. Where lines cross more than one boundary the higher derating factor is chosen. This allows for the possibility of technical solutions such as reactive compensation support and series capacitors to raise voltage and stability limits closer to the thermal limit level. Where lines cross no boundary a generic factor of 50% is used, representing a typically high rating once the potential for reactive compensation, series capacitors and other technical solutions have been applied, within an N-1 capability (as shown for example by Boundary 6).

E.2 Dividing total system demand between regional nodes

As described in Section 6.3.2, the regional annual electricity demands provided in DECC (2012b) were allocated to the nearest model node, to approximate the nodal distribution of annual electricity demand. However, there is clearly a difference between the total annual electricity consumption, and the power demand at any given moment in the year, such as the winter peak. The proportion of total annual demand any given area consumes may not be the same proportion as that of its contribution to system peak. To test whether these two different proportions are substitutable, the annual electricity demands by unitary authority were also summed to the level of SYS zone. It was then possible to compare the proportional contribution of each SYS study zone to annual demand according to DECC figures, with its proportional contribution to system peak in each of seven projected years, according to SYS.

Table 42: *Comparison of proportional contribution of SYS zones to winter peak, according to SYS projections, and to 2011 total electricity demand, according to DECC*

	Proportion of winter peak in seven year statement forecasts (%)							**Proportion of total 2011 annual electricity demand (%)**		
Zone	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Total	Domestic	Commercial / industrial
1	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.8
2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.8
3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.1
4	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.1	0.8
5	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.8	1.8	1.7
6	5.3	5.3	5.3	5.3	5.3	5.2	5.2	4.7	4.8	4.6
7	4.9	5.0	5.2	5.2	5.2	5.3	5.5	5.0	4.7	5.3
8	9.0	9.0	8.9	8.7	8.6	8.5	8.5	8.5	8.0	8.8
9	12.3	12.0	11.6	11.6	11.7	12.2	12.7	11.5	11.7	11.4
10	1.6	1.6	1.6	1.7	1.7	1.5	1.4	2.8	2.9	2.7
11	12.6	12.4	12.2	12.2	12.1	12.1	12.2	12.0	11.9	12.1
12	8.1	8.2	8.3	8.3	8.4	8.5	8.5	11.1	12.0	10.5
13	8.9	8.8	8.8	8.8	8.7	8.6	8.4	10.2	9.7	10.6
14	16.2	16.6	17.0	17.2	17.4	17.2	16.9	14.4	12.2	15.9
15	3.7	3.7	3.7	3.7	3.7	3.8	3.9	3.1	3.4	3.0
16	7.5	7.5	7.5	7.5	7.5	7.3	7.0	6.9	7.8	6.4
17	5.0	5.0	5.0	5.0	4.9	5.0	5.1	4.7	5.4	4.3

As shown in ***Table 42***, the percentage contributions to annual energy demand are a reasonable proxy for percentage contribution to system peak. In most zones the difference between the proportions is less than one percent. The largest discrepancies are found in Zones 10 (1.1-1.4%), 12 (2.6-3.0%), 13 (1.4-1.8%) and 14 (1.7-3.0%). These comparisons are made between SYS winter peak figures and the total annual demand. The DECC data also provides a breakdown of this total between domestic and commercial / industrial demands, as indicated in ***Table 42***.

The demand proportions of unitary authorities worked out from DECC data were therefore used to divide a scenario-based total system power demand figure into nodal demands for load flows.

E.3 Evolution of future demand

This section provides the underlying figures for the future demand trajectories presented in Section 6.3.3. The figures for current (2012) and future annual sectoral demands were predominantly derived from DUKES (DECC, 2013a) and the National Grid Future Energy Scenarios (FES) document, using the Gone Green scenario (National Grid, 2013c). The resulting trajectories were presented in Section 6.3.3 in the form of ***Figure 31***. The underlying figures are presented in ***Table 43***.

The FES assumes demand reductions in domestic appliances, lighting and resistive heating, as well as in the commercial and public administration sectors, due to uptake of energy efficiency measures. However, there is a rising demand from domestic heat pumps, and industrial demand also grows. Other sectors specified in DUKES, but not in the FES, are agriculture and fuel industries, and in the absence of detailed data their demands are held constant. DUKES also accounts for losses, which are included here.

The ratio of total energy demand to system peak in 2012 was calculated, and the same relationship was assumed to hold – as annual energy demand rises, so does the demand during the seasonal peak hours considered.

Table 43: *Annual electricity demand background by sector*

TWh		**2012**	**2018**	**2023**	**2028**	**2033**	**2038**	**2043**	**2048**
Domestic	**Total**	**114.698**	**109.056**	**108.750**	**113.592**	**121.669**	**146.8**	**171.924**	**197.051**
	Lighting	12.123	6.556	5.895	6.095	6.374	6.374	6.374	6.374
	Appliances	69.864	68.799	67.634	66.953	66.425	66.43	66.425	66.425
	Resistive heating	32.267	31.367	29.667	29.867	29.567	29.57	29.567	29.567
	Heat pumps	0.445	2.334	5.555	10.678	19.304	44.43	69.56	94.686
Commercial		**78.206**	**76.140**	**72.090**	**68.040**	**65.610**	**65.61**	**65.610**	**65.610**
Industry		**97.820**	**101.550**	**104.630**	**110.610**	**116.939**	**120.9**	**122.939**	**123.939**
Fuel industries		**29.72**	**29.72**	**29.72**	**29.72**	**29.72**	**29.72**	**29.72**	**29.72**
Public administration		**18.891**	**17.86**	**16.91**	**15.96**	**15.39**	**15.39**	**15.39**	**15.39**
Transport	**Total**	**4.089**	**5.621**	**7.340**	**10.380**	**16.137**	**27.56**	**50.871**	**99.240**
	Electric trains	4.089	4.626	5.234	5.922	6.700	7.581	8.577	9.704
	Electric vehicles	0.000	0.995	2.106	4.458	9.437	19.97	42.29	89.53
Agriculture		**3.871**	**3.871**	**3.871**	**3.871**	**3.871**	**3.871**	**3.871**	**3.871**
Sub total		**347.295**	**343.817**	**343.311**	**352.173**	**369.337**	**409.8**	**460.325**	**534.821**
Losses (8% in 2012)		**28.946**	**27.505**	**27.465**	**28.174**	**29.547**	**32.79**	**36.826**	**42.786**
Total		**376.241**	**371.323**	**370.776**	**380.347**	**398.884**	**442.7**	**497.151**	**577.607**
Winter PEAK sans EVs (GW)		60.000	59.057	58.793	59.944	62.106	67.41	72.537	77.834
2012 Peak:annual demand ratio		0.159							
% of EV charging in peak hour		0.040							
Addition from EV charging		0.000	0.109	0.231	0.489	1.034	2.189	4.635	9.812
TOTAL WINTER PEAK (GW)		**60.000**	**59.166**	**59.023**	**60.432**	**63.140**	**69.6**	**77.172**	**87.646**
Spring Peak sans EVs (GWs)		50.000	49.214	48.994	49.953	51.755	56.17	60.448	64.862
2012 Peak:annual demand ratio		0.133							
% of EV charging in peak hour		0.020							
Addition from EV charging		0.000	0.055	0.115	0.244	0.517	1.095	2.317	4.906
TOTAL SPRING PEAK (GW)		**50.000**	**49.269**	**49.109**	**50.198**	**52.272**	**57.27**	**62.765**	**69.768**
Summer Peak Sans Evs (GWs)		45.000	44.293	44.094	44.958	46.579	50.56	54.403	58.375
2012 Peak:annual demand ratio		0.120							
% of EV charging in peak hour		0.020							
Addition from EV charging		0.000	0.055	0.115	0.244	0.517	1.095	2.317	4.906
TOTAL SUMMER PEAK (GW)		**45.000**	**44.347**	**44.210**	**45.202**	**47.097**	**51.65**	**56.720**	**63.281**

The trajectory for electric vehicles however is treated separately. The assumption is that a close to full penetration of electric vehicles for private vehicle travel demands occurs by 2048, but that the growth occurs on an S-curve shape, with higher rates of growth towards the end of the period, as shown in ***Table 44*** and ***Figure 193***.

Table 44: *Growth in electric vehicle demand*

Year	% of vehicle kms	Bn vehicle kms	TWh
2018	1.1	6.6	1.0
2020.5	1.6	9.6	1.4
2023	2.3	14.0	2.1
2025.5	3.4	20.4	3.1
2028	5.0	29.7	4.5
2030.5	7.2	43.2	6.5
2033	10.5	62.9	9.4
2035.5	15.3	91.5	13.7
2038	22.2	133.2	20.0
2040.5	32.3	193.8	29.1
2043	47.0	282.0	42.3
2045.5	68.4	410.2	61.5
2048	99.5	596.9	89.5

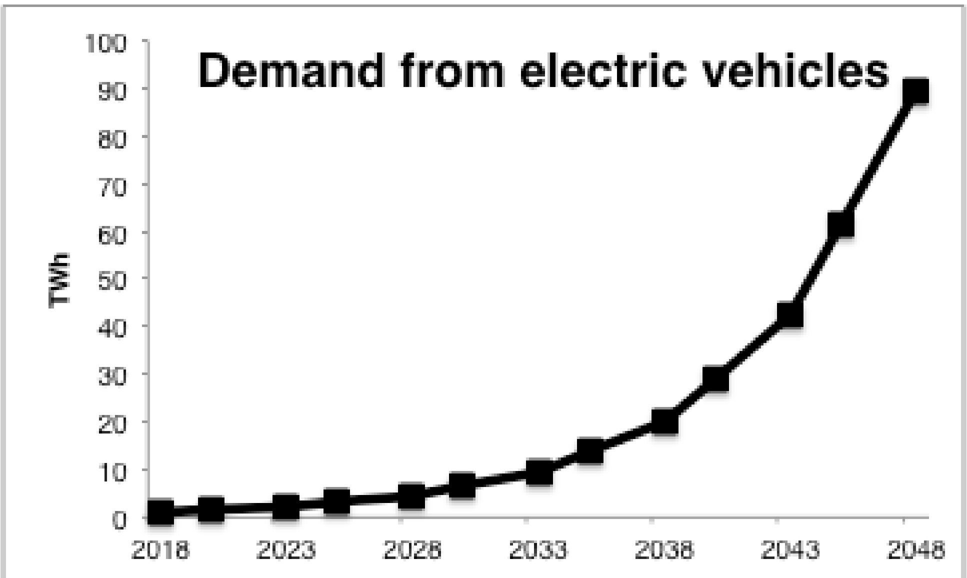

Figure 193: *Growth in demand from electric vehicles*

These assumptions on annual energy demand are combined with assumptions on what proportion of vehicles will be charging at the particular times for which the load flows are being run – 5-6pm in December / January, 12-1pm in July / August, and 12-

1pm in April. The basic assumptions for charging patterns follow the pattern used in FES, according to which 4% of the daily demand is recharging during the winter peak hour, and 2% during the other two conditions (***Figure 194***).

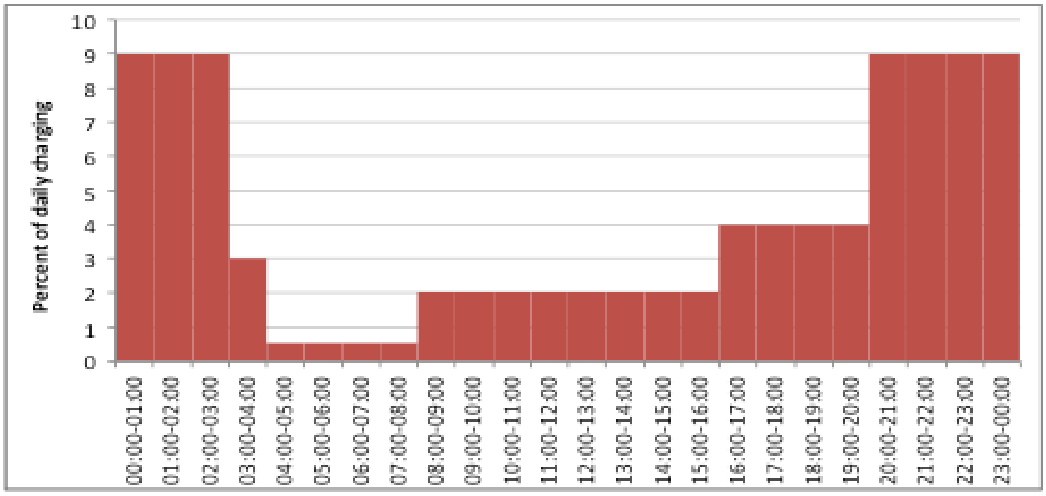

Figure 194: *Percentage of EV charging occuring in each hour, FES assumptions (National Grid, 2013c)*

The resulting addition from EV charging in each seasonal condition is added to the rest of demand.

E.4 Generation assumptions

As noted in Section 6.4, the generator assumptions are calibrated to the base year of 2013, using data from the SYS (National Grid, 2011b) as well as additional public information on closings and openings since the publication of the SYS. The following sections of this appendix provide more detail on certain key technologies, including additional data sources for establishing their capacities in the base year, and assumptions which guide and provide a framework for descriptions of how these capacities are added to within each of the scenarios.

E.4.1 Offshore wind

Table 45 lists the offshore wind sites in operation at 2013, as represented in the model at the 2013 base year.

Table 45: *Operational offshore wind sites, 2013. Source: (RenewableUK, 2013b)*

Site name	Capacity (MW)	Developer	Model node
Beatrice	10	SSE Renewables	6
Barrow	90	DONG Energy and Centrica	37
Walney 1	183.6	DONG Energy / SSE Renewables / Ampere Equity / PGGM	37
Walney 2	183.6	DONG Energy / SSE Renewables / Ampere Equity / PGGM	37
Ormonde	150	Vattenfall	37
Rhyl Flats	90	RWE Npower Renewables	38
North Hoyle	60	RWE Npower Renewables	38
Burbo Bank	90	DONG Energy	38
Lincs	270	Centrica / DONG / Siemens	43
Lynn and Inner Dowsing	194.4	Centrica Renewable Energy Ltd.	43
Scroby Sands	60	E.ON UK Renewables	43
Sheringham Shoal	316.8	Scira Offshore Energy Ltd	51
Greater Gabbard	504	SSE and RWE Npower Renewables	52
Gunfleet Sands 1	108	DONG Energy	62
Gunfleet Sands 2	64.8	DONG Energy	62
Gunfleet Sands 3	12	DONG Energy	62
London Array	630	DONG Energy / E.On Renewables / Masdar	62
Kentish Flats	90	Vattenfall	62
Thanet	300	Vattenfall	62
Robin Rigg	180	E.ON UK Renewables	76
Blyth Offshore	3.8	E.ON UK Renewables	77
Teesside	62.1	EdF ER	77
TOTAL	**3653.1**		

Table 46 lists offshore wind sites currently under construction, at 2013.

Table 46: *Offshore wind sites under construction, 2013. Source: (RenewableUK, 2013b)*

Site name	Capacity (MW)	Developer	Model node
Humber Gateway	219	E.ON UK Renewables	30
Westermost Rough	210	DONG Energy	30
West of Duddon Sands	389	Scottish Power / DONG Energy	37
Gwynt y Mor	576	RWE Innogy / SWM / Siemens	38
Methil Offshore Wind Farm Demo Site	7	Samsung Heavy Industries	
TOTAL	**1401**		

Table 47 lists offshore wind sites currently with consent, at 2013.

Table 47: *Offshore wind projects currently consented, 2013. Source: (RenewableUK, 2013b)*

Site name	Capacity (MW)	Developer	Model node
Blyth Offshore Wind Demonstration site (NAREC)	99.9	NAREC	77
Dudgeon	400	Statoil and Statkraft	51
European Offshore Wind Deployment Centre (EOWDC)	77	Vattenfall, Technip and Aberdeen Renewable Energy Group (AREG)	None allocated yet
Galloper (Greater Gabbard Ext)	504	SSE and RWE Npower Renewables	52
Kentish Flats 2	49.5	Vattenfall	62
Race Bank	580	Dong Energy Ltd	43
Triton Knoll	800	RWE Npower Renewables	30
TOTAL	**2510.4**		

This table lists the total capacities of the Round 3 development zones.

Table 48: *Total potential capacities of Round 3 offshore sites. Source: (Crown Estate, 2013)*

Site name	Capacity (MW)	Developer / License holder	Model node
Moray	1500	Moray Offshore Renewables – joint venture between EDP Renewables and Repsol	6
Firth of Forth	3465	SeagreenWind Energy Ltd – joint venture of SSE and Fluor	20
Dogger Bank	9000	Forewind – a consortium of RWE npower renewables, SSE, Statkraft, Statoil	24 (note connection points at Creyke Beck and Teesside)
Hornsea	4000	SmartWind – a joint venture between Mainstream Renewable Power and Siemens Project Ventures	29
Irish Sea	4200	Celtic Array – 50:50 joint venture between Centrica Renewable Energy Ltd and DONG.	39
East Anglia	7200	East Anglia Offshore Wind Ltd – a50:50 joint venture of SP Renewables and Vattenfall Wind power Ltd.	52
Southern Array (Rampion)	665	E.ON Climate and Renewables / UK Southern Array Ltd	67
West Isle of Wight (Navitus)	800 – 1200	Navitus Bay – 50:50 joint venture between Eneco Wind UK Ltd and EDF Energy Renewables	68
TOTAL	30830 - 31230		

The Round 3 sites were selected based on areas of the sea bed where shoals or banks make the water shallower than is typically found at such distances from the coast, thus making pile-driven offshore wind turbines a more feasible prospect. Significant development of offshore wind beyond these areas is therefore likely to require the development of floating turbine technology. Though not commercial, floating turbines are currently at the demonstration phase, including by the company Hywind which has built demonstration floating turbines off the coast of Norway, and which is proposing further demonstrations off the east coast of Scotland. However, in these scenarios floating turbines are considered too uncertain a prospect to factor in, and therefore the capacity totals listed in *Table 45*-*Table 48* are assumed are taken in combination to provide the outer envelope for offshore wind deployment in UK waters.

E.4.2 Onshore wind

Table 49 shows the location of transmission connected onshore wind as represented in the model. Data was collected from the Seven Year Statement (National Grid, 2011) for the year 2012-13. The SYS lists 117 individual wind farms, each of which was allocated to the nearest model node. The table below presents the SYS data amalgamated to the model node level.

Table 49: *Onshore transmission connected wind farms, 2013. Source: (National Grid, 2011b)*

Region	**Capacity (MW)**	**Model node**
Thurso	363.8	3
Stornoway	69.4	4
Beauly	371.5	5
Kintore	103.2	7
Peterhead	60.8	8
Dalmally	217.7	9
Erochty	204	10
Tealing	49	11
Glasgow	35	12
Kincardine	74	13
Auchencrosh	322.75	15
Strathaven	1389.4	17
Edinburgh	107	18
Torness Point	392.5	19
Gretna	115.5	21
Bristol / South Wales	299	57
TOTAL	**4174.55**	

The total figure for onshore wind listed by Renewable UK's Wind Energy Database is 6816 MW (RenewableUK, 2013b). This indicates that there are significant levels of onshore wind are not connected to the transmission network, but to lower voltage networks.

As ***Table 49*** shows the vast majority of large scale transmission connected wind is found in Scotland. This may partly reflect the fact that the definition of 'transmission' network in Scotland extends to 132 kV networks, whereas in England and Wales the transmission network is only the 400 and 275 kV lines. However it is also likely to reflect the higher average wind speeds found in Scotland.

The SYS lists onshore wind projects totalling 7863.55 MW in 2017-18, 7204.55 of which is in Scotland (along with the existing Pen y Cymoedd in south Wales, and two more proposed projects in mid-Wales). An outer envelope for Scottish onshore potential is 9.4 GW in addition to the current 3.9 GW, i.e. a total of 13.3 GW. This is derived from the Scottish Government's 2020 Routemap for Renewable Energy in Scotland, published in 2011. Section 3.2 of the document lists 2 GW as consented, in addition to 3.5 GW awaiting planning determination, and 3.9 GW of sites having requested pre-planning scoping opinion (Scottish Government, 2011). (http://www.scotland.gov.uk/Publications/2011/08/04110353/5#offshorewind). Following the SYS increase to 7205 MW in 2018, this would leave a further 6071 MW to be expanded into (based on 13.3 GW total).

The Welsh Government's ambition for onshore wind was recently set at 2 GW (RenewableUK, 2013a). Mid Wales currently has no transmission access so there would be network implications for this.

Based on the above discussion, the following outer envelopes for wind deployment in England, Wales and Scotland, are used in the scenario development.

Table 50: *Outer envelopes for onshore wind deployment in England, Wales and Scotland, as applied in scenario development*

Region	Model nodes	Potential capacity (MW)
Scotland	1-21	13300
Wales	34-36, 53, 57	2000
England	Remainder	2000
TOTAL		**17300**

E.4.3 Wave and tidal

The model begins in 2013 with no wave or tidal power deployed. In reality there are currently wave and tidal demonstration projects deployed in UK waters, but these total only 9 MW. According to Renewable UK, the industry is 'on track to deliver over 120 MW [of wave and tidal power] by 2020' (RenewableUK, 2013c). This being still a relatively small number in comparison to GB peak power demand, the background assumption is made across all scenarios that wave and tidal technologies are available to deploy at commercial scale, only from the 2023 timeslice onwards.

E.4.3.1 Wave

Wave power potential is greatest in areas of UK waters most exposed to long range ocean winds. This makes the South and North west coasts of Britain the most favourable near-shore areas in UK waters, as shown in Figure.

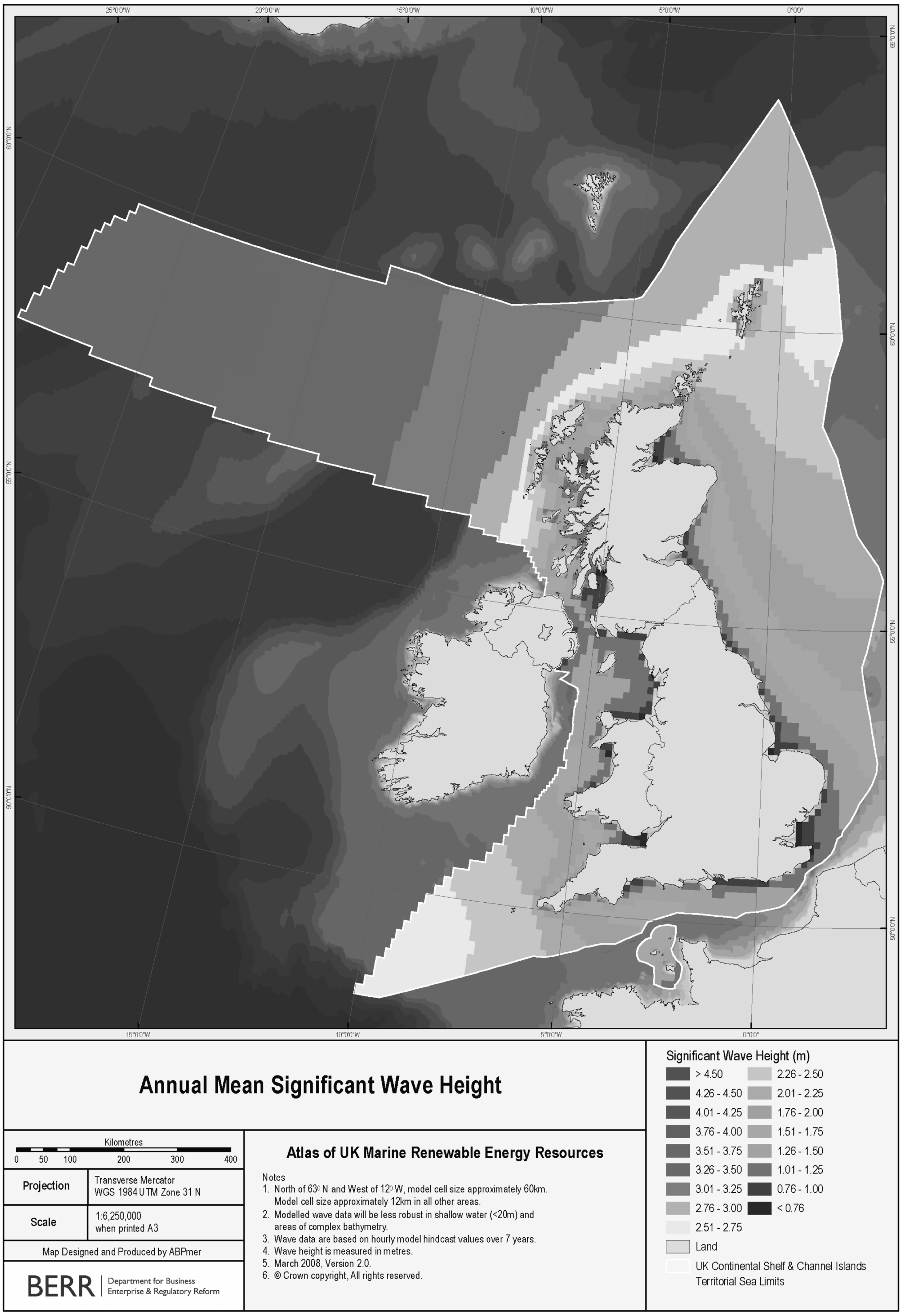

Figure 195: *Annual mean significant wave height, UK. Source: (BERR, 2008)*

ECI's (2005) assessment compares wave resources in 5 different regions, and confirms the favourability of sites on the Atlantic-exposed western coasts.

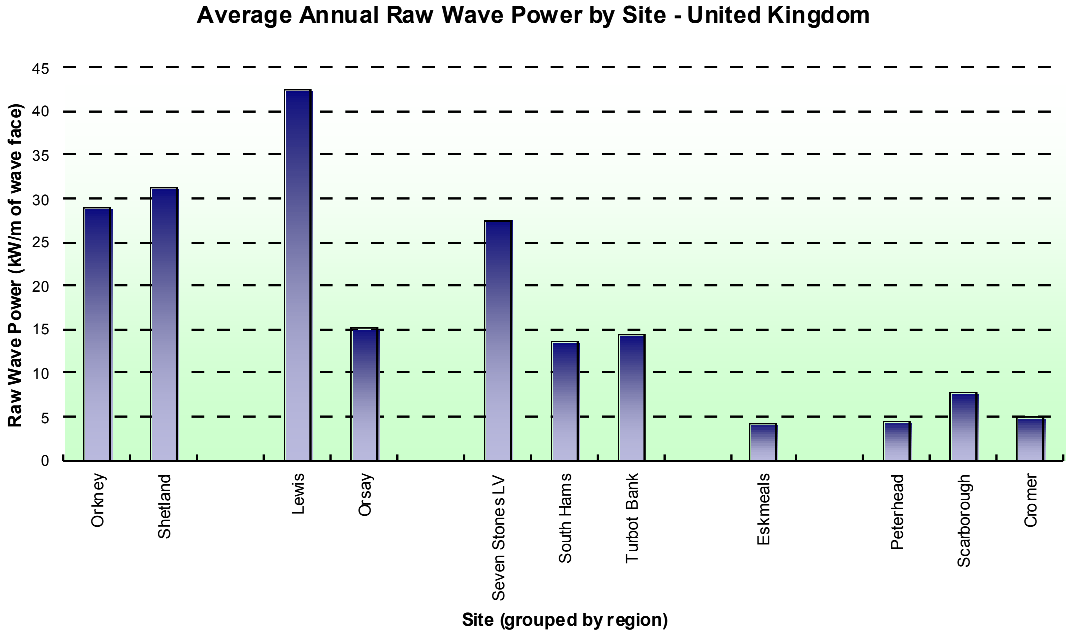

Figure 196: *Average annual raw wave power by site. Source: (ECI, 2005)*

Establishing an 'outer envelope' of wave power potential in the UK is not straightforward, as there are not obvious oceanographic constraints as the devices float on the water and thus do not require shallow waters. ECI (2005) use an estimate from Renewable UK that wave power could provide 15% of UK electricity, which amounts to around 19 GW of installed capacity of wave devices, assuming 30% capacity factor. The Zero Carbon Britain report (CAT, 2010) quotes the Offshore Valuation Group (2010) as estimating total wave potential of 40 TWh per year, which is equivalent to 15 GW at 30% load factor. David Mackay's rough estimate of 4kWh/person/day translates to an installed capacity of 33 GW at 30% load factor (MacKay, 2009). DECC Pathways analysis quotes 50 TWh/year as an estimate of practical resource, with 157 TWh/year cited as a full technical potential estimate (DECC, 2010a) – these figures are equivalent to 19 GW and 60 GW respectively.

In this thesis an outer limit of 20 GW installed capacity is assumed. These are shared 75-25 between the two Atlantic facing regions, Western Scotland and South-Western England, which have about 750km and 250km of coastline respectively (MacKay, 2009). The resource in these regions is shared evenly between the relevant offshore nodes, as shown in the table below.

Table 51: *Outer envelope for wave power capacity, as applied in scenario development*

Region	Model Node	Total potential capacity (MW)
Cornwall	72	2500
Devon	73	2500
Western Isles	75	3750
Hebrides	4	3750
Orkney	2	3750
Shetland	1	3750
TOTAL		**20000**

Based on the assessment of Renewable UK, cited above, of the current trajectory being towards 120 MW of wave and tidal by 2020, it will be assumed that wave is available to be deployed at a commercial scale in these locations from the 2023 timestep onwards. The output of wave devices uses the same availability factor data derived for wind, as wave is strongly correlated to wind (ECI, 2005).

E.4.3.2 Tidal stream

DECC (2010a) reports that there remains considerable variation in assessments of maximum tidal energy potential, in part related to the choice of modelling method. The report states that a 'widely quoted' total potential assessment is 17 TWh per year, referring to SKM (2008) – at 40% load factor this is equivalent to 4.9 GW installed capacity. At the other end of the scale the report cites assessments of 197 TWh/year (Mackay, 2009) (equivalent to 56 GW at 40% load factor). More recently the Offshore Valuation Group (2010) estimated 116 TWh per year (equivalent 33 GW at 40% load factor).

ECI (2005) draws on a tidal stream resource assessment by Black and Veatch (2005) to provide data for tidal stream potential in different locations across the UK, as summarised in the table below.

Table 52: *Estimates of regional tidal stream resource*

Region	Model node	Installed capacity (MW) (Black and Veatch)	Average capacity factor	Corrected capacity (MW)
Channel Islands	78	533	39%	1066
Shetland	1	149	40%	298
Orkney	2	169	34%	338
Western Scotland	75	325	40%	650
Pentland	3	2292	42%	4584
Bristol Channel	73	219	32%	438
Cornwall	72	30	26%	60
Isle of Wight / Portland	68	119	42%	238
TOTAL		3836		7672

This assessment appears to be at the conservative end of the scale, and it has been suggested that the method used underestimates the resource (DECC, 2010a). A recent academic assessment estimated the time averaged maximum potential output from the Pentland Firth as being 1.9 GW (Adcock et al, 2013). At a 42% capacity factor this would equate to approximately 4.5 GW peak, or double the peak capacity provided by Black and Veatch. On the basis that the Adcock et al (2013) report seems to be the current state of the art for tidal stream modelling, this factor is taken as a guide for the whole set of Black and Veatch estimates, which are all doubled (as shown in the final column of the table).

E.4.3.3 Tidal barrage

Tidal barrage has the potential to produce large amounts of power from specific locations. However it is also a technology associated with significant environmental impacts. A 2 year government feasibility study reported in 2010 that it did not see a case for public investment in the Severn barrage for the foreseeable future. However, it did not preclude private investment. Possible tidal barrage locations and estimated potential capacities are listed in the table below, based on DECC (2010a).

Table 53: *Outer envelope for tidal barrage deployment, as applied in scenario development*

Location	Model Node	Potential installed capacity (MW)
Solway Firth	22	7200
Morecambe Bay	31	3000
Wash	42	2400
Humber	28	1080
Thames	59	1120
Mersey	33	620
Dee	33	840
Severn (various projects)		
Cardiff-Weston Barrage	57	8640
Shoots Barrage	57	1050
Beachley Barrage	57	625
Welsh Grounds Lagoon	57	1360
Bridgewater Bay Lagoon	57	1360
TOTAL		16885 – 24900

E.4.4 Nuclear

The existing nuclear fleet is as listed in this table, and this fleet is reflected in the model base year of 2013.

Table 54: *Existing UK nuclear power stations, 2013*

Site	Model Node	Capacity (MW)	Scheduled decommissioning year
Hunterston B	16	890	2023
Hinkley Point B	71	870	2023
Hartlepool	25	1180	2019
Heysham 1	32	1160	2019
Dungeness B	61	1040	2018
Heysham 2	32	1220	2023
Torness	19	1190	2023
Sizewell	49	1191	2035
Wylfa	34	490	2014
TOTAL		**9231**	

Plants are removed from the model in accordance with the published scheduled decommissioning years shown in the Table. (Although EDF aims to extend the life of the plants scheduled to close before 2020).

The table below lists the sites proposed as available for new nuclear development. The capacity of 3260 MW is that proposed by EdF for the new Hinkley Point C reactor.

Table 55: *Outer envelope for nucelar power stations, as applied in scenario development*

Site	Model Node	Capacity (MW)
Sellafield	22	3260
Hartlepool	23	3260
Heysham	31	3260
Wylfa	34	3260
Sizewell	49	3260
Oldbury	57	3260
Bradwell	59	3260
Hinkley Point	71	3260
TOTAL		**26080**

E.4.5 Thermal

Fossil thermal plants in the base year are as listed in the 2012/13 SYS year, with additional plant closures since the publication of the SYS factored in. All currently existing fossil plant retire at some point during the scenario time frame. These are fixed assumptions across all scenarios, as described in Section 7.3.1.7.

E.4.6 Summary of outer envelopes and build rates

All scenarios operate within a quantitative assessment of the overall outer potential for each technology by location, and a year of availability. Each technology type is also confined by a maximum annual build rate, based on DECC (2010a). These key data are summarised in the table below.

Table 56: *Summary of outer envelopes and build rates for generation technologies*

Technology	Available from	Maximum total potential (MW)	Maximum build rate (MW/yr)
Wind offshore	2013	38718	3000
Tidal stream	2023	7672	1000
Tidal barrage	2023	16885	3000
Wave	2023	20000	1000
Hydro	2013	1417	500
Wind onshore	2013	17300	1000
Nuclear	2013	27287	3200

E.5 Seasonal availability factors and average load factors

E.5.1 Wind speed data

Wind speed data was collected and analysed to provide a range of simultaneous nationwide wind conditions against which the power flows could be tested. As described in Section 6.4.2.2, historic wind speed data was collected from the MIDAS database (UK Meteorological Office, 2012) for 9 representative wind monitoring stations, from the years 2002-2012. Wind speed data for the hours and months for corresponding to the three load flow conditions being analysed, were isolated. This produced three datasets – corresponding to the winter, spring and summer load flow conditions – consisting of around 350 measurements of wind speeds at each of the nine stations, in a particular hour of the day within a given season.

The data for each season was arranged and analysed. The mean wind speed of the nine stations was calculated for each of the recorded days. The Figure below shows the frequency distribution of the mean wind speeds in the winter peak hour.

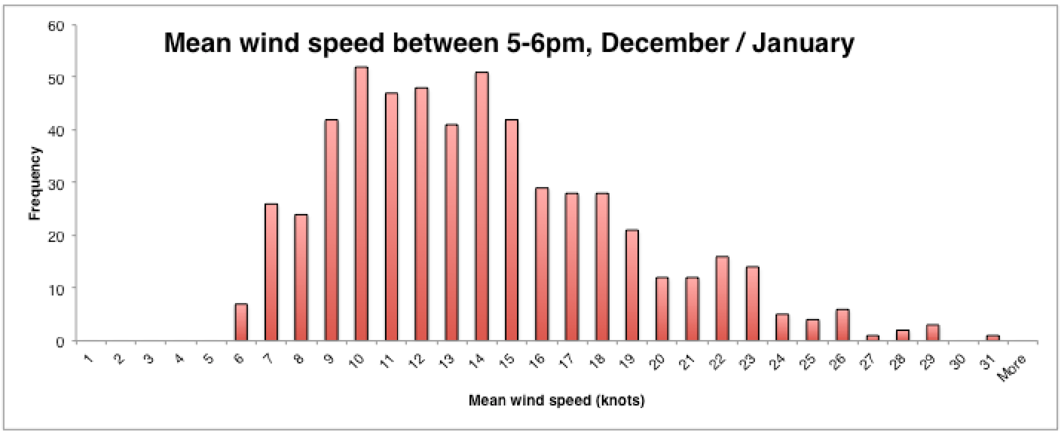

Figure 197: *Frequency distribution of mean wind speed between 5-6pm, December-January, 2002-2012. Source: (UK Meteorological Office, 2012)*

The nine weather stations were also divided into north and south by location, and the mean wind speed of the southern wind stations subtracted from the mean wind speed of the northern stations on each measured day, providing an indicator of the north-south gradient – how much more or less windy it is in the north compared to the south. The figure below shows the frequency distribution of the north-south gradient during the winter peak condition. It indicates that the most frequent gradient is of a slightly windier northern Britain, specifically a northern mean of between 0-1 knots higher than the southern mean.

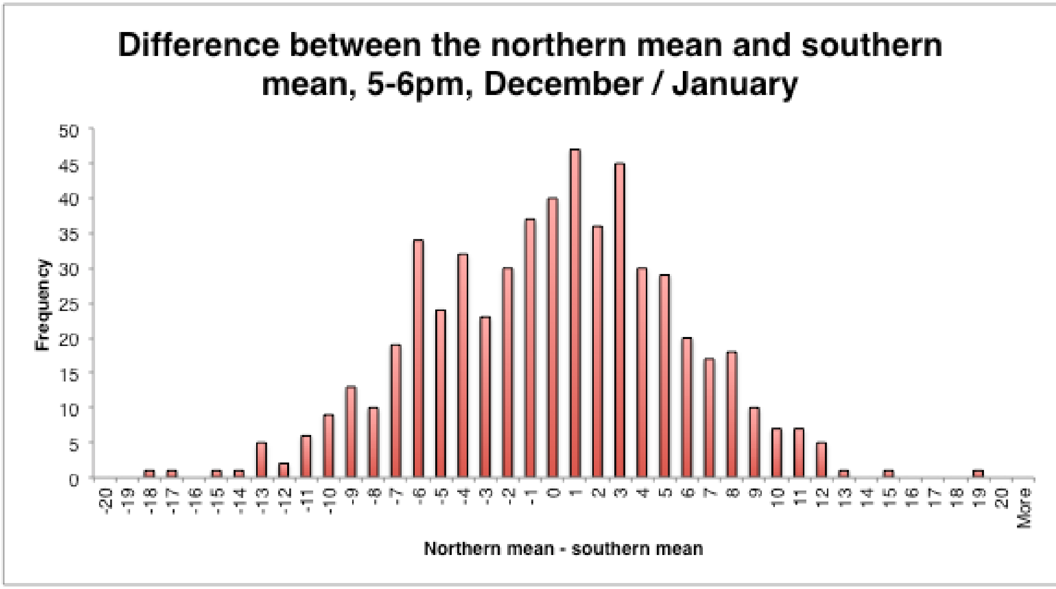

Figure 198: *Frequency distribution of the difference between the northen mean and the southern mean, 5-6pm, December-January, 2002-2012*

From this dataset, the days whose conditions produced the 95th and 5th percentiles of the means were selected to represent the high and low wind conditions respectively; and the days whose conditions produced the 95th and 5th percentiles of the northern mean-southern mean, were selected to represent the northern skew (NS) and southern skew (SN) conditions respectively. Further, a condition was selected which combined having a mean close to the mean of the total set, with having its north-south gradient within the modal frequency bin of the total north-south gradients. This condition was selected as the average condition.

The same process was repeated for the spring and summer datasets. This produced a set of real measured wind conditions which have taken place at the three seasonal hours being used for power flows, which in each case span a range of conditions from high and low overall to more northerly or more southerly winds. The selected conditions are given in the tables below.

Table 57: *Selected representative winter wind conditions*

Winter Condition, 5-6pm	Date recorded	Kirkwall	Stornoway	Peterhead	Boulmer	Weybourne	Langdon Bay	Machrihanish	Aberdaron	Camborne
95th pc mean	04/12/2007	16	28	20	23	17	18	25	35	19
5th pc mean	28/01/2012	7	17	3	3	5	10	6	4	6
95th pc N skew	14/12/2007	17	28	16	4	1	13	18	14	10
95th pc S skew	17/01/2004	3	7	8	6	25	21	1	17	19
"Average"	19/12/2011	7	16	11	11	13	13	23	14	13

Table 58: *Selected representative spring wind conditions*

Spring Condition, 12-1pm	Date recorded	**Kirkwall**	**Stornoway**	**Peterhead**	**Boulmer**	**Weybourne**	**Langdon Bay**	**Machrihanis h**	**Aberdaron**	**Camborne**
95th pc mean	05/04/2008	22	27	16	18	18	17	18	23	15
5th pc mean	10/04/2008	6	6	8	13	8	7	7	6	12
95th pc N skew	29/04/2005	23	23	15	18	7	5	10	14	9
95th pc S skew	04/04/2004	13	17	10	17	20	17	17	31	18
"Average"	16/04/2007	21	18	6	7	8	13	11	22	9

Table 59: *Selected representative summer wind conditions*

Summer Condition, 12-1pm	Date recorded	Kirkwall	Stornoway	Peterhead	Boulmer	Weybourne	Langdon Bay	Machrihanish	Aberdaron	Camborne
95th perc mean	17/07/2011	10	24	7	9	14	21	18	22	19
5th perc mean	12/08/2003	8	12	4	7	7	4	6	11	7
95 perc N skew	12/07/2006	20	15	17	15	6	5	5	16	7
95 perc S skew	01/07/2012	10	9	9	11	19	15	14	21	15
"Average"	20/08/2012	12	14	10	8	9	10	12	15	10

Following this, some simple conversions were made on the data to deliver onshore and offshore availability factors for renewable technologies. The wind speeds in knots were converted to metres per second. The wind speeds recorded at 10m in weather stations were converted to the wind speed at a hub height of 80m using a formula provided by Best et al (2008):

Equation 5

$$U_b = U_a \left(\frac{b}{a}\right)^p$$

where U = wind speed, a = original hub height, b = converted hub height, and p = roughness factor, given as 0.1429 in Best et al (2008).

Offshore wind speeds were derived from these onshore speeds using the following formula suggested by Hsu (1988):

Equation 6

$$U_{sea} = 1.62 + 1.17U_{land}$$

Finally, offshore and onshore wind speeds were converted to an availability using a power curve for a Siemens SWT 2.3 provided by Staffell (2012), illustrated below.

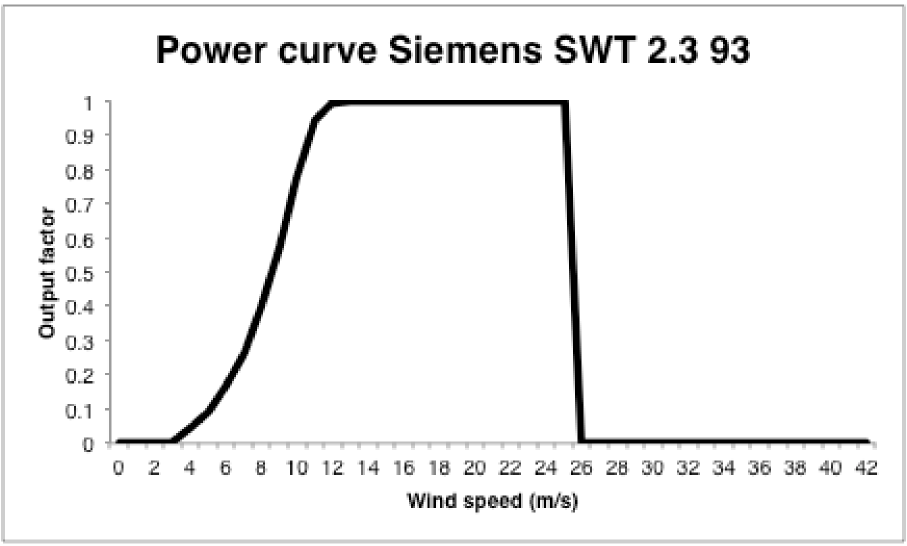

Figure 199: *Power curve for Siemens SWT 2.3 93 turbine. Source: (Staffell, 2012)*

E.5.2 Tidal output

A common availability factor was required for tidal power. The output of tidal installations in different locations would be staggered as the tides move around the different areas of the country. The aim of the approach was to identify the maximum availability factor that could potentially apply simultaneously in two distantly located tidal areas. The two areas chosen were the Bristol Channel and the Pentland Firth. High and low tide times were identified for Cardiff and Scrabster, to represent these areas. On the 25th March, 2014, these were:

Table 60: *High and low tide times for Cardiff and Scrabster*

	High	Low	High	Low
Cardiff	00:34	06:48	13:21	19:31
Scrabster	03:09	09:36	16:21	22:45

Source: www.tidetimes.org.uk

Using the tidal patterns for the relevant regions as indicated in ECI (2005), and the relative patterns suggested by the delay between the high and low tide times, a possible output pattern for tidal installations in the two areas was reconstructed.

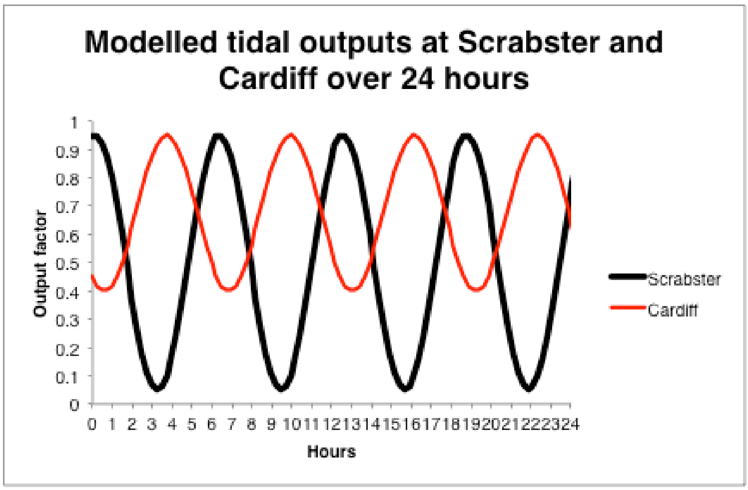

Figure 200: *Modelled tidal outputs at Scrabster and Cardiff over 24 hours*

This suggests that the maximum simultaneous output at the two sites is a 0.7 output factor.

E.5.3 Hydro output

For hydro, the first stage was to note the highest quarterly output factor in the last three years, according to DECC (2014b) as being 0.54, in 2011 quarter 4. This maximum output was then scaled against the ten year mean rainfall weighted by location of UK hydro resource for the months of January, April and August (DECC, 2014c). These were 167.9, 78.5 and 119.0 mm respectively. The January 10-year mean being the greatest, this was linked to the maximum output factor of 0.54 for the winter condition, and output factors for spring and summer calculated by scaling from 0.54 in proportion to the difference in mean rainfall. This produced 0.25 and 0.38 for spring and summer respectively. The mean of the three load factors is 0.39, a reasonable annual average figure for hydro (DECC, 2013a).

E.5.4 Annual load factors for emissions calculations

As well as identifying factors to indicate the available power output of technology types at the three seasons being modelled, it was also necessary to establish annual load factors from which the annual output from a given capacity of each technology could be calculated. This was necessary to evaluate the total contribution of different technology types for the purpose of calculating the figure for the carbon intensity of electricity.

Table 61: *Average annual load factors of electricity generation technologies*

Technology	Average annual load factor
Offshore wind	0.4
Tidal	0.3
Wave	0.3
Hydro	0.4
Onshore wind, northern UK	0.35
Onshore wind, southern UK	0.3
Nuclear	0.83
Biomass	0.9
CHP	0.9
Fossil	0.9
Fossil peaking	0.4

Sources: DECC (DECC, 2013a), Kannan et al (2007), Sinden (2007).

Appendix F: Estimating costs of transmission investment

The following cost parameters were used:

- **Onshore new AC overhead line: £1.58m/km.** Based on build cost of £118.2m for 6380 MVA, 400kV, 75km line, in Parsons Brinckerhoff (2012)

- **Offshore HVDC cable: £9.85m/km.** Based on build cost of £739.1m for 3000 MW 75km HVDC cable, in Parsons Brinckerhoff (2012)

- **Onshore uprate cost: £0.44m/km.** Based on low range of cost estimate for reconductoring, of $400/MWmile in Baldick and O'Neill (2009) and assuming 3000 MW line.