Infrastructure in a low-carbon energy system to 2030:

Transmission and distribution

Final report

for

The Committee on Climate Change

Imperial College

and

Element Energy

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Caveat

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The views and judgements expressed here are the opinions of the authors and do not reflect those of the CCC or the stakeholders consulted during the course of the project.

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1 Introduction

1.1 Background

The Committee on Climate Change commissioned Element Energy, with Imperial College and Grid Scientific, to characterise and cost the infrastructure that would be required for a low carbon system by 2030. The study explored infrastructure challenges associated with three distinct sectors/technologies:

- The transmission and distribution system
- Carbon Capture and Storage
- Smart Grid for delivering Demand Side Response

For each of these, the authors explored:

- A number of decarbonisation scenarios to 2030.
- The implications of these on the requirements on the above infrastructures, in terms of their extent and their cost.
- The barriers to the deployment of these infrastructures

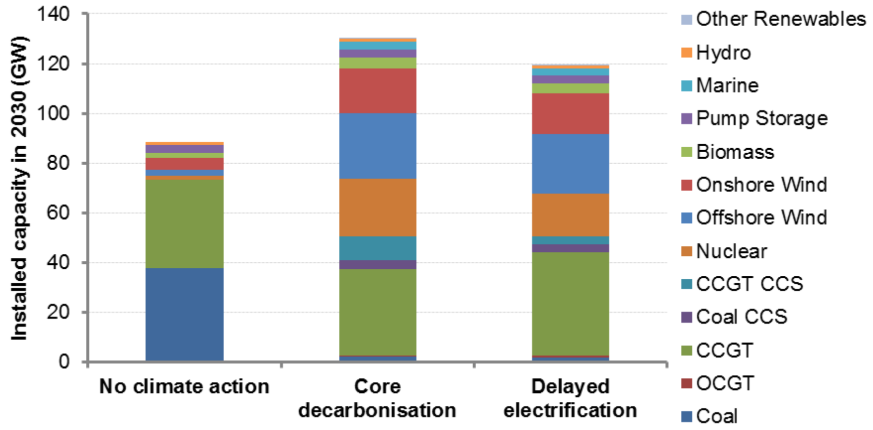
This document is one of three reports produced by the authors, and focuses on the characterisation, cost and deployment challenges associated with transmission and distribution networks.

1.2 Transmission and distribution

The UK's path towards a sustainable and low-carbon energy system will require a major shift in the structure of electricity generation technologies, primarily involving intermittent renewable resources and large-scale low-emission or zero-emission technologies such as nuclear power and Carbon Capture and Storage. Large-scale deployment of these technologies raises complex challenges in planning the supporting electricity infrastructure and real-time operation management of the system. Efficient planning of and investment in the cross-border and intra-transmission system will play a key role in facilitating cost effective transition to a low carbon future and it will be crucial that the investment decisions are timely.

This study examines the deployment of transmission and distribution infrastructure under a variety of CCC scenarios as shown in Figure 1:

- **The core decarbonisation scenario (CD)**, in which UK greenhouse gas emissions are 60% below 1990 levels in 2030, the power sector decarbonises to around 50 gCO_2/kWh and there is extensive electrification of heat and transport (i.e. deployment of heat pumps and electric vehicles).
- **The delayed electrification sensitivity (DE)**, in which electrification of heat and transport occurs at a slower pace and the power sector decarbonises to around 100 gCO_2/kWh.
- **The "no climate action" scenario (NCA)**, which will involve demand increasing with population and incomes, less energy efficiency improvement and very limited deployment of low-carbon technologies in power, transport or heat.



Source: CCC data, with additional OCGT capacity determined by Imperial College models

Figure 1: The UK's electricity generation mix in 2030 in the CCC scenarios.

In the base case analysis, the assumption is made that the UK is energy neutral, i.e. the annual electricity production in the UK is equal to annual electricity consumption while allowing short-term imports or exports of electricity to minimise EU wide system operating costs.

In addition to the core scenarios, the key features of required distribution and transmission network investments in the core decarbonisation scenario are assessed for the following sensitivities:

- **Impact of European electricity market integration,** in which both long-term and short-term cross border trading is enabled allowing the UK to be an annual net exporter or net importer, while minimising the overall EU wide generation operating costs. In this scenario, our analysis focuses on assessing the impact of electricity market integration on the need for additional investment in cross-border interconnection and transmission within the UK. .
- **EVs and HPs unevenly distributed**, in which uptake of electric vehicles (EVs) and heat pumps (HPs) is not distributed evenly (from a geographic perspective). It is expected that distribution of EVs and HPs may vary across the regions and a sensitivity analysis on uneven distribution of EVs and HPs is assessed to investigate possible impacts. It should be noted that the total number of EVs and HPs in each region is unchanged, while the distribution across the region varies. For more details see Section 6.1.2 and specifically Figure 19.
- **Demand response sensitivity**, in which reduction in peak demand is achieved by shifting demand from peak periods. Demand response utilises the flexibility of smart appliances, smart charging of electric vehicles, heat storage and other demand side management measures to enhance efficiency of system operation and reduce the network infrastructure investment.
- **Fast-charging EVs sensitivity**, in which fast-charging stations are installed in addition to residential charging. This sensitivity study assumes that 28% of EV demand is met through around 5,000 fast charging stations, each with a charging capability of 300 kW offered through 6 charging points. The stations are assumed to be in use between 11am and 11pm. Annual electricity demand for fast charging is estimated to be 2.76 TWh, with the peak demand of around 1.5 GW occurring in winter workday evenings.

The analysis reported below is based on:

- The Imperial College dynamic system and transmission investment models (DSIM and DTIM) of optimised transmission system infrastructure, given generation locations and energy consumption at a set of nodes representing the UK Transmission system, and nearby European nodes.

- The Imperial College representative models of UK Distribution Networks.

These are described in more detail in the appendix.

This report is the final deliverable from the “Transmission and Distribution” part of the Element Energy-led “Infrastructure in a low-carbon energy system to 2030” study for the CCC and presents:

- Characterisation and cost of transmission infrastructure to 2030 including interconnectors
- Characterisation and cost of distribution infrastructure to 2030
- Feasibility of T&D deployment in the UK

2 Characterisation and cost of transmission infrastructure to 2030

In this chapter, the requirements for the UK's interconnection and intra-transmission capacity are assessed for the CCC scenarios, namely: Core Decarbonisation, No Climate Action, and Delayed Electrification. A further analysis is also carried out to examine the characterisation and cost of transmission infrastructure under a variety of sensitivities.

2.1 Network expansion in the Core Decarbonisation Scenario

Table 1 shows the 2013 interconnection capacities, capacities expected to be in place by 2020 and the proposed 2030 capacity requirement for each UK cross-border interconnector. The *Dynamic System Investment Model (DSIM)* is used to determine the optimal interconnection capacity (transfer capacity) in the European system using our EU Grid model, which includes the electricity systems of Great Britain (GB), Ireland and continental (detailed description of the model is presented in Appendix).

Table 1: Interconnectors: additional transfer capacity and investment needed by 2020 and 2030 (CD scenario)

					Additional transfer capacity (MW)		CAPEX of new capacity (£bn)	
	Length (km)	Capacity in 2013 (MW)	Planned transfer capacity by 2020 (MW)	Total transfer capacity by 2030 (MW)	Between 2013 - 2020	Between 2020 - 2030	Between 2013 - 2020	Between 2020-2030
Scotland - Ireland	380	450	450	2,256	-	1,806	-	0.98
Midlands E&W - Ireland	480	500	500	6,757	-	6,257	-	4.82
South E&W - NorthEast France	440	2,000	2,000	2,769	-	769	-	0.51
South E&W - NorthWest France	495	-	1,000	1,000	1,000	0	0.83	0.00
South E&W - Netherlands	400	1,000	1,000	1,000	-	0	-	0.00
South E&W – Belgium	380	-	1,000	2,464	1,000	1,464	0.62	0.91
Scotland - South Norway	912	-	1,400	1,400	1,400	0	2.93	0.00
South E&W - South Norway	1,160	-	-	0	-	0	-	0.00
South E&W - North Spain	1,495	-	-	0	-	0	-	0.00
						Total	4.39	7.22

This includes not only the interconnection to Ireland, France, and the Netherlands, that exist at present, but also potential future interconnection towards Belgium, Norway, and Spain. The table shows the expected total capital expenditure (capex) associated with delivery of the transfer capacity including any onshore network reinforcements that may be triggered by the interconnection[1].

One can observe that by 2020, there will be 3.4 GW of additional interconnection capacity to mainland Europe, while a further 2.2 GW is proposed to be built by 2030. This indicates the importance of UK interconnectors to mainland Europe in order to facilitate efficient development of renewable energy sources not only in the UK but also in Ireland.

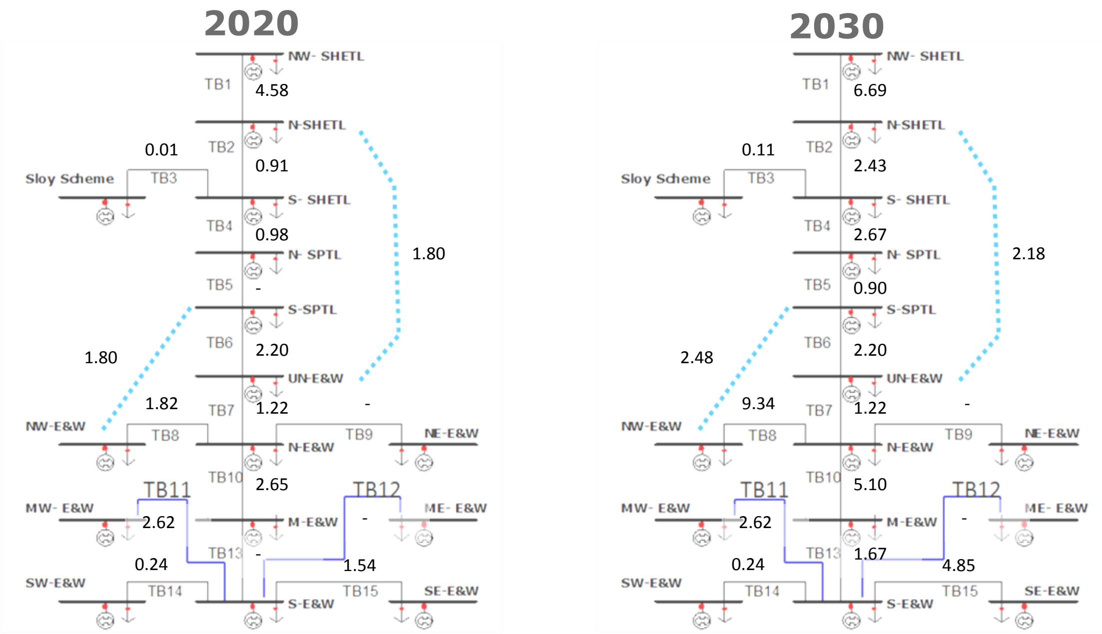
In this study, it is envisaged that the capacity of wind power generation in Ireland will reach 23 GW by 2030. This capacity exceeds by far the Irish peak demand, which is around 7 GW at present. In order to harness Irish wind energy, it will be efficient to increase interconnector capability between Ireland and UK, and then UK and mainland Europe, and facilitate exports of Irish wind to Europe. This is reflected in the significant upgrade (8.1 GW) of the interconnector between Ireland and the UK. Although the development of Irish wind also triggers demand for upgrading the UK's interconnector to the mainland Europe, this also provides a commercial opportunity for the UK to act as a hub for Irish wind and at the same time to improve the utilisation factor of its cross border interconnectors to the mainland Europe.

The upgrade and development of new UK interconnectors will cost around £4.4bn in the period between 2013 and 2020 and £7.2bn in the period between 2020 and 2030. By 2030, the total cost is estimated at £11.6bn.

In parallel to the development of UK cross-border interconnectors, the onshore and offshore intra-transmission system within the UK will also require significant upgrades. The capacity of interconnectors and the projected power flows from/to UK are used by the *Dynamic Transmission Investment Model* (DTIM) to determine the transfer capability across the main transmission *boundaries* of the Main Interconnection Transmission System (MITS) in the UK (a detailed description of DTIM is presented in Appendix). Figure 2 shows the additional capacity needed, with reference to the present capacity (described in the Appendix, Figure 15), on each of the main transmission boundaries on the GB system by 2020 and 2030 (the figures adjacent to each boundary indicate the additional capacity in GW). It is important to note that the additional capacities shown in Figure 2 (right) are cumulative; 2030 figures include the reinforcement required by 2020.

The boundary reinforcement costs in DTIM are calibrated to reflect the actual costs of projects associated with increasing boundary capacity as proposed in National Grid's "Gone Green" scenario[2].

[1] The total network costs implicitly include the cost of new substations including transformers, cost of overhead lines or underground cables, and the installation costs.
[2] The cost of boundary reinforcement implicitly includes all infrastructure and installation costs required taking into account the security level that needs to be satisfied. This is a standard practice for a high level transmission planning studies that makes use aggregated reinforcement cost rather than modelling the individual circuits and the substations involved.



Total AC: 18.8 GW
Total DC: 3.6 GW

Total AC: 40.0 GW
Total DC: 4.7 GW

Figure 2: Additional transfer capacity needed for each GB main transmission boundaries by 2020 and 2030 (CD scenario)

Given that the most significant renewable resources, especially large wind farms, are expected to be located in Scotland or Northern England, most of the transmission upgrades will be required in those areas. Two DC bootstraps (Western and Eastern) will also be needed, each with the capacity of 1.8 GW by 2020. The capacity needs to be further increased to 2.48 GW and 2.18 GW by 2030 for the Western and Eastern bootstraps, respectively, indicating increased capacity requirement to access renewables in the north. By 2030, a significant upgrade will also be needed in Wales and East coast to facilitate power transfer from Ireland to mainland Europe.

The reinforcement requirements are presented on regional basis, as shown in Table 2. The investment cost of reinforcing the transmission system is estimated at around £4bn by 2020, with another £2.2bn needed between 2020 and 2030, as shown in Table 3.

Table 2: Regions of transmission reinforcement

Transmission boundaries	Length (km)	Region
TB1	60	Scotland
TB2	100	
TB3	50	
TB4	120	
TB5	35	
TB6	150	Scotland - England
Eastern DC bootstrap	330	
Western DC bootstrap	280	
TB7	150	North to Midlands and Midlands to South
TB9	40	
TB10	93	
TB8	79	North Wales
TB11	75	Mid-Wales
TB14	195	South West
TB12	80	East Coast and East Anglia
TB15	60	
TB13	155	London

Table 3: Investment cost for upgrading the transfer capacity of GB main transmission infrastructure (in £bn). Costs in the 2020-2030 period are in addition to the costs in the previous period. (CD scenario)

Region	2013-2020	2020-2030
Scotland	0.38	0.40
Scotland-England	3.00	0.79
North to Midlands and Midlands to South	0.34	0.18
North Wales	0.11	0.46
Mid-Wales	0.15	-
South West	0.04	-
East Coast and East Anglia	0.07	0.15
London	-	0.20
Total	**4.08**	**2.19**

Note that the investments shown in Table 1 and Table 3 only include the capital cost of new transmission investment required to accommodate the additional generation required to meet the decarbonisation objectives in each scenario. In addition to this cost will be the routine cost of replacing the aging assets and the maintenance cost of existing assets, which may vary between £1.9m/km – £3.2m/km across the lifetime of the assets[3]

[3] Source: National Grid, Electricity transmission cost study – National Grid's view p.2,February 2012

2.2 Network expansion in the No Climate Action Scenario (NCA)

For the NCA scenario, DSIM does not require any upgrade and reinforcement of the UK's interconnectors since the current capacity is already sufficient to facilitate efficient power exchange between the UK and the mainland Europe. The results are illustrated in Figure 3.

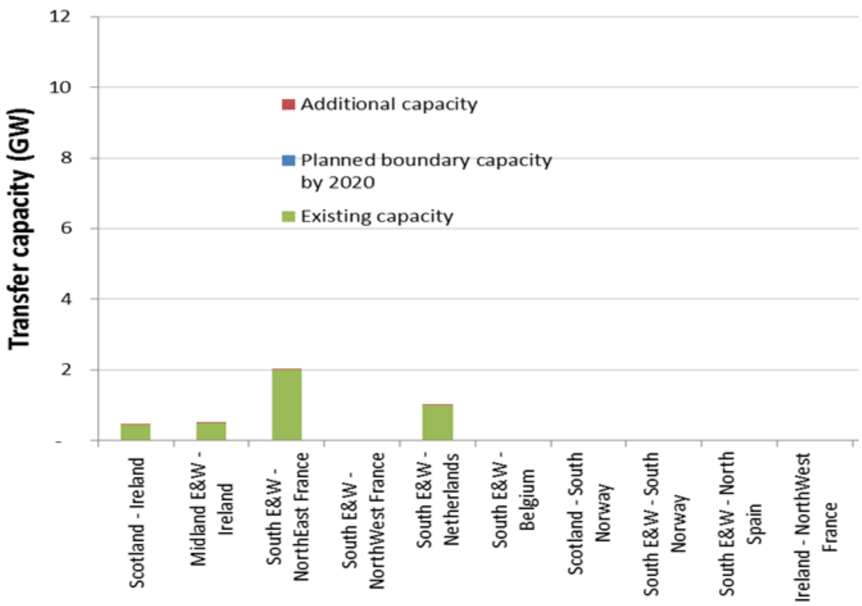


Figure 3: Interconnectors: transfer capacity and investment needed by 2030 (NCA scenario)

It can be inferred that developing new interconnectors (or upgrading the existing ones) is predominantly driven by the development of low marginal cost renewable generation. Note that this result is in line with a recent analysis by Redpoint which identified that the extent of interconnection capacity was closely related to the deployment of renewable generation[4]. Since the NCA scenario does not postulate any further increase in renewable capacity in the UK and in Ireland compared to today's levels, the DSIM model suggests that the present capacity of the interconnectors is adequate.

The demand for upgrading GB main interconnected transmission system (MITS) will be relatively modest by 2020. DTIM studies suggest the reinforcement of the SYS boundary 1 between the north-west part and north part of the Scottish Hydro Electric Transmission Limited (SHETL) network, as well as a modest upgrade at the boundary between Midlands and south part of GB and the south west. The total increased capacity of the on-shore AC MITS is 1.8 GW. Development of DC bootstraps is not proposed in this scenario.

By 2030, the total investment will be moderate with most of the upgrade occurring in the south east and south west of GB due to the development of new generation in those areas to meet the increasing demand. The total increased capacity of the onshore AC MITS is 11.2 GW. There is again no development of any DC bootstraps.

[4] "Impacts of further electricity interconnection on Great Britain", Redpoint Energy Limited for DECC, November 2013.

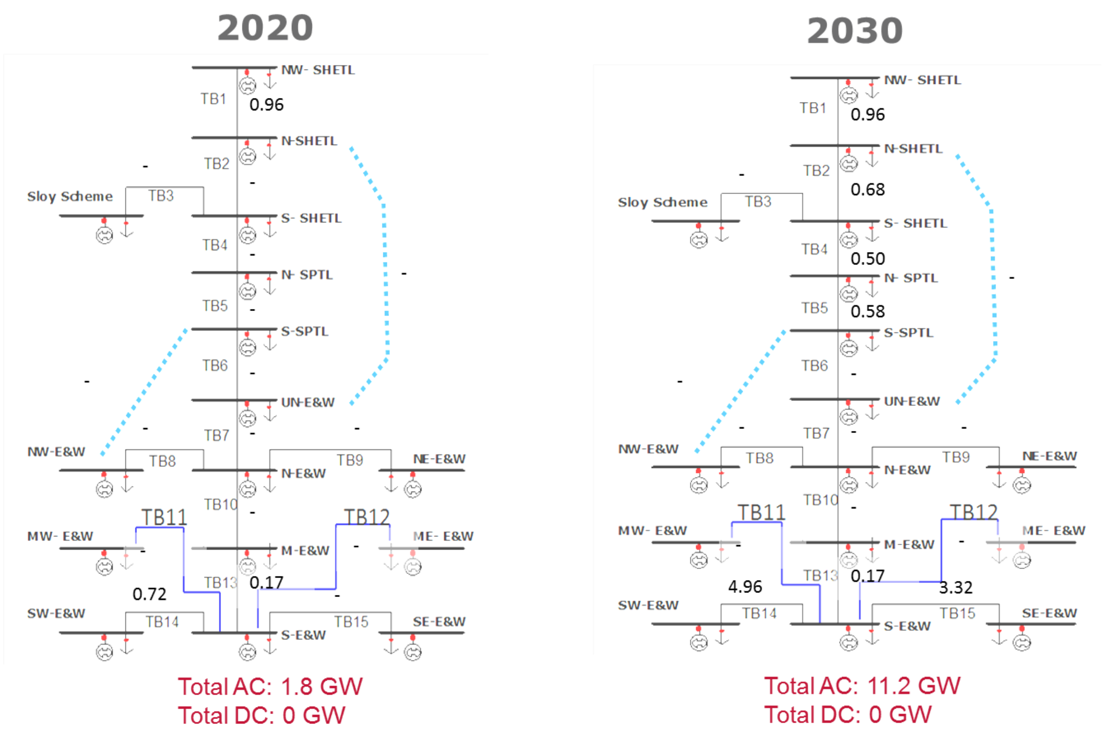


Figure 4: Additional transfer capacity needed for each GB main transmission boundaries by 2020 and 2030 (NCA scenario)

The investment cost of reinforcing the transmission system is estimated at about £0.2bn by 2020 and another £0.9bn will be needed between 2020 and 2030 as shown in Table 4.

Table 4: Investment cost for upgrading the capacity of GB main transmission infrastructure (in £bn, NCA scenario)

Region	2013-2020	2020-2030
Scotland	0.04	0.12
Scotland-England	-	-
North to Midlands and Midlands to South	-	-
North Wales	-	-
Mid-Wales	-	-
South West	0.11	0.65
East Coast and East Anglia	-	0.16
London	0.02	-
Total	**0.17**	**0.92**

There are some transmission developments in a number of regions between 2013 and 2030 in Scotland, East Coast, London and the South West, which is the largest one. The investment in the South West is considerably greater than the transmission development in the same region in the CD scenario. This is primarily driven by the lack of installed generating capacity in the South West postulated in the NCA scenario. In the CD scenario, the presence of new interconnection between South West of England and North West of France also contributes to providing supply to the demand in South West and therefore leads to less reinforcement required in the South West corridors. The installed generating capacity and the peak of demand minus import from the interconnector is shown in the figure below.

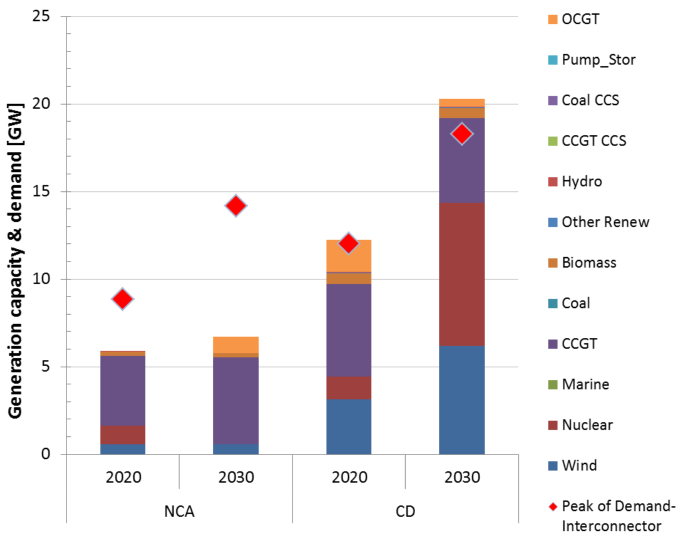


Figure 5: Installed generating capacity and peak demand in South West for both NCA and CD scenarios

The figure shows a significant capacity gap between the peak demand and generation, taking into account the interconnection available, and installed generating capacity in South West in the NCA scenario. This is in contrast to the CD scenario where the installed capacity is equal or greater than peak demand. As a consequence, there is a need to reinforce the South West transmission corridor to allow import from other regions.

2.3 Network expansion in the Delayed Electrification (DE) Scenario

The delayed electrification (DE) scenario is similar to the core decarbonisation (CD) scenario and it has a similar generation mix with a similar level of renewable penetration (see Figure 1). The key difference between the two scenarios is in the level of electrification of transport and heating sectors; in the DE scenario this electrification is slower. The consequence is lower electricity consumption and lower peak demand than in the CD scenario. Furthermore, the total capacity of low carbon generation technologies (renewables, nuclear and CCS) is also reduced; hence the average grid CO_2 emissions in this scenario (i.e. 100 g/kWh) are higher compared to the CD scenario (50 g/kWh).

Table 5 shows the 2013 capacity and the proposed 2020 and 2030 capacity requirement for each UK cross-border interconnector for the DE scenario. Table 5 also shows how much reinforcement is expected for each interconnector between 2013 and 2020, and what DSIM suggests should be added between 2020 and 2030. The estimated cost of each reinforcement project is also given in Table 5.

Table 5: Interconnectors: transfer capacity and investment needed by 2020 and 2030 (DE scenario)

				New transmission capacity (MW)		CAPEX of new transmission (£bn)	
	Capacity in 2013 (MW)	Planned boundary capacity by 2020 (MW)	Total boundary capacity requirement by 2030 (MW)	Between 2013 - 2020	Between 2020-2030	Between 2013 - 2020	Between 2020-2030
Scotland - Ireland	450	450	1,200	-	750	-	0.41
Midlands E&W - Ireland	500	500	7,318	-	6,818	-	5.25
South E&W - NorthEast France	2,000	2,000	2,572	-	572	-	0.38
South E&W - NorthWest France	-	1,000	1,000	1,000	0	0.83	0.00
South E&W - Netherlands	1,000	1,000	1,000	-	- 0	-	- 0.00
South E&W – Belgium	-	1,000	2,108	1,000	1,108	0.62	0.69
Scotland - South Norway	-	1,400	1,400	1,400	0	2.93	0.00
South E&W - South Norway	-	-	0	-	0	-	0.00
South E&W - North Spain	-	-	0	-	0	-	0.00
					Total	**4.39**	**6.73**

It is projected that by 2020, there will be a requirement for 3.4 GW of additional interconnection capacity to mainland Europe and another 1.7 GW will be built between 2020 and 2030. This suggests that upgrading the interconnectors to Europe is vital for the system to facilitate the development in generation and growth in demand assumed in this scenario.

As in the CD scenario, the Irish wind capacity is expected to reach 23 GW by 2030. This requires stronger interconnectors from Ireland to mainland Europe via the UK, as reflected in the significant upgrade (7.6 GW) of the interconnector between Ireland and the UK. Again, the development of renewables in Ireland also triggers demand for upgrading the UK's interconnector to the mainland Europe, as UK provides a more cost-efficient solution for the Irish wind to access European electricity markets.

However, the total additional capacity of Ireland-UK interconnectors in this case is slightly lower compared to the results of CD scenario. This is primarily due to less interconnection capacity between UK and the mainland Europe and also because of less electricity demand in the UK that affects the ability of the UK system to absorb wind power.

The upgrade and development of new UK interconnectors will cost circa £4.4bn in the period between 2013 and 2020 and £6.7bn in the period between 2020 and 2030. By 2030, the total cost is estimated at £11.1 bn.

In order to enable more intensive power exchanges at the UK cross-border interconnectors, the onshore and offshore intra-transmission system in the UK will also require significant upgrades. Figure 6 shows the additional GW capacity needed, with reference to the present capacity, on each of the main transmission boundaries on the GB system by 2020 and 2030.

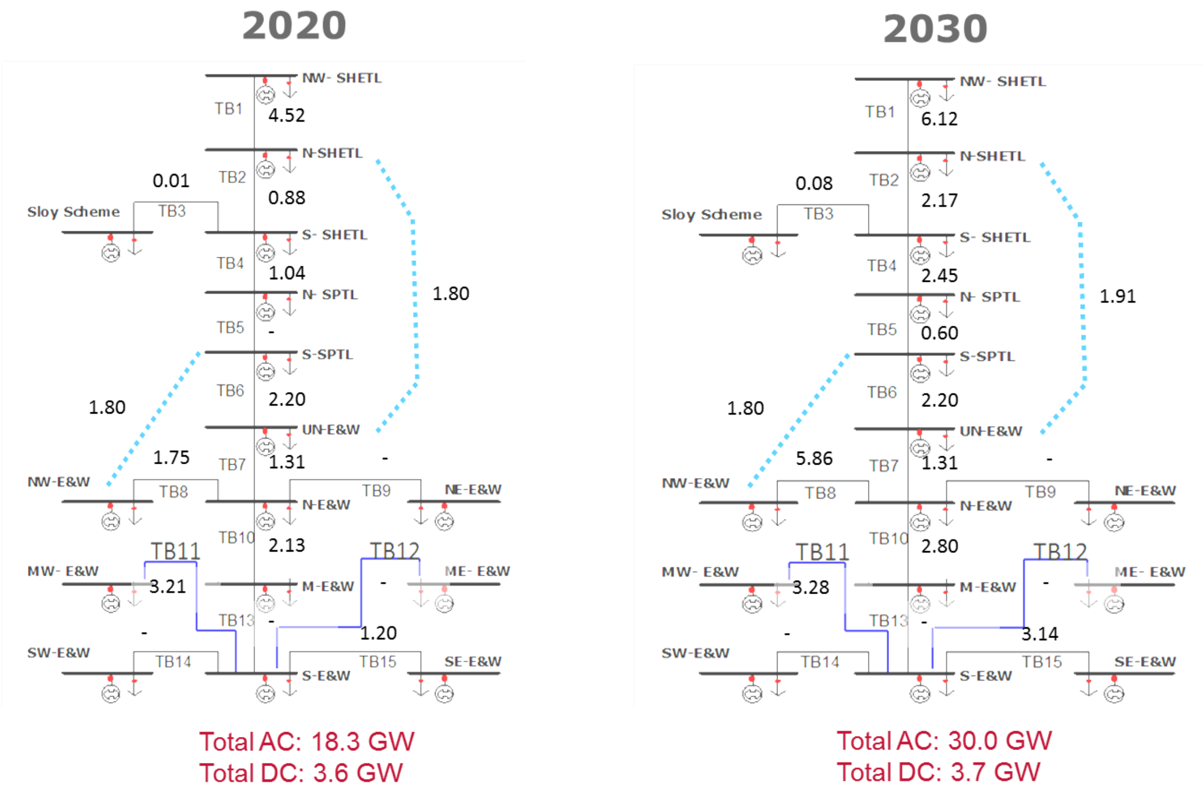


Figure 6: Additional transfer capacity needed for each GB main transmission boundaries by 2020 and 2030 (DE scenario)

Similar to the CD scenario, the DE scenario assumes that most of the renewable sources, especially large wind farms, will be located in Scotland or Northern England, requiring most of the transmission upgrades are carried out in those areas. Two DC bootstraps (Western and Eastern) will be needed with 1.8 GW of capacity each by 2020. The capacity of the Western bootstrap will need to be further increased to 1.91 GW by 2030. This may provide an opportunity for this bootstrap to be developed strategically in order to avoid the marginal upgrade between 2020 and 2030.

By 2030, a significant upgrade will also be needed in Wales and East coast to facilitate power transfer from Ireland to mainland Europe. The investment cost of reinforcing the transmission system is estimated circa £4bn by 2020 and another £0.8bn will be needed between 2020 and 2030 as shown in Table 6.

Table 6: Investment cost for upgrading the capacity of GB main transmission infrastructure (in £bn)

Region	2013-2020	2020-2030
Scotland	0.38	0.33
Scotland-England	3.00	0.09
North to Midlands and Midlands to South	0.31	0.05
North Wales	0.11	0.25
Mid-Wales	0.19	0.00
South West	-	-
East Coast and East Anglia	0.06	0.09
London	-	-
Total	**4.04**	**0.82**

The results also suggest that the period between 2013 and 2020 will be critical given that a large reinforcement project will be needed to upgrade the main interconnectors between Scotland and England. This will be essential to allow the demand in south to access renewable energy sources in the north of the GB system.

2.4 Sensitivity studies

The need for the interconnection and transmission infrastructure will also be affected by other factors such as the availability of both short-term and long-term access to the neighbouring electricity markets, or the characteristics of electricity demand including the implementation of Demand Response technologies. In order to quantify the impact of these factors on the interconnection and transmission infrastructure, we have carried out three sensitivity studies focusing on:

- The impact of European electricity market integration. In this scenario, we assume that UK does not need to be energy neutral i.e. that UK can export or import electricity from other European electricity markets not only in the short-term but also in the long-term energy markets. In other words, UK can be a net exporter or a net importer. (Note that all other scenarios assume that UK is energy neutral.) With the full electricity market integration, the interconnection also provides the opportunity for sharing capacity and to enable adjacent European Member States to support security for the UK system and vice versa. This will reduce the amount of generating capacity which is needed to secure demand;

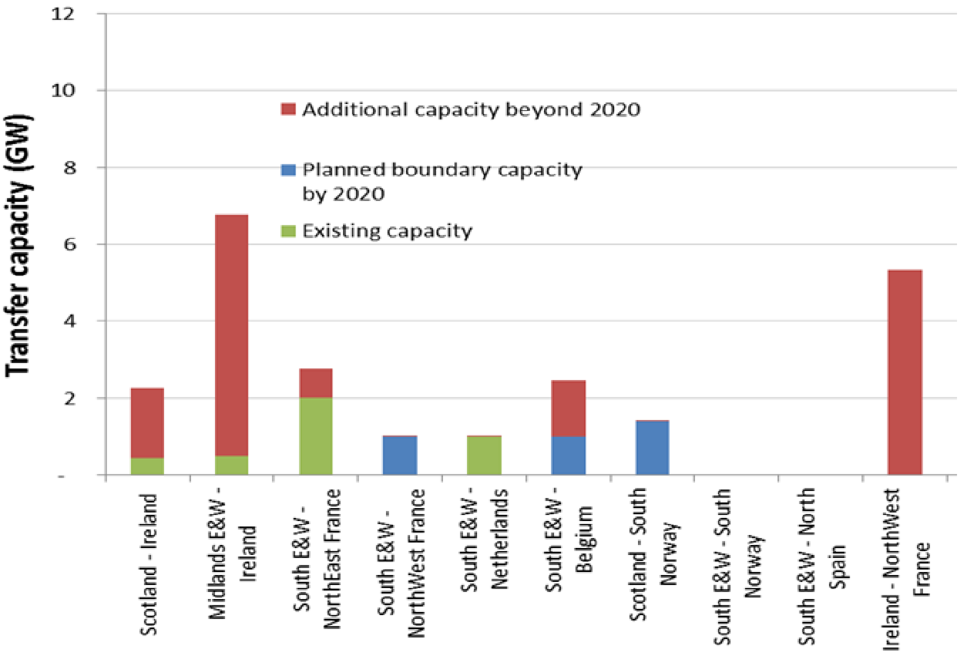
- The national roll out of fast-charging stations for electric vehicles; this will marginally increase peak demand, which may require upgrading the national transmission system and have impact on the interconnection requirements;

- The implementation of demand response (DR) technologies such as smart appliances, smart charging electric vehicles, smart control of heat pumps, etc. may also have implications on the network infrastructure requirements.

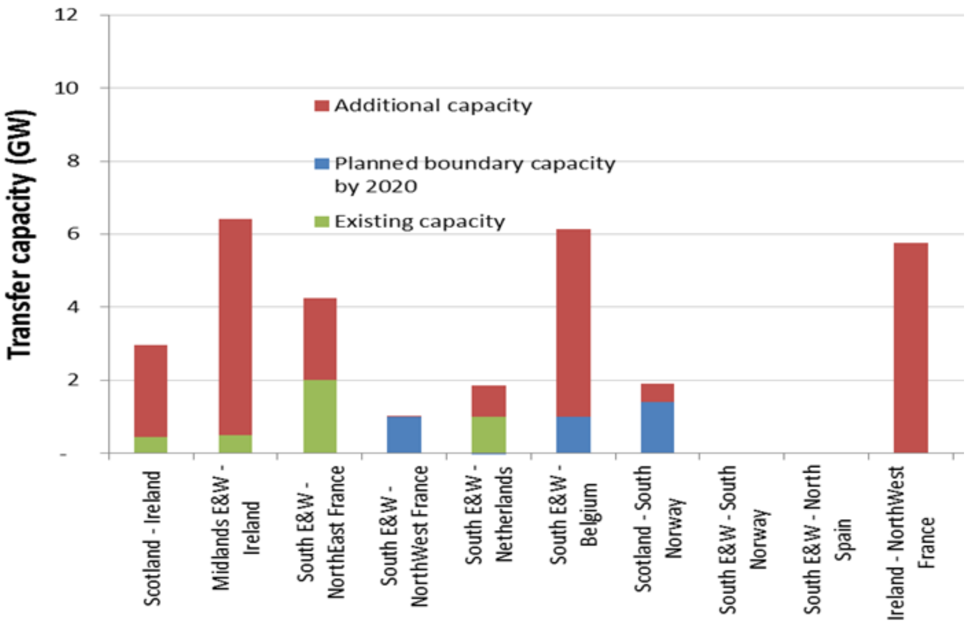
All the sensitivity studies are based on the 2030 CD scenario.

Impact of European electricity market integration

The proposed interconnection capacity for the CD scenario and the case with full EU electricity market integration is compared in Figure 7. The results suggest that significantly higher interconnection capacities will be required to facilitate a full integration of UK and EU electricity markets. This is reflected in the increased capacity of UK interconnectors to France, the Netherlands and Norway, while the largest increase is detected at the UK-Belgium interconnector – from 2.5 GW to around 6 GW. The total interconnection upgrade requirement increases from 13.7 GW in the CD scenario to 20.6 GW in the full market integration case.



(a) Core Decarbonisation

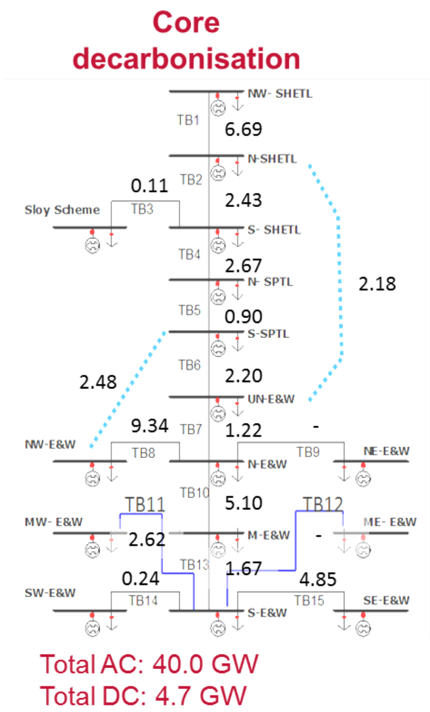


(b) Full EU electricity market integration

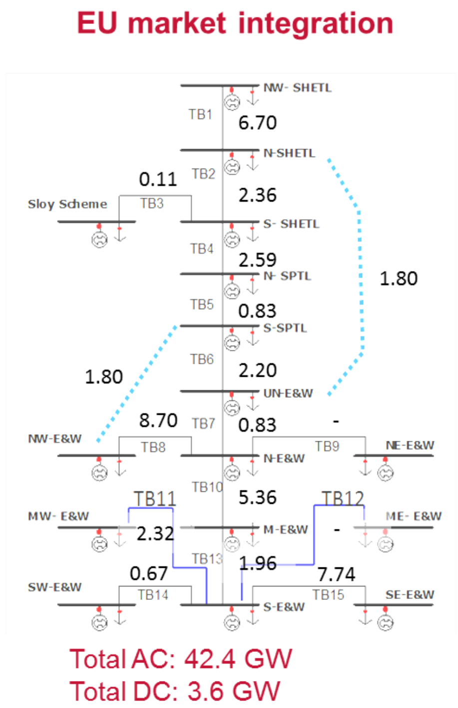
Figure 7: Impact of European electricity market integration on the UK interconnectors (sensitivity based on CD scenario)

The increased capacity of interconnectors not only facilitates larger volumes of electricity to be exchanged but also reduces the capacity of peaking plant in the UK from 29.7 GW to 8.3 GW as the security is now shared across EU Member States. Assuming a capex of peaking plant (i.e. Open Cycle Gas Turbine) of £450/kW[5], the savings are circa £9.6 bn..The cost saving from this reduction in generating capacity more than offsets the cost of upgrading the interconnectors, which increases from £11.6bn (CD) to £16.7bn by 2030.

The electricity market integration also has an impact on the GB MITS. We observe that the additional capacity requirements in the northern part of GB are slightly lower due to the slightly larger capacity of the Scotland-Norway interconnector that can help to relieve congestion of the bulk power transfer from north to south. In the south, the demand for upgrading the GB MITS is higher, especially in the south-east. This is triggered by the development of larger GB – mainland Europe interconnectors. The comparison between the additional capacities proposed for the GB MITS in the CD scenario and the EU full electricity market integration is illustrated in Figure 8.



(a) Core Decarbonisation



(b) Full EU electricity market integration

Figure 8: Impact of European electricity market integration on the GB MITS

The cost of upgrading GB MITS in the second case is lower than in the CD scenario. Although the total additional capacity is higher, the upgrade of transmission in the second case happens at the boundaries where the length of the boundary is shorter and therefore the cost is lower. The total cost of reinforcing GB MITS decreases from £6.3bn to £5.6bn. The comparison between the cost of upgrading GB MITS in the CD scenario and the EU full market integration is given in Table 7.

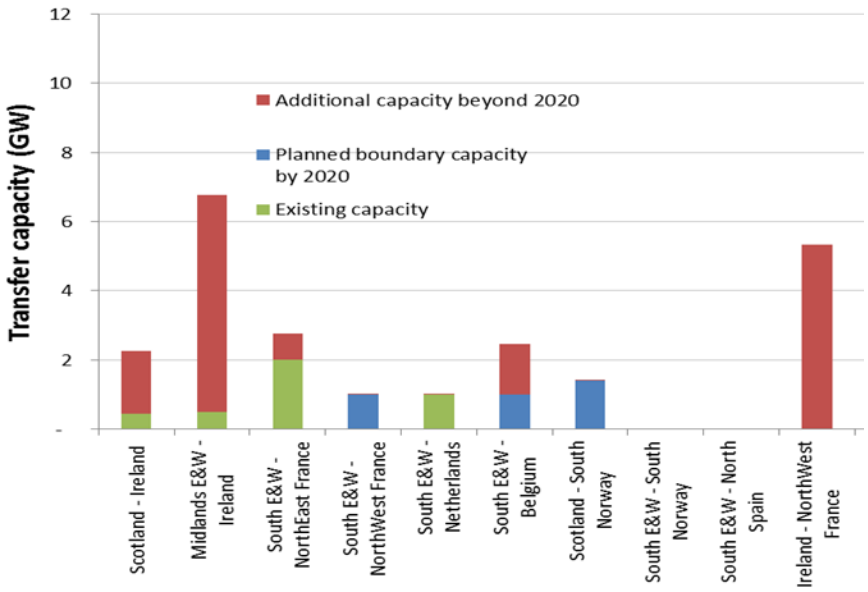
5 Source: National Renewable Energy Laboratory, Cost and Performance Data for Power Generation Technologies, 2012

Table 7: Investment cost for upgrading the capacity of GB main transmission infrastructure (in £bn)

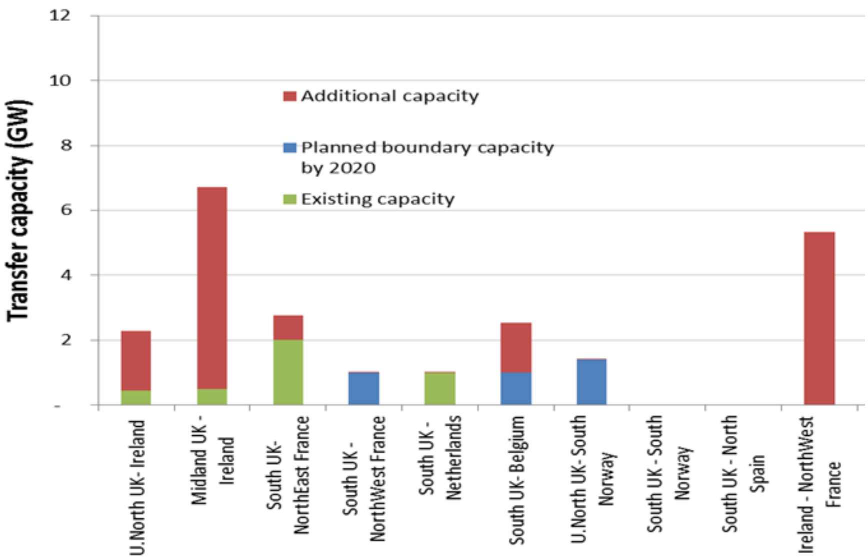
Region	Core decarbonisation	Full EU market integration
Scotland	0.78	0.77
Scotland-England	3.79	3.00
North to Midlands and Midlands to South	0.51	0.49
North Wales	0.58	0.54
Mid-Wales	0.15	0.14
South West	0.04	0.10
East Coast and East Anglia	0.23	0.36
London	0.20	0.24
Total	**6.28**	**5.62**

Impact of Fast Charging (FC)

The proposed interconnection capacity for the CD scenario and the FC scenario is compared in Figure 9, which shows that the FC scenario has no visible impact on the expansion programme of the UK cross-border interconnectors.



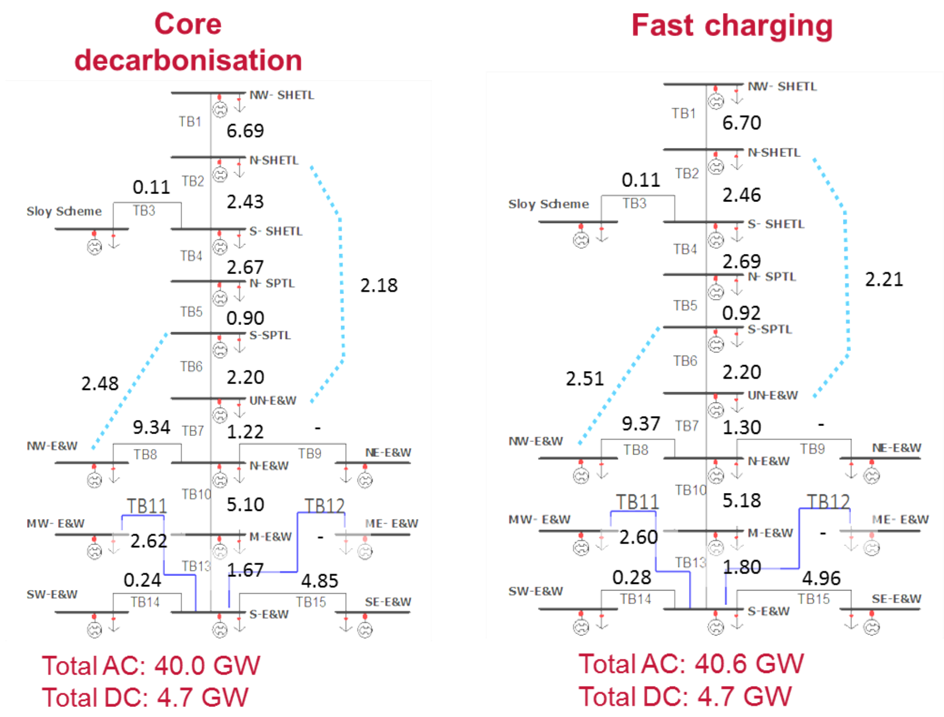
(a) Core Decarbonisation



(b) Fast charging

Figure 9: Impact of fast charging on the UK interconnectors

The impact of FC on the GB MITS is also modest. This is illustrated in Figure 8, which suggests that the proposed transmission reinforcement for each major boundary is almost identical as in the CD scenario. The total additional transmission capacity is only slightly larger in the FC sensitivity study, since the FC case only increases the peak demand by around 2 GW in comparison with the CD scenario. The cost of reinforcing the transmission grid in both cases is therefore very similar.

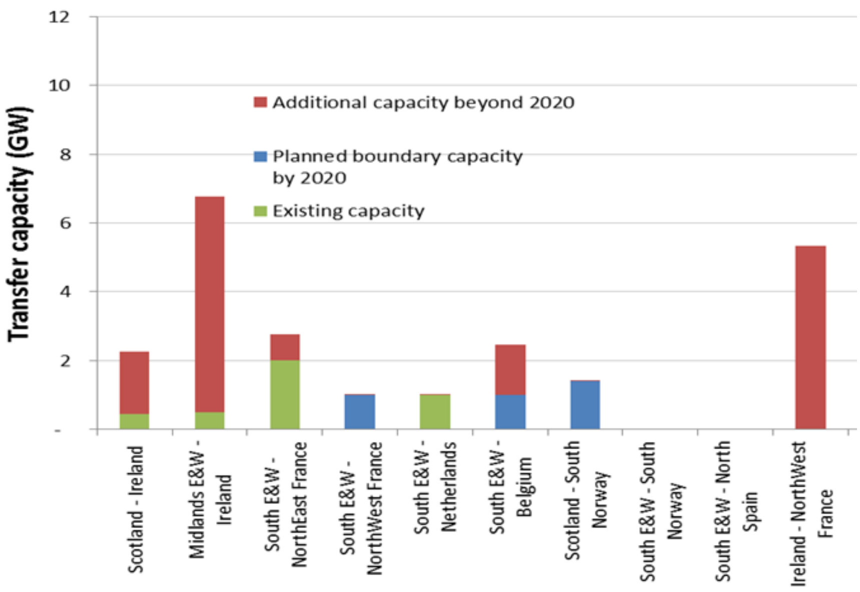


(a) Core Decarbonisation **(b) Fast charging**

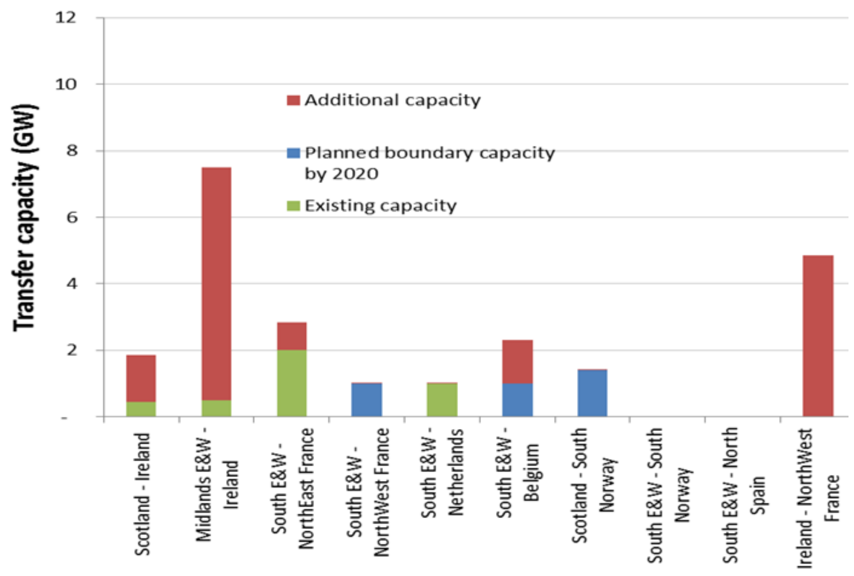
Figure 10: Impact of Fast Charging on the GB MITS

Impact of Demand Response (DR)

The results of our study suggest that the impact that DR has on the expansion programme of the UK cross-border interconnectors is relatively modest except for the GB-Ireland interconnectors. DR enables the GB system to accommodate more imported renewable generation from Ireland, which in turn reduces the capacity requirement for the direct connection between Ireland and mainland Europe. Other UK interconnectors are not affected by DR. Figure 11 shows the comparison between the proposed interconnection capacity for the CD scenario and the DR scenario.



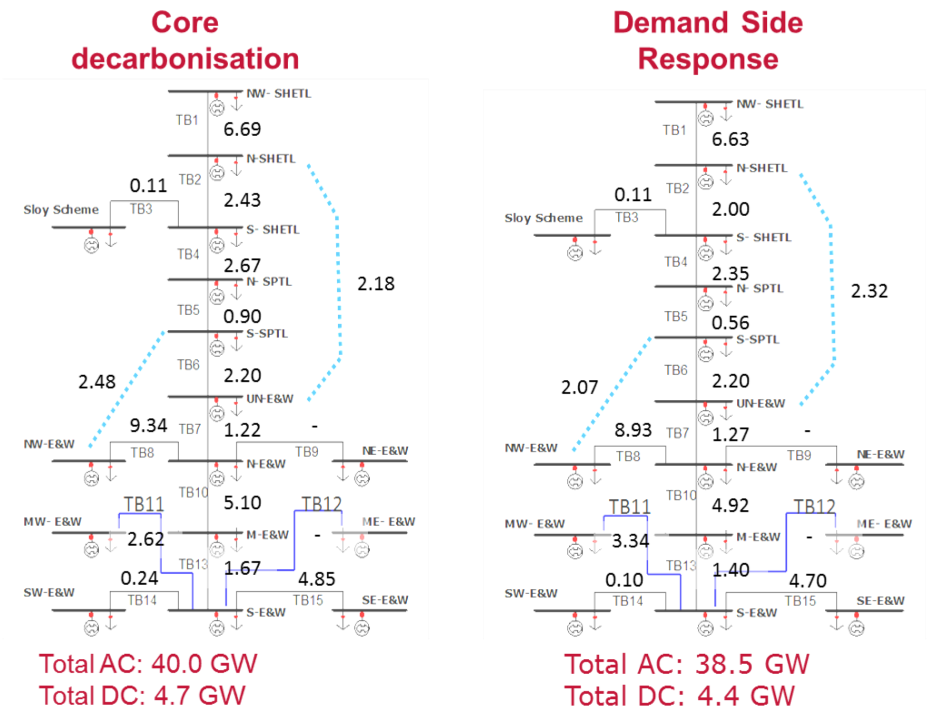
(a) Core Decarbonisation



(b) Demand Response

Figure 11: Impact of Demand Response on the UK interconnectors

The national roll-out of DR can help in reducing the additional capacity requirement on the GB MITS. It can be observed that the additional capacity requirements in most of the main transmission boundaries are slightly lower in comparison with the reference case (without DR). The results are expected since DR can effectively reduce the peak demand, which will in turn reduce the transmission capacity required to exchange power between regions. However, the impact of DR in this respect is not significant. In total, DR reduces the additional capacity requirement for the AC system by only 1.5 GW and for the offshore DC system by only 0.3 GW. The proposed GB MITS reinforcements for both the CD and DR scenarios are depicted in Figure 12.



(a) Core Decarbonisation **(b) Demand Response**

Figure 12: Impact of Demand Response on the GB MITS

The cost of upgrading GB MITS in the DR scenario is therefore lower than the cost in the CD scenario. Our analysis suggests that the savings due to DR by 2030 in reducing transmission investment are £0.3bn. The comparison between the cost of upgrading GB MITS in the CD scenario and the DR scenario is given in Table 8.

Table 8: Investment cost for upgrading the capacity of GB main transmission infrastructure (in £bn)

Region	Core decarbonisation	Full EU market integration
Scotland	0.78	0.71
Scotland-England	3.79	3.62
North to Midlands and Midlands to South	0.51	0.51
North Wales	0.58	0.55
Mid-Wales	0.15	0.20
South West	0.04	0.01
East Coast and East Anglia	0.23	0.22
London	0.20	0.17
Total	**6.28**	**5.98**

2.5 Comparison across scenarios

In order to analyse the impacts of different scenarios and sensitivities that have been studied in this project, the calculated costs of upgrading the UK interconnectors, the cost of upgrading GB MITS and the total cost of both for all case studies are summarised in Table 9 - Table 11.

Our study suggests that the investment in the UK interconnection will be driven by the increased installed capacity of low marginal cost generators (nuclear and renewables, particularly wind power), not only in the UK but also in Ireland and improved integration of the UK electricity market with continent Europe. This is demonstrated by the results of the CD, DE and the three sensitivity studies. The results of the NCA scenario also confirm the findings since, with no increase in the installed capacity of renewables, there is no increased demand for new UK interconnection capacity.

Considering a scenario with 23 GW of installed wind capacity in Ireland by 2030, the UK – Ireland interconnection will require major upgrades within 2020 to 2030 period. At the same time, the UK interconnection to Belgium and France will also need to be reinforced. If the pace of new installation of renewable power increases between 2020 and 2030, it will need to be facilitated by reinforcement of the UK interconnection.

Our study also investigates the potential of new interconnection corridors between Southern England and Southern Norway, and between Southern England and Northern Spain; the results suggest that interconnection at these two new corridors are not as competitive economically in comparison to other corridors and therefore the results indicate no development at these corridors. The total investment costs for upgrading the UK interconnectors across all scenarios are summarised in Table 9.

Table 9: Total investment cost for upgrading UK interconnectors (in £bn)

	Core decarbonisation		No Climate Action		Delayed electrification		Full EU Market Integration	Fast charging	DSR
Item	2013-2020	2020-2030	2013-2020	2020-2030	2013-2020	2020-2030	2020-2030	2020-2030	2020-2030
Scotland - Ireland	-	0.98	-	-	-	0.41	1.36	1	0.76
Midlands E&W - Ireland	-	4.82	-	-	-	5.25	4.56	4.79	5.4
South E&W - NorthEast France	-	0.51	-	-	-	0.38	1.49	0.5	0.56
South E&W - NorthWest France	0.83	0	-	-	0.83	0	0	0	0
South E&W - Netherlands	-	0	-	-	-	0	0.63	0	0
South E&W - Belgium	0.62	0.91	-	-	0.62	0.69	3.21	0.97	0.81
Scotland - South Norway	2.93	0	-	-	2.93	0	1.04	0	0
South E&W - South Norway	-	0	-	-	-	0	0	0	0
South E&W - North Spain	-	0	-	-	-	0	0	0	0
Total cost	**4.39**	**7.22**	**-**	**-**	**4.39**	**6.73**	**12.3**	**7.25**	**7.53**

Increased development of UK interconnection capacity between 2020 and 2030 may also reduce the burden of the intra GB transmission system; this is demonstrated in

Table 10 as the reinforcement costs between 2020 and 2030 for CD and DE are less significant than the reinforcement between 2013 and 2020.

Similar to the interconnection cases, the investment in GB MITS is primarily driven by development in low marginal cost generators (nuclear, renewables) as demonstrated by the results for CD, DE, and three sensitivity studies. Significant reinforcement will be required in the upper part of the GB system particularly for enhancing power transfer capability between Scotland and England as significant share of new capacity of renewable power will be installed in the north. The results of NCA also confirm the findings, and demonstrate low reinforcement requirements in the absence of development of renewable power generation.

Table 10: Total investment cost for upgrading GB MITS (in £bn)

	Core decarbonisation		No Climate Action		Delayed electrification		Full EU Market Integration	Fast charging	DSR
Item	2013-2020	2020-2030	2013-2020	2020-2030	2013-2020	2020-2030	2020-2030	2020-2030	2020-2030
Scotland	0.38	0.4	0.04	0.12	0.38	0.33	0.39	0.41	0.33
Scotland-England	3	0.79	-	-	3	0.09	-	0.84	0.62
North to Midlands and Midlands to South	0.34	0.18	-	-	0.31	0.05	0.15	0.19	0.17
North Wales	0.11	0.46	-	-	0.11	0.25	0.42	0.47	0.44
Mid-Wales	0.15	-	-	-	0.19	0	-	-	0.04
South West	0.04	-	0.11	0.65	-	-	0.07	0.01	-
East Coast and East Anglia	0.07	0.15	-	0.16	0.06	0.09	0.29	0.16	0.15
London	-	0.2	0.02	-	-	-	0.24	0.22	0.17
Total cost	**4.08**	**2.19**	**0.17**	**0.92**	**4.04**	**0.82**	**1.56**	**2.29**	**1.91**

The total costs of investment in the UK interconnection and GB MITS across all scenarios are summarised in Table 11.

Table 11: Total investment cost for upgrading UK interconnectors and GB MITS (in £bn)

	Core decarbonisation		No Climate Action		Delayed electrification		Full EU Market Integration	Fast charging	DSR
Item	2013-2020	2020-2030	2013-2020	2020-2030	2013-2020	2020-2030	2020-2030	2020-2030	2020-2030
UK Interconnection	4.39	7.22	-	-	4.39	6.73	12.30	7.25	7.53
UK Transmission	4.08	2.19	0.17	0.92	4.04	0.82	1.56	2.29	1.91
Total cost	**8.47**	**9.41**	**0.17**	**0.92**	**8.42**	**7.54**	**13.85**	**9.54**	**9.44**

It can be concluded that in most of the cases, the decarbonisation of the UK energy system is the main driver for enhancing the capacity of UK interconnectors and the GB MITS. This is demonstrated by modest investment requirement in the NCA scenario; while other scenarios which are based on the CD scenario require significant investment cost. As a summary, the investment needed for upgrading UK interconnectors and GB MITS in the CD scenario and its sensitivity cases may reach £18bn to £22bn within the period 2013-2030. In contrast, the total respective investment in the NCA scenario is only circa £1.1bn in the same period.

Another key driver for the network investment is the improved market integration between the UK and the rest of EU electricity markets. Although the investment cost increases by circa 47% in this case in comparison to the CD scenario in the period 2020-2030, the benefits of market integration are significant. For instance:

- It reduces the UK generating capacity requirement, particularly low load factor peaking plant that would be required to support security of supply.
- It reduces overall generation operation costs, as market integration facilitates increased utilisation of low marginal cost generation and reduces operation of high marginal costs generation

More analysis on the benefits of market integration can be found in the report to the EU Commission Directorate General of Energy entitled: "Benefits of an Integrated European Energy Market"[6].

The increased peak demand due to the deployment of fast charging stations for Electric Vehicles will also contribute to the increased investment cost of interconnection and transmission network infrastructure, but the impact is relatively modest.

In the DE scenario, the investment cost is £1.8bn lower than in the CD scenario. This is expected given that with less electrification of heating and transport sectors, the demand for additional infrastructure will also be lower.

With demand response, the impact on the overall cost is modest. On one hand, DR reduces the need for upgrading the GB MITS but on the other hand it facilitates higher volumes of power to be exchanged with Ireland and enables the GB demand to absorb more renewable sources.

[6] http://ec.europa.eu/energy/infrastructure/studies/doc/20130902_energy_integration_benefits.pdf

3 Characterisation and cost of distribution infrastructure to 2030

Key objective of this chapter is to assess the level of distribution infrastructure reinforcement required by 2030 across the range of scenarios and sensitivities considered.

To produce these outputs we have used the Imperial models of representative UK distribution networks. Imperial has developed a number of synthetic, statistical networks, which have been shown to be representative of different kinds of UK distribution networks. Expected UK electricity loads are distributed on these modelled networks, and where the infrastructure is determined to be insufficient, additional capacity is added to the networks. More information is provided in the appendices.

As with the transmission modelling, the distribution models were run for the three scenarios outlined previously in this report. Three sensitivities were run on the core decarbonisation scenario.

Table 12 shows the summary of volumes of new distribution assets for the whole of GB across all scenarios and sensitivities considered in this study, and the breakdown of reinforcement costs is given in Table 13.

More details on the modelling is provided in the appendix, however to determine the levels of infrastructure investment required, there are a number of failure criteria. These are:

- thermally driven constraints – where the power flow through a line or cable is above its rating[7];
- voltage driven constraints – where the voltage at a connection point is outside statutory limits[8];
- transformer rating constraints – where the power flow through a transformer is above its rating[9];
- substation constraints – where the capacity of substations is insufficient to security meet the demand[10].

When any of these failure criteria are identified, in the model, an investment is needed to overcome the relevant constraint. The investments are tabulated below.

[7] The maximum loading of the circuit cannot exceed the circuit rating. Network operators take into the account the maximum current and actual ambient conditions when specifying the threshold for a secure network operation i.e. to satisfy the security of supply standard. Network operators keep the current below the threshold by reinforcing the electric circuit or, if possible, by other mitigating actions (e.g. demand side response).

[8] Network operators have the obligation to ensure that the voltage at the connection point satisfies the statutory limits. On long circuits the voltage drop (or rise in the case of generation connections) can be significant enough to warrant the circuit upgrade before the thermally driven constraints trigger reinforcement.

[9] The transformers have an adequate rating in order that the security of supply standard is satisfied while keeping safe operation of the transformer.

[10] The total rating of a group of transformers in a substation needs to satisfy the security of supply standard while keeping safe operation of transformers.

Table 12: Summary of volumes of new distribution assets

Scenario	Year	Low voltage network upgrade length – thermal driven (km)	Low voltage network upgrade length - voltage driven (km)	Number of upgraded distribution transformers	High voltage network upgrade length (km)	Number of upgraded primary substations
Core decarb.	2020	21,280	10,781	50,643	26,393	1,228
	2025	52,205	36,746	156,595	76,227	1,875
	2030	87,424	46,784	278,898	109,825	2,465
Delayed electrification	2020	10,610	5,543	25,828	12,945	0
	2025	34,520	30,647	103,401	49,708	1,875
	2030	63,516	46,562	209,802	89,760	1,875
No climate action (NCA)	2020	21,011	26,335	80,463	33,681	0
	2025	39,366	40,648	158,773	60,184	1,875
	2030	59,138	52,722	223,262	84,800	1,899
Uneven EV & HP distr.	2030	77,895	36,119	250,062	90,213	1,917
DR	2030	79,801	46,038	255,198	106,057	2,199
Fast charging	2030	87,424	46,784	283,979	109,832	2,470

Source: Imperial College

The Delayed Electrification is the least-cost scenario in the years 2020 and 2025, while the No Climate Action scenario has the lowest cost in 2030. The Core Decarbonisation scenario is always more expensive than the Delayed Electrification due to higher penetration of EVs and HPs while base demand is the same. The NCA scenario however is characterised by higher base peak demand then the other two scenarios, due to limited energy efficiency measures. Another finding is that uneven EV and HP distribution throughout the network might require slightly less network reinforcement than with a uniform EV and HP distribution, reducing the network reinforcement cost from £31.4bn to £26.3bn. Given that the penetration of EVs and HPs is relatively high in the CD scenario, network reinforcement cost are lower when these technologies are confined to limited areas, rather then being uniformly distributed. On the other hand, if the overall penetration of EVs and HPs was low, then the cost of network reinforcement would be higher if these are concentrated in limited areas, rather than widespread. The use of Demand response also results in reinforcement cost savings in this case, where cost is reduced from £31.4bn to £29.7bn for the BaU option. The fast-charging option is only marginally more expensive given the relatively small number of charging stations compared to the number of distribution transformers that have to be upgraded.

Table 13: Summary of costs of new distribution assets

Scenario	Year	Low voltage network upgrade – thermal driven (£bn)	Low voltage network upgrade - voltage driven (£bn)	Distribution transformers upgrade (£bn)	High voltage network upgrade (£bn)	Primary substations upgrade (£bn)	Extra high voltage network upgrade (£bn)	Total upgrade cost (£bn)
Core decarb.	2020	2.08	1.06	0.48	2.52	0.93	1.42	8.50
	2025	5.12	3.62	1.44	6.53	1.42	3.62	21.74
	2030	8.57	4.60	2.28	9.04	1.86	5.05	31.40
Delayed electrification	2020	1.04	0.55	0.24	1.18	0.00	0.60	3.61
	2025	3.38	3.02	0.90	4.32	1.42	2.61	15.65
	2030	6.23	4.58	1.78	7.49	1.42	4.30	25.79
No climate action (NCA)	2020	2.06	2.59	0.66	2.70	0.00	1.60	9.61
	2025	3.86	4.00	1.26	4.93	1.42	3.09	18.57
	2030	5.80	5.19	1.73	6.85	1.44	4.20	25.20
Uneven EV & HP distr.	2030	7.63	3.55	1.98	7.44	1.45	4.27	26.32
DSR	2030	7.82	4.53	2.08	8.74	1.66	4.85	29.68
Fast charging	2030	8.57	4.60	2.28	9.05	1.87	5.06	31.42

Source: Imperial College

In addition to Business as Usual (BaU) network reinforcement we have also considered application of advanced voltage control (smart transformer option). In the BaU option, the violations of voltage constraints in the LV networks are mitigated by upgrading the conductors, a relatively expensive process which can be avoided by the application of advanced area voltage control through installing smart transformers. This technology in various forms is available and is expected to be commercially applied when the market need materialises. The potential savings across all scenarios are presented in Table 14. Irrespective of the scenario, the Smart transformer option is less expensive than BaU.

The highest potential savings are expected in the NCA scenario, driven by the low level of energy efficiency measures deployed in this scenario. It is interesting to observe that the potential savings are generally greater in 2025 than in 2030. The reason is that for a proportion of circuit reinforcements, initially the voltage driven investments (in 2025) become thermally driven (in 2030), which cannot be mitigated by the advanced voltage control.

Table 14: Potential savings of advanced voltage control

Scenario	Year	Cost BaU (£bn)	Cost Smart Transformer Option (£bn)	Potential savings (£bn)
Core decarb.	2020	8.5	7.5	1.0
	2025	21.7	18.3	3.4
	2030	31.4	28.1	3.3
Delayed electrification	2020	3.6	3.1	0.5
	2025	15.6	12.8	2.9
	2030	25.8	21.4	4.3
No climate action (NCA)	2020	9.6	7.2	2.4
	2025	18.6	14.8	3.8
	2030	25.2	20.3	4.9
Uneven EV & HP distr.	2030	26.3	23.7	2.7
DR	2030	29.7	26.0	3.7
Fast charging	2030	31.5	28.1	3.4

Source: Imperial College

The detailed reinforcement costs for 2030 are also shown in the Appendix for the three scenarios and the three sensitivities. The breakdown of investment cost is also given for five GB regions, which suggests that the highest reinforcement is needed in South England followed by North England. These broadly follow the distribution of customers per region (see Appendix):

- We observe that in 2020, CD and NCA scenarios are characterised by similar overall distribution network reinforcement costs, while the cost associated with the DE scenario are significantly lower.
- In 2025, the distribution network reinforcement costs more than double in the CD and NCA scenarios, while the cost in the DE scenario increase more significantly as the penetration levels of low carbon technologies accelerates.
- In 2030, expected cumulative distribution network reinforcement cost for the CD scenario are about £31.4bn, while the DE and NCA scenarios are characterised by about 15%-20% lower costs.
- Costs of distribution network reinforcement associated with uneven distribution, application of additional demand response and absence of fast charging are marginally lower.

In summary, the key features of required distribution network investment in different scenarios are as follows:

- Core decarbonisation scenario: High (£31.4bn by 2030) – driven by rapid electrification of heat and transport demand (despite energy efficiency measures),

- Delayed electrification scenario: Moderate (£25.8bn) – due to slower growth of electrified heat and transport demand requiring less grid reinforcements,
- No climate action scenario: Moderate (£25.2bn) – despite the lack of heat and transport electrification, reinforcements are needed due to faster demand growth resulting from less ambitious improvements in energy efficiency.

The impact of sensitivities performed on the CD scenario has been found to be the following:

- Uneven EV and HP distribution: Cost reduced by £5.1bn – higher reinforcement in areas with high EV and HP concentration more than offset by the cost avoided in areas with little or no EVs and HPs,
- DSR: Cost reduced by £1.7bn – resulting from DSR being able to reduce peaks in local networks,
- Fast charging: Slight increase compared to CD scenario (by £0.1bn) – fast charging requires reinforcements of HV distribution networks.

4 Feasibility of transmission and distribution deployment in the UK

4.1 Potential barriers, remedial actions and responsibilities for delivery of transmission and interconnection capacity

This section discusses the key challenges and barriers that will need to be overcome in order to ensure the deployment of efficient volumes of transmission and interconnection capacity in the GB electricity system.

(1) Lack of coordination in planning in onshore networks, offshore networks and interconnection

Given the carbon reduction targets, a substantial expansion of onshore and offshore transmission capacity and interconnection is expected. In Great Britain, it is projected that an unprecedented amount of transmission investment will take place in the next 10-15 years. Indicatively, these investments will be the largest transmission network reinforcements since post WW II expansion. Although an exceptionally large transmission investment program is expected over the next decade, there is currently a lack of coordination between planning in onshore networks, offshore networks and interconnection regimes, and given that the interaction between these regimes is growing in the absence of efficient locational marginal pricing framework, efficiency in network investment may be undermined.

The unprecedented level of transmission investment that is expected to take place will increase the risks associated with the decision making process, particularly as uncertainty in timing, location and volume of this investment will be significant. The consequence of the lack of coordination between regimes could lead to sub-optimal investment in network infrastructure, which would increase the overall cost of delivery of transmission network assets.

These coordination concerns, including the growing complexity and interactions between transmission network regimes, could be addressed by Government through establishing the GB Independent System Operator (GB-ISO) as an entity responsible for operating all onshore and offshore transmission networks in GB including interconnection, and for coordinating onshore, offshore and interconnection transmission plans. An alternative approach is a Shadow Independent Design Authority (IDA), which would scrutinise and challenge Transmission Owners' (TOs[11]) plans and co-ordinate planning across regimes through engagement with TOs and project developers. The emerging consensus on enhancing National Grid Electricity Transmission (NGET's) role to include new responsibilities for coordination of system planning, identifying strategic system needs and identifying coordination opportunities, is in line with the above recommendations.

In addition, it will be important to improve the interface between regimes (e.g. interconnectors pay the equivalent TNUoS[12] charge), extend good practice schemes (e.g. Network Access Policy) so as to improve co-ordination between TOs. In the longer term,

[11] By TOs in this case we refer to onshore, offshore and cross-border transmission owners
[12] For further information: National Grid, TNUoS tariffs for 2013/14, January 2013

GB-ISO should be supported by implementing an efficient locational marginal pricing market mechanism[13].

(2) Lack of EU-wide market integration

It is unlikely that sufficient interconnection capacity will be deployed with the current weak level of EU-wide coordination, burdened with conflicting interests driven by asymmetrical benefits of interconnection between neighbouring systems. To facilitate European electricity market integration, adequate coordination and compensation regimes will need to be established and cross-government coordination at EU level will be required. The increased level of coordination will require commitment from all EU Member States as well as the European Commission. If not successfully resolved, the lack of coordination will lead to an unnecessary increase in generation investment and system operating cost.

(3) Lack of stable interconnection regime

Delivery of adequate volumes of interconnection capacity with neighbouring countries may become compromised by uncertainties in the future commercial regime for interconnection, i.e. whether they will be built as merchant project (under auctions similar to the offshore regime) or as a part of regulated businesses. The underinvestment in interconnection will lead to an increase in generation operating cost and in unnecessary overinvestment in generation capacity in the UK.

In order to overcome this barrier, a cap and floor on the revenue that interconnector owners earn may be introduced. The level of cap and floor will in effect determine whether a project is classified as merchant or regulated. In case that the floor for revenue is set significantly below the cost of debt of the project then equity investors in effect take significant merchant risk given that the revenue will depend on the cross-border price arbitrage. In this case, the driver for establishing the cap & floor is to satisfy EU regulations regarding interconnections and at the same time cover some of the compliance costs that developers face. It would be important that Ofgem / DECC establish stable interconnection regimes, through setting appropriate cap and floor for revenues to investors, in order to facilitate significant investment in interconnection that GB would benefit from.

Ofgem's Integrated Transmission Planning and Regulation (ITPR) project recognises the challenges on delivering interconnector capacity, including a recognition that the existing merchant approach may be inadequate.

(4) Inadequate EMR capacity market design

Current EMR proposals[14] do not allow for generation outside GB to participate in the GB capacity market. Failure to allow generation outside GB to participate would lead to overinvestment in generation capacity in the UK. This would further reduce economic incentives to invest in interconnection, and lead to underinvestment in interconnection infrastructure and excessive overinvestment in UK generation capacity. In order to extract the value of existing interconnection and facilitate further investment in interconnection infrastructure, it is important to ensure that generation outside GB is able to participate in the GB capacity market.

[13] For further information: Imperial College and University of Cambridge "Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery", report for Ofgem, June 2013.
[14] DECC, Annex C Capacity Market: Design and Implementation Update, November 2012

(5) Lengthy planning permission process

Another potential barrier to timely transmission network development is the lengthy planning permission process for new transmission projects that may lead to delays in planning and delivery of required transmission infrastructure. For example, it took 10 years and two public hearings to obtain planning permission for the North Yorkshire Line. In many cases the delays are the result of the unwillingness of local communities to have new transmission infrastructure constructed in their areas. While a detailed assessment of the interventions is beyond the scope of this report, nevertheless it may be appropriate to consider actions that would de-risk and to shorten the planning process for new transmission infrastructure. This could include actions which:

- Simplify and shorten the planning process for new transmission infrastructure
- Develop schemes for rewarding local communities that are willing to support national energy policy objectives by agreeing to host strategic transmission projects in their areas.

This potential problem in many cases could be overcome developing underground or undersea transmission networks, which would lead to increase in costs.

Summary

In summary, while the delivery of the required transmission infrastructure may not be critically constrained by the above barriers, nevertheless these barriers do increase uncertainty in cost. Improved coordination of planning and operating on- and offshore networks may result in significantly lower investment requirements. Similarly, development of cost-effective interconnection projects will require the development of a stable interconnection regime and further integration of the EU electricity market. Failure to develop this will result in underinvestment in interconnection, which will increase the system integration costs both in the UK and mainland EU. All of these barriers will need to be removed without delay if economically optimal volumes of transmission capacity are to be delivered in the coming decade

Key barriers and the potential remedial actions are summarised in Table 15.

Table 15: Key barriers and remedial actions for delivery of transmission infrastructure

Barrier	Key actions to overcome the barrier	Responsibility
Lack of coordination in planning	Accelerate agreement to assign responsibility for coordination of entire GB onshore and offshore transmission network planning (currently proposed to extend National Grid's role to meet this requirement).	Ofgem/ National Grid/Government
Lack of EU-wide market integration	Establish coordination and compensation regimes – cross-governmental coordination at EU level is required	European Commission, Member States
Uncertainty in future regime for interconnection in GB	Establish stable interconnection regime.	Government, Ofgem

Inadequate EMR capacity market design	Ensure that generation outside GB is able to participate in the GB capacity market via interconnection	Government
Delays in planning and delivery of infrastructure (lengthy planning permission process)	1) Simplify and shorten the process 2) Develop schemes for rewarding local communities supporting national objectives	Government

4.2 Timelines and deployment of transmission and interconnection capacity

The modelling presented above has characterised the optimal transmission and interconnector infrastructure for 2020 and 2030, under a number of decarbonisation objectives and sensitivities. The modelling has identified that significant additional transmission capacity needs to be delivered by these dates, to achieve a least cost optimised network.

Timelines for deployment of GB transmission infrastructure

Based on the modelling, significant additional transmission capacity is needed by 2020 as shown in the table below.

Table 16: Additional capacity and investment needed by region in the CD scenario

Region	Core decarbonisation			
	Additional capacity needed (GW)		Investment cost (£bn)	
	2013 - 2020	2020 - 2030	2013 - 2020	2020 - 2030
Scotland	**6.49**	6.30	**0.38**	0.40
Scotland-England	**5.80**	1.07	**3.00**	0.79
North to Midlands and Midlands to South	**3.87**	2.45	**0.34**	0.18
North Wales	1.82	7.53	0.11	0.46
Mid-Wales	2.62	-	0.15	-
South West	0.24	-	0.04	-
East Coast and East Anglia	1.54	3.30	0.07	0.15
London	-	1.67	-	0.20
Total	**22.38**	**22.32**	**4.08**	**2.19**

It should be noted that the additional capacity requirements are those for an optimised network, and prioritising or shortlisting key pieces of infrastructure has limited validity[15]. Nevertheless table 17 does clearly show the importance of network upgrades in Scotland, and from Scotland to England, and Midlands-South (highlighted in red). The driver behind these upgrades is the additional wind capacity onshore and offshore in Scotland, which needs to be brought to centres of demand. Also, the above network accommodates significant transfer of wind energy from Ireland to Great Britain, and onwards to other markets.

Timelines and indicators for onshore transmission system deployment developed for the CCC[16] indicate that the project cycle to final commissioning time for a new onshore

[15] Lower capacity upgrades, will have knock-on impacts which would make the network operate sub-optimally.
[16] http://archive.theccc.org.uk/aws2/docs/503_WindTimelinesProgressIndicators_v7_0.pdf

overhead transmission line is around 1200 days. In order to deliver the transmission and interconnection infrastructure required by 2020 the project cycle for this infrastructure therefore needs to begin in 2015. Even putting aside concerns (mentioned earlier in this document) that planning may take significantly longer than the two years assumed in the (above referenced) Poyry report, the clear implication is that the measures required to address the barriers to deployment as identified in Section 4.1 are implemented as a matter of urgency to ensure that delivery of additional capacity arrives on time.

Timelines for deployment of interconnectors

In the table below, interconnector infrastructure characterised for 2020 and 2030 is assigned to the relevant carbon budget period based on the date capacity is delivered. The time period required to deliver a new interconnector may take longer compared to onshore transmission projects as interconnectors around the UK will be offshore and they will require cross-border collaboration, Planning/design process has already begun for these interconnectors, which are planned to be delivered within the third carbon budget period:

- England – Belgium[17]: National Grid and the Belgian TSO, Elia, have started working to connect the south east of England with Zeebrugge in. The project has a planned commissioning date of 2018.
- England – France[17]: National Grid and the French transmission company RTE signed a cost sharing agreement in 2010 to further investigate the feasibility of an interconnector linking the South coast of England with the Northern coast of France (planned commissioning date is around 2020).
- Scotland – Norway[18]: NorthConnect is a Joint Venture established to deliver an interconnector between Scotland and Norway. JV partners include Vattenfall UK, Agder Energi, E-CO Energi and Lyse. Following the design phase (2013-2015), the infrastructure is planned to be delivered within the third carbon budget period.

Table 18: Timeline for delivery of interconnectors

Interconnector	Timeline for delivery of infrastructure
South E&W - NorthWest France	Carbon budget 3 (2018-2022)
South E&W – Belgium (Phase I)	Carbon budget 3 (2018-2022)
Scotland - South Norway	Carbon budget 3 (2018-2022)
Scotland - Ireland	Carbon budget 5 (2028-2032)
Midlands E&W – Ireland	Carbon budget 5 (2028-2032)
South E&W - NorthEast France	Carbon budget 5 (2028-2032)
South E&W – Belgium (Phase II)	Carbon budget 5 (2028-2032)

[17] http://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR/factsheets/interconnectors130214-v12.pdf
[18] http://www.northconnect.no/files/31860-E01d_A4-version.pdf

Similar to the onshore transmission infrastructure, preparatory work to address the barriers identified in Section 4.1 needs to begin immediately to achieve cost-effective deployment of the infrastructure.

Impact of delays/uncoordinated deployment

Although it is outside the scope of this work to examine non-optimal deployment scenarios, it is important to understand the required resilience of the deployment schedule, particularly as this report recommends immediate action to safeguard the required transmission capacity at least cost.

There is strong evidence from National Grid, who conducted their own network studies, in response to consultation on the Offshore Electricity Transmission Owner (OFTO) arrangements. National Grid have identified that without a coordination role on transmission, the result would be the deployment of more radial networks i.e. single windfarm projects procuring transmission capacity optimised for their own needs. National Grid predict that this would lead to higher costs (an increase of 25%, or capex costs of £4-8 Billion) and longer delays and higher risks in planning – because of the increased number of transmission routes and landing sites required to serve the same overall capacity. The "Gone Green" scenario requires 20% less offshore assets and 75% less new onshore lines compared to an uncoordinated radial solution. Critically, National Grid also raised concerns that an uncoordinated approach would increase the likelihood of offshore route "sterilisation" and the blocking of landing sites, which are limited in number[19]. The clear implication of an uncoordinated deployment is not just higher cost, but also delays and lower deployment capacity.

The recommendation in this report of immediate action to safeguard capacity and cost benefits, is supported by National Grid: "work must start immediately if 2020 targets are to be met and the early benefits of an integrated design are not to be lost"[19].

Route to delivery

From previous consultations on the OFTO, Ofgem has recognised that Wider Network Benefit Investments (WNBI) need to be made and of the merit of onshore Transmission Owners (TOs) to undertake some central coordination. Ofgem has stated that "National Grid's System Operator responsibilities have also been extended offshore to enable the coordinated, efficient and economic development of the network".

In the current consultation on WNBI and options for the role of the TO, in all cases the responsibility for identifying the need/opportunity (of nationally and strategically valuable network assets) and selecting options is presumed to lie with the TO. However there are concerns of conflict of interest and the consultation is exploring who should identify preferred solutions, undertakes surveys and studies, and achieves consents for infrastructure[20]. This is also reflected in the Integrated Transmission Planning and Regulation (ITPR) project where a June 2013 consultation accepted the view that National Grid Electricity Transmission (NGET) should have new responsibilities for coordination of

19 https://www.ofgem.gov.uk/ofgem-publications/51375/national-grid-response-further-consultation-enduring-regulatory-regime.pdf

20 "Offshore Transmission: Non Developer-Led Wider Network Benefit Investment" Ofgem 10/01/2014.

system planning, identifying strategic system needs and identifying coordination opportunities[21]. ITPR is planning to report on a draft impact assessment by Summer 2014.

For the delivery of interconnectors, the planning process has already been started by National Grid and SSE for the three potential interconnector projects that will be required by 2020.

[21] ITPR open letter, Ofgem, 18 November 2013.

4.3 Potential barriers, remedial actions and responsibilities for delivery of distribution network capacity

This section outlines the key barriers associated with delivering the required distribution network infrastructure in GB in order to facilitate a cost effective transition to low-carbon electricity system.

(1) Lengthy permitting and consenting

In the no-climate action scenario, in which heat and transport sectors are not electrified, the total distribution network reinforcement cost is estimated to be around £25 billion. To benchmark this, annual capex investments by UK DNOs are over £1 billion[22]. Therefore, the investment of £25bn over 20 years represents an increase of 25% on historical investments. In reality, the cost of distribution network reinforcement could in fact exceed projections in this report as the impact and costs of wide-scale disruptions associated with network reinforcements, particularly in urban areas, could lead to even higher costs, which are not quantified in this study[23]. In this context, potential barriers to achieving a higher rate of reinforcement include permitting and consent issues, particularly in urban areas, as well as planned network outages during network upgrades.

This could be mitigated through timely planning of distribution network reinforcements. There is a gap between the deployment targets of low carbon technologies stated by government, and the policies/incentives/regulation that would deliver this. The uncertainty associated with deployment rates limits DNO ability to plan both adequately and cost effectively for future reinforcement. The current price control framework (RIIO-ED1) spans investment from 2015 to 2023. The uncertainty associated with the deployment of low carbon technologies should be reduced or removed long before (i.e. by 2020) the next price control period from 2023 onwards to ensure that adequate investments can take place.

Furthermore, coordinated installation of new infrastructure across different industry sectors such as water, gas, heat, electricity and ICT could facilitate cost effective and timely infrastructure reinforcements. For instance, if a heat network in a certain area is to be deployed, it may be beneficial to upgrade the electricity distribution network at the same time although its upgrade may only be required in later years; this would potentially avoid costly and disruptive interventions into (particularly urban) public infrastructure. The current regulatory regime however would not allow network investment to take place well ahead of need, which would lead to unnecessary increase in reinforcement costs. In this context there may be significant benefits in establishing strategic rather than incremental approach to network development. Government and regulatory agencies could develop processes to facilitate the timely coordination in order to deliver integrated service infrastructure in an efficient manner. In case that this is not resolved in time, there may lead to increased costs and delays in the delivery of the infrastructure needed.

(2) Materials and supply chain constraints

In addition, there may also be resource and material constraints, such as bottlenecks in the equipment supply chain, constraining e.g. the volume of new underground cables that can be delivered due to limited manufacturing capability. This will be primarily driven by the gap between the deployment targets of low carbon technologies stated by government

[22] DNO capex allowance for 2010-2011 was ca. £1.3bn (source: Electricity Distribution Annual Report 2010-11, Ofgem)

[23] Nor are they quantified in the approved cost methodologies used by Ofgem.

and the corresponding implementation policies. If unresolved, this barrier may lead to increased costs and delays in the delivery of the infrastructure.

Government and regulatory agencies could mitigate this through timely planning and coordination of the uptake of low carbon technologies that would inform the supply industry about the need for various types of equipment required to support timely distribution network reinforcements. Government and regulatory agencies could establish process for strategic and coordinated network planning. In order to avoid delays, this barrier should be resolved before 2020.

(3) Inadequate distribution network design standards

A number of previous studies on the impact of the electrification of transport and heat demand on the required reinforcements in distribution grids identified potentially significant cost associated with upgrading the existing distribution network under the "fit and forget" approach, without any contribution from demand-side response applications and smart technologies.[24,25] Similarly, it is estimated in this study that the required distribution network investment in the core decarbonisation scenario is £6 billion more compared to the no climate action scenario due to the growth in peak demand resulting from electrified heat and transport sectors.

The network reinforcement cost in the core decarbonisation scenario could be mitigated to a very significant extent by deploying smart network technologies such smart voltage regulation and demand-side response. The results suggest that around £5 billion (i.e. more than 80% of the additional reinforcement cost in the CD scenario) could be saved with the timely implementation of smart grid technologies and DSR services. However, efficient integration of these solutions is not a part of the existing network planning standards. There are current initiatives in place, led by the industry, aimed at performing a comprehensive review of the distribution network security standards and the associated regulatory arrangements governing the electricity distribution business. It is anticipated that the new planning standard will be established by 2016. This will allow for a cost effective deployment of non-network solutions in network planning (alongside conventional asset replacements and upgrades), and ensure least-cost provision of distribution network service. Planning tools used by distribution network operators will need to be updated accordingly to take into consideration the advanced real-time network control solutions.

(4) Increased risk and complexity associated with deployment of new technologies

Delivering adequate levels of distribution infrastructure until 2030 will benefit significantly from development and deployment of novel cost effective smart technologies and solutions. However, deployment of new technologies, such as those associated with smart grids, into actual distribution networks inevitably creates significant additional risks for distribution companies. It is unclear how these risks and the associated cost would be managed, particularly with respect to the application of more disruptive technologies. Risks associated with new technologies are not fully recognised by the current regulatory

[24] "Benefits of Advanced Smart Metering for Demand Response-Based Control of Distribution Networks", report for the Energy Networks Association, April 2010. Available at: www.energynetworks.org.

[25] "Understanding the Balancing Challenge" report for DECC, July 2012. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf

framework, which may present an impediment for their widespread adoption and lead to increase in network investment costs. Smart grids will also increase the complexity considerably compared to the traditional solutions, given that significant Information and Communication Technology infrastructure will be needed in addition to the advanced Distribution Management Systems applications (yet to be developed), all necessary to make use of available information and control in real time management of distribution networks.

Government and the regulatory agency should establish provisions to allow distribution companies to include the risk associated with new technologies in network planning. Furthermore, research and demonstration projects, facilitated through Network Innovation Allowance and Completion schemes should also assist the industry with understanding and reducing risks associated with the application of new emerging smart grid technologies.

(5) Lack of full market integration of distributed energy resources

Multiple benefits potentially generated by distributed energy resources (e.g. distributed storage, demand side response, distributed generation) across different sectors in the electricity system are not fully reflected in the current market environment and regulatory framework. For example, in addition to using storage to reduce peak loads in local distribution network and consequently improve network capacity utilisation, it may also be desirable for storage technologies to respond to opportunities in the energy, reserve and ancillary services markets at the national level. Applying smart grid technologies for distribution network management in isolation without considering these markets, will potentially undermine the business case for some of these technologies, and hence increase the overall cost of the end-to-end electricity delivery chain. If these technologies are to be deployed at cost effective levels, that would minimise the overall system operation and investment cost, it will be important to overcome market and regulatory barriers and ensure that service providers are rewarded according to the benefits they provide across the entire electricity supply chain. If unresolved, it is likely that the costs of network investment and system real time balancing costs will increase as these enabling technologies, although cost effective, would not be deployed due to insufficient revenues received due to market failures[26].

In this context, establishing a Distribution System Operator (DSO) type function, together with appropriate distribution network access and energy and ancillary services pricing structures, would facilitate both efficient real-time network operation and prevent overinvestment in future network reinforcements[27]. Establishing the DSO function, analogous to the Transmission System Operator, would not only support a more holistic approach to future distribution network management but also provide distributed energy resources with access to various markets at the national level (provision of various forms of reserve, capacity, transmission network management) and hence support more efficient operation of the national system. This would require restructuring of distribution businesses and active involvement from both the government and the regulator, and similar to other actions in the transition towards more active distribution networks, will require a time window of several years to implement the necessary changes (e.g. 2020).

[26] As demonstrated in DECC study: "Understanding the Balancing Challenge, 2012.
[27] As identified in Imperial College and Energy Networks, Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks, April 2010

(6) Voltage standards, harmonics and fault level issues

There are also a number of technical issues to be addressed in future distribution networks, such as voltage standards in the context of the EU harmonisation, harmonics and fault levels. It is expected levels of harmonics in distribution systems will increase due to penetration EVs, HPs and PVs using power electronics interfaces. Furthermore, the expected decrease in fault current level driven by substitution of synchronous generation with non-synchronous renewable sources (wind and PV), coupled with increased interconnection could present an additional challenge for protection management schemes and the related safety considerations in distribution networks. The magnitude and materiality of these issues has not been comprehensively analysed. Government, Ofgem and industry, through Smart Grid Forum and other demonstration project are engaging with these issues and it is anticipated that the information about possible implications may be available in the next couple of years, so that appropriate courses of actions can be established.

Table 19 summarises the key barriers and the associated corrective actions relevant for delivery of distribution infrastructure in the future GB system.

Table 19: Key barriers and remedial actions for delivery of distribution infrastructure

Barrier	Key actions to overcome the barrier	Responsibility
Lengthy permitting and consent (particularly in urban areas)	(1) Timely planning of distribution network reinforcements (ahead of next price control period) (2) Coordinated infrastructure deployment across different sectors (i.e. water, gas, heat, electricity, ICT)	Government, Regulators
Materials and supply chain constraints	Establish strategic and coordinated network planning	Government, Ofgem
Inadequate distribution network design standards	Review the distribution security standards and regulatory arrangements to incorporate non-network solutions in network planning	Government, Ofgem, DNOs
Increased risk and complexity associated with deployment of new technologies	(1) Establish provisions for dealing with increased levels of risks (2) Carry out demonstration projects aimed at understanding and mitigating risks	Government, Ofgem, DNOs
Lack of full market integration distributed energy resources	1) Ensure that actors in the market are rewarded according to the benefits they provide across the electricity supply chain 2) Establish the Distribution System Operator (DSO) function	Government, Ofgem
Technical issues foreseen in future distribution networks (e.g. voltage standards, harmonics and fault levels etc)	Conduct further research into understanding the magnitude and impact of these issues on future networks	Government, Ofgem, Industry

5 Conclusions

5.1 Transmission

The UK interconnection and GB MITS additional infrastructure requirements have been analysed for the three different generation and demand backgrounds, i.e. Core Decarbonisation (CD), No Climate Actions (NCA), and Delayed Electrification(DE) scenarios. Three sensitivity studies based on the 2030 CD scenarios have also been conducted investigating the impact that full EU market integration, national roll-out of fast charging EV stations, and the implementation of DR technologies on the investment needed by the UK interconnection and GB MITS . The results and the trends for each of the cases can be summarised as follows:

Core Decarbonisation (CD)

- Significant reinforcement of transmission network in Scotland to accommodate wind capacity.
- Both HVDC bootstraps constructed to facilitate North-South flows.
- Significant upgrade of GB - Ireland interconnectors.
- Need for significant interconnection to Europe to accommodate wind development in the UK and Ireland.

No Climate Action

- Modest network reinforcement in Scotland
- No HVDC bootstraps chosen for construction
- Reinforcement of western E&W – central E&W links focused on southern corridors
- No need for upgrade in interconnection to Europe

Delayed Electrification

- Similar results as in the CD scenario but slightly less in magnitude due to the lower electricity peak demand and annual energy consumption.

Sensitivities

- Overall, the results of the sensitivity studies are similar to the results in the CD scenario with the following notes:
- Fully UK market integration to EU: 50% more network cost; higher interconnection capacity but slightly offset by less transmission. However, the increase in network investment is fully justified, as it would lead to reduction in the overall generation operation and investment costs.
- Fast Charging: slight increase in the capacity requirement but not material.
- DSR: slightly lower in GB MITS but slightly higher in the GB-Ireland interconnectors since DR improves the GB system ability to absorb more renewable output including the wind output from Ireland.

It can be concluded that in most of the cases, the decarbonisation of the UK energy system is the main driver for enhancing the capacity of UK interconnectors and the GB MITS. This is demonstrated by modest investment requirement in the NCA scenario; while other scenarios which are based on the CD scenario require significant investment. As a summary, the investment needed for upgrading UK interconnectors and GB MITS in the CD scenario and its sensitivity cases ranges between £18bn and £22bn within the period 2013-2030. In contrast, the total investment in the NCA scenario is only about £1.1bn in the same period.

5.2 Distribution

In summary, the key features of required distribution network investment in different scenarios are as follows:

- Core decarbonisation scenario: High (£31.4bn by 2030) – driven by rapid electrification of heat and transport demand (despite energy efficiency measures),
- Delayed electrification scenario: Moderate (£25.8bn) – due to slower growth of electrified heat and transport demand requiring less grid reinforcements,
- No climate action scenario: Moderate (£25.2bn) – despite the lack of heat and transport electrification, reinforcements are needed due to faster demand growth resulting from less ambitious improvements in energy efficiency.

The impact of sensitivities performed on the CD scenario has been found to be the following:

- Uneven EV and HP distribution: Cost reduced by £5.1bn – higher reinforcement in areas with high EV and HP concentration more than offset by the cost avoided in areas with little or no EVs and HPs,
- DSR: Cost reduced by £1.7bn – resulting from DSR being able to reduce peaks in local networks,
- Fast charging: Slight increase compared to CD scenario (by £0.1bn) – fast charging requires reinforcements of HV distribution networks.

In contrast to the conclusions on Transmission, for distribution the main cost drivers are not decarbonisation but the growth in load in the period to 2030. The use of demand side management and smart grid technologies could offset most of the additional investment cost associated with the core decarbonisation scenario. Nevertheless there remains significant risk associated with the deployment and proven utility of smart grid technologies, the recruitment of consumers as an active participant in network management, and with the actual levels of low carbon technologies that will have to be deployed in networks by 2030.

6 Appendix

6.1 Methodology and assumptions

6.1.1 Transmission studies

The main role of the transmission and interconnection infrastructure is:

- To facilitate energy transfer from generation sources to demand centres while minimising the operation cost of generation system (and facilitate competition in electricity supply);
- To enhance long-term security of supply by sharing of generation capacity between regions;
- To share flexibility and reserves between regions by exploiting the benefits of diversity in demand and renewable energy sources; and improve efficiency of real time balancing task by providing access to the Transmission System Operator to procure balancing services from neighbouring systems[28]

In summary, transmission and interconnection infrastructure enhances the efficiency of system operation, increase security of supply, and enhance system flexibility to balance demand and supply in real time.

In order to design a multi-purpose interconnection and to determine the optimal network expansion programme, there is a need for an integrated planning approach that considers simultaneously the requirements for generation (both in terms of capacity adequacy and system balancing) and transmission infrastructure whilst taking into account security and economic considerations. The key challenge for such an approach will be to include the full representation of operational requirements and characteristics of the system including variability in intermittent renewable output, available demand response and energy storage) in a (multi) year-round network design framework that deals with the economics of bulk energy transport, seasonal/weekly allocation of hydro resources and reliability / security of supply.

For this purpose, we use a two-stage cost minimisation process to decompose the original very large optimisation problem into two manageable size sub-optimisation problems. First, the *Dynamic System Investment Model (DSIM)* is used to determine the optimal interconnection capacity and the bulk power exchanges on the entire European system using the EU Grid model, which includes the electricity systems of Great Britain (GB), Ireland and continental Europe. It is important to note that the capacity of cross border interconnection is not only affected by the systems directly connected to it but also by their adjacent systems; for example: the capacity of UK interconnection with France and Belgium may be influenced by development of renewable power in Ireland, or by capacity of the interconnection between Norway and UK, or Norway and Denmark. In order to capture the interaction between various developments, it is important for this study to use an European grid model to assess the interconnection requirements. However, due to high computational cost, the intra region transmission system cannot be modelled in much

[28] Balancing task is carried out by Transmission Network Operators and through integrated EU Balancing Market, that is currently being implemented, will enable them to exchange balancing services cross border, that will significantly reduce system balancing costs

detail in this model and therefore we use the second model, *Dynamic Transmission Investment Model (DTIM)* which represents all key transmission boundaries in the UK.

The capacity of interconnectors and the projected power flows from/to UK are used by the *DTIM* to determine the optimal capacity of the Main Interconnection Transmission System (MITS) in the UK. The following sections provide more details on the two models used in this study.

EU Grid Model and the Dynamic System Investment Model (DSIM)

The EU Grid model comprises all main cross-border interconnectors across Europe and the intra-national main transmission systems. Generation data (installed capacity per technology; investment and operating cost including fuel, O&M, start-up and no-load costs; dynamic characteristics including efficiency and flexibility such as ramp rates, minimum up and down time, response capability) and demand backgrounds are specified for each Member State, as well as the renewable generation profiles (wind, PV, hydro). The network data used by the model comprises the existing capacity and length, and the average network reinforcement cost per unit length and per unit capacity. Long interconnectors may be built using a combination of network technologies (AC/DC, on/off shore, Extra or Ultra High Voltage) that have different cost characteristics. This has to be reflected in the network cost data. The EU Grid Model used in the study is illustrated in Figure 13.

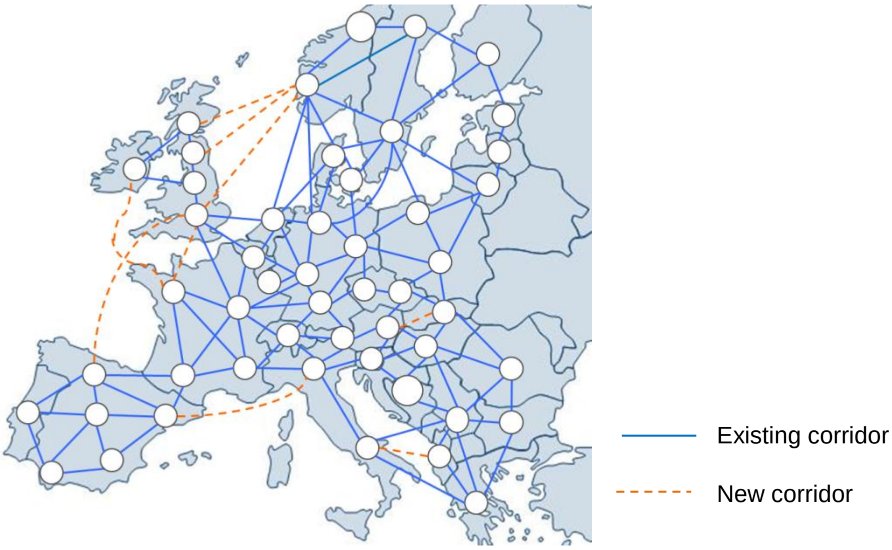


Figure 13: Modelling of EU Grid

DSIM is an analytical tool for power system studies, developed by Imperial College London, which seeks to minimize the total system cost as the sum of the following components:

- Investment cost in new generation and storage capacity;
- Investment cost in additional network capacity (both cross-border and intra-national); and

- Annual electricity production cost including the cost of providing balancing services.

These are all calculated while maintaining the required level of system reliability and respecting operating constraints. The overall modelling framework simultaneously optimises the investment and hourly system operation across the time horizon of a year, thus considering the tradeoffs between long-term decisions to invest into new infrastructure and short-term decisions on how to utilise this infrastructure on an hourly basis. At the same time, the DSIM model is capable of capturing the effects of sharing generation capacity through inter-regional transmission (if such a strategy is selected when studying the system) in order to minimize the overall additional infrastructure costs needed to deliver the required level of reliability.

The reliability target is defined in terms of the Loss of Load Expectation (LOLE), which is set to balance the cost of investment in peaking plant and cost of expected energy curtailed (driven by Value of Lost Load). This is based on an array of probabilistic inputs, which the model takes into account:

- Effects of forced outages of generating plant
- Optimised production schedule from available conventional generation technologies
- Seasonal availability of hydro power (as well as the variability of ‘run of river’ and hydro with reservoir)
- Dispatch of Concentrated Solar Power (CSP) plants considering thermal reservoir capacities and thermal storage losses, and
- Probable contribution from renewable generation and the associated short- and long-term correlations with demand.

Demand-side response and energy storage are both explicitly modelled in DSIM, including the effects of efficiency losses, in order to assess the effectiveness of such measures to reduce additional generating capacity and inter-regional transmission investments while maintaining the required system reliability performance.

Dynamic Transmission Investment Model (DTIM)

DTIM is used to support the Cost-Benefit Analysis (CBA) of different transmission expansion strategies. The model is formulated as a linear programming problem that minimizes the sum of the Present Values (PVs) of transmission investment cost and the cost of congestion in the system, taking into account uncertainties in the development of generation capacity, load growth, and evolution of investment and operating costs across a multi-year period (referred to as ‘epoch’ in the model). As depicted in Figure 14, DTIM balances the cost of network constraints against the cost of network reinforcement, minimising the overall cost of power system operation and expansion over a given study period (e.g. 20 years).

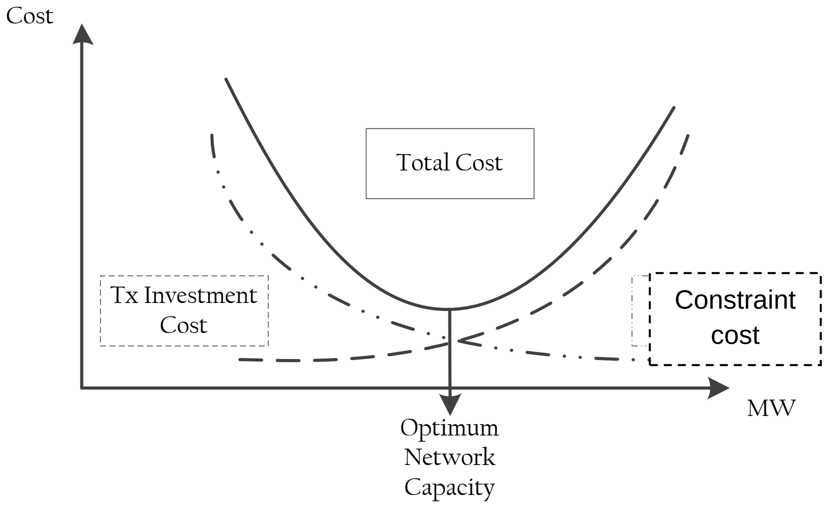
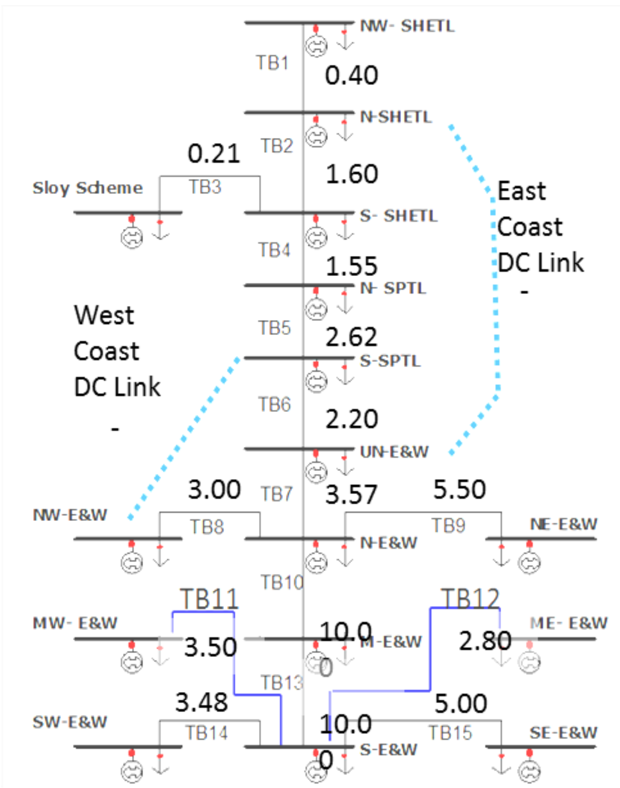


Figure 14: DTIM Cost-benefit analysis

DTIM can consider various network technologies and solutions capable of enhancing the power transfer capability of transmission corridors, such as e.g. reactive compensation, re-tensioning, re-conductoring or installing new lines. All of these options are considered when upgrading the transmission capacity across the planning period by using a piecewise approximation of the transmission investment cost function. A piecewise cost function is used for terrestrial transmission reinforcement so as to reflect the cost of various options in enhancing transfer capability of individual lines. Furthermore, DTIM has the capability to model investment in DC lines ("bootstraps") between pre-defined system nodes. It is also possible to use DTIM to choose from a portfolio of possible transmission expansion projects specified by the user. Both radial and meshed networks can be modelled.

Throughout the optimization period the model determines when, where and how much to invest. Key input data for the optimisation include the demand forecast, current and future fuel costs, bid and offer prices, evolution of installed generation capacity, the location and quantity of new wind capacity and transmission and generation maintenance plans. DTIM is capable of capturing inter-temporal changes in generation and demand thus optimizing both the amount of transmission capacity and the timing throughout the modelling period. For example, if a plant is decommissioned rendering an upgrade of a particular line sub-optimal in later years, DTIM will be able to capture this effect and invest accordingly.

A reduced GB main boundary transmission system is modelled in DTIM for the purpose of this study, as illustrated in Figure 15. TB1 to TB6 equate to SYS boundaries 1-6. TB7 is mapped to a non-SYS boundary, known as B7a, which runs South-of-Penwortham rather than South-of-Harker. TB8 is a non-SYS boundary to North Wales, namely West of Deeside and West of Treuddyn. TB9 is mapped to the Humber Estuary boundary, namely East-of-Keadby and cuts across Thorton--Creyke Beck circuit. TB10, TB13 and TB15 are SYS boundaries B8, B9 and B15 respectively. TB11 is south Wales boundary, namely West-of-Walham plus West-of-Melksham. TB12 can be mapped to East Anglia, i.e. transmission nodes Norwich Main, Sizewell and Bramford. TB14 maps to the boundary to Cornwall, Devon and Somerset.



Boundary	Length [km]
TB1	60
TB2	100
TB3	50
TB4	120
TB5	35
TB6	150
TB7	150
TB8	79
TB9	40
TB10	93
TB11	75
TB12	80
TB13	155
TB14	195
TB15	60
Eastern bootstrap	330
Western boostrap	280

Figure 15: A reduced GB main transmission system (transfer capacities in 2013)

Transmission System Cost Assumptions

DTIM has been used by National Grid as a validation tool for the proposed ENSG projects in 2009 as well as for system operation modelling within the fundamental SQSS review. In order to ensure the accuracy of DTIM in calculating the cost of reinforcing transfer capability across main transmission boundaries on the GB system, the reinforcement cost in DTIM are calibrated to reflect the actual costs of projects to increase boundary capacity proposed in reports from ENSG,[29] KEMA[30] and National Grid.[31]

The cost includes all infrastructure and installation costs required taking into account the security level that needs to be satisfied, for example: N-1. It is a standard practice for a high level transmission planning tools to use aggregated reinforcement costs per km rather than a detailed actual transmission network cost[32].

We have calibrated our DTIM model using assumptions on reinforcement costs, generation capacity, demand and marginal costs from National Grid's "Gone Green" scenario. The calibrated DTIM model has also been used in analysing the impacts of different transmission charging regimes in the TransmiT project[33]. To estimate

[29] Our Electricity Transmission Network: A Vision for 2020, ENSG, July 2009
[30] Assessment of the overall robustness of the transmission investment proposed for additional funding by the three GB electricity transmission owners, KEMA, December 2009
[31] Anticipatory Investment Update – 2010 , National Grid, 2010
[32] Electricity Transmission Costing Study: an independent report endorsed by the Institution of Engineering and Technology, 2012
[33] Project TransmiT: Impact of Uniform Generation TNUoS , a report prepared for RWE npower, Imperial College and NERA, 2011

transmission investment costs, we used the average annuitized investment cost of £50/MW/km/year, which is a conservative estimate that National Grid uses with the DTIM model.

In order to reflect the need of the DC bootstraps, we included constraints on maximum boundary capacities, the most important of which is the maximum capacity of 4.4GW on the Cheviot boundary. Increasing capacity beyond 4.4GW across this boundary would either require a relaxation of security standards, which we did not consider, or building a new line, which given the planning issues is very difficult. Hence we assume that any further increase in Scotland –England transmission capacity is delivered only through offshore DC links.

We defined assumptions on DC link costs from reports by ENSG and KEMA. In the Transport model DC links are modelled as 275/400kV cables, with the length adjusted to reflect DC link cost as quoted in ENSG report. The investment cost of the DC Links has also been calibrated using the same approach; the average annuitized investment cost of £160/MW/km/year is used in the study.

The costs of UK interconnection, taken from our study with European Climate Foundation[34]. The distance of the interconnection is calculated from the centre of the sending-end region to the centre of the receiving-end region. The cost of interconnection also includes the cost of reinforcing the onshore transmission and the subsea transmission, including the capital cost of the infrastructure (substations, transformers, converters if it involves DC links, conductors, protection systems) and installation costs.

Table 20: Interconnection length and unity cost

	Distance [km]	Annuitised cost of investment [£/MW/km per year]
Scotland - Ireland	380	91
Midlands E&W - Ireland	480	103
South E&W - NorthEast France	440	96
South E&W - NorthWest France	495	107
South E&W - Netherlands	400	118
South E&W - Belgium	380	105
Scotland - South Norway	912	147
South E&W - South Norway	1,160	137
South E&W - North Spain	1,495	137
North E&W - South Norway	1,036	140

Source: KEMA, ECF

The capital cost of the investment is calculated as a function of the annuitized investment cost, the proposed additional transfer capacity, economic lifetime of the asset (i.e. 40 years), and the discount rate (i.e. Weighted Average Cost of Capital = 5.7%).

DTIM is longer-term planning tool that considers the need for new cross-boundary transmission infrastructure over a specified time horizon, so that the network reinforcements are identified in advance of the need. Hence for a given future

[34] Power Perspective 2030, European Climate Foundation, available at http://www.roadmap2050.eu/project/power-perspective-2030

development scenario, DTIM will provide information about the timing of future investment and hence planning, network reinforcement and installation can be planned.

6.1.2 Distribution studies

Distribution networks in this analysis are modelled using Imperial's fractal network models calibrated against real GB networks. Fractal models reproduce realistic network topologies and network lengths and therefore allow for the characterisation of distribution networks of different types. For the purpose of the analysis presented in this report, mapping the entire GB distribution network, we have developed 10 representative networks that are used to evaluate the GB distribution network reinforcement costs.

The 10 representative networks capture the key statistical properties of typical network topologies that can range from high-load density city/town networks to low-density rural networks. The design parameters of the representative networks closely match those of realistic distribution networks of similar topologies.

The proposed representative networks map the GB distribution networks closely in terms of total number of connected customers, total overhead LV network length, total underground LV network length, total number of pole-mounted transformers (PMT), and total number of ground-mounted transformers (GMT). Table 21 demonstrates that Imperial's fractal model closely maps the GB aggregate values.

Table 21: Mapping of representative networks (RN) onto actual GB distribution networks

Parameter	GB value	RN value	Discrepancy (%)
Number of connected customers	29,416,113	29,410,374	-0.02%
Overhead LV network length (km)	64,929	64,905	-0.04%
Underground LV network length (km)	327,609	327,822	0.07%
Number of PMT	343,857	343,848	-0.00%
Number of GMT	230,465	230,323	-0.06%
Overhead LV network length per PMT (m)	189	189	-0.03%
Underground LV network length per GMT (m)	1,422	1,423	0.13%

Imperial's distribution network modelling tools are employed to quantify the network reinforcement costs across different future development scenarios. Figure 16 illustrates the analytical approach adopted. For each of the alternative electricity network control scenarios 'Uncontrolled' and 'Smart', we assess the required investment in the distribution network. The smart scenario involves the use of flexible demand to manage demand peaks, allowing us to identify the value of flexible demand for reducing the cost of network reinforcement.

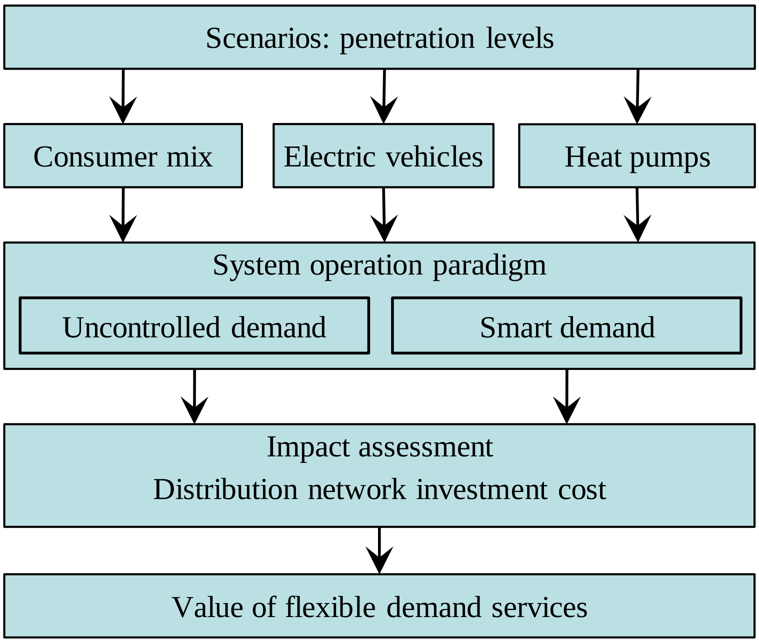


Figure 16: Methodology block diagram for distribution network analysis

Mitigating distribution network reinforcement

In our distribution network analysis we consider three development pathways: (i) Core decarbonisation (CD) pathway with the integration of low-carbon generation and demand technologies; and (ii) Delayed electrification; and (iii) No Climate Action. Within the Core decarbonisation pathway three further sensitivity scenarios are considered: EVs and HPs unevenly distributed, Demand response and Fast-charging of EVs.

Three snapshot years are considered, namely 2020, 2025 and 2030. They are characterised by the deployment of low carbon technologies and the growth rate of base load. Table 22 and Table 23 show the assumed number of installed HPs and EVs, as well as the growth rate of base load. The uptake of EVs and HPs in delayed electrification sensitivity is 50% of the core decarbonisation scenario. The base demand of the core decarbonisation scenario in 2020, which excludes heat and transport electrification demand, is used as a reference demand. Network reinforcements needed due to increase of the base demand and demand associated with integration of low carbon technologies is recorded.

Table 22: Deployment of Low Carbon Technologies (LCTs)

Scenario	Year	No residential HPs	No commercial HPs	No EVs
Core decarbonisation	2020	569,676	79,585	1,527,888
	2025	2,580,633	162,613	4,169,806
	2030	6,832,493	252,274	7,990,978
Delayed electrification	2020	284,838	39,793	763,944
	2025	1,290,317	81,307	2,084,903
	2030	3,416,247	126,137	3,995,489
No Climate Action	2020	-	-	-
	2025	-	-	-
	2030	-	-	-

Table 23: Growth rate of demand excluding LCTs

Year	Core decarbonisation	Delayed electrification	No climate action
2020	100%	100%	114%
2025	106%	106%	124%
2030	115%	115%	137%

Average reinforcement unit costs are given in Table 24 (based on the costs published by Ofgem[35]). The variation of underground cable reinforcement cost might be significant, particularly when cost associated with disruption is considered, particularly in urban areas.

Table 24: Average reinforcement unit costs

Asset upgrade	Overhead/PMT	Underground/GMT
LV circuit (£k/km)	30	98.4
HV circuit (£k/km)	70	185.8
Distribution transformer (£k)	2.9	13.2
LV voltage regulation (£k)	1	2
Primary substations (£k)		755.8
EHV network (% of all LV and HV costs)	20	20

Note: PMT – pole mounted transformer; GMT – ground mounted transformer.

Figure 17 and Figure 18 show the after-diversity profiles of off-peak EV charging and for domestic and commercial HP operation, respectively. Smart EV charging occurs off-peak i.e. during the night.

35 Ofgem, Electricity Distribution Price Control Review: Final Proposals - Allowed revenue - Cost assessment appendix, Ref: 146a/09, 7/12/2009, https://www.ofgem.gov.uk/ofgem-publications/46749/fp3cost-assesment-network-investmentappendix.pdf

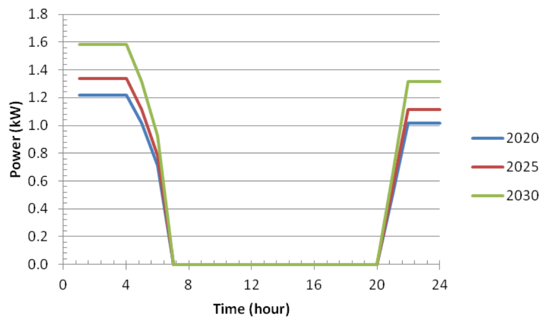


Figure 17: After-diversity profiles of EV charging for BaU and Smart scenarios

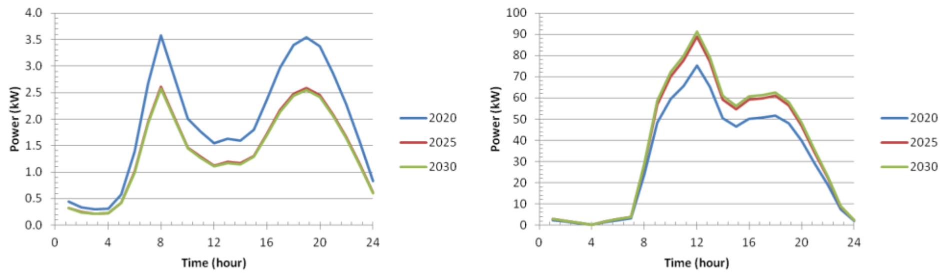


Figure 18: After-diversity profiles of domestic (l) and commercial HPs (r)

Uneven distribution of EVs and HPs, as sensitivity, is modelled by introducing seven clusters where penetrations of EVs and HPs are specified as multipliers of the average penetration as shown in Table 25. The size of each region in percentage is also given in the table. The resulting average concentration is the same as in the base case (i.e. when EVs and HPs are uniformly distributed), as shown in Figure 19. Demand response sensitivity is based on the peak reduction of 6.3% accomplished by using flexible demand, as identified in transmission studies. The sensitivity featuring the fast-charging of EVs assumes that 5,081 charging stations are deployed across GB with the annual electricity supplied in the amount of about 1/3 of total EV demand. It is assumed that fast charging needs installation of a new distribution transformer for each station.

Table 25: Cluster parameters

Multiplier	Percentage
0	26%
0.5	20%
1	18%
1.5	16%
2	13%
3	6%
4	1%

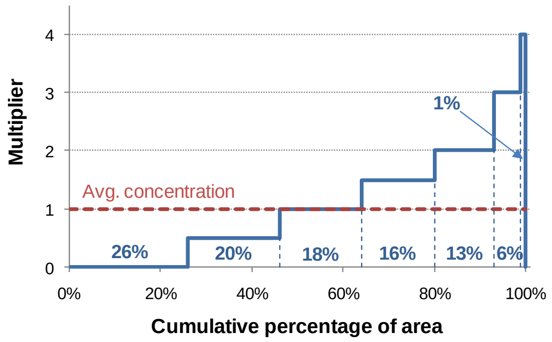


Figure 19: Cluster parameters

6.2 Detailed transmission costs

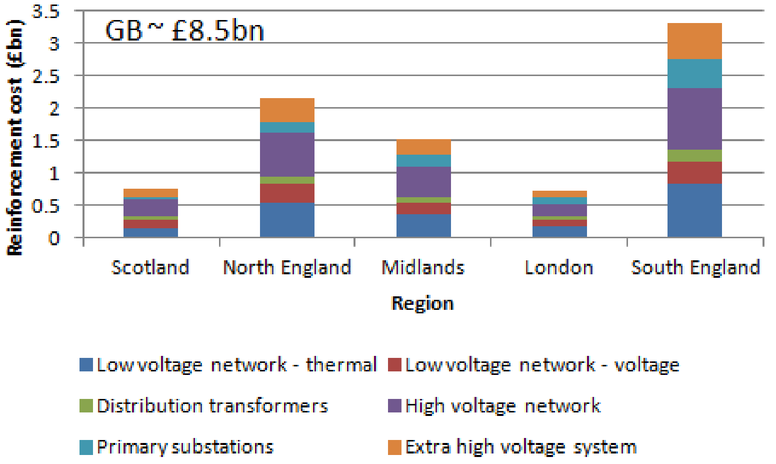
Table 26: Investment cost for upgrading UK interconnectors (in £bn)

	Core decarbonisation		No Climate Action		Delayed electrification		Full EU market integration	Fast charging	DR
Region	2013-2020	2020-2030	2013-2020	2020-2030	2013-2020	2020-2030	2020-2030	2020-2030	2020-2030
Scotland - Ireland	-	0.98	-	-	-	0.41	1.36	1.00	0.76
Midlands E&W - Ireland	-	4.82	-	-	-	5.25	4.56	4.79	5.40
South E&W - NorthEast France	-	0.51	-	-	-	0.38	1.49	0.50	0.56
South E&W - NorthWest France	0.83	0.00	-	-	0.83	0.00	0.00	0.00	0.00
South E&W - Netherlands	-	0.00	-	-	-	- 0.00	0.63	0.00	- 0.00
South E&W - Belgium	0.62	0.91	-	-	0.62	0.69	3.21	0.97	0.81
Scotland - South Norway	2.93	0.00	-	-	2.93	0.00	1.04	0.00	0.00
South E&W - South Norway	-	0.00	-	-	-	0.00	0.00	0.00	0.00
South E&W - North Spain	-	0.00	-	-	-	0.00	0.00	0.00	0.00
Total	**4.39**	**7.22**	**-**	**-**	**4.39**	**6.73**	**12.30**	**7.25**	**7.53**

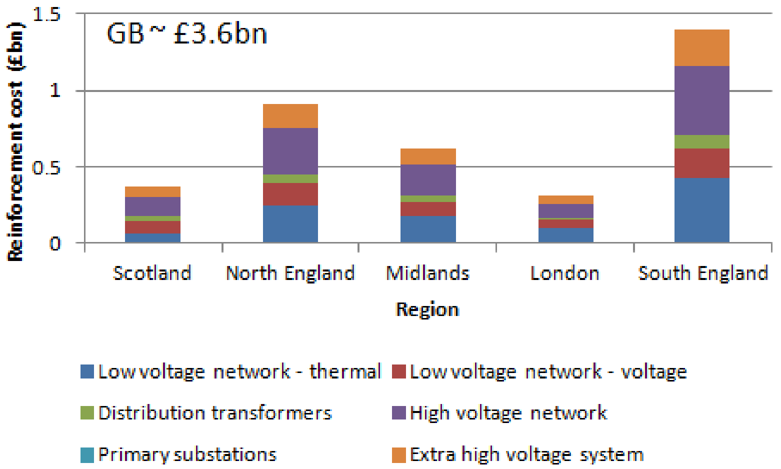
Table 27: Investment cost for upgrading GB MITS (in £bn)

	Core decarbonisation		No Climate Action		Delayed electrification		Full EU Market Integration	Fast charging	DSR
Region	2013-2020	2020-2030	2013-2020	2020-2030	2013-2020	2020-2030	2020-2030	2020-2030	2020-2030
Scotland	0.38	0.40	0.04	0.12	0.38	0.33	0.39	0.41	0.33
Scotland-England	3.00	0.79	-	-	3.00	0.09	-	0.84	0.62
North to Midlands and Midlands to South	0.34	0.18	-	-	0.31	0.05	0.15	0.19	0.17
North Wales	0.11	0.46	-	-	0.11	0.25	0.42	0.47	0.44
Mid-Wales	0.15	-	-	-	0.19	0.00	-	-	0.04
South West	0.04	-	0.11	0.65	-	-	0.07	0.01	-
East Coast and East Anglia	0.07	0.15	-	0.16	0.06	0.09	0.29	0.16	0.15
London	-	0.20	0.02	-	-	-	0.24	0.22	0.17
Total	**4.08**	**2.19**	**0.17**	**0.92**	**4.04**	**0.82**	**1.56**	**2.29**	**1.91**

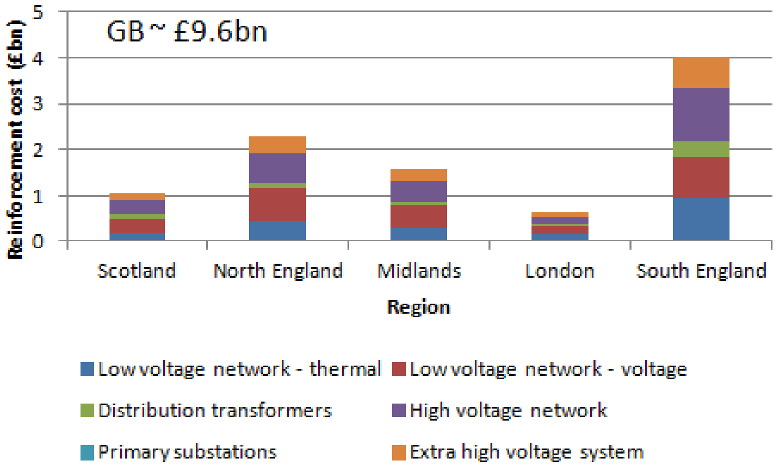
6.3 Detailed distribution costs



(a) Core Decarbonisation scenario

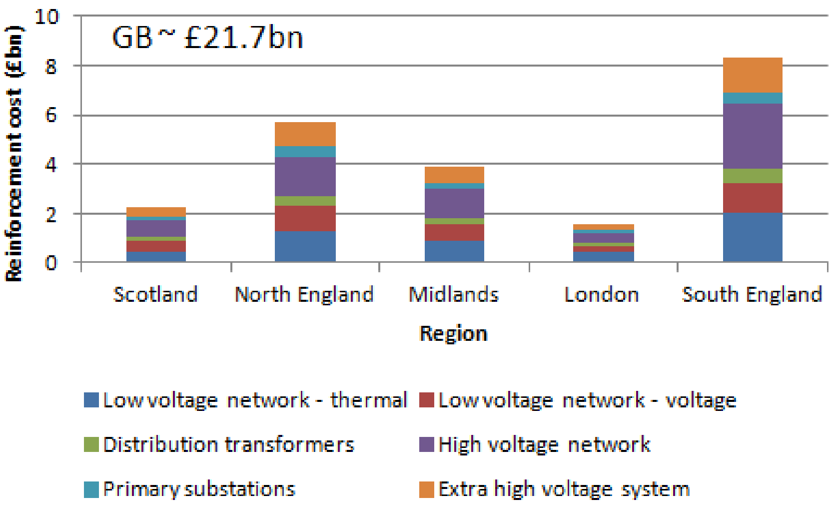


(b) Delayed electrification scenario

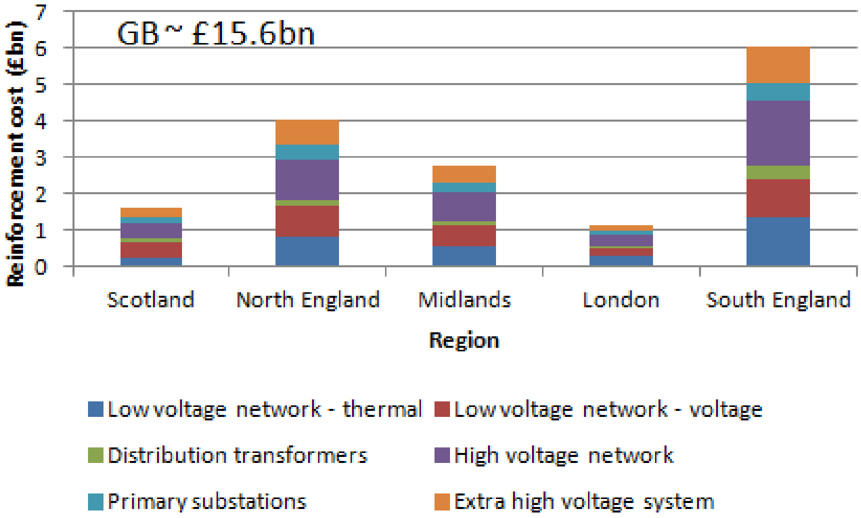


(c) No Climate Action scenario

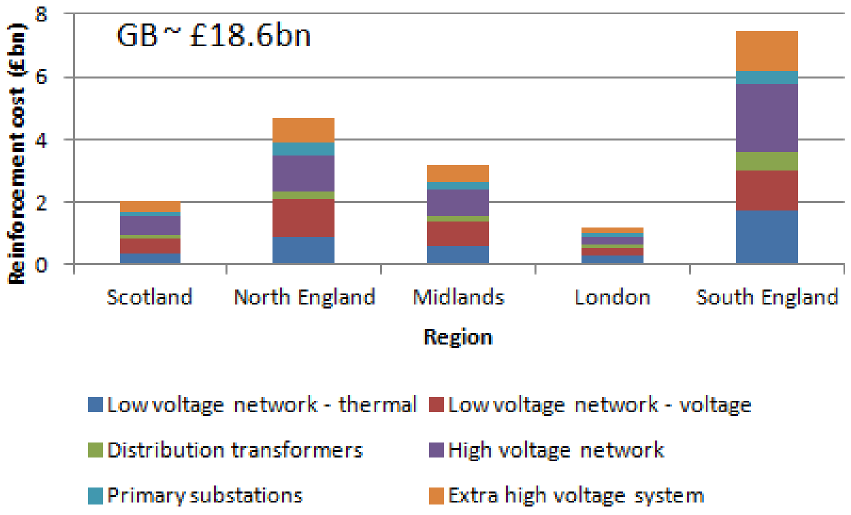
Figure 20: Reinforcement cost 2020 for core decarbonisation (a), delayed electrification (b) and no climate action (c) scenarios



(a) Core Decarbonisation scenario

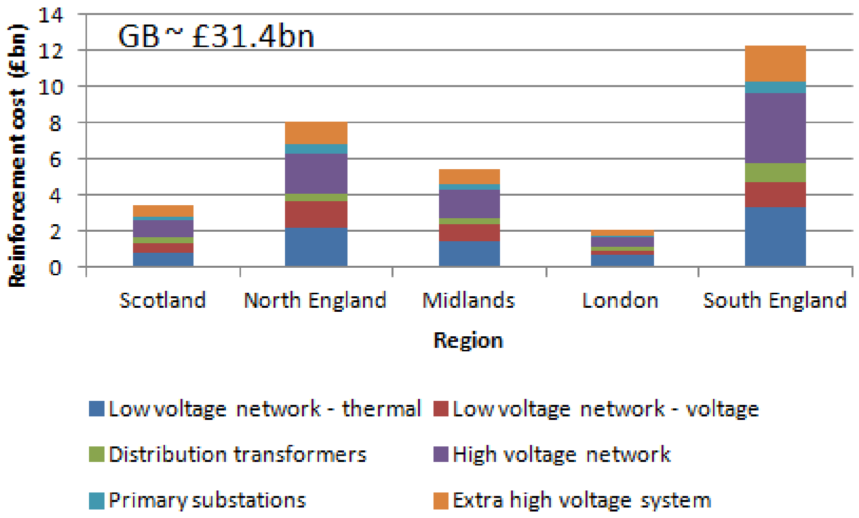


(b) Delayed electrification scenario

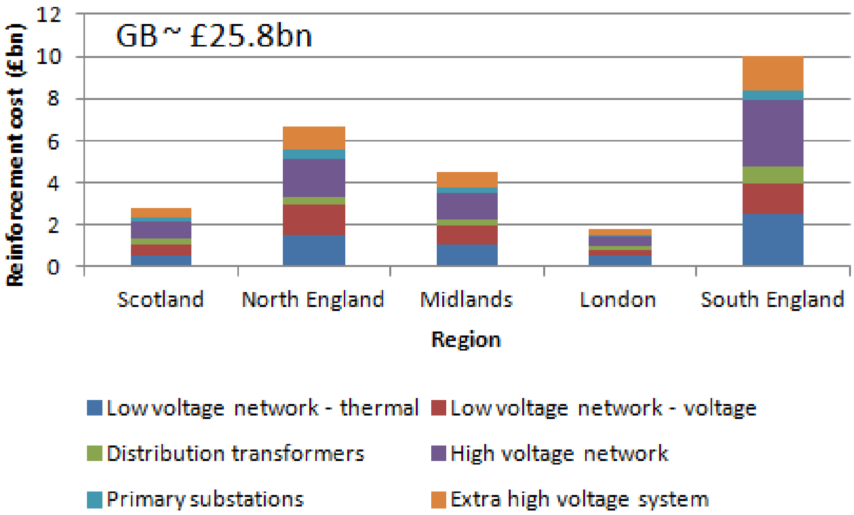


(c) No Climate Action scenario

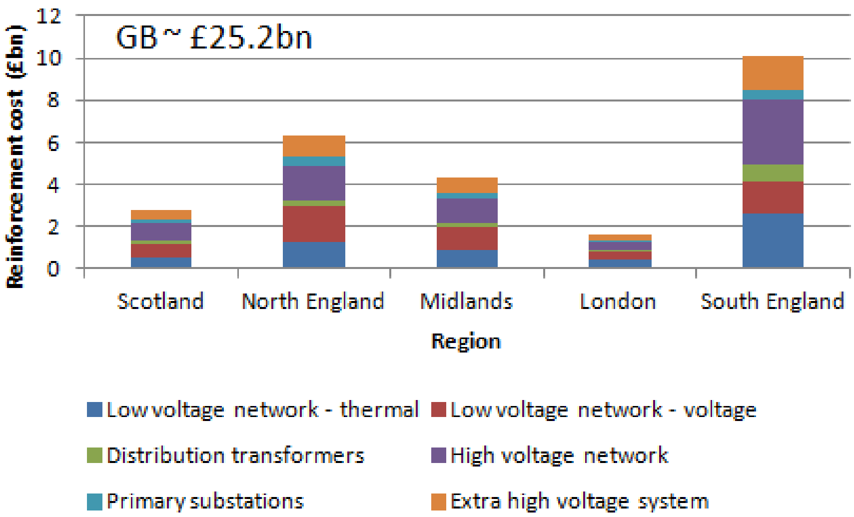
Figure 21: Reinforcement cost 2025 for core decarbonisation (l), delayed electrification (m) and no climate action (r) scenarios



(a) Core Decarbonisation scenario

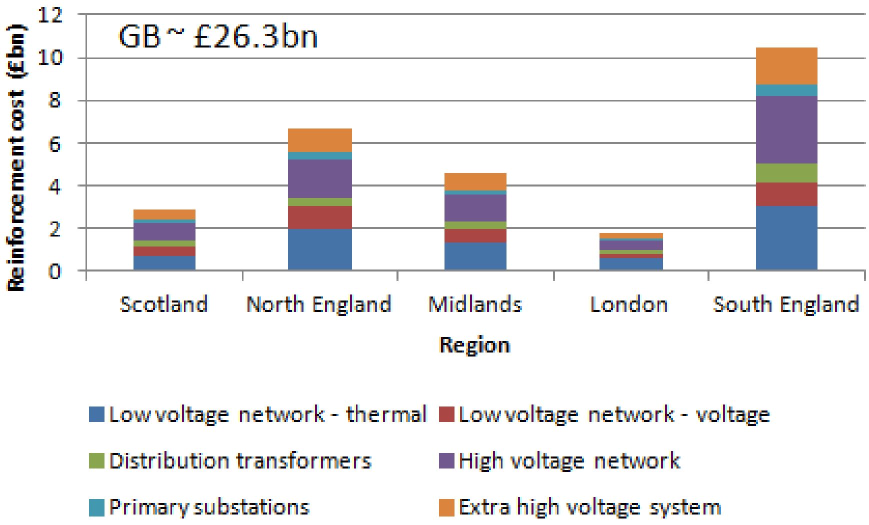


(b) Delayed Electrification scenario

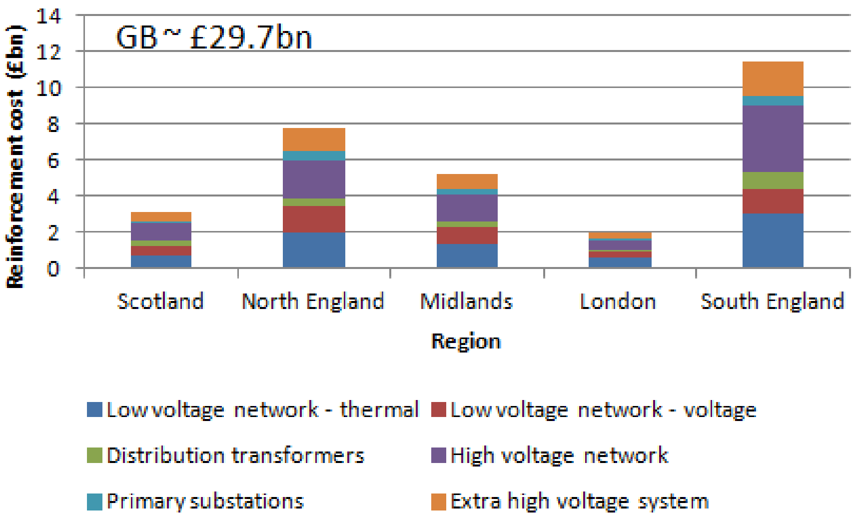


(c) No Climate Action scenario

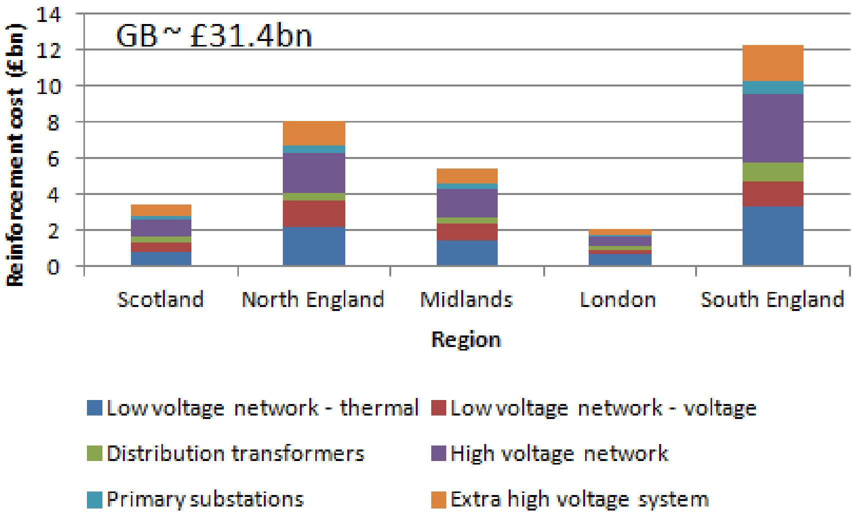
Figure 22: Reinforcement cost 2030 for core decarbonisation (a), delayed electrification (b) and no climate action (c) scenarios



(a) Uneven EV and HP scenario



(b) Demand Response scenario



(c) No Fast Charging scenario

Figure 23: Reinforcement cost 2030 for uneven EV and HP distribution (a), demand response (b) and no fast charging (c) sensitivities

Table 28: Reinforcement cost across time – CD vs. Uneven EV and HP distribution

Scenario	Year	Cost (£bn)	BaU
Core decarbonisation	2020	**8.5**	
	2025	**21.7**	
	2030	**31.4**	
Uneven EV & HP distribution	2020	**7.5**	
	2025	**18.3**	
	2030	**26.3**	

Table 29: Distribution of customers per regions

Region	Customers (%)
Scotland	10%
North England	26%
Midlands	17%
London	7%
South England	39%