Department for
Business, Energy
& Industrial Strategy

Appendix I: Electricity Networks Modelling

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Any enquiries regarding this publication should be sent to us at: enquiries@beis.gov.uk

Contents

Summary 4
1. Methodology & illustrative net zero scenarios 8
1.1 Methodology 8
1.2 Modelling tools used for the analysis 8
1.3 Illustrative net zero scenarios 9
2. Changes in electricity demand, generation, and capacity by 2050 11
2.1 Changes in electricity demand 11
2.2 Changes in electricity generation 14
2.3 Distribution network capacity 14
2.4 Transmission network constraints 16
3. Network costs and investment required to meet net zero 19
3.1 Network costs of reaching Net Zero 19
3.2 Onshore network investment required to reach Net Zero 21
4. Demand side response (DSR) 25
5. Impacts for consumers 29
6. Strategic investment into Great Britain's electricity distribution network 31
6.1 Assessing the value of early investment into distribution networks 31
6.2 Results: The benefits (& costs) of early network investment 33
7. Future employment & GVA impacts from onshore network investment 36
8. Detailed DSR & technology assumptions by 2050 37

Summary

This appendix provides supporting analysis for 'Electricity Networks: Enabling the Transition to Net Zero', which sets out our approach to transform the electricity network to ensure it can support meeting the sixth Carbon Budget (2033-2037) and net zero emissions by 2050. To achieve this, the UK will need to decarbonise whole sectors, and electrification will play a key role in achieving this. By 2035, electricity could make up around one third of final energy demand, an increase from 14% in 2020.[1] By 2050, BEIS analysis suggests total annual electricity demand is likely to at least double under Net Zero, while peak electricity demand could increase from around 58GW in 2020[2] to between 130-190 GW by 2050.

Great Britain's electricity network consists of a high voltage[3] onshore and offshore transmission network and a lower voltage[4] distribution network. The transmission network is owned by three transmission owners (TOs) and the distribution network is comprised of 14 Distribution Network Operator (DNO) license areas, operated by 6 companies. The TOs and DNOs are regulated regional monopolies and are responsible for maintaining, reinforcing, and extending the networks in their region. As of 2021, the onshore electricity network consists of approx. **20,000 km** of high voltage transmission cables, and approx. **800,000 km** of lower voltage distribution lines.[5] As peak electricity demand increases and new low-carbon generation capacity is installed as we move to net zero, this network will come under strain. Significant investment will be required to ensure the electricity network can support the increase in demand and peak demand.

This analysis aims to:

1. **Estimate the extent of network investment and network build required by 2050** under two illustrative net zero scenarios, including how this may be alleviated with the use of demand side response (DSR).[6]

2. **Examine the possible consumer impacts** (unit costs) that could materialise due to electricity demand and the necessary network investments in the lead up to net zero.

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[1] BEIS (2021), Net Zero Strategy, p. 81, https://www.gov.uk/government/publications/net-zero-strategy
[2] NGESO (2021), Winter Outlook Report, p.4, https://www.nationalgrideso.com/research-publications/winter-outlook
[3] Transmission network voltage is 275kV and 400kV in England and Wales, and 132kV, 275kV and 400kV in Scotland. In England and Wales, 132kV is classified as being part of the distribution network, whereas in Scotland 132kV is classified as being part of the transmission network.
[4] Distribution network voltage is 132kV, 66 kV, 33kV, 11kV, 6.6kV and <1kV in England and Wales, and 33kV, 11kV and <1kV in Scotland. In England and Wales, 132kV is classified as the distribution network, whereas in Scotland 132kV is classified as the transmission network. 6.6kV and above is classified as the primary distribution network and <1kV is classified as the secondary, low voltage distribution network.
[5] Totals were obtained from TO and DNO data tables, sourced via publicly available company/Ofgem annual statements. Note that the lengths of offshore transmission cables have not been quantified.
[6] Demand side response (DSR) can be used to shift demand from peak times to times when energy is more abundant, cheaper and cleaner. It is the sum of all actions on the electricity system that help reduce electricity consumption by consumers and businesses at peak times. These actions are the result of things like pricing incentives, the delivery of flexibility services by network operators and mandated smart charging.

3. **Examine the value of early strategic investment** into Great Britain's electricity distribution network, providing insight into whether investing ahead of need in order to manage uncertainty in demand growth can lead to more cost-effective investments.

4. **Estimate the possible employment impacts** that could arise from network investments.

The analysis is based on two illustrative net zero scenarios and aligns with the analysis that underpins the Net Zero Strategy[7] and the UK's sixth Carbon Budget. There are many different possible pathways to reach net zero as electricity demand grows and electricity generation decarbonises. Given this, there is significant uncertainty in the level of electricity network infrastructure required to meet net zero. This analysis focuses on two illustrative net zero scenarios to give a sense of the scale of change needed. In addition, this analysis was completed prior to publication of the British Energy Security Strategy[8], therefore the scenarios used in our analysis do not incorporate the latest assumptions and are likely to change in future updates[9]. The main findings of the analysis are:

- Net zero could increase electricity network costs by **£40-110bn** (PV 2021-2050, 2020 prices) compared to a baseline of **£230-240bn**. This means total electricity network costs could be **£270–350bn** under the net zero scenarios. It is important to note, however, that this analysis considers the impact of net zero on electricity networks only, so it **does not capture savings in other parts of the energy system**, such as reduced gas heating and petrol/diesel costs which will result from electrification of other sectors[10]. Also, note that the **estimated increase in network costs reflects an increase in electricity demand rather than an increase in unit costs**. In addition, note that most of these costs are annuitised over a 45-year period and represent the costs that can be recovered via network charges up to 2050. The total investment that these network costs are funding is outlined later. Finally, note that this analysis was completed prior to publication of the British Energy Security Strategy[11], so our scenarios do not incorporate this.
- The **cost of the network per unit of electricity generated** – and therefore the amount paid by consumers for each kilowatt hour – **is expected to stay broadly the same or even decrease** given wider efficiencies and the greatly increased supply of electricity. The final cost for end consumers will depend on their level and pattern of consumption, which will vary across households. The net zero transition will change the make-up of the average household energy bill as gas boilers and internal combustion engine cars are replaced by other technologies such as heat pumps and electric vehicles (EVs).

[7] BEIS (2021), Net Zero Strategy, https://www.gov.uk/government/publications/net-zero-strategy
[8] BEIS & No. 10 (2022), British Energy Security Strategy, https://www.gov.uk/government/publications/british-energy-security-strategy
[9] For example, the analysis excludes electricity demand for hydrogen production via electrolysis, as the modelling assumes this demand is met by curtailed renewables, but future planned analysis will consider demand from electrolysis drawing from a range of generation sources.
[10] We expect the net zero transition to see gas boilers and internal combustion engine cars replaced by other technologies such as electric heat pumps and electric vehicles, significantly reducing if not eliminating gas and fuel costs over the next 30 years.
[11] BEIS & No. 10 (2022), British Energy Security Strategy, https://www.gov.uk/government/publications/british-energy-security-strategy

This means that increases in electricity system costs, including network costs, should be considered alongside reductions in other costs such as gas system or transport fuel costs.

- Whilst the extent of future DSR is very uncertain, our analysis suggests that, in a scenario where DSR reduces peak demand by 15GW by 2050, this could lead to future system costs being reduced by **£40-50bn** (PV 2021-2050, 2020 prices). The figures presented in this analysis assume this level of DSR is achieved. Reduced distribution network costs account for around a third of this saving.
- The electricity network in Great Britain is likely to require significant levels of investment to support the expected increase in peak demand. This analysis suggests that the onshore network alone (excluding offshore) could require **£100-240bn** (undiscounted, 2020 prices) of investment by 2050. This includes **£40-60bn** for the onshore transmission network and **£60-180bn** of load-related investment for the distribution network.[12] Note, however, that this analysis was completed prior to publication of the British Energy Security Strategy[13], so our scenarios do not incorporate this. The estimated cost for the distribution network has a wider range because there is significant uncertainty in the current level of utilisation of the low voltage (LV)[14] (<1kV) distribution network, and therefore the spare capacity available. This is due to limited data on LV (<1kV) distribution network utilisation, meaning we have tested a range of spare network capacity scenarios.
- Strategic investment, otherwise referred to as ‘investment ahead of need’, can lead to efficient outcomes under certain scenarios, helping to reduce costs for consumers. Approximately 65 of the 99 investment scenarios (~66%) saw greater benefits with increased levels of investment foresight versus the baseline investment scenario of 5 years foresight. Our analysis suggests strategic investment has higher benefits where **a)** there is a high level of electricity demand and **b)** the level of spare LV (<1kV) capacity is lower than we presently assume. In all cases, our analysis suggests investment ahead of need is likely to reduce the number of network interventions required by DNOs, resulting in fewer disruptions to society such as works and road closures.
- Reinforcing the onshore electricity network to meet net zero could support **50,000 – 130,000 FTE jobs** by 2050 versus the baseline scenario; this mostly covers jobs involved in load-related reinforcement projects in the electricity network. Our analysis

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[12] Note that our analysis of investment into distribution networks only factors in load-related investment, largely due to a lack of sufficient data. We do not account for investments required to replace old or aging distribution network assets – this means that the figures could be underestimating the real amount of investment required.

[13] BEIS & No. 10 (2022), British Energy Security Strategy, https://www.gov.uk/government/publications/british-energy-security-strategy

[14] 6.6kV and above is classified as the primary distribution network and <1kV is classified as the secondary, low voltage (LV) distribution network. The LV / secondary distribution network alone accounts for approximately 50% (~400,000 km out of 800,000 km) of the total cabling length of the distribution network, see Ofgem, Electricity Distribution Quality of Service Data Tables, https://www.ofgem.gov.uk/publications/2008-2009-electricity-distribution-quality-service-data-tables

suggests these jobs could contribute between **£4-11bn**[15] to the economy in 2050 (Gross Value Added (GVA), undiscounted, 2020 prices).

- Transmission network constraints are expected to become more significant over the next decade. In Network Options Assessment 6 (NOA 6), National Grid Energy System Operator (NGESO) estimated that annual constraint costs could rise from around **£500m** in 2021 to a peak of **£1-2.5bn** (undiscounted, 2020/21 prices) in the mid-2020s, before reducing at the end of the decade when new major transmission investments are assumed to come online. The distribution network will also reach full capacity as it comes under increased utilisation – the network investment outlined above is required to solve these constraints, as well as a range of other policy measures being progressed.[16]

[15] Estimated by applying a value (£) per job as set out in: BEIS (2019), Energy Innovation Needs Assessments, https://www.gov.uk/government/publications/energy-innovation-needs-assessments

[16] See Section C.3: 'Changing how Electricity Networks are Planned and Managed' of 'Electricity Networks: Enabling the Transition to Net Zero'.

1. Methodology & illustrative net zero scenarios

1.1 Methodology

This analysis uses the **Dynamic Dispatch Model** (DDM) to explore the cost of Great Britain's electricity system by 2050 under a range of scenarios.[17] The analysis also uses the **Distribution Networks Model** (DNM) to quantify the costs of reinforcing and maintaining Great Britain's distribution network up to 2050 in each scenario. The estimates from the two models are combined to provide a complete picture of future electricity network costs.[18] More detail can be found in section 3 and detailed demand shifting assumptions are provided in section 8.

1.2 Modelling tools used for the analysis

The **DDM** is a comprehensive fully integrated power market model covering the GB power market over the medium to long term. The model enables analysis of electricity dispatch from GB power generators and investment decisions in generating capacity from 2010 through to 2050. It considers electricity demand and supply on a half hourly basis for sample days. Investment decisions are based on projected revenue and cashflows allowing for policy impacts and changes in the generation mix. The full lifecycle of power generation plant is modelled, from planning through to decommissioning, and also allows for risk and uncertainty involved in investment decisions. The DDM enables analysis comparing the impact of different policy decisions on generation, capacity, costs, prices, security of supply and carbon emissions, and also outputs comprehensive and consistent Cost-Benefit Analysis results. The DDM models future GB transmission network costs and these outputs were used to estimate the levels of investment that would be required into GB's onshore transmission network under each scenario.

The **DNM** is a nodal network model that uses specialist electrical engineering software to simulate GB electricity distribution network costs from 2010 to 2050. The DNM comprises a Power Flow Model (PFM) and an Investment Model (IM) and it uses representative network archetypes based on actual existing distribution networks in Great Britain. The PFM utilises power flow algorithms to model electricity flows through these representative networks, with the resulting outputs being fed back to the IM to simulate future DNO investment decisions. These are used to calculate changes in reinforcement costs under different scenarios. The power flows directly depend on the scenario inputs specified by the user to estimate future network breaches and constraints (in the form of thermal or voltage constraints). These inputs

[17] For further background information on the DDM please see: BEIS (2014), Dynamic Dispatch Model (DDM), https://www.gov.uk/government/publications/dynamic-dispatch-model-ddm

[18] The transmission network consists of almost 20,000 km of underground cables and overhead lines. The cost of reinforcing and maintaining these is calculated within the DDM. However, the electricity distribution network is much larger (~800,000 km of underground cables and overhead lines today) and requires the use of a separate model (the DNM) to quantify load related and non-load related distribution network costs for each scenario.

consist of peak/minimum demand profiles, Distributed Generation (DG) profiles, and varying levels of demand shifting. The DNM can also be used to vary the levels of assumed spare network capacity (see section 2.3) and simulate various DNO investment decisions – e.g., see section 6 on the value of early strategic investment into Great Britain's electricity distribution networks.

The DDM and DNM have been and continue to be subject to rigorous internal and external quality assurance. Both models continue to have their modelling assumptions updated on a regular basis and are periodically updated with new modelling tools and functionalities to keep pace with changes in the power sector.

1.3 Illustrative net zero scenarios

The analysis is based on two illustrative net zero scenarios which are outlined below. These scenarios are net zero consistent and fully align with the UK's sixth Carbon Budget (2033-2037), which sets out a target to cut emissions by 78% by 2035 compared to 1990 levels.[19] These scenarios are illustrative – other scenarios, with different power sector demands and carbon emission profiles, are possible to meet net zero. In addition, this analysis was completed prior to publication of the British Energy Security Strategy[20], so our scenarios do not incorporate this. The baseline scenario is also outlined below.

- **Net zero lower demand scenario:** Net zero is reached with lower electricity demand due to less electrification of heat and transport.
- **Net zero higher demand scenario:** Net zero is reached with higher electricity demand with close to full electrification of heat and transport.
- **Net zero strategy baseline scenario:** This scenario aligns with the "baseline" projections the indicative "delivery pathways" outlined in the Net Zero Strategy[21] were assessed against. It includes only government policies which have been implemented, adopted, or planned[22] as of August 2019 and therefore does not hit emissions targets.

In addition, we test scenarios where the capacity of the LV (<1kV) part of the distribution network (also known as the "secondary distribution network") is varied. This is to control for the

[19] BEIS, Prime Minister's Office, 10 Downing Street (2021), UK enshrines new target in law to slash emissions by 78% by 2035, https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035
[20] BEIS & No. 10 (2022), British Energy Security Strategy, https://www.gov.uk/government/publications/british-energy-security-strategy
[21] BEIS (2021), Net Zero Strategy, https://www.gov.uk/government/publications/net-zero-strategy
[22] This equates to expired, implemented, adopted, and planned policies as defined by the United Nations Framework Convention on Climate Change (UNFCCC). See Part II, Section V(A) paragraph 13, page 83 of: http://unfccc.int/resource/docs/cop5/07.pdf
This is a UNFCCC "with additional measures" (WAM) scenario. Annex D gives details of the policies we include.

significant levels of uncertainty that exist around the current level of capacity on the LV (<1kV) part of the distribution network.[23] Several other important limitations are:

- **The analysis does not account for distribution network connection costs:** This analysis does not consider the cost of connecting new sources of demand to the electricity distribution network due to a lack of data at this point. This is a limitation we intend to explore as future analysis is developed.
- **The analysis does not account for demand diversity on the distribution network:** This analysis assumes the system peak is replicated lower down the network. For example, increases in peak demand in the local LV (<1kV) networks are assumed to be proportionate to increases in the aggregated national system peak. In reality, local peaks may be higher due to a lack of demand diversity – especially in areas with relatively low (<30) customer density. These could require more reinforcement and increased investment costs compared to the estimates presented in this analysis. This is a limitation we intend to explore in future.
- **Section 3.2 of the analysis does not account for the non-Load Related Expenditure requirement of the distribution network:** our analysis of investment into distribution networks only factors in Load Related Expenditure (LRE), and as such does not account for changes in the DNO investment profile required to maintain the existing network and replace old or ageing assets. This is largely due to a lack of sufficient data on the age and condition of lower voltage network assets. Therefore, **section 3.2** is likely to underestimate the total level of distribution network investment that will be required. This is a limitation we intend to explore as future analysis is developed and supplemented with additional network data from DNOs.
- **The presented analysis considers the impact of net zero on electricity networks only**. It does not capture the impacts of net zero, for example, on the current gas network and transport system due to decreased use of gas for heating and oil for transport. Therefore, this analysis shows only a partial picture from an economy-wide perspective.

[23] The LV network accounts for approximately 50% of the total network length in Great Britain. See: ENA (2015), Climate Change Adaptation Reporting Power Second Round.

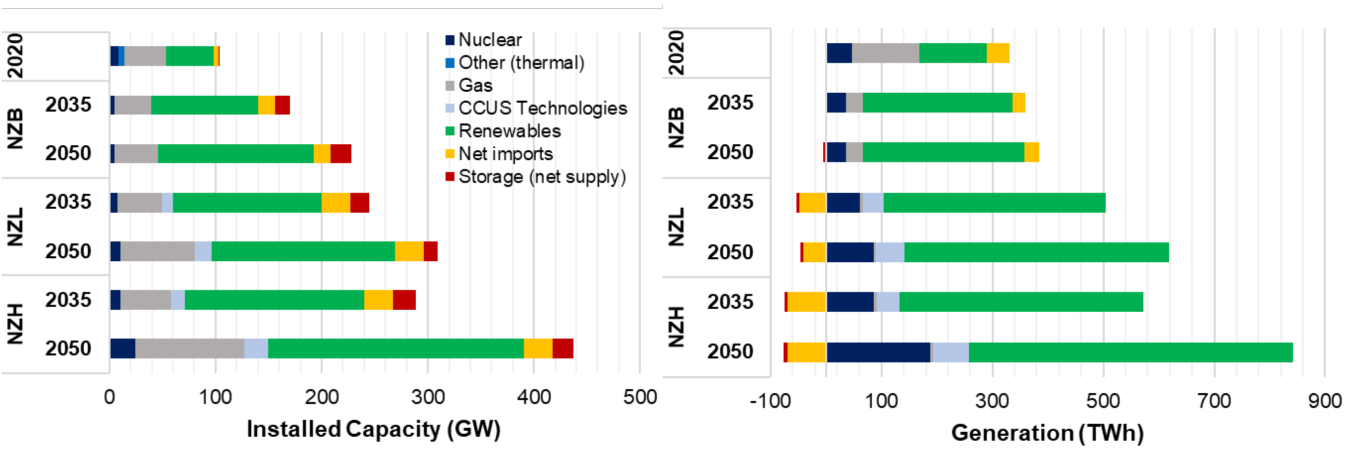
2. Changes in electricity demand, generation, and capacity by 2050

2.1 Changes in electricity demand

To achieve net zero, the UK will need to decarbonise whole sectors, and electrification will play a key role in achieving this. Currently, the electricity network experiences demand of 330 TWh per annum[24]. Depending on how we reach net zero, demand is expected to increase to between 450-500 TWh by 2035 and between 570-770 TWh by 2050 (see Figure 1).

By 2035, electricity could make up around one third of final energy demand, an increase from 14% in 2020.[25] By 2050, in the higher demand scenario, our analysis suggests system peak demand could grow from 58GW in 2020[26] to around 190 GW in 2050 (see figure 2), and total annual electricity demand could more than double from 330TWh in 2020 to 770TWh by 2050. In a Net Zero lower demand scenario, peak demand could increase to around 130GW in 2050 and annual demand could rise to nearly 570TWh. This represents an increase in peak demand of over 80% in the lower demand scenario and close to 180% in the higher demand scenario. This analysis supports section B.1.1 'Increase and Changing Nature of Electricity Demand' in 'Electricity Networks: Enabling the Transition to Net Zero'.

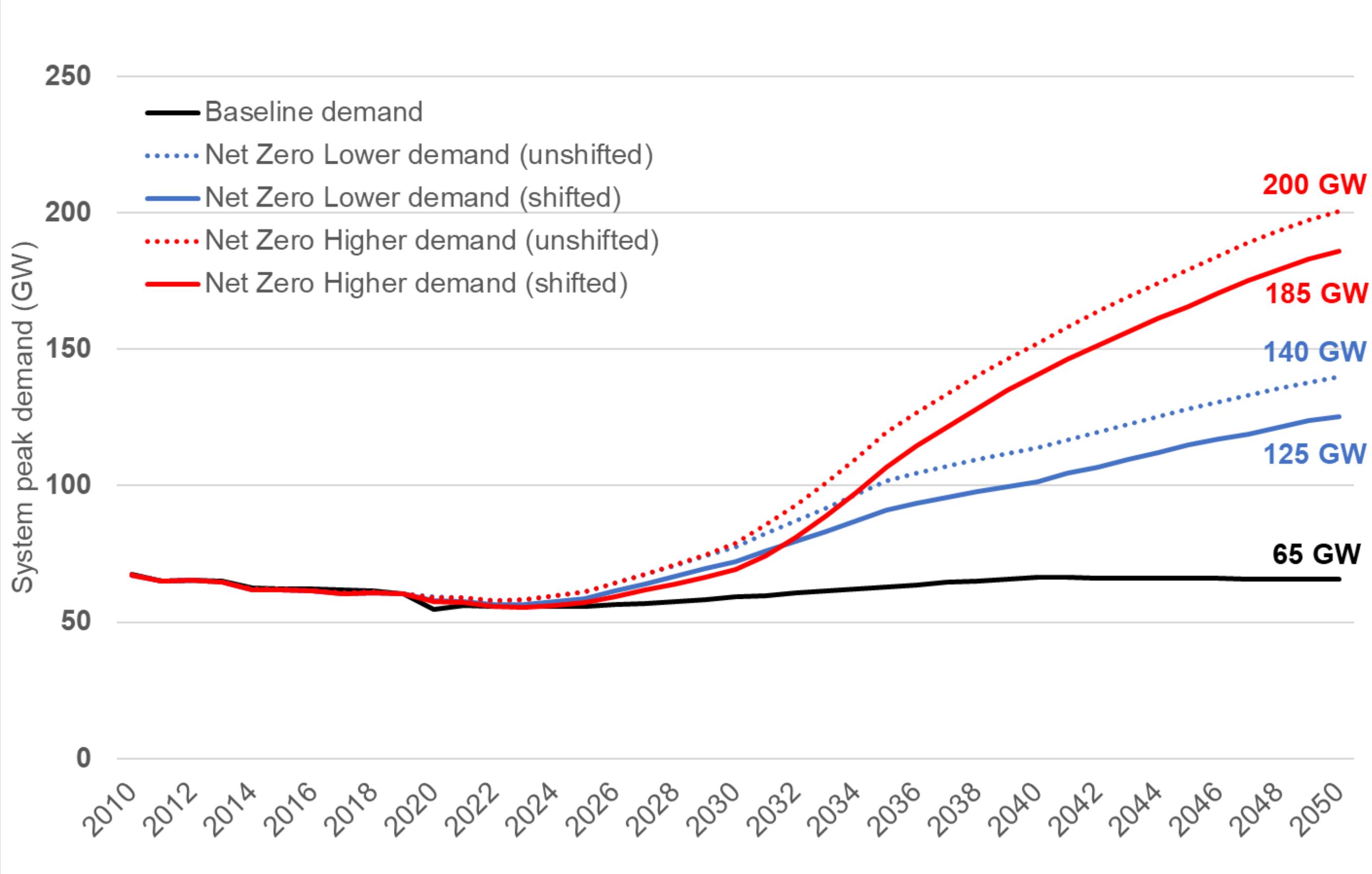
Figure 1: Modelled installed capacity (Great Britain only) and generation mix in Net Zero Baseline Demand, Net Zero Lower Demand and Net Zero Higher Demand scenarios in 2035 and 2050, compared to 2020[27]



[24] BEIS (2021), DUKES, p.26, https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2021
[25] BEIS (2021), Net Zero Strategy, p. 81, https://www.gov.uk/government/publications/net-zero-strategy
[26] NGESO (2021), Winter Outlook Report, p.4, https://www.nationalgrideso.com/research-publications/winter-outlook
[27] Data taken from the BEIS DDM: Net Zero Baseline Demand, Net Zero Lower Demand and Net Zero Higher Demand scenarios.

The potential impact of demand side response (DSR) is also shown in figure 2. DSR can be used to shift demand to times of the day when electricity is cheaper and more abundant. With unprecedented increases in system peak demand and electricity network utilisation, DSR could play a significant role in controlling future system costs by helping to reduce system peak demand. DSR potential by 2050 is highly uncertain and depends on technological developments, such as from smart technology, as well as consumer behaviour. We have used a set of assumptions to illustrate the potential benefits of DSR, but these assumptions are highly uncertain. In figure 2, "shifted" represents system peak demand with DSR and "unshifted" represents system peak demand with no DSR. Figure 2 shows that DSR could lower peak demand by approximately 15GW by 2050, which corresponds to a decrease of approximately 7-10% in the system peak by 2050. This decrease in system peak demand could be a source of substantial system cost savings, as system peak demand is a key driver of both system and network costs. Section 4 provides more detail on DSR.

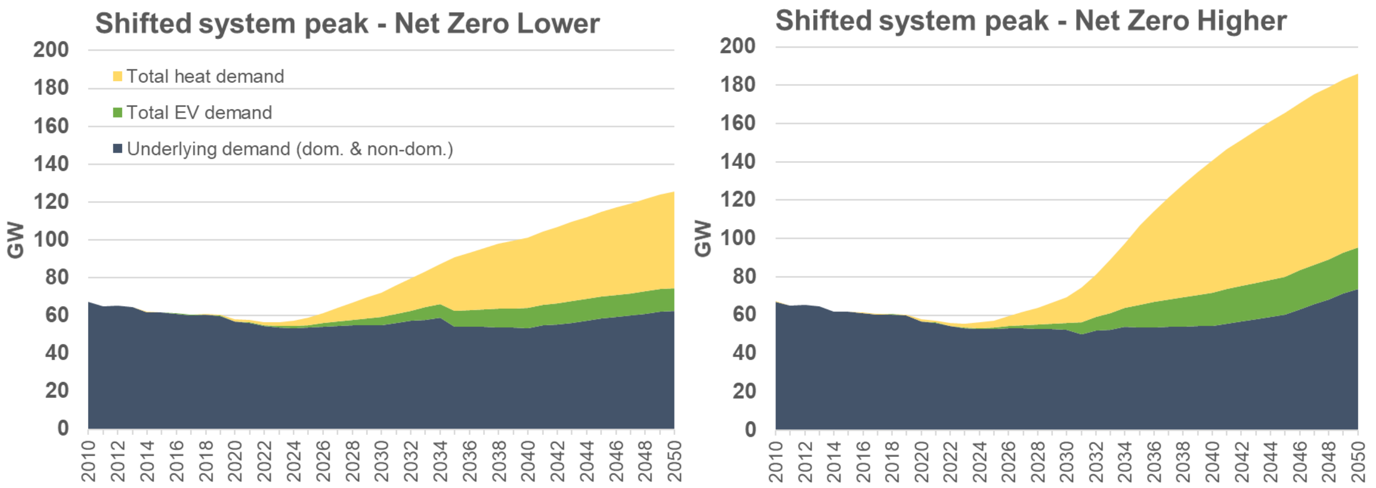
Figure 2: System peak demand and the impact of DSR[28]



The increase in peak demand is largely driven by planned electrification of the heat and transport sectors, both before and after DSR. Figure 3 shows the technology mix of the future system peak under the two net zero demand scenarios. Approximately 40-50% of the 2050 system peak will be from electrified heat demand with a further 5-10% coming from electrified road transport.

[28] Based on BEIS' DDM scenario results, November 2021. Please refer to section 8 of this annex for more details around the DSR assumptions that were used as part of this analysis.

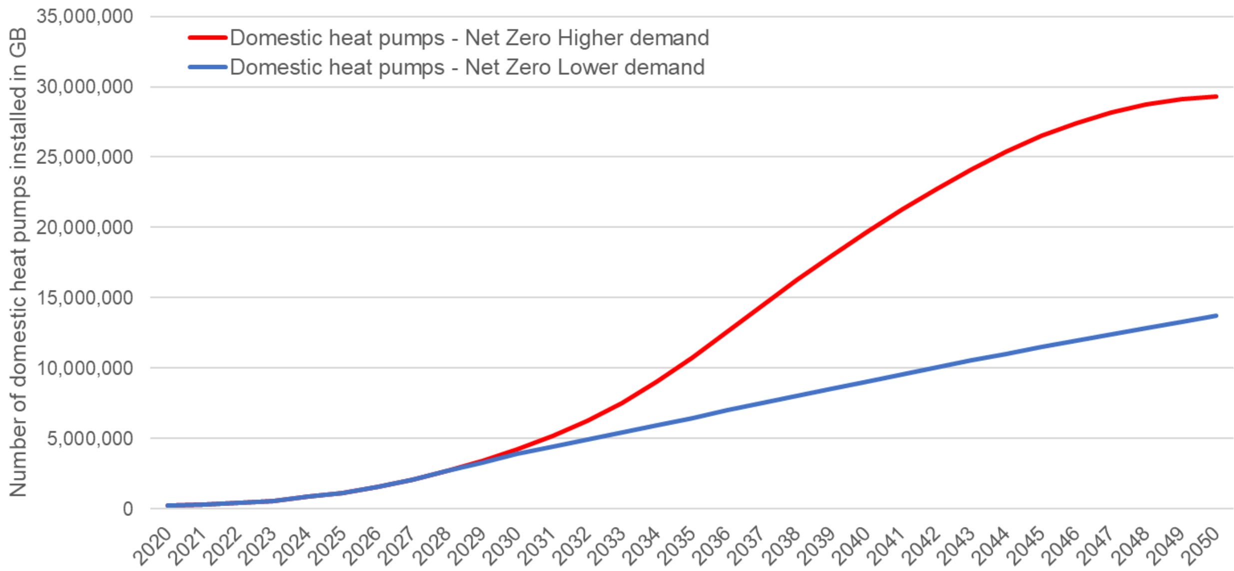
Figure 3: Share of system peak by technology after demand shifting



Source: BEIS DDM 2021

This dramatic increase in future peak demand is chiefly driven by the electrification of domestic heating. Both net zero scenarios are in line with the Government's target to install 600,000 heat pumps every year from 2028 under the 10-point-plan for a green industrial revolution.[29] Figure 4 shows the estimated number of domestic heat pumps installed under the two illustrative demand scenarios – almost 15 million by 2050 in the lower demand scenario and almost 30 million by 2050 in the higher demand scenario. The key difference between the two scenarios is that in the lower demand scenario we assume more homes use hydrogen for heating, resulting in fewer domestic heat pumps.[30]

Figure 4: Illustrative number of domestic heat pumps installed by households



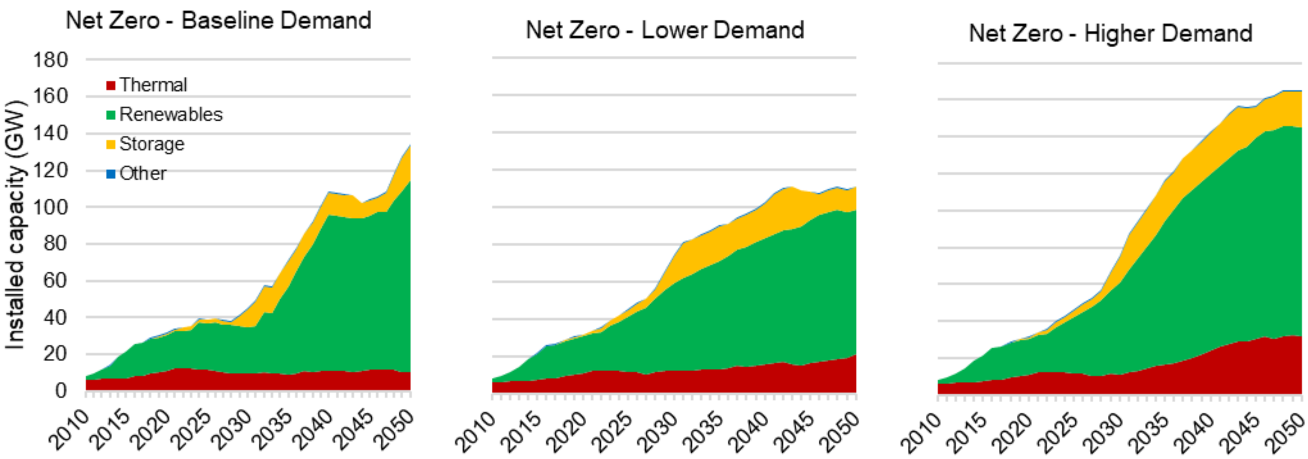
[29] BEIS, Prime Minister's Office, 10 Downing Street (2021), PM outlines his Ten Point Plan for a Green Industrial Revolution for 250,000 jobs, https://www.gov.uk/government/news/pm-outlines-his-ten-point-plan-for-a-green-industrial-revolution-for-250000-jobs

[30] The analysis does not include assumptions on how hydrogen is produced and electricity demand associated with this process.

2.2 Changes in electricity generation

The future electricity system will also see substantial changes in Great Britain's generation capacity mix. This is especially the case for the electricity distribution network – figure 5 shows how all three scenarios will see substantial increases in the amount of generation capacity connected to the distribution network, also known as "distributed generation". Categories in figure 5 include thermal (combined heat and power (CHP)[31] and gas), renewables (large wind, and large and small scale solar photovoltaic (PV)), storage, and other. The two net zero scenarios see increases in the amount of distributed generation capacity of between 80-140 GW by 2050. Most of this increase – between 70-75% depending on the scenario – comes from renewables. Storage and thermal account for approximately 10% and 20% of installed capacity by 2050 across both net zero scenarios, respectively. This analysis supports section B.1.2 'Increase and Changing Nature of Electricity Generation' in 'Electricity Networks: Enabling the Transition to Net Zero'.

Figure 5: Distributed generation capacity across the 3 demand scenarios



2.3 Distribution network capacity

This section outlines the current and future capacity of the distribution network. Transmission network constraints analysis is not included in this section. External analysis of transmission network constraints is outlined in section 2.4. This analysis supports section B.1.3.2 'Network Constraints' in 'Electricity Networks: Enabling the Transition to Net Zero'.

As a result of the expected increase and change in nature of electricity demand and generation, the distribution network will reach full capacity as it comes under increased utilisation. In our modelling, we assume that there is currently, on average, approximately 60% spare thermal capacity ("headroom") across all distribution network assets in Great Britain.[32]

[31] CHP is a process that captures and utilises the heat that is a by-product of the electricity generation process.
[32] Note that the 60% figure represents a very rough average. In reality, the level of network utilisation and therefore spare network capacity varies very widely between Great Britain's different regions and network types. There is also a very high level of variation within specific regional networks.

This assumption is based on a representative sample of network utilisation data from DNOs, and is relatively high partly due to peak demand today being approx. 10% lower than it was in 2005.[33] As we move to net zero, however, the distribution network will reach full capacity and reinforcement will be required.

The DNOs generally have a good understanding of the level of utilisation of the primary distribution network (33/11kV level and above) but have less visibility over the secondary LV network (1kV and below). Whilst many DNOs have started to take concrete steps in the last 5 years to increase the degree of LV network monitoring, secondary LV network utilisation remains poorly understood.[34] This creates uncertainty in this assumption given the secondary LV network comprises ~45% of the total length of today's distribution network (see Table 1). To control for this uncertainty, we created three LV network scenarios for each of the three demand scenarios:

1. **Baseline LV capacity**: a scenario where LV network capacity remains unchanged and remains at the estimated average for the whole network (~60%). This is assumed to be our central scenario.
2. **LV capacity -25pct**: LV spare capacity is reduced by 25% (one-quarter) of its predicted level in 2023, which can increase distribution network reinforcement costs.
3. **LV capacity -50pct**: LV spare capacity is reduced by 50% (halved) relative to its predicted level in 2023, which can significantly increase distribution network reinforcement costs. This represents a highly pessimistic scenario where the 'true' level of LV network utilisation is much higher than suggested by our sample data from DNOs.

Table 1: Total distribution network cabling in GB & NI, by voltage level[35]

Km of Distribution network cabling at each voltage level	**Primary distribution network (HV & EHV)**			**Secondary distribution network**	***Total km length***
	132 kV	**66 & 33 kV**	**20, 11 & 6.6 kV**	**LV (< 1 kV)**	
Overhead lines	16,471	29,120	168,962	64,874	279,427
Underground cables	3,191	90,991	153,883	311,237	559,302
Total	**19,662**	**120,111**	**322,845**	**376,111**	**838,729**
% of total Distribution network cabling	*2%*	*14%*	*38%*	*45%*	*100%*

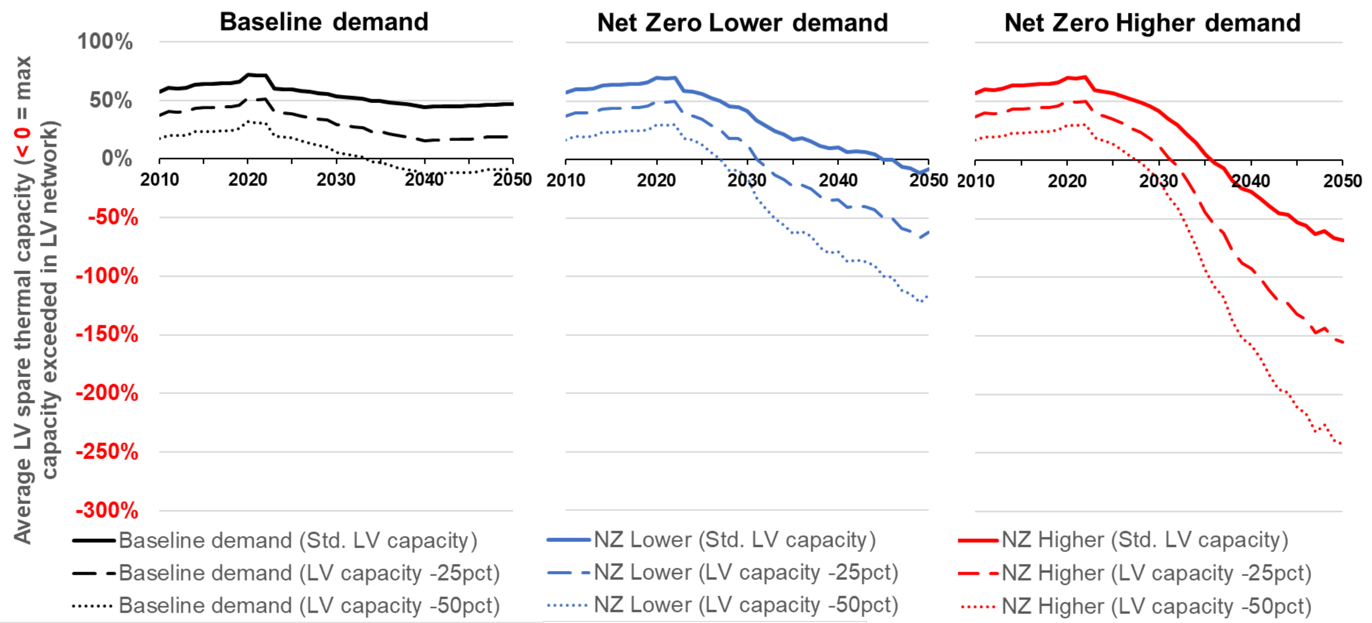
Figure 6 shows how a lower level of spare LV network capacity can greatly impact the overall loading of the low voltage network and affect the timing of large-scale network reinforcement.

[33] NGESO (2021), National Grid Future Energy Scenarios (FES) 2021, Flexibility, FL.4, https://www.nationalgrideso.com/document/199971/download
[34] Electricity North West (2014), Low Voltage Network Solutions (LVNS), https://www.enwl.co.uk/go-net-zero/innovation/smaller-projects/low-carbon-networks-fund/low-voltage-network-solutions/
[35] ENA (2015), Climate Change Adaptation Reporting Power Second Round, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/479267/clim-adrep-ena-2015.pdf, p 97. Note that these figures include Northern Ireland's DNO as well (~47,000 km of cables).

Lower levels of LV capacity could mean that large scale LV network reinforcement is needed 5 years earlier than would otherwise be the case (by 2030 instead of 2035). Reducing spare network capacity has an amplified effect in higher demand scenarios, increasing the required volume of distribution network reinforcement as well as requiring major reinforcement works to commence earlier across the country. We have assumed all price control periods will be 5 years in line with RIIO-ED2[36] (2023-2028). Network investment impacts are explored in section 3.

Future distribution network utilisation estimates were derived via the use of electricity power flow modelling in the DNM. The model reinforces any asset that has less than 0% spare capacity. The utilisation figures presented in the charts represent averages across a diverse range of networks and regions – so even if overall average capacity seems high, there could be assets that need reinforcing in particular networks and regions due to specific local network conditions. LV network capacity is only reduced in 2023 to ensure no excess network expenditure occurs before the end of the current electricity distribution price control period (RIIO-ED1, 2015-2023).

Figure 6: Historic and modelled average LV thermal capacity under BEIS' three demand scenarios. A decreased level of spare LV capacity across GB's LV network assets could lead to greater than expected level of thermal constraint by 2050



2.4 Transmission network constraints

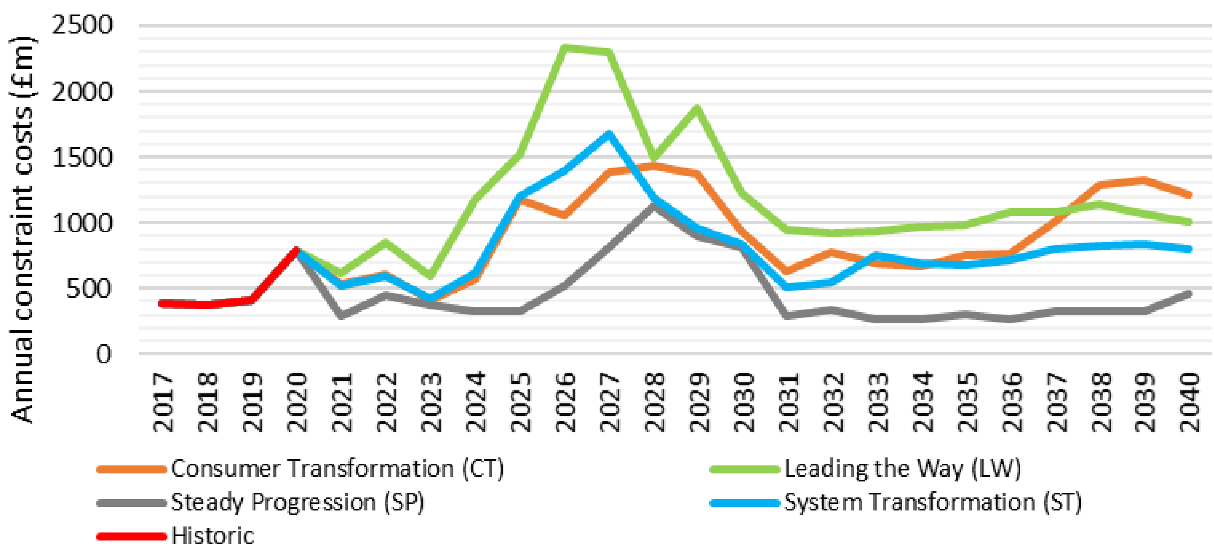
Transmission network constraints occur when the electricity transmission system is unable to transmit power to demand locations due to congestion on the network. As a result of the expected increase and change in the nature of electricity demand and generation, managing transmission network constraints on the network effectively will be increasingly important. The analysis in this section relies on data and analysis supplied by the National Grid Electricity

36 RIIO stands for Revenue = Incentives + Innovation + Outputs. ED2 stands for Electricity Distribution 2.

System Operator (NGESO) and is based on historic data which may not fully reflect future trends. It also assumes 'optimal reinforcement' up to 2040 as recommended by the Network Options Assessment (NOA) 6.[37] In reality, there may not be optimal reinforcement. In addition, this analysis was completed prior to publication of the British Energy Security Strategy[38], so NGESO analysis does not incorporate this. This analysis supports section B.1.3.2 'Network Constraints' in 'Electricity Networks: Enabling the Transition to Net Zero'.

NGESO manages constraints through the balancing mechanism, by paying generators that are located far from demand (on the opposite side of the constraint) to switch-off (turn-down) when transmission transfer capacity is being breached and switching-on (turn-up) generation closer to demand instead. Figure 7 shows that annual transmission network constraint management costs were around £400m per year between 2017 and 2019. In 2020, this doubled to almost £800m because low electricity demand due to the COVID lockdown coupled with increasing renewable generation increased the need for actions to satisfy locational constraints. While the electricity network is not sourced entirely from low carbon generation, any curtailment of renewable technology may be replaced with carbon-emitting technology (due to the location of the plant), which could increase power sector emissions.

Figure 7: Historic and modelled annual transmission network constraint costs (£m) after NOA6 Optimal reinforcements in GB, 2017 – 2040



Source: NGESO MBSS and NOA 6 2020/21

Figure 7 shows that annual constraint costs are expected to increase from around £500m in 2021 to a peak of **£1bn-£2.5bn** (undiscounted, 2020/21 prices) in the mid-2020s, before reducing, according to the NGESO NOA 6 analysis which uses four Future Energy Scenarios

37 NGESO (2021), Modelled Constraint Costs: NOA 2020/21, https://www.nationalgrideso.com/documents/194436-modelled-constraint-costs-noa-202021
38 BEIS & No. 10 (2022), British Energy Security Strategy, https://www.gov.uk/government/publications/british-energy-security-strategy

(FES).[39] This is because investment in network capacity upgrades has much longer timescales than connecting new renewable generation. As a result, a lot of renewable generation is connected before major transmission investments are assumed to come online, resulting in higher costs to manage network constraints in the short-term.

[39] NGESO (2020), Analysing the costs of our Future Energy Scenarios, https://www.nationalgrideso.com/news/analysing-costs-our-future-energy-scenarios. To note that these scenarios are generated by National Grid ESO and are not necessarily consistent with BEIS Net Zero Strategy scenarios which underpins the rest of the analysis in this annex.

3. Network costs and investment required to meet net zero

This section estimates the network costs of meeting net zero and the investment required to upgrade and reinforce Great Britain's onshore electricity network to reach net zero. Investment in the electricity network is recovered over a 45-year period through allowed revenues. Allowed revenues represent the network costs that network companies (TOs, DNOs and Offshore Transmission Owners (OFTOs)) will be allowed to recover annually. Section 3.1 outlines the network costs of meeting net zero under the two illustrative net zero scenarios and section 3.2 sets out the onshore network investment that these network costs are funding.[40] Any increase in electricity network costs should be considered relative to reductions in gas system and transport fuel costs, as the net zero transition will see gas boilers and internal combustion engine vehicles replaced by other technologies such as electric heat pumps and EVs. These savings in other parts of the energy system, as well as accompanying decommissioning costs, are not captured by our analysis. In addition, this analysis was completed prior to publication of the British Energy Security Strategy[41], so our scenarios do not incorporate this. This analysis supports section C.1 'Investing in our Electricity Networks' in 'Electricity Networks: Enabling the Transition to Net Zero'.

3.1 Network costs of reaching Net Zero

Table 2 shows the potential range of network costs of reaching net zero in the power sector. Our modelling suggests that, under the two illustrative net zero scenarios, future network costs may increase by approximately £40-70bn (PV 2021-2050, 2020 prices) in the baseline LV capacity scenario. This rises to £50-110bn in the LV capacity -50pct scenario. An increase of this size would represent approximately 20-30% of the total expected increase in electricity system costs by 2050. Distribution networks are reinforced for either system peak demand (a day in winter) or when there is a combination of low demand and very high levels of distributed generation (a day in summer). Therefore, in the analysis, distribution network costs are determined using these two winter and summer days only as they are most costly from a networks perspective.

The transmission network costs in table 2 are a simplified representation. These estimates use the DDM to model the expected transmission network flows and historic cost data to predict the cost of expanding and maintaining the transmission network up to 2050. The costs of the distribution network were estimated using the DNM, which simulates power flows across a set

[40] Network costs presented in section 3.1 include both onshore and offshore network costs, whereas onshore network investment presented in section 3.2 includes onshore network investment only.
[41] BEIS & No. 10 (2022), British Energy Security Strategy, https://www.gov.uk/government/publications/british-energy-security-strategy

of representative networks to estimate future distribution network constraints and predict future distribution network reinforcement costs.

There is a significant degree of uncertainty in these modelled estimates – we attempt to control for these by using two illustrative demand scenarios (NZ Lower and NZ Higher) and two LV network spare capacity scenarios. The latter applies to the distribution network only and is designed to control for the significant amount of uncertainty that exists around the degree of spare thermal capacity that is present in LV assets today.

Table 2: Cumulative network costs of achieving net zero in the power sector

Cumulative electricity network costs from 2021 (bn, PV, 2020 £ real)	Baseline demand		Net Zero Lower demand		Change in costs vs Baseline demand scenario	
Cost type	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**
Transmission network costs	100	100	130	130	30	30
Distribution network costs	130	140	140	160	10	20
Total network costs	**230**	**240**	**270**	**290**	**40**	**50**
% share of total system costs	*27%*	*28%*	*26%*	*28%*	*24%*	*28%*
Cumulative electricity network costs from 2021 (bn, PV, 2020 £ real)	**Baseline demand**		**Net Zero Higher demand**		**Change in costs vs Baseline demand scenario**	
Cost type	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**
Transmission network costs	100	100	150	150	50	50
Distribution network costs	130	140	150	200	20	60
Total network costs	**230**	**240**	**300**	**350**	**70**	**110**
% share of total system costs	*27%*	*28%*	*25%*	*28%*	*21%*	*30%*

The shading in Table 2 shows how network costs in the two net zero demand scenarios compare against the Baseline demand scenario. Values shaded in red represent cost increases vs the Baseline demand scenario.

The estimates above represent the cumulative, annuitised network costs that network companies (TOs, DNOs and OFTOs) will be allowed to recover by 2050 to fund the required network investment to reach net zero. In reality, allowed revenues will be decided by Ofgem as part of their RIIO price control framework, and so the above estimates should be interpreted as indicative of how investment costs could be recovered, rather than any forecast of exact allowed revenue decisions through the RIIO process. The total onshore investment that these network costs are funding is outlined separately in section 3.2.[42] Network companies recover the above network costs by charging those who use the electricity network, such as generators and electricity suppliers, who then pass these costs onto consumers through electricity bills. See section 5 for further information on consumer impacts. Additional network costs are likely to materialise due to **a)** the need to connect new generating capacity to the transmission

[42] Network costs presented in section 3.1 include both onshore and offshore network costs, whereas onshore network investment presented in section 3.2 includes onshore network investment only.

network and reinforce the network to cope with the added flows, and **b)** the need to reinforce the distribution network in the face of increasing network utilisation due to increasing demand and the resulting thermal/voltage violations on its assets.[43] However, the electricity network cost per unit of electricity consumed is expected to stay broadly the same or even decrease in some scenarios during the net zero transition. See section 5 for further information on consumer impacts and per-unit costs.

3.2 Onshore network investment required to reach Net Zero

This section quantifies the total **onshore** network investment (TOTEX) required to meet our net zero scenarios, which is funded by the network costs outlined above.[44] Figure 8 shows that in the central case for LV network spare capacity, between £100-£140bn (undiscounted, 2020 prices) of additional investment could be required by 2050. This is necessary to upgrade and reinforce Great Britain's onshore electricity network to support additional demand required to reach net zero across the economy. This is in addition to the baseline demand scenario, where the onshore network is estimated to require around £70bn of investment by 2050, the majority of which will be in the transmission network rather than the distribution network.

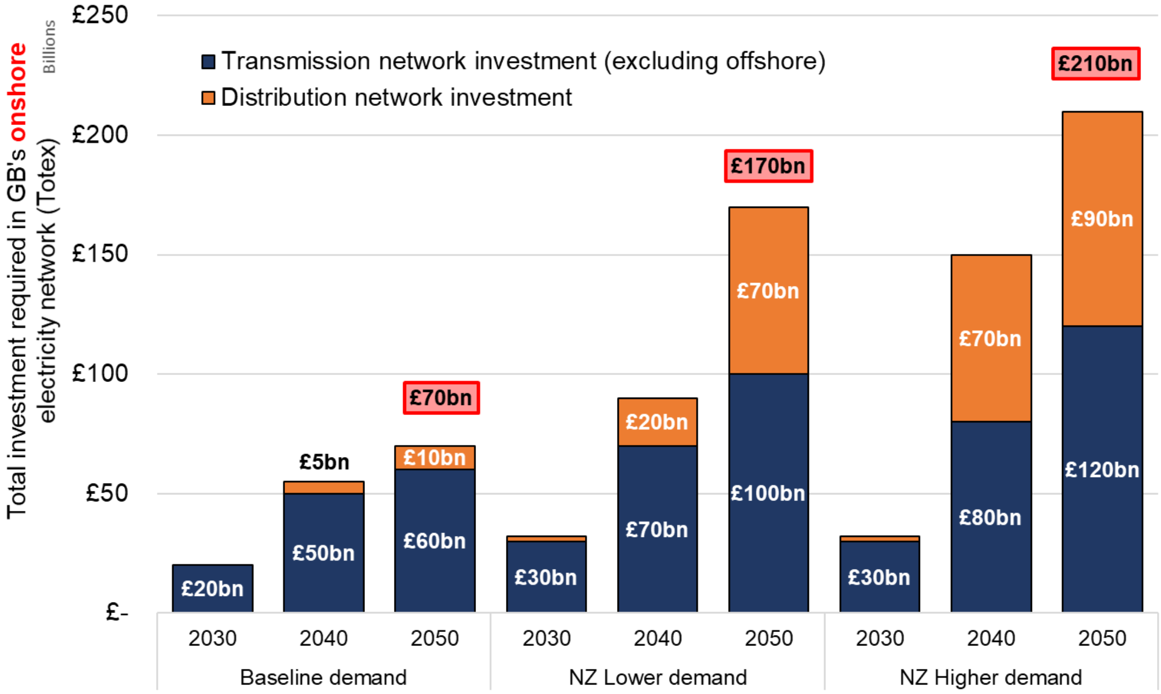
Note that our analysis of investment into distribution networks only factors in investment in the form of **load-related expenditure** (LRE), and as such does not account for changes in the DNO investment profile required to maintain the existing network and replace old or ageing assets (non-LRE). This is largely due to a lack of sufficient data on the age and condition of lower voltage network assets. Therefore, this section is likely to underestimate the total level of distribution network investment that will be required in the future. We also do not factor in the complexities around electricity network supply chain capabilities, which could be a challenge for both the transmission and distribution networks, but particularly the transmission network due to the relatively long lead times that are required for larger scale transmission projects.

This analysis quantifies investments in the **onshore network only**.[45] This is because the onshore transmission network investment that we modelled relies on data from Ofgem's Price Control Financial Model (PCFM), which we use to reverse engineer the DDM's estimates of future onshore transmission allowed revenues. This is based on RIIO-ET2, which encompasses onshore transmission networks only.[46] Offshore networks are not subject to the electricity transmission price control regime (RIIO-ET2, 2021-2026) – they are managed via the separate OFTO regime[47] and are therefore excluded from the analysis. Distribution network investment was estimated using the DNM, which directly estimates future load-related

[43] Connection costs are not included in these cost estimates.
[44] Network costs presented in section 3.1 include both onshore and offshore network costs, whereas onshore network investment presented in section 3.2 includes onshore network investment only.
[45] The transmission network costs presented in section 3.2 and 3.3 include both onshore and offshore network costs. Offshore costs comprise ~47% of total transmission network costs in both net zero scenarios, while the remaining 53% is attributed to the onshore network. By necessity, the transmission Totex derived via this analysis excludes almost half of the future transmission network.
[46] RIIO stands for Revenue = Incentives + Innovation + Outputs. ET2 stands for Electricity Transmission 2.
[47] Ofgem, Offshore Electricity Transmission (OFTO), https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/offshore-electricity-transmission-ofto

distribution network investment via power flow modelling and investment analysis on the DNM's 10 representative networks. For the purposes of this analysis, we have assumed that DNOs can deploy a mix[48] of conventional network reinforcements (additional underground cabling, installation of overhead lines, transformers etc.) and novel or "smart" solutions to alleviate distribution network constraints.[49] There are a range of smart network solutions that DNOs could potentially deploy in the future, which could defer the need for large and expensive conventional reinforcements – however, in some instances, they may not be able to fully resolve capacity issues in the long-term.

Figure 8: Cumulative onshore network investment[50] required from 2021 in each demand scenario (undiscounted, 2020 £) – Central scenario (baseline LV capacity)



The estimates presented in figure 8 represent the central case (baseline LV capacity) which is our best estimate. To understand the sensitivity of these estimates and reflect uncertainty around the level of LV network utilisation as outlined in section 2.3, we also test a scenario where LV utilisation is greater than that suggested by our data (LV capacity -50pct). Figure 9 shows that the estimated load-related network investment required increases as LV capacity decreases. In the LV capacity -50pct scenario, our analysis suggests £100-240bn

[48] The precise mix of solutions used varies by each scenario and depends of when distribution network constraints are predicted to arise. The DNM uses a cost optimisation function to decide which solutions to deploy based on their relative costs and network benefits.
[49] Novel/smart solutions encompass newer network solutions that tend to be cheaper than conventional reinforcements. These innovative solutions usually rely on real time network monitoring and customer data. These include (but are not limited to): power electronics, Enhanced Automatic Voltage Control, Real Time Thermal Rating (varying the thermal rating of a circuit or transformer in real time dependent on weather conditions), and Dynamic Network Reconfiguration (changing the configuration of the network in real time to better manage power flows). Note that this list of novel/smart solutions used by the DNM is not exhaustive – the DNM does not for example model manual phase balancing, which could further help reduce reinforcement costs.
[50] Note that our analysis of investment into distribution networks only factors in load-related investment, and as such does not account for investments required to maintain the network and replace old or aging distribution network assets.

(undiscounted, 2020 prices) of additional load-related investment could be required by 2050 versus the baseline demand scenario. This highlights the impact of LV utilisation and the degree of uncertainty in our estimates given LV network utilisation is poorly understood.

Our analysis indicates that significant load-related distribution network investment won't take place until the mid-late 2030s and 2040 despite electricity demand increasing in the late 2020s and early 2030s. This is due to the presence of significant amounts of spare thermal capacity in the distribution network, which is expected to delay the need for significant network reinforcements. However, as discussed above, the degree of spare thermal capacity is highly uncertain at the LV level, which comprises ~50% of the total length of today's distribution network. If actual levels of spare capacity in the LV network are lower than assumed in our baseline LV scenario, this could lead to a much earlier need for load-related distribution network investment and reinforcement – as early as 2030.

Figure 9: Cumulative onshore network investment[51] required from 2021 under the -50pct LV network capacity scenario (undiscounted, 2020 prices)

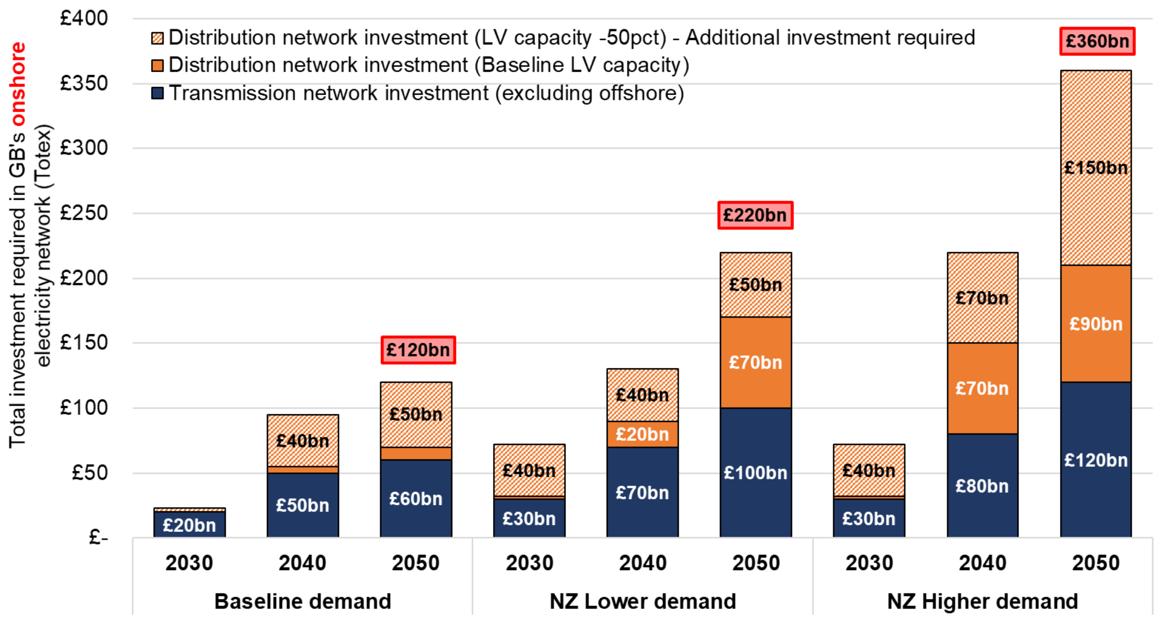
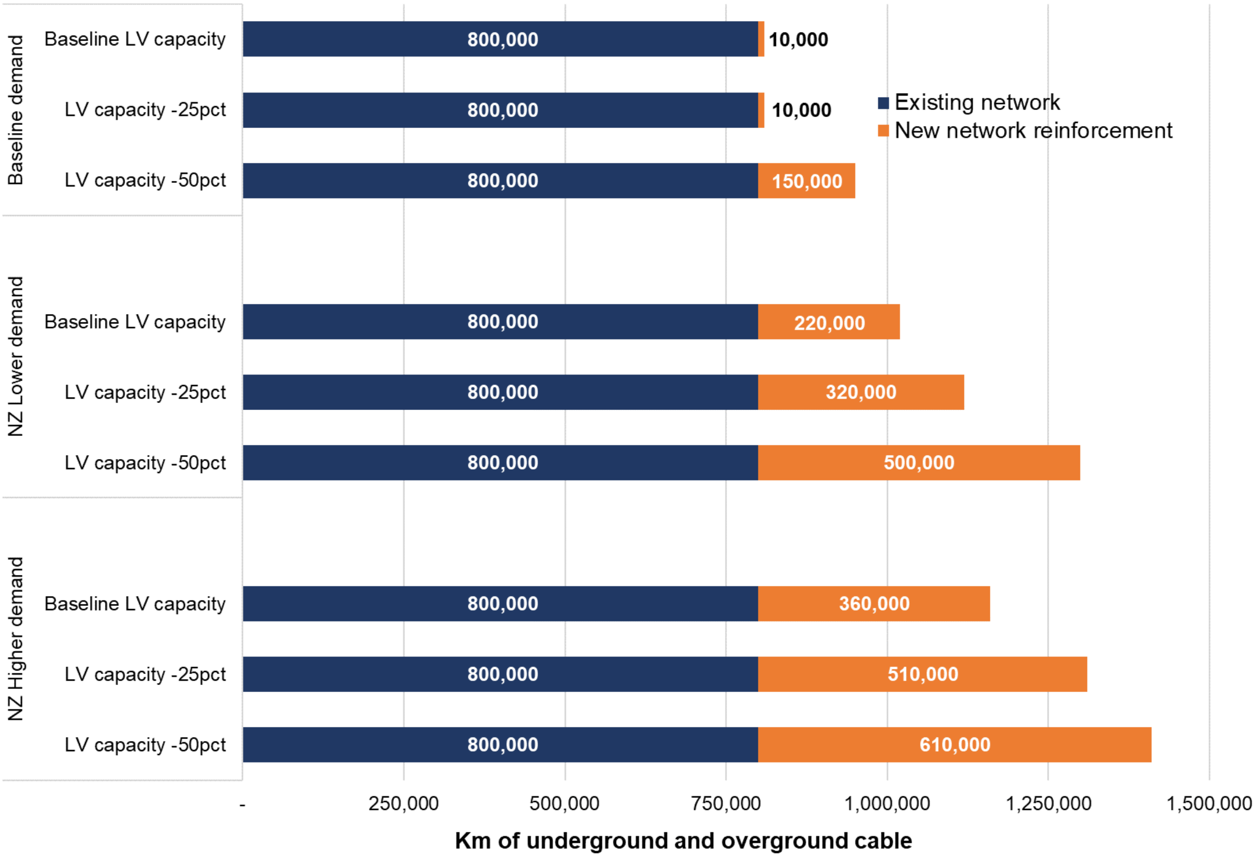


Figure 10 shows how the requirement for additional distribution network overhead wires and underground cabling across Great Britain varies by demand scenario and how it is dependent on the level of LV capacity in the network today. Our analysis suggests that the distribution network in GB could require between 210,000 – 460,000 km of additional distribution network cabling by 2050 versus the baseline demand scenario.

[51] Note that our analysis of investment into distribution networks only factors in load-related investment, and as such does not account for investments required to maintain the network and replace old or aging distribution network assets.

Figure 10: Distribution network overhead wires and underground cabling needed across Great Britain by 2050 (kilometres)



4. Demand side response (DSR)

This section outlines the potential impact of demand side response (DSR) by 2050 under the two illustrative net zero scenarios. This analysis supports section B.2 'Coordination with Smart and Flexible Solutions' and C.2 'Unlocking Capacity with Smart Solutions and Data' in 'Electricity Networks: Enabling the Transition to Net Zero'. DSR can be used to shift demand to times of the day when electricity is cheaper and more abundant. It can be provided from a range of different demand sources, including EVs, heat pumps, smart appliances, and non-domestic consumers. Today, industrial and commercial consumers are providing around 1GW of DSR to the system, but participation from domestic and smaller non-domestic consumers remains at an early stage.[52] Our analysis suggests there may be potential for this to increase to 15GW of actual peak demand reduction by 2050 under the two illustrative net zero scenarios (see figure 2 in section 2.1) but this is highly uncertain and crucially depends on a number of assumptions.

The potential of DSR in 2050 depends on technological developments, such as from smart technologies, as well as consumer behaviour. The DDM uses an aggregated, top-down approach to model consumer demand (i.e. what happens behind the meter), but there is uncertainty in the level of behavioural response we will see in reality, which can greatly influence DSR potential. Our analysis assumes uptake of enabling factors such as smart meters, smart devices (e.g. charge points) half-hourly settlement and time-of-use tariffs but assumes no vehicle-to-grid (V2G)[53] technology. We assume that DSR will materialise in both net zero scenarios due to price signals to consumers and government regulation, such as the recent requirement for private EV chargepoints to be smart.[54] Despite the analysis assuming no V2G technology, we recognise the potential of this technology and have recently published a call for evidence on the role of V2G technology in a net zero energy system.[55]

Our analysis assumes that, under the two illustrative net zero scenarios, demand shifting by 2050 comes mostly from smart domestic EV charging (modelled as "off-street EV charging") due to the recent requirement for all private EV chargepoints to be smart. We assume that off-street EV charging, which could account for 50-60% of all EV demand, could shift up to 90% of its peak load by 2050. The amount of flexible EV charging load is highly uncertain and depends on key factors such as where EV owners charge their vehicle, the equipment they use and their willingness to engage with smart charging[56]. Our estimates are driven by

[52] BEIS (2021), Transitioning to a net zero energy system: Smart Systems and Flexibility Plan, p. 21, https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021
[53] A technology that enables energy to be discharged to the power grid from the battery of an electric car.
[54] BEIS (2021), Electric vehicle smart charging, https://www.gov.uk/government/consultations/electric-vehicle-smart-charging
[55] BEIS (2021), Role of vehicle-to-X technologies in a net zero energy system: Call for evidence, https://www.gov.uk/government/consultations/role-of-vehicle-to-x-technologies-in-a-net-zero-energy-system-call-for-evidence
[56] Access to financial incentives (e.g. an EV or time of use (TOUT) electricity tariff) is likely to be a significant factor in determining a consumers willingness to engage in smart charging.

assumptions on these factors and, as mentioned above, our modelling assumes no V2G technology. Under these assumptions, figures 11 and 12 show that smart charging could lead to a demand reduction during the evening peak of 10-14GW under the two illustrative net zero scenarios. This level of demand shifting would move the system peak from the evening (17:30) to 10:00 in the morning. These savings are expected to be greater if V2G technology was included in our modelling, which may be realistic in the future.

Domestic and non-domestic demand are also expected to be important sources of demand shifting, thanks to the use of smart appliances. See section 8 for more detail on the shifting assumptions that were used in this analysis.

Figure 11: Half-hourly demand under Net Zero Lower (2050, winter peak day)

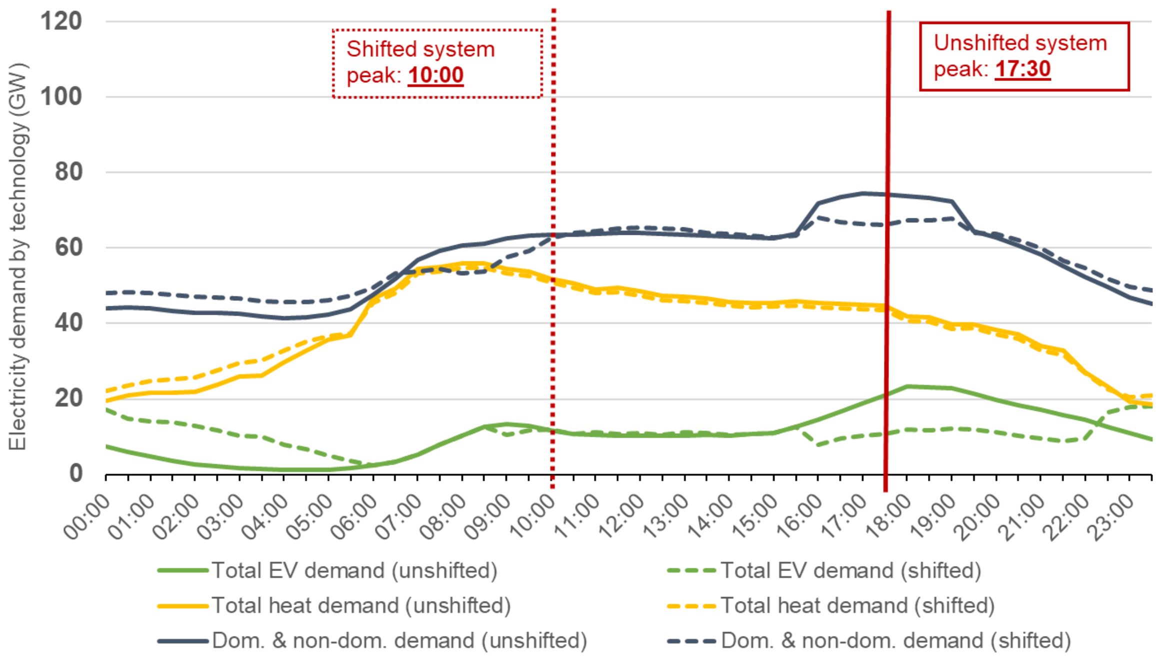


Figure 12: Half-hourly demand under Net Zero Higher (2050, winter peak day)

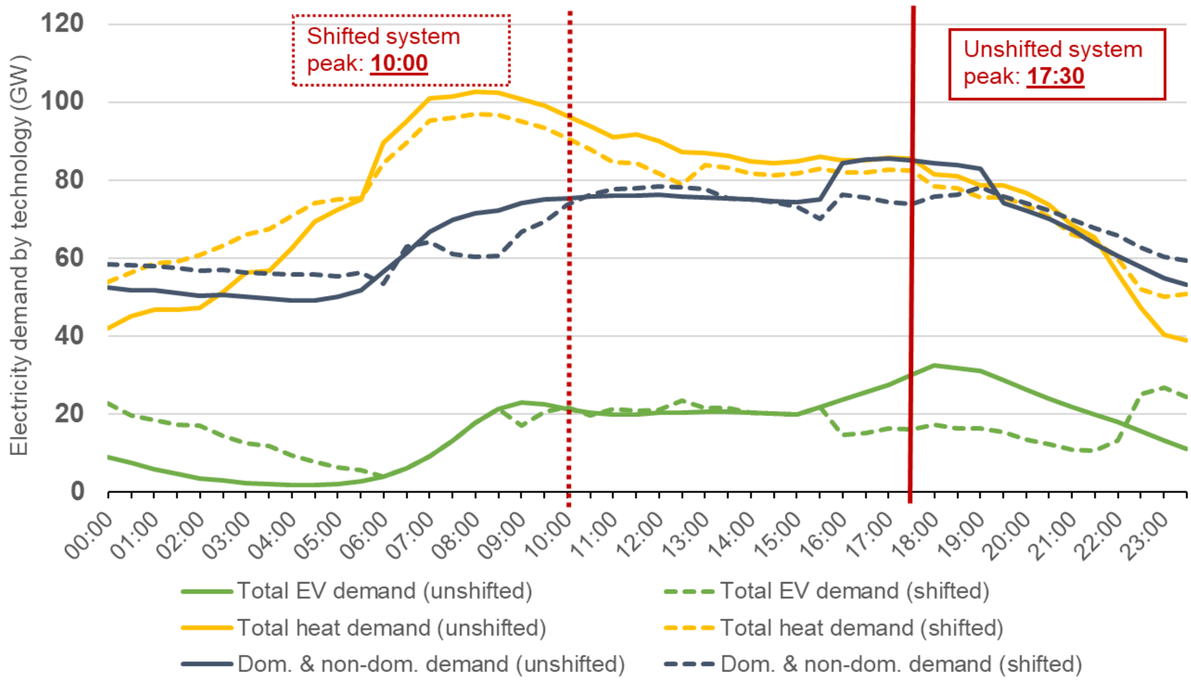


Table 3 illustrates the system benefits that could materialise by 2050 under the DSR scenarios outlined above (15GW potential by 2050). Our analysis suggests that this level of DSR could reduce future system costs by £40-50bn (PV 2021-2050, 2020 prices), depending on the level of LV capacity, which is a reduction of around 5%. The analysis suggests between £10-20bn (approx. 20-50%) of these estimated savings would be derived from lower distribution network reinforcement costs. DSR reduces distribution network utilisation by lowering the overall level of demand during the winter peak, which reduces the need for network reinforcement. The remaining savings would be due to lower capital and generation costs from not having to build and run alternative technologies (such as battery storage) to meet the higher demand.

Table 3: Electricity system and network cost savings due to DSR

Cumulative electricity system costs from 2021 (bn, PV, 2020 £ real)	Net Zero Lower demand - No demand shifting		Net Zero Lower demand - Demand shifting enabled		Change in costs due to demand shifting	
Cost type	2050 Baseline LV capacity	2050 LV capacity -50pct	2050 Baseline LV capacity	2050 LV capacity -50pct	2050 Baseline LV capacity	2050 LV capacity -50pct
Transmission network costs	130	130	130	130	0	0
Distribution network costs	150	180	140	160	-10	-20
Other system costs	790	790	760	760	-30	-30
Total system costs	**1,070**	**1,100**	**1,030**	**1,050**	**-40**	**-50**
Cumulative electricity system costs from 2021 (bn, PV, 2020 £ real)	**Net Zero Higher demand - No demand shifting**		**Net Zero Higher demand - Demand shifting enabled**		**Change in costs due to demand shifting**	
Cost type	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**	**2050 Baseline LV capacity**	**2050 LV capacity -50pct**
Transmission network costs	150	150	150	150	0	0
Distribution network costs	160	220	150	200	-10	-20
Other system costs	930	930	900	900	-30	-30
Total system costs	**1,240**	**1,300**	**1,200**	**1,250**	**-40**	**-50**

The shading in this table shows the changes in system costs due to DSR demand shifting. Negative values (green) represent cost savings vs scenarios where demand shifting does not occur.

These estimates are broadly in line with that in the smart systems and flexibility plan, which estimates flexibility could reduce system costs by £30-70bn by 2050 (PV 2020-2050, 2012 prices).[57] The difference in the range is because a) the smart systems and flexibility plan tested potential needs for flexibility under a broader range of scenarios than this analysis and b) the smart systems and flexibility plan considers a wider range of flexible technologies including storage and interconnection, whereas this analysis considers DSR only, which is just one source of flexibility.

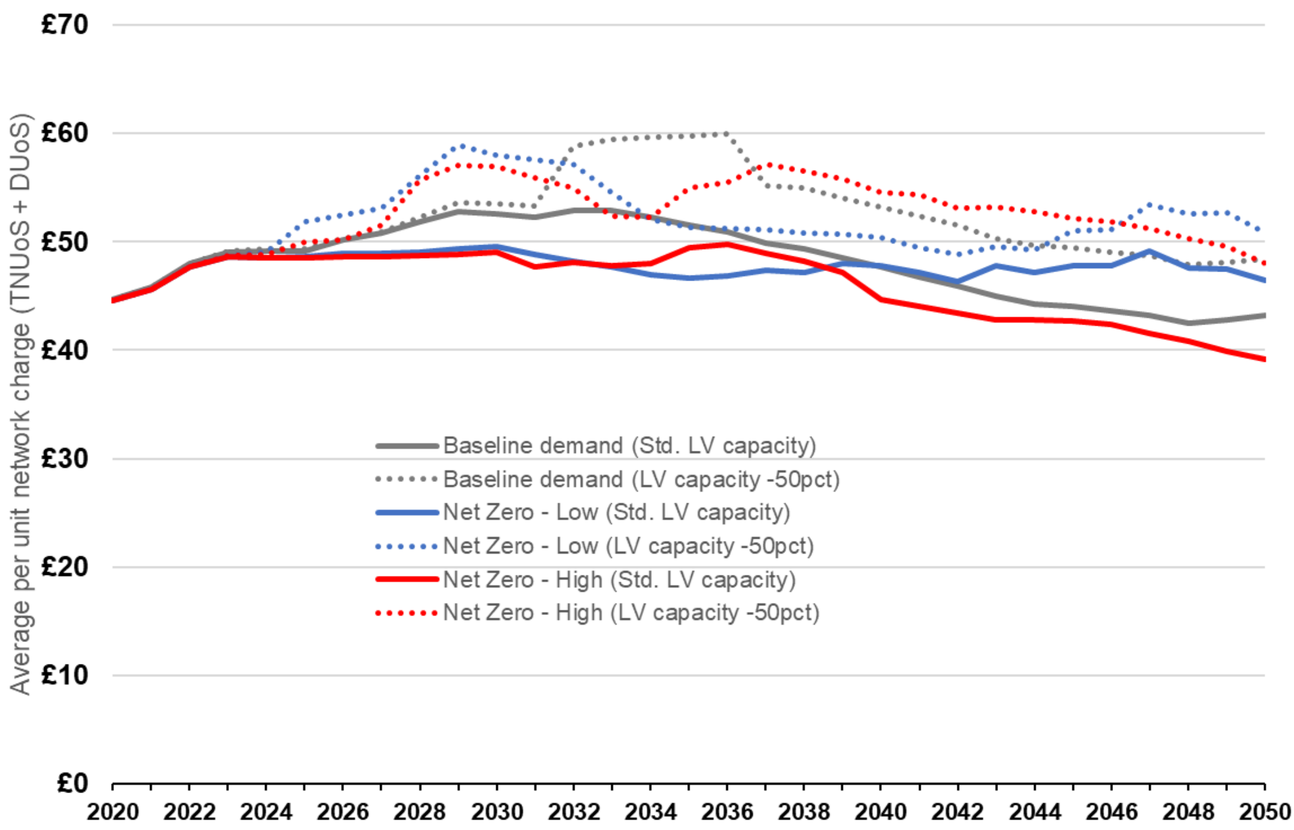
In our modelling, DSR minimises the difference between demand and supply (net of intermittent generation). This approach reflects ‘implicit DSR’, where consumers are changing behaviour in response to prices but are not actively participating in markets (i.e. ancillary services or balancing). The modelling assumes there are no costs associated with DSR. That may be appropriate if, for example, DSR is the result of changes in consumer preferences or the technology that enables DSR would have been installed anyway at a similar cost. However, it may underestimate costs where, for example, specific technologies have been installed to enable DSR or there are costs associated with aggregating individual consumers to participate in DSR.

[57] BEIS (2021), Smart systems and flexibility plan 2021: Appendix I – Electricity system flexibility modelling, p. 5, https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

5. Impacts for consumers

The average per-unit cost of the electricity network is driven by two factors: total electricity demand and total network charges levied on network users (i.e., consumers and generators) to pay for network costs. Both these factors increase due to the transition to net zero, but they have opposite impacts on the per unit final network charges that consumers will pay. An increase in allowed revenues means that there is a higher cost for consumers to bear overall. By contrast, increases in demand mean that there is a larger base to spread costs over. Figure 13 below shows that the **cost of the electricity network per MWh of electricity consumed for households is not expected to increase substantially due to net zero and could be lower for some periods**. This analysis supports section C.6 ‘Ensuring a Fair Distribution of Costs’ in ‘Electricity Networks: Enabling the Transition to Net Zero’.

Figure 13: Average per-unit network costs for households (£/MWh, 2020 prices)



The final cost for end consumers will depend on their level and pattern of electricity consumption, which will vary across households, and the cost of the rest of the system. The net zero transition will change the make-up of the average household energy bill as gas boilers and internal combustion engine vehicles are replaced by other technologies such as heat pumps and EVs. This means that **increases in electricity system costs, including network costs, should be considered relative to reductions in other costs** that would be incurred in the baseline scenario, such as gas system costs or transport fuel costs. The final impact for a household depends on its consumption and how the household uses electricity in the future.

There is significant uncertainty in several factors of this analysis. Lower headroom capacity on the LV network increases costs for consumers. In addition, there is wider uncertainty on efficiencies (e.g., of the home as well as technological efficiencies with heat pumps and/or EVs) and future policy decisions (which will determine how costs will be paid for). This analysis has also been based on the current charging regime for network costs. Future changes to this regime would have impacts for different consumer groups and their share of the cost burden towards the overall upkeep of the network system.

6. Strategic investment into Great Britain’s electricity distribution network

This section looks at the value of early strategic investment into Great Britain’s electricity distribution networks. So far, the analysis has assumed DNOs will make investment decisions to alleviate network constraints only within a 5-year period, which is the assumed length of future RIIO price controls. This effectively means that, under the analysis, DNOs are limited to having a maximum investment foresight of 5 years. Here, we consider the impact of different levels of DNO ‘investment foresight’ on distribution network costs in the long-term. Strategic investment (represented by very high levels of DNO foresight) may lead to more efficient outcomes by ‘future-proofing’ the network for the expected increase in demand and generation. However, strategic investment in an uncertain environment creates a risk that the network will not be fully utilised, with a corresponding reduction in efficiency and impact on consumer costs. This section assesses whether strategic investment into the distribution network leads to more efficient outcomes. This analysis is for the distribution network only and supports section C.1 ‘Investing in our Electricity Networks’ in ‘Electricity Networks: Enabling the Transition to Net Zero’.

6.1 Assessing the value of early investment into distribution networks

This section defines the metrics and scenarios that will be used to assess the case for investment ahead of need into Great Britain’s electricity distribution networks. This analysis will use three separate metrics to assess the value of strategic investment:

- **Network TOTEX** – the amount of investment that will be required on the distribution network by 2050.
- **Social disruption costs** – the indirect costs to society and consumers from network reinforcement and DNO works. These capture negative externalities that are not directly part of system costs, such as transport disruptions due to road works, lengthy local consultations, and temporary disconnections of sections of the network, etc. Note that there is significant uncertainty in this metric – it aims to capture key negative externalities but may not capture all.
- **Number of DNO interventions (i.e. reinforcements)** required in the network to address network constraints.

We split the investment timeframe between 2023-2050 into separate price control periods during which investments are made by DNOs, each lasting 5 years, starting with RIIO-ED2 (2023-2028). We then applied foresight scenarios where the DNOs reinforce the network 5 years ahead of need (baseline), separate scenarios for each year where DNOs reinforce the network between 6-15 years ahead of need, and a final maximum foresight scenario where

DNOs reinforce the network up to 20 years ahead of need – for a total of 99 different investment scenarios.

All results are compared with the baseline foresight scenario of 5 years. We use the three electricity demand scenarios, LV capacity scenarios and the above foresight scenarios. This captures three types of uncertainty: demand uncertainty, spare network capacity uncertainty (thermal headroom), and uncertainty around DNO investment behaviour (foresight). For the purposes of this analysis, we have assumed that DNOs can only deploy conventional network reinforcements (additional underground cabling, installation of overhead lines, transformers etc.). Smart solutions were excluded from the analysis due to modelling limitations.

Figures 14 and 15 are an illustrative example of the decision to invest in a single high voltage (HV) asset – a HV feeder. With an investment foresight of 5 years (figure 14), the DNO decides not to invest in the HV feeder during the RIIO-ED2 price control (2023-2028), as the maximum thermal capacity is not exceeded within the 5-year period. Instead, the cable's maximum design rating is only exceeded in 2034, during RIIO-ED4, which is when the investment takes place in the baseline scenario. With a 20-year investment foresight (figure 15), the DNO will invest in the HV feeder in 2028 (the end of the RIIO-ED2 price control period), as the maximum thermal capacity of the feeder will be exceeded within the foresight period.

Figure 14: Illustrative example of the decision to invest in a single high voltage asset with 5 years investment foresight (baseline)

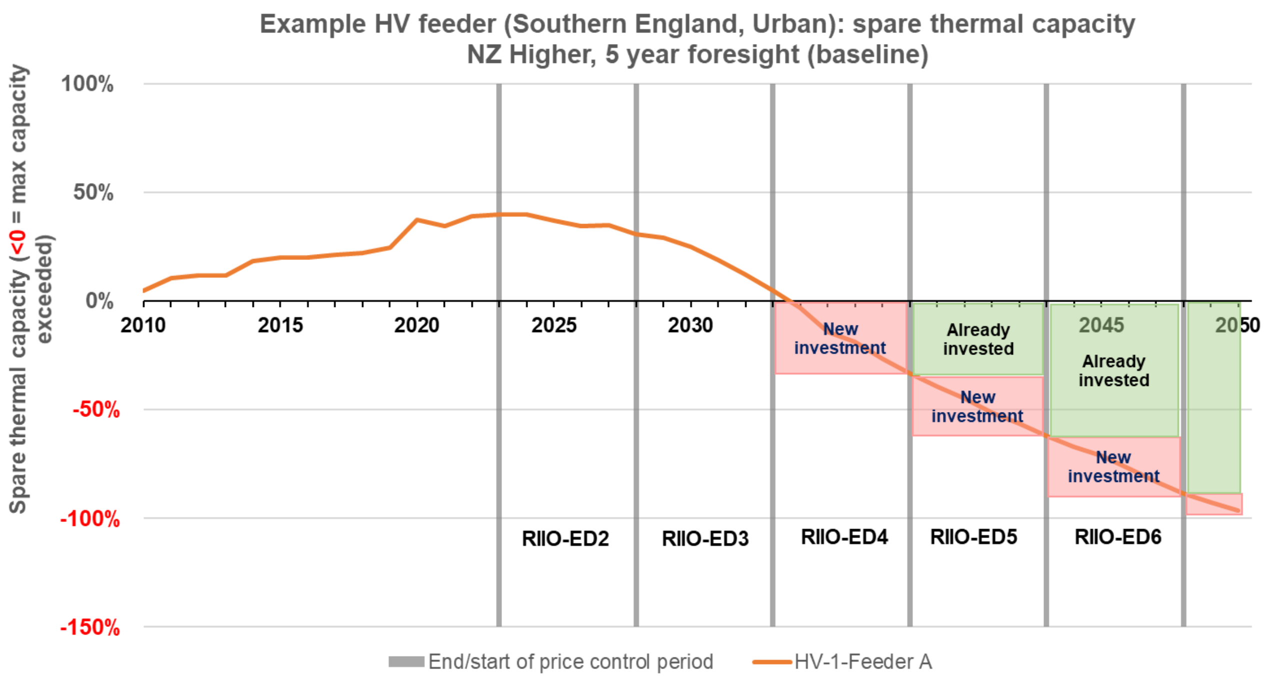
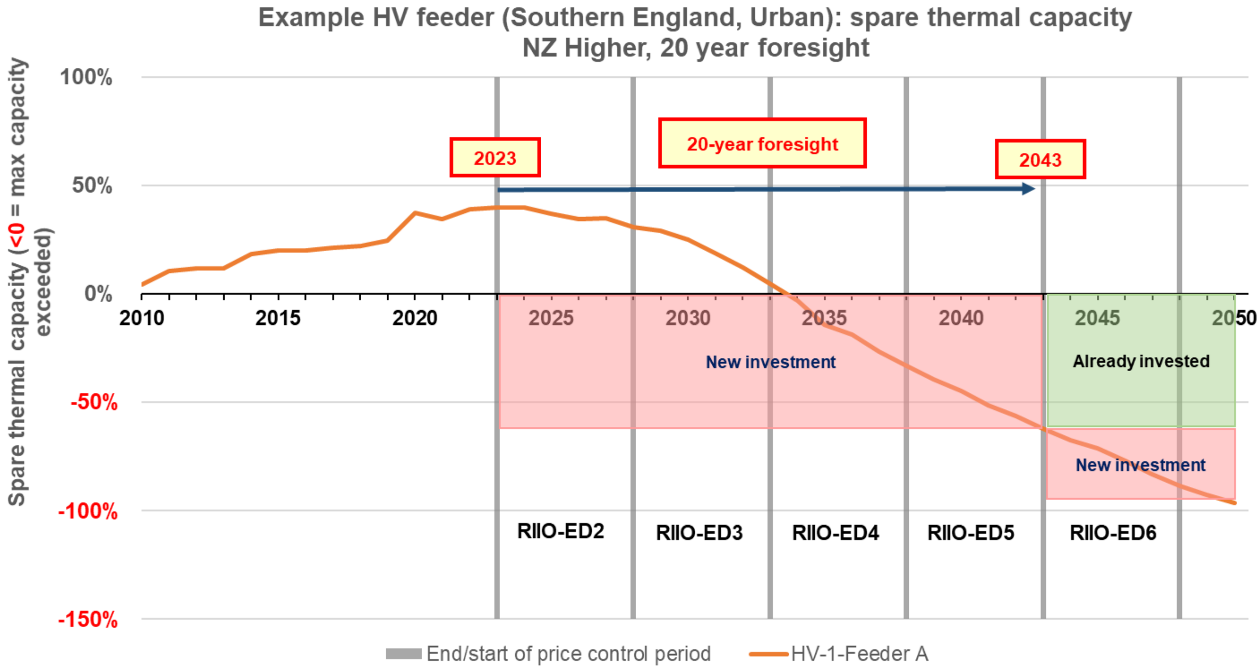


Figure 15: Illustrative example of the decision to invest in a single high voltage asset with 20 years investment foresight



6.2 Results: The benefits (& costs) of early network investment

This section outlines the results of the strategic investment analysis. Tables 4 and 5 below both provide a snapshot of the results. Table 4 combines distribution network TOTEX and social disruption costs to form a single metric that aims to capture the social efficiency gains that can come from investing into networks ahead of need. Note that this analysis may not capture all benefits – for example, it does not capture whether investment ahead of need could reduce losses or support faster deployment of low carbon assets such as EV charge points and renewable generation.

The results suggest that strategic investment may, in some circumstances, bring substantial TOTEX savings and may significantly reduce the levels of social disruption from network reinforcement. However, the benefits depend on **a)** the level of demand we expect to see on the system, and **b)** the level of spare LV network capacity we assume is available on the distribution network. Approximately 65 of the 99 investment scenarios (~66%) saw greater benefits with increased levels of foresight versus the baseline investment scenario of 5 years look ahead, which suggests a mixed picture. Our analysis suggests increased levels of DNO investment foresight are particularly likely to bring higher benefits in scenarios where future demand levels are higher (net zero higher demand scenario) and when the level of spare LV network capacity is lower (e.g., LV capacity -25pct and -50pct scenarios).

Table 4 shows distribution network TOTEX and social disruption costs under a selection of different DNO foresight scenarios. The analysis suggests that, in some cases, a longer period of foresight can lead to higher costs by 2050, with most of this cost increase being derived from increased TOTEX. This is largely due to social discounting of future costs and benefits. Discounting allows costs and benefits with different time spans to be compared on a common “present value” (PV) basis by adjusting for social time preference, which captures ‘time preference’ (the value society attaches to present, as opposed to future, consumption) and the ‘wealth effect’ (reflects expected growth in per capita consumption over time).[58] Because society attaches a higher value to present costs and benefits, investment costs that occur earlier are discounted less (making them more expensive in PV terms) and investment costs that occur later are discounted more (making them cheaper in PV terms).[59] Therefore, in some of the high foresight scenarios, the cost savings from strategic investment are not large enough to outweigh the effect of discounting. However, as mentioned above, this analysis may not capture all benefits – for example, it does not capture whether investment ahead of need could reduce losses or support faster deployment of low carbon assets such as EV charge points and renewable generation.

Table 4: Distribution network TOTEX and social disruption costs under various levels of DNO foresight (£bn, PV 2021-2050, 2020 prices)

Dx Totex & social disruption costs (£bn PV, 2020 prices)		Net Zero Lower demand			Net Zero Higher demand		
		Baseline reinforcement	Strategic investment	Difference vs baseline	Baseline reinforcement	Strategic investment	Difference vs baseline
LV spare network capacity assumed	Network reinforced X years ahead of need	2050	2050	2050	2050	2050	2050
Std. LV capacity	5 years	68			104		
	7 years		53	-15		83	-21
	10 years		53	-15		82	-22
	15 years		58	-10		89	-15
	20 years		59	-9		106	2
LV spare network capacity assumed	Network reinforced X years ahead of need	2050	2050	2050	2050	2050	2050
LV capacity -50pct	5 years	127			213		
	7 years		138	11		170	-42
	10 years		143	16		172	-41
	15 years		151	24		154	-58
	20 years		153	27		153	-59

In addition, it’s important to note that on an undiscounted basis, the analysis suggests that increased levels of foresight almost always lead to more efficient investments – the greater the level of foresight, the greater the reduction in TOTEX (undiscounted). This is due to the DNM choosing fewer, but larger and more expensive network solutions, earlier, in place of smaller and cheaper network solutions, later. When discounting is applied, however, these investment costs that occur earlier are discounted less, making them more expensive in PV terms and

[58] The Green Book (2020), A6, https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent
[59] The discount rate used by DNOs is also already built into DNM modelling.

offsetting the cost savings from early strategic investment. Note, however, that this is a theoretical case with an assumed level of DNO foresight and knowledge of the existing network. In reality, the levels, timing and location of both new demand and generation will be uncertain. In addition, the distribution network is large (800,000 km in length) and complex, so it is not realistic or possible for DNOs to understand the capacity of every circuit.

Table 5 shows the number of DNO network interventions required by 2050 to address network constraints under different DNO foresight scenarios. Our analysis suggests that investment into networks ahead of need is likely to reduce the number of network interventions required by DNOs, resulting in fewer disruptions to society, such as road works, road closures, etc.

Table 5: Number of DNO network interventions required to address network constraints by 2050 under various levels of DNO foresight

Number of network interventions required (solutions deployed)		Net Zero Lower demand			Net Zero Higher demand		
		Baseline reinforcement	Strategic investment	Difference vs baseline	Baseline reinforcement	Strategic investment	Difference vs baseline
LV spare network capacity assumed	Network reinforced X years ahead of need	2050	2050	2050	2050	2050	2050
Std. LV capacity	5 years	1,510,000			1,490,000		
	7 years		900,000	-610,000		1,150,000	-340,000
	10 years		790,000	-730,000		990,000	-500,000
	15 years		780,000	-730,000		810,000	-680,000
	20 years		700,000	-820,000		680,000	-810,000
LV spare network capacity assumed	Network reinforced X years ahead of need	2050	2050	2050	2050	2050	2050
LV capacity -50pct	5 years	2,060,000			2,200,000		
	7 years		1,390,000	-680,000		1,270,000	-930,000
	10 years		850,000	-1,210,000		760,000	-1,440,000
	15 years		740,000	-1,330,000		480,000	-1,720,000
	20 years		620,000	-1,450,000		470,000	-1,730,000

7. Future employment & GVA impacts from onshore network investment

This section analyses the employment and Gross Value Added (GVA) impacts from onshore network reinforcement, focusing on the onshore network only. This analysis supports section D 'Wider Benefits' in 'Electricity Networks: Enabling the Transition to Net Zero'.

The results in table 6 suggest that the reinforcement of Great Britain's onshore electricity networks could support between **50,000 – 130,000 FTE jobs** by 2050 versus the baseline scenario, covering jobs involved in electricity network reinforcement. This was quantified using the network investment estimates derived from the DDM and DNM under the net zero and LV capacity scenarios and applying factors of jobs per pound (£) of investment to this. These factors, derived separately, were based on data obtained from DNOs and TOs in 2020. The results in table 7 suggest these jobs could contribute between **£4-11bn** of Gross Value Added (GVA in 2050, 2020 £). GVA was estimated by applying a value (£) per job based on a methodology and estimate of GVA per job that was set out in the Energy Innovation Needs Assessments (EINAs).[60]

Table 6: FTE onshore network jobs supported (cumulative) due to network reinforcement and investment needs, vs baseline demand

	2050		
Demand scenario	Baseline LV capacity	LV capacity -25pct	LV capacity -50pct
NZ Lower	50,000	60,000	50,000
NZ Higher	70,000	110,000	130,000

Table 7: GVA of onshore network jobs supported (cumulative) due to network reinforcement and investment needs, vs baseline demand (£m, 2020 £)

	2050		
Demand scenario	Baseline LV capacity	LV capacity -25pct	LV capacity -50pct
NZ Lower	£4,000 m	£5,000 m	£5,000 m
NZ Higher	£6,000 m	£10,000 m	£11,000 m

[60] BEIS (2019), Energy Innovation Needs Assessments, https://www.gov.uk/government/publications/energy-innovation-needs-assessments

8. Detailed DSR & technology assumptions by 2050

Technology	Net Zero Lower Demand	Net Zero Higher Demand	Comment
Domestic/Non-domestic (% of half-hourly demand than can shift to a different half-hour)			
Domestic (Smart Appliances)	7%	11%	Demand can shift 4 hours
Non-domestic	14%	18%	Demand can shift 4 hours
Electric vehicles (EVs) (% of peak half-hourly demand than can shift to a different half-hour)[61]			
Domestic	75%	90%	Demand can shift up to 8 hours later between 4pm and 10pm
Heat (heat storage)			
Heat (domestic and non-domestic)	c20% of buildings with heat pumps are assumed to have additional storage (equivalent to 200L for the average dwelling) for shifting space heating demand.	c20% of buildings with heat pumps are assumed to have additional storage (equivalent to 200L for the average dwelling) for shifting space heating demand.	Demand can shift 24 hours. No. of buildings with heat pumps is lower in lower demand scenario so there is less DSR in the lower scenario despite % being the same

[61] Illustrative assumptions have been used to capture potential smart charging behaviour at some public charging locations. These represents a very small proportion of total EV flexibility.

This publication is available from: www.gov.uk/government/publications/electricity-networks-strategic-framework

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