Produced for the National Infrastructure Commission by Regen,
in partnership with EA Technology Ltd

# Electricity Distribution Network Capacity Analysis

Project summary report

November 2024

**Client**

This project was carried out for the National Infrastructure Commission. The Commission provides government with impartial, expert advice on major long term infrastructure challenges.

**About Regen**

Regen provides independent, evidence-led insight and advice in support of our mission to transform the UK's energy system for a net zero future. We focus on analysing the systemic challenges of decarbonising power, heat and transport. We know that a transformation of this scale will require engaging the whole of society in a just transition.

Regen is a membership organisation with more than 200 members who share our mission, including clean energy developers, businesses, local authorities, community energy groups and research organisations across the energy sector. We also manage the Electricity Storage Network – the industry group and voice of the grid-scale electricity storage industry in GB.

**About EA Technology Ltd**

EA Technology's mission is to promote the development of resilient, accessible, low cost energy networks globally, accelerating the transition to energy decarbonisation. EA Technology are committed to providing customers with innovative products and services, consultancy and training which deliver tangible benefits for their businesses enabling them to create safer, stronger and smarter networks for today and the future.

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# Executive summary

In February 2024, HM Treasury asked the National Infrastructure Commission (NIC) to undertake a study on the challenges to making the electricity distribution networks in Great Britain fit for net zero.

The terms of reference for the distribution networks study can be found here. The remit includes a broad objective to look at the load-related expenditure needed in the GB distribution network to electrify heat and transport and deliver a Net Zero power system. The NIC was also asked to consider the policy and regulatory frameworks that govern how network companies invest in and operate their networks, the opportunities to use flexibility and smarter network solutions, and the role of key actors, including Ofgem, the Distribution Network Operators (DNOs) and the new Regional Energy Strategic Planning (RESP) function at the National Energy System Operator (NESO).

To support the distribution networks study, the NIC commissioned Regen and EA Technology Ltd to conduct an **Electricity Distribution Network Capacity Analysis**. As well as providing research and analysis, the key output of the capacity analysis is a model that shows how future network loads might change between now and 2050 in a net zero decarbonisation scenario, the extra network capacity that might be needed to meet these additional loads, the overall cost of load-related expenditure (LRE) and how alternative flexible and non-network asset solutions might be used to manage and reduce costs.

This report provides a high-level summary of the capacity analysis study. Additional details can be found in the three technical work package reports and supporting data workbooks. These outputs are intended to give the NIC an evidence base to consider the potential scale of network load related expenditure across all GB distribution networks and the challenges this will present at both a network and a local level.

## Modelling approach

The network capacity study has undertaken two types of modelling:

- A **GB network analysis,** which uses the EA Technology Limited Transform Model® to provide a GB-wide, year-by-year analysis of load growth and resulting network capacity and related expenditure (including capital investment and operational expenditure, flexibility and smart solutions) for the period to 2050.
- Separately, a set of **local network case studies** was produced using the EA Technology Limited VisNet Design® tool to illustrate how load growth may affect different archetypes of network assets in different locations; rural, suburban and urban. For this study, seven case studies have been produced using representative examples of network data provided by the network operators.

As with any modelling study, the model output is heavily dependent on the input scenario data, load profiles, assumptions and sensitivities that have been used. These are documented in detail in the accompanying Scenario Development and Load Profile Selection report. The primary source of input for the study was the ESO 2023 FES Consumer Transformation scenario, and the profiles and other load data provided by the six GB distribution network operators (DNOs) who kindly responded to a Request for Information (RFI). In some areas, the scenario data and load profiles have been amended or augmented for the specific purposes of this study or to test a particular sensitivity or hypothesis. These amendments have been documented, reviewed and agreed with the NIC.

## Model limitations and considerations

It is important to be aware of the model limitations before drawing conclusions from the study results. Model limitations and their implications for interpretation of results are outlined in detail in Section 2.7. Three of the most important limitations to be aware of include:

1. **Differences with DNO network planning:** although the study has used similar input datasets and profiles, top-down network-wide modelling is not the same as the asset-by-asset analysis and options appraisal that a network planning team in a DNO would conduct. For example:

    i. The Transform model does not replicate the entire GB distribution network. Instead it uses network archetypes to create representative models of distribution networks to simulate and analyse the behaviour of different types of electricity grids and as a basis to model baseline network capacity, load growth and resulting load-related expenditure.

    ii. In the model, the uptake of low-carbon technologies (LCTs) and load growth is allocated to the network asset archetypes using a distribution algorithm based on Distribution Future Energy Scenario (DFES) and Electricity Capacity Register (ECR) datasets. Although this has been developed with input from the DNOs, to represent a realistic network load, this is not the same as the real-life connection data and location-specific load growth inputs that a network planner would have to consider.

    iii. The model treats the input data with foresight certainty; the model does not consider the degree of uncertainty and risk as a network planner would. As discussed in Section 3, load growth certainty in a modelled environment does influence the choice of solution. The analysis includes multiple model runs to investigate the impact of different technology uptake rates and load behaviour.

2. **Network asset scope:** the Transform Model® includes Low Voltage (LV), High Voltage (HV) and Extra High Voltage (EHV) networks. EHV is defined as voltage tiers operating

above 33kV, but not including, 132 kV[1]. The model does not include 132 kV networks, LV service cables (the connection to individual customers) or customer connection assets. The results should therefore be interpreted in the knowledge that further expenditure will be required at the 132 kV network level and for customer service and connection assets.

3. **Sector scope:** the analysis includes domestic underlying demand, road vehicle charging, domestic and commercial heating, and I&C demand (including data centres). It also includes all forms of generation and storage technologies. However, it does not include potential new loads from sectors such as shipping, aviation, non-road transport and machinery, agriculture or industrial process electrification. The implication of this is that if demand from those sectors materialises then load-related expenditure in some locations and on some network assets could be higher than projected in this analysis.

## GB network analysis results

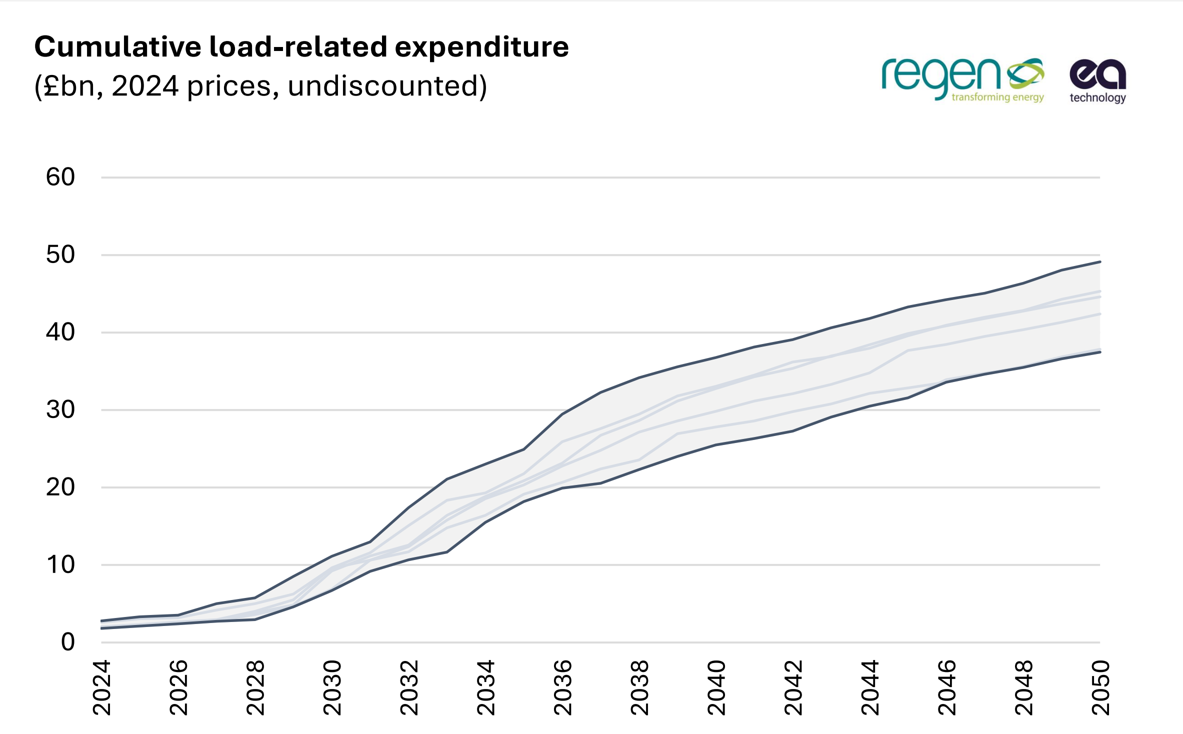


Figure 1: Range of cumulative distribution network load-related expenditure in main model runs. Note: excludes 132kV network and LV service cables.

[1] Definition of EHV from Ofgem, 2011

The National GB Network analysis was conducted over 14 model runs with variations in assumptions about the mix of heat technology, flexibility, heat demand and other sensitivities, which are described in Table 4.

The key findings from the GB network analysis include:

- **The main model runs (1-6) produced an expenditure range of £37 bn to £49 bn, depending on the heating mix and assumed flexibility levels.** Figure 1 shows the profile of undiscounted load-related cumulative load-related expenditure across the GB networks produced by the model runs between 2024 and 2050.
- **Peak demand for the main model runs ranges from 108 GW to 119 GW in 2050.**
- **The expenditure profile varies with each model run. The average annual expenditure ranges between £1.4 bn and £1.8 bn in the main model runs.** This range is lower than the range modelled in previous distribution network investment studies. For example, the joint DESNZ/Ofgem Electricity Networks Strategic Framework modelling suggested an expenditure range that equated to £2.3 bn to £3 bn per year on average[2]. The DESNZ modelling included 132 kV network assets which this analysis did not.
- **This would be a significant increase when compared with recent price control reinforcement and load-related expenditure.** The RIIO-ED1 price control period delivered an average of £274 million per annum in distribution network reinforcement (from 2015-22). The average load-related budget for the five-year RIIO-ED2 price control period (2024-28) is £640 million [3] [4]. Section 3.3 includes a more detailed comparison of the results with other modelling and recent price control determinations.
- **The majority of load-related expenditure will be in the low voltage (LV) network.** In the main model runs, 62% and 68% of expenditure will be to solve constraints on the LV network. The LV network provides power to homes and businesses at 230V and is the most expansive voltage tier, making up 45% of cable length and 96% of substations on the distribution network[5]. (Note the model scope did not include the 132 kV network).
- **The winter stress test sensitivity (model run 7) significantly increases peak loads and expenditure**: The model's winter peak stress test sensitivity led to an increase in cumulative network load-related expenditure to £76 bn (2024 to 2050), and an increase in the peak distribution network demand to 153 GW in 2050. In this model run, loads from heat pumps and electric heating technologies were increased significantly and lower levels of flexibility from EV charging, heat and storage were assumed. The heating loads and flexibility assumptions are not based on a defined resilience standard but

[2] Electricity networks strategic framework Appendix I: Electricity Networks Modelling, DESNZ and Ofgem
[3] RIIO-ED1 Annual Report 2021/22 Tab1-22 Supplementary Data File, Tab: CH4 expenditure drivers 2
[4] RIIO-ED2 Final Determinations Core Methodology Document, Paragraph 3.12 page 18
[5] Electricity networks strategic framework Appendix I: Electricity Networks Modelling, DESNZ and Ofgem, page 15

were deliberately conservative. Arguably, in a real winter stress event, we would expect to see a fall in demand in some sectors; the results do, however, underscore the importance of future network resilience standards and how they are modelled in the context of providing critical energy for heat and transport.

- **Heat and transport will become the key drivers of network load:** As expected, the key drivers of network load are the forecasted growth of EVs and heat pumps and the electrification of residual domestic and commercial heat. In 2050 in model run 1, which has higher heat pump adoption and higher levels of flexibility, during peak system demand at 9.00-9.30am, 45 GW comes from heat and 22 GW comes from road transport. These results are outlined in more detail in Section 3. Industrial and commercial demand contributes 33 GW to the peak (as discussed in Section 2.7, the modelling of Industrial and Commercial demand was highly simplified).
- **Higher levels of implicit flexibility reduce expenditure:** All model runs included some level of both implicit and explicit flexibility. Implicit flexibility, where consumers and flexibility providers (including batteries) are assumed to respond to price signals, is built into the load profiles and has the effect of reducing peak loads on the network. The effect of increased levels of implicit flexibility with higher heat pump uptake is a reduction in cumulative load-related expenditure by £7 bn from £45 bn to £38 bn. As well as reducing the level of expenditure, the greater use of flexibility also has the impact of delaying the need for expenditure (providing further benefit on a discounted basis). In model run 4, with lower levels of flexibility, heat contributes 40 GW and road transport contributes 28 GW to peak demand in 2050.
- **The model selected network and non-network solutions over explicit flexibility in most cases:** Explicit flexibility, whereby DNOs can call upon flexibility providers to increase or reduce loads for a fee, was included as one of the available model solutions. Explicit flexibility was expected to provide a cost-optimal solution to manage marginal constraints where the frequency and severity of a constraint is low. However, in the model runs this solution was utilised less often than may have been expected. The reasons for this, which are in part to do with the model function, are discussed in Section 3.1.

## Insight from the local case studies

The local case study analysis provides a closer-to-real-life illustration of the options and choices that network planners will face when examining specific network locations. The seven archetype case studies are illustrative only and the results cannot be extrapolated to the GB level. However, they do demonstrate the importance of geography and local demographics, as well as the exact configuration of the legacy network, in determining the distribution of load growth and the optimal intervention strategy.

Several key themes emerged from the case studies:

- **Increased scale of network reinforcement:** Physical interventions were unavoidable in all but one of the case studies modelled. LV networks have historically been designed for relatively low loads per customer (the case study networks ranged from 1 to 5 kVA[6] per customer) with energy for heat and transport provided by fossil fuels. Although these results are illustrative, they do support the overall national analysis that the scale and pace of LV network reinforcement needed is far larger than the present level of reinforcement works.
- **Flexibility can enable reinforcement delay or avoidance:** Targeted, local Demand Side Response could enable DSOs to manage capacity constraints on the LV networks. This could provide them more time to assess future network reinforcement options or, in select cases, avoid reinforcement over a longer period.
- **The location of new demand determines when intervention is required:** In some case studies the years of intervention varied widely, along with whether flexibility would be a suitable intervention. The case studies highlight that geographical distribution of customer loads of LV feeder cables can drive the need for physical network reconfiguration, even if the upstream secondary substation capacity is not exceeded.
- **Network suitability for the future:** The existing network topology is a major factor for the ability of an LV network to be able to supply the large volume of new loads.
- **Projected constraints varied by network archetype:** The types of properties an LV network feeds, and their ability to accommodate new LCTs, is a key factor in the likelihood they will require interventions.

A key learning from the case studies is that, whereas the upgrade of the transmission network is concerned with the delivery of a smaller number of very large upgrades, the upgrade of the low voltage networks is concerned with the delivery of hundreds of thousands of individual interventions and investments. This requires a different approach and emphasises the importance of; data quality, monitoring, forecasting, decision support tools, the ability to use smart solutions, resource planning and the skills and expertise of network planners. It also requires a high level of coordination and delivery planning between network operators and a range of stakeholders, including local authorities, customers and businesses, and supply chain partners.

## Project outputs

The report and data outputs of this project are detailed below in Table 1.

Table 1: List of outputs from this project.

| Report output | Supporting data output |
| --- | --- |
| Project summary report (this document) | N/A |

[6] 1 kVA (kilovolt-amperes) is approximately the network capacity required to deliver 1kW (kilowatt) of power.

| Report output | Supporting data output |
|---|---|
| Scenario development report | Scenario development data workbook |
| | Load profile selection data workbook |
| National modelling report | National modelling data workbook |
| Local case studies report | Local case studies data workbook |

# Contents

# 1 Distribution network context

The electricity network in Great Britain consists of an onshore and offshore transmission network and a distribution network operating at lower voltages that takes power from where it is generated to where it is used.

Six network companies own and operate the electricity distribution network under a regulation framework that is overseen by Ofgem, the industry regulator. The network consists of around 600,000 substations and over 800,000 km of overhead lines and underground cables operating across several voltage levels that serve around 29 million domestic and business customers[7].

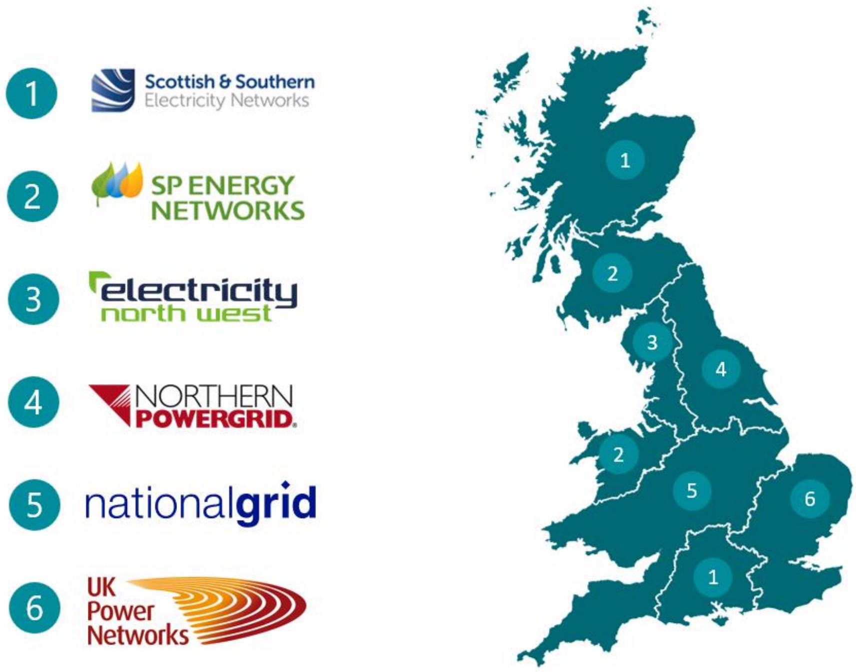


Figure 2 Distribution Network Operators (DNOs) in Great Britain

The electricity networks have already undergone a significant transformation. Traditionally, large, centralised power generation plants connected to the transmission network and provided electricity to domestic and commercial demand customers connected at the distribution level. Today there is around 40 GW of power generation and storage capacity, from around 7,500 assets, connected to the distribution networks[8]. Increasingly power flows up to the transmission network as well as down to consumers.

[7] Electricity networks strategic framework Appendix I: Electricity Networks Modelling, page 15
[8] DNO Network ECR register accessed October 2024

Although the roll-out of both heat pumps and electric vehicles is still at an early stage, they are already beginning to make their presence felt in terms of a new source of electricity demand. There are currently around 400,000 domestic heat pumps and almost 2 million plug-in and battery electric cars in GB. By 2040 there could be over 16 million domestic heat pumps and 40 million electric vehicles [9]. A key challenge for the network planners is to plan for the rate of growth of low carbon technologies and where these will connect to the network.

Table 2: Distribution network assets and customers supplied, by voltage tier.[10]

| Voltage level | 132kV | 66 & 33kV | 20, 11 & 6.6kV | LV (<1kV) | Total |
|---|---|---|---|---|---|
| **Length of lines and cables** | 2% | 14% | 38% | 45% | 840,000 km |
| **Number of Transformers** | 0.3% | 2.2% | 1.5% | 96.0% | 600,000 transformers |
| **Typical size of transformer** | 240 to 1000 MVA | 60 to 240 MVA | 10 to 30 MVA | 100 kVA to 1000 kVA | N/A |
| **Typical number of customers supplied[11]** | 500,000 to 50,000 | | 30,000 to 5000 | 500 to 1 | N/A |

[9] ESO Future Energy Scenarios 2023, Consumer Transformation scenario
[10] Electricity networks strategic framework Appendix I: Electricity Networks Modelling, page 15. Note: 1) these figures include Northern Ireland's distribution network (~47,000km of cables) and 2) in Scotland, transmission voltages include 132kV (as well as 275kV and 400kV).
[11] Climate change adaptation reporting power second round, 2015, Table 2, page 29

# 2 GB network modelling approach

## 2.1 National modelling tool

This project uses the Transform Model®, EA Technology's proprietary parametric network modelling tool to represent the electricity distribution network across Great Britain (GB). The Transform Model® has been developed over several years with input and support from the GB DNOs. It uses network archetypes to create representative models of distribution networks to simulate and analyse the behaviour of different types of electricity grids. These archetypes are designed to capture the diversity of real-world networks by incorporating variations in factors such as urban, sub-urban, and rural settings, network voltage levels, customer types, and load profiles in each area. This allows for a systemic approach to planning, rather than needing to simulate every individual network separately.

Figure 3 provides an overview of the inputs and outputs associated with the Transform Model®.

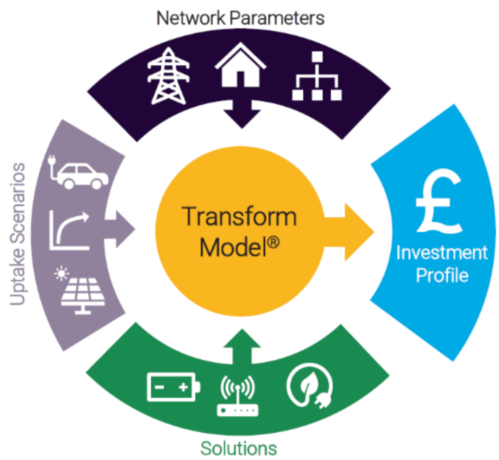


Figure 3: Diagram illustrating the Transform inputs and outputs.

It is based on a model representation of the electricity distribution network parameters (limits) and generates estimates of future load requirements on electricity grid assets using a set of data inputs (scenarios) for the forecasted growth of new low-carbon technologies, such as EVs and heat pumps, and other new load sources.

It then uses the load requirements to identify points at which network limits are exceeded and seeks to solve those exceedances by applying one of a number of solutions.

Solutions can be 'conventional' solutions such as a network upgrade; new transformer, underground works, new split feeders etc. or 'smart solutions' such as; the use of flexibility or other technical solutions to manage faults or optimise existing asset capacity. Solutions are applied in a cost merit-order and the model provides an overall profile of the investment cost.

The network constraints are addressed by selecting solutions through a cost merit-order approach. When a constraint is identified, the model assesses a range of potential interventions—both conventional and smart solutions—and applies them in order of cost -effectiveness. These costs take into account the capital and operational expenditure of the solution along with estimates of other factors such as the customer disruption, network reliability impacts and fault levels. The model selects the solution (or combination of) that deliver sufficient capacity at the least cost over their lifetime.

The Transform Model® evaluates how different networks will respond to increasing adoption of LCTs, and what types of network reinforcements or flexibility solutions will be needed. More information on the Transform Model® can be found in Section 3 of the GB network modelling report.

**Network asset scope:** the Transform Model® includes LV, HV and EHV networks. EHV is defined as voltage tiers operating above 33kV, but not including, 132kV[12]. The Transform Model® does not have the capability to model 132kV networks, LV service cables (the connection to individual customers) or customer connection assets.

## 2.2 Scenario development

A baseline net-zero technology uptake scenario was developed and agreed with the NIC, defining the uptake of technologies and new load sources anticipated to connect to the electricity distribution network.

For each technology, appropriate load profiles were selected from data provided by Distribution Network Operators (DNOs). The technology scope is shown in Table 3.

Table 3: Technology scope

| Sector | Sub technology |
|---|---|
| Road transport (electric vehicle chargepoints) | Domestic off-street |
| | Workplace (incl. fleets) |
| | Public slow and fast (up to 50kW) |
| | Public rapid (over 50kW) |
| Heat | Domestic heat pumps (air source and ground source) |
| | Non-domestic heat pumps |
| | Direct electric heating incl. night storage |
| | Heat networks (district heat) |
| Industrial and commercial demand | I&C underlying demand |
| | Electrolysis |
| | Data centres |
| Domestic | Appliances, lighting, computing etc. |
| Generation and storage | Small-scale solar (capacity less than 1MW) |
| | Small-scale storage (capacity less than 1MW) |
| | Grid-scale solar (capacity over 1MW) |
| | Wind |

[12] Definition of EHV from Ofgem, 2011

| Sector | Sub technology |
|---|---|
| | Grid-scale storage (capacity over 1MW) |
| | Dispatchable generation |

The technology uptake scenario was based on data from ESO's Future Energy Scenarios 2023 Consumer Transformation scenario, with variations to the heat technology mix tested via sensitivity analysis (outlined in Table 4). This net-zero scenario was chosen because it aligns with the NIC's recommendations from the Second National Infrastructure Assessment, and reflects rapid and high levels of heat and transport electrification. The FES 2024 dataset was not available at the time of project scenario development. FES 2023 Consumer Transformation was compared to the most recent energy scenarios and it was found that this scenario would be suitable based on the uptake of low-carbon technologies with sensitivities designed to quantify key uncertainties.

Important features of the FES 2023 Consumer Transformation scenario for electricity distribution networks include:

- **Heat:** Domestic and commercial space and water heating is rapidly electrified. Almost all homes are heated by a heat pump, resistive heating or electric heat network in 2050. There is no uptake of hydrogen boilers. The domestic heating mix is shown graphically in Figure 4.
- **Road transport:** There is rapid uptake of battery electric vehicles across vehicle types and by 2050 all cars and almost all HGVs, buses and vans are battery powered. Regen's Electric Vehicle Chargepoint model was used to develop chargepoint capacity projections from FES projections of electric vehicles. The number of domestic off-street chargepoints installed across Great Britain is shown graphically in Figure 5.
- **Generation:** Installed generation capacity on the distribution network increases from 42 GW to 111 GW in 2050, driven largely by increases in solar and wind generation. The capacity of dispatchable technologies, currently mainly made up of fossil fuel technologies, decreases from 16.5 GW to 11 GW in 2050.
- **Storage:** The installed capacity of all types of storage technologies increases from 4.7 GW to 20 GW in 2050, driven mainly by large-scale batteries and, to a lesser extent, small-scale domestic and commercial batteries. Note that the FES 2024 Holistic Transition has a much higher uptake of storage by 2050.

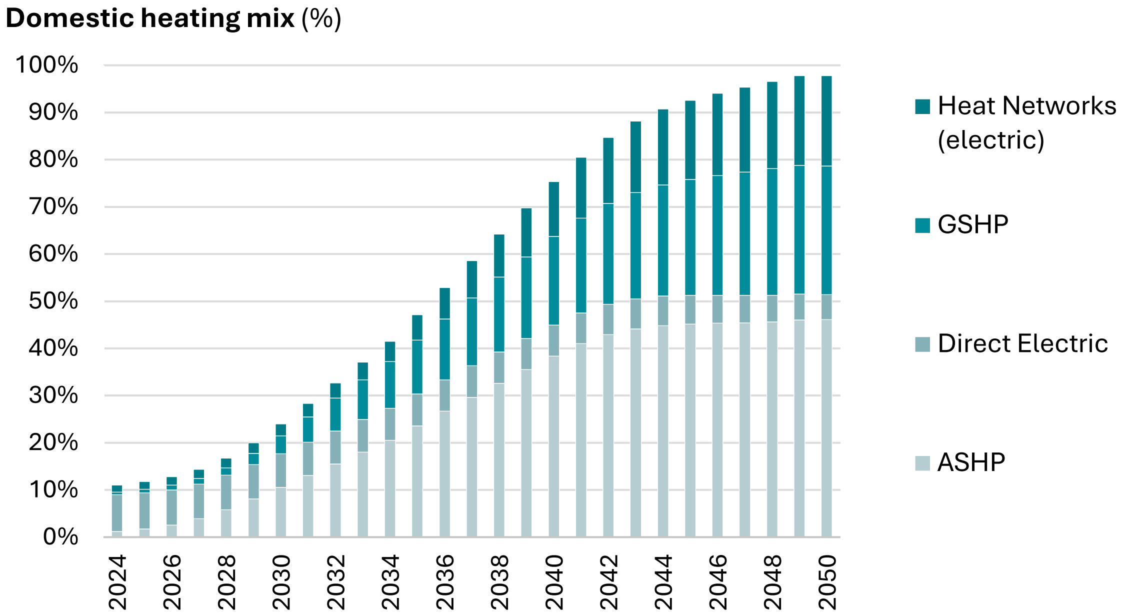


Figure 4: Domestic heating technology mix (FES 2023 Consumer Transformation. Remaining households are heated by non-electric technologies. Air-source heat pump and ground-source heat pump abbreviate to ASHP and GSHP.

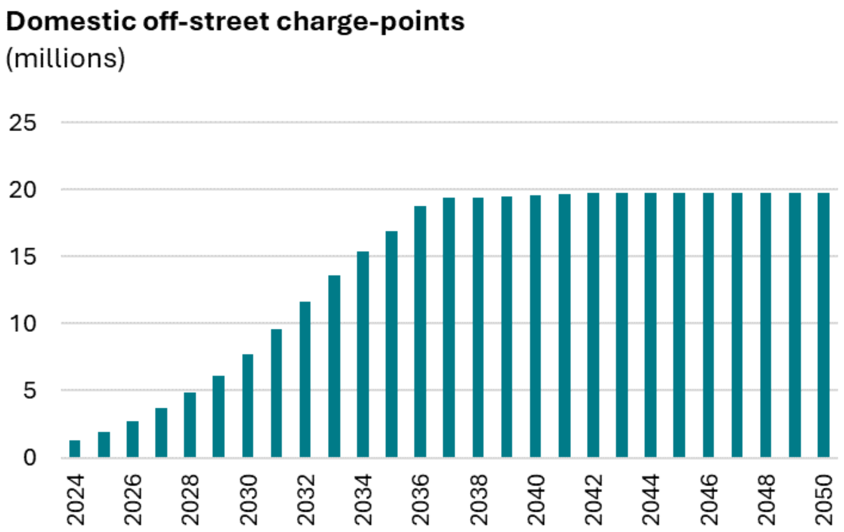


Figure 5: Domestic off-street EV chargepoints installed across Great Britain, based on vehicle energy consumption data from FES 2023 Consumer Transformation scenario using Regen's Electric Vehicle Chargepoint model.

## Scenario sensitivities

Additional model runs were defined to answer key study questions:

- Variations in the assumed mode of operation of electric vehicles, heat pumps and battery storage systems were introduced to test the network impact of higher and lower levels of implicit flexibility.
- Variations in heating technology mix were made to test i) the effect a slower uptake of heat pumps compared with the uptake rate defined in Consumer Transformation ii) a higher share of resistive electric heating.
- Significantly higher electric heating loads were included in the winter stress test

Further model runs tested low certainty model inputs – I&C demand, data centre deployment, higher storage deployment and the impact of different investment horizons. The full set of model runs is outlined in Table 4.

The winter stress test (run 7) intends to test the network impact of a significantly higher heat demand profile (the highest provided by the DNOs) combined with a lower level of flexibility and without a reduction in transport or I&C demand. This model run is not aligned to a specific resilience standard or defined weather conditions.

Further details on profile selection can be found in the scenario development report.

Table 4: Description of model runs.

| | Name | Test description | Heat technology mix |
|---|---|---|---|
| 1 | FES 23 CT - high flex | Higher levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 2 | FES 23 CT delayed HP - high flex | Higher levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions | Delayed heat pump adoption |
| 3 | Lower HP - high flex | Higher levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions | Lower heat pump adoption with higher electric resistive heating |
| 4 | FES 23 CT - low flex | Lower levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 5 | FES 23 CT delayed HP - low flex | Lower levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions | Delayed heat pump adoption |
| 6 | Lower HP - low flex | Lower levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions | Lower heat pump adoption with higher electric resistive heating |
| 7 | Winter stress test | Winter stress test with higher heating loads and low flex | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 8 | Lower I&C demand | Lower I&C demand | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 9 | High data centre deployment | Higher data centre deployment to test more recent evidence of deployment rates | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 10 | High initial small-scale storage deployment | High initial small-scale storage deployment to test more recent evidence of storage uptake | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 11 | 10-year investment horizon - high flex | Testing impact of changes to investment horizon with higher levels of flexibility | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 12 | To 2050 investment horizon - high flex | Testing impact of changes to investment horizon with higher levels of flexibility | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 13 | 10-year investment horizon - low flex | Testing impact of changes to investment horizon with lower levels of flexibility | Higher heat pump adoption (FES 2023 Consumer Transformation) |
| 14 | To 2050 investment horizon - low flex | Testing impact of changes to investment horizon with lower levels of flexibility | Higher heat pump adoption (FES 2023 Consumer Transformation) |

## 2.3 Network archetypes and allocation of technologies

The network capacity analysis carried out in the Transform Model is specific to the network archetypes found on the electricity distribution network covering geographic attributes (urban, semi-urban, rural), network topology (meshed, radial) and cable installation (underground or overhead).

The network archetypes include:

- Six EHV network archetypes (e.g. urban underground radial)
- Seven HV network archetypes (e.g. rural overhead radial)
- Eighteen LV network archetypes (e.g. meshed rural street)

Each archetype has profiles assigned to it which represent existing and emerging demand types (i.e. demand from properties along with demand from EV chargers). These profiles are assigned to the archetypes based on a combination of data sources. For the LV connected technologies, assignment is based on data provided by NGED as part of their 2024 DFES. For the HV and EHV connected technologies, assignment is based on analysis of all the DNO Embedded Capacity Registers.

To account for variability between archetypes, each is represented by 10 cluster bins with a proportion of the associated technologies assigned to it. For example in 2030, 21% (397,062) of all non-managed domestic off-street chargers are assumed to be installed on terraced streets (LV8). The cluster bins range means that some will have 24% (94,090) of these connected and represent those networks which could have challenges earlier vs 1% (8,280) on the lowest penetration cluster bin.

## 2.4 Technology load profiles

The Transform Model®, models three 24-hour network loading periods throughout the year. Three daily load profiles were selected for each technology to cover the range of conditions that the network could be expected to handle without loss of supply.

The three representative days are defined as:

- **Winter peak demand**, with minimum coincident generation – an assessment of the network's capability to meet peak winter demand conditions when demand is high and generation is low
- **Intermediate cool peak demand,** with minimum coincident generation – an assessment of the network's capability to meet demand conditions outside of winter and summer
- **Summer peak generation,** with minimum coincident demand – an assessment of the network's capability to handle generation output.

Load profiles were selected from data provided by all six GB Distribution Network Operators in response to a Request for Information. Where possible, load profiles that came from published sources and sat within the range provided by DNOs were selected for use in the analysis. Further details on profile selection can be found in the scenario development report.

The profiles selected for use in this analysis do not represent the load of an individual customer, which would be highly variable, but the load per customer of a large group of customers. The load profiles used for domestic air-source heat pumps operating in different modes (with different levels of implicit flexibility) are shown in Figure 7

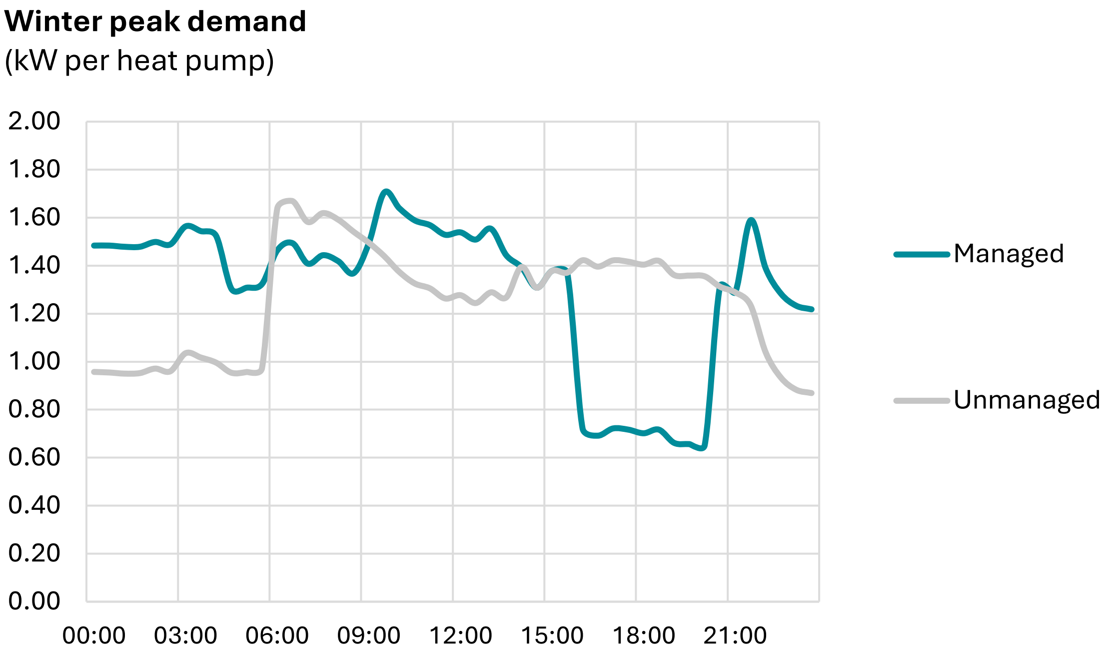


Figure 6: Load profile for domestic air-source heat pump on winter peak demand representative day.

## 2.5 Flexibility

This study assumes two separate categories of flexibility services:

1. **Implicit flexibility** is introduced via load profiles. This includes changes in energy use behaviour taken by customers in response to a variety of signals or technological changes such as time-of-use tariffs, dynamic prices signals or demand side response procured at the system level by the National Energy System Operator.
2. **Explicit flexibility** includes flexibility services, including demand side response (DSR), procured and instructed by Distribution System Operators (DSOs). This form of flexibility is not accounted for in the load profiles and is a solution to network constraints in Transform.

**Note:** The load profiles used in the modelling assume a high degree of demand diversity as currently observed by DNO analysis. The modelling did not take into account the possibility that highly flexible demand, responding to market signals during periods of high renewable generation (with low wholesale prices), could lead to demand correlation and a loss of demand diversity resulting in higher peak loads on network assets at specific locations and voltage levels. This will be an important consideration for network planners and operators and for future market design.

### Flexibility example

Domestic off-street chargepoints can be operated in various ways to suit different users. In this analysis, several different chargepoint management types are grouped into three categories to include the variety of approaches that can be used to charge vehicles:

1. **Non-managed charging:** The charging session begins immediately when plugged in.
2. **Managed charging (externally and user-managed):** Charging is managed by the user or externally managed (for example by an energy supplier) to avoid peak demand periods.
3. **Bi-directional charging:** Energy is exported from the vehicle, either to use in the home or for export to the grid.

Figure 7 shows the assumed uptake of different management modes in the lower and higher flexibility cases. More detail can be found in Section 3.2 of the Scenario development and load profile selection report.

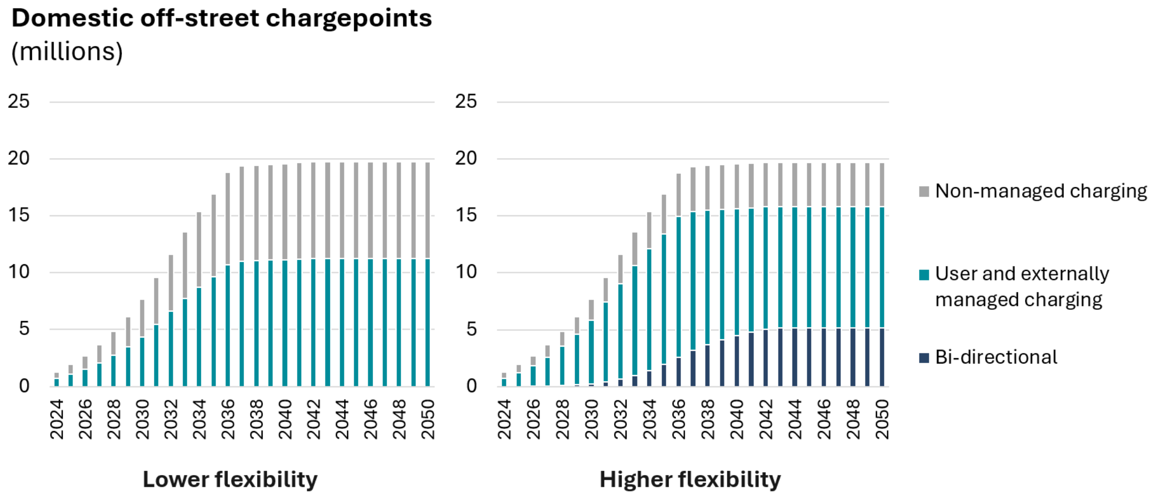


Figure 7: Breakdown of chargepoint operation modes, showing variation between lower and higher implicit flexibility levels.

## 2.6 Constraint types and solutions

The Transform model identifies three types of network constraints for both demand and generation:

- **Thermal cable constraints** occur when load (from demand or generation) exceeds the rated thermal capacity of a cable or line.

- **Thermal transformer constraints** occur when load (from demand or generation) exceeds the rated thermal capacity of a transformer.
- **Voltage constraints** occur when the voltage drop caused by demand or voltage rise caused by generation exceeds allowable power quality limits.

Solutions refer to the interventions applied to resolve network constraints. Solutions are categorised based on their type:

- **Conventional solutions** involve traditional network upgrades that increase physical capacity and reinforce the network.
- **Smart solutions** typically focus on optimising existing infrastructure to release more network capacity.

Details of all the solutions considered in this analysis broken down by their voltage level (LV, HV and EHV) applicability are included in the GB network modelling report.

## 2.7 Limitations and implications for interpreting results

It is important to be aware of the model limitations before drawing conclusions from the study results. This section outlines key model limitations and their potential impact on the results.

Table 5 Key model features and limitations

| Model features and limitations | Potential result impact |
|---|---|
| The modelling has considered only new load-related investments. The investment estimate does not include ongoing operations and maintenance, or the replacement of existing assets that have developed faults or have reached their end-of-life. | The results should be interpreted as load-related expenditure only – i.e. further expenditure in age and condition related asset replacement has not been modelled. It is possible that load-related interventions are made where age/condition related interventions are needed anyway - this has not been modelled. |
| 132kV networks, customer connection assets and LV service cables have not been modelled | **132kV:** In terms of cable length the 132kV network represents only 2% of cable kilometres, but 132kV substations and assets will require significant investment. Results from the DESNZ/Ofgem network modelling shared with the NIC found that 132kV expenditure was a small component of the total (between 2 and 3.5% of total load-related expenditure in 2050).<br><br>**Customer connection assets:** these costs are borne by individual customers and so |

| Model features and limitations | Potential result impact |
| --- | --- |
| | should not be included in GB-wide investment figures.<br><br>**LV services:** Significant levels of additional investment may be required in LV services, not accounted for in this work. For unlooping (separating neighbouring property services) Ofgem currently allows DNOs to recover £1600 per underground service, £350 overhead, £300 per cut out and £130 per fuse.<br><br>On top of this, some customers are supplied with looped connections which would require un-looping. DNOs have estimated over 1 million looped services which could cost around £2bn to resolve for them alone[13]. |
| When the Transform model allocates LCTs to network archetypes it ensures that the number of LCTs does not exceed the number of properties. Network archetypes can become saturated with insufficient property numbers for the forecasted volumes of LCTs. Whilst this method prevents unrealistic overloading in the model, a limitation is that it can introduce discrepancies in the calculated net demand between the bottom-up approach in Transform and a top-down network agnostic approach. | This impact is greatest in the later study years where high volumes of LCT installations lead to some archetypes saturating and no further installations are possible. The impact is that loads on each archetype are more accurately represented but overall net demand may be underestimated. Mitigations to this could lead to some archetypes in the model having unrealistically high densities of LCT deployments. |
| The load profiles do not change across the time period and include simplifications of how the actual load will behave. In reality, consumer behaviour, technologies, and their resulting network loads will very likely change over time. | Profiles are evolving but do represent the current understanding of load behaviour. Future changes could reduce or increase peak network loads. |

[13] SPEN Enabling the path to Net Zero: Our RIIO-ED2 Business Plan and ENWL RIIO-ED2 Business plan Annex 1: Customer research findings

| Model features and limitations | Potential result impact |
|---|---|
| Diversity of load is assumed and is not degraded by the use of implicit or explicit flexibility. The model has not considered how flexibility might cause a concurrence of demand behaviour – e.g. a high number of EV chargers responding to a price signal that could lead to a loss of diversity and demand spike | Diversity loss could have a significant impact on network loads, especially at the lower voltage tiers.<br><br>This has implications for future market design and the way in which demand response is incentivised and coordinated. |
| Heating load profiles do not vary by property archetype. Whilst the model allocates underlying domestic loads from different property archetypes (e.g. very old detached, new terraced etc.) to LV network archetypes (e.g. rural radial, urban meshed etc.) the new heating load profiles do not vary as significantly by property type, with only a greater heating component being required for old detached properties than others. | In practice, heating loads will vary significantly depending on building attributes (such as type, age, size etc.) and occupier attributes (number of habitants, tenure, socio-economic factors). The impact of this model limitation is to reduce the accuracy of projected heating loads on individual network archetypes but representing the forecast volumes at the national level. |
| Direct heating loads are based on data from the current GB heating mix. The factors that lead to low direct electric heating loads (such as use in smaller properties and the high cost of electricity relative to gas) may not occur in the future with more properties heated with direct electric heating. | If a greater range of larger properties adopt direct electric heating, the model is likely to under-estimate the contribution of direct electric heating to peak demand and network investment. |
| A single load profile represents industrial and commercial (I&C) demand. I&C demand is extremely diverse and, therefore, difficult to model in a top-down model.<br>The future behaviour and opportunity to use I&C flex could be the subject of a further study with more granular inputs. | The impact of lower I&C demand (increased flexibility) is shown in sensitivity run 8. The behaviour of I&C demand is complex and likely to be site and sub-region specific. Further analysis would be required to determine whether more granular modelling of the I&C sector would lead to higher or lower expenditure than in this analysis. |
| Dispatchable generation capacity in the Consumer Transformation scenario reduces from 16.5 GW in 2024 to 11 GW by 2050. In this scenario, 6 GW of the 11 GW dispatchable capacity in 2050 is fuelled by hydrogen in 2050. Hydrogen fuelled thermal generation is technically feasible but | If hydrogen-fuelled or other clean dispatchable technologies do not materialise then the results from this modelling may underestimate the peak net demand loads on the HV and EHV part of the distribution networks. |

| Model features and limitations | Potential result impact |
|---|---|
| whether it materialises in significant capacity is highly uncertain. | |
| The way both implicit and explicit flexibility is provided has been simplified. Not every load source that could provide flexibility has been modelled.<br><br>High-level assumptions have been made, for example, that batteries will, on average, provide positive flexibility to alleviate constraints in the high-flex sensitivity run. In reality, individual batteries may provide higher or less flex support at a given network location depending on a number of market and technical factors. | Overall, the scale and use of flexibility has been considered appropriate for this study and is part of the sensitivity analysis. The use of flexibility is discussed in each model run and is one of the key uncertainties. |
| Some location-specific new network loads have not been modelled. Examples include: shore power for shipping, electrification of aviation, off-road transport, agriculture and industrial processes. | In reality DNOs will need to invest to support these, and at some locations, the level of investment will be significant. The split of loads between distribution and transmission will depend to some extent on availability of local network infrastructure and at a national level is highly uncertain. The modelled expenditure (at HV and EHV voltage tiers) would be higher if these sectors were included. |
| Transform has a finite number of subtechnology input fields (defined in Table 3). A further division of technologies and sub-technologies would add more detail but was not considered appropriate given the study focus on heat and transport and the project timescale. | A wider set of subtechnologies would enhance the model results where aggregations have been made such as: public chargepoints, workplace/fleet chargepoints, resistive heating (direct electric and storage). |

# 3 GB network analysis results and interpretation

## 3.1 Results summary

A summary of model results, with a brief description of run conditions, is shown in Table 6.

Table 6: Summary of key results

| | Name | Test description | Cumulative expenditure 2024 to 2050 (£bn, undiscounted, 2024 prices) | Peak demand in 2050 (GW, distribution system, net) |
|---|---|---|---|---|
| 1 | FES 23 CT - high flex | Higher levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions | 38 | 108 |
| 2 | FES 23 CT delayed HP - high flex | | 37 | 108 |
| 3 | Lower HP - high flex | | 42 | 110 |
| 4 | FES 23 CT - low flex | Lower levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions | 45 | 115 |
| 5 | FES 23 CT delayed HP - low flex | | 45 | 116 |
| 6 | Lower HP - low flex | | 49 | 119 |
| 7 | Winter stress test | Winter stress test with higher heating loads and low flex | 76 | 153 |
| 8 | Lower I&C demand | Lower I&C demand | 36 | 102 |
| 9 | High data centre deployment | Higher data centre deployment | 38 | 114 |
| 10 | High initial small-scale storage deployment | High initial small-scale storage deployment | 38 | 108 |

## 3.2 **Peak demand in 2050**

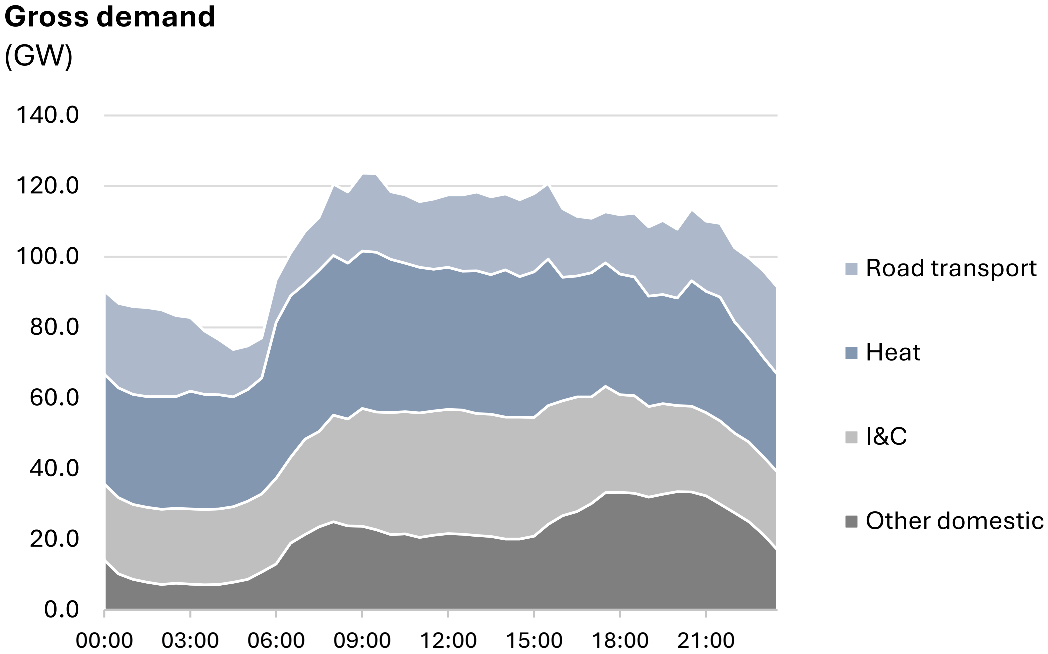


Figure 8: Gross demand during a winter day for run 1, with higher heat pump adoption and higher levels of flexibility. Note chart shows gross rather than net demand and is before explicit flexibility solutions are applied.

The net peak demand load for the main model runs was in the range of 108 to 120 GW in 2050. Net demand includes the contribution from generation and storage technologies, reducing demand at the system level.

Gross demand, which excludes flows from distribution connected generation and storage, ranges between model runs from 124 GW to 133 GW. This is slightly higher than the projected 112 GW gross peak distribution network demand in the FES 2023 Consumer Transformation scenario and 107 GW in the FES 2024 Holistic Transition scenario.

The key drivers of network load in the model are the forecasted growth of EVs and heat pumps and the electrification of residual domestic and commercial heat. Heat demand peaks at 45.8 GW and road transport peaks at 25.2 GW. Peak demand periods shifted slightly depending on the model run and use of flexibility, with a reduction in the evening peak but a slight increase in the morning peak. A summary of peak demand contributions is shown in Table 7. The impact of different levels of implicit flexibility is shown in Figure 9 for model runs 1 and 4.

Table 7: Contribution to peak demand by sector. Model run 1 (higher flexibility and high heat pump adoption).

| **Sector** | **Demand at peak (GW)** |
|---|---|
| Heat | 44.6 |
| Road transport | 22.0 |
| Industrial and commercial | 33.3 |
| Other domestic | 23.7 |
| Gross demand total | 123.7 |

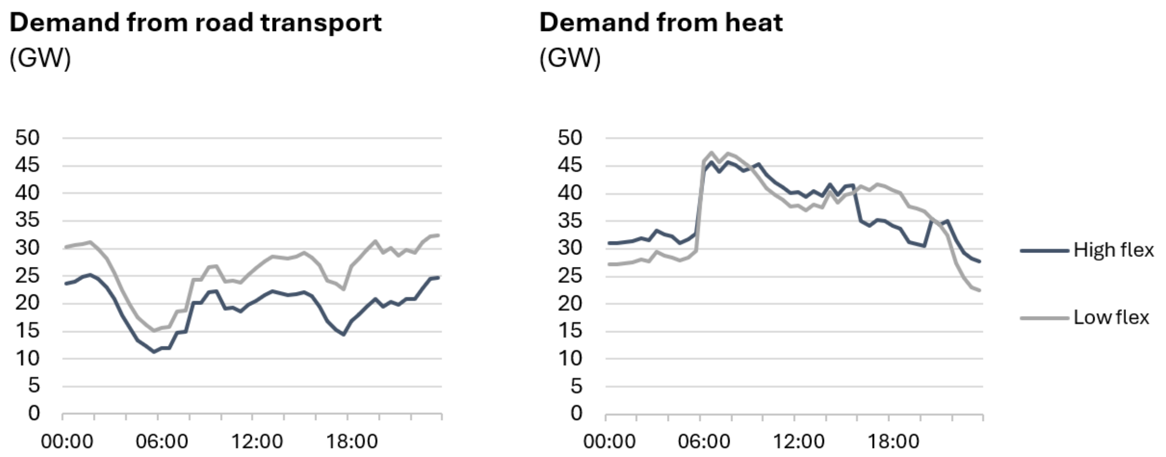


Figure 9: Impact of implicit flexibility - comparison of run 1 (high flex) and run 4 (low flex) on aggregate loads from road transport and heat.

## 3.3 Expenditure results comparison

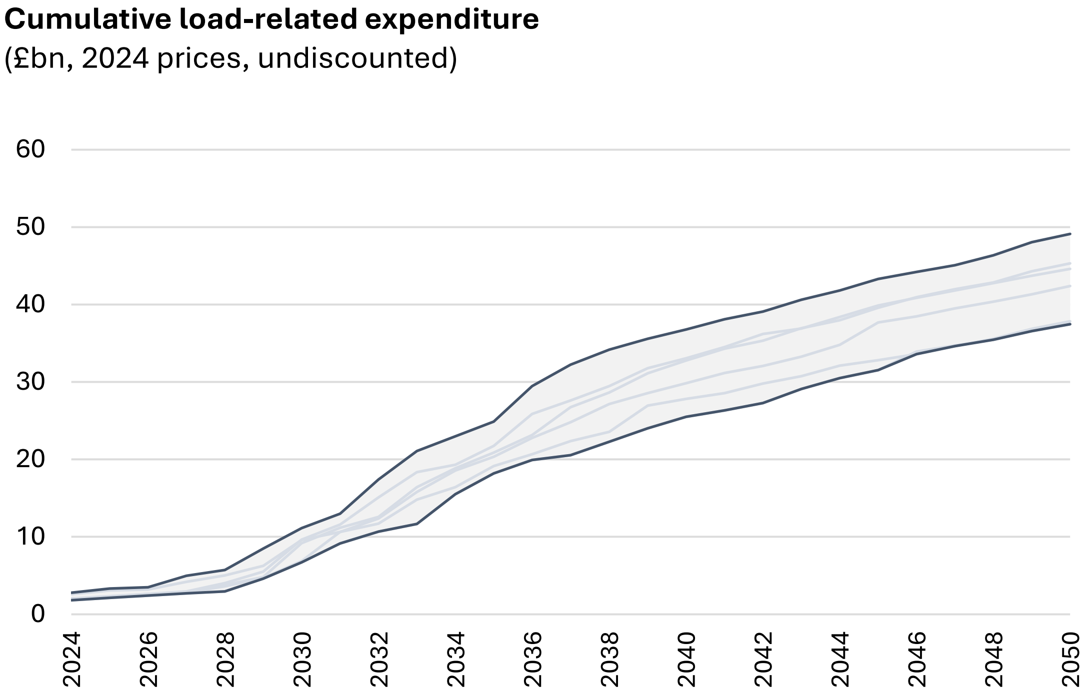


Figure 10: Range of cumulative load-related expenditure in main model runs.

Across the main winter and summer representative day model runs and sensitivities, the cumulative (2024 to 2050) undiscounted load-related expenditure for the distribution network across Great Britain ranges between £37 bn and £49 bn. This is shown in Figure 10.

On an annualised basis, the £37 bn to £49 bn range equates to £1.4bn to £1.8bn per year (see Table 8). This range is lower than the range modelled in previous distribution network investment studies. For example, the joint DESNZ/Ofgem Electricity Networks Strategic Framework modelling suggested an expenditure range that equated to £2.3bn to £3bn per year on average[14]. The DESNZ study includes the 132kV network (which this analysis does not), the studies used different network models, and the model input parameters were different.

Looking at recent historic spend shown in Table 9, the annual load-related expenditure of £1.4bn to £1.8bn from this analysis would be a significant step up compared to the average reinforcement expenditure of £274 million per annum delivered in the RIIO-ED1 price control

[14] Electricity networks strategic framework Appendix I: Electricity Networks Modelling, DESNZ and Ofgem

period (2015-23) and the average load-related expenditure budget of £640 million for the five-year RIIO-ED2 price control period (2024-28) [15] [16].

Table 8: Summary of load-related expenditure results from this analysis

| | **Cumulative load related expenditure** (2024 to 2050, 2024 prices) | **Average annual load-related expenditure** |
|---|---|---|
| High flexibility and higher heat pump uptake (run 1) | £37.8bn | £1.4bn per year |
| Low flexibility and higher heat pump uptake (run 4) | £44.6bn | £1.7bn per year |
| Winter stress test, low flexibility and higher heat pump uptake (run 7) | £76.2bn | £2.8bn per year |

Table 9: Historic Distribution Network Operator budgets and expenditure for load-related expenditure

| | **Average annual baseline allowance** (excludes additional funding available via uncertainty mechanisms, 2020-21 prices) | **Average annual actual expenditure** (2020-21 prices) |
|---|---|---|
| **RIIO-ED1 Price Control**[17] (Apr 2015 to Mar 2023) **Network Reinforcement expenditure** | £363m per year | £274m per year |
| **RIIO-ED2 Price Control** [18] (Apr 2023 to Mar 2028) **Load related expenditure** | £640m per year | Data not yet available |

[15] Reinforcement expenditure data from Ofgem ED1 Financial Performance Reporting
[16] Total LRE budget (including allowance for SCR) from ED2 final determinations. Does not include investment that could be supported by Uncertainty Mechanisms.
[17] RIIO-ED1 Annual Report 2021/22 Tab1-22 Supplementary Data File, Tab: CH4 expenditure drivers 2. Note: at time of writing 2022/23 data has not yet been published.
[18] RIIO-ED2 Final Determinations Core Methodology Document, Paragraph 3.12 page 18

Table 10: Other distribution network investment study results

| Study information | | Cumulative load-related expenditure | Average annual expenditure |
|---|---|---|---|
| **Electricity Networks Strategic Framework**[19]<br><br>Appendix I: Electricity Networks Modelling, 2022 DESNZ (then BEIS) and Ofgem<br><br>**Scope:** LV, HV, EHV including 132kV. Service cables and connection assets explicitly excluded. | Net Zero Higher Demand<br><br>(185 GW peak demand in 2050) | £90bn to 2050 (undiscounted, 2020 prices) | £3bn per year |
| | Net Zero Lower Demand<br><br>(140 GW peak demand in 2050) | £70bn to 2050 (undiscounted, 2020 prices) | £2.3bn per year |
| **Accelerated Electrification and the GB Electricity System**[20]<br><br>Vivid Economics and Imperial College London commissioned by the Climate Change Committee, 2019<br><br>**Scope:** LV, HV, EHV excluding 132kV. Documentation does not mention service cables or connection assets (assumed excluded). | Central<br><br>(77 GW peak demand in 2035) | £41bn to 2035 (undiscounted, 2019 prices) | £2.6bn per year |
| | Rapid EV + HPP<br><br>(84 GW peak demand in 2035) | £47bn to 2035 (undiscounted, 2019 prices) | £2.9bn per year |

[19] Electricity networks strategic framework Appendix I: Electricity Networks Modelling, DESNZ and Ofgem
[20] Accelerated Electrification and the GB Electricity System, Vivid Economics and Imperial College London commissioned by the Climate Change Committee

## 3.4 The role of flexibility

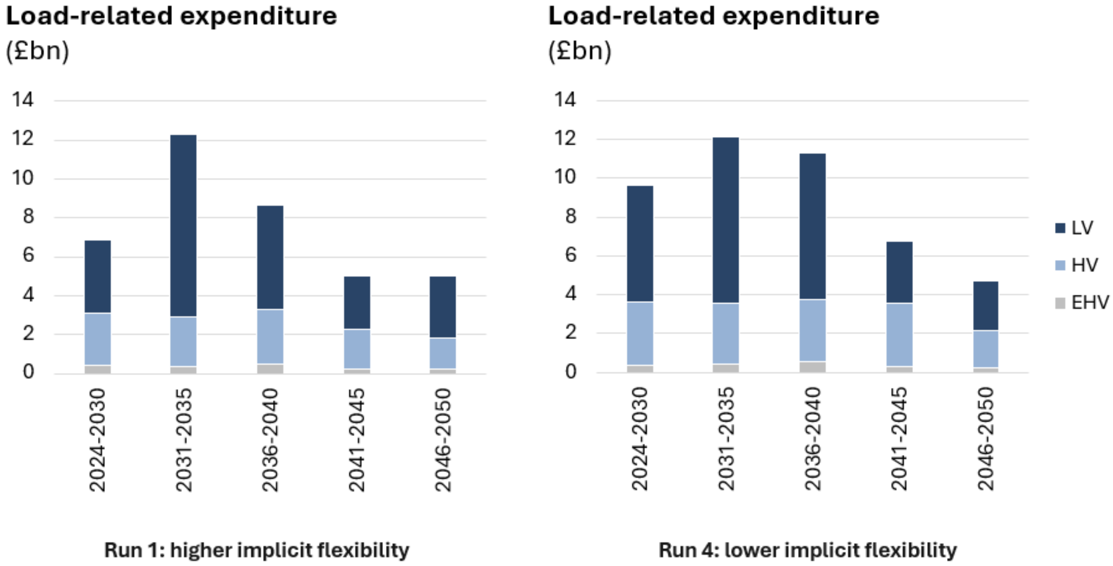


Figure 11: Profile of load-related expenditure, split by voltage tier, with higher implicit flexibility (Run 1) and lower implicit flexibility (Run 4)

**Impact of implicit flexibility:** All model runs included some level of both implicit and explicit flexibility. Implicit flexibility, where consumers and flexibility providers (including batteries) are assumed to respond to price signals, is built into the load profiles and has the effect of reducing peak loads on the network. The effect of increased levels of flexibility with higher heat pump uptake is a reduction in cumulative expenditure by £7bn from £45bn to £38bn.

Figure 11 shows how, as well as reducing the level of load-related expenditure, the greater use of flexibility also has the impact of delaying the need for expenditure. This equates to an additional financial benefit when cumulative expenditure is calculated on a discounted basis.

**The role of explicit flexibility:** Explicit flexibility, whereby DNOs can call upon flexibility providers to increase or reduce loads for a fee, was included as one of the available model solutions. Explicit flexibility was expected to provide a cost-optimal solution to manage marginal constraints where the frequency and severity of constraint is low. However, in the model runs this solution was utilised less often (less than 0.2% of total expenditure in all runs) than may have been expected for the following reasons:

- The inclusion of implicit flexibility within the input load profiles has the effect of flattening the overall load profile, meaning that constraints became more binary; either the network was not constrained, or it was constrained.

- The model did not consider the impact of uncertainty and the value of explicit flexibility to provide the option to delay asset investment where the level of constraint is uncertain.
- The model did not consider other operational and delivery factors, which may lead network planners to deploy explicit flexibility to delay network expenditure ("flex first") or as an additional assurance alongside investment ("flex plus"). For example, so that network investment plans can be better coordinated and aligned, or to allow for potential delays in network reinforcement delivery.

Table 11: Impact of flexibility on model results.

| **Heating mix** | **Higher implicit flexibility** | **Lower implicit flexibility** | **Impact of flexibility level** |
|---|---|---|---|
| | **Net peak demand in 2050** (GW) | | |
| Higher heat pump adoption | 108 | 115 | 7 |
| Delayed heat pump adoption | 108 | 116 | 9 |
| Lower heat pump adoption | 110 | 119 | 10 |
| | **Cumulative load-related expenditure** (£bn) | | |
| Higher heat pump adoption | 37.8 | 44.6 | 6.8 |
| Delayed heat pump adoption | 37.5 | 45.3 | 7.9 |
| Lower heat pump adoption | 42.4 | 49.1 | 6.7 |

## 3.5 Winter stress test

The main model runs are based on representative winter, shoulder season (spring/autumn) and summer days. Model run 7 has been used to model a winter stress test event with much higher heat demand.

The winter stress test was not based on a specific cold weather resilience standard or specific weather conditions such as a 1-in-20 year weather event. It did, however, seek to stress test the network model with much higher heat demand, doubling the average peak load for air-source heat pumps to 3 kW (using the most conservative load profile provided by the DNO's) with a similar increase for other electric heating technologies. These profiles were derived from studies of heat pump behaviour in cold weather events. More detail on the selection of load profiles for heating technologies can be found in Section 3.3 of the Scenario development report.

In all model runs, peak winter demand conditions feature very little generation output from wind and solar generation technologies. The winter stress test model run also featured lower levels of flexibility from electric vehicles, heat pumps and energy storage technologies (with no demand reduction from commercial and industrial consumers).

The results showed a significant uplift in cumulative network investment to £76bn (2024 to 2050) and an increase in the peak distribution network demand to 153 GW in 2050.

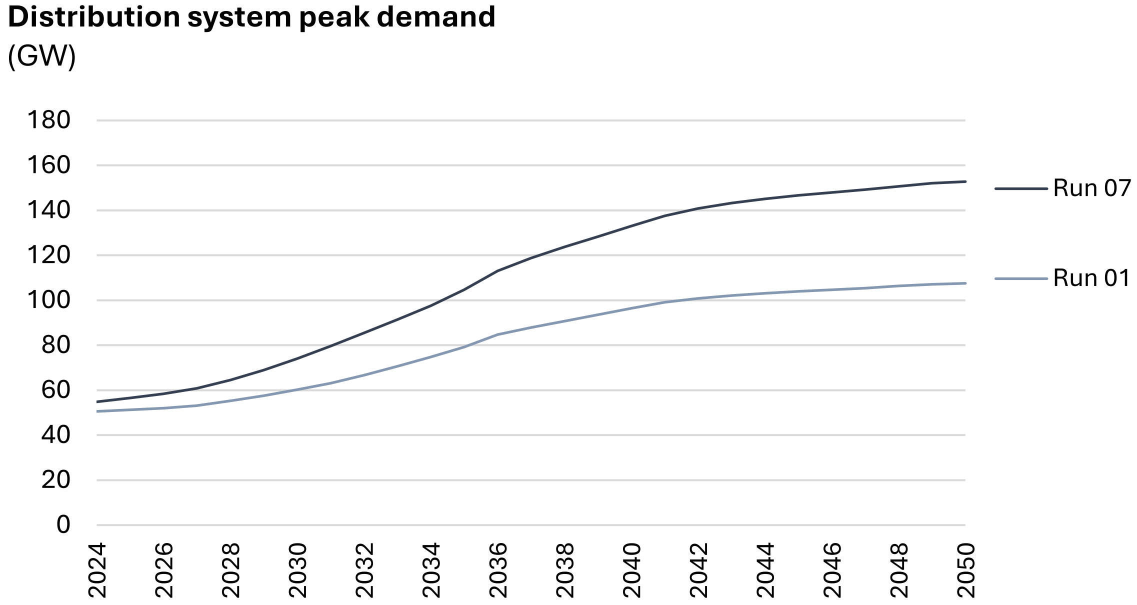


Figure 12: Net distribution system demand in run 01 (higher flexibility, higher heat pump adoption) and run 7 (winter stress test, lower flexibility, higher heat pump adoption).

The network impact of this model run was discussed with the DNO representatives. Modelling of significantly higher heating loads was deemed valid but there was some debate around the extent to which non-heating loads (such as EV charging and I&C demand) would reduce in such conditions. The approach taken may be excessively conservative (with lower levels of implicit demand side flexibility), but it highlighted that there could be a need to define a new resilience standard for the electricity network in the context of providing critical energy for heat and transport.

Important considerations in the definition of this standard would include regional and local differences, rural versus urban settings, availability of flexibility at different voltage levels and the requirements of different customer archetypes, including customers in vulnerable circumstances.

## 3.6 Impact at each voltage tier

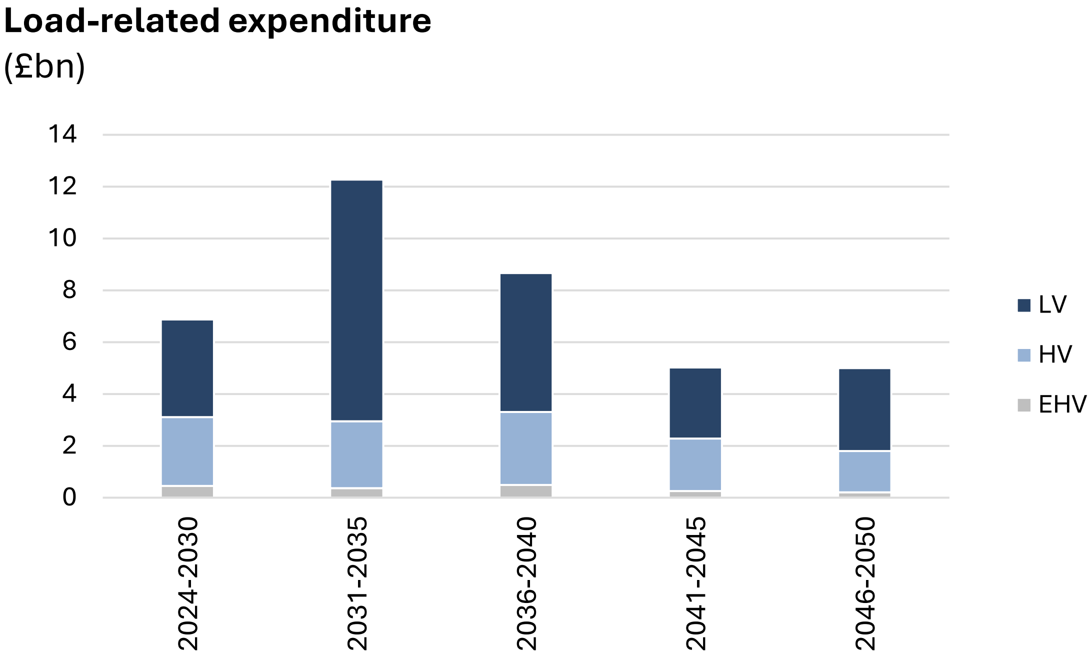


Figure 13: load-related expenditure for run 1 (higher heat pump adoption and higher levels of flexibility) broken down by voltage tier.

The bulk of load-related expenditure across the period to 2050 is in the low voltage part of the network. The results of this modeling show that, in the base model run with higher heat pump adoption and high levels of flexibility, 64% of the cumulative £38bn expenditure will be in the LV network. The range of LV investment across main six runs ranged from 62% to 65%. In the winter stress test the share of expenditure at LV level was 68%, driven by higher heating loads from LV-connected electric heating devices.

These results are not surprising given the LV network makes up 45% of the total distribution network by cable length and contains 96% of all substations. Although individually the LV assets may be considered less complex, the sheer number of assets that need to be monitored, maintained and upgraded is the main challenge. These results emphasise the potential impact on the LV network of a rapid electrification of heating and transport.

## 3.7 Constraints and solutions

The analysis identifies thermal constraints on transformers and circuits as the most prevalent challenges. The model results show these constraints occurring on a significant volume of LV networks where new loads from electric vehicles and electrified heating are connecting. Voltage constraints appear less frequently than thermal issues, though these are often masked by network upgrades that increase thermal capacity while simultaneously reducing voltage issues. This point that voltage constraints may be more prevalent than the model suggests was raised by the DNO's.

Typical solutions to resolve these constraints include a range of physical upgrades and innovative network management techniques. A breakdown of the most frequently deployed solutions can be found in Table 12. On the LV network, commonly deployed physical upgrades are new ground-mounted transformers along with additional overhead circuits in rural areas. These are complemented by data-driven solutions leveraging network monitoring to optimise the capacity of existing assets using techniques such as real-time thermal ratings, to optimise the capacity of existing assets. For the HV and EHV networks, interventions still rely heavily on infrastructure upgrades but are supported by dynamic network reconfiguration technologies to maximise resilience and capacity as demand continues to grow.

Table 12: Summary of top five solutions deployed on each voltage tier (measured by number of solutions deployed) for model run 1.

| **LV** | | **HV** | | **EHV** | |
|---|---|---|---|---|---|
| LV overhead minor works | 27% | EHV/HV transformer upgrade | 25% | Active network management / Dynamic Network Reconfiguration | 35% |
| Network data monitoring | 20% | Active Network Management / Dynamic Network Reconfiguration | 20% | Permanent meshing of networks | 21% |
| Permanent meshing of networks | 16% | Real time thermal ratings for overhead lines | 19% | Real time thermal ratings for overhead lines | 16% |
| LV Ground mounted HV/LV transformer upgrade | 15% | Permanent meshing of networks | 11% | Underground network split feeder | 12% |
| Real time thermal ratings for HV/LV transformers | 7% | Real time thermal ratings for underground cables | 8% | Real time thermal ratings for underground cables | 7% |

## 3.8 Investment horizons

In all 10 model runs described earlier in this report, the investment horizon was set at 5 years. Investment horizon refers to how far into the model looks when implementing a network upgrade. With a 5 year horizon, when a constraint is met the model investigates solutions which are able to resolve the constraint and meet the forecast demand and generation increases for the next 5 years. For example, solutions to a constraint that occurs in 2025 must be able to meet forecasted demand in 2030.

Two additional investment horizons (10 years and to 2050) were also investigated. The 10 year investment horizon highlighted that although a higher upfront cost is necessary, it delivers the capacity increase needed for a longer duration and the resulting cumulative (undiscounted) load-related expenditure remained the same. However, when looking at investment horizons that aimed to increase network capacity to meet the 2050 requirements some modelling limitations were encountered. Some solutions deployed to meet demand in 2050 had shorter lifetimes than the investment horizon, which meant they were deployed and then required replacement leading to very high cumulative investment. In practice, a DNO would not choose solutions with lifetimes shorter than the investment horizon. Whilst the analysis does not support a particular horizon length, the limitations encountered highlight the importance of considering uncertainty in forecasts, investment risks, lead times and asset lifetimes when choosing an investment horizon.

# 4 Local network case studies

## 4.1 Local case study modelling tool

The local case study analysis uses EA Technology's VisNet Design® tool to model the impact of load growth from Low Carbon Technologies (LCT) on LV networks. VisNet Design® is a connectivity model based electrical network simulation tool specifically developed to analyse the performance of LV distribution networks, incorporating real-world data from DNOs. This toolset is in active use by several GB DNOs enabling the use of accurate network models to carry out the local case study analysis.

The tool allows evaluation of load growth from technologies such as electric vehicles, heat pumps, and distributed generation on an accurate representation of a LV network. When capacity constraints are identified, VisNet Design® allows the user to investigate a range of solutions to manage them effectively through options such as transformer reinforcements, network reconfiguration, voltage management schemes, etc.

## 4.2 Approach

Separate to the GB network analysis, the challenges of LCT uptake on seven local network case studies were investigated using real-world network data provided by Distribution Network Operators.

The purpose of these local case studies is:

- To demonstrate that LCT uptake under a high-electrification net zero scenario can impact different network archetypes (urban, suburban and rural) in different ways
- To demonstrate how the local geographical distribution of LCT uptake on the same network can lead to different interventions over varying timescales
- To demonstrate the range of potential reinforcement and intervention strategies that need to be considered

Three categories of LV networks (urban, sub-urban and rural) were investigated with two or three case studies for each demonstrating the different impacts of the forecasted level of LCT installation required for Net Zero. The LCTs considered in the local case studies are: EV chargers, electric heating technologies and solar generation. The volume of LCTs connected to each LV network in any given year is based on the FES 2023 Consumer Transformation forecasts with a translation based on network type (urban, rural, sub-urban) and normalising to the actual number of connected customers on each case study model. A summary of the case study networks and results are shown in Table 13.

The LV network case studies modelled the impact of LCT uptake rates from 2025 to 2050 in five-year intervals. Within each year of study, the locations of the LCTs were varied to investigate the uncertainty associated with customers driving the LCT installation. The progressive impact of the new demands on the network were analysed and when constraints were seen on the network interventions were considered. Interventions modelled in the case studies included physical reinforcements, like transformer upgrades and network reconfiguration, and flexible interventions like explicit flexibility procurement.

The primary constraints that were reviewed in this modelling exercise were transformer capacity constraints, mains cable thermal constraints and voltage constraints. Due to the nature of electrical networks, reinforcing the network to solve for transformer capacity constraints and cable thermal constraints will often solve the voltage constraints.

When choosing physical interventions each intervention was tested with the 2050 LCT uptake rates to investigate whether the solution could be considered a "touch the network once" intervention or if further reinforcement would be required. Reinforcing ahead of need was most relevant in the networks that reached transformer constraints early in the study and often included network reconfiguration to enable the final 2050 demand.

In each case study, the final volume of heating technologies aligns with net zero compliant forecasts, each domestic property connected is heated through electrical means. Where the properties are not heated via heat pumps, they are heated through direct electric resistive means.

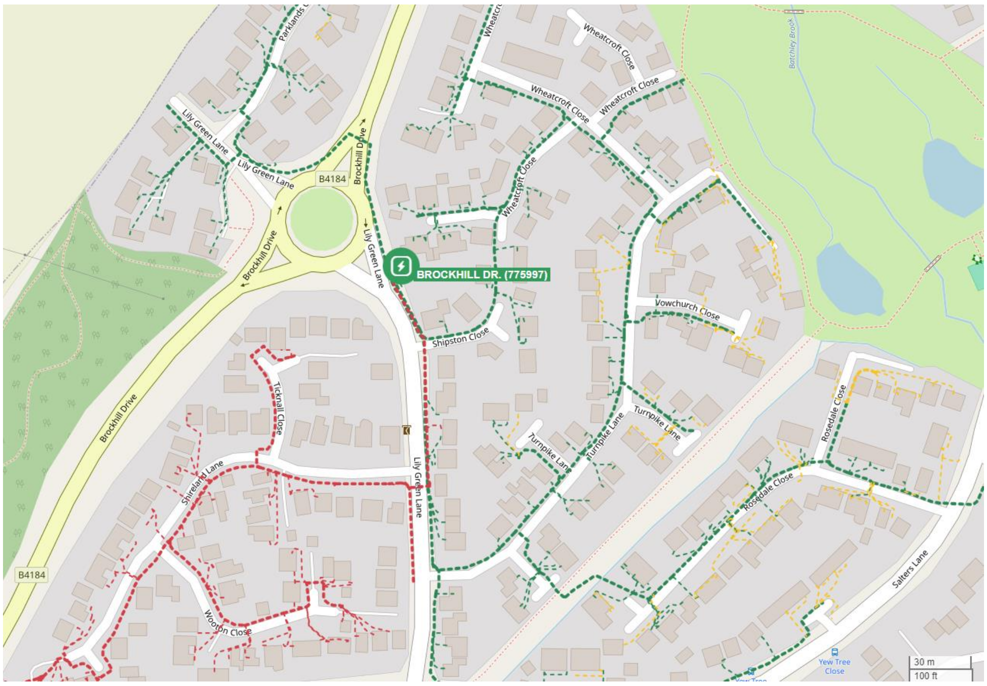


Figure 14: Example network schematic (Brockhill Drive).

## 4.3 Results

Table 13: Summary of case study networks and results.

| Case study network | Type | No. of Customers | Capacity in 2024 (kVA) | Capacity per customer (kVA) | Capacity required in 2050 (kVA) | Capacity per customer in 2050 (kVA) | Intervention year |
|---|---|---|---|---|---|---|---|
| Spen Road, County Durham | Rural | 93 | 100 | 1.1 | 315 | 3.4 | 2030 |
| Chaddesley Corbett, Worcestershire | | 77 | 300 | 3.9 | 500 | 6.5 | 2035 |
| Duxmoor, Ludlow | | 9 | 50 | 5.6 | 100 | 11 | 2040 |
| Brockhill Drive, Redditch | Sub-urban | 338 | 800 | 2.4 | 1400 | 4.1 | 2035 |
| May Street, Durham | | 186 | 500 | 2.7 | 500 | 2.7 | 2050 |
| Mosborough Crescent, Central Birmingham | Urban | 293 | 1000 | 3.4 | 1000 | 3.4 | 2035 |
| Dunston Industrial East, Gateshead | | 200 | 1000 | 5.0 | 1000 | 5 | 2040 |

## 4.4 Themes from the case studies:

While there is no one size fits all solution to LV network planning when considering new types and volumes of electrical loads, there are some common themes that can be drawn out.

- **Increased scale of network reinforcement:** Physical interventions were unavoidable in all but one of the case studies modelled. LV networks have historically been designed for relatively low loads per customer (the case study networks ranged from 1 to 5 kVA per customer) with energy for heat and transport provided by fossil fuels. This suggests a scale and pace of LV network reinforcement that is far larger than the present reinforcement works undertaken by the networks.
- **Flexibility enabling reinforcement delay or avoidance:** Targeted, local Demand Side Response could enable DSOs to avoid capacity constraints on the LV networks. This could provide them more time to assess future network reinforcement options or, in select cases such as May Street, avoid reinforcement over a longer period.

- **Impact of Implicit flexibility:** As customers respond to energy price signals, the initial positive impact of shifting away from the evening peak can lead to the creation of new overnight peaks on the networks. This could lead to DNOs requiring investment for new peaks or increased use of explicit flexibility to further shift demand.
- **Location of new demands determines when intervention is required:** In some case studies the years of intervention varied widely, along with whether flexibility would be a suitable intervention. The case studies highlight the importance of even customer load distribution across feeders in whether the network requires physical reconfiguration, even if the transformer capacity is not exceeded.
- **Network suitability for the future:** The existing network topology is a major factor for the ability of an LV network to be able to supply the large volume of new loads.

## Challenges by network archetype:

**Urban:** These networks are found in built up areas and feed a high number of customers. They are also likely to feed commercial properties as well as domestic customers.

- Neither case study network saw capacity issues arise, due to their large initial transformer sizes and the limited physical space to support new LCT loads. Issues primarily arose from customers connected unevenly across feeders.

**Sub-urban:** These networks feed domestic properties across a number of streets and can supply several hundred homes.

- The largest network modelled, a large sub-urban housing estate, required the greatest amount of intervention, with a second transformer installed to increase the network capacity. This intervention was required in 2035, driven by the area's projected uptake of EV charging as well as the forecast heat pump uptake.
- Highlighting the diversity in networks, the other sub-urban case study network representing a terraced street, was the only network to not require physical intervention. However, it is likely that some form of demand side management would be required to enable safe operation in 2050.

**Rural:** These networks generally have smaller capacity transformers and will feed smaller numbers of customers, these case studies had under 100 connected customers each.

- Every rural network required a transformer upgrade, due to the small level of existing capacity, some as early as 2030. This early intervention requirement in 2030 demonstrated the potential of a “touch the network once” approach targeting projected 2050 demand and installing a significantly larger transformer.
- Rural properties are more likely to be heated by oil, gas or other combustible fuels and therefore have the lowest amount of existing electrical heating load. This leading to a proportionally significant increase in electricity demand.
- Alongside this, there is limited understanding in when and how rural industries, like farms, plan to decarbonise. If electrification is their chosen avenue to decarbonise, then rural distribution networks will have even more significant electrical demands to consider.

A key learning from the case studies is that, whereas the upgrade of the transmission network is concerned with the delivery of a smaller number of very large upgrades, the upgrade of the low voltage networks is concerned with the delivery of hundreds of thousands of individual interventions and investments. This requires a different approach and emphasises the importance of; data quality, monitoring, forecasting, decision support tools, the ability to use smart solutions, resource planning and the skills and expertise of network planners. It also requires a high level of coordination and delivery planning between network operators and a range of stakeholders, including local authorities, customers and businesses, and supply chain partners.

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