REPORT

National Modelling of Electricity Distribution Network Capacity Analysis

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Executive Summary

This report contains the outputs from the National Modelling component of the Electricity Distribution Network Capacity Analysis, carried out by Regen and EA Technology Ltd. for the National Infrastructure Commission (NIC). The NIC commissioned this project to evaluate potential future distribution network loads and their impacts, as part of a broader study on the policies needed to ensure the electricity distribution network is suitable for achieving net zero by 2050.

The project is split into two work packages.

Work Package 1 (WP1)

During Work Package 1, the project develops several future load scenarios using the Electricity System Operator (ESO) 2023 Future Energy Scenarios (FES) as a primary input and identified a set of load profiles from distribution network operators (DNOs) and assumptions, including the potential impact of demand flexibility.

Work Package 2 (WP2)

In Work Package 2, the distribution network impacts of the scenarios and sensitivities developed in WP1 are analysed. The modelled output from Work Package 2 is intended to give the NIC an evidence base to look at the potential need for network expenditure across all GB distribution networks.

Work Package 2 is split into two separate modelling studies:

- First, the National Modelling carries out national analysis to quantify the additional distribution network capacity required under the various demand scenarios developed in WP1.
- Secondly, the Local Case Study Modelling demonstrates the impact of Low Carbon Technology (LCT) adoption on some case study Low Voltage networks.

This report presents outputs from the first study.

Context

The widespread adoption of LCTs, such as electric vehicles (EVs), heat pumps, and renewable energy systems, is critical for decarbonising Great Britain. Understanding the uptake of these technologies is essential for several reasons, including ensuring the reliability of electricity distribution networks, achieving national climate targets, and informing the investment strategies of Distribution Network Operators (DNOs).

As Great Britain transitions away from the reliance on fossil fuels, adoption of LCTs will place new demands on electricity distribution networks, particularly during peak periods. EVs will shift the energy source for transport to electricity. Similarly, the installation of heat pumps is central to the decarbonisation of heating in buildings. Embedded generation supplying this new demand will also introduce new methods of network operation and energy storage may operate to reduce or increase these energy flows depending on the markets. All of these changes will increase electricity flows, particularly on the low voltage network. Understanding the uptake of these technologies, the level of flexibility available, and the potential DNO investment strategies is vital to maintaining grid stability and resilience as the energy transition progresses.

Scope of This Report

The purpose of this report is to demonstrate a view of the national impact of LCT uptake on the distribution network. EA Technology's Transform Model® is designed to quantitatively assess future national network distribution network (Low Voltage, High Voltage, Extra High Voltage) capacities and the spectrum of necessary load related expenditure across the entire distribution network. Analysis of the 14 model runs identified in WP1 explores the effects of heating technology uptake rates, high or low demand side flexibility, energy storage availability and distributed generation, challenges of significant demand customers and the impact of a winter stress test, combining maximum winter peak heat demand with low flexibility and no mitigations .

The analysis in this report presents findings on:

- Load related expenditure requirements under different scenarios broken down by timeframe and voltage level.
- Peak network demand and impacts of different technology uptake assumptions along with higher heating demand with lower flexibility availability.
- A discussion of the most prominent traditional network interventions (i.e. new circuits and larger transformers) along with novel solutions such as improved network visibility and dynamic operation.
- The impact of demand side flexibility broken down as implicit and explicit flexibility. Implicit flexibility representing customer-led changes in electricity usage in response to supplier tariff signals. Explicit flexibility representing customers responding directly to DSO requests to change the electricity consumption as an alternative to network upgrades to avoid constraints.

Key Findings

The analysis presented within this report highlights the significant challenges and opportunities presented by the increasing adoption of LCTs across Great Britain. Key findings demonstrate that the rate of electrification, particularly from electric vehicles (EVs) and heat pumps, combined with varying levels of operational flexibility, will play a pivotal role in determining the extent and timing of necessary network investments. Throughout this report, cumulative load related expenditure is presented in undiscounted, 2024 values and refers only to the load related expenditure required by the distribution network to meet the growing demand and generation levels. This does not include investment required as a result of ageing existing infrastructure which may also be significant. The scope of the network covered includes the LV main to EHV and excludes upgrades to service cables along with upgrades to the 132 kV network.

Figure 1 provides a comparison of the undiscounted, load related expenditure over the study period (2024 to 2050) for the core model runs and Table 1, towards the end of the executive summary, provides a breakdown of the peak demand projections. The range of cumulative expenditure up to 2050 for load-related expenditure in the distribution network ranges from £37 billion to £49 billion (undiscounted) across core model runs. The annual investment ranges between £1.4 billion and £1.8 billion per year in the core model runs (Run 01 to Run 06). This range is lower than the range modelled in previous distribution network studies. For example, the joint DESNZ/Ofgem Electricity Networks Strategic Framework modelling suggested an investment range that equated to £2.3 billion - £3 billion per year on average[1]. The higher on average investment range modelled by DESNZ can be accounted for by their inclusion of a 1-in-20 year weather event alongside representative winter days, as well as including the 132 kV network assets which this analysis did not.

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

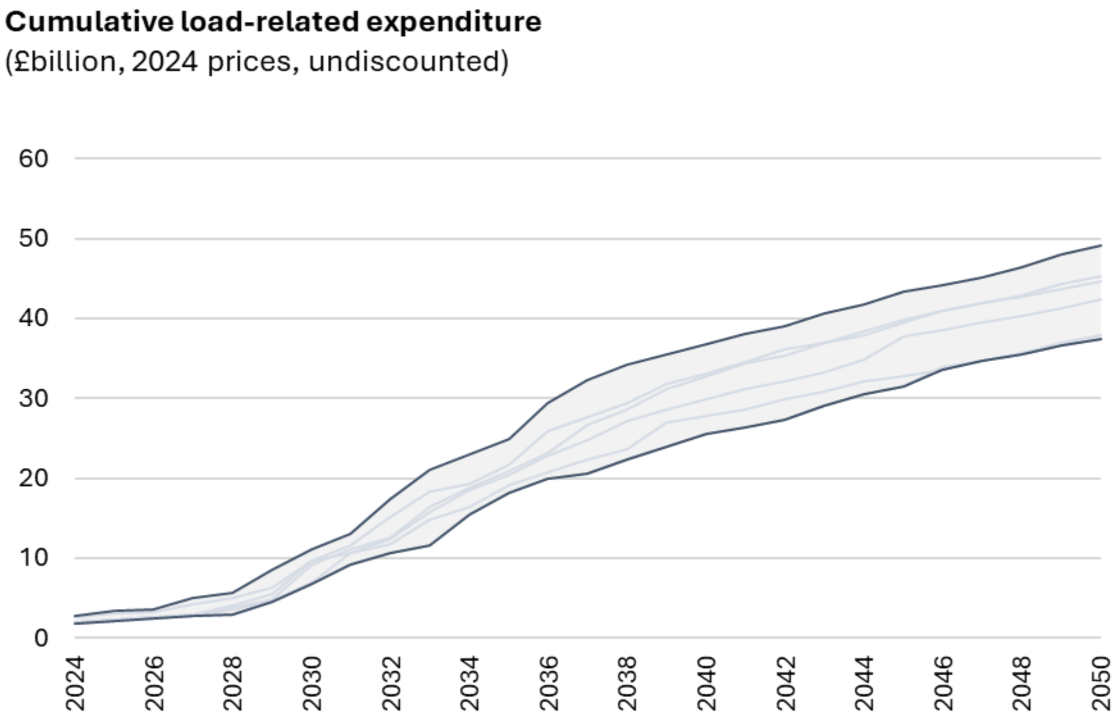

Figure 1 Comparison of cumulative, undiscounted, load related expenditure for the main model runs. Note: excludes 132 kV network and LV service cables.

Electrification of Heat

The uptake of heat technologies, particularly heat pumps, plays a critical role in determining the scale and timing of network intervention. Scenarios with accelerated heat pump adoption show an earlier requirement for network reinforcement, especially at the LV level where localised constraints emerge as more households electrify their heating. Conversely, delaying heat pump adoption results in lower expenditure in the near term but necessitates significant investment post-2035 as adoption catches up. Importantly, reliance on alternative heating technologies, such as electric resistive heating, leads to higher cumulative expenditure throughout the study period due to their higher demand during peak periods.

The impact of a winter stress test, as seen in sensitivity analysis (Run 07), underscores the additional stress that electrified heating could place on the electricity network, leading to much higher peak demand and network expenditure. Peak demand in this scenario reaches 153 GW by 2050, significantly exceeding the 102-119 GW range observed in the core model runs (Run 01 to Run 06). Cumulative expenditure in this scenario reaches £76 billion, far higher than any other, underscoring the need for a detailed discussion on resilience planning. This is in the range of the study outlined by DESNZ and Ofgem, which implemented a 1-in-20 year approach yielding a 185 GW peak in 2050[2].

Flexibility

The scenarios tested emphasise the importance of flexibility in managing network demand. High flexibility scenarios consistently show lower peak demand and delayed network reinforcement compared to low flexibility scenarios. This underscores the potential benefit shifting demand usage can have on reduced network investment. In this analysis, most of the demand reduction was provided through implicit flexibility relating to customers shifting demand usage away from system peaks. As a result, there was limited explicit flexibility, based on the same sources, to achieve further peak demand reduction, which necessitated substantial network infrastructure upgrades.

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

Large Demands and Energy Storage

The sensitivity analyses for industrial and commercial (I&C) demand, data centres, and energy storage provide valuable insights into how these sectors affect future network requirements. Uncertainty around the I&C profile showed that a reduction by 22% (Run 08) resulted in a significant reduction in peak demand and overall network expenditure, emphasising the need for further work to understand the diverse energy demand profiles and decarbonisation pathways in this sector.

The high deployment of data centres (Run 09) increased demand at the EHV level but had a relatively modest effect on cumulative network expenditure due to their concentrated load and minimal impact on LV networks. However, there is still significant uncertainty around the volume, connection voltage and energy demand profiles for data centres as demand for their services increase. A greater volume of data centres or connections into HV or LV networks would likely have a more significant impact on network investment.

Increased small-scale energy storage deployment (Run 10) had limited impact on the overall peak demand due to the limited electricity import or export from small-scale storage at times of peak-demand e.g. morning and evening peaks. Together, these sensitivity runs highlight the need for further investigation around these sectors, their demand profiles and growth rates. Small changes in the assumptions around demand profiles for small-scale storage could have a significant impact on the distribution networks.

Investment Horizons

The deployment of solutions varies depending on the investment horizon considered. Short investment horizons (Run 01 and Run 04) favour lower-cost interventions, such as network monitoring and minor LV upgrades. In contrast, longer horizons (Runs 11-14) focus on major infrastructure upgrades to support the anticipated growth in electricity demand towards 2050. These major upgrades often involve substantial early investments in network capacity to avoid repeated interventions. Runs 11 and 13 aimed to simulate a touch-the-network-once philosophy through the use of a 26-year investment horizon. The results show significant initial expenditure to meet the 2050 capacity requirement but several of these solutions then reach end of life before they are required for the network capacity release. This is a limitation in the modelling approach and as a result are re-deployed multiple times, in practise the network planning engineers would not utilise the time-limited solutions until necessary for capacity release, instead simply ensuring that any earlier upgrades are future proofed as part of the detailed design and cost-benefit assessment.

This report is delivered alongside a data workbook that provides access to a suite of customisable graphs and associated raw data for each scenario.

Table 1 Breakdown of load-related cumulative expenditure and peak demand from all study runs.

Run	Description	Cumulative expenditure (£/billion)[3]	Peak demand 2024(GW)	Peak demand 2035(GW)	Peak demand 2050(GW)
01	High flexibility and typical winter peak (5-Year Investment Horizon)	£37.8	50.6	79.2	107.6
02	High flexibility and delayed heat pump uptake (5-Year Investment Horizon)	£37.0	50.6	77.7	107.6
03	High flexibility and lower heat pump adoption with higher electric resistive heating (5-Year Investment Horizon)	£42.4	51.2	81.3	109.8
04	Low flexibility and typical winter peak (5-Year Investment Horizon)	£44.6	52.5	86.2	115.0
05	Low flexibility and delayed heat pump uptake (5-Year Investment Horizon)	£45.3	52.4	84.8	116.2
06	Low flexibility and high heat pump uptake (5-Year Investment Horizon)	£49.1	53.2	89.6	119.5
07	Weather stress test: higher heating demand with lower flexibility availability (5-Year Investment Horizon)	£76.2	54.8	104.7	152.8
08	Lower I&C demand profiles with high flexibility (5-Year Investment Horizon)	£35.6	45.3	73.3	101.7
09	Higher deployment of data centres with high flexibility (5-Year Investment Horizon)	£38.0	50.8	82.4	113.7
10	Higher initial small-scale storage deployment with high flexibility (5-Year Investment Horizon)	£37.7	50.5	79.8	107.6
11	High flexibility and typical winter peak (10-Year Investment Horizon)	£39.0	50.6	79.2	107.6
12	High flexibility and typical winter peak (26-Year Investment Horizon)	£53.5	50.6	79.2	107.6
13	Low flexibility and typical winter peak (10-Year Investment Horizon)	£44.7	52.5	86.2	115.0
14	Low flexibility and typical winter peak (26-Year Investment Horizon)	£54.1	52.5	86.2	115.0

[3] Cumulative expenditure for load-related expenditure only. This does not include expenditure associated with asset condition based replacement.

Contents

Appendices

1. Introduction

This report, prepared for the National Infrastructure Commission (NIC), investigates the impact of future demand growth on the electricity distribution network across Great Britain. The project is divided into two work packages:

Work Package 1 (WP1)
Several future load scenarios are developed using the Electricity System Operator's (ESO)[4] 2023 Future Energy Scenarios (FES) as the foundation. These scenarios incorporate load profiles from distribution network operators (DNOs) and assumptions, including the potential contribution of implicit demand flexibility, to model decarbonisation pathways. The report and associated dataset contain technical details on these inputs[5].

Work Package 2 (WP2)
WP2 analyses the network impacts of the scenarios developed in WP1, providing an evidence base to assess the potential need for network expenditure across all GB distribution networks. WP2 is split two modelling studies:

- First, the National Modelling carries out national analysis to quantify the additional distribution network capacity required under the various demand scenarios developed in WP1.
- Secondly, the Local Case Study Modelling demonstrates the impact of Low Carbon Technology (LCT) adoption on some case study Low Voltage networks.

This report presents the outputs from the first study, quantifying the capacity required to accommodate future demand growth. The analysis utilises EA Technology's Transform® Model (hereafter "Transform"), a techno-economic tool designed to simulate the performance of the GB electricity network. The study provides insights into the cost and timing of network investment and the role of flexibility under 14 scenarios and sensitivities to ensure the distribution networks can support decarbonisation targets.

Given the growing reliance on electricity for transport, heating, and industrial processes, accurately forecasting LCT uptake is essential to inform investment decisions and ensure grid reliability. The increased engagement in flexibility solutions like demand-side response can help DNOs mitigate some of the pressure on the grid, avoiding costly network reinforcements while maintaining supply security.

This report examines the importance of understanding LCT uptake across Great Britain and highlights the challenges posed by this transition to the electricity distribution networks. Through detailed modelling, it highlights the role of flexibility, infrastructure investment, and strategic planning in supporting electrification of heat and transport, ensuring a sustainable and resilient energy future.

Methodology (section 3) - Describes the modelling approach, data sources, and assumptions used to develop the network scenarios, including details on the scenarios tested.

Transform Overview (section 3.1) - An overview of Transform, its purpose, necessary inputs, analysis approach, and how it was used to assess future distribution network capacity and expenditure needs.

Results (section 4) - Presents the outcomes of the modelling analysis, focusing on the impact of different heat technology uptake rates, varying levels of flexibility, the effect of demand profile changes (heating and industrial) and the impact of data centre, or small-scale storage uptake rates.

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[4] Now known as the National Energy System Operator (NESO)
[5] Regen, Work Package 1: Electricity Distribution Network Capacity Analysis - Scenario development and load profile selection, September 2024

Conclusions (section 5) - Summarises the key findings from the modelling and provides insights into the implications for future network planning, expenditure, and the role of flexibility.

2. Definitions

ADMD	After Diversity Maximum Demand
ASHP	Air Source Heat Pump
CAPEX	Capital expenditure
CLNR	Customer Led Network Revolution
Cumulative Expenditure	Refers to cumulative load related expenditure and throughout this report is presented undiscounted in 2024 values
DNO	Distribution Network Operator
DSO	Distribution System Operator
DSR	Demand Side Response
ESO	Electricity System Operator
EV	Electric Vehicle
FCO	First Circuit Outage
Feeder	A power line through which electricity is passed in a power system
FES	Future Energy Scenarios
FES2023 CT	Future Energy Scenarios 2023 Consumer Transformation
GB	Great Britain
GSHP	Ground Source Heat Pump
GW	Gigawatts (1,000,000,000 Watts)
HV	In the context of this report, the voltage level greater than 230 V.
I&C	Industrial and commercial
ICE	Internal Combustion Engine
kW	Kilowatts (1,000 Watts)
LCT	Low Carbon Technology.
LV	Distribution network voltage, 230 V in the UK.
Load Related Expenditure	Expenditure required by the distribution networks to deliver sufficient capacity for the future electricity demand. This does not consider expenditure associated with age related replacements. Throughout this report, all expenditure is quoted in undiscounted, 2024 values.
Mains	Forms the trunk of the LV network.
Meshed Network	An electricity network where multiple transformers are interconnected to allow electrical current to flow through various paths. Each customer can be fed by more than one transformer.
MW	Megawatts (1,000,000 Watts)
NGED	National Grid Electricity Distribution (formerly Western Power Distribution).

NIC	National Infrastructure Commission
NPg	Northern Power Grid
OHL	Overhead line
OPEX	Operational expenditure
PV	Photovoltaic (solar panels).
Radial Network	An electricity network where there is no meshing between distribution transformers. Each customer can only be fed by one transformer.
Rated Capacity	Each asset on a network has a “rating” which determines the parameters within which the asset can safely operate. Parameter examples: temperature, voltage and current.
Service	The service conductor connects a property to the mains supply.
Statutory Voltage Limits	The measured voltage supplied to a consumer installation must remain within the statutory limits of 230V +10/-6%.
TOTEX	Total expenditure
ToUT	Time of Use Tariff.
Transform	EA Technology’s proprietary modelling toolset, Transform Model®
Transformer Capacity	Provided in kVA, this is the apparent power a transformer is rated to supply.
UGC	Underground cable.
WP1	Work Package 1
WP2	Work Package 2

3. Methodology

This section sets out the methodology employed as part of this study and the principles for how Transform carries out analysis and estimates network expenditure.

3.1 Transform

Transform is a comprehensive tool designed to represent the electricity distribution network across Great Britain (GB). Its primary function is to forecast network expenditure requirements in response to growing electricity demand, particularly from Low Carbon Technologies (LCTs) such as electric vehicles (EVs), heat pumps, and distributed generation.

The model allows network operators and interested parties to evaluate the potential impacts of future demand scenarios and to identify the best investment strategies, blending conventional solutions (e.g., new cables, transformers) with smart solutions (e.g., energy storage, demand-side response). The model projects network performance and expenditure based on the input from uptake forecasts and can support decision-making to ensure that the distribution network can meet future demands as GB transitions to a low-carbon future.

Transform is used by regulators, policymakers, and distribution network operators (DNOs) to assess potential network constraints and the timing and cost of network reinforcements. By incorporating both business-as-usual (BAU) and future-facing smart grid solutions, the model provides a detailed, flexible tool for long-term network planning.

Transform uses network archetypes to refer to representative models of distribution networks that are used 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. By using these archetypes, the Transform model can efficiently evaluate how different networks will respond to increasing adoption of LCTs, and what types of network reinforcements or flexibility solutions will be needed. The use of archetypes allows for a systemic approach to planning, rather than needing to simulate every individual network separately. Details on the archetypes used can be found in Appendix I.

The following sub-sections provide a general overview of the key inputs, analysis and outputs of Transform. Full details on the production of Transform can be found in the Smart Grids Forum – Work Stream 3 report and this report goes into detail around elements specific to this project[6].

3.1.1 Necessary Inputs

Transform relies on a range of input data to build its parametric representations of the networks, simulations of LCT uptake and generate outputs. These inputs include:

- Network Topologies: The model incorporates predefined feeder archetypes that represent common low-voltage (LV) and high-voltage (HV) feeders across GB. These feeder types are configured by defining parameters such as the capacity, number and types of customers, construction arrangements (overhead or cable), and geographical characteristics (rural, urban

[6] Ofgem, Assessing the impact of low carbon technologies on Great Britain's power distribution networks, 3 August 2021: [Assessing the impact of low carbon technologies on Great Britain's power distribution networks | Ofgem]

and sub-urban). For this analysis, 32 archetypes are included in the analysis as detailed in Appendix I.

- Load Profiles: The model uses load profiles that reflect real-world electricity consumption patterns, broken down by property type and LCT. Initial load profiles are provided for different periods, including summer and winter average days, as well as peak winter demand. The load data also incorporates scenarios for implicit flexibility, where loads are adjusted based on supplier led flexible consumption patterns. The load profiles used were derived during WP1 and are detailed separately in Work Package 1: Electricity Distribution Network Capacity Analysis[7].
- Scenario Characterisation: The model's scenario inputs are derived from the analysis carried out in WP1 and reflect various uptake rates of LCTs (e.g., electric vehicles, heat pumps). Each scenario reflects potential pathways for GB to achieve its carbon reduction targets, with varying levels of LCT adoption. Details of the uptake scenarios and sensitivities are detailed in Table 3 and work package 1 for further details.
- Solution Sets: The model includes both conventional and smart solutions, ranging from traditional network reinforcement (new cables, transformers) to advanced technologies like energy storage and dynamic thermal ratings. Each solution is characterised by cost, applicability, and expected benefits in terms of network headroom and legroom (i.e., capacity release). Full details of the solutions considered in this analysis are included in Appendix II.
- Enablers: Some smart solutions require enabling technologies (e.g., control systems, communication infrastructure, etc.). These enablers are also defined in the model, with associated costs and deployment requirements.
- Investment Horizon: Transform allows the user to consider different investment horizons for this analysis. This reflects the number of years into the future that the network is designed to remain compliant for, ensuring that network investment is delivered in an efficient manner but also avoiding assumptions around perfect foresight into network investment need.

3.1.2 Analysis Approach

The Transform Model follows a structured approach to modelling and analysis. It is based on a combination of parameterised networks and scenario-driven demand forecasts. The core steps in the analysis process are:

- Building Network Models: Analysis begins by constructing the set of representative network topologies based on parametric real-world data provided during the model development[8]. These networks are parameterised according to key attributes such as customer density, feeder type, and initial load capacity. The volumes of each network and associated sub-networks based on voltage level which then allows a parametric representation of the GB-wide distribution network covering LV, HV and EHV to be developed.
- Applying Future Scenarios: Once the network models are built, future load growth is applied according to the selected scenarios. The model uses load profiles and LCT uptake rates to simulate the additional demand that will be placed on the network over time. This allows users to test different decarbonisation pathways and the varying impacts on network infrastructure. This also accounts for reductions in demand as a result of energy efficiency measures or new technologies. LCTs are modelled as being adopted in specific geographic areas or "clusters" within a distribution network, where certain regions see higher or lower adoption rates. This reflects real-world behaviour where LCT adoption is adopted by factors such as wealth, urban vs. rural settings, and housing types. Each cluster can have a different impact on the network,

[7] Work Package 1: Electricity Distribution Network Capacity Analysis
[8] Smart Grids Forum – WS3: Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks – EA Technology

depending on the penetration rate of LCTs. For example, a cluster with high EV adoption may experience higher evening peak loads due to vehicle charging patterns. As a cluster reaches saturation, the maximum expected uptake of LCTs, the model shifts focus to a new cluster. The demand patterns change as new clusters of LCT users emerge, allowing the model to simulate the gradual spread of technologies across the network. Further information on clustering can be found in Appendix III

- Assessing Network Constraints: The model runs dynamic simulations to assess when and where network constraints (e.g., thermal or voltage limits) are likely to occur under each scenario. These constraints arise when the capacity of existing infrastructure is insufficient to meet growing demand.
- Applying Solutions: Once constraints are identified, the model applies a cost-benefit analysis to determine the most appropriate solution. The analysis considers the level of capacity release necessary, investment horizon to consider for the additional capacity release and future cost of each solution. The merit order then identified the most appropriate solution or combination to apply until the network can support the forecasted load. Merit order weighting factors in a solutions availability for re-deployment, the disruption caused by installation/operation, lead time, cross network benefits, in combination with TOTEX (Total expenditure) and duration of use.
- Explicit Flexibility: The cost of procuring flexibility services are compared against the cost of implementing a permanent solution. The model uses the volume of flexibility available, the cost of providing flexibility services, and the frequency and duration of required flexibility services against the magnitude of a network constraint to determine whether to deploy flexibility.
- Cost Analysis: The model calculates the costs associated with each solution, both in terms of capital expenditure (CAPEX) and operational expenditure (OPEX). It also takes into account the lifecycle of each solution and when it would need to be replaced or whether it could be relocated elsewhere if it was no longer needed.

3.1.3 Outputs

The outputs generated by Transform provide detailed insights into the future investment needs of the electricity network. Key outputs include:

- Expenditure Profiles: The model generates yearly expenditure profiles showing the total expenditure required to maintain network reliability and meet future demand. This includes a breakdown of costs by network archetype (e.g., LV rural, LV urban, HV sub-urban, etc.) and by individual solutions (e.g., minor works, new transformers, generator constraint management, etc.).
- Network Performance Metrics: The model produces load profiles that show network loading over time, highlighting areas where capacity constraints occur. These metrics are provided on a half-hourly basis for key demand representative days (e.g., winter peak, summer average).
- Solution Deployment: The model tracks the deployment of solutions, indicating the number of times each solution is applied and where it is most effective. This includes both conventional and smart solutions, offering insights into the potential role of new solutions that have not yet been widely deployed.
- Scenario Comparisons: Users can compare the outputs across different model runs and input scenarios, assessing the cost and impact of various LCT adoption pathways. This provides a strategic view of how different policy and technology choices can influence long-term network expenditure.

3.2 Low Carbon Technology Uptake Rates

The LCTs considered include EVs, heat pumps, and distributed generation like solar and storage systems. Uptake rates for these technologies are projected based on the FES 2023 Consumer Transformation scenario (FES 2023 CT) and a scenario with lower heat pump adoption than FES 2023 CT[9]. FES 2023 CT anticipates rapid adoption to meet the UK's 2050 net-zero target. For instance, the scenario envisions high levels of EV adoption by 2030, significant penetration of heat pumps, and a large-scale shift toward renewable electricity generation. Each of these LCTs brings additional load to the electricity distribution network, which is modelled to assess its impact on network capacity and the required expenditure.

Further details on the scenarios modelled are set out in section 3.8 and technical details provided in both the WP1 report and WP2.2 associated data workbook[10-11].

3.3 Low Carbon Technology Profiles

In Transform, a profile is needed for each electrical generation or demand types on each representative day (winter peak, intermediate cool and summer peak generation). These represent the electrical energy the network must be capable of delivering and are broken down into a range of sub-types to account for the variety of different modes of LCT operation. For example, EVs may be charged off-street at domestic or commercial properties or may be charged on-street and with public infrastructure. Additionally, customers may choose to charge overnight in response to lower cost tariffs. The LCT demand profiles used in Transform are set out in WP1.

Demand Diversity

In Transform, a single profile is assumed for each sub-type throughout the study window. It is possible to transition a technology from one sub-type to another (i.e. an EV moving from a non-managed to managed profile) but the profiles themselves do not change. This means that Transform is not currently able to account for aspects such as demand diversity or public charging infrastructure utilisation. Instead, the profiles used already assume a level of diversity. Further information on diversity in profiles can be found in WP1.

Industrial and Commercial Customers

As highlighted in the WP1 report, developing accurate Industrial and Commercial (I&C) profiles poses significant challenges due to the diverse range of consumption patterns across different industries and sectors. To address this, without better information, a single I&C load profile is applied uniformly across all I&C customers in the analysis. This profile is selected and scaled to ensure alignment with the peak demand values indicated in the FES 2023 Consumer Transformation scenario.

I&C customers are distributed across the LV and HV networks at a 75% to 25% split respectively, reflecting the varying network connections typical for businesses of different sizes and electricity demands. This analysis excludes potentially large, locationally specific, and likely higher voltage (132kV) sources of I&C demand e.g. shore-power for shipping. This breakdown provided a more granular understanding of the distribution network's capacity requirements across voltage levels.

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[9] Aurora Energy Sector Modelling for the second National Infrastructure Assessment, Project B, High Heat Pump scenario

[10] Work Package 1: Electricity Distribution Network Capacity Analysis

[11] Work Package 2: National Modelling Data Workbook

3.4 Constraint Types

Through analysis of the Transform constraint identification and output, constraints can be categorised into six common but distinct types.

Voltage constraints

The distribution networks are required to ensure that all customers are supplied with a voltage that remains within statutory limits. For LV connected customers, that is 230 V -6%/+10% (216.2 to 253 V) whilst at HV and EHV it is -/+6%. Where generation or demand is sufficient to exceed these limits a voltage constraint is identified.

In Transform, voltage constraints are split into 2 categories:

- Voltage drop constraints which occur when increases in demand cause the voltage drop along a feeder to exceed the lower limit.
- Voltage rise constraints occur as a result of increased embedded generation, increasing voltages along a feeder until the upper voltage limit is exceeded.

To account for LV networks traditionally predominately only seeing demand supplied, DNOs do not target a 230 V no-load voltage but instead operate at a higher level to provide a greater voltage drop range with a reduced voltage rise range. Transform has assumed voltage headroom and legroom values for each network archetype. Typically, as a starting point, it is assumed that LV networks have 1% headroom and 15% legroom, while HV and EHV networks have 6% headroom and 6% legroom.

Transformer thermal constraints

Transformers have a maximum current that can flow through them before they exceed their safe operating range and ageing is accelerated. It is possible for transformers to have different ratings in terms of demand or generation (reverse power flow) and therefore Transform captures these constraints separately to allow better understanding of the cause:

- Thermal Transformer (Load) constraints occur when the maximum net import to a feeder exceeds the thermal capacity of the transformer.
- Thermal Transformer (Generation) constraints occur when the maximum net export from a feeder exceeds the thermal capacity of the transformer.

Each archetype in Transform has an associated assumed transformer rating and indication of the number of transformers at an associated substation. At LV, these ratings range from 50 kVA for the smallest, rural archetype to 1000 kVA for the archetypes supplying dense urban and commercial districts. At HV the transformer capacities range from 12 to 32 MVA and at EHV 60 to 90 MVA.

Circuit thermal constraints

Like transformers, cables and overhead lines (OHLs) have a maximum current that they can deliver before they exceed their design capacity and risk accelerated ageing or breaching safety tolerances. Circuits do not distinguish between the direction of the power flow (demand or generation) but Transform captures the constraints separately to understand the cause of any necessary intervention:

- Thermal Cable (Load) constraints occur when the maximum net import to a feeder exceeds the thermal capacity of the cable for that particular feeder.
- Thermal Cable (Generation) constraints occur when the maximum net export to a feeder exceeds the thermal capacity of the cable for that particular feeder.

Each archetype in Transform has an assumed circuit rating along with assumptions on the number of circuits that are supplied from each substation. The result is a significant range in circuit ratings, for the LV circuits this ranging from 70 kVA for the smallest, rural archetype with only a single circuit to 400 kVA and 5 circuits per substation for the most densely populated areas. At HV the range is 3 MVA to 7 MVA and at EHV the range is 24 MVA to 42 MVA.

Constraint Identification

Often, multiple constraints, such as thermal transformer and voltage drop limits occur simultaneously on the same feeder. When the analysis is shown in this report, it displays the first constraint that is resolved, and therefore the type of constraint identified in the analysis. Each time a constraint is detected, Transform deploys the most cost-effective solution for T+X years (X is 5, 10 or 26 years in this analysis and T is the year the constraint is identified).

For example, a transformer thermal constraint identified in 2025 could be resolved by installing a larger transformer. This would simultaneously improve the voltage drop capacity of the feeder and ensure that the voltage drop constraint that may have happened in 2026 does not happen and is therefore not recorded.

As LCT uptake continues, new constraints will emerge, requiring additional interventions. For example, a single feeder may face several constraints over the study period, leading to multiple interventions.

3.5 Solutions

Solutions refer to the interventions applied to resolve network constraints. Solutions reflect traditional network upgrades that increase physical capacity and reinforce the network. Examples include replacing transformers, cables or overhead lines with higher capacity options. Broadly speaking, these solutions are characterised by high CAPEX, with longer lead times for planning and construction, but provide long-term capacity relief compared to smart solutions. Newer, more novel solutions are also considered which typically focus on optimising existing infrastructure to release more network capacity. For example, the introduction of real time thermal ratings (RTTR) is one example of a smart solution that through increased monitoring of circuit loading and weather conditions can increase thermal capacity. This is important at LV given the relative lack of data available at LV level.

Details of all the solutions considered in this analysis broken down by their LV, HV and EHV applicability are included in Appendix II.

Investment Horizons 2024 - 2050

When identifying solutions to solve a constraint, Transform aims to resolve based on knowledge of the future demand and generation requirement to ensure that repeat network interventions are not considered within a short duration. This is typically considered to be 5 years, aligning with regulatory windows and avoiding utilising perfect foresight that a model can provide.

As part of this analysis, investment horizons of 10 and 26 years (solving until 2050) were also tested. This means that network interventions are implemented once an initial constraint is identified that avoid repeat visits to the same substation for a longer duration.

3.6 Network expenditure

Network expenditure is the process of allocating resources to upgrade, maintain or optimise the electricity network to accommodate increased demand. To enable comparison against other results and datasets, network expenditure is in 2024 prices, and is not discounted in these runs and in the associated data workbook is provided in annual values. The expenditure is broken down into three financial components: CAPEX, OPEX and TOTEX. CAPEX refers to the upfront cost of upgrading or expanding the physical network infrastructure. OPEX includes the ongoing costs associated with operating and maintaining the network. These costs are incurred regularly. TOTEX is the combined total of both CAPEX and OPEX, providing a holistic view of the overall cost required to maintain and improve the network.

3.7 Flexibility

Flexibility is modelled through two main categories; implicit and explicit flexibility, each representing different mechanisms by which demand-side response (DSR) is integrated into the analysis.

Implicit Flexibility (Customer Led):
Implicit flexibility refers to changes in energy use behaviour by customers in response to external signals, without direct control by the network operators. This type of flexibility is primarily driven by customer actions based on price signals or incentives provided through mechanisms such as:

- Time-of-use tariffs, where trends in wholesale prices are passed onto customers via tariffs
- Tariff innovations based on smart metering and remote control such as dynamic wholesale price trackers
- Demand side response procured at the national level by the Electricity System Operator (ESO)

In this project, implicit flexibility is incorporated directly into the load profiles developed in WP1. These profiles reflect customer behaviour changes due to evolving technology adoption and price responsiveness, which are embedded within the future demand scenarios modelled[12].

Explicit Flexibility (Network Operator Procured):
This 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 (WP1) and is a solution to network constraints modelled in Transform.

Explicit flexibility involves customer response to signals provided by DSOs, to address specific local network constraints. This type of flexibility is seen as a solution to mitigate network issues, such as capacity or voltage violations, and is considered when traditional infrastructure reinforcements (e.g., upgrading transformers) is not cost-effective in the short term.

One benefit that a DSO can obtain from explicit flexibility is accounting for the risk of demand appearing slower than forecast, avoiding unnecessary early network expenditure. For example, a DSO may have identified a transformer that will exceeds its rated capacity for 1-hour on the winter peak based on forecast demand projections. The DSO can enter into a contract with a local business that agrees to reduce its demand for during the winter peak if the DSO requests and in return receives both an availability and utilisation payment (if called upon). The DSO can therefore avoid upgrading the transformer and reassess nearer the winter peak whether they require the local business to reduce its demand for that 1-hour window.

In the Transform Model, explicit flexibility is treated as an alternative to investment in traditional new network hardware or control system solutions. When the model forecasts a network constraint, it compares the cost of procuring flexibility services with the cost of permanent network upgrades. Factors considered in this comparison include:

- The volume of flexibility available.
- The size and frequency of the constraint (e.g., how often the flexibility service will be needed throughout the year).
- The cost to compensate customers for reducing their demand (measured in £/kWh).

[12] Regen, Electricity Distribution Network Capacity Analysis, Work package 1: review of load profiles

Explicit flexibility is applied if it is cheaper than the conventional solution and can defer the need for permanent reinforcements for at least one year. However, as demand increases over time, the flexibility service may eventually be insufficient, at which point permanent solutions are implemented.

Modelling Flexibility in Transform

The model requires several inputs to simulate flexibility services:

- Costs of enabling flexibility: This includes the capital (CAPEX) and operational (OPEX) expenditures required to set up and maintain the necessary infrastructure, such as procurement platforms and communication systems.
- Customer flexibility costs: The cost paid to customers for reducing their demand during constrained periods. It is possible within Transform to define a flexibility cost (£/kWh) by each technology type to reflect a consumer's willingness to provide flexibility for each technology. For example, a customer may be willing to shift EV charging for a lower cost than heat pump flexibility during the winter. However, there are currently no large datasets to inform these prices from the flexibility services that have been procured and so for the purposes of this project all technologies are assumed to respond to the same cost.
- Availability: In this analysis, it has been assumed that customers which are engaged and provide implicit flexibility (i.e. response to market signals) are those that are also most likely to provide explicit flexibility. Therefore, in scenarios with low implicit flexibility, the availability of explicit flexibility is also assumed to be low.

Flexibility services are considered on a rolling one-year basis, meaning that each year, the model re-evaluates whether the service can continue to meet demand or if permanent upgrades are required.

Each of the GB DNOs provide an annual dataset of the flexibility service contracts they have tendered for and successfully procured. This is part of the Ofgem C31E Procurement and Use of Distribution Flexibility Services Annual Report process[13]. The Energy Networks Association provides an annual summary on the GB flexibility figures as part of their Open Networks project[14]. Table 2 sets out the costs considered in Transform and has been produced based on the compilation of the C31E reporting of the individual DNOs.

Table 2 Solution costs required for explicit flexibility in Transform with CAPEX reflecting the implementation of the system and OPEX being the ongoing maintenance.

Connection Level	CAPEX (£)	OPEX (£)	Description
EHV	£6,979	£48,851	DNO triggered Demand Side Response to interact with customer load to resolve generation / demand EHV network constraints
HV	£6,979	£27,915	DNO triggered Demand Side Response to interact with customer load to resolve generation / demand HV network constraints
LV	£1,396	£56	DNO triggered Demand Side Response to interact with customer load through an aggregator to resolve generation / demand LV network constraints

[13] Ofgem, Electricity Distribution Standard License Condition 31E: Flexibility Procurement Statements 2021 - [Electricity Distribution Standard Licence Condition 31E: Flexibility Procurement Statements 2021 | Ofgem]

[14] ENA ON GB Flexibility Figures 2023/2024: [ENA ON GB Flexibility Figures 2023/2024 – Energy Networks Association (ENA)]

The required volume of flexibility is determined by the size of the network constraint it is meant to resolve. The model calculates the exact volume of flexibility by determining how much demand needs to be shifted or generation needs to be curtailed to alleviate the identified network constraint. This calculation depends on factors such as:

- Peak load reduction needed to bring the network back within operation limits.
- Duration of peak events (how long the flexibility must be provided).
- Frequency of flexible events (how often the flexibility service will need to be called upon).

After the volume of flexibility is calculated, the model checks if the available flexibility resources can provide the required volume and duration of relief. This included assessing the available electricity demand reduction from flexibility resources like battery storage and LCTs capable of providing flexibility in the model.

Flexibility Assumptions

The following assumptions are made when carrying out flexibility modelling in Transform:

- ESO / DSO Conflict: There could be a conflict of signals between ESO and DSO instigated flexibility services and there is ongoing activity in the industry to avoid this through the ENA led 'Primacy Rules' work[15]. As those rules have not been fully defined and agreed, it is not currently suitable to model that behaviour.
- Energy Not Supplied: The analysis carried out by Transform assumes that the energy associated with a customer providing explicit flexibility will need to be provided at a later point in time. For example, if a customer is paid to reduce their EV charging demand it is assumed they will still need to charge their EV at some point. The maximum window within Transform modelling for the load to be shifted is 24 hours and therefore any demand reduction must be returned within 24 hours without creating a new constraint. In reality, consumers are not restricted to a hard 24-hour window.
- Costs for Flexibility Procurement Platforms
  When Transform deploys a solution, they are deployed for the specific network archetype that is facing the constraint. This may not align with the approach a DNO is likely to take, instead procuring a system to coordinate flexibility services across a region or voltage level. Despite this limitation, the approach still demonstrates the scaling nature of necessary flexibility platforms and services as LCT uptake increases and the network becomes more constrained.

[15] ENA ON – Primary Rules for ESO/DNO Coordination: [ENA ON - Primacy Rules for ESO/DNO Coordination – Energy Networks Association (ENA)]

3.8 Modelling runs

The variable modelling runs shown were developed in WP1. These 14 runs can be summarised as 8 different tests:

- Impact of heat technology uptake with higher levels of flexibility
- Heat technology uptake with lower levels of flexibility
- Winter stress test
- Lower industrial and commercial (I&C) demand profiles from possible flexibility
- Very high deployment of data centre capacity
- Higher initial small-scale storage deployment
- Changes to investment horizon (10-year and to 2050) with higher levels of flexibility
- Changes to investment horizon (10-year and to 2050) with lower levels of flexibility

A detailed description of each of the modelling runs can be found in Table 3, and information on their purpose in work package 1 report.

Table 3 Table of network capacity modelling runs.

Run	Test	Heat Technology Uptake Rate	Flexibility Level and winter weather conditions	Winter Weather Conditions	Investment Horizon
01	Testing impact of different rates of heat technology uptake with higher levels of flexibility	FES 23 Consumer Transformation	Higher levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.	Typical winter peak	5 years
02		FES 23 Consumer Transformation with delayed heat pump uptake			5 years
03		Lower heat pump adoption with higher electric resistive heating			5 years
04	Testing impact of different rates of heat technology uptake with lower levels of flexibility	FES 23 Consumer Transformation	Lower levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.	Typical winter peak	5 years
05		FES 23 Consumer Transformation with delayed heat pump uptake			5 years
06		Lower heat pump adoption with higher electric resistive heating			5 years
07	Winter stress test: higher heating demand with lower flexibility availability	FES 23 Consumer Transformation	Lower levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.	Winter stress test	5 years
08	Testing impact of lower I&C demand profiles from possible flexibility	FES 23 Consumer Transformation	Higher levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.	Typical winter peak	5 years
09	Testing impact of very high deployment of data centre capacity	FES 23 Consumer Transformation	Higher levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.	Typical winter peak	5 years
10	Testing impact of higher initial small-scale storage deployment	FES 23 Consumer Transformation	Higher levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.	Typical winter peak	5 years
11	Testing impact of changes to investment horizon with higher levels of flexibility	FES 23 Consumer Transformation	Higher levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.	Typical winter peak	10 years
12		FES 23 Consumer Transformation		Typical winter peak	To 2050
13	Testing impact of changes to investment horizon with lower levels of flexibility	FES 23 Consumer Transformation	Lower levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.	Typical winter peak	10 years
14		FES 23 Consumer Transformation		Typical winter peak	To 2050

3.9 Assumptions

In the Transform analysis, there are some inherent assumptions made in the approach and the key ones along with potential impact are listed below.

- This analysis only focuses on load related expenditure to meet growing network demand and generation requirements. This inherently ignores asset health related expenditure which could lead to some existing assets being due for replacement and that being utilised as an opportunity to invest in larger capacity assets to avoid a future load related expenditure.
- When considering the investment horizon, solutions are deployed based on the capacity required by the network at the end of the investment horizon period. The 26-year horizon is used to represent a "touch-the-network once" approach to network expansion. However, due to some solutions having a shorter lifetime this can lead to deployment of solutions which expire and are re-deployed before the future capacity need is reached (this is depicted graphically in section 4.5.1). In practice, a distribution network would not deploy this intermediate solution unless there was a significant level of uncertainty in their network forecast. The result in this analysis is a higher capital expenditure than would be realised in practise, recognising that this approach already assumes perfect foresight on future network demand and generation forecast.
- The lifetime of assets on the network prior to the modelling start date is not considered. Existing assets are assumed to continue operating until 2050. This means Transform does not consider the replacement of assets due to end of life and is only focussed on load related expenditure. The requirement of networks to replace old assets will require additional expenditure and, in some cases, may increase capacity alongside that replacement.
- In GB, DNOs are not currently allowed to own battery storage, and it is assumed for the purpose of this analysis that will continue.
- Fault levels (the capacity for a network to handle faults) remain unaffected by loads or generators at higher or lower voltages. This simplification allows the model to focus on other capacity constraints without recalculating fault levels based on different network voltage levels.
- As a parametric model based on representative feeders, Transform is not an exact replica connectivity model of the distribution network. To capture the full diversity of feeders on the physical network a full connectivity model would need to be developed, which is out of scope for this project. To ensure that the model is representative, various verification checks have been conducted to ensure key input and output parameters in the model are in alignment with observed values. EA Technology have engaged with DNO members providing network modelling information, and solution lists prior to engaging in modelling runs.
- Demand diversity - A static profile is assumed for each technology subtype throughout the study. Technologies can transition between profiles (e.g., non-managed to managed EV charging) but without changing the profiles themselves. This approach does not fully account for demand diversity and so a particular level of diversity is embedded within the static profiles.
- Winter stress test (Run 07) – This sensitivity assumes an increase in the demand for heating during the winter peak. In Transform, the analysis assumes that a winter stress test with higher heating demand occurs every year rather than a 1-in-10 or 1-in-20 style of assumption. This leads to a requirement to ensure the network is able to meet that heightened demand every year rather than occasionally. The year that a winter stress test event may occur is unknown, thus the network must be sufficiently reinforced to deal with the occurrence at any year of the study period, meaning the demand must be considered in relation to other loads in all years. In practice, it is possible that alternative solutions could be considered for an occasional winter stress test such as accelerated asset ageing or greater use of explicit flexibility however, it is impossible to determine what year this would occur and therefore how this would balance with the requirement of other technology deployment on the network.
- Clustering of LCTs – When the Transform model allocates LCTs to network archetypes it ensures that the number of LCTs does not exceed the number of properties available. 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.

- 2024 expenditure – Transform applies the same LCT profile for every year in the study window and makes certain assumptions around available network capacity for each archetype (Appendix I). Additionally, an assumption around the LCT uptake in 2024 and its distribution to each of the network archetypes is necessary to build upon in the subsequent study years. As a result, the analysis shows some level of expenditure is needed in 2024 to ensure there is sufficient network capacity to meet the 2024 winter peak demand assumptions. This investment can vary between the study runs to account for different LCT profiles such as the winter stress test (Run 07) scenario.

4. Results

4.1 Overview

This section presents an overview of the national analysis results. This analysis quantifies the additional distribution network capacity required under the various future scenarios developed in WP1. It explores the impacts of different LCT uptake rates, varying levels of flexibility, and changes in demand profiles for significant customers. Additionally, the effect of assumptions around investment horizons is assessed to provide insights into how distribution network planning can accommodate future energy demand.

This section presents an overview of some of the key trends across all the results with a more detailed comparison between specific model runs highlighted in subsequent sections. Table 4 provides a breakdown of how the runs are compared in the subsequent report sections.

Table 4 Overview of comparisons between modelling runs and relevant results section.

Description	Comparison	Relevant Section
Impact of heat technology uptake	Runs 01 vs 02 vs 03 Runs 04 vs 05 vs 06	Section 4.2.1 Section 4.2.2
Winter stress test	Run 01 vs Run 07	Section 4.2.3
High implicit flexibility vs low implicit flexibility	Runs 01 vs 04 Runs 02 vs 05 Runs 03 vs 06	Section 4.3
Testing lower levels of I&C demand	Run 01 vs Run 08	Section 4.4.1
Data centre demand uptake	Run 01 vs Run 09	Section 4.4.2
Higher initial small-scale storage uptake	Run 01 vs Run 10	Section 4.4.3
Impact of investment horizons	Runs 01 vs 11 vs 12 Runs 04 vs 13 vs 14	Section 4.5

4.1.1 Demand Overview

Table 5 presents the peak electricity demand for all the runs in 5-year increments and Figure 2 presents this graphically. The initial peak demand during 2024 ranges from 51 to 53 GW across the core model runs and rises to between 108 and 119 GW by 2050. This is excluding Run 07 and Run 08, with Run 07 testing the impact of higher heating demand with lower flexibility availability and Run 08 testing the impact of reduced I&C demand.

During 2024 there is a range in starting peak demand values, this is a result of needing to assume the same demand profiles throughout the study period. For example, in the winter stress test scenario there is significantly more demand for heating which results in a greater 2024 peak demand (55 GW vs 51 GW in Run 01).

In the near-term (2024 – 2030), peak demand increases at a steady pace and is largely consistent across all study runs with the exception of Run 07. In the mid-term (2030 – 2040), technology uptake accelerates with peak demand increasing more than 50% (30 GW) over the 10-year window. Additionally, the differences in assumptions around heating choices (Runs 01 to 03) and flexibility (Runs 01 vs 04) become more pronounced.

In the long term (2040 – 2050), the increase in demand stabilises as all scenarios converge towards net-zero goals. The peak demand across the core runs now covers 108 to 119 GW to highlight the varying levels of peak demand based on levels of technology uptake, flexibility, weather, sectoral demand and investment horizons. While all scenarios aim to achieve net-zero goals by 2050, the pace and intensity of technology adoption differ, resulting in the differences outlined in peak demand across the period.

Table 5 Peak electricity demand (GW) for each run in 5-year increments across the 26-year window.

	Peak electricity demand (GW)						
Run	2024	2025	2030	2035	2040	2045	2050
01	50.6	51.2	60.2	79.2	96.4	104.0	107.6
02	50.6	51.2	59.9	77.7	95.4	103.5	107.6
03	51.2	52.3	62.8	81.3	98.4	105.7	109.8
04	52.5	53.5	64.9	86.2	104.5	111.7	115.0
05	52.4	53.4	64.4	84.8	103.5	111.8	116.2
06	53.2	54.7	67.5	89.6	107.8	115.3	119.4
07	54.8	56.5	74.0	104.7	133.0	146.7	152.8
08	45.3	46.0	54.9	73.3	90.5	98.1	101.7
09	50.8	51.5	61.6	82.4	101.0	109.5	113.7
10	50.5	51.1	59.9	79.8	96.4	104.0	107.6
11	50.6	51.2	60.2	79.2	96.4	104.0	107.6
12	50.6	51.2	60.2	79.2	96.4	104.0	107.6
13	52.5	53.5	64.9	86.2	104.5	111.7	115.0
14	52.5	53.5	64.9	86.2	104.5	111.7	115.0

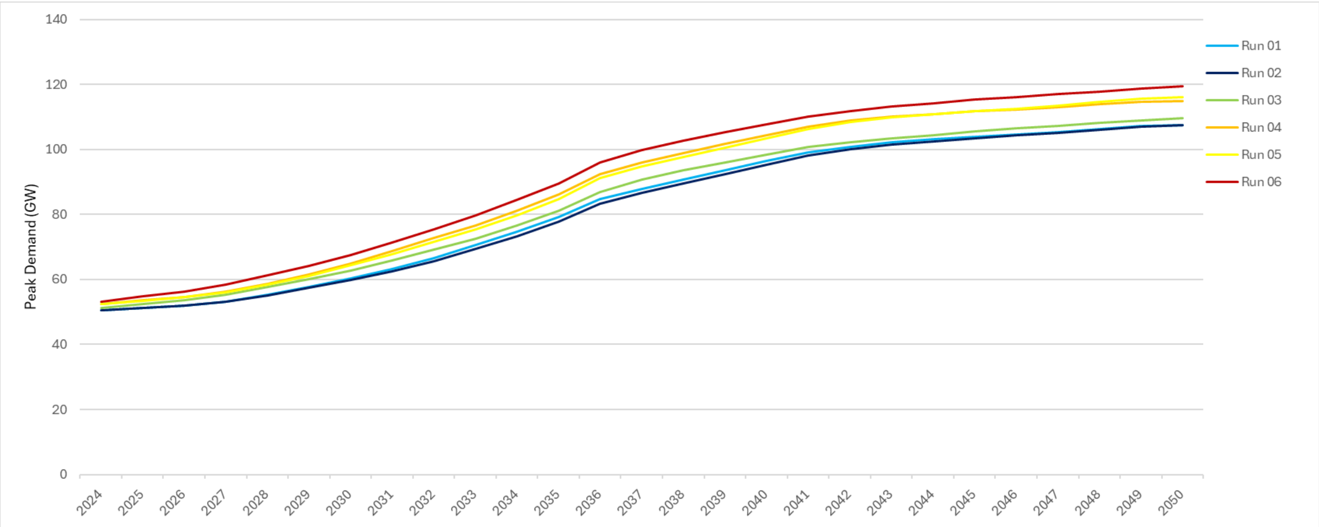


Figure 2 Peak demand between 2024 – 2050 across Runs 01-06.

4.1.2 Aggregate Demand Profiles

This section includes an analysis of the aggregate within day, half-hourly profiles for the three representative days: winter peak, intermediate cool, and summer peak. These profiles are presented to show how they change over the 26-year study window (2024 to 2050) and Run 01 has been used an example. Further comparison between runs is provided where relevant in the subsequent sections.

The half-hourly profiles provide insight into the fluctuations in electricity demand throughout the day, highlighting the peaks and troughs that drive network capacity requirements and expenditure decisions. As new demand and generation is connected to the network and depending on the level of implicit demand flexibility, these change over time introducing new peaks (section 3.7).

Winter Peak Demand

During the winter peak period, demand is driven primarily by heating and evening lighting, alongside other domestic and commercial loads. The half-hourly profile is currently characterised by a rise in demand in the late afternoon and early evening, coinciding with residential heating, cooking, and lighting needs. The growth in electrification of heat is also expected to play a significant role in driving up demand during this period, as their operation coincides with the coldest part of the day. EV charging also contributes to this evening peak, though managed charging can help shift some of this load to later in the evening or overnight, reducing the strain during the critical 17:00 to 19:00 period. Figure 3 demonstrates how the profile changes over the period for the high flexibility scenario (Run 01), the evening peak reducing relative to the morning peak but with an overall increase in electricity demand.

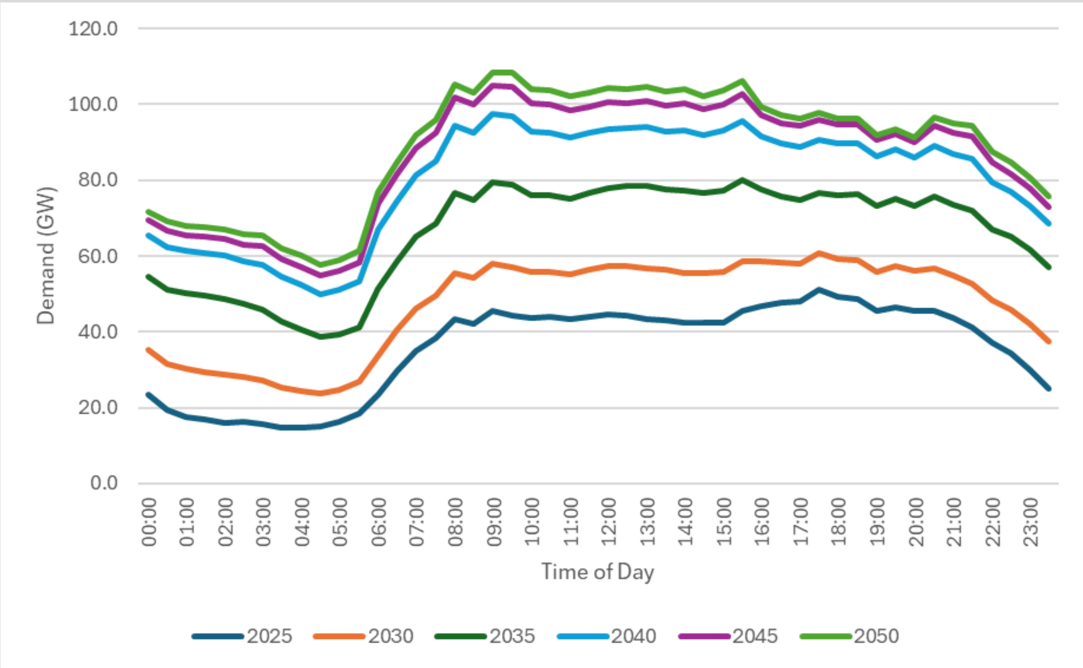


Figure 3 Winter peak demand profile from 2025 to 2050 for Run 01.

Intermediate Cool

The intermediate cool day profile presents a more balanced demand pattern compared to the winter peak. This is typically referred to as the shoulder season by distribution networks and considered as an assessment of the network's capability to meet demand conditions outside of the winter stress test and summer scenarios. While heating demand is still a factor, it is less intense. Generation starts to play a greater role, reducing the demand during the middle of the day. Figure 4 shows the change in the daily profile over the study period for the high flexibility scenario (Run 01), there is limited difference to the winter peak demand profile and therefore is not expected to be a driving factor in requirement for network intervention.

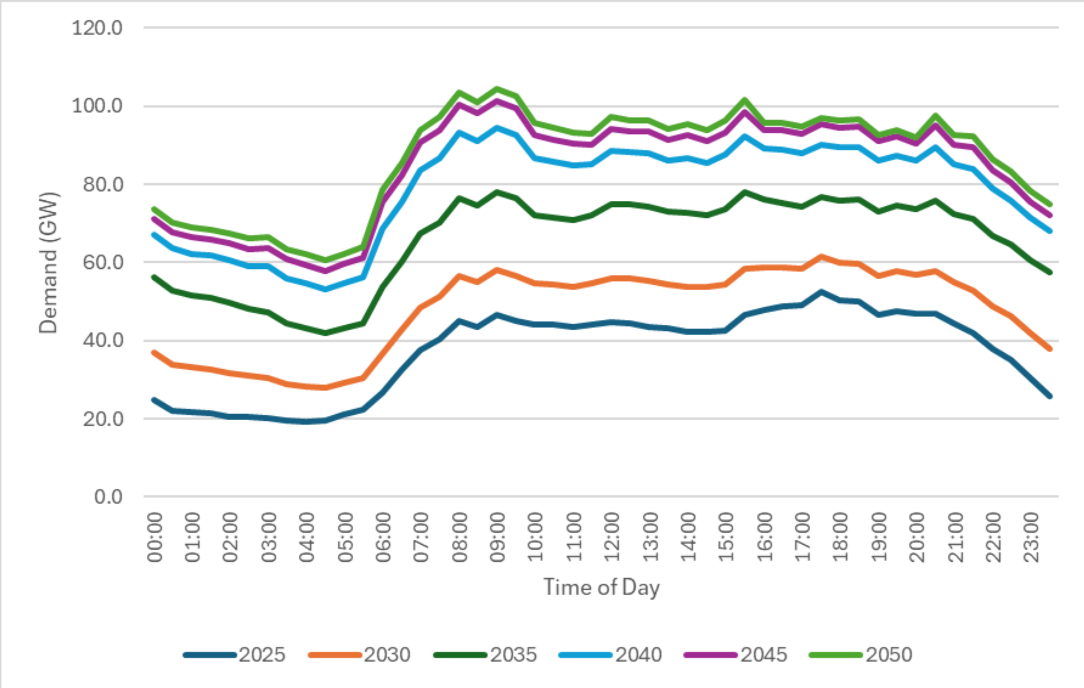


Figure 4 Intermediate cool demand profile from 2025 to 2050 for Run 01.

Summer Peak Generation

In the summer peak profile, the focus is on minimum demand and maximum generation conditions. There is a significant reduction in heating demand but increased volumes of embedded generation. With longer daylight hours and higher temperatures, lighting demand is lower, and heat pumps are used less frequently. However, the reduced demand combined with increases in solar generation can result in reverse power flows and associated network expenditure. Figure 5 shows that over the study window, the increase in embedded generation, particularly solar photovoltaic leads to an increase in export. Increased curvature of the profile out to 2050 reflects the uptake in solar photovoltaic and the generation output associated with solar generation. In this analysis, energy storage is also modelled and profiles assumed for small scale storage show an absorbing of excess generation during the morning before capacity is reached and net export increases. Further details on each of the profiles for solar generation and small-scale storage are available in WP1.

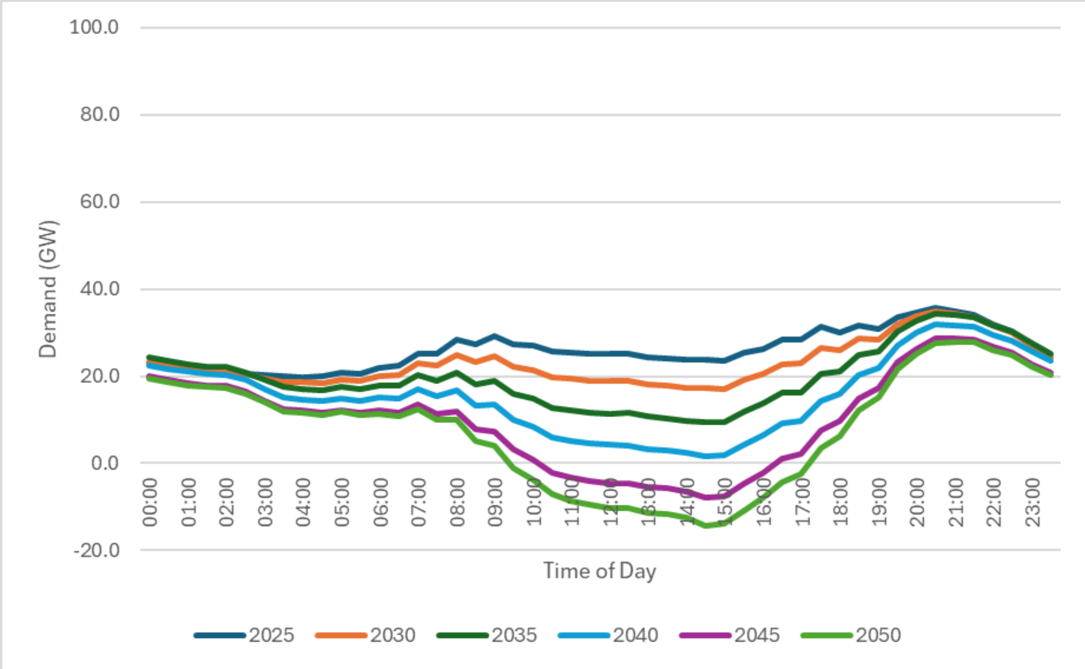


Figure 5 Summer peak generation profile from 2025 to 2050 for Run 01.

4.1.3 Archetypal Demand Profiles

The previous section has presented the aggregate demand profiles across the system, but it is important to recognise that not all archetypes will peak at the same time. This diversity ensures that the HV and EHV networks do not have to be able to deliver the peak demand for all archetypes but does mean that some LV archetypes may experience different peaks and therefore investment needs.

Figure 6 provides an example of the range in archetypal demand profiles for the following 3 archetypes (selected due to having a similar peak at different times of day):

- LV03 – Town Centre – 2050 peak at 09:30
- LV08 – Terraced Street – 2050 peak at 16:00
- LV09 – Rural village (overhead construction) – 2050 peak at 08:00

The plots show how initially the demand on the town centre archetype is greatest during the day and reduces early evening whereas the rural village and terraced streets show more of your evening peak (17:00 -19:00). However, as new LCTs connect to the system the demand patterns significantly shift. The town centre (LV03) now having a significant morning peak (09:00-10:00). The terraced street (LV08) and rural village (LV09) showing the clear impact of profiles associated with implicit flexibility and reducing demand early evening (17:00-20:00). Instead, the demand during the day is largely constant with a heightened morning peak (09:00-10:00) and late afternoon peak (16:00-17:00).

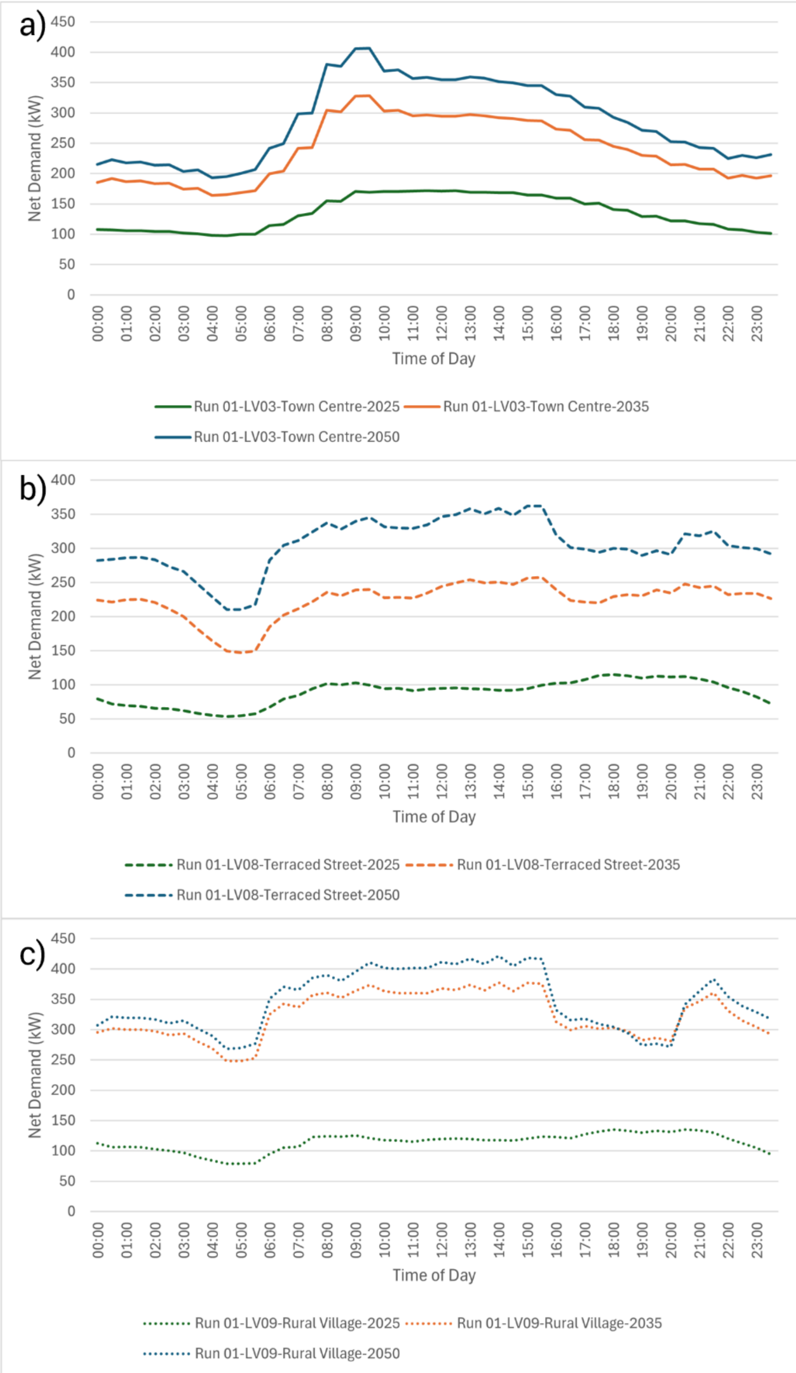


Figure 6 Winter peak net demand profile for archetypes a) LV03, b) LV08 and c) LV09.

4.1.4 Load Related Expenditure Overview

Table 6 shows the undiscounted, cumulative, load related expenditure in 5-year increments for all 14 runs and Figure 7 presents this graphically. There is initial network intervention shown in 2024 and this is as a result of initial investment needed to ensure the model has sufficient capacity for the winter 2024 peak. This occurs as a result of the profiles and technology uptake volumes assumed for the start year combined with starting network capacity. For a breakdown of load related expenditure by voltage tier, see Section 4.3, Impact of Flexibility.

Initial expenditure in 2024 starts relatively low, around £2-3 billion for Runs 01-06, testing the impact of different uptake rates of heat technology, and Runs 09-10, exploring very high deployment of data centres, and higher small scale storage deployment. The impact of the winter stress test (Run 07) yields higher initial expenditure of £8 billion in 2024 due to assumptions around the network capacity needed to ensure the network is resilient to higher winter peak electrical heating demands (detailed further in section 4.2.3). Runs 11 and 13 show large initial expenditure required in 2024, £4 billion each, and this is a direct result of ensuring that solutions deployed are sufficient to meet the 2050 target (detailed further in section 4.5).

Table 6 Cumulative load related expenditure (undiscounted) between 2024-2050 for all 14 modelling runs.

Cumulative load related expenditure (£/billion)[16]							
Run	2024	2025	2030	2035	2040	2045	2050
01	£2.0	£2.3	£6.9	£19.1	£27.8	£32.8	£37.8
02	£2.0	£2.3	£6.7	£18.2	£25.5	£31.6	£37.5
03	£2.6	£3.1	£9.6	£20.4	£29.8	£37.7	£42.4
04	£2.0	£2.4	£9.6	£21.8	£33.1	£39.9	£44.6
05	£1.8	£2.1	£9.2	£20.9	£32.8	£39.6	£45.3
06	£2.8	£3.3	£11.1	£24.9	£36.8	£43.3	£49.1
07	£8.1	£8.3	£22.5	£38.2	£58.1	£68.3	£76.2
08	£2.1	£2.1	£5.4	£18.0	£24.6	£29.6	£35.6
09	£2.0	£2.3	£6.9	£19.2	£27.8	£32.9	£38.0
10	£2.0	£2.3	£6.9	£19.7	£28.0	£33.0	£37.7
11	£3.6	£4.1	£9.0	£21.8	£29.8	£34.8	£39.0
12	£8.2	£9.2	£16.7	£29.8	£37.5	£46.2	£53.5
13	£4.0	£4.7	£13.5	£24.4	£35.3	£40.1	£44.7
14	£7.8	£8.9	£19.6	£32.7	£41.9	£47.8	£54.1

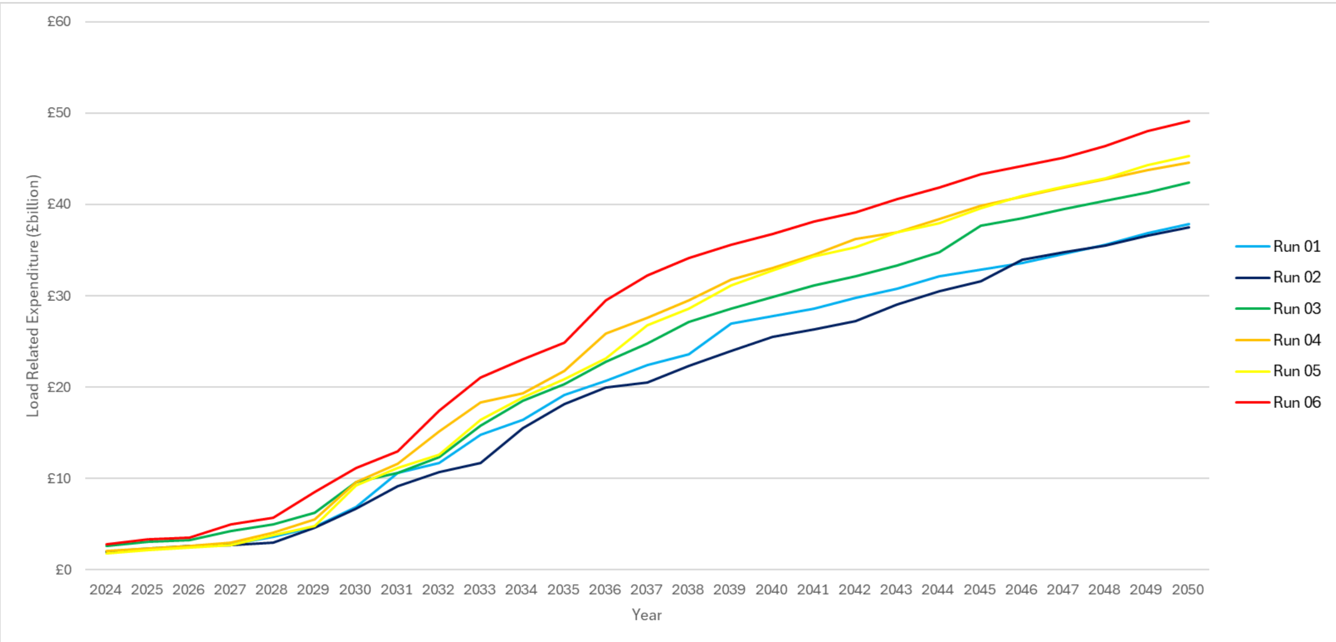


Figure 7 Cumulative load related expenditure between 2024 – 2050 for all core runs.

There is significant mid-term growth in expenditure between 2030-2040. By 2030, cumulative expenditure ranges from £7 billion (Run 02) to £22 billion (Run 07). Once again Runs 07, 12 and 14 show significantly higher load related expenditure compared to the other runs. This continues to rise and by 2040 ranges from £24 billion (Run 02) to £58 billion (Run 07). The variance between different runs becomes more pronounced during this period, reflecting the different scenarios and investment horizons.

Runs 01-3 show final cumulative expenditure around £37-42 billion with Run 03 showing slightly higher investment due to the increased use of electric resistive heating. Runs 04-06 show higher final cumulative expenditure between £45-49 billion, a direct consequence of lower levels of implicit and explicit flexibility assumptions compared to Runs 01-03.

The range across the core runs (01-06) is £37-49 billion which equates to, on average, around £1.5 billion to £1.9 billion per year over the period analysed. These investment levels represent a significant increase compared to recent price control budgets as shown in Table 7. They are lower than previous analysis carried out by DESNZ (Table 8) but there is overlap with Run 07. The DESNZ analysis included 132 kV associated load related expenditure, which has not been included in this study along with delivering an overall higher peak demand. The DESNZ analysis incorporates 1-in-20 year weather event profile which will also deliver an overall higher peak demand.

Table 7 Historical distribution network operator budgets and expenditure.

	Allowed load-related investment	Actual expenditure
RIIO-ED1 Price Control[16] (Apr 2015 to Mar 2023)	£363m per year	£274m per year
RIIO-ED2 Price Control[17] (Apr 2023 to Mar 2028)	£640m per year	Data not available yet

Table 8 Results from the Electricity Networks Strategic Framework[18].

Study information	Cumulative investment	Average annual investment
Net zero higher demand (185 GW peak demand in 2050)	£90 billion to 2050 (undiscounted, 2020 prices)	£3 billion per year
Net zero lower demand (140 GW peak demand in 2050)	£70 billion to 2050 (undiscounted, 2020 prices)	£2.3 billion per year

Compared to Run 01, testing the impact of higher deployment of data centres (Run 09) and small-scale battery storage (Run 10) show little impact on overall cumulative expenditure, totalling around £38 billion. Run 08 assumes a reduced I&C demand, accounting for energy efficiency measures across that industry and this leads to a corresponding reduction in load related expenditure to £36 billion. Runs 11 and 13 show final cumulative expenditure at similar levels to Runs 01 and 04, suggesting that increasing the investment horizon from 5- to 10- years may have minimal difference on overall load related expenditure by 2050, detailed further in section 4.5.

[16] RIIO-1 Electricity Distribution Annual Report 2021-22 and Regulatory Financial Performance Annex to RIIO-1 Annual Reports | Ofgem Tab: CH4 expenditure drivers 2
[17] RIIO-ED2 Final Determinations Core Methodology Document (ofgem.gov.uk) Paragraph 3
[18] Electricity networks strategic framework Appendix I: Electricity Networks Modelling (publishing.service.gov.uk)

4.1.5 Typical Constraints

As outlined in section 3.4, constraints can be categorised as relating to demand or generation increases and whether they cause voltage or thermal (transformer or circuit) ratings to be exceeded. As an example, Figure 8 shows the constraints placed on the network for Run 01 between 2024-2050[19]. The total number of constraints increase until 2035, before tapering off after 2036.

Thermal constraints across both transformers and cables dominate in each period, with the highest peak occurring in 2031-2035. This suggests that a large number of interventions will be required to resolve thermal constraints, so solutions that release thermal headroom, such as new transformers and circuits have the potential for widescale deployment. Load growth from EVs and heat pumps drive the demand on the LV network and drive a lot of these constraints.

It is typically expected that voltage drop constraints are a bigger concern than thermal constraints which has not been captured in this analysis. There are a couple of elements driving this:

- Resolving a thermal constraint through the implementation of a network intervention for example through the introduction of a new transformer, cable circuit or tap changing scheme will also release voltage legroom. Therefore, those voltage drop constraints may well have occurred alongside the thermal constraint should it not have been resolved.
- As detailed in section 3.4, the distribution networks typically operate towards the upper end of their statutory voltage range and the modelling assumptions have assumed a starting headroom of 1% and legroom of 15%. If the networks were operating closer to nominal (+10%/-6%) then more voltage drop constraints could be expected.

Voltage rise constraints will be experienced on feeders across all periods, typically corresponding to the summer peak generation representative day. In some instances, solutions that resolve thermal constraints (i.e. increasing transformer capacity) will also create additional voltage headroom and resolve voltage constraints at the same time. However, there are some solutions, such as dynamic voltage management, which focus on resolving voltage constraints specifically.

[19] These are the first constraint identified for the analysed archetype during each study year. Additional constraints could also need resolving and so solutions are identified that resolve all constraints.

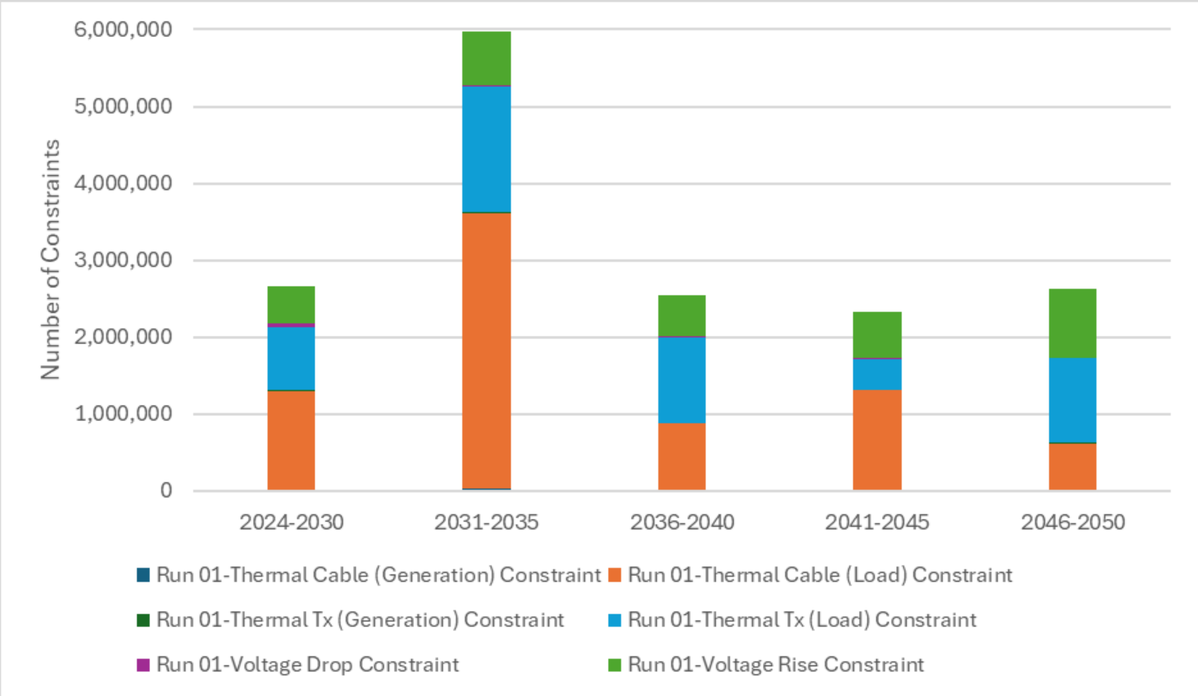


Figure 8 Constraints placed on the network during Run 01 across 2024-2050[20].

4.1.6 Typical Solutions

While the 14 modelling runs vary by uptake rates, flexibility and expenditure horizon, there are typical solutions deployed across the 26-year study period, regardless of the scenario tested. Due to the volume of circuits and growth in demand on the LV network, the majority of solutions are deployed on the LV network. For example, in Run 01 there are 860k solutions deployed of which 93% are on the LV network, 6% on the HV and 1% at EHV.

Figure 9 shows a breakdown of the 860k solutions and 247k enablers installed on the network over the study window for Run 01. The volume of solutions needed during each 5-year interval remaining largely constant with the trend in the number of constraints met.

Figure 10 presents a breakdown of the typical solutions deployed during Run 01 on the LV network over the full study window. There is a heavy reliance on new physical builds and network upgrades such as LV overhead minor works, LV ground mounted transformers and permanent meshing of networks. The following sections present comparisons of the other runs to highlight differences, but these solutions were consistently high across all the runs, reflecting a strong requirement for infrastructure upgrades to release sufficient capacity.

There are some solutions seen in reasonable proportions on the LV networks and in HV networks (Figure 11) that highlight a significant investment in use of data to increase utilisation of existing assets. This can be seen in the form of the increased use of LV network monitoring combined with real time thermal ratings (RTTR) and active network management[21].

Figure 12 shows the breakdown of solutions for Run 01 at the EHV level. There is a strong mixture of use of network data to dynamically operate the network to increase the capacity from existing infrastructure as shown by the use of RTTR and active network management. Alongside this, there is also a need for new build infrastructure and interventions to upgrade capacity from the existing circuits.

Solutions such as permanent meshing of networks at the LV, HV and EHV levels appear frequently in several runs, indicating a focus on releasing capacity through improvements in balancing of demand across the

[20] This figure can be interrogated further in worksheet NC2 of the accompanying data workbook
[21] Active network management in this context refers to the dynamic reconfiguration of the network rather than the re-dispatch of embedded demand and generation which is captured through explicit flexibility.

feeders. It should be noted that this is technically very challenging to do, requiring a high level of engineering involvement to understand the impact on both the local and wider network in terms of protection schemes and supply resilience.

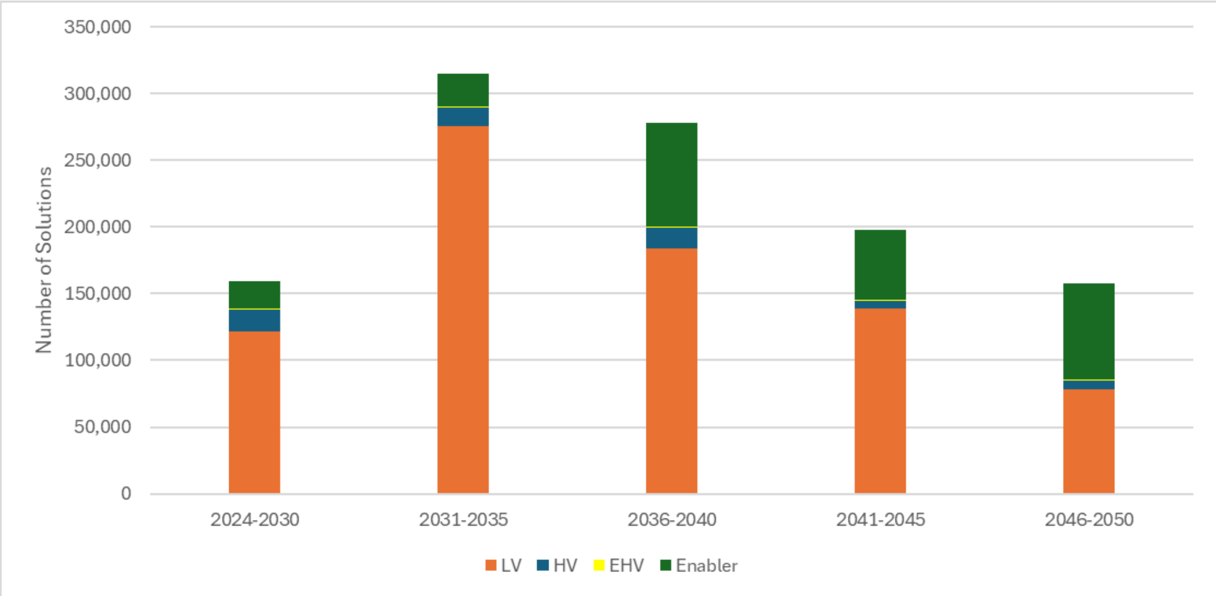


Figure 9 Number of solutions installed on the network over the study window in Run 01 by voltage window (solutions) or enabler.

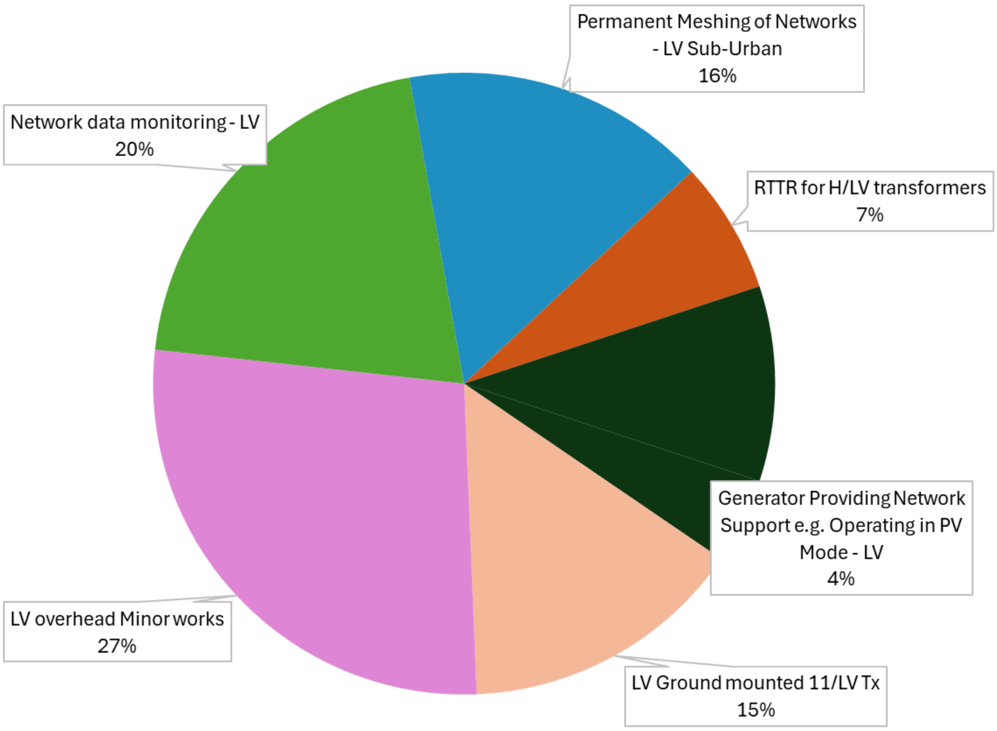


Figure 10 Proportion of key LV solutions deployed over the study period for Run 01.

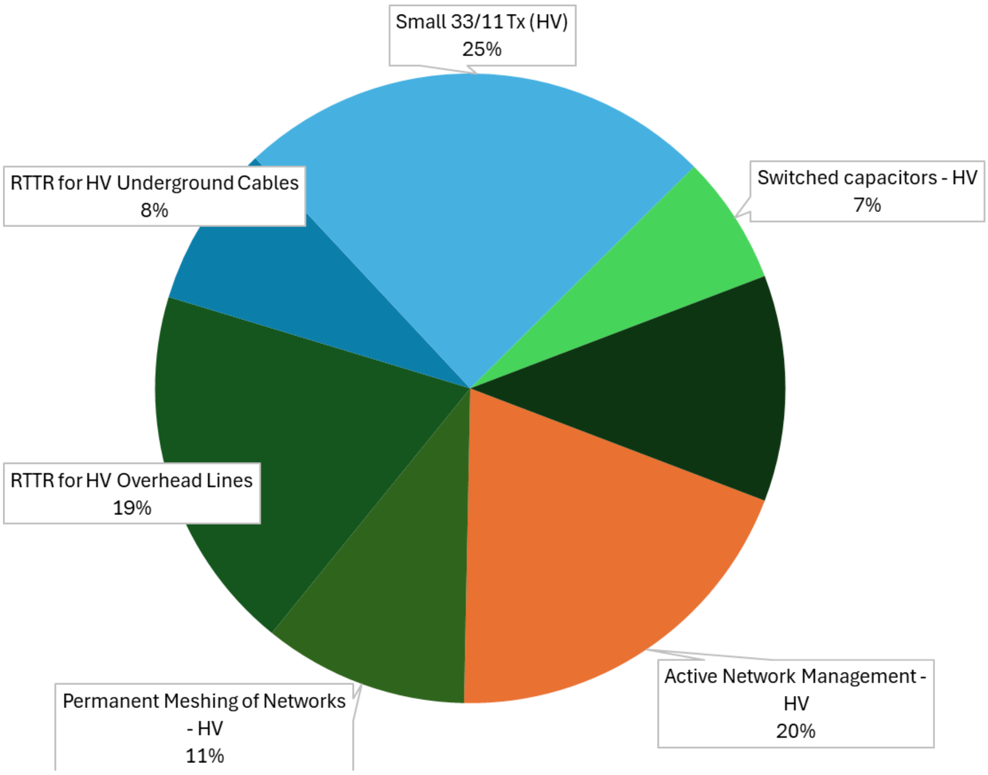


Figure 11 Pie chart showing the percentage deployment of HV solutions across Run 01.

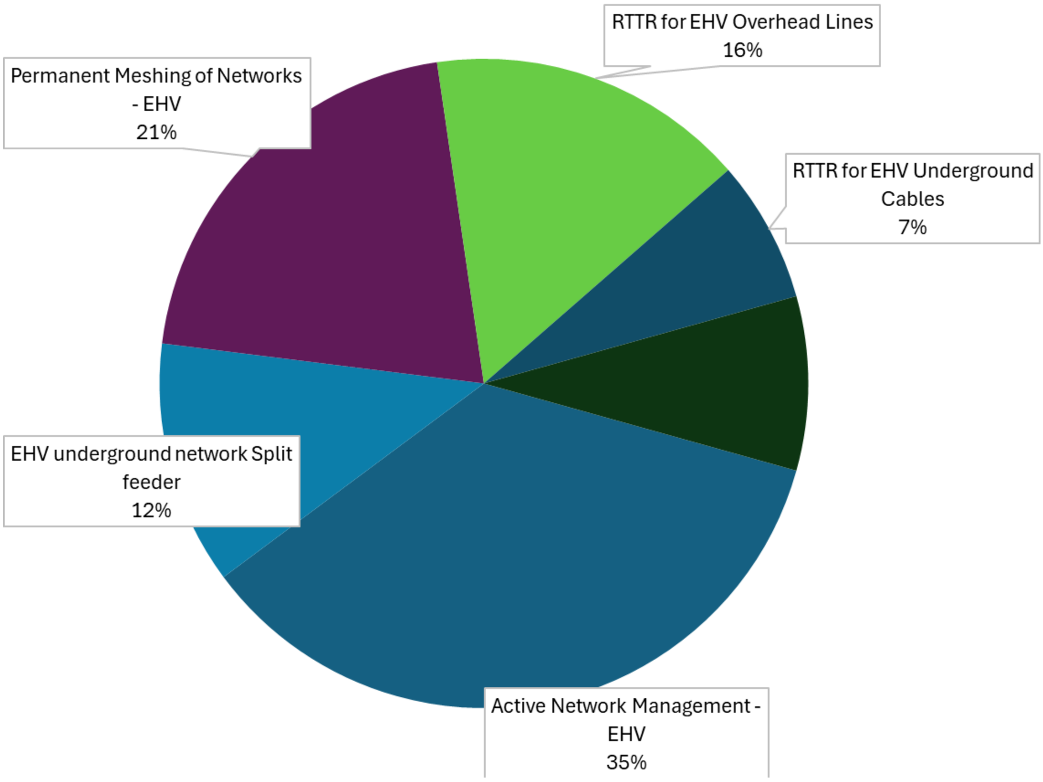


Figure 12 Pie chart showing the percentage deployment of EHV solutions across Run 01.

4.1.7 Implicit and Explicit Flexibility

In the modelling, both implicit and explicit flexibility are considered (section 3.7) but across all study runs, the expenditure on explicit flexibility remains very low. Table 9 shows that in the majority of cases there is very little expenditure associated with the utilisation of explicit flexibility, noting that this is in millions rather than billions. After 2040 the expenditure on explicit flexibility does increase, this aligning with when there are greater volumes of technologies able to provide flexibility available along with a reduction in the rate of demand increase.

Table 9 Undiscounted cumulative expenditure on explicit flexibility between 2024-2050.

	Cumulative expenditure (£/million)						
Run	2024	2025	2030	2035	2040	2045	2050
01	-	-	-	-	-	-	£25.53
02	-	-	-	-	-	-	£13.91
03	-	-	-	-	-	-	£8.17
04	-	-	-	-	-	-	£3.50
05	-	-	-	-	-	-	-
06	-	-	-	-	-	-	£4.51
07	-	-	-	-	-	-	£1.48
08	-	-	-	-	-	-	£14.24
09	-	-	-	-	-	-	£25.53
10	-	-	-	£0.56	£0.56	£5.87	£29.25
11	-	-	-	-	-	-	£11.72
12	-	-	-	-	-	£0.91	£44.61
13	-	-	-	-	-	£0.64	£5.78
14	-	-	-	£0.15	£0.45	£6.61	£18.49

However, the expected use of explicit flexibility remains much lower than expected and is explained in three areas:

1. The cost assumptions associated with the utilisation of explicit flexibility may be too high for it to be considered a significant alternative to traditional reinforcement solutions. In the model, assumptions around the cost of explicit flexibility have been derived from the latest flexibility procurement activities as detailed in section 3.7. As these services scale the operational costs associated with BaU operation may be significantly less, reducing the cost of explicit flexibility and therefore increasing use.
2. It is assumed that technologies able to provide explicit flexibility are those technologies that are also participating in implicit flexibility. As a result, at the times when the explicit flexibility is needed those technologies have already shifted a significant proportion of their demand to other points in the day. For example, in the case of managed domestic off-street EV charging at 17:30 for Run 01 there is 318 MW of demand available across the entire network (less than 0.5%). Non-managed domestic off-street EV charging equates for nearly 10% (8.1 GW) of the 17:30 demand during Run 04 but is not considered flexible.
3. The model assumes perfect foresight, meaning the future trends in technology adoption, policy changes and consumer behaviour are treated as predictable. This assumption does not fully account

for uncertainties that impact network planning, such as localised surges in EV uptake or alternative heating technologies. When dealing with uncertainty, explicit flexibility may provide an option to delay decision making on permanent solutions until more information is available about LCT uptake and/or LV constraints.

4.2 Impact of Heat Technology Uptake (Runs 01-07)

This section explores the impact of varying heat technology uptake rates on the distribution network, focusing on forecasted heat pump adoption and the associated implicit flexibility of these technologies. The analysis includes several scenarios based on different rates of heat pump deployment, as outlined in the WP1[5].

Table 10 summarises the key runs related to heat technology uptake with further details around all the runs presented previously in section 3.8:

Table 10 Run numbers and descriptions specific to heat technology uptake.

Run	Heat Technology Uptake Rate	Flexibility Level
01	Higher heat pump adoption	Higher levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.
02	Delayed heat pump adoption	
03	Lower heat pump adoption	
04	Higher heat pump adoption	Lower levels of flexible operation of Electric Vehicles, Heat Pumps and Energy Storage.
05	Delayed heat pump adoption	
06	Lower heat pump adoption	

The scenarios are designed to test how different levels of electrification in heating systems affect the network's capacity and required expenditure. Additionally, implicit flexibility, particularly from heat pumps, is a key factor in the level of network capacity requirement as it represents the consumer engagement in shifting demand away from times of system peak. The following sections therefore breakdown the analysis initially to compare the heat uptake (Runs 01 to 03) and then the flexibility impact (Runs 01 to 06).

Figure 13 shows the peak demand across 2024-2050 for Runs 01-06. This chart shows the effect of high (solid) and low (dashed) levels of implicit flexibility, and the effect of heat pump uptake rate, on the final demand. Runs 01-03 show that peak demand in 2023 is 51-52 GW. Demand trajectory begins to differ between the years 2030-2040, before converging to 108-110 GW in 2050. Runs 04-06 show similar demand trajectories, starting around 2 GW higher than their high flexibility counterpart in 2024. The trajectory of Run 06 shows higher deviation from Runs 03 and 04 through the 2030s, with demand staying much higher until 2050.

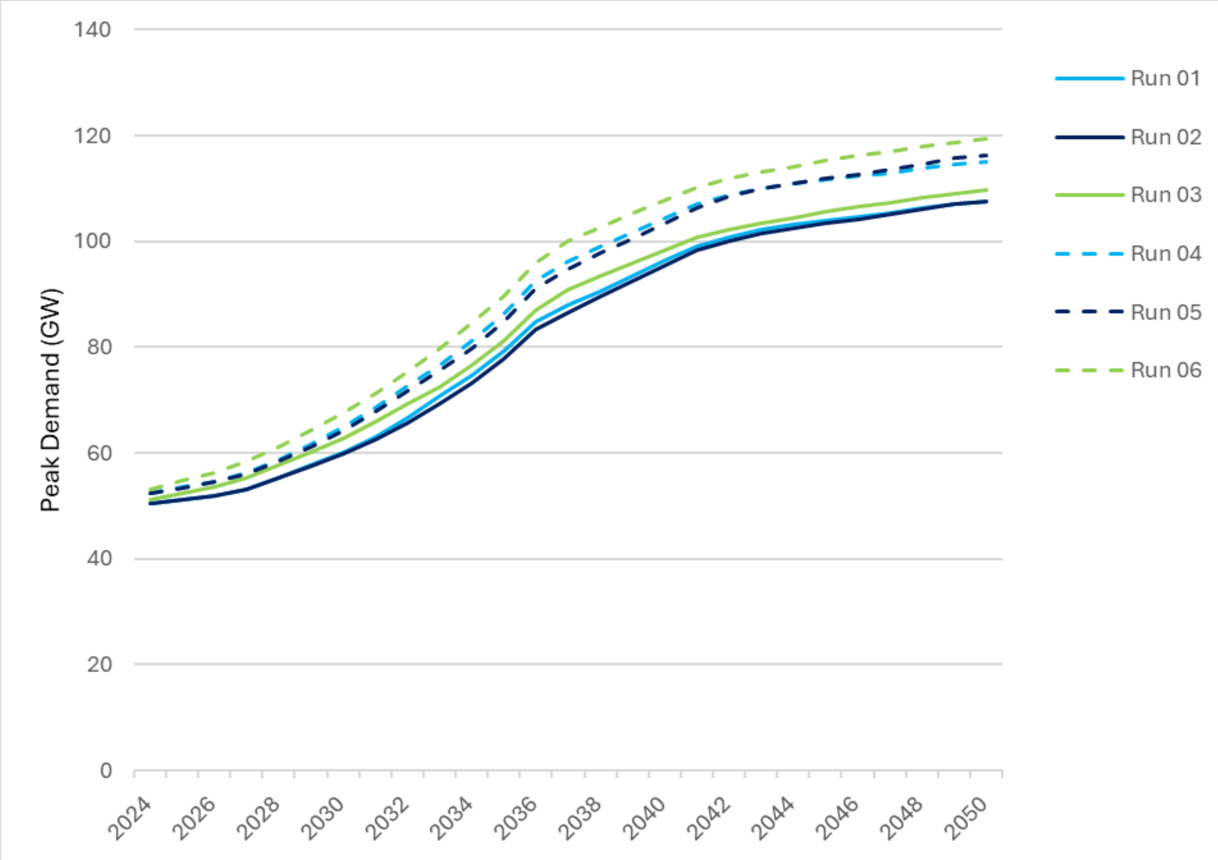


Figure 13 Peak demand between 2024 – 2050. Runs 01-03 show the effect of heat pump uptake in a high implicit flexibility scenario (solid lines). Runs 04-06 show the effect of heat pump uptake in a low implicit flexibility scenario (dashed lines).

4.2.1 High Flexibility (Runs 01, 02 and 03)

Runs 01 to 03 represent different adoption pathways for electrification of heat under an assumption of high levels of demand side flexibility (both implicit and explicit). Table 11 shows the peak demand remains largely in line over the study period (2024 – 2050). The results show that peak demand largely follows in line with each other except for between 2035 to 2045 where there is the largest separation in peak demand values.

Table 11 Peak demand (GW) for model Runs 01 to 03, investigating heat pump uptake.

Run	Description	2025	2030	2035	2040	2045	2050
01	High flexibility and higher heat pump uptake	51.2	60.2	79.2	96.4	104.0	107.6
02	High flexibility and delayed heat pump uptake	51.2	59.9	77.7	95.4	103.5	107.6
03	High flexibility and lower heat pump uptake	52.3	62.8	81.3	98.4	105.7	109.8

Network expenditure is largely driven by a need to meet the peak demand conditions and therefore the expenditure profile (Table 12) follows a similar trend as that of the peak demand. Digging further into the expenditure shows that Run 02 has an initially lower level of expenditure which correlates with the delayed uptake in heat pumps. The compressed timescales for the uptake of heat pumps to meet the 2050 targets then leads to an increase in expenditure from 2030 onwards. Conversely, Run 03 which initially has a higher adoption of direct electric heating leads to increased expenditure initially but then remains in line with the expenditure rate of Run 01.

Table 12 Cumulative, undiscounted, load related expenditure for Runs 01 to 03.

	Cumulative expenditure (£/billion)[16]						
Run	2024	2025	2030	2035	2040	2045	2050
01	£2.00	£2.30	£6.87	£19.14	£27.81	£32.84	£37.84
02	£1.95	£2.26	£6.70	£18.18	£25.50	£31.55	£37.47
03	£2.60	£3.08	£9.60	£20.35	£29.83	£37.69	£42.40

Investigating the types of solutions deployed shows little difference between Runs 01, 02 or 03 with the same significant requirement for new overhead circuits driven by rural demand increases and new LV ground mounted transformers. This is combined with increased use of data monitoring and use of real time thermal ratings on transformers. Figure 14 shows the breakdown of the key LV solutions deployed on Run 02.

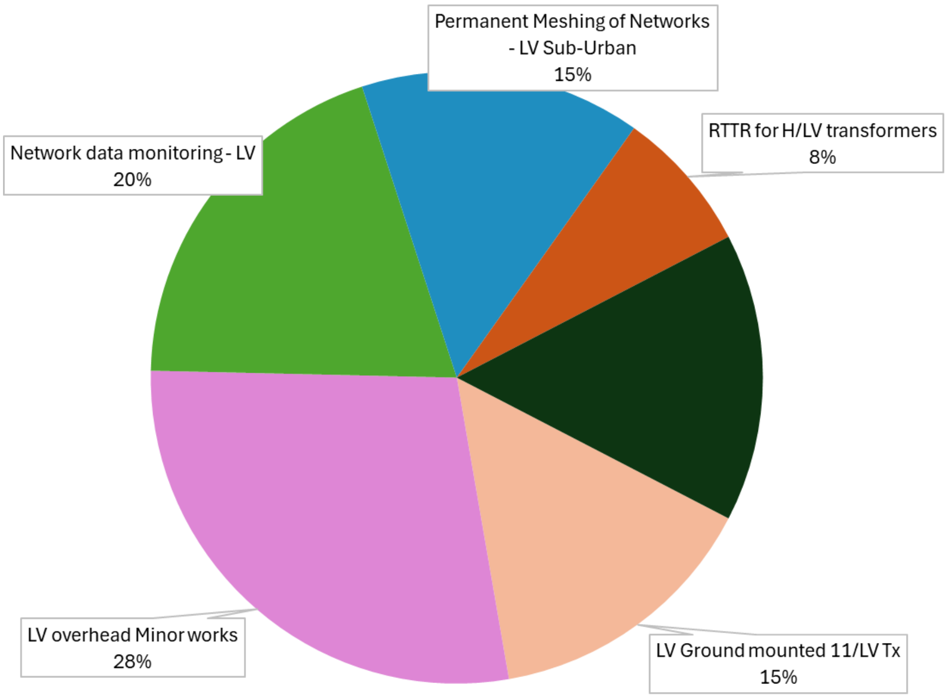


Figure 14 Breakdown of key LV solutions deployed during the study window for Run 02.

The main difference between the solution deployment across Runs 01 to 03 is the timing of when they are required (Figure 15). Run 01 sees a requirement for network interventions that max out up to 2035. These numbers decrease slightly out to 2040 before dropping off up to 2050. Run 02 is initially also low with a lower steadier increase in solutions out to 2040, reflecting the delay in heat pump uptake. Run 03 initially has a higher number of solutions deployed to the network which remains high to support the greater volume of resistive heating.

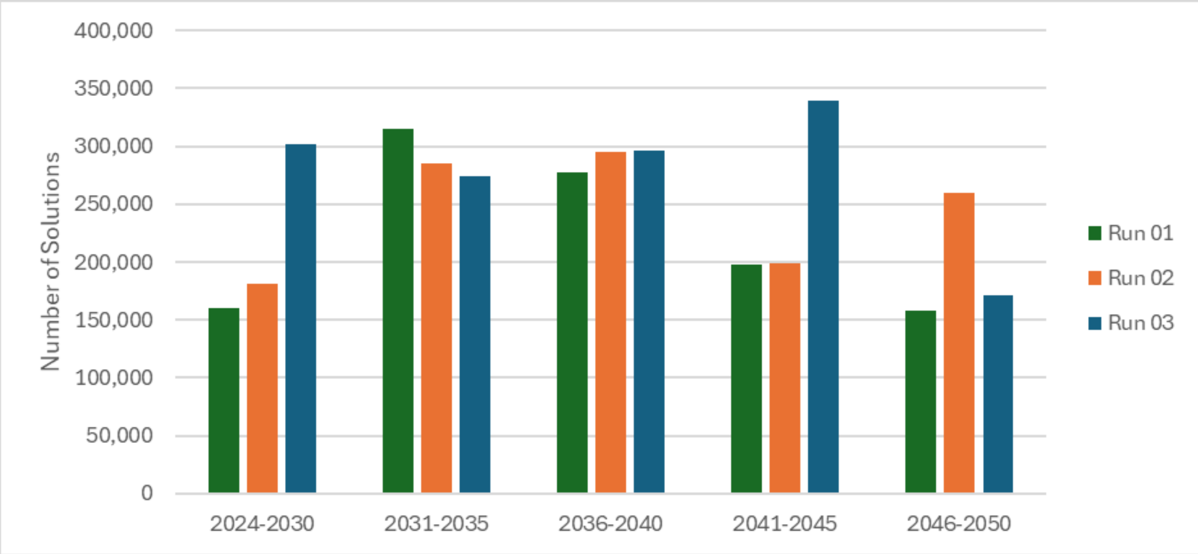


Figure 15 Number of solutions deployed in 5-year intervals for Runs 01 to 03.

4.2.2 Low Flexibility (Runs 04, 05 and 06)

Runs 04 to 06 represent the same electrification of heat scenarios as Runs 01 to 03 but with a lower assumption around demand side flexibility (both implicit and explicit). Table 13 shows the peak demand remains largely in line over the study period (2024 – 2050). The results show that for Runs 04 and 05 peak demand largely follows in line with each other except for between 2035 to 2045 where there is the largest separation in peak demand values. Run 06 stays divergent after 2035 until 2050.

Table 13 Peak demand (GW) for model Runs 04 to 06, investigating heat pump uptake.

Run	Description	2025	2030	2035	2040	2045	2050
04	Low flexibility and higher heat pump uptake	52.5	53.5	64.9	104.5	111.7	115.0
05	Low flexibility and delayed heat pump uptake	52.4	53.4	64.4	103.5	111.8	116.2
06	Low flexibility and lower heat pump uptake	53.2	54.7	67.5	107.8	115.3	119.4

As with Runs 01 to 03, the cumulative expenditure profile, shown in Table 14, follows a similar trend to the peak demand but with a greater total investment need due to lower levels of flexibility.

Table 14 Cumulative, undiscounted, load related expenditure for Runs 04 to 06

Run	Cumulative expenditure (£/billion)[16]						
	2024	2025	2030	2035	2040	2045	2050
04	£2.03	£2.35	£9.64	£21.76	£33.06	£39.86	£44.61
05	£1.82	£2.13	£9.21	£20.89	£32.78	£39.57	£45.32
06	£2.79	£3.34	£11.14	£24.90	£36.79	£43.29	£49.13

As with Runs 01 to 03, the types of solutions deployed are largely the same in proportion across Runs 04 to 06 and the timing of those solutions follow the same trend as Runs 01 to 03. The most significant difference is to compare the impact of high and low flexibility which is covered in section 4.3.

4.2.3 Winter stress test: higher heating demand with lower flexibility availability (Run 07)

The winter stress test (Run 07) was designed to stress-test the network with significantly higher heat demand and low levels of flexibility. This scenario assumed an increase in peak loads for heat pumps to approximately 3 kW per household[22]. It also assumed low levels of flexibility from customers and no reduction in power demand for transport or I&C sectors. These conditions represent a highly conservative approach and in practice, reduction in non-domestic demand that might be expected during such weather conditions.

Under these assumptions, there is a substantial increase in network interventions needed, with cumulative load-related investment rising to £76 billion by 2050 (Figure 16). This is significantly higher than the £37-49 billion range observed in the core model runs (01 to 06). This correlates with the peak demand increasing considerably, reaching 153 GW by 2050 (Figure 17).

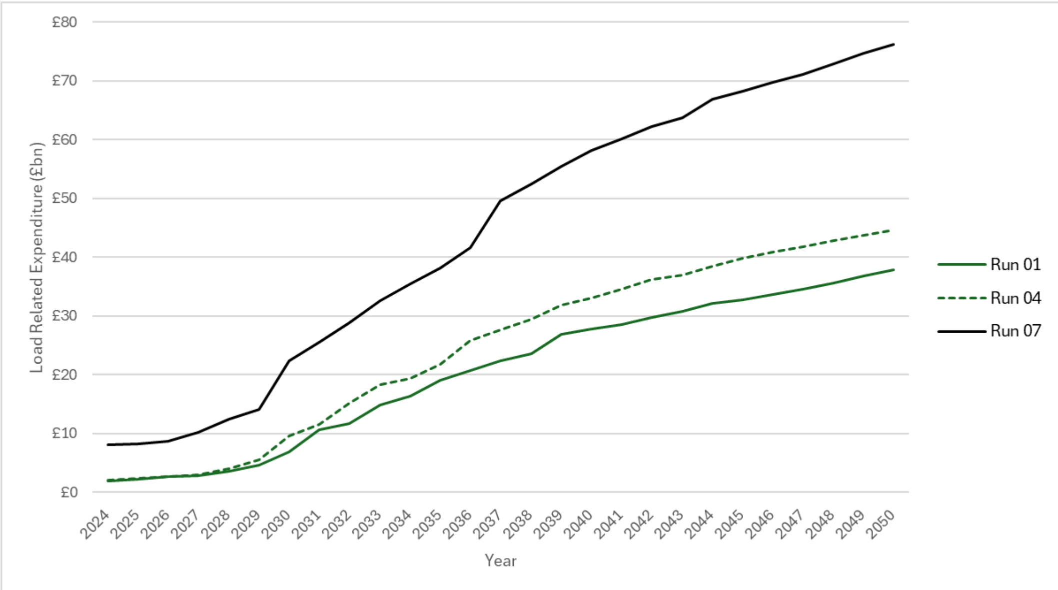


Figure 16 Cumulative, undiscounted, load related expenditure comparison between Runs 01, 04 and 07 highlighting the impact of higher heating demand with lower flexibility availability.

[22] Regen, Electricity Distribution Network Capacity Analysis, Work package 1: review of load profiles

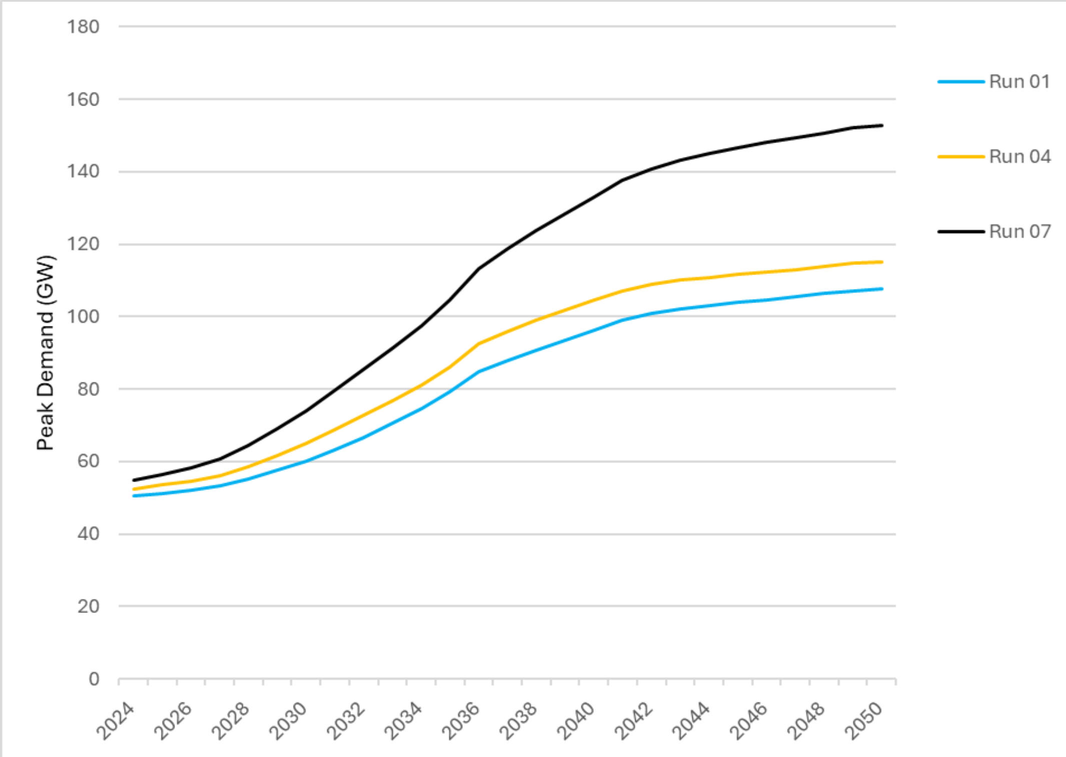


Figure 17 Peak demand (GW) comparison between Runs 01, 04 and 07 highlighting the higher heating demand impact.

Figure 18 shows the peak winter day profile for Runs 04 and 07, highlighting the significant increase in demand during the winter stress test during 2035 and 2050. It is also noticeable that there is a greater increase in the morning (07:00 – 09:00) and evening (17:00 – 20:00) resulting from the additional heating demand during those periods.

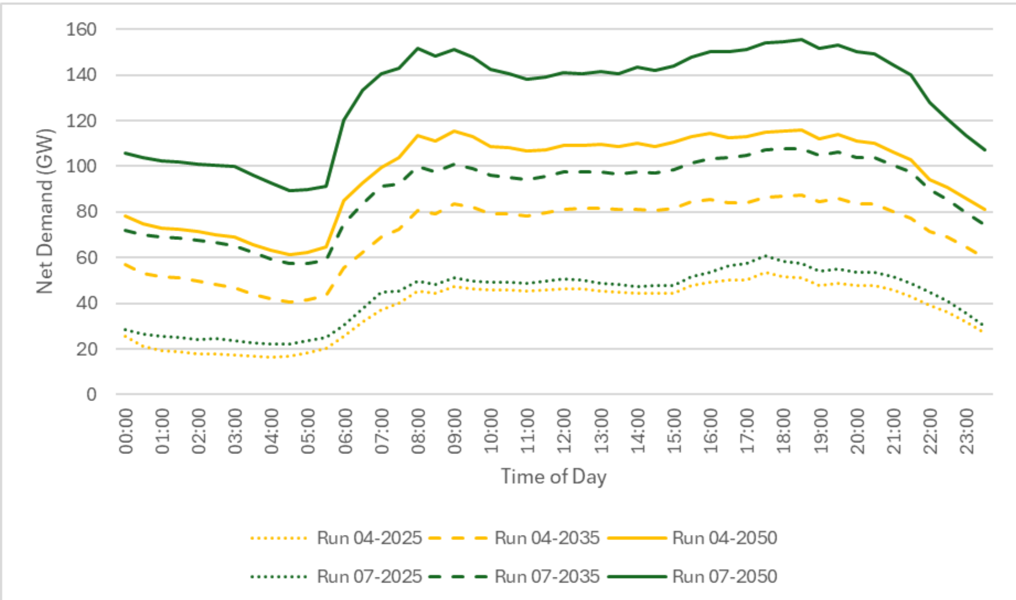


Figure 18 Winter peak day demand profile comparison between Runs 04 and 07 (winter stress).

Figure 19 shows the number of solutions deployed across all voltage levels during the study window. This highlights the significant number of solutions needed in Run 07 to ensure that the distribution network can meet demand.

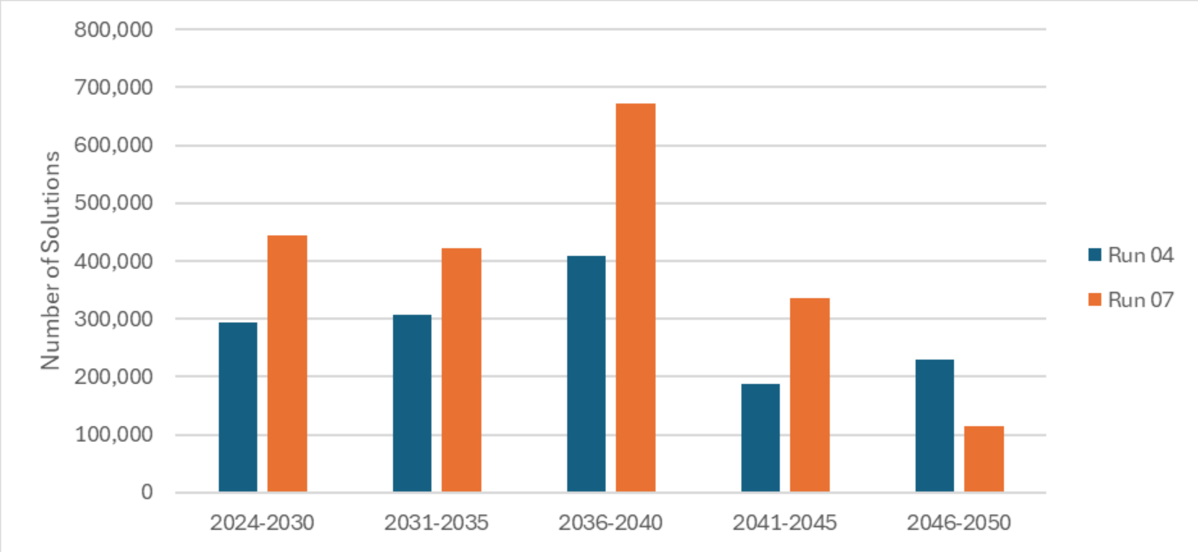


Figure 19 Number of solutions deployed across all voltage levels for Runs 04 and 07.

Breaking these solutions down by type shows the same dominance of LV upgrades to network infrastructure (LV overhead works, ground mounted transformers and network meshing) along with some use of monitoring and real time thermal ratings. Figure 20 presents this breakdown of the solutions for Runs 04 and 07. Run 07 has an increase in use of other small solutions and the most noticeable ones from that collection are:

- Splitting of existing LV underground network feeders (2% of solutions) and introducing new split LV feeder (3% of solutions)
- New LV pole mounted transformers (2% of solutions)

At the HV and EHV level, the breakdown of solutions remains largely consistent. There is a slightly greater use of permanent network reconfiguration through meshing and splitting of feeders in Run 07 at both HV and EHV. The change in solutions that have been selected at LV, HV and EHV aligns with the need to significantly increase the capacity of the network to meet the peak demand capability. These all represent breaking the existing network into smaller sections so that each transformer supplies fewer customers along with the use of new larger transformers. There is less opportunity for benefits from the iterative but relatively small capacity release available through smarter solutions such as active network management[23], network monitoring and dynamic ratings.

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 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.

This sensitivity highlights the significant impact of higher heating demand with lower flexibility availability on network planning and underlines the potential need for resilience strategies that account for higher loads, especially given the increased reliance on electricity for heating in a net zero future. The results underscore the importance of ensuring that both physical network capacity and flexibility services are resilient to such peaks in demand.

[23] Active network management in this context refers to the dynamic reconfiguration of the network

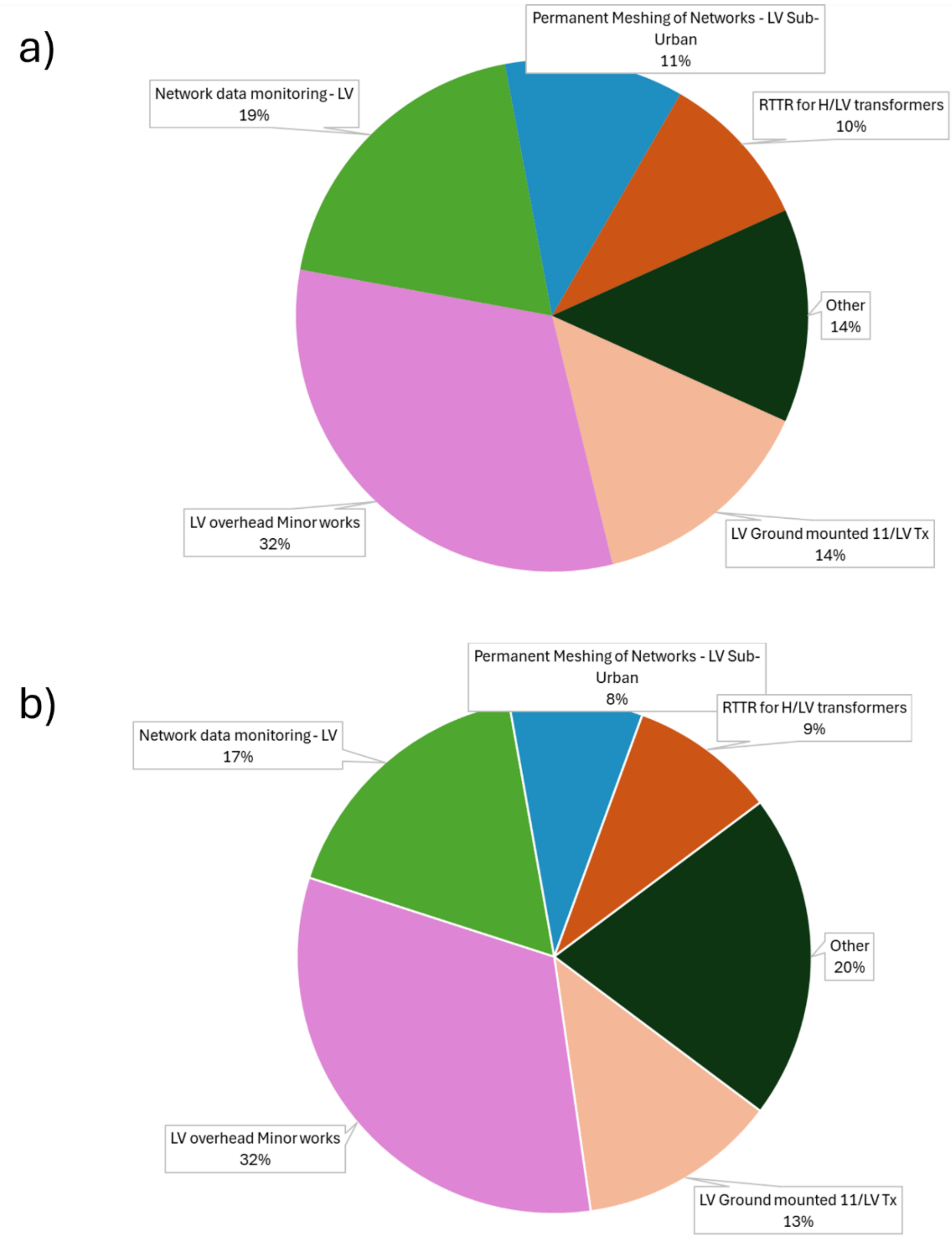


Figure 20 Proportion of LV solutions by type across Run 04 (a) and Run 07 (b).

4.3 Impact of Flexibility (Runs 01 & 04, Runs 02 & 05, and Runs 03 & 06)

Flexibility plays a critical role in managing future electricity demand, particularly in a system experiencing rapid electrification of heat and transport. Across the model runs, the inclusion of both implicit and explicit flexibility was shown to reduce peak loads and delay the need for network reinforcement, thereby lowering overall costs.

The pairings of Runs 01 & 04, Runs 02 & 05, and Runs 03 & 06 allows a comparison of cumulative expenditure with the same assumptions around heat electrification but different assumptions on customer engagement with flexibility. Runs 01-03 representing the high flexibility scenario show lower levels of cumulative expenditure than the low flexibility scenarios (Runs 04-06). By 2050, the cumulative, undiscounted load related expenditure is more than £6bn lower as follows:

- Run 04 – Run 01 = £7 billion (FES 2023 Consumer Transformation).
- Run 05 – Run 02 = £8 billion (FES 2023 Consumer Transformation with delayed heat pump uptake).
- Run 06 – Run 03 = £7 billion (Lower heat pump adoption with higher electric resistive heating).

By 2030 the cumulative, undiscounted load related expenditure (Table 15) for the low flexibility scenario is already more than 15% higher than the high flexibility scenario. This highlights how early engagement with flexibility services and customers shifting demand could reduce the overall need for network investment. By 2050 the cumulative expenditure is approximately 12% to 15% greater in the low flexibility scenarios irrelevant of the heating electrification assumptions.

Table 15 Cumulative expenditure (undiscounted) between 2024-2050 for modelling Runs 01-06.

Run	Description	Cumulative expenditure (£/billion)[16]						
		2024	2025	2030	2035	2040	2045	2050
01	High flexibility and higher heat pump uptake	£2.0	£2.3	£6.9	£19.1	£27.8	£32.8	£37.8
02	High flexibility and delayed heat pump uptake	£2.0	£2.3	£6.7	£18.2	£25.5	£31.6	£37.5
03	High flexibility and lower heat pump uptake	£2.6	£3.1	£9.6	£20.4	£29.8	£37.7	£42.4
04	Low flexibility and higher heat pump uptake	£2.0	£2.4	£9.6	£21.8	£33.1	£39.9	£44.6
05	Low flexibility and delayed heat pump uptake	£1.8	£2.1	£9.2	£20.9	£32.8	£39.6	£45.3
06	Low flexibility and lower heat pump uptake	£2.8	£3.3	£11.1	£24.9	£36.8	£43.3	£49.1

Figure 21 breaks down this cumulative expenditure into 5-year blocks and by voltage level. In all runs, LV network consistently shows the highest expenditure in both scenarios, reflecting the significant reinforcement needed at this voltage tier to accommodate new demands from heat pumps and electric vehicles. The difference between Run 01 and Run 04 is most pronounced in this category, indicating that flexibility has a major impact on reducing the need for investment in the LV network.

The HV network costs are also higher in the low-flexibility scenario, but the difference between the two runs is less stark compared to LV. This suggests that, while flexibility helps reduce costs at the HV level, its primary benefits are seen at the LV level, where distributed energy resources and consumer behaviours have the most direct impact. There is minimal difference in the HV and EHV network expenditure between Runs 01 and 04.

In both scenarios, the need for investment peaks during the 2036-2040 period, which aligns with expected growth in electric vehicle adoption and heat pump installation. This is followed by a gradual decline in required network intervention as the network capacity is increased and the demand increase stabilises.

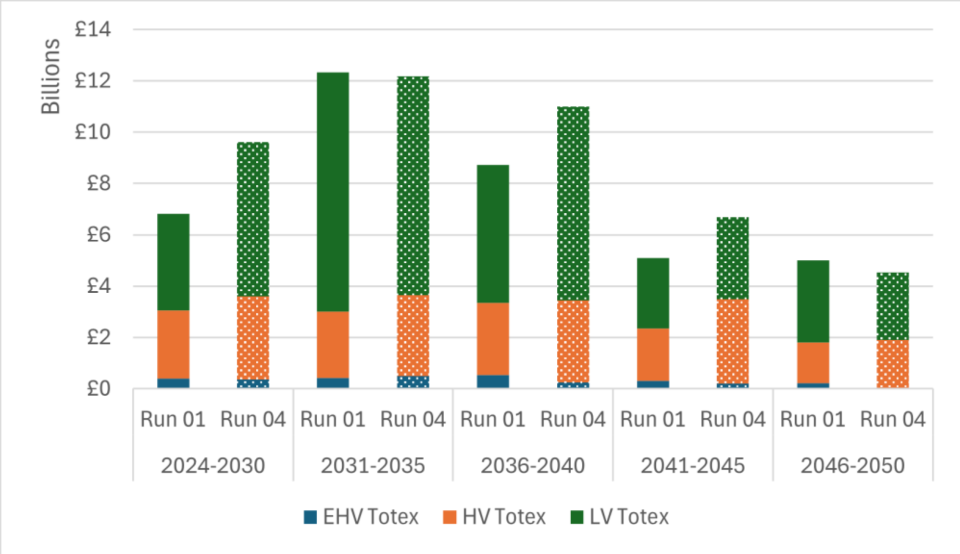


Figure 21 Cumulative expenditure (undiscounted) in 5-year blocks for Runs 01 and 04 broken down by voltage level.

Table 16 shows the peak demand for the high and low flexibility runs. Without the ability to shift or manage demand peaks through supplier signals, the distribution network experiences higher peak loads. This leads to earlier capacity constraints and aligns with the front-loaded expenditure profile presented above.

Table 16 Peak demand (GW) comparison for high flexibility (Runs 01-03) and low flexibility (Runs 04-06)

Run	Description	2025	2030	2035	2040	2045	2050
01	High flexibility and higher heat pump uptake	51.2	60.2	79.2	96.4	104.0	107.6
02	High flexibility and delayed heat pump uptake	51.2	59.9	77.7	95.4	103.5	107.6
03	High flexibility and lower heat pump uptake	52.3	62.8	81.3	98.4	105.7	109.8
04	Low flexibility and higher heat pump uptake	52.5	53.5	64.9	104.5	111.7	115.0
05	Low flexibility and delayed heat pump uptake	52.4	53.4	64.4	103.5	111.8	116.2
06	Low flexibility and lower heat pump uptake	53.2	54.7	67.5	107.8	115.3	119.4

The impact of reduced flexibility is most prominent at the evening peak (17:00 – 19:00) as shown in Figure 22 with a comparison between Run 01 and Run 04. The high flexibility scenario (Run 01) shows that as the overall demand increases the evening peak becomes reduced due to the profiles assumed for implicit flexibility. The profiles generally aim to shift demand away from the evening peak, later into the evening. By 2050 the peak demand is occurring during the morning peak (09:00 – 10:00) instead. During the low flexibility scenario (Run 04), peak demand remains in the evening and increases, driving the greater levels of network investment.

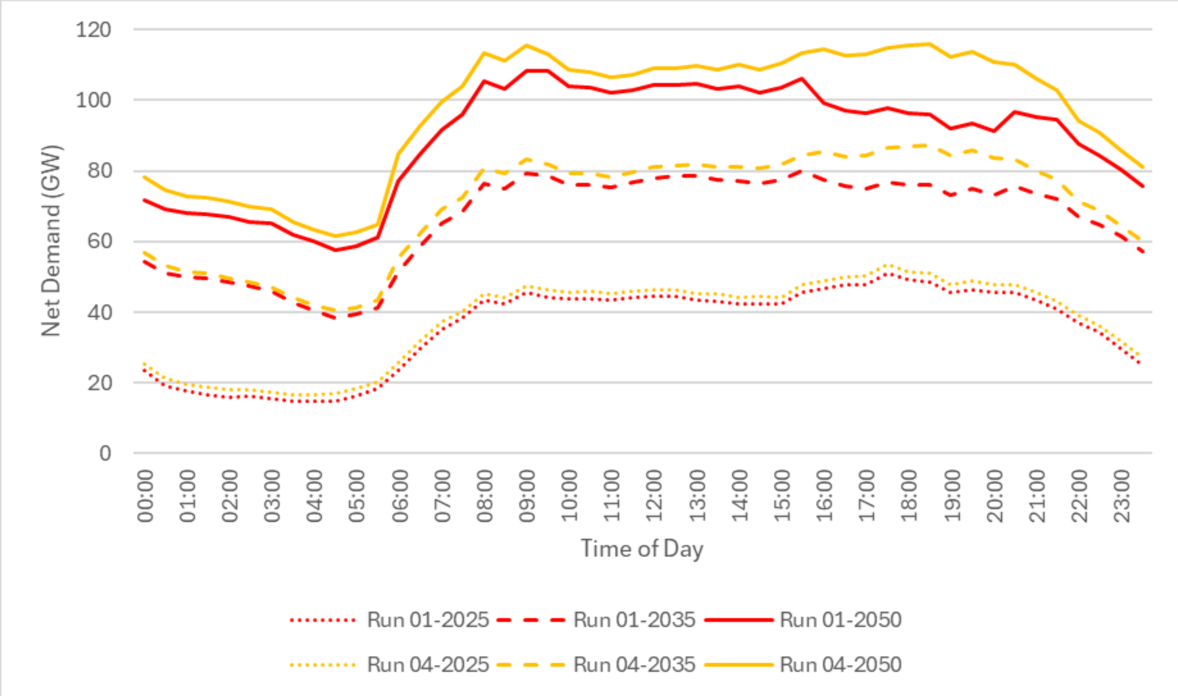


Figure 22 Demand profile comparison between high flexibility (Run 01) and low flexibility (Run 04) during 2025, 2035 and 2050.

4.4 Impact of Large Demands and Energy Storage (Runs 08-10)

The section explores the effects of demand profile and LCT uptake variations on the network, focusing on assumptions for I&C and data centre demand, as well as small-scale storage deployment. These different demand profiles are tested to determine how they contribute to network constraints, and the additional capacity required to support growing demand, particularly in scenarios with increasing electrification of industry and services.

Figure 23 presents a comparison of the undiscounted, cumulative load related and Figure 24 presents the peak demand comparison for the large demand and energy storage sensitivity studies. Run 01 is the FES 2023 Consumer Transformation scenario with high flexibility, Run 08 representing the I&C demand sensitivity, Run 09 the impact of data centre demand and Run 10 shows the impact of small-scale storage. The subsequent sections go into further detail comparing the results between each of these sensitivity studies.

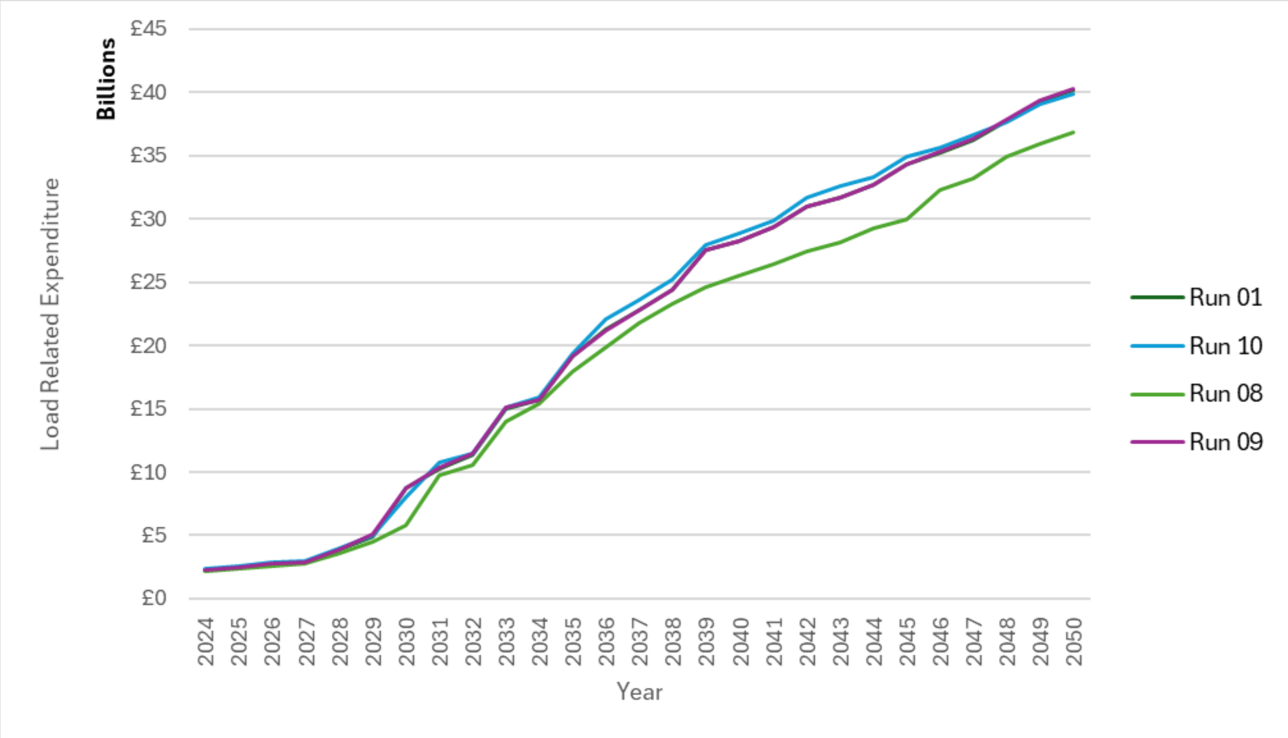


Figure 23 Cumulative, undiscounted, load related expenditure comparison between Run 01, Run 08 (I&C), Run 09 (data centres) and Run 10 (storage) relating to the sensitivity studies for large demands and energy storage.

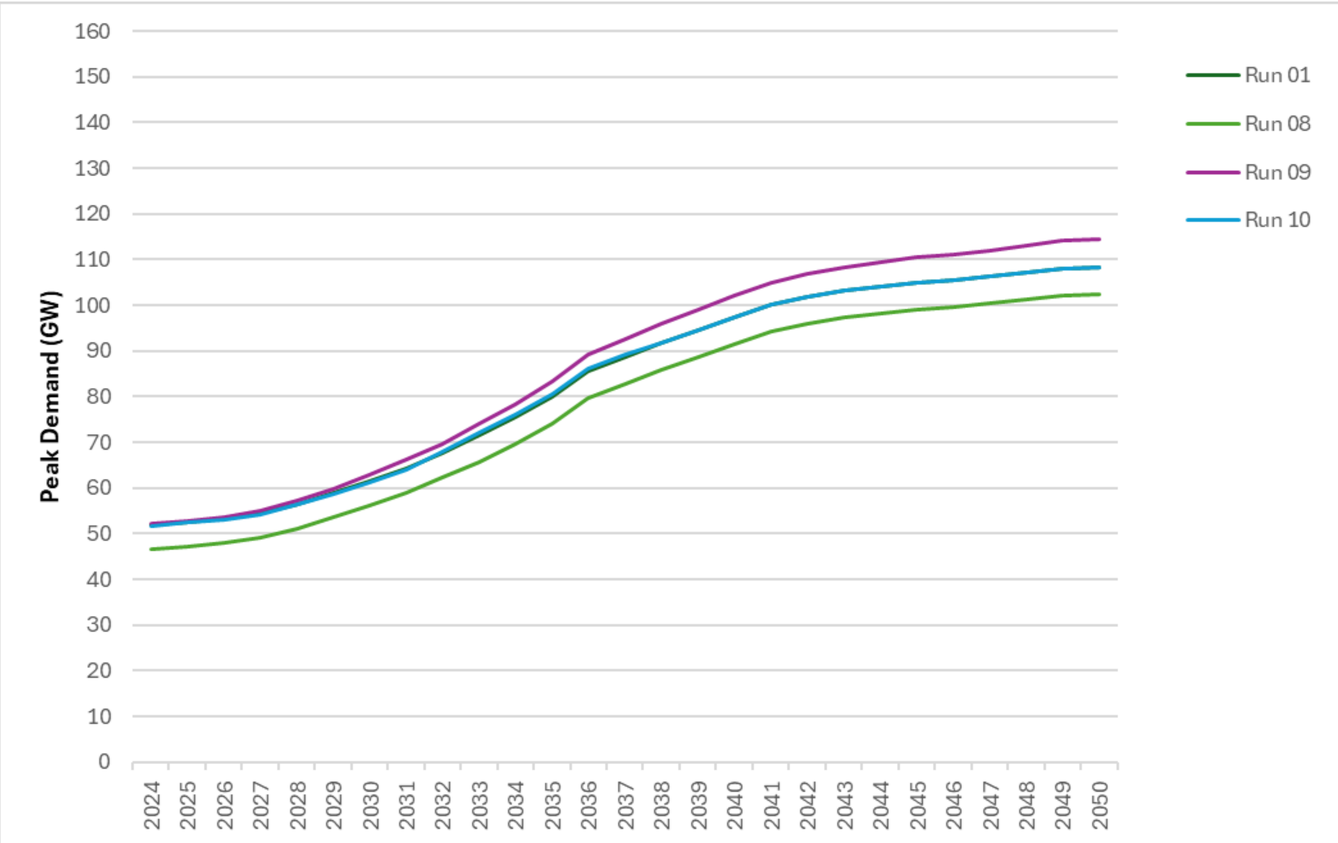


Figure 24 Peak demand comparison between Run 01, Run 08 (I&C), Run 09 (data centres) and Run 10 (storage) relating to the sensitivity studies for large demands and energy storage.

4.4.1 I&C Demand (Run 08)

The modelling of I&C demand presented several complexities, largely due to the diverse and dynamic nature of this sector. Unlike residential loads, which can be more predictably modelled based on the uptake of electric vehicles and heat pumps, I&C demand spans a wide range of activities, from small businesses to large industrial processes, each with unique load profiles[24]. The model, therefore, employed a simplified approach to I&C demand, applying a single, representative load profile across the sector. I&C customers are distributed across the LV and HV networks at a 75% to 25% split respectively, reflecting the varying network connections typical for businesses of different sizes and electricity demands.

This sensitivity modelled the same I&C profile but reduced by 22% to understand the potential impact of I&C flexibility. A comparison of the I&C profiles is presented in WP1.

Table 17 shows a comparison of the peak demand between model Runs 01 and 08 showing the overall reduction in peak demand. Both runs are controlled for high heat pump adoption, with higher levels of flexible operation of EVs, heat pumps and energy storage, with typical winter conditions.

Table 17 Peak demand (GW) for model Runs 01 and 08 investigating the impact of I&C demand assumptions.

Run	2025	2030	2035	2040	2045	2050
01	51.2	60.2	79.2	96.4	104.0	107.6
08	46.0	54.9	73.3	90.5	98.1	101.7

Table 18 shows a comparison of the cumulative load related expenditure between Runs 01 and 08. As expected, the reduced peak demand as an associated impact on reducing the overall expenditure as less network capacity increase is necessary.

Table 18 Cumulative expenditure (undiscounted) comparison for Runs 01 and 08.

	Cumulative expenditure (£/billion)[16]						
Run	2024	2025	2030	2035	2040	2045	2050
01	£2.00	£2.30	£6.87	£19.14	£27.81	£32.84	£37.84
08	£2.05	£2.14	£5.43	£18.00	£24.64	£29.63	£35.61

4.4.2 Data Centre Demand (Run 9)

As data centres become increasingly central to modern digital infrastructure, their impact on electricity demand is growing significantly. Data centres are characterised by high and continuous energy consumption due to the need for constant cooling, powering servers, and maintaining resilient systems. These facilities often operate 24/7, which results in high baseline loads, with demand peaks corresponding to increased server utilisation and cooling requirements during periods of peak usage.

In this sensitivity (Run 09), the data centre demand profile is the same between all runs (a constant 1 MW/MW of connected demand in the winter and 0.2MW/MW in the summer). However, the uptake projections are significantly different with more than 3.5x the MW connected data centre demand by 2050 in Run 09. Figure 25 shows how this varies over time with. In 2050, the data centre demand for Run 09 is 8 GW representing approximately 7% of the 17:30 winter demand (114 GW). For Run 01, the data centre demand is only approximately 2 GW, 2% of the 17:30 winter demand (108 GW).

[24] Regen, Electricity Distribution Network Capacity Analysis, Work package 1: review of load profiles

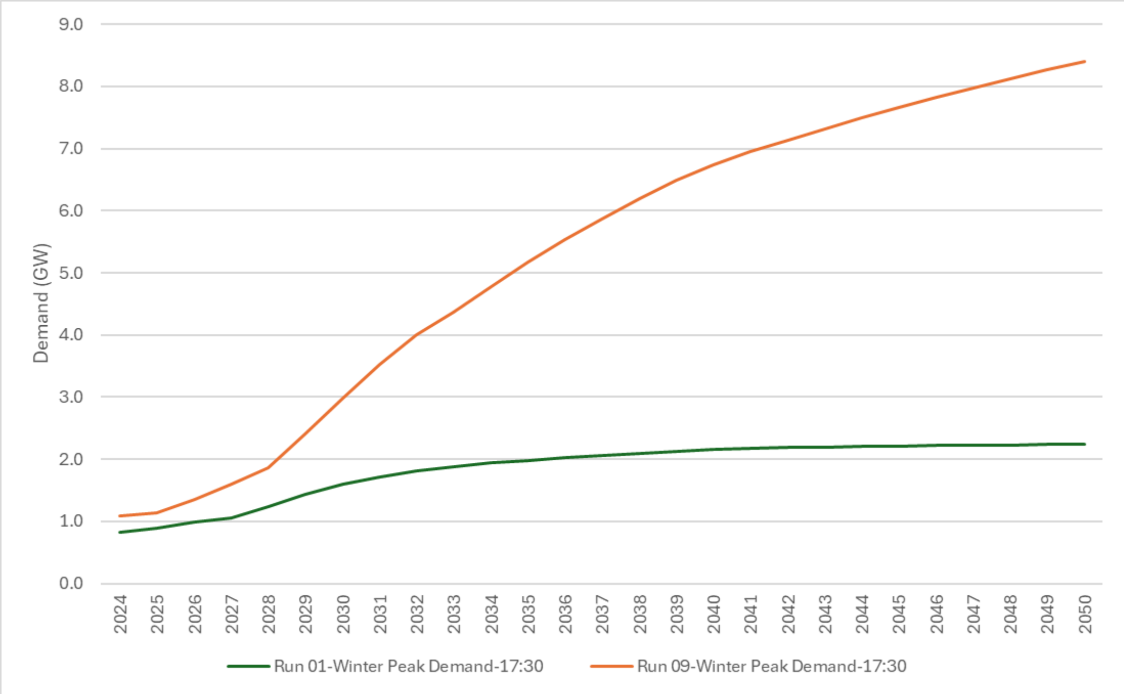


Figure 25 Comparison of total demand from data centres between Runs 01 and 09.

In this analysis, data centres are assumed to be connected at EHV and therefore the increase in network expenditure for Run 09 compared with Run 01 is all at EHV. Only an additional £0.1 billion is forecast to be needed over the study window by 2050 (Table 19).

Table 19 Cumulative expenditure (undiscounted) comparison for Runs 01 and 09.

	Cumulative expenditure (£/billion)[16]						
Run	2024	2025	2030	2035	2040	2045	2050
01	£2.00	£2.30	£6.87	£19.14	£27.81	£32.84	£37.84
09	£2.00	£2.30	£6.87	£19.16	£27.83	£32.87	£37.96

4.4.3 Small Scale Storage Deployment (Run 10)

The small-scale storage deployment sensitivity (Run 10) investigates the impact of increased deployment of distributed energy storage systems, such as domestic batteries and community-level storage, on the electricity distribution network. Small-scale storage could play a critical role in enhancing grid flexibility by allowing energy generated during off-peak periods (or from renewable sources like rooftop solar) to be stored and discharged during periods of high demand. This can help smooth out demand peaks and reduce the strain on network infrastructure.

In this sensitivity, an initially higher baseline level and faster growth of small-scale storage is assumed. The deployment then follows an s-curve to reach the same installed capacity levels by 2050 and is depicted further in WP1. The profile for small-scale storage remains consistent in both scenarios, having an export during the winter evening peak and an import during summer peak generation.

Figure 26 shows the impact this change has on the 17:30 winter peak demand between Runs 01 and Run 09. The peak demand at 17:30 increases from 57.1 GW to 97.8 GW between 2024 and 2050 and so this change of less than 0.25 GW has negligible impact. However, as detailed in WP1, there is significant uncertainty in the appropriate profile for small-scale storage and small changes in the use could have significant impact on the overall demand level.

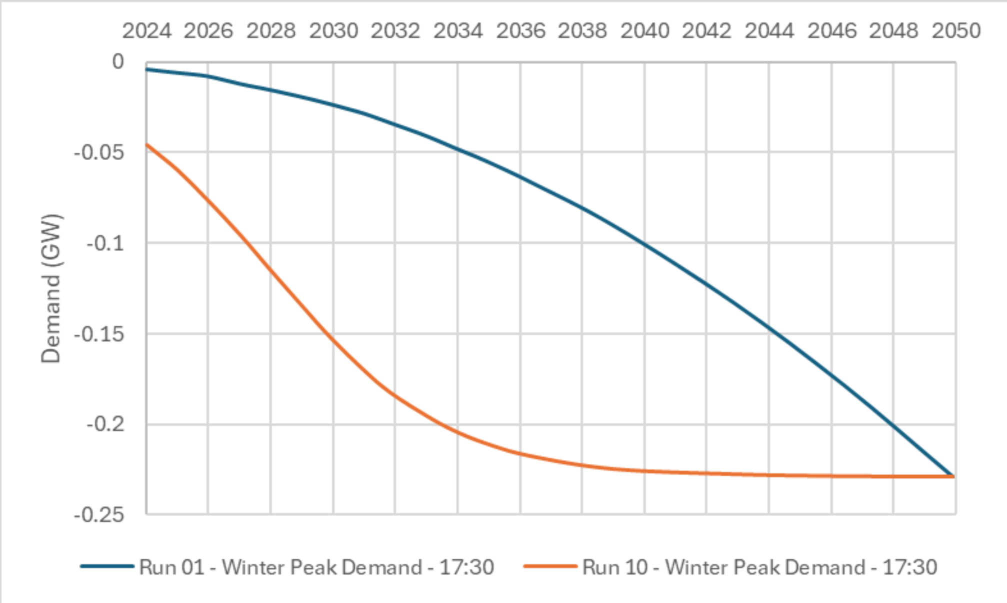


Figure 26 Impact on winter peak demand (17:30) from small-scale storage.

Figure 27 shows the impact that the small-scale storage has on the overall peak export during the summer maximum generation period (14:30). There is a greater impact during Run 10 with more than 2.5 GW reduction in the generation export during 2035 compared with approximately 0.5 GW in Run 01. However, since most network expenditure is associated with meeting the winter peak this has limited impact on the overall level of network investment.

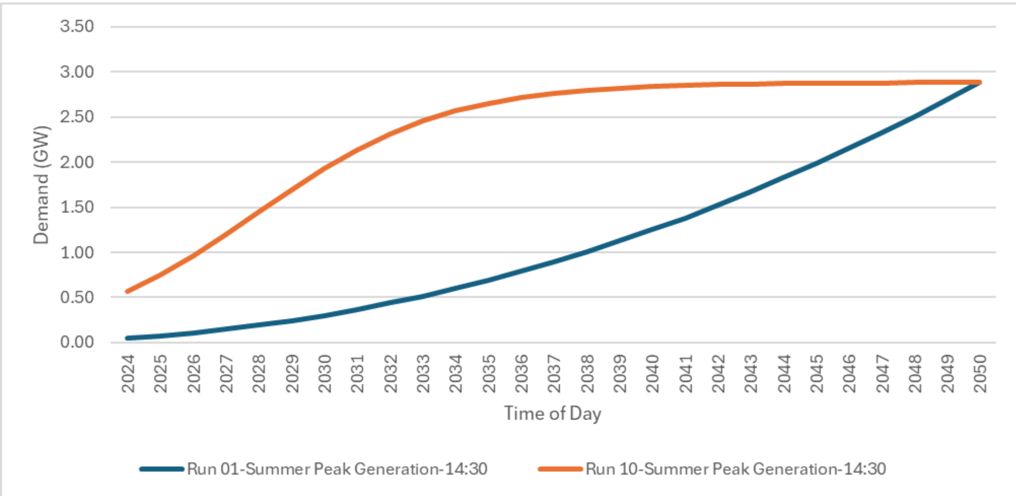


Figure 27 Impact on summer peak generation (14:30) from small-scale storage.

The results show that increased small-scale storage deployment has limited impact on the overall network expenditure, reducing the total expenditure by 0.5% compared to Run 01 (£37.8 billion to £37.7 billion). However, it does slightly shift the spend profile, delaying some expenditure that would have been needed prior to 2030 as can be seen in Figure 28.

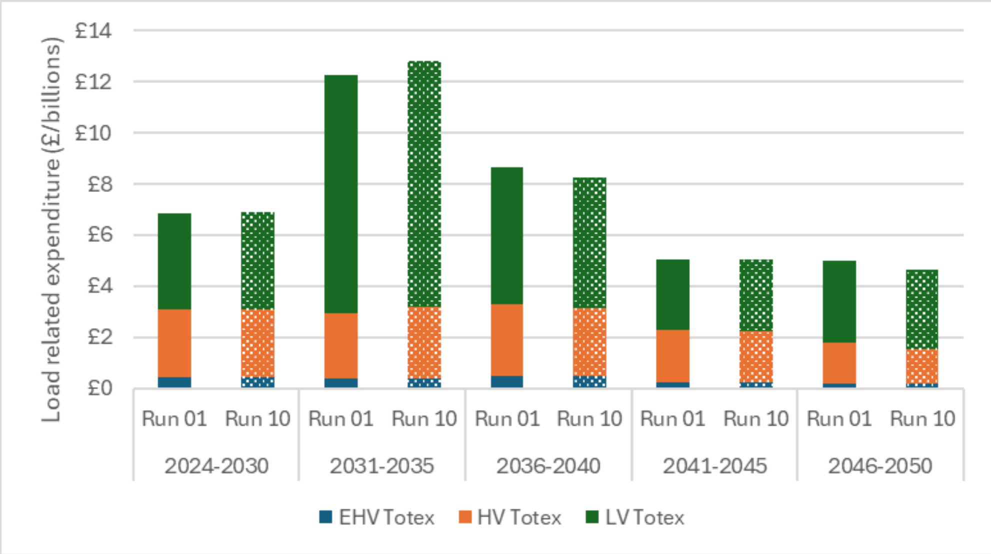


Figure 28 Breakdown of cumulative expenditure (undiscounted) by voltage level for Run 10.

4.5 Investment Horizons (Runs 01, 04 and Runs 11-14)

The results here assess the impact of varying investment horizons on network capacity requirements. In this analysis, investment horizon relates to how far into the future the network is analysed when implementing a network upgrade and three approaches are compared:

- 5-years – When a constraint is met, the analysis investigates solutions which are able to resolve the constraint and meet the forecast demand and generation increases for the next 5 years.
- 10-years – This analysis investigates solutions which are able to meet the forecast demand and generation requirement for the next 10 years.
- To 2050 – Once a constraint is reached any solutions which are deployed are selected to deliver the capacity requirement needed to reach 2050. This is aiming to approximate a touch-the-network once scenario with regards to load related expenditure, ensuring there is enough capacity to meet a 2050 demand scenario.

This offers insights into how different approaches to network planning affect the timing and scale of expenditure required to accommodate future energy demand.

One key aspect around the "touch the network once" philosophy in this modelling approach is the assumption around perfect foresight into how network demand will materialise over the 26-year study window. In reality, this is not possible and there would be a level of risk surrounding both over and under expenditure associated with this approach which would need to be accounted for.

Figure 29 presents an overall comparison of the investment horizons for 5, 10 and 26-year horizons. Comparison should be made between Runs 01, 11 and 12 which reflect the high flexibility scenario and Runs 04, 13 and 14 which present the low flexibility scenario. There is no change in technology uptake between the 5, 10 and 26-year investment horizons and therefore no change in the peak demand.

At a high level, the results show that with a 5 or 10-year investment horizon the cumulative expenditure remains largely the same by 2050. The 10-year results causing expenditure earlier in the study window but then reducing expenditure per year to align with a similar 2050 value. Further analysis comparing the 5 and 10-year investment horizon is presented in section 4.5.1.

Comparing the 5 and 26-year investment horizon shows the 26-year horizon requiring an initially higher expenditure and then continuing to diverge from the 5-year investment horizon . The initially high expenditure is expected as a result of investing earlier to meet the 2050 capacity requirement but the divergence from the 5year investment horizon is not expected and section 4.5.2 presents further analysis to explain this.

Comparison across Runs (01 vs 11 vs 12 and 04 vs 13 vs 14) shows that the trends remain similar irrelevant of assumptions around availability of implicit or explicit flexibility.

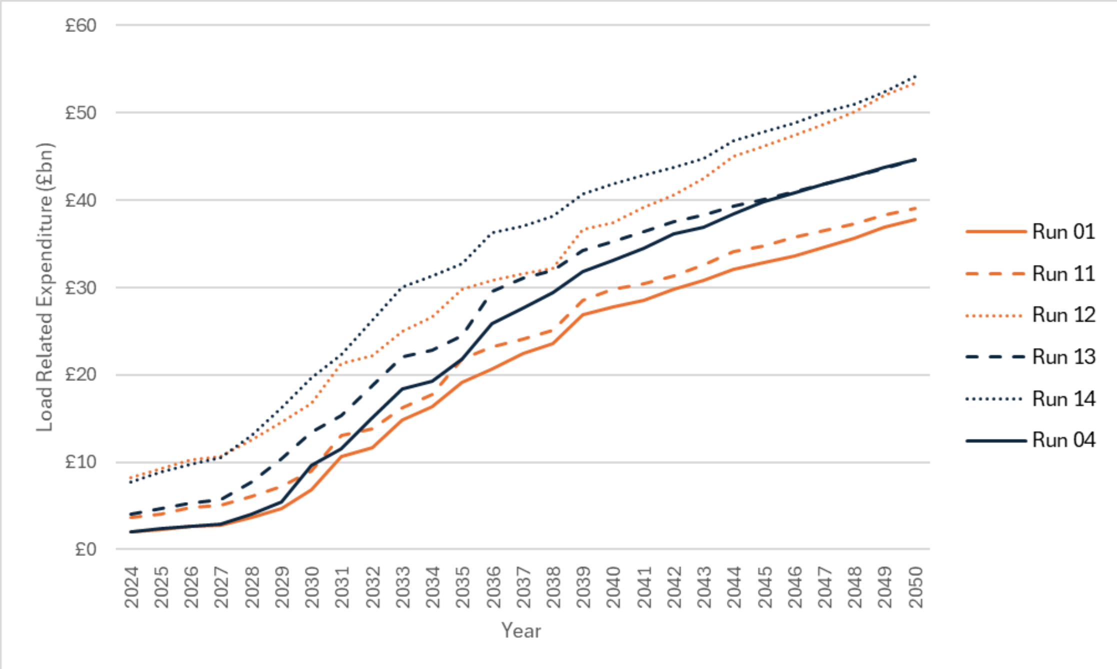


Figure 29 Comparison of cumulative, undiscounted, load related expenditure depending on investment horizon. Solid lines = 5 years, dashed lines = 10 years, dotted lines = to 2050.

4.5.1 Impact of 10-year investment horizon

Table 20 presents a comparison of the cumulative expenditure between the 5 and 10-year investment horizons for the high (Runs 01 and 11) and low (Runs 04 and 13) flexibility scenarios. In both cases, there is initially more network expenditure in 2024 (approximately £1.6 billion) as a result of deploying solutions which meet a 10-year capacity requirement. However, as the demand continues to increase, the rate of expenditure slows such that by 2050 the load related investment is approximately the same irrelevant of the investment horizon.

Table 20 Cumulative expenditure (undiscounted) between 2024-2050 for 5 and 10-year investment horizons.

Run	Implicit flexibility	Investment Horizon	Cumulative expenditure (£/billion)						
			2024	2025	2030	2035	2040	2045	2050
01	High	5 years	£2.00	£2.30	£6.87	£19.14	£27.81	£32.84	£37.84
11	High	10 years	£3.64	£4.06	£9.03	£21.84	£29.75	£34.80	£39.04
04	Low	5 years	£2.46	£2.71	£10.14	£21.62	£34.67	£40.70	£45.34
13	Low	10 years	£3.99	£4.67	£13.48	£24.43	£35.26	£40.11	£44.65

Capacity Release

The 10-year investment horizon results in bigger steps in capacity release as the solutions deployed aim to resolve for bigger demand requirements. Figure 30 presents an example of this for the rural village archetype (LV09) showing a comparison in the capacity release between 5-year (Run 01) and 10-year (Run 11) investment horizons.

The results show that whereas Run 01 has iterative increases in capacity towards the 2050 requirement, Run 12 has an initial large step change in capacity release that limits further capacity release requirement until 2035. In 2035 there is a further step increase in capacity as solutions are deployed. It should be noted this plot presents an aggregate of the demand and capacity across all LV09 networks and that there is variability within each archetype based on the clustering of technologies as explained in section 3.1.

The ability to make an investment decision with a 10-year horizon is dependent on the accuracy of the forecast and this modelling does not consider uncertainty in that forecast.

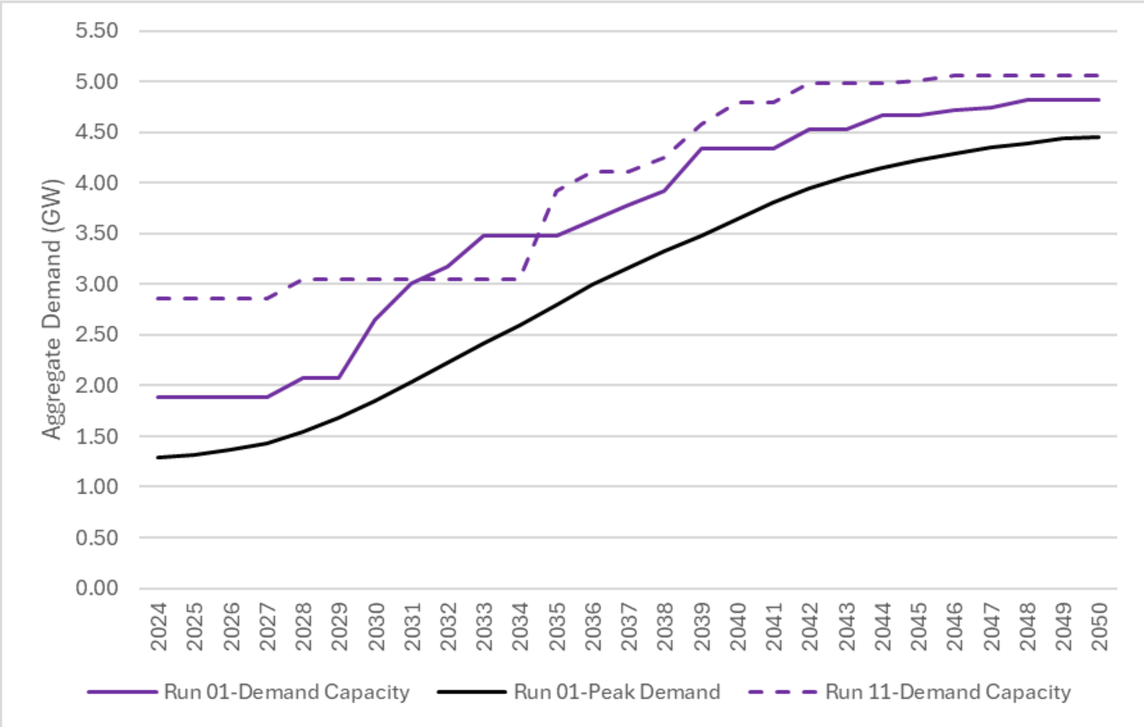


Figure 30 Aggregate capacity release[25] for all LV09 (rural village with overhead construction) archetypes.

Solutions Deployed

Shifting from a 5-year to a 10-year investment horizon does have some impact on the typical solutions that are deployed on the network. Figure 31 presents a comparison of the typical HV solutions deployed between Runs 01 and 11. In Run 11 there is an increase in the utilisation of dynamic network configuration types of solutions in the form of active network management and temporary meshing. These solutions enable the network to be reconfigured to deliver greater capacity from existing assets.

On the LV network there is also a greater use of physical infrastructure upgrades for a 10-year horizon vs a 5-year horizon, such as new overhead circuits and transformers, solutions which offer significant capacity increases on the LV network where the greatest demand increase is seen. These differences are similar to those for the 5 and 26-year horizons as presented in section 4.5.2.

[25] Note – this is aggregate demand and capacity across the entire model for this archetype and not representative of any individual feeder

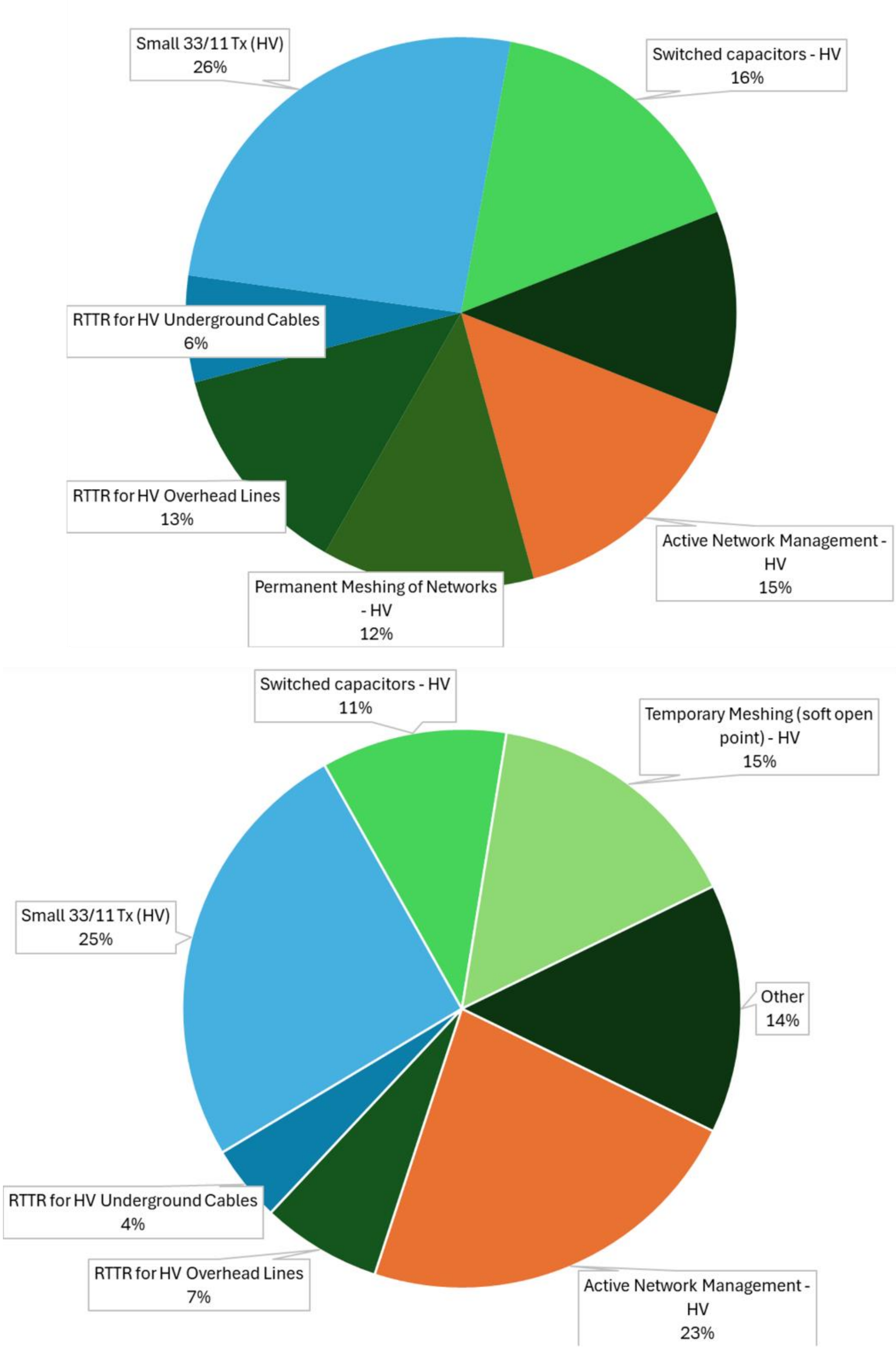


Figure 31 Comparison of the HV solution deployment between Run 01 (top) and Run 11 (bottom).

4.5.2 Impact of 26-year investment horizon

Table 21 presents a comparison of the cumulative expenditure between the 5 and 26-year investment horizons for the high (Runs 01 and 12) and low (Runs 04 and 14) flexibility scenarios. In both cases, there is significant expenditure in 2024 (approximately £6 billion) as a result of resolving constraints with solutions that meet the 2050 capacity requirements. However, a high rate of expenditure continues resulting in approximately £54 billion cumulative load related expenditure by 2050. This section provides some further explanation as to the reasoning behind this and some limitations in the analysis.

Table 21 Cumulative expenditure (undiscounted) between 2024-2050 for all 5 and 26-year investment horizons.

Run	Investment Horizon	Cumulative expenditure (£/billion)						
		2024	2025	2030	2035	2040	2045	2050
01	5 years	£2.00	£2.30	£6.87	£19.14	£27.81	£32.84	£37.84
12	26 years	£8.24	£9.19	£16.72	£29.75	£37.47	£46.17	£53.45
04	5 years	£2.46	£2.71	£10.14	£21.62	£34.67	£40.70	£45.34
14	26 years	£7.78	£8.86	£19.63	£32.71	£41.85	£47.76	£54.13

Solution deployment in Transform to meet 2050 capacity requirements

During the 26-year investment horizon assessment, Transform implements solutions in the first year a constraint is reached that solves for calculated volumes of demand and generation required to meet 2050. The solutions deployed may have a shorter lifetime than the 26-year horizon. This results in the expiration of these solutions prior to the network reaching 2050 constraints. At their point of expiration, the solutions become unavailable on a network and thus the ratings of the assets decrease. As the load continues to grow this reduced demand leads to a new constraint being reached and the application of additional solutions needed and therefore additional expenditure.

Figure 32 presents a simplified visual representation of this where in 2028 a constraint is reached which requires multiple solutions to be deployed to reach the 2050 requirement (i.e. new transformer + HV/LV monitoring). After 10 years (2038) one of the solutions, for example the HV/LV monitoring, expires but since this does not immediately result in a constraint, the capacity is reduced. In 2045, this reduced capacity is no longer sufficient and so the solution is redeployed to meet the 2050 capacity requirement.

A consequence of the variance in solution lifetime and investment horizon is that solutions are deployed to the network initially, which may be considerably earlier than they are needed and leading to their expiration and redeployment. In the modelling, on heavily loaded networks this solution redeployment happens several times and leads to both initially high costs but continued expenditure to replace expired solutions which were not required.

In practice, this approach would not occur, distribution networks would not install a solution that is not forecast to be needed unless there was a significant uncertainty around the forecast. In this instance, distribution networks may also prefer to utilise explicit flexibility first. Instead, the solution with a shorter life would only occur at the time it was needed to meet a network constraint.

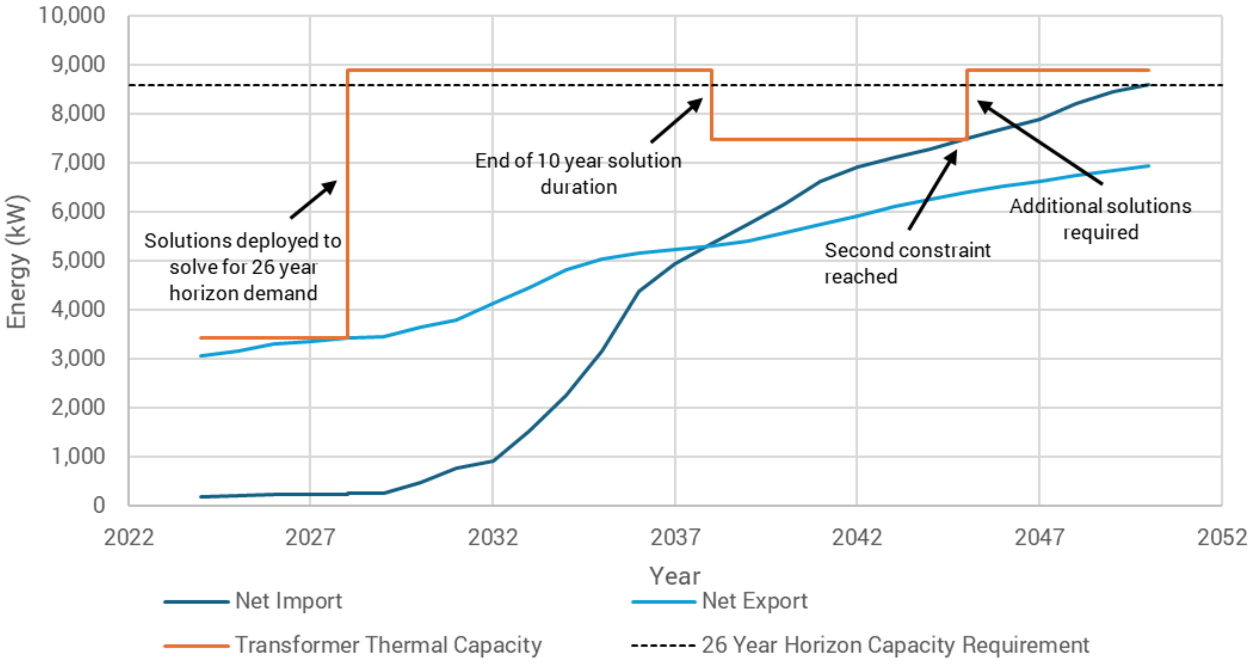


Figure 32 Indicative diagram to demonstrate solution deployments in Transform under a 26-year investment horizon.

The result of this in the analysis is that the 26-year investment horizon has a significantly higher expenditure in earlier years which aligns with being required to deliver the 2050 capacity requirement. However, there is then additional expenditure in later years as solutions reach their design lifetime, expire and require replacement.

Capacity Release

Figure 33 presents an example of this for the rural village archetype (LV09) showing a comparison in the capacity release between 5-year (Run 01) and 26-year (Run 12) investment horizons. The results show that whereas Run 01 has iterative increases in capacity towards the 2050 requirement, Run 12 has an initial large step change in capacity release. However, over the 26 years, some of the solutions deployed for Run 12 expire and a new solution is identified, notably in 2038 where there is a reduction in the available capacity. It should be noted in this plot that this presents an aggregate of the demand and capacity across all of the LV09 networks and that there is variability within each archetype based on the clustering of technologies as explained in section 3.1.

This highlights that although an approach to investing early and avoiding repeat visits to the network may be beneficial, it must be aligned with the forecasts and lifetime of solutions. The example presented here is unlikely to be an approach adopted by distribution networks and instead shorter-life solutions which remain cost-effective over larger implementations would be deployed nearer to time of need. If looking out to 2050, a DNO may also wait before implementing a more expensive solution that possibly has a longer asset life, to resolve constraints expected between 2024 and 2050, rather than doing the work immediately in 2024.

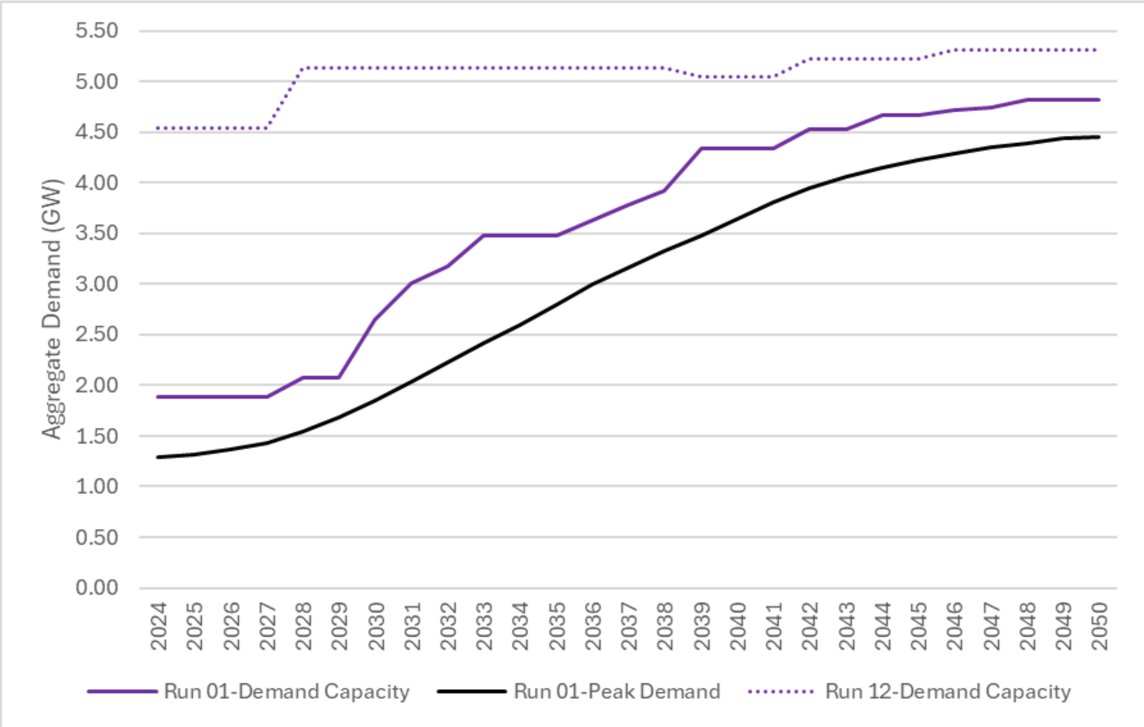


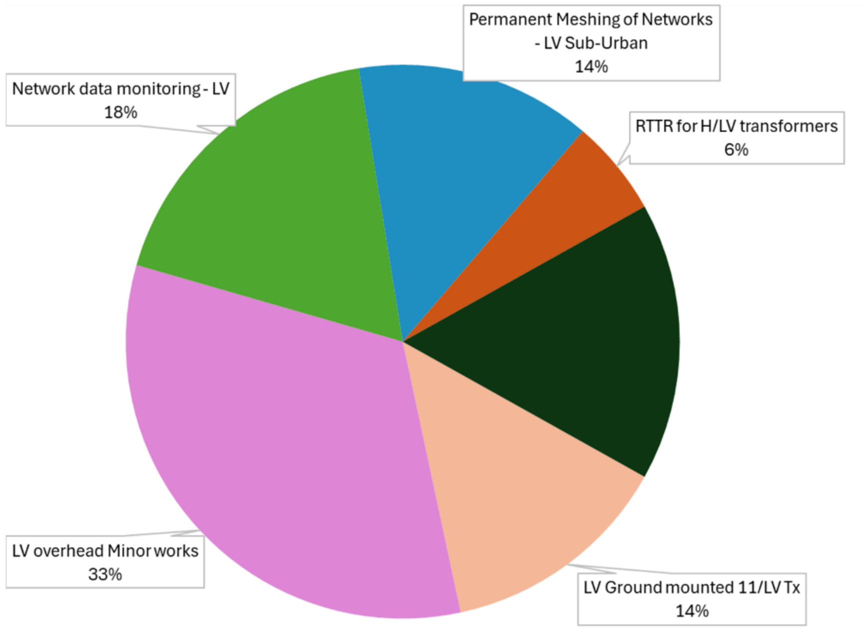
Figure 33 Aggregate capacity release[26] for all LV09 (rural village with overhead construction) archetypes.

Solutions Deployed

Identifying network interventions which release larger amounts of network capacity does lead to a different make up of solutions deployed to the network. Figure 34 presents a comparison of the typical LV solutions deployed between Runs 01 and 12. Figure 35 shows that in Run 12 there is clearly a significant increase in the volume of physical infrastructure upgrades, in this case LV overhead minor works which relate to the introduction of new LV overhead circuits.

Analysis into the HV and EHV solutions showed less variation at those voltage levels with a strong requirement for dynamic network reconfiguration (active network management), real time thermal ratings and traditional network upgrades through new circuits and transformers. These solutions showed similar volumes across investment horizon sensitivities.

[26] Note – this is aggregate demand and capacity across the entire model for this archetype and not representative of any individual feeder. Individual feeders will reach constraints and require different solutions depending on the proportion of the each technology modelled as being connected to it.



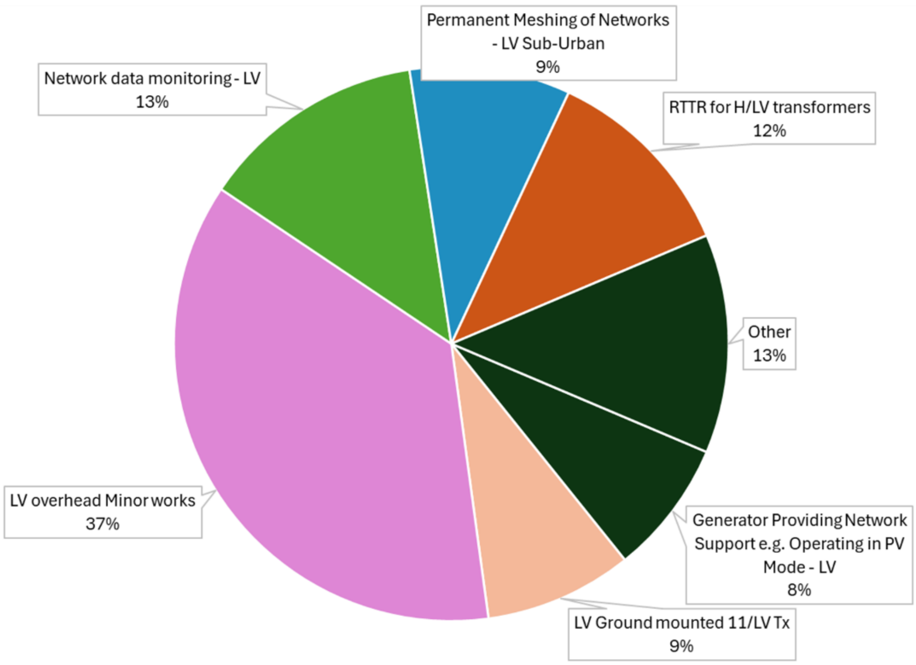


Figure 34 Comparison of the LV solution deployment between Run 01 (top) and Run 12 (bottom).

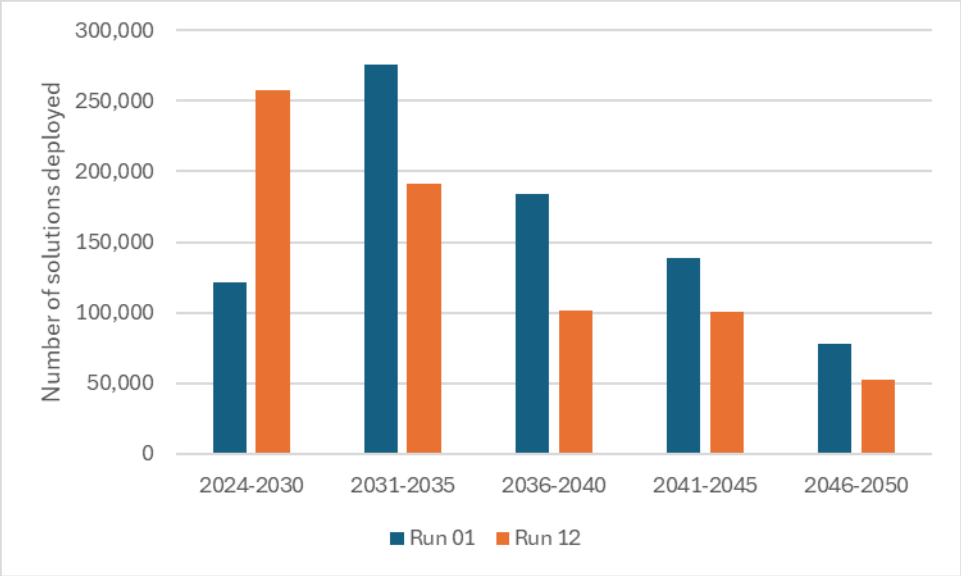


Figure 35 Volume of solutions deployed in Runs 01 and 12.

5. Conclusions

This report outlines the main findings from the national modelling of electricity distribution network capacity. The results show a wide range of cumulative, undiscounted, load-related expenditure, between £36 billion and £76 billion by 2050, with flexibility, heat technology and winter resilience assumptions being key determinants of network investment needs.

Initial expenditure seen in 2024 is needed due to network constraints identified to ensure sufficient capacity for the assumed demand profiles and baseline LCT levels. For most runs, (Runs 01-06 and 08-10), this remains relatively low at between £2-3 billion. The higher upfront costs (£8 billion) seen in Run 07 relates to ensuring the network has sufficient capacity to meet higher winter peak electrical heating demand, whereas the higher upfront costs in Runs 11 to 14 (£4-8 billion) reflect scenarios where distribution networks invest to deliver capacity for longer forecast demand increases.

A significant rise in expenditure occurs between 2030 and 2040, with mid-term network expenditure reflecting the accelerated adoption of low carbon technologies (LCTs) like heat pumps and electric vehicles. Cumulative expenditure by 2030 varies widely, from £7 billion in Run 02 to more than 3x greater (£23 billion) in Run 07, highlighting the impact of different technology uptake rates and the impact of elevated heating. By 2040, excluding the winter stress test (Run 07), the load related expenditure range has reduced with Run 02 being £25 billion and Run 14 being £42 billion (1.5x).

Final cumulative expenditure across the core runs (01-06) settles between £37-49 billion by 2050, averaging £1.5 to £1.9 billion per year. These investment levels represent a notable increase compared to historical budgets, such as the RIIO-ED1 price control period, where load-related investments were around £363 million per year. RIIO-ED1 also included 132 kV and service cables, hence the increase in average estimated spending. The analysis reveals that lower levels of flexibility, as seen in Runs 04-06, result in higher final costs due to the earlier need for network upgrades. In contrast, Runs 09 and 10, focused on increased data centre and small-scale storage deployment, show little impact on overall expenditure, highlighting the more localised effect of these technologies on the distribution network.

Peak electricity demand follows a similarly varied trajectory, beginning at 51-53 GW in 2024 across the core runs and rising steadily to 108-119 GW by 2050. Scenarios involving higher heating demand with lower flexibility availability (Run 07) or reduced industrial and commercial demand (Run 08) demonstrate a wider range, with the winter stress test reaching a substantial peak of 153 GW by 2050. The acceleration of low carbon technology uptake—particularly heat pumps and electric vehicles—drives significant increases in demand from 2030 to 2040, with more than a 50% rise in peak demand across most runs during this period.

5.1 Typical Constraints and Solutions

The analysis reveals that thermal constraints—both for transformers and circuits—are the most prevalent issues faced by the network because of increasing demand from electrification of heat and transport. These thermal constraints are concentrated on the LV network, where this new demand is connecting. Transformer overloading and circuit thermal constraints are expected to increase steadily until the 2030s, peaking between 2031-2035, with solutions like transformer replacements and circuit upgrades becoming necessary to maintain network reliability.

Voltage constraints, though less common than thermal constraints in the model, are also significant and are captured under both voltage rise and voltage drop. Voltage rise constraints emerge during periods of high generation and low demand, especially during summer months. Voltage drop constraints appear less frequently but may often be masked in the analysis by the resolution of thermal constraints, with solutions that increase thermal capacity often simultaneously releasing voltage capacity.

Regarding typical solutions, the most frequently deployed interventions are on the LV network and relate to physical upgrades such as new ground-mounted transformers, new overhead circuits in rural areas and permanent meshing of LV networks. These are complemented by more novel use of data through network monitoring and real time thermal ratings to extract greater use from the existing assets. For HV and EHV networks, although there is still a significant level of new infrastructure there is also a use of solutions that utilise dynamic network reconfiguration (active network management and temporary meshing).

5.2 Electrification of Heat

The electrification of heat through heat pumps and the transition to electric vehicles are dominant factors driving network demand. Scenarios investigated the impact of heat electrification through three different scenarios:

- Runs 01 and 04 based on FES 23 Consumer Transformation scenario for heat pump uptake.
- Runs 02 and 05 based on FES 23 Consumer Transformation scenario but with a delayed uptake in heat pumps.
- Runs 03 and 06 with lower heat pump uptake and greater use of electric resistive heating.

Heat pump uptake rates impact on the early requirement for investment, particularly at the LV level, where localised constraints emerge. Delayed heat pump adoption leads to a concentration of network investments post-2035, creating risks for magnitude of intervention needed and potentially be mitigated through earlier, more proactive investments. The analysis also highlights that a greater reliance on electric resistive heating leads to higher levels of load related expenditure throughout the study window.

Winter stress test

The winter stress test (Run 07) presents the most severe scenario, with peak demand reaching 153 GW by 2050, a sharp contrast to the 108-119 GW seen in the rest of the scenarios. This illustrates the stress that designing a system to deliver the same level of resilience for higher heating loads could introduce. The cumulative load related expenditure under this scenario reaches £76 billion—far higher than any other scenario. This illustrates the importance of a strong debate around resilience planning in distribution networks and approaches to support higher heating demand under an electrified heating scenario.

In this analysis it was assumed that although heating demand significantly increased there was no reduction in other demands such as I&C or EV charging. This may be overly conservative as it could be assumed that in a winter stress test there is less travel and some businesses may well close, reducing the peak demand. At the time of writing there is not an agreed standard on what this type of scenario should look like. In reality, other methods may be deployed to mitigate the effect of a winter stress test, which aren't captured in this scenario, such as the use of thermal storage.

5.3 Impact of Flexibility

The modelling assumed scenarios with both high and low levels of demand side flexibility representing the ability for technologies such as EVs, heat pumps and energy storage to shift demand away from the evening peak. Flexibility is categorised into two types, implicit and explicit. Implicit flexibility representing customers shifting usage patterns in response to supplier signals and captured in the demand profiles. Explicit flexibility representing DSO procured flexibility, i.e. paying customers to shift demand in response to a local constraint.

High flexibility scenarios, utilising managed charging for electric vehicles and demand-side response from heat pumps, consistently show lower peak demands and a delayed need for network reinforcements, which results in significant cost savings. In contrast, low flexibility scenarios drive earlier network constraints and front-load investment requirements. For example, in low flexibility runs, the peak demand reaches 115-119 GW by 2050, while in high flexibility runs, this is reduced to 108-110 GW. The results highlight that flexibility can reduce cumulative expenditure by up to £8 billion by 2050.

However, a key observation is the low utilisation of explicit flexibility, which may be due to a combination of assumption around procurement costs, availability at times of demand peaks, and the use of perfect foresight inherent to any modelling scenario. Explicit flexibility technologies were assumed to be those that were already providing implicit flexibility and as a result the demand available to participate in explicit flexibility is already significantly reduced.

5.4 I&C Demand, Data Centres and Energy Storage Impacts

Industrial and Commercial (I&C) Demand

The modelling of I&C demand reveals the complexity of forecasting this sector due to its diverse range of activities, from small businesses to large industrial operations, each with distinct load profiles. Unlike residential demand, I&C loads are more difficult to predict, prompting the use of a simplified, representative profile across the sector.

A sensitivity analysis (Run 08) was conducted, reducing this profile by 22%, to explore the impact of lower I&C demand. This sensitivity was picked as an illustration of the potential value of I&C demand side response, as I&C customers offer significant potential vector for demand side response, as shown by the reduction in system peak due to Triad avoidance by large commercial and industrial demands[27]. The results demonstrate a notable reduction in peak demand by 2050, from 108 GW (Run 01) to 102 GW (Run 08). This decrease in demand directly affects cumulative load related expenditure reducing from £38 billion (Run 01) to £36 billion (Run 08) by 2050. These findings highlight the significant influence of I&C demand assumptions on network planning, highlighting the importance for further investigation and analysis in this sector to understand and model the decarbonisation journey.

Data Centre Demand

As data centres grow in importance as part of the modern digital infrastructure, their impact on electricity demand is becoming increasingly significant. These facilities operate continuously, with high baseline energy consumption driven by the need for constant cooling and server power. In the sensitivity analysis (Run 09), data centre demand is projected to grow at a greater rate and contribute more than 8% (8.4 GW) of the 17:30, 2050 winter demand. This contrasts with Run 01, where data centre demand only accounts for 2.2% of the 17:30 winter demand. This highlights the uncertainty and potential impact the role of data centres is expected to play in overall network demand.

Despite this growth, the impact of data centres on overall network load related expenditure remains relatively modest. Since, in this analysis, data centres are assumed to connect to the EHV network, the additional cumulative expenditure required in Run 09 compared to Run 01 is minimal—only an additional £0.1 billion by 2050. While data centres contribute significantly to peak demand at EHV, the majority of network expenditure and capacity release is forecast on the LV network as a result of residential transport electrification and heat pump uptake. Nevertheless, strategic planning will be required to manage localised demand and prevent congestion at EHV substations as data centre uptake continues to rise.

Small-Scale Storage Deployment

The small-scale storage deployment sensitivity (Run 10) explores the impact of increased uptake of distributed energy storage systems, such as domestic batteries and community-level storage, on the electricity distribution network. Small-scale storage has the potential to enhance grid flexibility by storing excess energy generated during off-peak times or from renewable sources like rooftop solar and discharging it during periods of high demand. This could help to smooth out demand peaks, reduce strain on network infrastructure, and support the integration of renewable energy. In this sensitivity, an accelerated deployment of small-scale storage is assumed, following an s-curve to reach the same total installed capacity by 2050 as in the baseline scenario.

[27] Work Package 1: Electricity Distribution Network Capacity Analysis

Despite the potential of small-scale storage to influence peak demand, the modelling results show that its overall impact on the 17:30 winter peak demand is minimal, with a reduction of less than 0.25 GW by 2050. However, the analysis does highlight a more significant impact on summer peak generation, where small-scale storage helps reduce peak export during maximum solar generation periods by over 2.5 GW in 2035 compared to Run 01. Although this reduces reverse power flows during the summer, the overall effect on cumulative network expenditure remains limited, lowering total investment by just 0.5%. This modest reduction reflects the fact that most network investment is driven by the need to meet winter peak demand, where small-scale storage has a lesser impact.

However, one of the key uncertainties that remains is the appropriate usage profile for small-scale storage systems in the future. The model assumes a fixed profile for import and export based on current technology and usage patterns, but as storage technologies and user behaviour evolve, these profiles may change significantly. For example, increased adoption of smart home systems, advanced energy management algorithms, and dynamic tariff structures could shift the timing of when storage systems charge and discharge. Even small variations in these profiles could have a considerable impact on demand peaks and the overall level of network investment required. Therefore, developing more sophisticated and flexible profiles for small-scale storage usage will be critical to fully understanding its long-term role in reducing network constraints and optimising grid operations.

5.5 Investment Horizons and Planning

The investment horizon plays a critical role in determining the scale and timing of network upgrades. A shorter, five-year investment horizon was assumed for the core studies and results in incremental interventions throughout the study window. In contrast, a longer investment horizon of 10 years leads to earlier load related expenditure initially that then tapers to result in the same overall undiscounted expenditure by 2050.

The 26-year investment horizon was selected to simulate a “touch the network once" scenario whereby once a constraint is reached, solutions are identified to deliver the capacity required for 2050. This sees a substantial, upfront investment in the network to release sufficient capacity for 2050. However, a limitation in the analysis is that some of those solutions have a lifetime that means they require replacement before 2050 and potentially before they have been needed for the network capacity. Although this would give the network plenty of flexibility against an uncertain forecast it could also mean the installation of redundant infrastructure.

5.6 Limitations and Areas for Further Study

While this analysis provides a comprehensive view of the future distribution network under various scenarios, several limitations exist. The model assumes perfect foresight, meaning the future trends in technology adoption, policy changes and consumer behaviour are treated as predictable. This assumption does not fully account for uncertainties that impact network planning, such as localised surges in EV uptake or alternative heating technologies.

Additionally, the modelling assumes current regulatory constraints remain static, such as limitations on Distribution Network Operators (DNOs) owning or operating energy storage assets. This constrains the range of potential solutions that could be deployed that could evolve and provide alternative options for network capacity release. Additionally, the focus of this study has been into load-related expenditure and has excluded asset health considerations, which could impact timelines for network interventions along with bring additional expenditure.

132 kV networks, customer connection assets and LV service cables have not been modelled. In terms of cable length the 132 kV network represents only 2% of cable kilometres, but 132 kV substations and assets will require significant investment. 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. On top of this,

some customers are supplied with looped connections which would require un-looping. Two DNOs have estimated over 1 million looped services which would cost around £2 billion to resolve for them alone[28].

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. While profiles are evolving, the ones used in this analysis represent the current understanding of load behaviour. Future changes could reduce or increase peak network loads.

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) could be higher if these sectors were included.

A significant limitation is the simplified modelling of Industrial and Commercial (I&C) demand. The current model applies a broad, representative load profile across all I&C sectors as a result of data availability limitations, but this approach will not capture the full complexity and diversity of demand in this sector. For example, large manufacturing facilities, data centres, and small retail businesses each have vastly different load profiles and flexibility potential. Detailed, granular research is required to understand how each subsector might decarbonise and what the specific impact of energy efficiency measures, DSR and electrification pathways might be across various regions. For instance, industrial electrification in agricultural areas will create different challenges compared to urban I&C environments, requiring tailored network solutions.

In summary, while this report outlines the extensive load related expenditure and interventions required to meet the UK's electrification goals, the importance of flexibility, early interventions, and detailed sectoral analysis, particularly within I&C demand and emerging storage technologies, cannot be understated. These technologies will shape the future requirements of distribution networks and it's important they are able to remain resilient, adaptable, and cost-effective on the journey to net zero.

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

Appendix I Archetypes

Table AI.1 Network details used in Transform for the EHV, HV and LV archetypes

Archetypes	Substation Capacity (kW)	Thermal Conductors Capacity (kW)	Planning Voltage Upper Headroom Limit (%)	Planning Voltage Lower Limit (%)	kW/%[29]	Number of Networks in Model
EHV1 Urban Underground Radial	90000	25020	6%	6%	19300	540
EHV2 Urban Underground Meshed	45000	18000	6%	6%	18000	810
EHV3 Suburban Mixed Radial	60000	22260	6%	6%	7700	360
EHV4 Suburban Mixed Meshed	45000	18000	6%	6%	8600	840
EHV5 Rural Overhead Radial	48000	15240	6%	6%	18000	257
EHV6 Rural Mixed Radial	48000	16140	6%	6%	12500	200
HV1 Urban Underground Radial	4000	4504	6%	6%	6100	5643
HV2 Urban Underground Meshed	2500	4567	6%	6%	5200	2997
HV3 Suburban Underground Radial	3429	3552	6%	6%	3900	3120
HV4 Suburban Underground Meshed	1875	3121	6%	6%	3300	4200
HV5 Suburban Mixed Radial	6000	3400	6%	6%	440	5760
HV6 Rural Overhead Radial	2400	2474	6%	6%	280	6750
HV7 Rural Mixed Radial	2400	3045	6%	6%	800	3450
LV1 Central Business District	238	231	1%	15%	40	16246
LV2 Dense urban (apartments etc)	190	164	1%	15%	40	50098
LV3 Town centre	190	179	1%	15%	40	32154
LV4 Business park	238	184	1%	15%	40	70119
LV5 Retail park	238	184	1%	15%	40	13502
LV6 Suburban street (3 4 bed semi detached or detached houses)	119	111	1%	15%	40	122765
LV7 New build housing estate	119	164	1%	15%	40	149492
LV8 Terraced street	119	111	1%	15%	40	336919
LV9 Rural village (overhead construction)	48	131	1%	15%	40	24122
LV10 Rural village (underground construction)	100	113	1%	15%	40	24802

[29] This is the number of kW required to deliver a 1% change in the voltage headroom or legroom.

Archetypes	Substation Capacity (kW)	Thermal Conductors Capacity (kW)	Planning Voltage Upper Headroom Limit (%)	Planning Voltage Lower Limit (%)	kW/%[29]	Number of Networks in Model
LV11 Rural farmsteads small holdings	48	56	1%	15%	40	4993
LV12 Meshed Central Business District	380	359	1%	15%	40	6179
LV13 Meshed Dense urban (apartments etc)	190	328	1%	15%	40	13284
LV14 Meshed Town centre	190	359	1%	15%	40	11677
LV15 Meshed Business park	190	369	1%	15%	40	12096
LV16 Meshed Retail park	190	369	1%	15%	40	2520
LV17 Meshed Suburban street (3 4 bed semi detached or detached houses)	190	226	1%	15%	40	26208
LV18 Meshed New build housing estate	190	226	1%	15%	40	5040
LV19 Meshed Terraced street	190	384	1%	15%	40	44482

Appendix II Solutions and Enablers

Table AII.1 Agreed EHV solutions list deployed within Transform for national modelling

Solutions implemented at EHV voltage level	Description
D-FACTS - EHV connected STATCOM	STATCOMs (Static Synchronous Compensators) are power electronics device, capable of injecting VArs to a network for voltage support or power flow management of EHV networks
Distribution Flexible AC Transmission Systems (D-FACTS) - EHV	Series or shunt connected static power electronics as a means to enhance controllability and increase power transfer capability of the EHV network
Fault Current Limiters_EHV Non-superconducting fault current limiters	The use of non-superconducting (e.g. magnetic) materials, as a form of non-linear resistor, to clamp fault current levels at EHV to within predefined limits
Fault Current Limiters_EHV Superconducting fault current limiters	The use of superconducting materials, as a form of non-linear resistor, to clamp fault current levels at EHV to within predefined limits.
New Types of Circuit Infrastructure_Novel EHV tower and insulator structures	The deployment of new, higher capacity, EHV overhead line infrastructure incorporating modern conductor types and designed in a way to minimise electrical resistance and reactance.
New Types of Circuit Infrastructure_Novel EHV underground cable	The deployment of new, higher capacity, EHV underground cables incorporating modern conductor types and designed in a way to minimise electrical resistance and reactance
Permanent Meshing of Networks - EHV	Converting the operation of the EHV network from a radial ring (with split points) to a solid mesh configuration.
RTTR for EHV Overhead Lines	The use of measurement and ambient forecasting data to predict the rating (and hence current carrying capacity) of assets in a real-time mode. This variant considers RTTR for EHV overhead line circuits.
RTTR for EHV Underground Cables	The use of measurement and ambient forecasting data to predict the rating (and hence current carrying capacity) of assets in a real-time mode. This variant considers RTTR for EHV underground cable circuits
Switched capacitors - EHV	EHV connected mechanically switched devices as a low-cost form of reactive power compensation. They are used for voltage control and network stabilisation under heavy load conditions.
Temporary Meshing (soft open point) - EHV	"Temporary meshing" refers to running the network solid, utilising latent capacity, and relying on the use of automation to restore the network following a fault

Solutions implemented at EHV voltage level	Description
EHV underground network Split feeder	Lay a new EHV underground feeder out of a BSP to the midpoint of an existing feeder. Break the existing feeder and pick up the 50% of the load from that feeder onto the new feeder
EHV underground New Split feeder	Lay a new EHV feeder from a primary substation, part way along the already split EHV feeder. Perform some cross jointing such that one third of the total load on the original feeder and the split feeder is now transferred to the new split feeder. A diagram showing this is included in 13.2 of the WS3 Report.
EHV underground Minor works	This solution involves fairly extensive restructuring of the EHV network to spread the load more evenly within a small geographic area via the use of additional circuits
EHV underground Major works	The major works at EHV is primarily composed of significant amounts of cable laying to create new EHV circuits (because the model does not consider grid transformers directly). This allows for headroom on existing EHV circuits to increase as load is transferred to the new feeders
EHV overhead network Split feeder	Install a new EHV overhead feeder out of a BSP to the midpoint of an existing feeder. Break the existing feeder and pick up the 50% of the load from that feeder onto the new feeder.
EHV overhead New Split feeder	Install a new EHV feeder from a primary substation, part way along the already split EHV feeder. The new feeder needs to be connected into the existing network such that one third of the total load on the original feeder and the split feeder is now transferred to the new split feeder. A diagram showing this is included in 13.2 of the WS3 Report.
EHV overhead Minor works	This solution involves fairly extensive restructuring of the EHV overhead network to spread the load more evenly within a small geographic area via the use of additional circuits
EHV overhead Major works	This major works at EHV is primarily composed of significant amounts of overhead line construction to create new EHV circuits (because the model does not consider grid transformers directly). This allows for headroom on existing EHV circuits to increase as load is transferred to the new feeders.
Active Network Management - EHV	The pro-active movement of EHV network split (or open) points to align with the null loading points within the network in real-time. Headroom Release (%) Cost (£) Life Expectancy of Solution: 20 Merit Order £2,500 3 1 £40,000 £500 £7,106 Year solution is available: 2012 Year data is available: 2014 0% Source of Data: SGF - Workstream 2 model and report Smart Solution Relevance (WS3 Ph1) Smart D-Networks 1 Quality of supply; enhancements to existing network architecture Intelligent Switching SGF-WS3 Solution Annex

Solutions implemented at EHV voltage level	Description
FLEX - EHV connected generation / demand	DNO triggered Demand Side Response to interact with customer load to resolve generation / demand EHV network constraints

Table AII.2 Agreed HV solutions list deployed within Transform for national modelling

Solutions list at HV voltage level	Description
D-FACTS - HV connected STATCOM	STATCOMs (Static Synchronous Compensators) are power electronics device, capable of injecting VArs to a network for voltage support or power flow management of HV networks
Fault Current Limiters_HV reactors - mid circuit	The application of reactors part way down a HV circuit to limit fault current.
Fault Current Limiters_HV Non-superconducting fault current limiters	The use of non-superconducting (e.g. magnetic) materials, as a form of non-linear resistor, to clamp fault current levels at HV to within predefined limits.
Fault Current Limiters_HV Superconducting fault current limiters	The use of superconducting materials, as a form of non-linear resistor, to clamp fault current levels at HV to within predefined limits.
Generator Constraint Management GSR - HV connected generation	The use of commercial contracts, underpinned with automated signalling, between a DNO and generation customer(s) to ramp down export under certain network conditions. This variant considers any generators connected to the HV network.
Generator Providing Network Support e.g. Operating in PV Mode - HV	Contracting with a HV connected generator for them to operate their sets in PV (Real power and volts) mode rather than the conventional PQ (Real and Reactive power). The generator will draw VArs from the network at certain times, but ensure that the voltage on the network is not excessively raised at the point of connection.
New Types Of Circuit Infrastructure_Novel HV tower and insulator structures	The deployment of new, higher capacity, HV overhead line infrastructure incorporating modern conductor types and designed in a way to minimise electrical resistance and reactance.
New Types Of Circuit Infrastructure_Novel HV underground cable	The deployment of new, higher capacity, HV underground cables incorporating modern conductor types and designed in a way to minimise electrical resistance and reactance
Permanent Meshing of Networks - HV	Converting the operation of the HV network from a radial ring (with split points) to a solid mesh configuration.
RTTR for E/HV transformers	The use of measurement and ambient forecasting data to predict the rating (and hence current carrying capacity) of assets in a real-time mode. This variant considers RTTR for Primary transformers.
RTTR for HV Overhead Lines	The use of measurement and ambient forecasting data to predict the rating (and hence current carrying capacity) of assets in a real-time mode. This variant considers RTTR for HV overhead line circuits.
RTTR for HV Underground Cables	The use of measurement and ambient forecasting data to predict the rating (and hence current carrying capacity) of assets in a real-time mode. This variant considers RTTR for HV underground cable circuits
Switched capacitors - HV	HV connected mechanically switched devices as a low-cost form of reactive power compensation. They are used for voltage control and network stabilisation under heavy load conditions.

Solutions list at HV voltage level	Description
Temporary Meshing (soft open point) - HV	"Temporary meshing" refers to running the network solid, utilising latent capacity, and relying on the use of automation to restore the network following a fault
HV underground network Split feeder	Lay a new HV underground feeder out of a primary substation to the midpoint of an existing feeder. Break the existing feeder and pick up the 50% of the load from that feeder onto the new feeder.
HV underground New Split feeder	Lay a new HV feeder from a primary substation, part way along the already split HV feeder. Perform some cross jointing such that one third of the total load on the original feeder and the split feeder is now transferred to the new split feeder.
Large 33/11 Tx (HV)	Replacement of a ground mounted primary transformer (such as a 12/24MVA Tx) with a higher rated transformer in the same location (such as a 19/38MVA Tx). Note that these transformers are larger than those observed for a comparable overhead network.
HV underground Minor works	This solution takes the form of an additional primary transformer at, or near to, the location of the original transformer. A small amount of EHV cabling is allowed for, while the solution also incorporates the construction of several HV circuits to connect to the existing HV infrastructure. A diagram showing the solution can be found in section 13.2 of the WS3 report.
HV underground Major works	The major works option here is composed of the construction of several new substations (with associated cabling) in an area that has seen significant load growth and requires wholesale investment.
HV overhead network Split feeder	Install a new HV overhead feeder out of a primary substation to the midpoint of an existing feeder. Break the existing feeder and pick up the 50% of the load from that feeder onto the new feeder.
HV overhead New Split feeder	Install a new HV feeder from a primary substation, part way along the already split HV feeder. The new feeder needs to be connected into the existing network such that one third of the total load on the original feeder and the split feeder is now transferred to the new split feeder.
Small 33/11 Tx (HV)	Replacement of a small primary transformer (such as a 10/14MVA Tx) with a larger primary transformer (such as a 12/24MVA Tx). Note that this replacement results in a smaller Tx than that for a comparable underground network.
HV overhead Minor works	This solution takes the form of an additional primary transformer at, or near to, the location of the original transformer. A small amount of EHV overhead line is allowed for, while the solution also incorporates the construction of several HV overhead circuits to connect to the existing HV infrastructure.
HV overhead Major works	The major works option here is composed of the construction of several new substations (with associated new overhead lines) in an area that has seen significant load growth and requires wholesale investment.

Solutions list at HV voltage level	Description
Active Network Management - HV	The pro-active movement of HV network split (or open) points to align with the null loading points within the network in real time.
FLEX - HV connected generation / demand	DNO triggered Demand Side Response to interact with customer load to resolve generation / demand HV network constraints

Table AII.3 Agreed LV solutions list deployed within Transform for national modelling

Solutions list for LV voltage level	Description
EAVC - HV/LV Transformer Voltage Control	As the network starts to operate closer to these limits, DNOs may opt to introduce additional automatic voltage control devices over and above those located at the grid and primary transformers. Together these new and existing voltage control devices will constitute an EAVC system.
Generator Constraint Management GSR - LV connected generation	The use of commercial contracts, underpinned with automated signalling, between a DNO and generation customer(s) to ramp down export under certain network conditions. This variant considers larger generators (e.g. supermarkets, commercial buildings) connected to the LV network - it is not deemed to be a residential solution
Generator Providing Network Support e.g. Operating in PV Mode - LV	Contracting with a larger LV 3-phase connected generator for them to operate their sets in PV (Real power and volts) mode rather than the conventional PQ (Real and Reactive power). The generator will draw VArs from the network at certain times, but ensure that the voltage on the network is not excessively raised at the point of connection.
Permanent Meshing of Networks - LV Urban	Converting the operation of the LV network from a radial feeder (with split points) to a solid mesh configuration
Permanent Meshing of Networks - LV Sub-Urban	Converting the operation of the LV network from a radial feeder (with split points) to a solid mesh configuration.
RTTR for H/LV transformers	The use of measurement and ambient forecasting data to predict the rating (and hence current carrying capacity) of assets in a real-time mode. This variant considers RTTR for Secondary distribution transformers
RTTR for LV Overhead Lines	The use of measurement and ambient forecasting data to predict the rating (and hence current carrying capacity) of assets in a real-time mode. This variant considers RTTR for LV overhead line circuits
RTTR for LV Underground Cables	The use of measurement and ambient forecasting data to predict the rating (and hence current carrying capacity) of assets in a real-time mode. This variant considers RTTR for LV underground cable circuits.
Switched capacitors - LV	LV connected mechanically switched devices as a low cost form of reactive power compensation. They are used for voltage control and network stabilisation under heavy load conditions.
Temporary Meshing (soft open point) - LV	"Temporary meshing" refers to running the network solid, utilising latent capacity, and relying on the use of automation to restore the network following a fault
LV Underground network Split feeder	Lay a new LV underground feeder out of a distribution substation to the midpoint of an existing feeder. Break the existing feeder and pick up the 50% of the load from that feeder onto the new feeder

Solutions list for LV voltage level	Description
LV New Split feeder	Lay a new LV feeder from a distribution substation, part way along the already split LV feeder. Perform some cross jointing such that one third of the total load on the original feeder and the split feeder is now transferred to the new split feeder. A diagram showing this is included in 13.2 of the WS3 Report.
LV Ground mounted 11/LV Tx	Replacement of an existing distribution transformer with a larger unit
LV underground Minor works	This solution takes the form of a second distribution transformer at, or near to, the location of the original transformer. A small amount of HV cabling is allowed for, while the solution also incorporates the construction of several LV circuits. A diagram showing the solution can be found in section 13.2 of the WS3 report.
LV underground Major works	The major works option here is composed of the construction of several new substations (with associated cabling) in an area that has seen significant load growth and requires wholesale investment. An example of how this might be represented can be seen in section 13.2 of the WS3 report.
LV overhead network Split feeder	Install a new LV overhead feeder out of a distribution substation to the midpoint of an existing feeder. Break the existing feeder and pick up the 50% of the load from that feeder onto the new feeder.
LV overhead network New Split feeder	Install a new LV feeder from a distribution substation, part way along the already split LV feeder. The new feeder needs to be connected into the existing network such that one third of the total load on the original feeder and the split feeder is now transferred to the new split feeder. A diagram showing this is included in 13.2 of the WS3 Report
LV Pole mounted 11/LV Tx	Replacement of a pole mounted distribution transformer with a larger pole mounted transformer
LV overhead Minor works	This solution incorporates the installation of a new pole mounted transformer, close to an existing HV line and heavily loaded pole mounted transformer. The solution involves HV and LV lines as well as the new transformer. A representative diagram can be found in section 13.2 of the WS3 report.
LV overhead Major works	The major works option here is composed of the construction of several new pole mounted substations (with associated conductoring) in an area that has seen significant load growth and requires wholesale investment. An example of how this might be represented can be seen in section 13.2 of the WS3 report.
Active Network Management - LV	The pro-active movement of LV network split (or open) points to align with the null loading points within the network in real time.
Local smart EV charging infrastructure_Intelligent control devices (LV)	A novel monitoring and control solution to manage the supply of electricity to EVs connected to distribution networks, ensuring that the load of all EV chargers does not take the load above the rating of the LV circuit.

Solutions list for LV voltage level	Description
Dynamic voltage management using OLTCs - LV	Dynamic voltage management using On-Load Tap Changers (OLTCs) refers to a method of controlling and stabilizing the voltage levels in an electrical power distribution network. OLTCs are devices that can adjust the voltage ratio of transformers under load without interrupting the power supply.
Dynamic voltage management using power electronics - LV	Dynamic voltage management using power electronics refers to the use of semiconductor devices to control and manage the voltage levels in an electrical power distribution network. These devices, such as inverters, converters, and other power electronic components, can rapidly adjust the voltage to maintain stability and efficiency in the network, especially in the presence of renewable energy sources and variable loads.
Network data monitoring - LV	Network data monitoring at the LV (Low Voltage) level involves the collection and analysis of data from the electricity distribution network to better understand and manage the flow of electricity. It includes monitoring parameters such as voltage, current, power flow, and load profiles of transformers and feeders.
FLEX - LV connected generation/demand	DNO triggered Demand Side Response to interact with customer load through an aggregator to resolve generation / demand LV network constraints

Table AII.4 Agreed Enabler list deployed within Transform for national modelling

Solutions list for LV voltage level	Description
Advanced control systems - EHV	System to intelligently control remote equipment and hence facilitate solutions such as Active Network Management / Dynamic Network Reconfiguration
EHV Circuit Monitoring	Device to monitor the voltage (and load) along EHV circuits to inform solutions such as EAVC by allowing revised set points to be calculated based on observed voltages.
Link boxes fitted with remote control	Devices equipped to link boxes to enable them to be operated remotely to facilitate solutions such as Active Network Management / Dynamic Network Reconfiguration
Communications to and from devices - LAST MILE ONLY	Communications infrastructure to customer devices
Weather monitoring	Weather monitoring stations with localised communications for use in RTTR solutions at all voltages
Advanced control systems - HV	System to intelligently control remote equipment and hence facilitate solutions such as Active Network Management / Dynamic Network Reconfiguration
HV Circuit Monitoring (along feeder)	Device to monitor the voltage (and load) along HV circuits to inform solutions such as EAVC by allowing revised set points to be calculated based on observed voltages

Solutions list for LV voltage level	Description
HV Circuit Monitoring (along feeder) w/ State Estimation	Device to monitor the voltage (and load) along HV circuits, making use of state estimation, to inform solutions such as EAVC by allowing revised set points to be calculated based on observed voltages
HV/LV Tx Monitoring	Device to monitor the load and voltage observed at a distribution transformer to facilitate solutions such as EAVC at various voltage levels
RMUs Fitted with Actuators	11kV RMUs that are equipped with actuators allowing automatic operation in response to network triggers to facilitate Active Network Management / Dynamic Network Reconfiguration solutions
Dynamic Network Protection 11kV	Network protection to support solutions such as temporary meshing
Phase imbalance -HV circuit	Device to monitor the load on three phases of an HV circuit and hence determine the level of imbalance that exists between phases
Advanced control systems - LV	System to intelligently control remote equipment and hence facilitate solutions such as Active Network Management / Dynamic Network Reconfiguration
LV Circuit Monitoring (along feeder)	Device to monitor the voltage (and load) along LV circuits to inform solutions such as EAVC by allowing revised set points to be calculated based on observed voltages
LV Circuit monitoring (along feeder) w/ state estimation	Device to monitor the voltage (and load) along LV circuits, making use of state estimation, to inform solutions such as EAVC by allowing revised set points to be calculated based on observed voltages

Appendix III LCT allocation in Transform

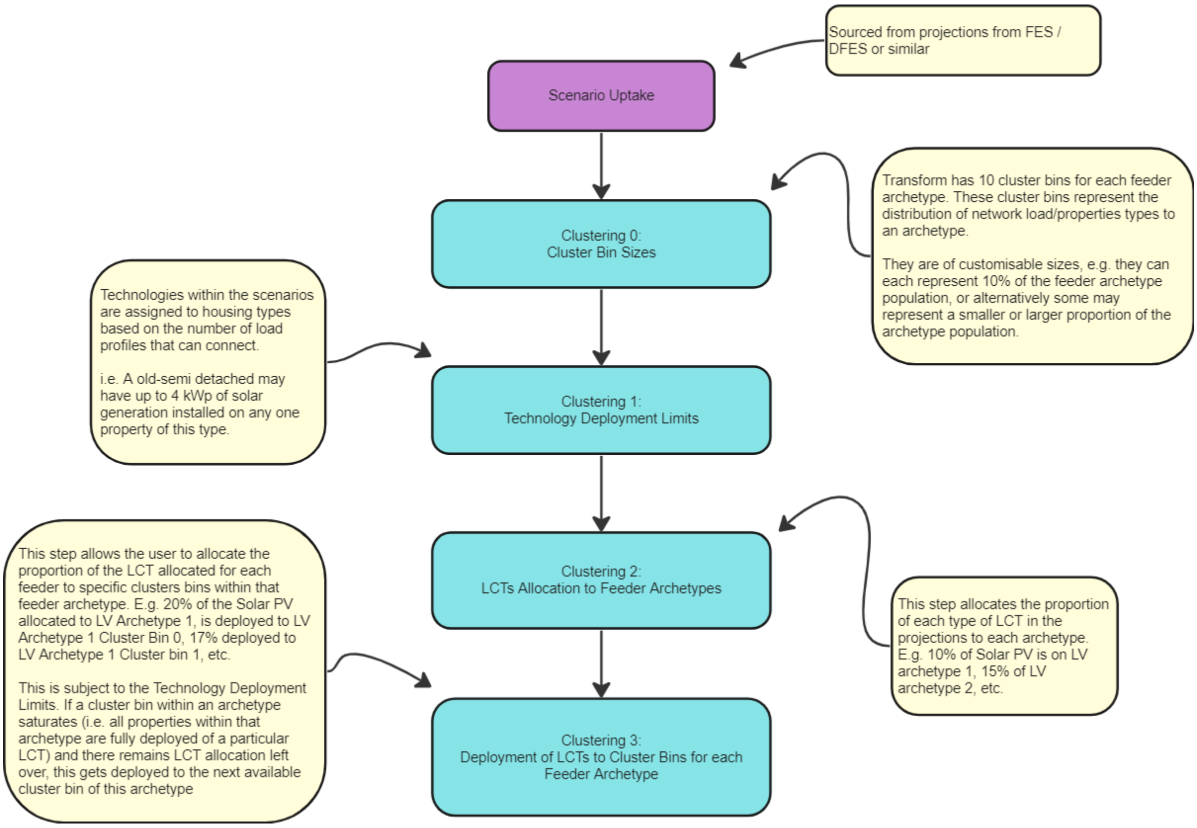


Figure AIII.1 LCT allocation in Transform to understand network capacity requirements while considering variability across different geographies and network topologies.

Classification: Public

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