REPORT

Low Voltage Network Case Studies

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Executive Summary

This document contains the outputs from Work Package 2 of the Electricity Distribution Network Capacity Analysis, carried out by Regen and EA Technology Ltd for the National Infrastructure Commission (NIC).

The NIC are conducting a study on the policy decisions required to make the electricity distribution network suitable for achieving net zero. In support of this study, the NIC commissioned Regen and EA Technology to evaluate potential future distribution network loads and their possible impact on the network.

The project is split into two work packages.

Work Package 1

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

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 investment across all GB distribution networks, and to consider the challenges of investment at a local level.

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 Work Package 1.
- The Local Case Study Modelling demonstrates the impact of Low Carbon Technology adoption on some case study Low Voltage networks.

This report presents the outputs from the second study.

Context

Connecting new Low Carbon Technologies (LCTs) to the Low Voltage (LV) network is an essential step in decarbonising domestic properties across the UK. What technologies are installed, where they are installed and when they are installed will have huge impacts on how the Distribution Network Operators (DNOs) plan their network reinforcements.

The term "technologies" refers to devices like electric vehicles (EVs), heat pumps, or power generation systems, as well as their ability to control and manage demand. As demand on Low Voltage (LV) networks increases, these technologies offer greater flexibility in managing that demand, provided customers choose to engage with this flexibility. This could bring significant advantages for DNOs. However, the total number of new LCTs added to the network will influence overall demand. In some cases, no amount of flexibility can fully offset the impact of a large increase in load relative to the available capacity.

The location of the new LCTs matters greatly, both in a national context and on an individual network basis. Where a network is located, urban, sub-urban or rural, will indicate how many LCTs may be installed on that network, as property types vary and so does the physical space for new installations. A network in a city feeding large blocks of flats will have a different set of challenges with new LCTs to that of a rural village. Additionally, the LCT location within an individual network also has an impact. For example, an EV connected close to a transformer has a different impact on the network compared to an EV connected at the very end of a feeder, the term for the main cable connecting customers to a transformer.

The electricity distribution network in Great Britain (GB) exhibits significant diversity in both load and generation across voltage tiers, with the extent of this diversity decreasing as the voltage tier increases due to less customers with higher load and generation capacities. At lower voltage tiers, there are more directly connected entities, leading to greater variability in load and generation patterns, however, each individual connection has a smaller impact on the overall network. In contrast, at higher voltage tiers, the number of directly connected customers reduces, and while there is less diversity in load and generation, the larger scale of individual connections has a greater influence on network stability and operation. Each of these larger connections tends to be more predictable than those in the lower tiers.

From a DNO perspective, the timing of the installation of these new loads on the network will impact them the greatest when considering their network planning activities.

Scope of this report

The purpose of these local case studies is to demonstrate, through worked examples, that the same number and type of LCTs can lead to the requirement for different interventions over varying timescales when deployed on the same LV network in alternate configurations. At an individual case study level, it is always challenging to identify a “typical” arrangement as it depends on a range of very local factors. The case studies used within this report share common features with LV networks of each their types, and the case studies provide insights into the general challenges associated with the changing scope of demand and generation connecting to the LV networks. The analysis will demonstrate the impacts new demands placed on the network by these technologies could have on the network constraints and investment need.

Three categories of LV networks, urban, sub-urban and rural, are considered within this report, with two or three case studies demonstrating the different impacts of the forecasted level of LCT installation required for Net Zero. The LCTs that are in scope for study within this report are: EV chargers, heat pumps and solar generation. The impact of additional direct electric heating demand and heat networks are also considered in order to achieve solutions that are net zero compliant.

The key aim is to demonstrate the challenges at a local level of ensuring the electricity distribution network is fit for Net Zero by 2050, when it is achieved through large scale electrification of domestic heating and transport.

Key Findings

Table 1 provides a summary of the seven LV case study networks, the year intervention is first required and a high-level overview of the network solution that would enable the 2050 LCT uptake forecast. These case studies were selected through dialogue with the DNOs at the start of the project to cover a range different urban, sub-urban and rural representative networks.

The networks used in these case studies came from two DNOs, National Grid Electricity Distribution (NGED) and Northern Powergrid (NPg). NGED is the DNO for the East and West Midlands, South West Endland and South Wales and NPg is the DNO for the North East of England. Both DNOs supply urban, sub-urban and rural areas.

Table 1 Overview of LV case study properties

Case Study Name	DNO	Type	Location	Transformer Capacity[1]	No. of Customers
Mosborough Crescent	NGED	Urban	Central Birmingham	1000 kVA	293
Dunston Industrial East	NPg	Urban	Gateshead	1000 kVA	200
Brockhill Drive	NGED	Sub-urban	Redditch	800 kVA	338
May Street	NPg	Sub-urban	Durham	500 kVA	186
Spen Road	NPg	Rural	County Durham	100 kVA	93
Chaddesley Corbett	NGED	Rural	Worcestershire	300 kVA	77
Duxmoor	NGED	Rural	Ludlow	50 kVA	9

When discussing and testing interventions on each of the case studies there are two options: the chosen solution solves the issues within the year of study, or the chosen solution solves the issue on the network until 2050. In some of the case studies, there is a range of years associated with intervention. The variability as to when interventions can be applied is due to the uptake scenarios having different intervention requirements and also explicit flexibility procurement being an avenue to avoid or delay physical reinforcement.

2050 is used in this report as the investment horizon to ensure alignment with Net Zero 2050 and interim carbon budgets. It is assumed that the volume of LCTs on the LV network will be suitable for reaching the Net Zero by 2050 target.

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[1] kVA is the unit for Apparent Power, which relates to the maximum power a transformer can supply, referred to as capacity in this report. 1 MVA is 1000 kVA.

Table 2 Overview of LV case study results

Case Study Name	Type	2024 Base Demand	Constraint	Intervention Year	Solution Enabling 2050 LCT Forecast
Mosborough Crescent	Urban	351.47 kVA	Thermal on feeder cable	2035-2050	Network reconfiguration through use of existing link boxes installed on the network is possible.
Dunston Industrial East	Urban	519.69 kVA	Thermal on feeder cable	2040-2045	Domestic loads increase significantly on one feeder. Network reconfiguration or the addition of a new feeder to feed domestic properties is required.
Brockhill Drive	Sub-urban	442.42 kVA	Demand at transformer, statutory voltage excursions	2035	New loads on the network by 2050 will increase the demand on the network to beyond 1000 kVA. Additional transformer required.
May Street	Sub-urban	268.43 kVA	Demand at transformer	2045-2050	Peak demand in 2050 is likely to be manageable through flexibility procurement
Spen Road	Rural	79.61 kVA	Demand at transformer, statutory voltage excursions	2030	New, larger transformer required, alongside the creation of a new feeder.
Chaddesley Corbett	Rural	152.62 kVA	Demand at transformer, statutory voltage excursions	2040-2045	Flexibility may delay reinforcement requirement but an increase in transformer capacity will be required.
Duxmoor	Rural	26.5 kVA	Demand at transformer, statutory voltage excursions	2035-2050	Implementing flexibility likely a suitable solution for this network to defer network reinforcement, however it is likely a transformer upgrade will be necessary by 2050.

To summarise Table 2, there are two main constraints that are most important to solve. Other constraints exist, like statutory voltage requirements, and are discussed where required. The thermal constraints on the mains feeder and the overall maximum demand at the transformer are the two that require intervention to ensure network asset health is not compromised.

Where the constraint remains a thermal conductor constraint in 2050, for example, the demand on a single feeder causes the rating of the feeder cable to be exceeded, the solutions to these issues may be flexible or smart. Smart solutions here would mean LV network monitoring to understand changing customer demand while flexible solutions would be the targeted procurement of demand reduction on the LV network. Where loadings are unbalanced, if one feeder is heavily loaded compared to others, there may be a requirement to physically reinforce the network by changing the network design.

If the constraint in 2050 is the exceedance of transformer capacity, in some cases flexibility could be used to delay the network reinforcement but the maximum demand in 2050 suggests that a transformer upgrade would be required.

In Brockhill Drive, the new demand pushes the substation's supplied group demand beyond 1 MW, triggering a network reinforcement discussion more complex than a simple transformer capacity upgrade. Large sub-urban areas, with lots of physical space to install LCTs and customers with the financial means to do so, will be areas at risk of requiring greater network intervention.

On the other end, small, rural substations, like Spen Road and Duxmoor, are also more at risk from the shock of new demands on their networks, especially if there are low numbers of connected customers which reduces diversity factors. These areas are also likely to not presently have electrified heating.

Any substation feeding customers primarily supplied by gas for their heating load will be at risk if those customers choose to switch to heat pumps at scale, with the winter peak being the most critical time. How heat is decarbonised, and whether that heat load is connected to the LV network, will be critical to understand so network can prepare appropriately. It is likely that customers switching to heat pumps (and / or EVs), will also switch to time-of-use tariffs (ToUT), the impact of which is complex, but might reduce diversity.

ToUT load profiles are equivalent to the Managed Charging profiles in WP1 and demonstrate implicit flexibility in the network. This form of flexibility is accounted for in the load profiles used as part of the local case study modelling. In this report, as the EV ToUT charging load profiles follow existing ToUT pricing signals, it is appropriate to utilise more specific wording when referring to their effects on the network. Whilst they can often result in similar end results, customers responding to a ToUT tariff is not the same as managing the charging directly in response to the needs of the network in the moment.

The impact of supplier ToUT extends beyond EV charging behaviours and warrants further study. These tariffs influence customer behaviour and load profiles, reducing diversity as ToUT penetration increases. Even with demand shifted from peak times, the altered load profiles affect transformers by altering the cooling and heating cycles they are expected to operate in.

In general, LV network monitoring is often identified as an enabler to improve customer supply quality and ensure the network is designed for new loads as it reduces the number of unknowns and assumptions[2]. LV monitoring has not been considered an intervention in these case studies as it would only provide visibility of the problems to choose the most cost-effective solution, rather than solving the issues itself. It can be described as an enabler for safer and more secure network operation and energy supply.

Each LV case study is discussed in detail in this report, providing technical information on the driving forces behind the need for the individual interventions.

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[2] Department for Business, Energy & Industrial Strategy, Electricity Networks Strategic Framework: Enabling a secure, net zero energy system, August 2022: [Electricity networks strategic framework - GOV.UK]

Conclusions

These conclusions emphasise the importance of a long- and medium-term network planning, recognising that localised, flexible approaches may be more cost-effective than traditional reinforcement. The best approach will be specific to the location, and the continually evolving energy landscape.

- **Case-Specific Network Interventions:** Each case study highlighted that the necessary interventions depend heavily on the local network's characteristics. For example, urban networks like Mosborough Crescent showed potential for network reconfiguration using existing infrastructure, while rural networks like Duxmoor may require more direct transformer upgrades due to smaller capacities and fewer customers.
- **Increased Scale of Network Reinforcement:** In comparison to present network planning decisions, the volume of reinforcement required to support the new loads connecting to the network is far larger in scale. Not only will LV transformers need to be upgraded in some networks but the network configuration will have to be updated to ensure stability of supply.
- **Impact of Customer Location**: The distribution of customers on LV feeders plays a critical role in determining network constraints. In Brockhill Drive (sub-urban), the uneven distribution of load across feeders accelerated the need for intervention. Conversely, networks like May Street (sub-urban) demonstrated that balanced customer distribution can delay the need for upgrades.
  - Networks with fewer feeders or uneven distribution of customers across feeders will see the impact of new loads on the network earlier than other networks.
  - Location and grouping of new LCTs on an LV feeder plays a significant impact on when network upgrades are required.
- **Reduced Load Diversity:** As LCT uptake increases, load diversity decreases, amplifying network stress. In the Spen Road (rural) case, the small number of customers and concentrated LCT adoption significantly impacted the network, demonstrating that rural areas with limited diversity will face constraints earlier than urban or sub-urban areas.
- **Flexibility Delays Reinforcement:** In several case studies, such as Chaddesley Corbett (rural) and Dunston Industrial East (urban), flexibility services like demand-side response and targeted EV charging could delay the need for costly reinforcements, but only if local customers actively participate in demand-shifting schemes.
- **Explicit Flexibility and Implicit Flexibility Conflict:** While implicit flexibility, through time of use charges from a supplier, is broadly beneficial to networks in the present day, eventually the strain on the network may materialise at a different time. In some modelled case studies the need arises to procure explicit flexibility to solve the new demand issues created by customers responding to Time of Use Tariff signals (implicit flexibility).
- **Monitoring as a Crucial Tool:** In all case studies, continuous network monitoring was identified as essential for managing increasing LCT uptake. By using monitoring to anticipate constraints, DNOs can avoid over-investing in reinforcements and focus

on targeted, flexible solutions, especially in dense urban networks like Mosborough Crescent.

- **Diverse Intervention Needs:** Across all case studies, the required interventions varied in complexity and cost. For instance, Spen Road required a straightforward transformer upgrade, while Brockhill Drive called for a larger-scale transformer replacement due to the projected load increase. This underscores the need for tailored solutions based on specific local conditions.
- **Further Study on ToUT Impacts:** The case studies reveal the complexity of Time-of-Use Tariffs (ToUT). While shifting load outside of peak periods reduces strain, as seen in the Duxmoor rural network, ToUTs could reduce overall diversity in load profiles, making networks more susceptible to concentrated peak demand, even outside traditional peak hours.

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1. Definitions

ADMD	After Diversity Maximum Demand
ASHP	Air Source Heat Pump
CLNR	Customer Led Network Revolution
Diversity	Design of electrical networks includes consideration that the timing of individual customer peak demand will vary.
DNO	Distribution Network Operator
DSO	Distribution System Operator
DSR	Demand Side Response
ESO	Electricity System Operator
EV	Electric Vehicle
Explicit flexibility	Flexibility that a DNO can selectively procure flexibility on a targeted LV network
FCO	First Circuit Outage
Feeder	A power line through which electricity is passed in a power system
FES	Future Energy Scenarios
GB	Great Britain
GSHP	Ground Source Heat Pump
HV	A circuit voltage 1kV to 20kV.
ICE	Internal Combustion Engine
Implicit flexibility	Demand flexibility from customers responding to price signals in their tariff from their electricity supplier
kVA	Apparent Power measured in Kilovolt amperes (1,000 Volt Amperes)
kW	Kilowatts (1,000 Watts)
LCT	Low Carbon Technology.
LV	Distribution network voltage, 230 V single-phase in the UK.
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
MVA	Apparent power measured in Megavolt amperes (1,000,000 Volt Amperes)
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

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%.
ToUT	Time of Use Tariff, in this report, the EV ToUT charging load profiles follow current ToUT pricing signals. While managed charging and ToUT charging have similar load profiles currently, ToUT charging is used to provide insight on the effects of tariff driven charging behaviour.
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

2. Introduction

This report, prepared for the National Infrastructure Commission, explores the impact of connecting new LCTs to LV networks across the UK. With the UK committed to achieving net-zero emissions by 2050, integrating technologies such as electric vehicles, heat pumps, and renewable energy generation is essential to decarbonising the energy system. The adoption of these technologies will significantly affect how DNOs manage and plan their networks.

The project is split into two work packages.

Work Package 1

During Work Package 1, the project develops several future load scenarios using the Electricity System Operator (ESO)[3] 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[4].

Work Package 2

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 investment across all GB distribution networks, and to consider the challenges of investment at a local level.

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 Work Package 1.
- The Local Case Study Modelling demonstrates the impact of Low Carbon Technology adoption on some case study Low Voltage networks.

This report presents the outputs from the second study and the purpose is to assess how the uptake of LCTs will challenge LV networks and identify possible interventions to manage increased demand. Seven distinct case studies have been conducted to represent urban, sub-urban, and rural network types. Each case study provides an in-depth examination of the physical characteristics, customer profiles, and anticipated LCT adoption rates, illustrating the variations in demand growth and the associated constraints across different network types.

As the volume of LCTs increases, LV networks will need to adapt to manage the resulting load growth, while ensuring reliable supply. This report demonstrates how various LCT deployment scenarios can affect network performance and outlines potential solutions such as flexibility services or network reinforcement that address these challenges.

The findings in this report provide insights that can be used by DNOs and policymakers in planning for future network reinforcements and ensuring that LV networks are equipped to support the UK's transition to a low-carbon future.

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[3] Now known as the National Energy System Operator (NESO)

[4] Regen, Work Package 1: Electricity Distribution Network Capacity Analysis - Scenario development and load profile selection, September 2024

3. Case Study Selection

When considered in isolation, one portion of network can vary considerably from another. However, upon closer inspection, networks exhibit certain traits that can be characterised by a number of parameters. For example, a LV network in a city centre will be composed exclusively of underground cables; generally, of large cross-sectional area, fairly short in length (as all of the demand is focused in a small area) and supplied by large ground mounted transformers. Whether the network operates in a radial or interconnected manner will determine the actual conductor size and the likely distance between substations. A rural network, by contrast, will often be overhead construction, with longer circuits to reach customers in a lower density area, supplied by small, pole mounted transformers.

Further to these characteristics, certain networks are likely to be of older build, such as those in town centres or sub-urban areas populated with an old building stock, such as 1930s semi-detached properties. Others will be of different design having been constructed much later (a 1990s housing estate, for example). By looking at networks in this way, it is possible to characterise the very large number of feeders in existence across the country into a much smaller, and hence more manageable, number of feeders for modelling purposes.

To conduct the analysis for the case study networks, seven distinct models are proposed to represent rural, urban, and sub-urban networks. Given the wide range of network topologies, constructions, and lengths across Great Britain (GB), it is not yet possible to create detailed network models that encompass all possible network types. Instead, these seven models are chosen to represent different network archetypes anticipated to experience varying levels of Low Carbon Technology (LCT) uptake and associated constraints.

The LV networks for the case studies are from two Distribution Network Operators (DNOs): Northern Powergrid (NPg) and National Grid Electricity Distribution (NGED). Shown in Figure 1, GB is divided into 14 different licence areas which are operated by six DNOs. NPg has two license areas covering the Northeast of England and Yorkshire, while NGED's four licence areas cover the East Midlands, West Midlands, South Wales and the South West.

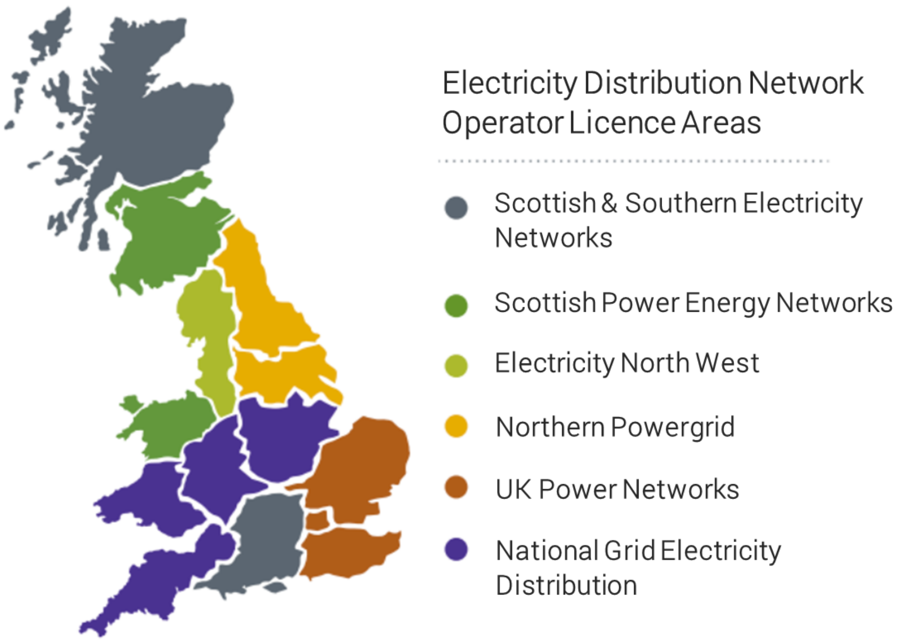

Figure 1 Map of GB DNOs, showing locations of NPg and NGED in yellow and purple.[5]

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[5] Map from Ofgem

The development of any case study models is contingent upon the availability of data to create accurately representative models. Consequently, these seven models are selected based on existing VisNet Design models available from both NGED's and NPg's regions[6]. This methodology and the selection of all seven case studies reflect requests from DNOs during a workshop on 10th July 2024 and agreed to be representative of the majority of their existing networks. These case studies are not representative of new builds as they will be designed using suitable demand forecasts.

The LV case studies cover 66% of the total LV network archetypes included within the National Modelling work package analysis[7]:

- Terraced Street – 35%
- Dense Urban – 5%
- Sub-urban Street – 13%
- Business Park – 7%
- Rural Village (Overhead Construction) – 2%
- Rural Village (Underground Construction) – 3%
- Rural Farmstead/Small Holdings – 1%

All LV networks modelled in this report are of radial construction as they are the most common type of LV network in NPg and NGED's region and the across UK DNO licence areas. The remaining types of radial LV networks not modelled are Central Business District, Town Centre, Retail Park and New Build Housing Estates. The New Build type makes up the bulk of the non-modelled LV radial networks at 15% of the circuits.

The remaining LV circuit types are meshed versions of the previous LV network types and the two network types are described here:

- Radial networks: Circuit has a single path to the customer from the transformer with no ability to divert flow through another feeder.
- Meshed networks: In normal running arrangement there will be a single path to the customer from the transformer. If operationally required, the network can be switched to enable a different flow of energy to the customer. Networks can be permanently meshed, thereby having at least two permanent routes by which a customer is energised.

The selected network archetypes and their technical characteristics are provided in Table 3 An overview of property heating, ownership types and building types of each case study is provided in Table 4 and further commentary on each case study is provided in the following section.

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[6] VisNet® Design is a commercially available software developed by EA Technology. It is currently used by NGED and NPg to model and assess tomorrow's electricity networks.

[7] EA Technology, National Modelling of Electricity Distribution Network Capacity Analysis (EA27108-TR02)

Table 3 Seven network models classified by network type. A third rural network was incorporated by DNO request, to identify issues in rural areas with minimal customers and a <100 kVA transformer.

Classification	NGED Case Studies		NPg Case Studies
Urban	**Mosborough Crescent (NGED)** **Central Birmingham**		**Dunston Industrial East (NPg)** **Gateshead**
	Typical mixed use urban environment.		Incorporates large industrial loads alongside terraced houses.
	1000 kVA transformer		1000 kVA transformer
	4 LV feeders		5 LV feeders
	293 customers		200 customers
Semi-Urban	**Brockhill Drive (NGED)** **Redditch**		**May Street (NPg)** **Durham**
	Typical sub-urban environment with detached, semi-detached homes with drives.		Incorporates terraced housing environment.
	800 kVA transformer		500 kVA transformer
	4 LV feeders		4 LV feeders
	338 customers		186 customers
Rural	**Chaddesley Corbett (NGED)** **Worcestershire**	**Duxmoor (NGED)** **Ludlow**	**Spen Road (NPg)** **County Durham**
	Individual dwellings, likely to use EV cars with heat pumps and solar.	Very rural	Smaller transformer, terrace houses and all overhead lines.
	300 kVA transformer	50kVA transformer	100 kVA transformer
	5 LV feeders	1 LV feeder	1 LV feeder
	77 customers	12 customers	91 customers

Table 4 Overview of property heating, ownership and building types on the LV case studies

	Property Heating Types (%)[8]				Property Ownership Types (%)[9]			Housing Type
Region	Gas	Electric	Multiple	Oil	Council	Private	Owned	
Central Birmingham	62	12	17	0	53	30	12	Flats and Duplexes
Gateshead	82	3	12	0	25	25	50	Terraced
Redditch	89	2	7	0	4	9	82	Detached and semi-detached
Durham	70	15	10	0	0	34	62	Terraced
Tyne & Wear	84	0	13	0	14	9	73	Terraced
Worcestershire	75	3	12	4	2	15	70	Detached or semi-detached
Ludlow	14	5	17	50	0	0	100	Detached or semi-detached

The types of heating do not add up to 100% as there are small proportions of other methods of heating that are not included in the table for space. The remaining types of heating for each area are small volumes of other combustible fuels, like wood or other solid fuels, some non-mains gas, and lastly properties with no stated form of central heating within the census data. Similarly, the three types of tenure that were most prominent across all case studies were drawn out for comparison: council rented, privately rented and owned. The remaining tenure types, where the percentages do not add to 100% are other forms of rented accommodation.

This information on ownership and heating type is provided to contextualise the wider areas where the LV case studies are situated, there may be some variation on a street by street basis. The boundaries for the areas these values are sourced from do not align exactly with the boundaries for the are the case study substations supply.

The rest of this section will provide more detailed overviews for each of the LV case studies.

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[8] Office of National Statistics Heating Type, based on 2021 census data Type of central heating in household - Census Maps, ONS

[9] Non-gas map nongasmap.org.uk

3.1 Urban – Mosborough Crescent

This network model represents an urban LV network in NGED's region and includes a 1 MVA (1 MVA = 1000 kVA) capacity rated transformer with four feeders supplying 293 customers in a number of multi-occupancy buildings. There are two 15-storey tower blocks which each have 90 individual dwellings and a number of small flats/maisonettes where there are two storeys with one address on the ground floor and the second address on the first floor. Other properties within the model include buildings with a number of small shops on the ground floor with residential properties above. It displays some typical features of urban LV networks like many properties densely clustered and minimal space for car parking.

The network schematic can be seen in Figure 2. Where there are small blue bubbles, those designate where multiple properties are connected, for example in the block of flats. Those properties share a connection point.

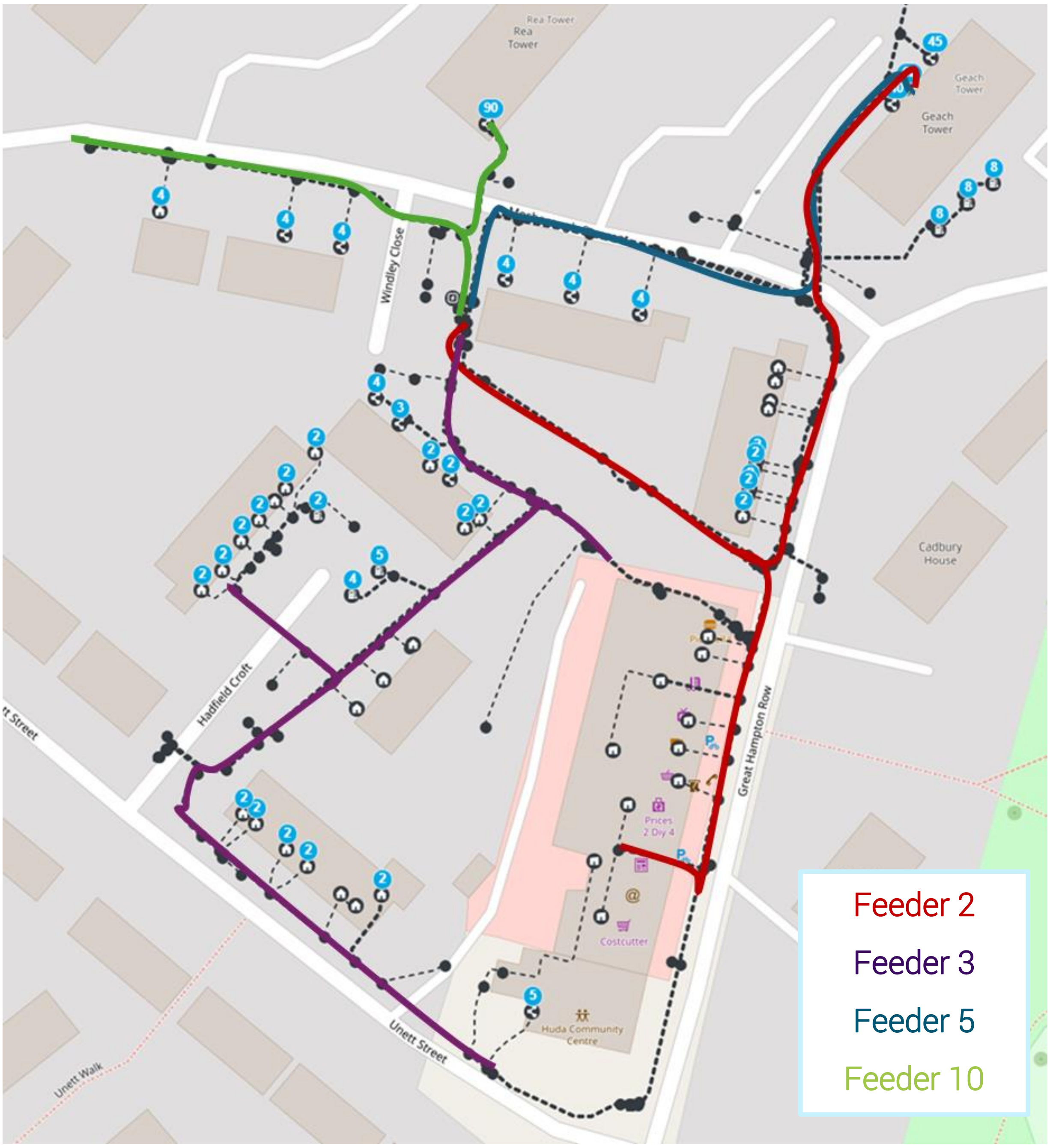

Figure 2 Network schematic of urban network Mosborough Crescent, showing the feeders differentiated by colour.

As shown in Table 5, the majority of properties are rented in this area, suggesting that the uptake of LCTs will be dependent on property owners choosing to install the LCTs rather than the inhabitants. The types of building in the area are less suitable for the installation of solar panels, which is reflected in the reduced installation rates. As most of the people within the area are unlikely to have a designated car parking space, any car charging points will likely be public / on-street.

Table 5 Mosborough Crescent area context

	Property Heating Type (%)[10]				Property Ownership Type (%)[11]			
Region	Gas	Electric	Multiple	Oil	Council	Private	Owned	Housing Type
Central Birmingham	62	12	17	0	53	30	12	Flats and Duplexes

The Mosborough Crescent 1 MVA transformer has four feeders with connected customers broken down as shown in Table 6. The network diagram shows another three unused feeder ways. There are two link boxes installed on this network.

Table 6 Mosborough Crescent network information

Feeder Name	Number of Customers
Feeder 2	94
Feeder 3	58
Feeder 5	39
Feeder 10	102
Total Connected Customers	293

A link box is a compartment installed underground in urban areas that enables a network to be reconfigured through the use of removeable links (Figure 3). These links can enable the transfer of customers from one feeder to another through reconfiguration of the open points in the link boxes.

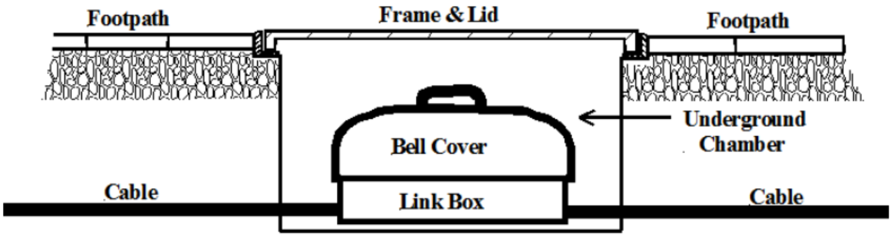

Figure 3 Diagram of LV network link box

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[10] Office of National Statistics Heating Type, based on 2021 census data Type of central heating in household - Census Maps, ONS

[11] Non-gas map nongasmap.org.uk

3.2 Urban – Dunston Industrial East

This LV network in NPg’s region represents a different type of urban network to Mosborough Crescent. The transformer is 1 MVA (1 MVA = 1000 kVA) and has five feeders supplying 200 customers. 148 of connected customers are domestic properties, the other 52 customers are a mixture of commercial and small industrial properties. This network was chosen because it demonstrates a network where domestic and commercial customers are in close proximity and the case study looks at how the concentration of domestic properties onto one feeder impacts the network performance using the forecast uptake rates. The network schematic can be seen in Figure 4.

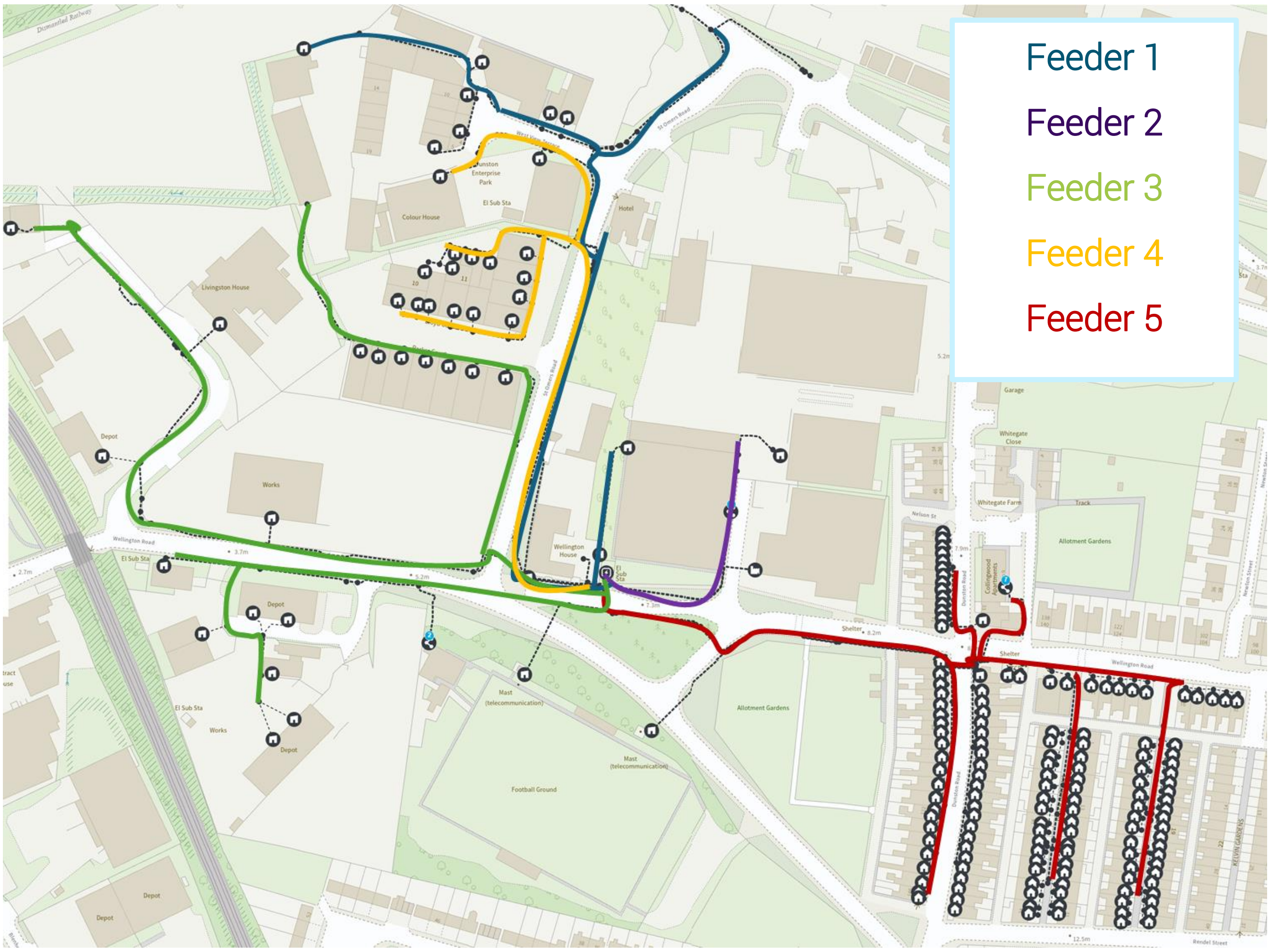

Figure 4 Network schematic of urban network Dunston Industrial East.

The percentage ownership values in Table 7 only refer to the domestic or residential properties in the area, so in this case study in some of the scenarios there has been installations of LCTs on industrial or commercial buildings.

Table 7 Dunston Industrial East network context

	Property Heating Type (%)[12]				Property Ownership Type (%)[13]			
Region	Gas	Electric	Multiple	Oil	Council	Private	Owned	Housing Type
Gateshead	82	3	12	0	25	25	50	Terraced

As shown in Table 28 this network is supplied by a 1 MVA transformer. Table 8 provides network information for Dunston Industrial East. The largest feeder (Feeder 5) supplies seven rows of terraced houses. Feeder 1, 2, 3 and 4 supply industrial customers in the baseline model, which is why the number of their connected customers is lower. Feeder 5 connects all the domestic customers on the network.

Table 8 Dunston Industrial East network information.

Feeder Name	Number of Customers
Feeder 1	18
Feeder 2	4
Feeder 3	13
Feeder 4	17
Feeder 5	148
Total Connected Customers	200

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[12] Office of National Statistics Heating Type, based on 2021 census data Type of central heating in household - Census Maps, ONS

[13] Non-gas map nongasmap.org.uk

3.3 Sub-Urban – Brockhill Drive

This sub-urban LV network model in NGED’s region represents supplying a housing estate in the outskirts of a town or city. The properties in the network selected are a mixture of terraced, semi-detached, and detached properties and there are no commercial or industrial properties included within the network. The transformer has a capacity rating of 800 kVA and there are four feeders associated with the substation supplying 338 customers. This case study is used to investigate a LV network that is likely to see high LCT uptake rates as it has the space, off-street parking, and the type of customers, homeowners, that are more likely to install LCTs.

The network schematic can be seen in Figure 5 below.

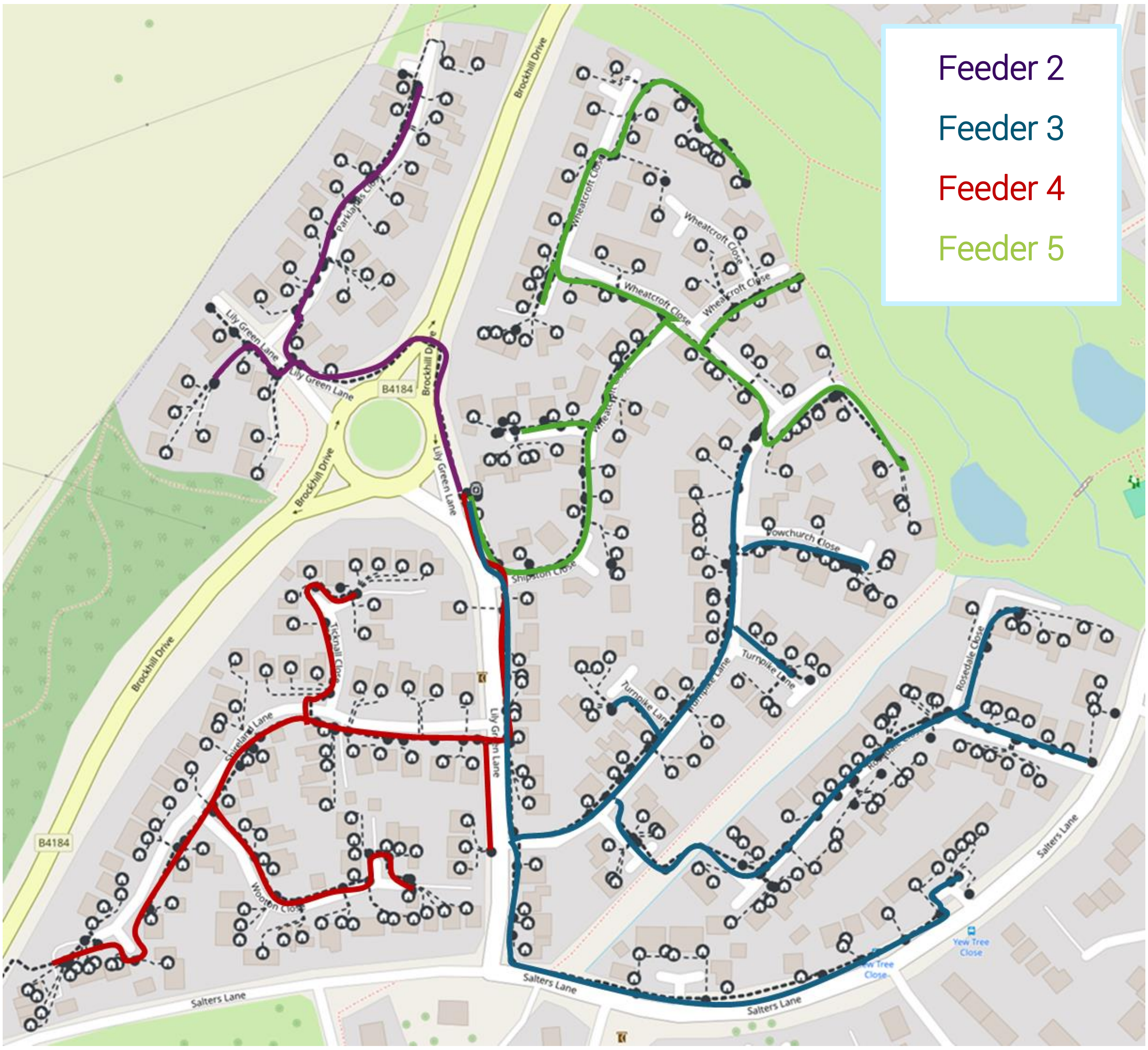

Figure 5 Network schematic of sub-urban network Brockhill Drive, the four feeders are delineated by colour.

Contextual details for the area where the network is situated are provided in Table 9 to drive analysis and the discussion surrounding possible LCT uptakes. Close to 90% of properties are heated using gas central heating and therefore it is anticipated that the transition to electric heating will create a large increase in network demand.

Table 9 Brockhill Drive area context.

	Property Heating Type (%)[14]				Property Ownership Type (%)[15]			
Region	Gas	Electric	Multiple	Oil	Council	Private	Owned	Housing Type
Redditch	89	2	7	0	4	9	82	Detached and semi-detached

This LV network is supplied by an 800 kVA transformer with four feeders (Table 10). Feeder 3 has significantly more connected customers than the next largest feeder and over four times the number compared to the smallest feeder. Before any addition of LCTs to the network is considered, this imbalance of customer demand signals that there may be feeder overloading before a transformer capacity issue is created.

Table 10 Brockhill Drive network information

Feeder Name	Number of Customers
Feeder 1	0
Feeder 2	33
Feeder 3	137
Feeder 4	89
Feeder 5	79
Total Connected Customers	338

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[14] Office of National Statistics Heating Type, based on 2021 census data Type of central heating in household - Census Maps, ONS

[15] Non-gas map nongasmap.org.uk

3.4 Sub-Urban – May Street

This LV network model in NPg's region represents a sub-urban terraced street, fed by underground cables with limited space for car parking, both on-street and off-street. The transformer is 500 kVA and has four feeders supplying 186 customers, almost entirely domestic terraced homes. It provides a sub-urban example of a type of LV network that has physical space constraints when it comes to adding new LCTs to a network, which affects EV uptake in particular. The network schematic can be seen in Figure 6. Blue bubbles with numbers designate where multiple properties are connected at one location, for example a small apartment building.

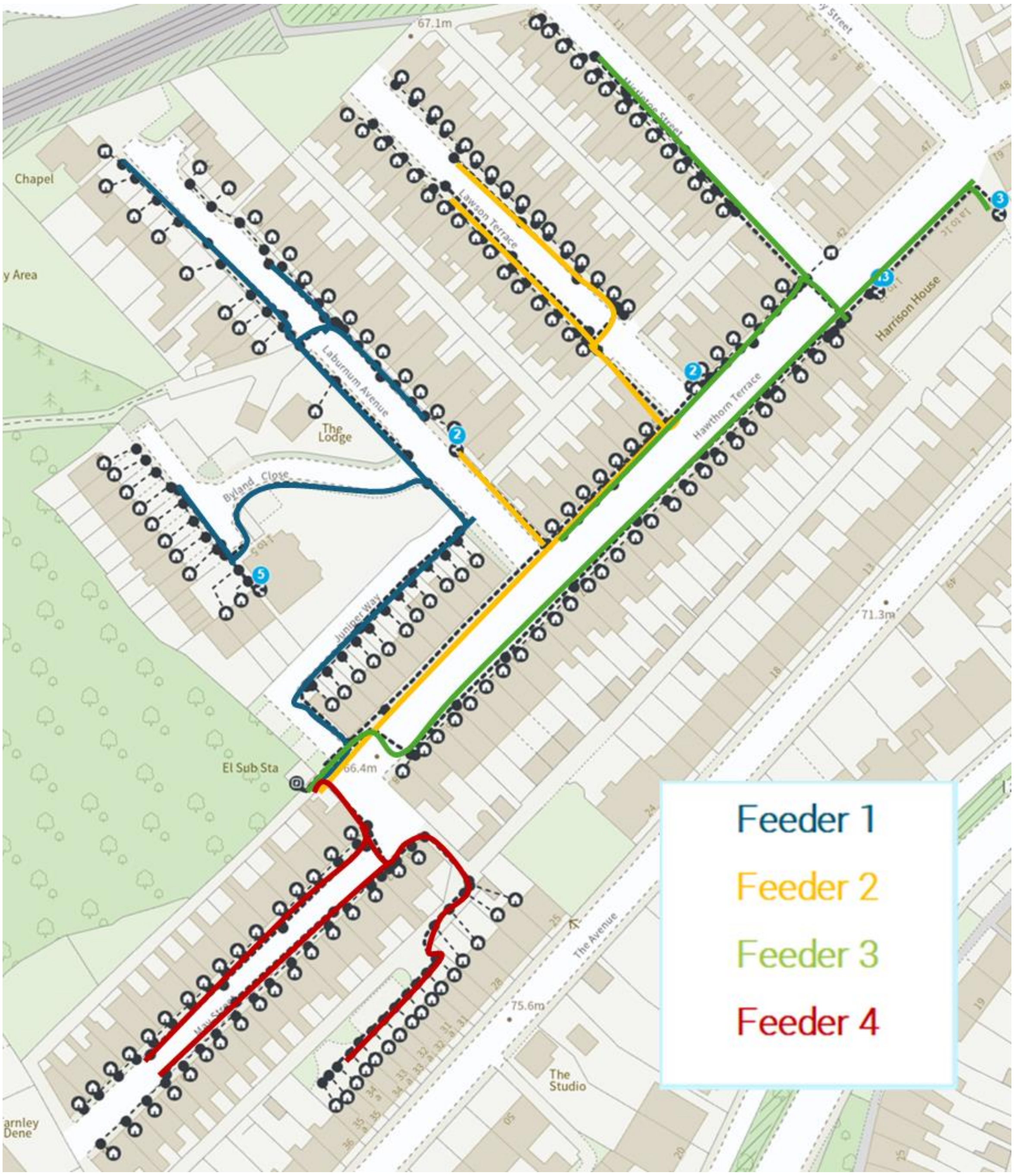

Figure 6 Network schematic of sub-urban network May Street with feeders delineated by colours.

Table 11 May Street network context

	Property Heating Type (%)[16]				Property Ownership Type (%)[17]			
Region	Gas	Electric	Multiple	Oil	Council	Private	Owned	Housing Type
Durham	70	15	10	0	0	34	62	Terraced

70% of properties in this region contain gas heating, with 62% of properties being owned (Table 11).The connected customers are relatively evenly distributed between the four feeders, Table 12. The baseline loading for the network, from assumed DNO customer load information, is below 50% at peak utilisation. This suggests that the network has significant capacity for increased load to be supplied.

Table 12 May Street network information

Feeder Name	Number of Customers
Feeder 1	45
Feeder 2	33
Feeder 3	59
Feeder 4	49
Total Connected Customers	186

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[16] Office of National Statistics Heating Type, based on 2021 census data Type of central heating in household - Census Maps, ONS

[17] Non-gas map nongasmap.org.uk

3.5 Rural – Spen Road

The rural LV network model in NPg's region includes a single feeder that supplies multiple terraced houses by overhead lines with no underground lines present. The network schematic can be seen in Figure 7.

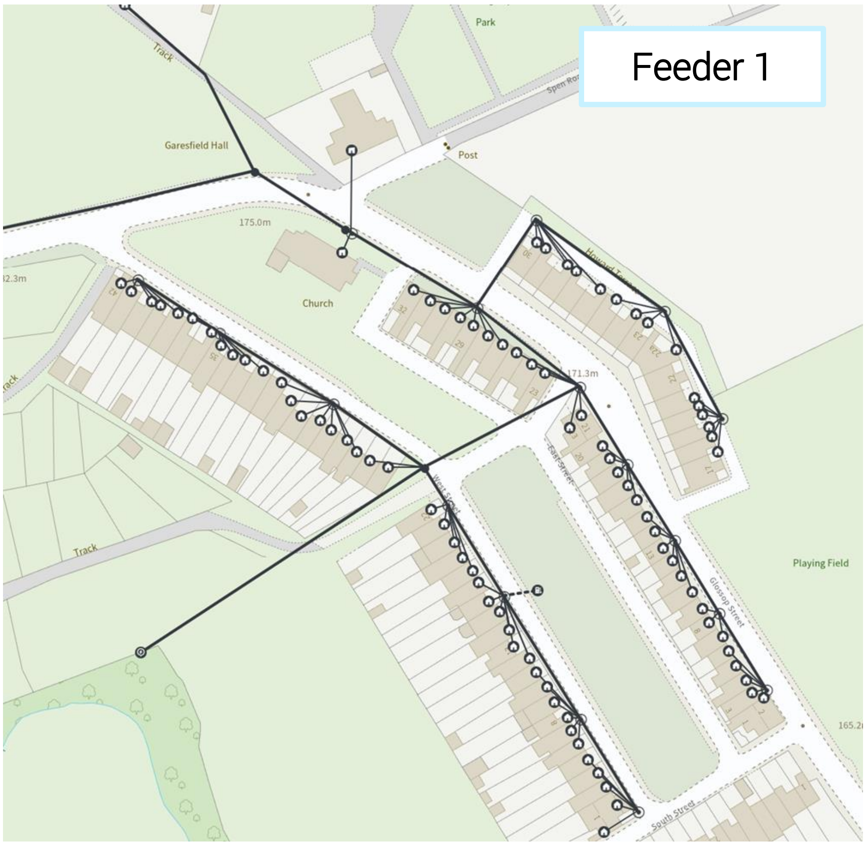

Figure 7 Network schematic of rural network Spen road, this network only has one feeder.

As illustrated in Table 13, the area is primarily assumed to be owned by the residents of the home, there is an increased likelihood that the levels of technology installations forecast would be implemented by the residents. However, as with other case studies, EV charging locations are more uncertain on networks where properties do not have driveways or designated parking.

Table 13 Spen Road network context.

	Property Heating Type (%)[18]				Property Ownership Type (%)[19]			
Region	Gas	Electric	Multiple	Oil	Council	Private	Owned	Housing Type
Tyne & Wear	84	0	13	0	14	9	73	Terraced

This network is fed by a single pole-mounted 100 kVA transformer with all customers connected to one feeder (Table 14).

Table 14 Spen Road network information

Feeder Name	Number of Customers
Feeder 1	93

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[18] Office of National Statistics Heating Type, based on 2021 census data Type of central heating in household - Census Maps, ONS

[19] Non-gas map nongasmap.org.uk

3.6 Rural – Chaddesley Corbett

This rural network model is a ground-mounted transformer fed from 11 kV overhead lines with 77 customers by a mixture of LV underground and overhead lines. There is a mixture of commercial and residential properties within the village. The transformer capacity rating, 300 kVA, provides an example of a different type of rural LV network, one with a larger transformer, a range of connected property types and more feeders, five, than the other rural network case studies. The non-domestic properties are: two pubs, a church and a few other small shops. The network schematic can be seen in Figure 8. 75% of properties contain gas heating (Table 15).

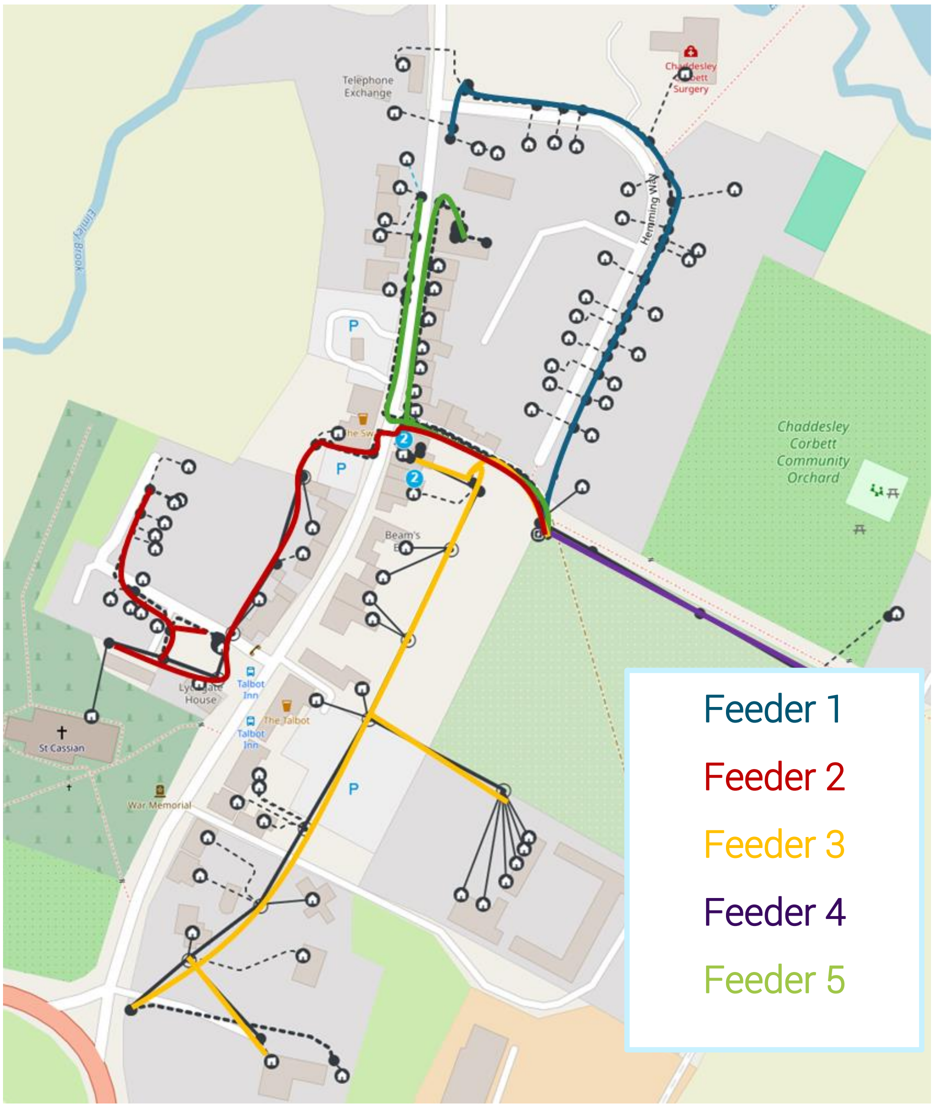

Figure 8 Network schematic of rural network Chaddesley Corbett, where feeders are delineated by colour.

Table 15 Chaddesley Corbett network context

	Property Heating Type (%)[20]				Property Ownership Type (%)[21]			
Region	Gas	Electric	Multiple	Oil	Council	Private	Owned	Housing Type
Worcestershire	75	3	12	4	2	15	70	Detached or semi-detached

This LV network is fed by a 300 kVA ground mounted transformer, the network is comprised of three feeders (2,3 and 4) that are mainly overhead line (OHL) and two (1 and 5) which are entirely underground cable (UGC). This is shown in Table 16.

Table 16 Chaddesley Corbett network information

Feeder Name	Number of Customers
Feeder 1	25
Feeder 2	21
Feeder 3	25
Feeder 4	2
Feeder 5	12
Total Connected Customers	77

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[20] Office of National Statistics Heating Type, based on 2021 census data Type of central heating in household - Census Maps, ONS

[21] Non-gas map nongasmap.org.uk

3.7 Rural – Duxmoor

This LV network model in NGED's region is used to represent rural networks with small transformers and low customer numbers. It contains residential dwellings and overhead lines, as well as feeding a farm at the end of the network. The purpose of including this network is to demonstrate the effect of even small numbers of LCTs connecting to small, rural substations, where each addition has a proportionally larger impact. The network schematic can be seen in Figure 9.

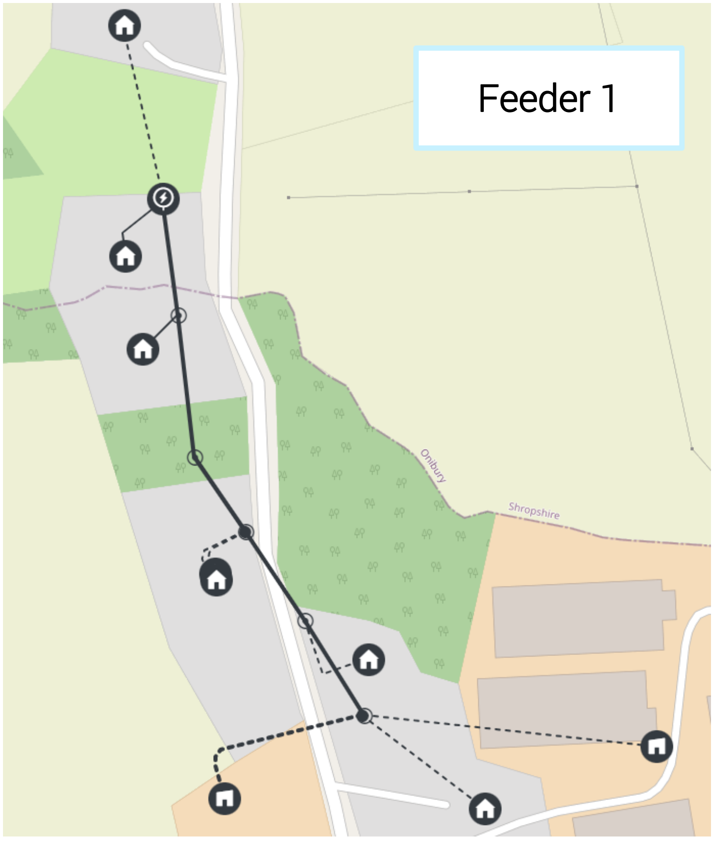

Figure 9 Network schematic of rural network Duxmoor.

Table 17 Duxmoor network context

	Property Heating Type (%)[22]				Property Ownership Type (%)[23]			
Region	Gas	Electric	Multiple	Oil	Council	Private	Owned	Housing Type
Ludlow	14	5	17	50	0	0	100	Detached or semi-detached

It is likely that on rural networks, where gas, oil and other combustible materials are used for heating, the existing electrical load on the network is lower and less tied to temperature or seasonal changes (Table 17).

The network information for Duxmoor is shown in Table 18, where 9 customers are situated on one feeder. The number of customers includes the farm within the count.

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[22] Office of National Statistics Heating Type, based on 2021 census data Type of central heating in household - Census Maps, ONS

[23] Non-gas map nongasmap.org.uk

Table 18 Duxmoor network information

Feeder Name	Number of Customers
Feeder 1	9

This LV case study was included at the request of the DNO representatives to provide an insight into rural networks fed by transformers with lower capacities. Across all DNO licence areas small capacity transformers, particularly in rural areas, will be heavily impacted by an increase in demand in any form. The installation of an LCT on a small capacity rural transformer can have a greater proportional impact compared to that same LCT connecting to a larger capacity transformer.

This network is supplied by a 50 kVA transformer, which comprises 23% of NGED's pole-mounted substation stock. As shown in Figure 10, more than 71 % of all NGED's pole-mounted transformers are less than 100 kVA.

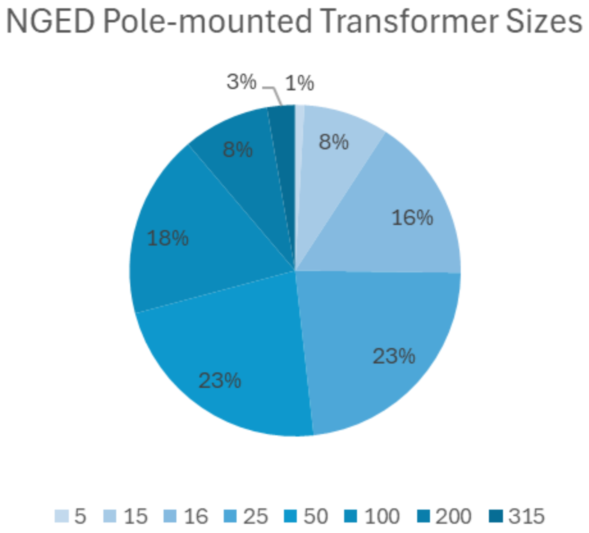

Figure 10 Breakdown of volume of NGED pole-mounted transformer capacities (kVA)[24]

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[24] Source: NGED Distribution Substation information

4. Methodology

The purpose of this modelling activity is to demonstrate the local challenges getting the distribution network ready for net zero, and how this varies across localities. This study will show that the type, volume and location of new demand connected to LV networks can have varying impacts on capacity requirements. Some networks may face challenges related to transformer capacity, and therefore may require a transformer upgrade, while others could absorb the new demand if network reconfiguration or other demand reduction options are possible.

This modelling exercise aims to demonstrate several critical factors that must be considered to ensure the successful and safe operation of the LV network across various demographic regions. Load profiles for each technology, are likely to evolve and become more uncertain towards 2050, as more practical evidence is gained from more widespread use of the technologies. Predicting and implementing future customer baseload profiles is not a sensitivity explored in this study as the case studies focus on the new LCT loads.

All models within VisNet Design will have a diversity factor calculated and then applied when the model is run. The load profiles used within VisNet Design are consistent between both NGED and NPg. The EV profile was derived from Electric Nation[25] data and the Heat Pump profile from Customer-Led Network Revolution (CLNR) data[26]. The PV profile is original to WinDebut, the LV modelling software that preceded VisNet Design. Technology load profiles can be found in Appendix I.

This work package uses the low flexibility forecasts from WP1 as the uptake rates for LCTs on the LV networks.

4.1 Volume of LCTs Connected

Uptake rates for LCTs are taken from WP1. The years of study are every five years from 2025 to 2050, creating a step change in demand on the networks. The volume of LCTs on the network impact both the voltage and the current flow patterns on the network.

To allocate the WP1 uptake rates to the LV case studies, the LCTs were distributed across the LV networks by type of network. Transform assumes an average number of connected customers for each network type. Where this average number does not match the number of connected customers the formula in Figure 11 is used to normalise the LCT volumes to the networks.

$$\frac{No. of\ customers\ in\ model}{No. of\ customers\ in\ Transform\ archetype} \times Number\ of\ LCT = The\ number\ of\ LCTs\ to\ be\ added$$

Figure 11 Formula used to apply the forecast number of LCTs to the LV case studies

This formula is implemented for each LCT type in each year of study to provide the number of each technology that is connected to the LV network models.

4.1.1 Heat Decarbonisation

For each LV network, the heat pump uptake rates that are calculated were reviewed to ensure they were within the uptake rates shown in Figure 12. Each LV network contains different property types and different levels of gas network connectivity. Where properties are already heated using electricity, some of the case studies have lower heat pump uptakes than others, but all heat pump uptake rates used are consistent with those provided.

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[25] National Grid - Electric Nation - Powered Up

[26] Homepage - Customer-Led Network Revolution

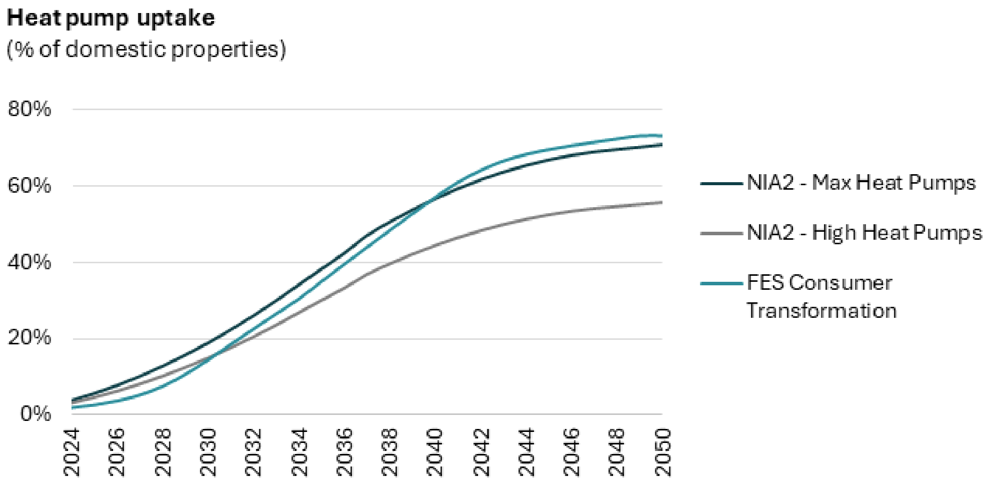

Figure 12 Heat pump uptake forecasts, contextualises the calculated uptake rates for each LV case study[27]

These uptake rates do not consider the geographies of an individual LV network when assigning air source heat pumps (ASHPs) or ground source heat pumps (GSHPs) to specific LV networks. The heat pumps applied to each LV network during the case studies do not necessarily represent specifically an ASHP or a GSHP since the DNOs do not currently utilise distinct profiles for each technology, instead they are scaled to different peak demands. Both NGED and NPg each use the same load profile for the modelling of ASHPs and GSHPs, with NPg using the same maximum demand for both while NGED assumes GSHPs have lower peak demands than an ASHP by around 1 kW.

Some networks, and the properties which they feed, will be unsuitable for GSHPs. Similarly, some properties on networks may be unsuitable for ASHP installation. While applying heat pumps to the LV case study networks it has been assumed that each property can accommodate a heat pump. In reality the physical qualities of some properties will not be suitable for heat pumps, whether that is due to space, insulation types or other technical limitations. Assuming maximum levels of heat pump penetration will enable heaviest heating demand for the LV network to be viewed, as DNOs doing network planning activities look to the worst-case scenarios to enable levels of mitigations required to be reviewed.

When considering the remaining households without heat pumps installed, a net zero heating load will be reached through other means. Some households could move to other forms of electric heating, such as the common resistive heating or less common infrared heating panels. In the case studies, to provide a net zero solution in 2050, properties not heated by heat pumps have had either direct electric heating loads included in the profile or have profiles that include electrical storage. In these case studies a proportion of the properties without electric heating sources were transitioned to electric heating profiles each year, following the uptake rates provided in WP1.

For the two urban case studies, heat networks were used to transition customers to a net zero source of heating. Urban areas are more likely to have heat networks installed due the density of connected properties making it more efficient than in other network types. None of the case study locations have existing heat networks and the year of installation within the two case studies is flexible depending on project planning, design and construction factors.

As new technologies are developed, customers will be making decisions on what is best for their properties and their lifestyles. DNOs should be proactive in understanding how their customers are choosing to heat their homes.

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[27] Data Deliverable Technology Uptake Data WP1.3 taken from the ESO's 2023 Consumer Transformation Scenario.

4.1.2 EV Forecasts Across Network Types

When reviewing the EV uptake rates applied to each LV network type, it is helpful to consider the following information in Figure 13. For more urban networks, or those with higher densities of properties, car ownership is reduced, while in rural or more sub-urban housing estates it is more common for a property to have two vehicles.

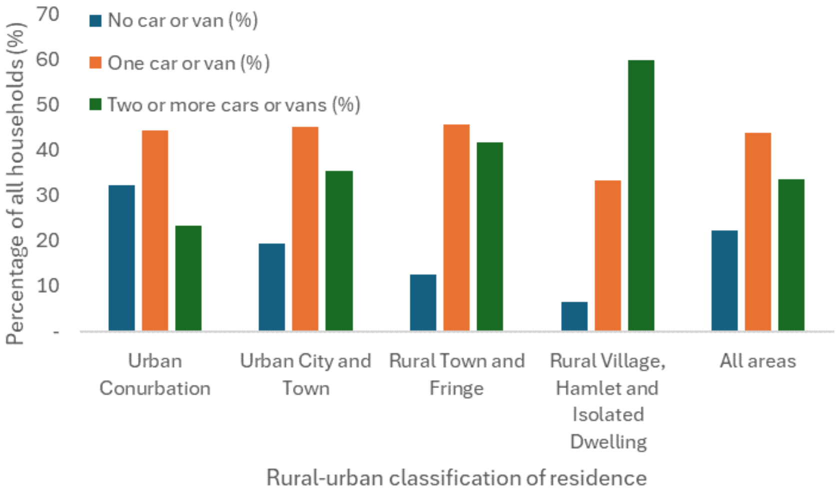

Figure 13 Household car ownership, England. National Travel Survey 2021, Department for Transport[28].

The total number of electric cars owned by customers on an LV network is not necessarily the total number of cars charging from domestic chargers simultaneously on an LV network, however it provides a baseline. There is limited research available surrounding the car charging needs and habits of a household with two EVs.

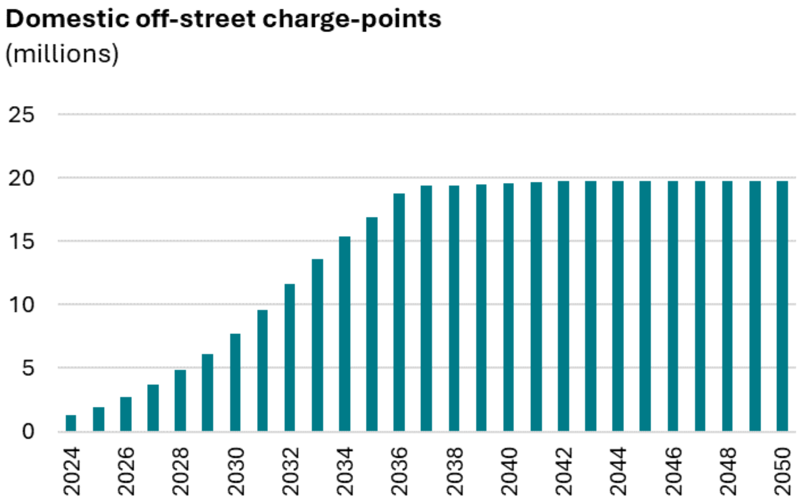

Figure 14 Annual road transport electricity consumption by vehicle archetype from the ESO's 2023 FES Consumer Transformation scenario[27].

Electricity consumption by electric vehicles is set to rise steadily until 2030. From 2030 to 2040, consumption increases at a greater rate, in line with the anticipated internal combustion engine (ICE) ban. Electricity consumption plateaus beyond 2040 (Figure 14).

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[28] Region and Rural-Urban Classification - GOV.UK (www.gov.uk)

In this study, the maximum number of electric vehicles connected in an LV network has been assumed to be limited by the number of properties at either 1 or 2 per property depending on the uptake projections and property type.

4.2 LCTs in Scope

Within this workstream, commonly connected LCT types have been used to demonstrate the impact of increasing volumes of electrical demand added to an LV network (Table 19).

Table 19 Overview of LCT types and description of their load profile.

LCT Profile	Description
Solar Panel (PV)	Solar generation has a greater impact on the network during the summer, especially the summer minimum. At the critical times of winter peak demand solar is not generating. In these case studies the PV installations are domestic, small-scale.
Air Source Heat Pump (ASHP)	Air source heat pumps transfer heat energy from outside a building to the inside of a building. In the modelling undertaken it is assumed that there is no associated heat storage.
Direct electric resistive heating	This is the common form of electric heating present in homes. In these case studies, direct electric heating is assumed to have at least some thermal storage included and is accounted for in the load profile.
Heat networks	Heat networks have a central source of heat generated and then distributed to properties. Within this modelling work, heat networks are assumed to be connected at HV and therefore do not have a direct impact on the LV demand.
Ground Source Heat Pump (GSHP)	Ground source heat pumps work on the same principle as air source heat pumps except from that they exchange heat using pipes inserted in the ground. The profile used in these case studies are not inclusive of thermal storage.
On-street charging (slow)	Generally provided to simulate “lamp post charge points” and other similar low power charge points. For some LV network types, where private driveways or designated car parking spots are unavailable, this may be the most common charger available.
On-street charging (fast)	As the penetration of EVs increases, the need for faster and more efficient charge points available to the public will increase. This LCT profile is used to cover these charger types.
Non-managed off-street	This profile simulates a customer not on a tariff which incentivises charging at certain times of day. In network performance terms, this will negatively impact the network as charging will still occur at times of peak demand.
Time of Use Tariff (ToUT)	This type of EV charge profile is implemented to simulate the impact of time of use tariffs, which a meant to incentivise customers to charge their vehicles at times that are most beneficial to the network. This includes a reduction in demand around the evening peak.

ToUT charging encourages consumers to use electricity during off-peak hours when demand is lower, which can provide cost savings for consumers and helps balance the load on the grid. This can reduce grid strain. A risk of this assumption is that this does not consider consumers who work non-traditional hours who may not be able to avoid peak-time electricity usage. ToUT charging follows the supplier price signals, which are not presently localised.

ToUT load profiles are equivalent to the Managed Charging profiles in WP1 and demonstrate implicit flexibility in the network. This form of flexibility is accounted for in the load profiles used as part of the local case study modelling.

The impact of supplier time of use tariffs beyond just their impact on EV charging behaviours, is complex and should be considered a major area of continued study. A small limitation for these case studies, as the future of supplier driven load shifting is unclear, is the effect of these tariffs on customer behaviour and therefore their load profiles. This will directly reduce diversity as penetration of ToUTs increases throughout the marketplace. As customer demand is increased, even if it is shifted from peak times, it will impact the transformers by altering the cooling and heating cycles they are expected to operate in.

There are also other charging types such as bi-directional chargers, which like domestic battery storage may reduce the substation demand but at this stage their profiles and impact on the local LV network has not been modelled. There is still an emerging technology and there is limited data and significant uncertainty in how households will utilise these technologies.

Each LV case study has an uptake volume for each of the technologies for each year of study.

4.3 Location of New LCT Connections

The physical location of new demand connecting to the network can have an impact on the voltage recorded at other properties across the network. The voltage supplied to LV connected customers is nominally 230 V, with the statutory limits for voltage drop and voltage rise set to -6% and +10% respectively[29]. This gives an allowed range of 216 V to 253 V at customer properties with the DNO responsible for maintaining supplies within this to avoid potential damage to customers equipment.

There are other considerations for where LCTs are placed, for example, where they can be physically placed. In terraced streets and built-up urban environments, there are limitations for car parking availability so charging profiles will be constrained to certain areas of a network or the number of charging profiles on a street will be limited. Similarly, the impact of installing solar panels on their roof is greater on some properties, like detached homes, whereas for other building, like large blocks of flats, the number of solar panels that can be installed may be lower than the number of individual properties.

While information on the tenancy types has been gathered for the areas where the case study networks are situated, as there is not detailed information it has not been used to direct LCT placement. It is something to consider when reviewing LCT uptake rates rather than the specific locations of LCTs on an LV network. Homeowners generally have larger scope and greater ability to install LCTs or otherwise improve the efficiency of their properties, so networks with greater levels of homeownership are likely to see more pronounced change to their network energy profile and demand requirements.

In the baseline models provided by the DNOs, some properties are assumed to have electric heating. The load profiles associated with the properties are the indication of the existing heating types on the network. When new heating technologies have been added to the network, the heat pumps and direct electric heating, they have been placed in line with the methodology shown in Figure 15, with consideration for housing types where possible. The installation of new heating technologies is the decision of the property owner so there will be variation, but the three scenarios aim to demonstrate the effects of locational variation.

To demonstrate the impact physical location has on the impact of the network, LCT distribution on the network has been modelled for three scenarios: Close, Distributed and Far (Figure 15). When building these scenarios, the assumption that a property which has one LCT will also have others is made[30]. The Close and Far scenarios aim to demonstrate possible “worst case” installation positions for LCTs on an LV network, the Distributed

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[29] BS EN 50160 & BS EN 60038

[30] We're on the Road to Net Zero Socioeconomic Inequality in LCT Adoption

scenario is a median option. However, as LCT installation is dependent on customer choice and not within the control of the DNOs, it is important to consider the impact of multiple adjacent customers connecting new LCTs. In later years of the study, 2045 and 2050, the scenarios become less distinct from each other as the number of LCTs tends close to the number of properties available for connection.

Close

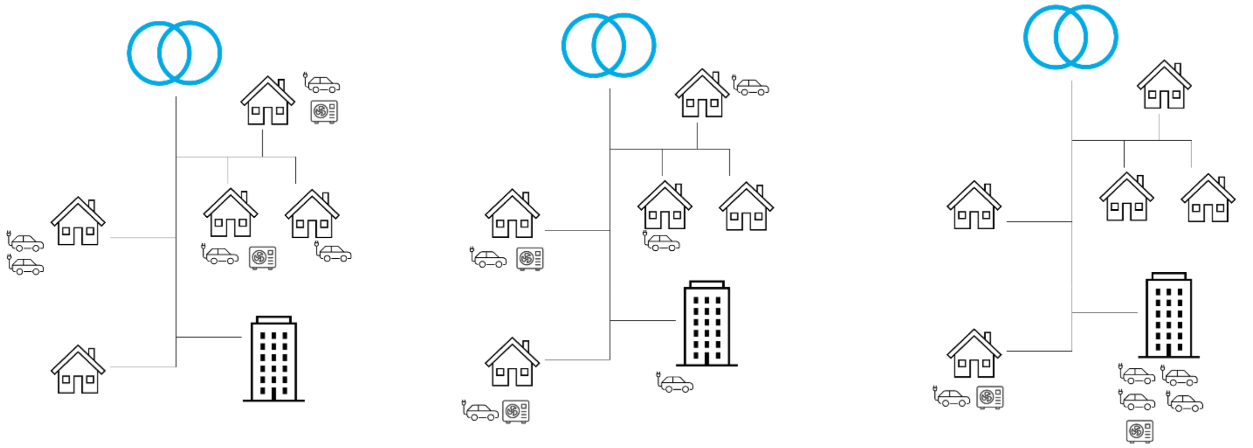
This scenario involves placing LCTs electrically close to the distribution transformer. Properties have one LCT of each type installed sequentially until the number of LCTs connected to the network reaches the required volume. Where networks have multiple feeders, one may be designated as "close" to allow for concentration of LCTs on the network, which is classed as a "worst case" option for LCT installation.

Distributed

As far as practicable, the LCTs are distributed across the network and feeders. This scenario aims to demonstrate a spread of customer uptake that is more sporadic. LCTs can be placed on any feeder, if the transformer has multiple feeders, and can be placed at any distance from the transformer. Where customer numbers and uptake rates allow, the placement of LCTs on adjacent properties is avoided until a saturation point is reached, which is likely to occur in a later year of study.

Far

The focus of the LCT placement in a "far" scenario is to place them as distant to the transformer as possible, based on the length of the cable. If there are multiple feeders on a network, one or two may be designated as the "farthest" feeder, especially where other feeders have more properties closer to the transformer. In general, this scenario will contrast with the close scenario in that feeders chosen in one scenario will not be chosen in the other.



Technologies are deployed closer to the transformer, may be more concentrated on one feeder

Technologies are deployed at points across the network, where there is more than one feeder they will be spread across multiple feeders

Technologies are deployed at the extremities of the network, technologies may be deployed on different feeders and on branches.

Figure 15 Three scenarios, Close, Distributed, and Far, of LCT connection locations on the local network.

4.4 Constraints and Solutions

Each of the seven LV networks chosen for the case study analysis are modelled, with the baseline chosen as 2024. This enables the network model to be tested and assured it functions. The following process in Figure 16 is implemented to understand when network issues would manifest and what those issues are.

The LCTs are added to the network based on the uptake rates per year and where practical the close, distributed and far scenarios are modelled. In some of the smaller networks there is minimal difference between these scenarios and the variation in location of LCTs across each LV network reduces in later years.

When the addition of new LCTs to the LV network creates issues, the types and magnitudes are reviewed to understand the next steps. This allows for the discussion of some novel solutions that may be suitable to implement such as if the issues are minor or solvable through a flexible service. When considering using flexibility as a method of delaying physical works this is considered "explicit flexibility", where a DNO can selectively procure flexibility on a targeted LV network. "Implicit flexibility" is when customers respond to price signals from suppliers, for example through their tariff from their electricity supplier, however this type of flexibility is not currently considered specifically targeted towards individual LV networks. Suppliers do not currently have knowledge of individual network constraints to tailor price signals. As larger percentages of customers on an individual network are incentivised towards using energy at certain times the traditional evening peak may shift to a different time and that peak may be larger.

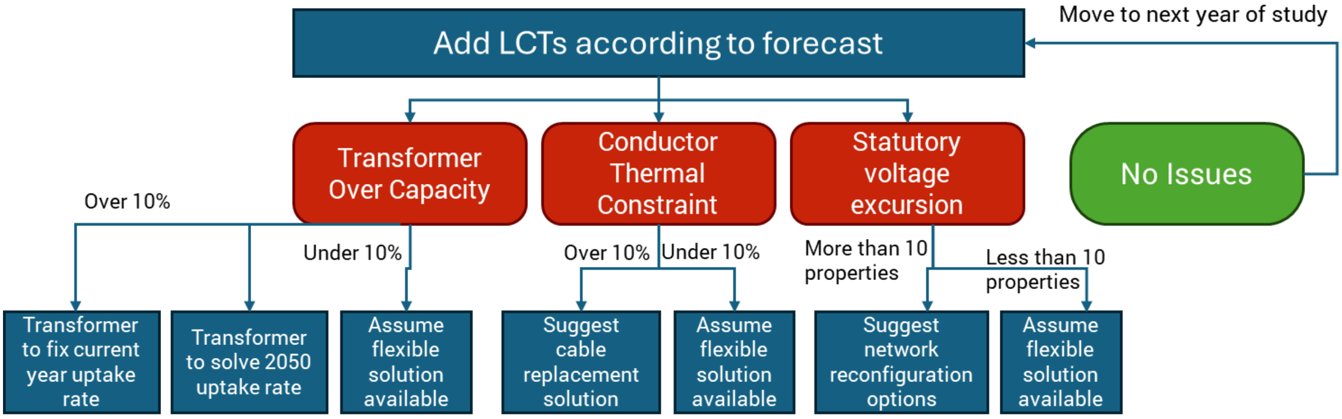


Figure 16 Methodology for demonstrating possible interventions available when adding new LCTs to a network.

When considering how new technologies may be installed on an LV network, there are real world limitations that impact where and when new demand may be connected. Some of these factors are implicit within the uptake rates for each technology in each network type and other factors are considered when the technologies are placed in the model. The factors that are considered in applying LCTs to each LV case study are:

- Location of the network.
- Property types.
- Physical space available.
- Ownership of the properties.
- Existing energy supply type.

All interventions are applied to a network model with 2050 LCTs forecasts installed as the analysis assumed a "touch the network once" approach, especially for large reinforcements like transformer upgrades or network reinforcement. "Touch the network once" refers to a solution or intervention that enables the network to function until an investment horizon is reached, in this report the investment horizon is 2050.

Of the LV network solutions utilised within the National Modelling work package, 12 of those solutions are physical network reinforcement such as transformer and conductor replacement solutions. Another 12 of the solutions are forms of flexible intervention, some alleviate thermal constraints, and some alleviate demand constraints. The LV solutions considered within the National Modelling work package and how they are grouped is detailed in Appendix II.

The use of LV network monitoring is an informative tool that DNOs can utilise to understand and plan their network operations but will not directly affect the balancing of demand and network capacity in times of network constraints.

Flexible interventions in these case studies are temporary solutions that will be implemented every time a peak demand event or thermal constraint occurs. The practical implementation of flexibility is undergoing trials, with positive outlooks for customer acceptance of demand turn down[31], but there is some limited evidence of targeted flexibility being utilised on congested LV networks. This will change as DNOs develop their Distribution System Operator (DSO) function further and understand the functional limits for flexibility, specifically LV demand side response as a method to delay reinforcement or avoid it entirely.

Network reconfiguration or reinforcement interventions in these case studies are permanent, physical changes to the network to enable the LCT uptakes.

4.5 Modelling Assumptions

This work package is primarily focused on the impact of new LCTs loads and associated load profiles on existing networks. For the purposes of the analysis of interventions and solutions, some assumptions have been taken to enable focus on the issue of LCTs.

Asset Ageing

The purpose of these LV case studies is to demonstrate the required load related interventions associated with LCTs, asset ageing is not within the scope of analysis.

In the future, where DNOs must upgrade their network, a “touch the network once” approach is considered as the best option, for cost and resource efficiency, which is demonstrated through some of the case studies provided within this analysis. Where interventions require significant network upgrade or reconfiguration it is assumed that existing assets will be replaced where necessary to enable the network to function.

Number of Connected Customers

The second assumption is that the number of connected customers, and their location on the LV network, remains the same throughout the period of study. This ensures the addition of LCTs is the primary driver for new network load, and therefore the case studies are primarily testing these impacts. In some of the case studies there is minimal space to construct additional properties.

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[31] Octopus Energy EQUINOX Heat Pump Flexibility Trial: https://octopus.energy/blog/EQUINOX-heat-pump-trial-2023-4/

4.6 Load Diversity

The diversity of load and generation across the electricity distribution network in GB plays a critical role in determining how the network operates at different voltage tiers. "Diversity" in this context refers to the variability and range of loads and generation sources connected at each tier, which impacts the overall demand, generation profile, and the operational flexibility of the network. Diversity also affects the way new technologies, such as solar PV, electric vehicles (EVs), and heat pumps, are integrated into the grid. Appendix III provided further details on how Diversity is modelled across different low carbon technologies and voltage levels.

Understanding Diversity through Domestic Load Example

At the Low Voltage (LV) network level, where numerous domestic properties are connected, diversity is a fundamental concept that helps the network handle varying levels of demand and generation without exceeding capacity. For instance, in a neighbourhood of 100 homes, not all households will use their appliances or demand power at the same time. This inherent variability means the network can be designed to supply a peak load that is less than the total maximum potential demand of every home combined—a benefit of diversity.

For example, while each house may have peak demands for heating, cooking, and electrical appliances, these peaks typically occur at different times across households. The network takes advantage of this staggering in demand to ensure that it doesn’t need to be overbuilt. This concept is also applied to small-scale generation like rooftop solar PV, where not every household’s solar panels will generate at full capacity simultaneously, allowing for more connections without overloading the grid.

How Diversity is Relevant for this Work

Individual load profiles, if applied to a model with no assumed diversity, would require a network several times larger than what would be needed to function in real operation. Diversity is simply the consideration of how customer behaviour can be viewed collectively, for example individuals across an LV network would not all turn on their lights at exactly the same time, so the network does not to be designed to accommodate that condition. They also do not have the exact same maximum demand requirements, as energy needs vary from property to property.

These factors are taken into consideration in the methodology that underlies the software and is therefore included in the future network demands and challenges.

4.7 Results Table Explanation

For each of the case studies discussed in this report there is a table that includes various results, which indicate what interventions are required by each case study. Table 20 provides an explanation for each entry.

Table 20 Example of results analysis for the seven case studies and a description of each parameter

Modelled Variable	Example Value	Description
Max. Transformer load (kVA)	592.01 kVA	Maximum load experienced on the transformer during the analysis and is therefore the capacity that the transformer will need to supply.
Max. Feeder Current Feeder 2 Feeder 3 Feeder 5 Feeder 10	 189.18 A 436.89 A 104.43 A 477.28 A	Maximum current seen on each outgoing feeder from the transformer. Those highlighted in red exceeded their current ratings.
Mains Warnings	2	Number of mains circuit warnings that have been highlighted. This is when a mains circuit exceeds its thermal capacity or voltage exceeds statutory limits.
Service Warnings	None	Number of properties where the service cable supplying them exceeds either thermal capacity or voltage issues. It is more common for voltages to exceed statutory limits but may be due to LCT installations at other properties along the feeder

5. Case Study Results

5.1 Mosborough Crescent – Birmingham, Urban

This LV network shown in Figure 17 is comprised of two large blocks of flats, some local shops and multiple blocks of duplex apartments. There is minimal purpose-built parking for residents and from a visual inspection it seems like the majority of vehicles will need to park on-street.

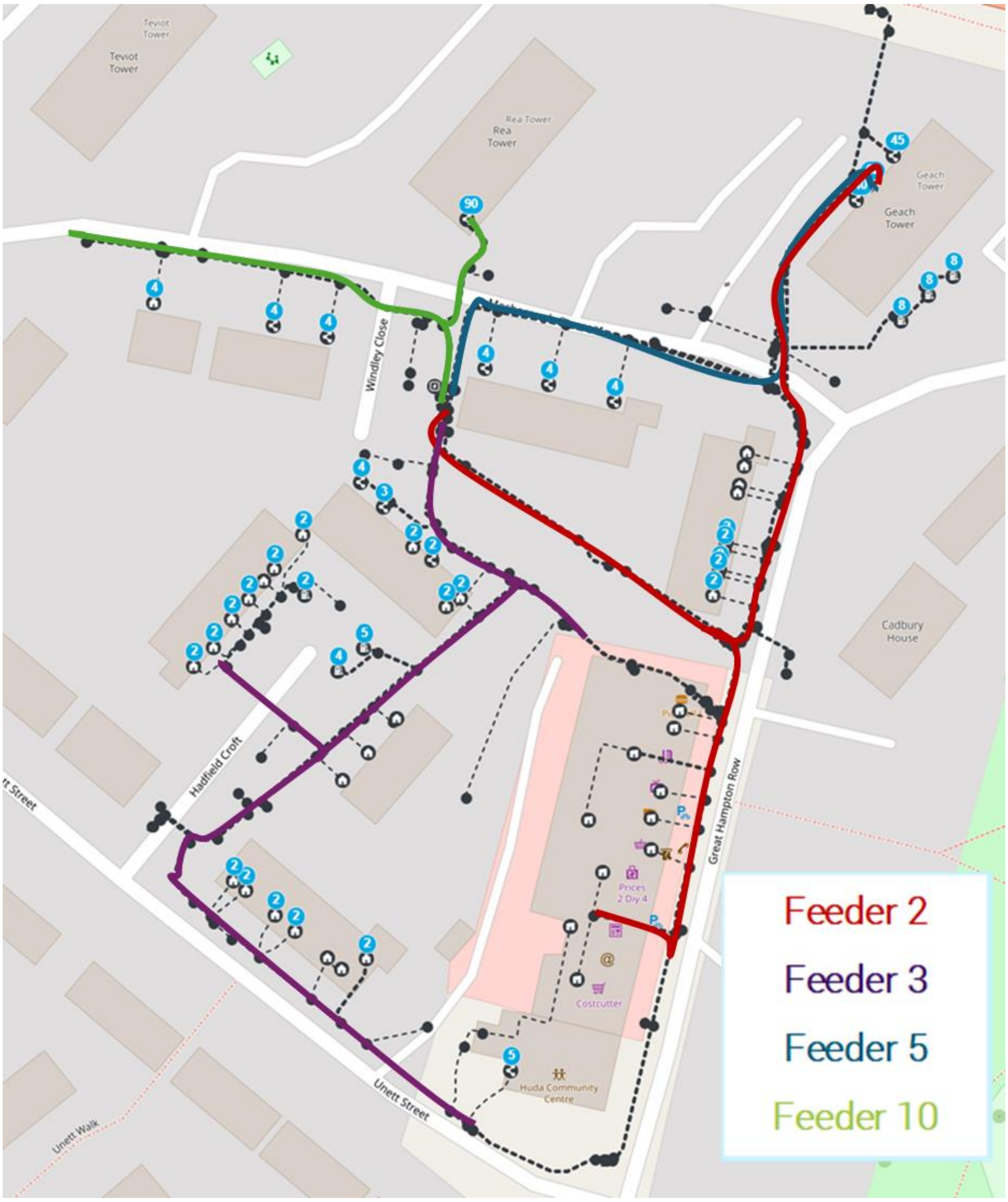

Figure 17 Mosborough Crescent network layout[32].

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[32] A description of the user interface components can be found in the publicly available user guide, VisNet Design – Software User Guide

Challenges specific to this LV network

As is typical of intensely urban areas, this LV network does not have large amounts of physical space for additional new technologies. This reduces the impact of LCTs on the network as the constraint is less likely to be electrical and more likely to be physical.

Compared to the sub-urban and rural case studies discussed in the report, per property there is a lower percentage of LCTs forecast to be installed on the Mosborough Crescent network (Table 21). However, a key challenge to this network will be the impact of heat pumps, since over half of the properties are heated through gas central heating. 110 properties have electric storage heating profiles in the baseline model, which remains consistent throughout the years of study, with one remaining home assumed to switch to an electric heating type to enable a net zero compliant solution in 2050. Heat pumps will transfer existing energy required for heating demand from the gas network to the electricity network. The heat network will supply some of the heating demand but is assumed to come from a dedicated supply, potentially HV, and is considered out of scope for this section of the study.

Table 21 Mosborough Crescent LCT uptake 2024 – 2050.

Year	PV	Domestic ASHP	Domestic GSHP	Electric Resistive Heating	Heat Network	On-street Charging (Slow)	On-street Charging (Fast)	Non-managed Off-street Charging	ToUT Off-street Charging
2025	4	8	8	110	0	1	1	6	3
2030	8	25	5	110	0	5	1	20	10
2035	13	47	12	110	0	9	3	44	20
2040	17	71	18	111	70	10	4	51	24
2045	21	82	23	111	70	10	4	52	24
2050	25	86	26	111	70	10	4	52	24

The Mosborough Crescent case study is well placed to demonstrate the impact of the location of LCTs on an electrical network, as the transformer has capacity available to support the new LCTs even in the 2050 scenario. In the winter peak, the transformer utilisation reaches a maximum of 75% in 2050, up from 35% in the baseline year of winter 2024. With the low numbers of forecasted PV installation, 25 out 293 customers, there is no likelihood of generation creating any net export capacity issues.

However, the network has issues related to other assets, primarily the utilisation of the mains cables. Table 22 summarise the issues for the network with 2035 LCT uptake rates and Table 23 for the network with 2050 uptake rates, before interventions have been applied.

Table 22 Mosborough Crescent – Installation of LCTs up to 2035 before interventions have been applied.

	LCT Close	LCT Distributed	LCT Far
Max. Transformer Load (1000 kVA)	592.01	590.97	584.45
Max. Feeder Current (400 A rating)			
Feeder 2	189.18 A	275.25 A	231.45 A
Feeder 3	436.89 A	322.68 A	289.86 A
Feeder 5	104.43 A	197.65 A	263.94 A
Feeder 10	477.28 A	389.81 A	347.63 A
Mains Warnings	2	None	None
Service Warnings	None	None	None

The uneven loading of the existing feeders is visible in these scenarios. Feeder 5 only connects a few customers, while Feeder 10 is connected to an entire block of flats and some other duplexes.

Table 23 Mosborough Crescent – Installation of LCTs up to 2050 before interventions have been applied.

	LCT Close	LCT Distributed	LCT Far
Max. Transformer Load (1000 kVA)	751.77	735.11	737.99
Max. Feeder Current (400 A rating)			
Feeder 2	309.24 A	288.31 A	407.78 A
Feeder 3	473.7 A	431.68 A	359.05 A
Feeder 5	131.48 A	249.92 A	268.52 A
Feeder 10	550.04 A	400.65 A	367.18 A
Mains Warnings	2	2	1
Service Warnings	3 on duplex apartments	None	None

In each scenario, there are feeders that are loaded well within their rated capacity (for example, Feeder 5) which indicates it would be theoretically possible to distribute the forecasted LCT uptake rates to the network without breaching the ratings of any cable. However, on this network new technologies were concentrated due to the property types and customers drive the connection locations. The worst-case loadings on the feeders were always due to large placements of ASHPs in the blocks of flats.

District or communal heat networks are assumed to be installed in the blocks of flats. In this network the location of the heat network feeding 70 customers is varied in each scenario, which simulates uncertainty from the perspective of network planning. As the heat networks are not assumed to be connected to the existing LV network in these models, it avoids adding new demand directly to any individual feeder and can almost enable a net zero compliant network in the Far scenario. Blocks of flats, and other high density housing types, are well suited for communal heating being utilised instead of individual home direct heating or heat pumps.

Separately, in 2050, the Far scenario is almost within the thermal limits of Feeder 2. If it is demonstrated that flexibility can be targeted down to an individual feeder level, then it may be a suitable intervention option for this network and could avoid any reinforcement.

The service warnings in the Close scenario were due to multiple LCTs being connected to a property, investigating what would be the limit for a service cable in this network. In general, the service cables were rarely highly utilised.

Possible Interventions to Enable 2050 LCT Uptake

The interventions discussed for the urban Mosborough Crescent network aim to solve two problems. The first is solving the high utilisation problem on Feeders 3 and 10 in the Close and Distributed scenarios. The second aims to reduce the load on Feeder 2 as seen in the far scenario.

Intervention 1: The existing circuit model has additional unused feeders. As the affected feeders (3 and 10) are close to the transformer and the unused Feeder 4 is terminated close to both, as shown in Figure 18, there is an opportunity to investigate the effect of redistributed loads from the overloaded feeders.

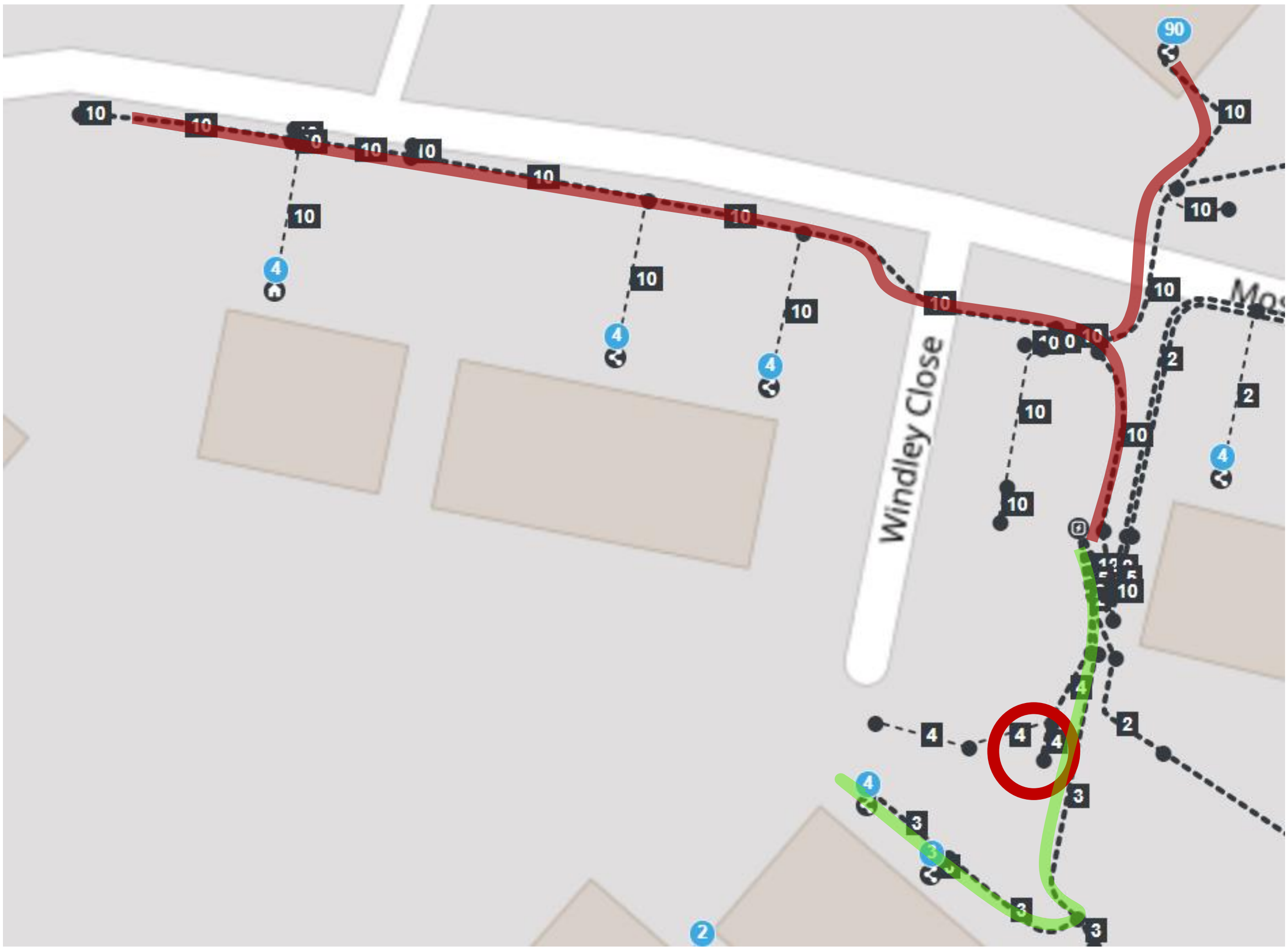

Figure 18 Mosborough Crescent, Feeder 4 termination, circled, and Feeder 3 and 10, highlighted green and red respectively

The properties physically closest to Feeder 4 on Feeder 3 and 10 were connected to Feeder 4, as shown in Figure 18, and the model was re-run.

Table 24 shows the intervention was demonstrated on the LCT Distributed scenario for 2050 however similar network reconfiguration could be achieved on the Close scenario. The same reconnection to Feeder 4 would occur and it would also require the reconnection of some public EV charge points to the lower loaded Feeder 5.

Table 24 Mosborough Crescent intervention option 1 impact: 2050 load redistribution to unused feeder.

	LCT Distributed
Max. Transformer Load (1000 kVA rating)	735.11 kVA
Max. Feeder Current (400 A rating) Feeder 2 Feeder 3 Feeder 4 Feeder 5 Feeder 10	 288.31 A 354.88 A 149.14 A 249.92 A 350.94 A
Mains Warnings	None
Service Warnings	None

Network reconfiguration on this scale would require an outage at the substation, along with significant ground works to lay the new cables. While the transformer capacity is suitable for the 2050 network demand, the placement of new customer LCT loads on the network will change the time frame in which the network reinforcement may be required. It is not possible to state when interventions will be required without monitoring of the network, as understanding evolving demand needs, year-on-year, will be the most accurate way to plan for network reinforcement or flexible operation.

As most of the EV load on this type of network is assumed to be through public charge points, it is likely that a DNO would be aware of the increasing load on their network and could support its connection in suitable locations as they come online. This would reduce the likelihood of the Close scenario becoming an issue if good and streamlined engagement processes exist.

Intervention 2: In the 2050 scenario where LCTs are connected at the network's extremities, only one of the feeders experiences a feeder exceeding its rated capacity. As Feeder 2 and 5 are connected to the same link box and Feeder 5's mains cable was not at its rated capacity, there is an opportunity to reconfigure the network without requiring large ground works. The results are shown in Table 25.

Table 25 Mosborough Crescent intervention option 2 impact: 2050 network reconfiguration.

	LCT Far
Max. Transformer Load (1000 kVA rating)	737.99 kVA
Max. Feeder Current (400 A rating) Feeder 2 Feeder 3 Feeder 5 Feeder 10	 302.72 A 359.05 A 365.93 A 367.18 A
Mains Warnings	None
Service Warnings	None

The second intervention is only possible due to the existing link boxes installed on the network. A comparison between the two interventions is provided in Table 26, which provides a comparative assessment between the two options, only for this LV case study.

Table 26 Mosborough Crescent comparison of intervention options

Solution	Cost (£)	Level of Disruption	Time frame	One time cost?
New feeder connection based on the new customer demand on other feeders.	£££	Significant ground works to enable cable laying and jointing works.	Months - years	Yes
Highly specific use of existing network properties, link box reconfiguration	£	Small outage to enable link box reconfiguration.	Weeks - months	Yes
Highly specific targeting of LV explicit flexibility, at a feeder granularity	£	No physical disruption but will require technology and investment to enable	Instant	No, and this LV flexibility by feeder has not been explored.

A DNO would have to review the layout and connections on their LV network to understand which intervention would be suitable. The intervention chosen depends on both the location of network assets, such as link boxes, and the specific location of new customer demand, for example whether one block of flats has a large volume of ASHPs or if the ASHPs were installed in different blocks of flats. The physical network reconfiguration options, where a new feeder is connected would be considered a “touch the network once” approach.

NGED’s Investment Map[33] provides guidance on the duration and impact of the works suggested for each of the case studies.

- Similar works to the scope for Option 1 suggest 3-month delivery, with construction works impacting customers on the network for that duration. The exact method of connecting customers to a new feeder would impact the works length and level of disruption.
- The broad delivery scope for Option 2 in Table 26 suggests work would be completed in 3 weeks, with less time required if no cables need to be replaced and no other physical installations are required to complete the work. As previously stated, this would require an outage to reconfigure the network but otherwise no additional disruption to customers.

If the network is monitored and the forecast demands across the network are accounted for the network will not require emergency works and could be completed within a business-as-usual work programme.

This case study, Mosborough Crescent, demonstrates that there is highly localised variation that will determine the right solution for each network. Even within this case study, the location of the LCTs determine which intervention is preferable.

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[33] NGED Investment Map https://www.nationalgrid.co.uk/our-network/investment-map-application

5.2 Dunston Industrial East – Gateshead, Urban

This urban LV network shown in Figure 19 with all feeders comprised solely of underground cables, containing both terraced properties and an industrial estate, demonstrates the changing load location of customers and how the network will have to adapt. This case study modelling focuses on the domestic customers, to enable comparison with other LV networks, but some consideration of the evolving energy needs of businesses in an industrial estate is included in the discussion.

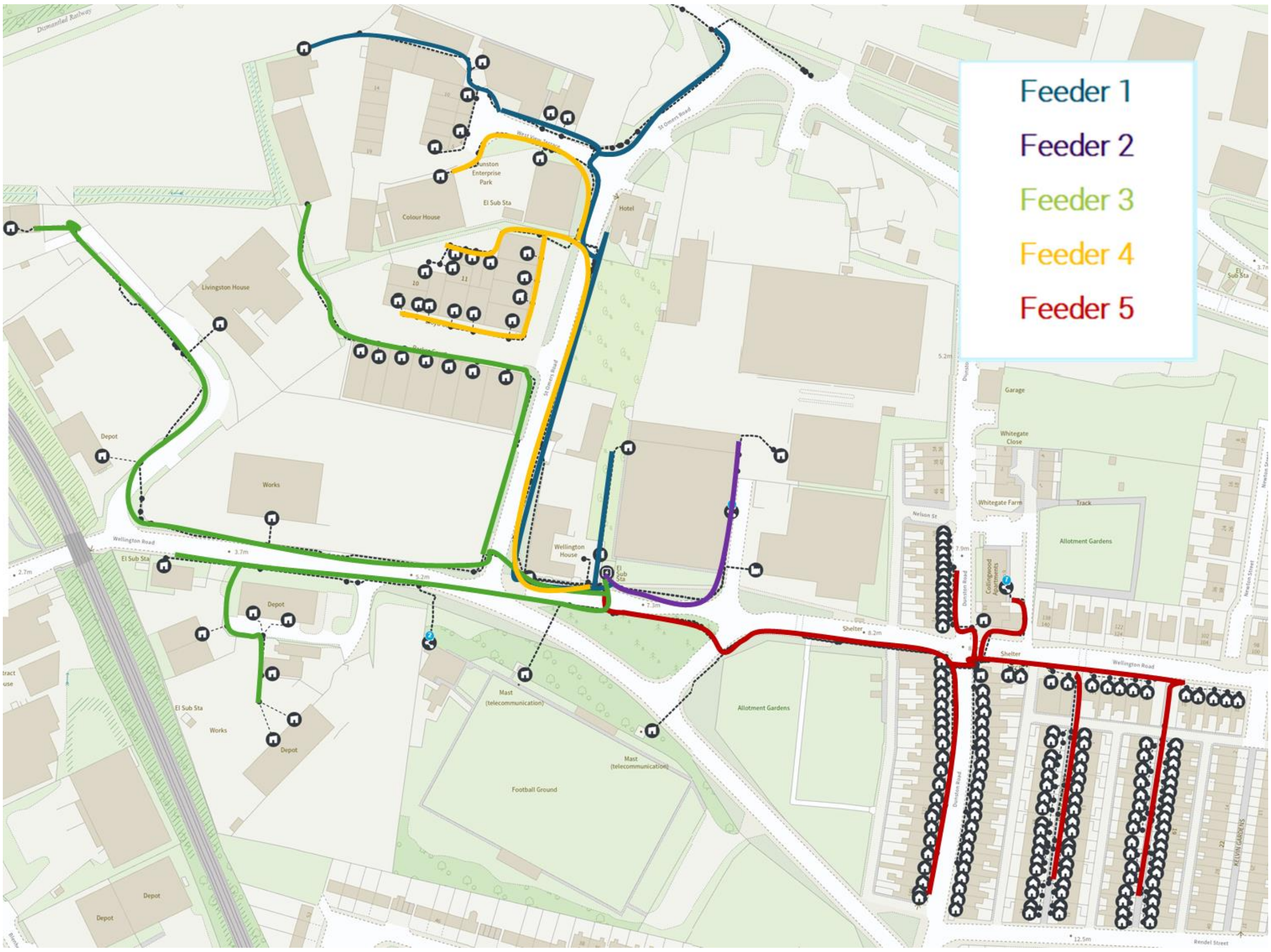

Figure 19 Dunston Industrial network layout

Challenges specific to this LV network
This network has a large volume of domestic customers fed by a single feeder. Removing gas as a source of heating on networks like this will have an adverse effect on the operation of the network.

The low number of EV charging points align with other terraced and densely packed LV networks (Table 27). Similarly, as only Feeder 5 supplies domestic customers, the heat pump installation penetration by 2050 is slightly under 60%, which is within the forecast range for heat pump uptake.

As previously stated, 52 of the properties on the network are commercial properties, so variation surrounding the location of all types of LCTs across feeders was lessened in this case study. 148 of the properties are connected to feeder 5. 17 of the properties have existing load profiles which assume electric heating. The volume of heating types on the network corresponds with the domestic property numbers.

Table 27 Dunston Industrial East LCT forecast uptake rate 2024 – 2050.

Year	PV	Domestic ASHP	Domestic GSHP	Electric Resistive Heating	Heat Network	On-street Charging (Slow)	On-street Charging (Fast)	Non-managed Off-street Charging	ToUT Off-street Charging
2025	3	6	2	17	0	1	1	4	2
2030	6	19	4	17	0	4	1	15	7
2035	10	36	9	17	0	7	2	34	15
2040	13	54	14	17	46	7	3	39	18
2045	16	63	17	17	46	7	3	40	18
2050	19	65	20	17	46	7	3	40	18

As summarised in Table 28, the issue in all scenarios is the heavy loading on the feeder with domestic customers. The Far scenario exaggerates the issues by placing all new LCTs on domestic properties, while the Close and Distributed scenarios have some of the new LCTs placed on different feeders, mainly the EV and PV LCTs. The heating loads are assumed to be installed primarily in the domestic properties across all scenarios, which is why feeder 5 remains the most heavily loaded across all scenarios.

Domestic properties which are not heated via heat pumps or existing electric means could be heated through a heat network, which could be a viable alternative in built up areas. If a heat network is not considered in this network by 2050, the transformer is likely to have sufficient capacity for electric heating, but the problem with unbalanced feeder loading remains.

Table 28 Dunston Industrial East – LCT uptake rate until 2050.

	LCT Close	LCT Distributed	LCT Far
Max. Transformer Load (1000 kVA rating)	698.4 kVA	695.51 kVA	687.57 kVA
Max. Feeder Current (400 A rating)			
Feeder 1	128.57 A	139.44 A	115.34 A
Feeder 2	189.26 A	165.14 A	149.54 A
Feeder 3	267.3 A	272.24 A	211.16 A
Feeder 4	234.7 A	247.6A	206.61 A
Feeder 5	581.74 A	557.45 A	706.3 A
Mains Warnings	1	1	1
Service Warnings	80 customers with voltage below statutory limit	70 customers with voltage below statutory limit	130 customers with voltage below statutory limit

No assumptions were made surrounding changes in the industrial customer demands, the baseline industrial profiles are based on the unrestricted Elexon profiles 5-8[34], which were assigned by the DNOs in the development of the model built for VisNet Design. EVs and PV generation were connected at these customer sites in the Close and Distributed scenarios, but the underlying load profiles were unchanged. Commercial

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[34] Information on Elexon profiles: https://www.elexon.co.uk/settlement/profiling/#:~:text=We%20create%20Profiles%20(daily,%20seasonal,%20yearly,%20per%20day%20type,

customer load forecasting is an area of active investigation for DNOs as it is presently challenging to estimate industrial loads at a local level. The feeders to which the commercial customers are connected and the transformer itself have capacity to accommodate some further demand in this case study, as per Table 28.

The driver of new demand on feeder 5 is not just heating load, so while the impact of other types of heating are important to consider, the primary issue with this network is the imbalance of connected customers which is evident from the baseline model.

Possible interventions to enable 2050 LCT uptake

Feeder 5, which has most of the customers, is generally distant from the other feeders. However, Feeder 2 and Feeder 3 are in suitable locations to provide some opportunity to re-distribute customer supplies more evenly across the network's feeders (Table 29). All of the network reconfiguration for this case study would be done through new installation of cables in the ground. This would be a significant undertaking, with street works required to install new cable joints and new cables which would require some diversion of traffic on the road. This work would require an outage at the substation; however the duration would be dependent on the exact nature of the network reconfiguration. There are no link boxes in this network to enable less invasive network reconfiguration.

Table 29 Dunston Industrial East intervention option: Network reconfiguration of customers onto an additional feeder in 2050.

Feeder Name	Number of Customers
Feeder 1	29
Feeder 2	27
Feeder 3	91
Feeder 4	17
Feeder 5	36
Total Connected Customers	200

While this intervention does not require a transformer upgrade, the redistribution of customers across feeders would require a significant network redesign. Service cables to properties may be able to remain in-situ, however the solution required new feeder installation and link-boxes. In this solution the new feeder cables are generally assumed to remain in similar locations to the original cables, however, for a 1 MVA transformer there may be other unused feeders that could also be connected.

If a new feeder connection can be added, the customer loads could be distributed more evenly without the need to joint into existing cables (Table 30). With this intervention, the loading on Feeder 3 in 2050 would be reduced as another feeder could carry some of the customer demand.

Table 30 Dunston Industrial East intervention option: Network reconfiguration effect on the network in 2050.

	LCT Intervention
Max. Transformer Load (1000 kVA rating)	689.91 kVA
Max. Feeder Current (400 A rating)	
Feeder 1	357.6 A
Feeder 2	282.85 A
Feeder 3	325.02 A
Feeder 4	247.6 A
Feeder 5	184.89 A
Mains Warnings	None
Service Warnings	None

Table 31 summarises the intervention option described for this case study requiring significant physical network upgrades potentially taking several months. As the loading of new demand is so heavily situated on one feeder, flexibility is not considered as an intervention in a 2050 scenario.

Table 31 Dunston Industrial East summary of intervention option

Solution	Cost (£)	Level of Disruption	Time frame	One time cost?
Customers connected to new, existing feeder	££	Street works disruption and short outages to energise new connection.	Months	Yes

The primary constraint with this intervention would be the ability to take outages to reconfigure the network with many industrial and commercial customers on the network. The total level of disruption to the local population will depend on the exact location of the cables and street works that will be required, but in the best-case scenario this would be limited to cable crossings. Additionally, the long term decarbonisation pathways for industrial and commercial customers is still uncertain and an active area of research to better inform forecasts.

5.3 Brockhill Drive – Redditch, Sub-urban

This network shown in Figure 20 is an example of a network that feeds sub-urban housing estates with mostly detached properties and some semi-detached properties. Almost all the properties on the network have a driveway and the roof top space to install PV. The network has four feeders with connected customers and one feeder (designated Feeder 1) has no connections and is pot-ended, which means the cable has no connected customers and stops shortly outside the substation.

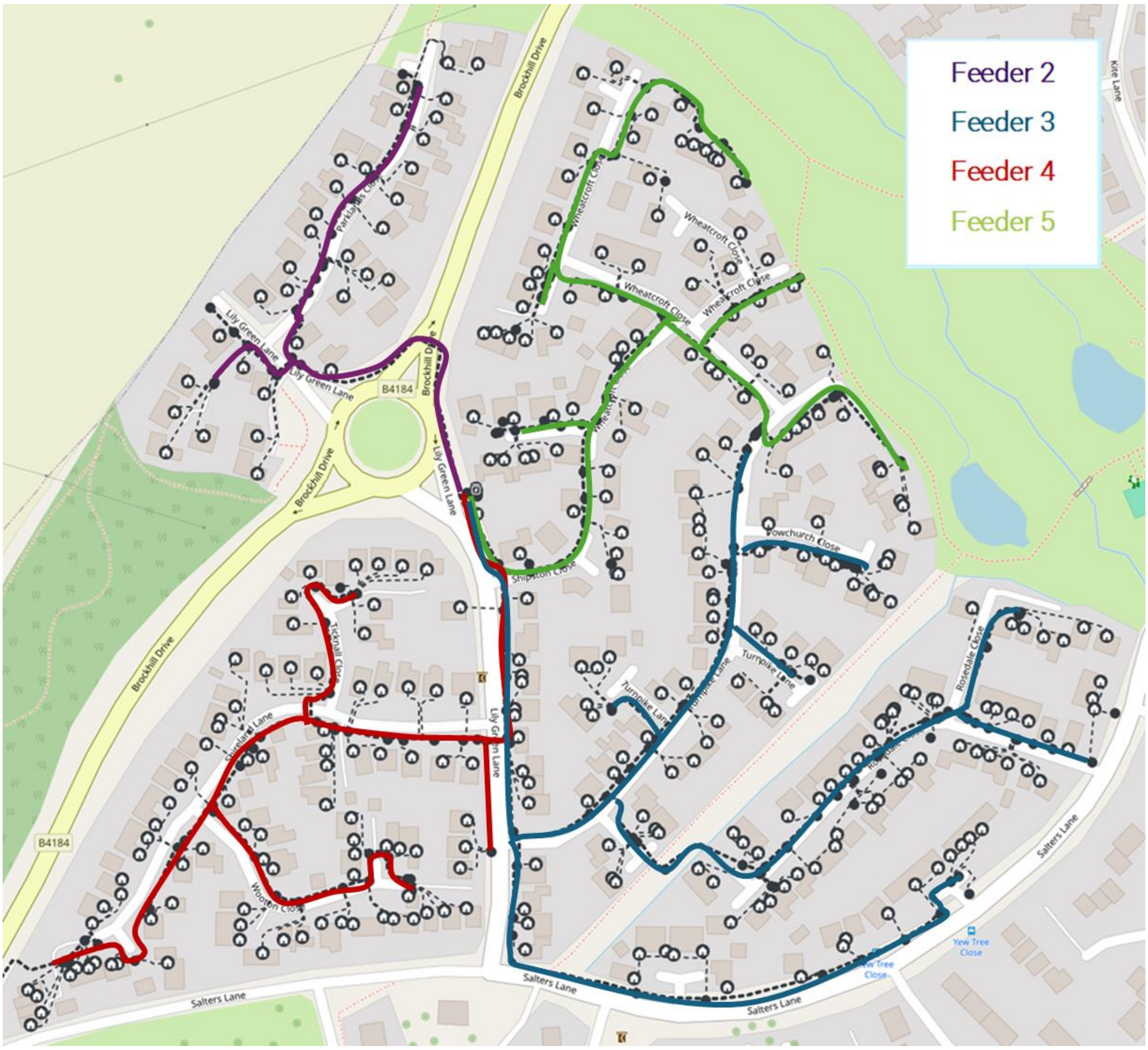

Figure 20 Brockhill Drive network layout

Challenges specific to this LV network

As shown in Table 32, the main challenge associated with this LV network is the large volume of new LCTs forecast to be connected. By 2050, every property on this network is assumed to have at least one electric vehicle. From a visual inspection, most properties have a driveway and a considerable number of cars could be parked on-street, supporting this assumption.

The installation rate of solar panels could be conservative for this type of network, as all properties have their own suitable roof space. Solar generation is unlikely to support the network in the winter peaking hours of demand and on networks with larger volumes of connected customers the network benefits of generation is lowered during the winter. However, customers will see benefits of solar generation during the summer and from a network perspective the minimum demand seen on the network during the summer will drop as more customers install solar panels and batteries. As uptake of solar increases in localised areas, this does introduce the potential for high voltage issues, and back-feeding, where the feeder, or feeders connected to a substation move into a state where the generation exceeds demand, resulting in reverse power flow.

If the LCTs are placed inefficiently on the network, there is a risk of network overload occurring (Table 33). However, even in the distributed LCT scenario, the choice for placement of LCTs on the network to enable continual function is limited. This is due to Feeder 3 being heavily loaded in the baseline, with a significantly larger number of connected customers. It will be a common issue on larger networks with multiple feeders to have more capacity on one feeder than another. This case study highlights the challenges of achieving balanced loading across several feeders on a larger network.

There are 20 properties with electric storage heating in the baseline model, this is accounted for in the table. The 2050 model has all 338 properties heated by electric methods.

Table 32 Brockhill Drive – LCT forecast uptake 2024 - 2050

Year	PV	Domestic ASHP	Domestic GSHP	Electric Resistive Heating	On-street Charging (Slow)	On-street Charging (Fast)	Non-managed Off-street Charging	ToUT Off-street Charging
2025	18	15	3	35	2	1	16	21
2030	35	52	14	43	6	1	63	84
2035	53	98	33	57	13	1	139	183
2040	71	148	51	72	14	1	160	212
2045	89	171	66	81	14	1	162	213
2050	108	179	74	85	14	1	162	213

Table 33 Brockhill Drive – Installation of LCTs up to 2030.

	LCT Close	LCT Distributed	LCT Far
Max. Transformer Load (800 kVA rating)	738.54 kVA	737.35 kVA	751.94 kVA
Max. Feeder Current (400 A rating)			
Feeder 2	77.19 A	237.8 A	77.19 A
Feeder 3	423.65 A	394.84 A	413.95 A
Feeder 4	386.03 A	354.23 A	633.07 A
Feeder 5	391.62 A	365.18 A	209.84 A
Mains Warnings	1	None	2
Service Warnings	None	None	None

In 2035 the number of new LCTs on the network begins to reach a saturation point, so the number of scenarios is reduced as there was minimal effect of the location of LCTs on the network (Table 34). After one simulation new loads on the network increase the demand in 2035 beyond the 800 kVA transformer rating.

Table 34 Brockhill Drive – Installation of LCTs up to 2035

	LCT Uptake
Max. Transformer Load (800 kVA rating)	1150.81 kVA
Max. Feeder Current (400 A rating)	
Feeder 2	326.05 A
Feeder 3	649.58 A
Feeder 4	522.47 A
Feeder 5	660.94 A
Mains Warnings	3
Service Warnings	Significant volumes of voltage drop warnings across the network

This creates a challenging situation from a network design perspective. In the five-year span between 2030 and 2035 the maximum demand increased by 400 kW, three feeders breach their rated capacity, and the transformer capacity is exceeded. Unlike in other case studies, where network reconfiguration and a transformer upgrade may provide a solution to the issues, the loading in 2035 exceeds 1 MVA even without the new LCT connections forecast for 2050. This reduces the intervention options.

Possible interventions to enable 2050 LCT uptake

Once the LV network exceeds 1 MVA, significant network reconfiguration is needed. The installation of a larger transformer may be possible but creates additional challenges for the DNO to meet their design standards for restoration as set out in Engineering Recommendation P2/8[35]. This Engineering Recommendation covers 'Security of Supply', which stipulates the minimum demand to be restored within defined time periods following the loss of supplies in different outage scenarios including network faults.

The load required to enable a net zero network in 2050 for Brockhill Drive is 1,472 kW. This is larger than the original transformer capacity, 800 kVA, and would place the Brockhill Drive LV network into a "B" Class of Supply within the P2/8 recommendation. For a network classed as Group B, with a demand between 1 MW and 12 MW, the minimum demand that must be restored within three hours of a First Circuit Outage (FCO) is "Group Demand minus 1 MW". This means that for a fault on the transformer the DNO would not be able to restore customers quick enough to remain compliant. For an illustrative example, if a single transformer of 1.5 MW was installed and it had a fault that took it completely out of service for longer than three hours it would not be compliant due to the inability to restore supplies via network reconfiguration.

Therefore, instead of increasing the size of the transformer a new transformer would need to be introduced, and the existing LV feeders split so that some of the customers were supplied from the new transformer. Figure 17 shows a potential solution with the existing transformer remaining in location, the top red circle, while a new transformer is located close to the feeders that had greater loads. The new transformer location is not representative of where a HV connection may be made in realistic terms but is provided as an example of how a new transformer would alleviate the load concerns from the original network.

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[35] P2/8: https://dcode.org.uk/assets/uploads/files/ENA_EREC_P2_Issue%208_(2023).pdf

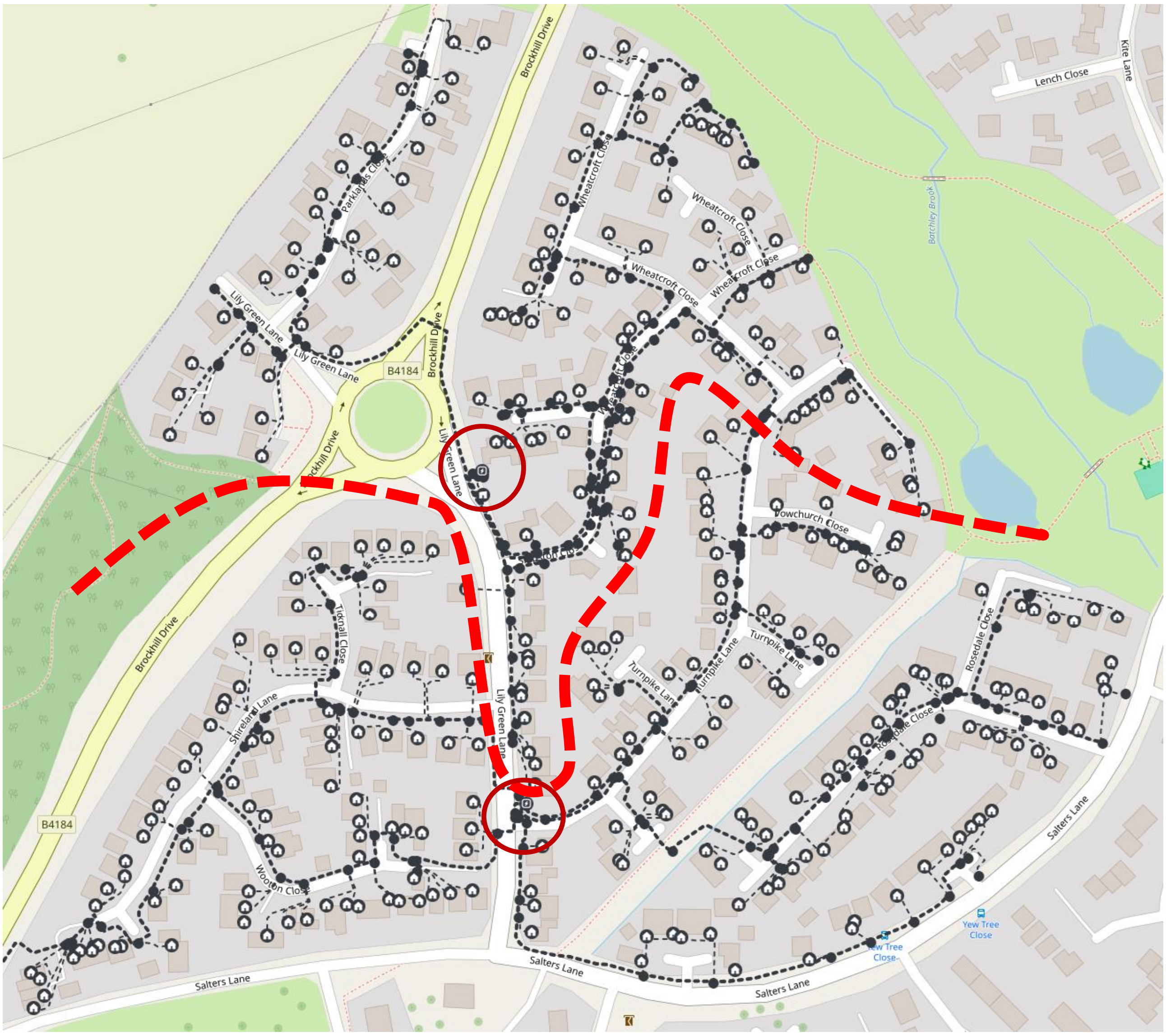

Figure 21 Brockhill Drive, 2050. Red circles highlight both transformers, dashed line indicates the boundaries of each substation's supply

The feeders connecting customers have remained broadly in place, with the primary differences being the loads split across multiple feeders instead of one.

Table 35 shows the results of the introduction of this new transformer. The network was split into an upper and lower section, and a 1 MVA transformer was connected to the original Feeder 3 and Feeder 4. Significant changes of feeder connection were required to ensure the new feeders would be capable of supplying the customers.

Table 35 Brockhill Drive – Intervention impact: Transformer upgrade to enable 2050 uptake

	Existing 800 kVA transformer	New 1 MVA transformer
Max. Transformer Load (kVA)	642.01 kVA	830.14 kVA
Max. Feeder Current (400 A rating)		
Feeder 1	351.34 A	389.25 A
Feeder 2	299.92 A	300.87 A
Feeder 3	250.65 A	299.72 A
Feeder 4	168.56 A	354.98 A
Feeder 5	209.66 A	372.69 A
Mains Warnings	None	None
Service Warnings	None	None

The new transformer feeds 215 of the original 338 customers. The customers connected to the original feeders were reconnected to the five new feeders from each transformer: Feeder 2 and 5 from the baseline network remained connected to the existing transformer while customers on Feeders 3 and 4 were connected to the new transformer, Figure 21.

This scale of network reconfiguration, a new transformer and re-connecting customers, would cause significant disruption. However, on this network, it is unavoidable if the connected customers are to install LCTs at the suggested volumes. The key consideration for a DNO in this situation is at what point is reinforcement ahead of need triggered and can flexibility delay this decision to reduce uncertainty. In this scenario, LV network monitoring would need to be in place to capture the rise in demand and understand the time at which critical reinforcement is required.

The more information a network operator has with regards to LV networks with greater likelihood of LCT installation, the more cost effective and safe decisions that can be made.

This type of sub-urban network with high home ownership demonstrates a likely scenario for similar LV networks across the country, where space is available, and customers have incentives to install heat pumps the network will see very large increases in demand.

The placement of the new transformer may not be optimised for network operation, the loadings vary considerably between the lowest loaded feeder and the heaviest loaded feeder, as it is only provided to demonstrate the need for a significant network re-design. A detailed review of the energy demands of an area would likely be undertaken before a transformer installation and network reconfiguration of this scale could take place. A summation of the impact of this type of solution is presented in Table 36.

Table 36 Brockhill Drive summary of intervention option

Solution	Cost (£)	Level of Disruption	Time frame	One time cost?
New transformer installed to satisfy P2/8 security of supply conditions	££££	Disconnection and reconnection of new feeders. New transformer installation in built up area.	Months - years	Yes

This level of network reinforcement is only considered for this case study because of the significant increase in demand. In other networks, flexibility could be considered viable. In this network, flexibility would be required to remove 700 kW at times of peak demand, 47% of the peak demand, which is a volume of required targeted LV demand reduction that has never been proven. The costs associated with guaranteeing the level of demand able to be removed during every high load event is not something that can be estimated due to lack of experimental data.

Similar works to the suggested intervention suggest a 36-week duration of the works (excluding land acquisition, planning permission)[36], during which customers would experience disruption on roads and pathways as new cables are laid and, in some cases, old cables replaced. As previously discussed, these works could be planned ahead of time if monitoring data or connection requests show evidence of increasing demand on the LV network. As demand for new transformers increases, both within GB and globally, ensuring a robust supply chain will become a priority to ensure that the reinforcement requirements can be met.

When considering flexibility as an option it must be remembered that demand must be removed during every high peak event, which is a repeated cost incurred, assuming that in the future flexibility must be procured. Furthermore, at some point, greater numbers of customers, and increased frequency of flexibility requirements will result in traditional reinforcement being a more cost-effective option in the long-term. This is however dependent on the local network architecture, number of customers, extent of turn-down required, and how essential (and hence costly) the turn-down request is.

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[36] NGED Investment Map https://www.nationalgrid.co.uk/our-network/investment-map-application

5.4 May Street – Durham, Sub-urban

Terraced streets represent approximately 23% of the UK domestic properties[37]. They appear in other LV case studies in various capacities, but this network is chosen to highlight some of the specific challenges associated with terraced streets (Figure 22).

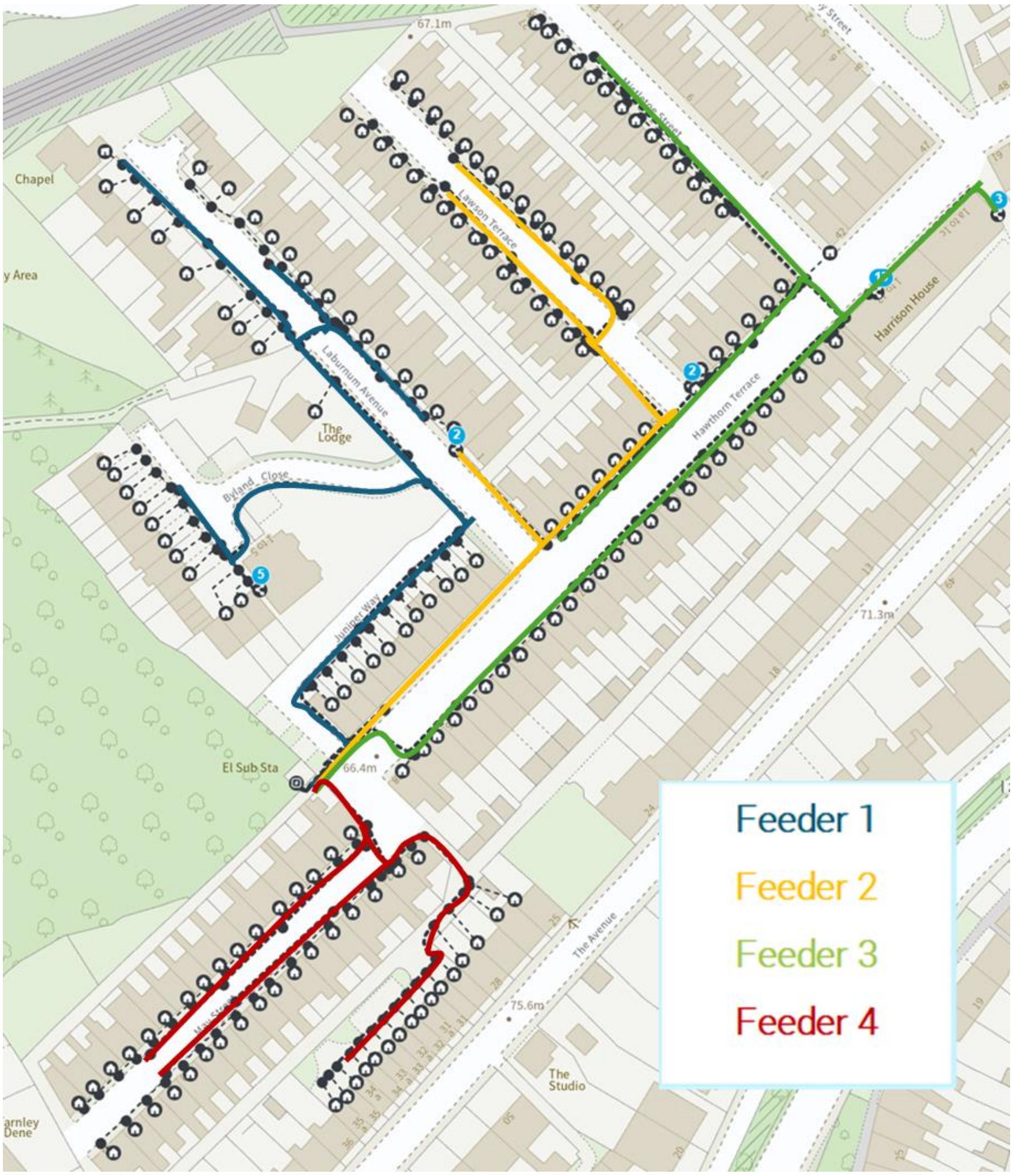

Figure 22 May Street network layout

Challenges specific to this LV network

The forecast LCT uptake rate for this network type, terraced houses, may look low compared to some other network types, like sub-urban housing estates (Table 37). However, the terraced streets have minimal available parking (generally less than one on-street parking space per property) so it is likely that under 50% of connected properties will have an EV charger of some form. This network also includes some small shops and some flats which are included in the customer numbers.

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[37] Office for National Statistics, Census 2021: Accommodation type, tenure, rooms and bedrooms, central heating and car or van availability in England and Wales, 05 January 2023

There are 20 properties with electric storage heating in the baseline model, this is accounted for in the table. The 2050 model has all 186 properties heated by electric methods.

Table 37 May Street – Forecast LCT uptake rates 2024-2050.

Year	PV	Domestic ASHP	Domestic GSHP	Electric Resistive Heating	On-street Charging (Slow)	On-street Charging (Fast)	Non-managed Off-street Charging	ToUT Off-street Charging
2025	9	5	3	33	1	1	4	2
2030	17	17	9	41	4	1	15	7
2035	26	31	22	54	7	2	34	15
2040	34	46	34	68	7	3	39	18
2045	43	53	43	76	7	3	40	18
2050	53	56	50	80	7	3	40	18

As with all other case studies, LCTs are added to the network to find the year that some intervention would be required. On this network, the addition of LCTs continued until 2050 and there are minimal issues with the network highlighted. The results of the 2040, 2045 and 2050 models are provided in Table 38.

In May Street, none of the scenarios, Close, Distributed and Far, had any current constraints on the mains feeders. The effects of different placements of LCTs were minimal on the network, due to both the existing capacity available as well as the even distribution of existing connected customers. There is some variation between the most heavily and least loaded feeders

Table 38 May Street – LCT installation for years leading up to 2050.

	2040	2045	2050
Max. Transformer Load (500 kVA rating)	468.45 kVA	506.72 kVA	533.58 kVA
Max. Feeder Current (400 A rating)			
Feeder 1	288.67 A	299.51 A	316.69 A
Feeder 2	194.52 A	205.86 A	211.72 A
Feeder 3	300.64 A	296.94 A	311.2 A
Feeder 4	233.62 A	244.84 A	262.86 A
Time of peak	Evening peak	Overnight peak	Overnight peak

The LCTs would have to be concentrated more to have a greater effect on any individual feeder. This shows that there is a necessity to ensure customer loads on a network are evenly distributed across the feeders. Different feeders may have higher loads at different times of day, which provides another consideration for when and where demand can shift, both in a time constraint and in a physical constraint.

As can be seen in Table 38, the time of winter peak demand shifts from the traditional evening peak to an overnight peak. This is driven by the continued addition of overnight electric storage heating on the network adding to the existing ToUT EV load profiles.

Possible interventions to enable 2050 LCT uptake rate

The overnight peak in 2045 and 2050 is due to two assumptions, firstly, that customers are choosing to use energy when it is cheapest and secondly that energy remains cheapest overnight. The first assumption is likely to hold true in any year, but the second assumption is the product of the historic energy pricing and may not reflect the 2050 energy tariffs. The transformer exceeds its rated capacity by almost 35 kW, a volume of demand which is likely able to be reduced through flexibility, especially since the peak is created as a product of implicit flexibility and the significant electrical demand storage heating introduces even at lower volumes.

May Street also demonstrates the benefit of having a network with well-balanced feeders to avoid customer demand increases requiring interventions. Monitoring the distribution network will enable networks to understand the individual loadings on the network and look for novel solutions that may avoid physical reinforcement. Issues related to unbalanced demand across a network, both by feeder and by circuit phase, will be easier to find earlier through LV network monitoring, otherwise, some issues may not become apparent until there is a fault on the network.

Table 39 May Street summary of intervention option

Solution	Cost (£)	Level of Disruption	Time frame	One time cost?
Local, targeted procurement of LV flexibility	£	No physical disruption.	Instant	No, flexibility must be procured every time an exceedance is forecast.

5.5 Spen Road – County Durham, Rural

This case study shown in Figure 23 provides an example of a rural network with terraced houses and a pole-mounted 100 kVA transformer. From a visual inspection, few properties seem to have driveways and most parking is on-street.

Figure 23 Spen Road network layout.

Challenges specific to this LV network

The domestic properties connected to this LV network are terraced, with no driveways or marked bays for parking outside.

As shown in Table 40, by 2050, the forecast suggests that over two thirds of the properties on this network will have an EV and around two thirds of properties will have a heat pump. In a rural area of this type, it may be more feasible for properties to have a ground source heat pump, which are assumed to have a slightly lower peak energy demand.

There is one property with electric storage heating in the baseline model, this is accounted for in the table. The 2050 model has all 91 properties heated by electric methods.

Table 40 Spen Road – LCT uptake 2024-2050.

Year	PV	Domestic ASHP	Domestic GSHP	Electric Resistive Heating	On-street Charging (Slow)	On-street Charging (Fast)	Non-managed Off-street Charging	ToUT Off-street Charging
2025	4	2	1	8	1	0	3	4
2030	8	12	2	12	3	1	12	14
2035	12	21	4	18	5	1	27	31
2040	15	32	10	25	6	2	31	36
2045	19	37	18	29	6	2	31	36
2050	23	39	21	31	6	2	31	36

As summarised in Table 41, while the number of properties affected by statutory voltage limit excursions vary by scenario, the properties that are most affected are generally properties at the extremities of the feeder. It does not matter if those properties have LCTs installed or not, the impact of other LCTs on the network may not be felt by the properties with LCTs.

Table 41 Spen Road – LCT uptake rate up to 2030

	LCT Close	LCT Distributed	LCT Far
Max. Transformer Load (100 kVA rating)	145.48 kVA	143.38 kVA	144.73 kVA
Max. Feeder Current (200 A rating)	264.97 A	274.67 A	267.86 A
Mains Warnings	1	1	1
Service Warnings	Few properties outside of statutory voltage limits, however not properties with LCTs installed	Around 30% of properties are outside of statutory voltage limits	Around 35% of properties are outside of statutory voltage limits

Possible interventions to enable 2050 LCT uptake

Without interventions the key issues are the capacity of the transformer and the feeder exceeding its rated current in all scenarios.

As this LV network sees high utilisation in 2030 for the pole-mounted 100 kVA transformer with a single feeder, following the decision methodology the first assumption is that a transformer upgrade is required. As the forecast suggests significant further demand on the network due to new LCTs the other considerations under review are the number of feeders and whether the feeders should be underground cables instead of overhead lines.

Options investigated:

- 200 kVA pole-mounted transformer with two feeders, remaining overhead lines (Table 42).
- 315 kVA ground-mounted transformer with two feeders, underground mains (Table 43).

The 200 kVA transformer upgrade, and the configuration of the network to be supplied by two feeders would be a suitable solution to solve the immediate problems in the 2030 context (Figure 24).

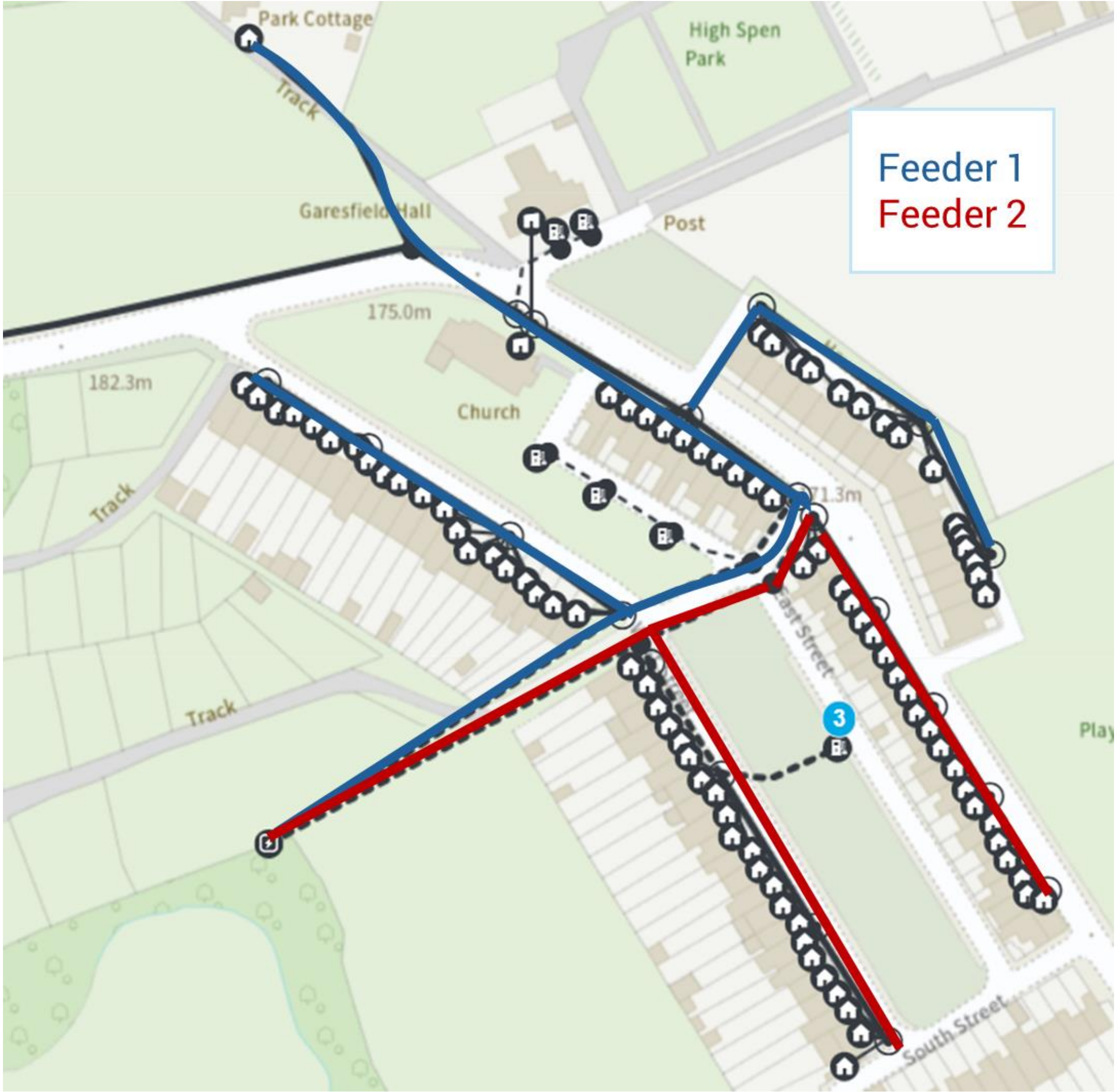

Figure 24 Spen Road network intervention layout, with additional feeder

However, to support the “touch the network once” approach to network planning, the 2050 forecasts for LCTs were added to this network. Once the additional demand had been distributed, the scenario saw more capacity issues, voltage drop issues at properties and overhead lines exceeding their rated capacity. While a 200 kVA multiple feeder network would be acceptable in earlier years, by 2050 the network would again exceed capacity.

Table 42 2050 Spen Road intervention option 1 impact – 200 kVA pole-mounted transformer

	LCT Distributed
Max. Transformer Load (200 kVA rating)	338.72 kVA
Max. Feeder Current (315 A rating) Feeder 1 Feeder 2	 339.82 301.02
Mains Warnings	1
Service Warnings	Customers are experiencing voltages outside of statutory limits

Intervention option 1 would not be suitable for a 2050 LCT forecast.

Smart interventions, like flexibility events or increased customer storage, could reduce demand in times of peak winter demand, however there is no practical evidence of targeted demand reduction on an individual transformer basis. The removal of over 100 kW of demand during a winter peak, 69% of the 200 kVA transformer rated capacity, when demand is primarily heating, will be difficult to deliver with certainty through other interventions. While some demand reduction trials have proved there is a customer willingness to reduce demand for compensation, it has not been proven on a local scale to this extent. During extreme cold spells, where the heating demand is most critical, there will also be lower variation in customer peak demands as heat pumps will be turned on at the same time, and for longer periods, reducing the load diversity.

Therefore, the preferred network option would be to install a 315 kVA ground-mounted transformer. Investing in a larger capacity transformer earlier, 315 kVA, would enable the forecasted uptake rates to be implemented on the network in 2050.

Table 43 2050 Spen Road intervention option 2 impact – 315 kVA ground-mounted transformer

	LCT Distributed
Max. Transformer Load (315 kVA rating)	338.72 kVA
Max. Feeder Current (400 A rating) Feeder 1 Feeder 2	 339.82 301.02
Mains Warnings	None
Service Warnings	No customers outside statutory limits

While Table 43 shows the 2050 demand at the transformer exceeding its capacity by around 25 kW, choosing a larger capacity transformer in this situation is not a preferred solution. The capacity exceedance is due to the types of loads that are creating that peak demand. This case study demonstrates a net zero solution where all properties have electrified forms of heating, including storage heating.

This network has moved from a traditional evening peak in 2050 to an overnight peak in 2050. This is due to coincident ToUT charging coupled with the uptake of electric storage heating, which heats at night. It is reasonable to assume that other, non-physical reinforcements like flexibility would enable safe operation of the network in 2050. The assumptions that drive ToUTs in the present, primarily that excess energy generated overnight must be used, may not be applicable in 2050, which means the peak demand may be lower than modelled.

Flexibility can be assumed a safe and secure method to ensure the 2030 reinforcement continues to be viable in 2050, to reduce any remaining peak demand outside the transformer capacity. This is backed by the primary driver of this peak being at night and is driven by present load profiles assuming cheapest energy costs overnight, which may not be the case in a 2050 energy market.

Customers no longer have voltage issues and the capacity problem has been solved assuming the peak overnight demand can be reduced. This is an example of a network requiring significant reinforcement and network reconfiguration work to enable the forecast uptake rate of 75% of customers to have an EV and 66% of properties to have a heat pump. The remaining properties have some direct electric heating, but the majority is assumed to have moved to electric based storage heating. Table 44 shows a comparative review of the intervention options for this LV case study.

Table 44 Spen Road comparison of intervention options

Solution	Cost (£)	Level of Disruption	Time frame	One time cost?
New pole-mounted 200 kVA transformer with creation of second feeder	££	Lower disruption. All overhead, no ground works and substation is in a field so construction replacement could be installed before existing transformer is disconnected.	Weeks – months	No, this intervention in 2030 would not support the forecast demand in 2050.
New ground-mounted 315 kVA transformer with undergrounding of parts of the feeders.	£££	Larger disruption as some groundworks will take place, substation site is in a field so outage requirements may be reduced with planning.	Months - years	Yes, enables 2050 forecasted demand.

The replacement of a pole-mounted transformer with a larger ground-mounted transformer and the undergrounding of some of the feeder will cause some disruption to the customers. However, as the transformer site is in a field this may help reduce some of the construction work disruption. According to the previously referenced NGED Investment Map, works similar to this intervention could take between 8 and 24 weeks. This intervention happens much earlier than in other case studies, so the ability to reinforce so far ahead of demand may be limited, but the assumption of a fully electrified base heating load suggests that the future capacity will be required.

5.6 Chaddesley Corbett – Worcestershire, Rural

This LV case study shown in Figure 22 demonstrates a rural LV network where a whole village is fed from the same small (300 kVA) transformer and has a mixture of OHL and UGC feeders. This case study is useful to demonstrate a rural area with a very high penetration of EVs and a moderately high penetration of heat pumps.

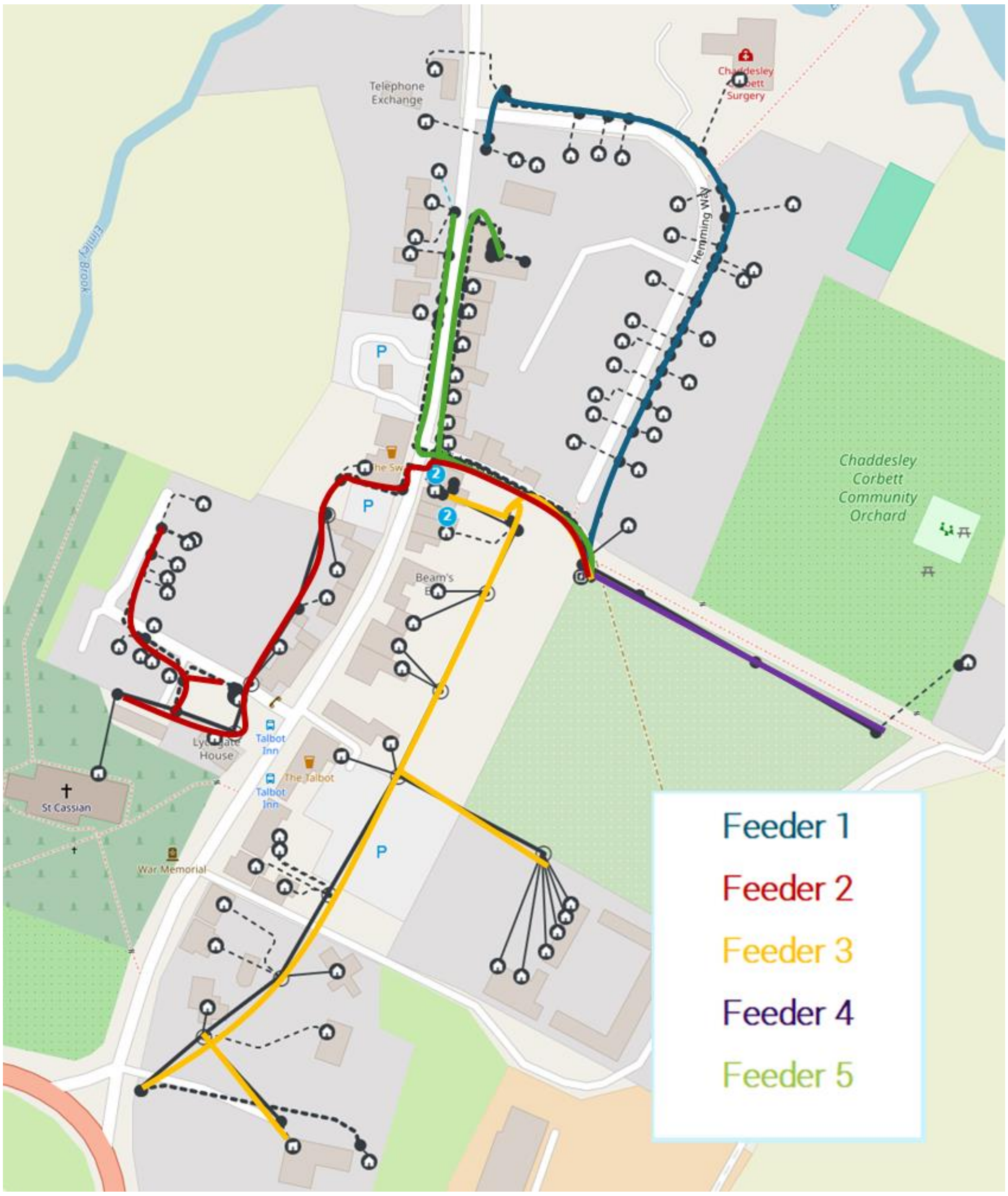

Figure 25 Chaddesley Corbett network layout

Challenges specific to this LV network

The uptake rates suggest that every property on the network will have at least one EV by 2050 and that around 67% of buildings will have a heat pump (Table 45). Heating type remains the choice of each customer, very few customers have electric heating at present and there are various options as to how customers could choose to have their properties heated via electrical means. Both EV and heat pump uptakes align with the reasoning that rural customers are likely to own more than one car and higher heat pump penetration[28]. The uptake rates also suggest that a large number of the EVs installed will adopt ToUT, shifting peak demand for EV charging away from the standard evening peak.

There are 13 properties with electric storage heating in the baseline model, this is accounted for in the table. The 2050 model has all 88 properties heated by electric methods.

Table 45 Chaddesley Corbett forecast LCT uptake rates 2024-2050.

Year	PV	Domestic ASHP	Domestic GSHP	Electric Resistive Heating	On-street Charging (Slow)	On-street Charging (Fast)	Non-managed Off-street Charging	ToUT Off-street Charging
2025	4	2	2	18	1	0	4	8
2030	8	8	5	21	2	0	15	30
2035	11	15	11	26	5	1	32	67
2040	15	22	17	31	5	1	37	77
2045	19	26	22	35	5	1	37	78
2050	23	27	25	36	5	1	37	78

In 2035, the volume of EVs on the network means winter peak demand exceeds the transformer 300 kVA capacity (Table 46). Before 2035, this LV network could handle the new loads associated with some heat pump installation and just over half of the properties owning one EV.

However, in 2040, the LV network has an EV charging on every property, with some having two (Table 45) as well as the continued installation of electric heating. The 13 properties with voltage drops outside of statutory limits are also an issue. This will prevent customers devices from working, in particular EV chargers and heat pumps. The 2050 LCT uptake forecast demands are shown in Table 47 and the three scenarios remain in use as there are some differences as the LCT installations have not reached parity.

Table 46 Chaddesley Corbett LCT uptake rates up to 2035.

	LCT Close	LCT Distributed	LCT Far
Max. Transformer Load (300 kVA rating)	348.5 kVA	346.69 kVA	340.11 kVA
Max. Feeder Current (315 A rating) Feeder 1 Feeder 2 Feeder 3 Feeder 4 Feeder 5	 252.03 A 166.93 A 224.41 A 62.51 A 1134.18 A	 242.05 A 179.95 A 225.95 A 69.56 A 120.63 A	 230.44 A 204.02 A 267.19 A 267.19 A 97.76 A
Mains Warnings	None	None	None
Service Warnings	None	None	13 properties with voltage drop outside the statutory limits

Table 47 Chaddesley Corbett uptake rates up to 2050.

	LCT Close	LCT Distributed	LCT Far
Max. Transformer Load (300 kVA rating)	412.82 kVA	410.40 kVA	406.35 kVA
Max. Feeder Current (315 A rating)			
Feeder 1	257.97 A	299.74 A	261.76 A
Feeder 2	204.46A	192.17 A	211.89 A
Feeder 3	285.57 A	279.35 A	311.41 A
Feeder 4	63.24 A	78.59 A	51.36 A
Feeder 5	139.39 A	183.71 A	135.06 A
Mains Warnings	None	None	None
Service Warnings	Numerous properties with voltage drop outside the statutory limits	Numerous properties with voltage drop outside the statutory limits	Numerous properties with voltage drop outside the statutory limits

At present, flexible solutions are not likely to be able to guarantee the reduction of demand by 37%, especially in the colder winter months when the peak demand occurs. On this network, the high penetration of EVs with managed charging on a ToUT in combination with the assumed use of overnight electric storage heating push the peak to the middle of the night. This network has some assumed overnight loads from commercial properties, like pubs. This substation feeds a whole village so there is a range of energy needs that are apparent.

In 2050, there are 78 EVs on a managed charging profile which are therefore assumed to be able to provide flexibility, as the peak is now overnight in 2050 they would have to be incentivised to charge at other times. The challenge of how you engage with and aggregate flexibility at the local level is a continued area of research. Active customer trials are being developed to understand the availability of this flexible demand and to demonstrate the effectiveness of local demand control (NPg Community DSO[38]), so DNOs will have more data available to support the deployment of flexibility in scenarios like this.

The driver for the additional demand increase is the additional electric storage heating, more heat pumps and the remaining EVs. The new LCT loads are large in proportion to the number of customers; Chaddesley Corbett has a high ratio of assumed EVs to the number of connected properties, much like Brockhill.

Possible interventions to enable 2050 LCT uptake

With the additional capacity forecast to connect to the network by 2050, the most likely intervention would be a larger capacity transformer to be installed (Table 48).

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[38] NPg Community DSO project: https://www.northernpowergrid.com/community-dso

Table 48 Chaddesley Corbett intervention option: 2050, 500 kVA transformer upgrade.

	LCT Close	LCT Distributed	LCT Far
Max. Transformer Load (500 kVA rating)	412.82 kVA	410.40 kVA	406.35 kVA
Max. Feeder Current (315 A rating)			
Feeder 1	257.97 A	299.74 A	261.76 A
Feeder 2	204.46A	192.17 A	211.89 A
Feeder 3	285.57 A	279.35 A	311.41 A
Feeder 4	63.24 A	78.59 A	51.36 A
Feeder 5	139.39 A	183.71 A	135.06 A
Mains Warnings	None	None	None
Service Warnings	None	None	None

A 500 kVA transformer was installed in place of the existing 300 kVA transformer. In this simulated scenario, no other assets had to be replaced to enable safe operation of the network, however, in practice, some of the conductors would be replaced while the outage is taking place. Which assets are replaced would be dependent on the network's asset management programme and analysis.

Table 49 summarises the options for interventions for this network. Flexibility has been included here to show that flexibility procurement for a single event will be cheaper than a transformer upgrade, the unknown of how often it would be required to be procured will create cost risks. Flexibility as a tool to delay investment to understand more variable on an individual LV network is where it is most suitable to be used. This comparison table only compares the interventions for this LV network in terms of relevant cost, disruption and installation time frame.

Table 49 Chaddesley Corbett comparison of intervention options

Solution	Cost (£)	Level of Disruption	Time frame	One time cost?
New ground-mounted transformer.	£££	Disruption generally associated with a transformer upgrade, outages and construction work in a constrained area.	Months – years	Yes.
Targeted, LV demand reduction or generation turn up.	£	No physical disruption, customers must be engaged to participate.	Weeks - months	No, this cost would be incurred every time there is a high load event.

5.7 Duxmoor – Ludlow, Rural

The network is pictured in Figure 26. The nine customers fed by Duxmoor are mainly domestic customers, but it also feeds a farm. Within this case study, the farm has been treated similarly to a domestic property when considering the addition of new LCTs to the network. There is significant work taking place across the DNOs (NPg Rural Electrification 2.0[39]) to better understand the decarbonisation journey for farming and agricultural communities which is out of scope for this report. The area contains properties with a mixture of heating types, and 100% owned properties.

Figure 26 Duxmoor network layout

Challenges specific to this LV network

This network does not have enough customers to require the three Near, Distributed and Far scenarios, as there is insufficient variation to provide any insights.

The uptake rates in Table 50 assume all properties on the network will have at least one EV by 2040 and that every home will have a heat pump by 2045. While it is probable that rural customers will have a second vehicle, the calculated uptake rates only account for one non-managed EV. All values in the table refer to the number of individual installations.

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[39] NPg Rural Electrification 2.0 https://smarter.energynetworks.org/projects/npg_nia_042/

Table 50 Duxmoor LCT uptake rates 2024-2050

Year	PV	Domestic ASHP	Domestic GSHP	On-street Charging (Slow)	On-street Charging (Fast)	Non-managed Off-street Charging	ToUT Off-street Charging
2025	4	1	0	0	0	0	1
2030	8	3	0	0	0	0	4
2035	11	6	0	0	0	1	8
2040	15	9	0	0	0	1	9
2045	19	10	0	0	0	1	9
2050	23	10	0	0	0	1	9

While the volume of PV uptake is greater than the number of customers connected, due to the methodology used, it is reasonable to assume that rural properties could have more space to install solar generation. On this network there is a farm, which likely has greater area available on which to install generation. The other LCT uptake rates align with the number of customers on the network, including the fact there is no street available for a customer to park on and therefore charge a vehicle. The farm may choose to install charging infrastructure on-site, which is an area of uncertainty that is out of scope for this project, as the possible electrification of farm vehicles is not presently included in the FES. Unique customer requirements on each network type should be investigated further to reduce assumptions surrounding specific customer types.

As illustrated in Table 51, the transformer capacity exceedance in 2035 is low (6 % overload). It is likely that a flexible or smart solution could be well placed in this type of network. Current trends suggest that battery storage is being installed alongside solar generation, and on a network where there is a high forecast of PV installations, it is likely these customers will have storage. The flexibility required to avoid reinforcement of the network 2035 is likely to be available on this network. However, by 2050 the transformer overload is significant (21%) and explicit flexibility is not considered sufficient to avoid network upgrades.

Table 51 Duxmoor LCT uptake rates until 2035 and 2050.

	LCT 2035	LCT 2050
Max. Transformer Load (50 kVA rating)	53.86 kVA	60.49 kVA
Max. Feeder Current (160 A rating)	174.98 A	184.82 A
Mains Warnings	1	1
Service Warnings	None	3 properties with voltage drop outside of statutory limits

Possible interventions to enable 2050 LCT uptake

The existing 50 kVA transformer is split-phase and has a single feeder. Split-phase means that only two of the usual three-phases are used to supply customers, this is used in various locations primarily to reduce the cost of supplying electricity to low demand customers as one less conductor is required. The most significant issue in the years of study is the addition of the LCT loads, as the transformer capacity is exceeded with the addition of multiple electric vehicles and heat pumps. An initial intervention, upgrading to a 100 kVA capacity transformer would solve the capacity issue. However, the voltage drop at heavier loaded customers at the end of the network, the farm, remain outside of statutory limits.

The excess solar generation contributed to a demand minimum in the summer, however the network never exceeded the statutory voltage rise limits with the generation installed. As previously discussed, there are both upper and lower statutory voltage limits, in the 2050 scenario it is the lower voltage limit that was exceeded. Generation mostly affects the upper statutory limits (10% voltage rise). If larger volumes of solar panels were installed on this network it could lead to a voltage limit excursions issues at properties along with reverse power flow across the transformer.

To enable greater power transfer to and from customers, two interventions were tested on this network.

- 100 kVA, split-phase transformer is installed. Additional feeder is constructed to feed the farm and associated properties.
- 100 kVA, three-phase transformer installed. Network configuration remains the same, with one feeder, and mains cables are upgraded to three-phases.

There are some benefits to customers from having a three-phase supply, including higher rates of power transfer and option to install three-phase appliances, like motors. Higher power, faster EV chargers will require three-phase connections at some power levels.

Both interventions solved the demand capacity problems affecting the network in 2035 until 2050, enabling a "touch the network once" solution to be implemented between 2035 and 2040 with minimal additional justification. While a three-phase solution was modelled for demonstration purposes, the split-phase solution would be the preferred option if required.

Installing another split-phase transformer is the preferred option as the HV network connection is also split-phase, Figure 27. Triggering an HV network upgrade, when a replacement split-phase transformer is generally suitable, is not a cost-effective option. If the HV network was to be upgraded to three-phases before the LV transformer reaches its capacity, then a three-phase transformer upgrade would be the preferred option as it would enable the customer demands to be distributed between the three phases instead of two.

Figure 27 Duxmoor pole-mounted transformer, showing split-phase HV connection[40] where the HV circuit only has two phases

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[40] Google street view of Duxmoor substation: 52.391414, -2.818526

Table 52 shows a comparison of the interventions options considered for Duxmoor. These comparisons are only intended to compare the impacts and costs on this LV case study with the relevant costs, disruption and installation time frame.

Table 52 Duxmoor comparison of intervention options to meet 2050 requirments

Solution	Cost (£)	Level of Disruption	Time frame	One time cost?
New 100 kVA split-phase pole-mounted transformer installed	££	Disruption only to customers on LV network with some enabling works for new feeder poles to be installed.	Months	Yes Explicit flexibility not considered viable to meet 2050 requirements
New 100 kVA three-phase pole-mounted transformer installed	£££££	Large disruption to both LV network and HV network if HV upgrade to three-phase is required as enabling works.	Months - years	Yes Explicit flexibility not considered viable to meet 2050 requirements

Challenges associated with modelled interventions on this network:

- The existing HV feeder is split-phase itself, creating additional, incidental costs for the LV network reinforcement if a three-phase LV transformer is chosen.
- In all interventions tested the network experienced some voltage rise, no matter where the solar generation was located. This is due to the very low customer demand at times with large volumes of PV generation.
- There is uncertainty surrounding new rural industrial loads, like farms, and how additional electrical energy demand or generation will arise. The implementation and timeline are highly unique and specific to the individual property and their future business models.

Connection of LV generation will be a continual challenge in rural areas if other interventions are not considered. The strategic use of storage solutions will likely reduce some of the greatest impacts on the networks, from both generation and demand sources. As DNOs are not able to control or own storage, the ability to rely upon the intervention is limited.

6. Challenges by Network Type

The case studies provide insights on how each individual network is affected by the installation volume and location of the LCTs on each network, but specific discussions drawn from these case studies may not be applicable to other LV networks.

However, some key points and consistencies can be found between the LV network types when considering the future installation of new LCTs (Table 53). The primary constraint column highlights the constraint that is of highest priority to solve. Voltage constraints appear on the network alongside the demand constraints but by solving for capacity first, the other constraints are solved. Similarly, where there are capacity constraints at the transformer, it is likely that there are feeder cable ratings exceeded, these are not included in the table.

Table 53 Overview of LV case studies and interventions enabling a 2050 forecast

Case Study Name	Type	2024 Demand (kVA)	2050 Demand (kVA)	Primary Constraint[41]	Intervention Year	Solution Enabling 2050 LCT Forecast
Mosborough Crescent	Urban	351.5	738.9	Thermal on feeder cable	2035-2050	Network reconfiguration through use of existing link boxes installed on the network is possible.
Dunston Industrial East	Urban	519.7	689.9	Thermal on feeder cable	2040-2045	Domestic loads increase significantly on one feeder. Network reconfiguration or the addition of a new feeder to feed domestic properties is required.
Brockhill Drive	Sub-urban	442.4	1,472.1	Demand at transformer	2035	New loads on the network by 2050 will increase the demand on the network to beyond 1 MW. Additional transformer is required.
May Street	Sub-urban	268.4	533.6	Demand at transformer	2050	Network exceeds transformer capacity by a small volume, so flexibility solutions should be utilised.
Spen Road	Rural	79.6	338.7	Demand at transformer	2030	New, larger transformer required, alongside the creation of a new feeder.
Chaddesley Corbett	Rural	152.6	410.4	Demand at transformer	2035-2040	Flexibility may delay reinforcement requirement but an increase in transformer capacity will be required.
Duxmoor	Rural	26.5	60.5	Demand at transformer	2035-2050	Implementing flexibility likely a suitable solution for this network to defer network reinforcement, however it is likely a transformer upgrade will be necessary by 2050.

The range of dates in the intervention year column represent either:

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[41] Some networks experienced excursions of statutory voltage limits on service cables alongside thermal constraints. Resolving the thermal constraint also resolved the voltage constraints.

- The variation between the three scenarios (close, distributed and far) causing new demands to overload one of the feeders. This is the case for the urban networks. The variation shows the first year a constraint is met in at least one scenario.
- The possibility to use explicit flexibility to delay physical reinforcement on the network. This is the case with the two rural networks.

If an overload on a single feeder remains an issue, especially when that issue appears across more than one of the scenarios, a more physical solution like network reconfiguration will become a requirement. This report does not assume that targeted demand reduction will be common on a per feeder basis, explicit flexibility will remain a tool to manage demand at the transformer.

6.1 Commonalities Across Case Studies

The primary challenge for all case studies, and is the challenge facing DNOs, is that customers drive the installation of new LV demand on the network. The variation in LCT location was used to demonstrate this uncertainty and across the case studies the location of the LCTs created different constraints on the feeders.

In general, solar generation at the LV level was not installed at a high enough density to impact the network, except on the smallest rural network. Domestic solar generation is generally assumed to be used within a property, either immediately or stored in a battery system. As storage was not considered in this manner, the impact of solar generation would be reduced further if every installation was tied with a storage system, since new tariffs that incentivise the storage of solar power instead of the immediate export to the grid are becoming available to customers. In effect, these tariffs, like Octopus Intelligent Flux[42], will reduce the impact of solar generation at the LV level, if some form of storage is installed alongside a solar panel.

For use on the LV case studies, the only type considered in WP1 is domestic batteries, which are classed as small-scale storage. WP1 ties storage to LV small-scale solar in terms of installed capacity, Figure 28. The total capacity of small-scale storage is very low in comparison and general assumptions for average domestic battery sizes are being investigated.

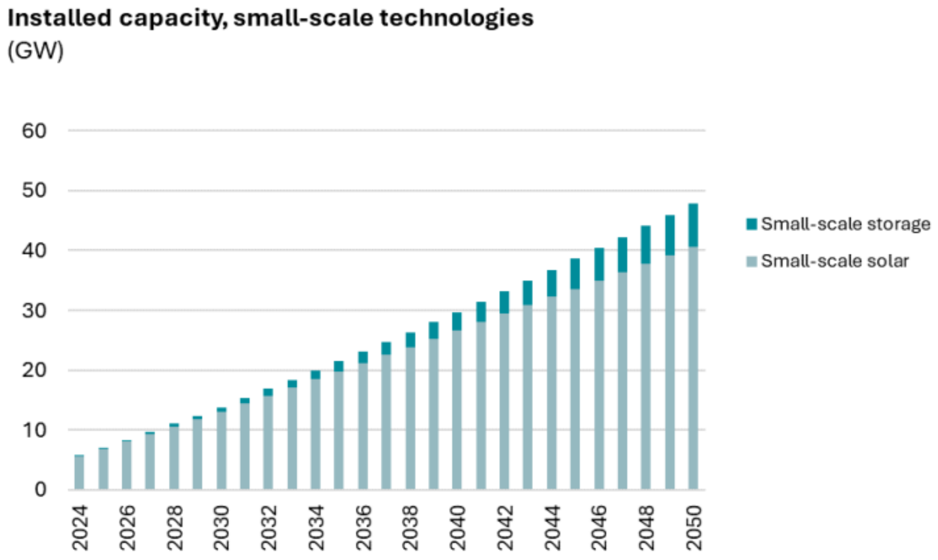

Figure 28 FES 2023 small-scale and storage capacity projections, WP1

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[42] Octopus Intelligent Flux https://octopus.energy/intelligent-flux-faqs/

Where terraced houses are the primary property type, these networks are limited by physical space for the connection of new EVs and GSHPs. It is likely that these networks will see lower or slower uptake of LCTs, however this is also dependent on the type of customers who live in these properties.

For example, levels of existing car ownership should be considered a key metric for identifying likely levels of new EV ownership and therefore new car charging demands.

In streets where properties do not have guaranteed car parking locations and are unlikely to have home installed car charging points, there are two conclusions that can be drawn. The first, is that terraced homes will likely have greater volumes of on-street charging required and the second is that car owners may not have the same access to ToUT and vehicle to grid charging opportunities that other customer will have. This will impact multiple factors: the demand from EV charging, the availability of explicit and implicit flexibility on the network and the value customers can receive from owning an EV.

In two of the case studies, Chaddesley Corbett and Duxmoor, the addition of a proportionate and controllable volume of energy storage could delay reinforcement on the network, although a transformer upgrade is likely at some point in the future. On others, if controllable energy storage was placed suitably on the network, for example on the heaviest loaded feeders in tandem with new heat pumps, it could remove the need for network reconfiguration entirely. This is discussed further in the Storage section in this report.

Networks where there are higher volumes of rented accommodation may see lower volumes of LCT installations if landlords are not required to install them. Many benefits of LCTs and their long-term cost savings are only seen by the inhabitants of the property, which raises concerns for those who are unable to own their own home having access to future needs, like EV charge points.

6.2 Skilled Worker and Supply Chain Requirements

Six out of the seven case study networks required some form of physical intervention at some point before 2050, which means ensuring there is a dedicated workforce with experience and capability is critical to enabling a net zero compliant electricity network. Replacement of all the rural transformers in the case studies, and especially the pole-mounted transformers in the earlier years of study, is an indication of the level and timing of additional reinforcement that is required.

Continued forecasting of additional demands and monitoring of assets will be required to ensure scheduling of works across the distribution networks. Managing supply chain expectations and delaying reinforcement where possible will be required to ensure the most at-risk assets are upgraded at the right time, with interventions that will be suitable for supplying future demands.

Management of personnel and having a robust supply chain will be key enablers for ensuring the distribution networks are capable of supplying the 2050 customer demands. The energy transition is occurring globally, other countries and industries will require the same skillsets and assets as Great Britain to support their own decarbonisation efforts. This increases the importance of understanding future reinforcement needs as early as is practicable.

6.3 Urban

Characteristically, these networks have lower percentage LCT penetration than the sub-urban and rural networks. When considering the available physical space, the types of properties and the population demographics of urban areas the calculated uptake rates are sensible, as for example, there is less space to park vehicles. In these types of networks, the location of the LCTs will impact the network more than the volume.

If customers in urban areas are to have access to EV charge points, it is most likely that they will not have singular access to a private charge point and will rely on a public charging network. This presents an opportunity for DNOs to enable most efficient use of their network when public charging locations are being planned. Understanding where capacity is available within the LV network will reduce future works.

For a DNO, careful consideration of new connections and understanding of the increasing load demands of urban networks may enable operation of the existing assets without significant network interventions. This could be through greater LV network monitoring or through reviewing smart meter data that is available.

This conclusion is only applicable to the specific network configurations looked at in these case studies and should not be considered true for other urban networks, especially those that do not have similar features to the case study networks, without review. Each DNO would have to investigate their own networks for features that appear in each of these case studies. For example, considering link boxes as a solution, understanding the number and connectivity arrangements for link boxes on their LV networks may enable greater options for future network management.

6.4 Sub-urban

These case studies demonstrate two ends of the spectrum when considering a sub-urban network. Large housing estates or cul-de-sacs have considerable physical capacity to install LCTs, especially EVs, whereas terraced streets are likely to be unable to support new LCTs from a physical standpoint, so the electrical network may be less strained. This dichotomy was visible from the two chosen case studies, with the terraced May Street the only case study not requiring any physical interventions while Brockhill Drive required an additional transformer.

As customers will drive the installation of LCTs on the LV network, areas where properties are already suitable for heat pump installation and have access to off-street parking will be most at risk of significant and fast increases in network demand. LV networks that feed properties that are owned by their inhabitants will also be likely see the increase of LCTs faster than networks with more rented properties.

6.5 Rural

Of the three rural case study networks, one will require a transformer upgrade and a network reconfiguration, one will need a larger capacity transformer, and one may be able to utilise flexibility to avoid reinforcement until 2050. Rural networks are more susceptible to individual customer decisions impacting the operation of the network as they have smaller capacity transformers and fewer customers which leads to lower diversity.

A major area of further review will be the understanding of future electrical loads for large rural customers, especially those that previously used other forms of energy, like oil or gas to fulfil their needs since there is more variation in rural housing stock heating requirements. The direct electric heating profile of a rural property may differ to the direct electric heating load profile of an urban or sub-urban property. It may be more likely that new, large, individual, customer connections will trigger network reinforcement before cumulative, incremental LCT additions to a network become a concern.

7. Limitation of Impacts and Further Interventions Options

The development of the LV case studies in this document has focused on the required network interventions related to asset health and service quality. The network reinforcements are discussed in each section in the context of not only the asset upgrades or replacements that maybe be required, but the timeliness of those works. In some cases, for example the rural networks, capacity issues are confronted within the next decade whereas in others the issues may be seen only in the latter years of study.

Reinforcement is not the only avenue to ensure security of supply in a net zero electricity network, flexibility is poised to be a powerful tool in both avoiding reinforcement and delaying reinforcement until the most efficient delivery window.

7.1 Limitations of Heating Assumptions in Modelling

The electrification of heat is one of the biggest challenges to the LV networks, some properties will not own electric vehicles, but many will change their heating type from gas to electric.

The existing customer loads in the baseline provided by the DNOs already include some customers having overnight electric storage heating, for example Economy 7 or Economy 10. These remained in the LV models throughout the case studies, as those homes would already be heated by electrical energy. Adding more direct electric storage heating increased the overnight load on networks, which had a negative effect when combined with EVs charging on a ToUT.

The electric storage heating profiles are based on existing storage heating technology, however storage heater technology is being modernised, so the impact of storage heaters on the overnight demand may be reduced.[43]

This modelling work did not consider the level of insulation in properties in the LV case studies and therefore the possible impact on heating demands, which is a limitation in this report. As more properties are heated through electric means there will be greater evidence of their prospective impact on the network and these load profiles should be separated by insulation level where possible. This will enable LV network forecasting demand to assess best and worst cases on networks by varying the assumptions surrounding insulation of properties.

On LV networks with high density of properties or large volumes of customers with gas central heating, continuous forecasting of the future network demands from new heating sources is needed to reduce the impact on the network. This modelling work did not consider storage of heat as part of the ASHP or GSHP load profiles and it may be a challenge to rely on significant flexibility of heat without it. However, storage of heat was included in direct electric heating uptake forecasts.

For LV networks where there are blocks of flats, like Mosborough Crescent, or terraced streets, like in Dunston Industrial, heat networks may enable greater decarbonisation of heating for the properties with reduced strain on the electrical networks. However, retrofitting these areas, and the associated costs and disruption, is likely to be a complex project which will be prohibitive to an individual customer. In these cases, housing associations, councils or government would have to be the driving force behind a large-scale installation on a street-by-street basis. No case studies have existing heat networks, but the urban case studies would be potential candidates for heat networks, especially the blocks of flats within Mosborough Crescent.

In WP1, electrified district heat networks are assumed to be connected at HV level which would remove some heating loads from the LV case studies. However, there are uncertainties about the number of district heat connections reported by different sources, so assuming high heating loads directly connected to the LV network by individual customers will provide the highest level of demand in each case study. There is also uncertainty surrounding the creation of new district heating networks in existing areas.

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[43] EDF Energy – Electric Storage Heaters Explained https://www.edfenergy.com/heating/advice/storage-heaters-explained

7.2 Storage and Flexibility

The case studies were assessed with low flexibility sensitivity as per WP1, requiring a reinforcement heavy response to challenges on the network. Most commonly domestic batteries are used to supply household demand during peak times and shift this load to off-peak times[44]. Unlike grid-scale batteries, they are less reflective of the variability in demand and generation from sources such as wind and solar but more so to that of the household demand profiles.

DNOs presently have very conservative assumptions of how storage will behave on the LV network. Battery behaviour at LV connection is largely dependent on the type of tariff a customer has chosen, which is a supplier decision. NGED and NPg, the networks where the case networks are situated, each have their own assumptions as to how storage may behave on their network. These conservative assumptions are due to a lack of data available to model different future usage patterns, therefore there is a need to design a network for a range of scenarios.

Presently, NGED assumes a battery will always operate at the most negatively impactful time, Figure 29 left, that it will export when demand is low and import when demand on the network is high. The NPg load profile, Figure 29 right, assumes the battery is paired with solar generation, however in the winter, if this profile is to remain consistent, the battery will be charged from the grid supply.

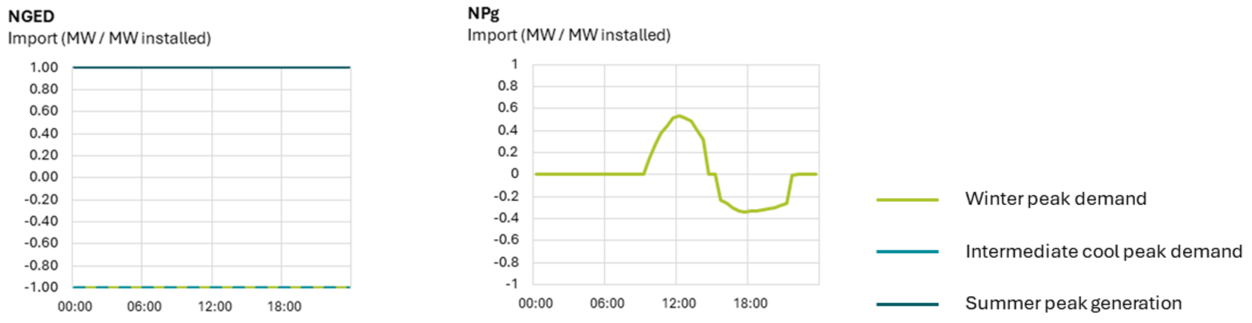

Figure 29 Present NGED and NPg assumptions of battery storage import and export[45]

Domestic storage could benefit the distribution network if all battery installations are assumed to be able to receive and process price signals that would enable demand side response on the network. However, signalling flexibility at an LV level is something that is still in the early stages of network trials and not rolled out across significant regions of the country.

As the LV network modelling was undertaken without assuming utilisation of explicit flexibility services, the 2050 demands with LCTs included can be compared to the capacities of the networks as they exist now (Table 54). This provides some visibility as to where flexibility could be utilised.

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[44] Battery storage - Centre for Sustainable Energy (cse.org.uk)

[45] Battery storage profiles, Regen WP1.1

Table 54 LV case studies transformer capacity exceedance in 2050.

Case Study Name	Transformer Capacity (kVA)	2050 Max Demand (kW)	Capacity Exceedance (%)
Mosborough Crescent	800	738.9	None
Dunston Industrial East	1000	689.9	None
Brockhill Drive	800	1,472.1	184%
May Street	500	533.6	106%
Spen Road	100	338.7	338%
Chaddesley Corbett	300	410.4	136%
Duxmoor	50	60.5	121%

Two networks, Brockhill Drive and Spen Road, cannot be assumed to be able to reduce their peak demand in the 2050 forecast scenario to meet transformer capacity, given the high-capacity exceedance. One network, Duxmoor, may be able to utilise flexibility to meet its demand needs in the 2050 scenario through a 21% reduction in peak demand, but this level of demand side control on small LV networks may be a challenge. This would equate to 2 of the 10 EVs shifting their charging away from the evening peak.

Chaddesley Corbett may be able to delay network reinforcement by deploying flexible interventions, reducing the 2035 forecast on the peak demand days. However, by 2050 the LV network would have to be capable of reducing its demand by a significant margin, a guaranteed reduction of 72 kW at peak winter demand. The most likely demand flexibility tool would be through vehicle charging times, however targeted flexibility has not been demonstrated in the volume of demand required here, as it is an area of continuing investigation by DNOs[46].

This table does not reflect the loadings of individual feeders on each network. 6 out of the 7 networks had conductor loading issues even if they did not have transformer capacity issues. If energy storage solutions are available on feeders with specific loading challenges, those networks could avoid reinforcement for longer or entirely.

However, with present regulations in place, the DNOs have limited control over the level or location of storage on their network, so they must rely on customer adoption and market signals. Further investigation into the ability of local price signalling or other DSO load control is being investigated to demonstrate and trial the potential for local flexibility services to meet DNO needs.

Implicit and explicit flexibility impact in case studies and wider considerations

In the discussion following intervention requirements for the LV case studies, explicit flexibility is assumed to be available in the form of localised Demand Side Response (DSR) in the latter years of study. The mechanism and methodology for signalling the need for local flexibility is actively being developed and tested and is assumed to be in place for the years where it has been suggested as an intervention.

However, as seen most prevalently in the May Street case study, implicit flexibility and the assumed increase in demand responding to national price signals can drive new peak demands. The time of use tariff may remove demand from the traditional peak time but if the price incentives remain it could create new, larger issues, especially if including greater volumes of battery charging and other flexible demands. This creates a conflict between the traditional price signals used by suppliers, which is driven by national generation and demand mismatch, and the new price signals which could be used by DSOs to balance their LV network.

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[46] Northern Powergrid's Community DSO project is one that looks to develop a framework for flexibility and energy balancing at an LV level: https://www.northernpowergrid.com/community-dso

Automated flexibility response may also create issues for the safe running of the distribution network, if erroneous signals are provided to the market.

Finland provides an example of engaged customers responding to pricing signals in a manner that negatively impacts the electricity network. In November 2023, due to a price submission error from a generator, the price of energy became negative, and customers increased their demand in response, leading to a large increase in consumption. Across the network domestic fuses melted and some LV network fuses had to be replaced due to highly flexible customers, with spot-price-based tariffs, responding to the price signal.[47]

Flexibility must be implemented at a national level in a manner that ensures the distribution network is not compromised. Similarly, local, explicit flexibility signalling must not be in direct competition with national, implicit flexibility signals. If there are conflicts in the price signal, this may confuse customers and create inefficiencies.

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[47] Effects of negative spot market prices on Electricity distribution network loading, experiences from the Finnish distribution system. Juha Haakana[1] (lead author) LUT University, Finland. CIRED 2024

8. Conclusions

There is no “one size fits all” solution to LV network planning when considering the new types and volumes of electrical loads that will be connected to the network before 2050. Even within a single network, the location and type of LCTs connected can impact the intervention timings greatly. However, the total volume of LCTs on a network will ultimately determine what interventions must take place to ensure the network will function safely while suppling these new loads in the future. The timing of the LCT deployment will impact when and how DNOs must respond to the new demands and the new demand types being installed on the network. As they have no control over the number of these new LCTs it is important that there is continued review of these forecasted uptake rates to understand what the best approach is to ensure customers continue to have a safe and secure supply of energy.

The limitations of this study primarily surrounded uncertainties about existing LCT load profiles, like domestic batteries which were out of scope, and the possible developments in LCT load profiles that were in scope. Further evidence of the functional load profiles for LCTs must be researched and developed continually to support DNO planning activities:

- EV charging profiles of all types must be updated and refined, with particular focus on the impact of changing energy tariffs on consumer charging behaviour.
- Heat pumps profiles in different property types should be investigated to support better LV network forecasting, as property types are similar across an LV network. If there is a large difference in heat pump load profiles for a large, detached house compared to a terraced house this could have compounded impacts on forecasting ability for individual LV networks.
- Similarly, as domestic battery storage operation becomes more commonplace on the LV network it will be possible to include batteries in modelling and forecasting.

This modelling work reviewed the impacts of new LCT loads on LV networks that comprise around 66% of GBs LV network types. All networks discussed in this report are of radial construction, meshed networks may have different interventions that could be utilised to absorb and support the new LCT loads. New build housing developments were also not considered as network planners now consider LCTs during the design phase.

If an asset is to be replaced during the period of study due to age or deterioration consideration of how a “touch the network once” may be enabled by reviewing forecasted future network demands. An asset being replaced in 2030-2040 must be designed to meet the future network capacity needs. However, these asset replacement and upgrade plans also need to take into consideration the accuracy and reliability of LCT uptake forecasts.

Further studies on the potential for heat flexibility are required to understand where and when large heating demands will impact the network. The ageing housing stock of the UK and the different building construction standards and technologies will impact the ability of a household to supply energy flexibility through varying their heating profile. The majority of the interventions highlighted in this report are to deliver winter peak demand which is largely driven by the demand for electrified heat.

- **Case-Specific Network Interventions:** Each case study highlighted that the necessary interventions depend heavily on the local network's characteristics. For example, urban networks like Mosborough Crescent showed potential for network reconfiguration using existing infrastructure, while rural networks like Duxmoor may require more direct transformer upgrades due to smaller capacities and fewer customers.
- **Increased Scale of Network Reinforcement:** In comparison to present network planning decisions, the volume of reinforcement required to support the new loads connecting to the network is far larger in scale. Not only will LV transformers need to be upgraded in some networks but the network configuration will have to be updated to ensure stability of supply.

- **Impact of Customer Location**: The distribution of customers on LV feeders plays a critical role in determining network constraints. In Brockhill Drive (sub-urban), the uneven distribution of load across feeders accelerated the need for intervention. Conversely, networks like May Street (sub-urban) demonstrated that balanced customer distribution can delay the need for upgrades.
    - Networks with fewer feeders or uneven distribution of customers across feeders will see the impact of new loads on the network earlier than other networks.
    - Location and grouping of new LCTs on an LV feeder plays a significant impact on when network upgrades are required.
- **Reduced Load Diversity:** As LCT uptake increases, load diversity decreases, amplifying network stress. In the Spen Road (rural) case, the small number of customers and concentrated LCT adoption significantly impacted the network, demonstrating that rural areas with limited diversity will face constraints earlier than urban or sub-urban areas.
- **Flexibility Delays Reinforcement:** In several case studies, such as Chaddesley Corbett (rural) and Dunston Industrial East (urban), flexibility services like demand-side response and targeted EV charging could delay the need for costly reinforcements, but only if local customers actively participate in demand-shifting schemes.
- **Explicit Flexibility and Implicit Flexibility Conflict:** While implicit flexibility, through time of use charges from a supplier, is broadly beneficial to networks in the present day, eventually the strain on the network may materialise at a different time. In some modelled case studies the need arises to procure explicit flexibility to solve the new demand issues created by customers responding to Time of Use Tariff signals (implicit flexibility).
- **Monitoring as a Crucial Tool:** In all case studies, continuous network monitoring was identified as essential for managing increasing LCT uptake. By using monitoring to anticipate constraints, DNOs can avoid over-investing in reinforcements and focus on targeted, flexible solutions, especially in dense urban networks like Mosborough Crescent.
- **Diverse Intervention Needs:** Across all case studies, the required interventions varied in complexity and cost. For instance, Spen Road required a straightforward transformer upgrade, while Brockhill Drive called for a larger-scale transformer replacement due to the projected load increase. This underscores the need for tailored solutions based on specific local conditions.
- **Further Study on ToUT Impacts:** The case studies reveal the complexity of Time-of-Use Tariffs (ToUT). While shifting load outside of peak periods reduces strain, as seen in the Duxmoor rural network, ToUTs could reduce overall diversity in load profiles, making networks more susceptible to concentrated peak demand, even outside traditional peak hours.

Appendix I Load Profiles

This section contains a summary of the load profiles that are embedded in VisNet Design for each of the new technologies being modelled. VisNet Design uses established diversity algorithms to model diversity for these profiles.

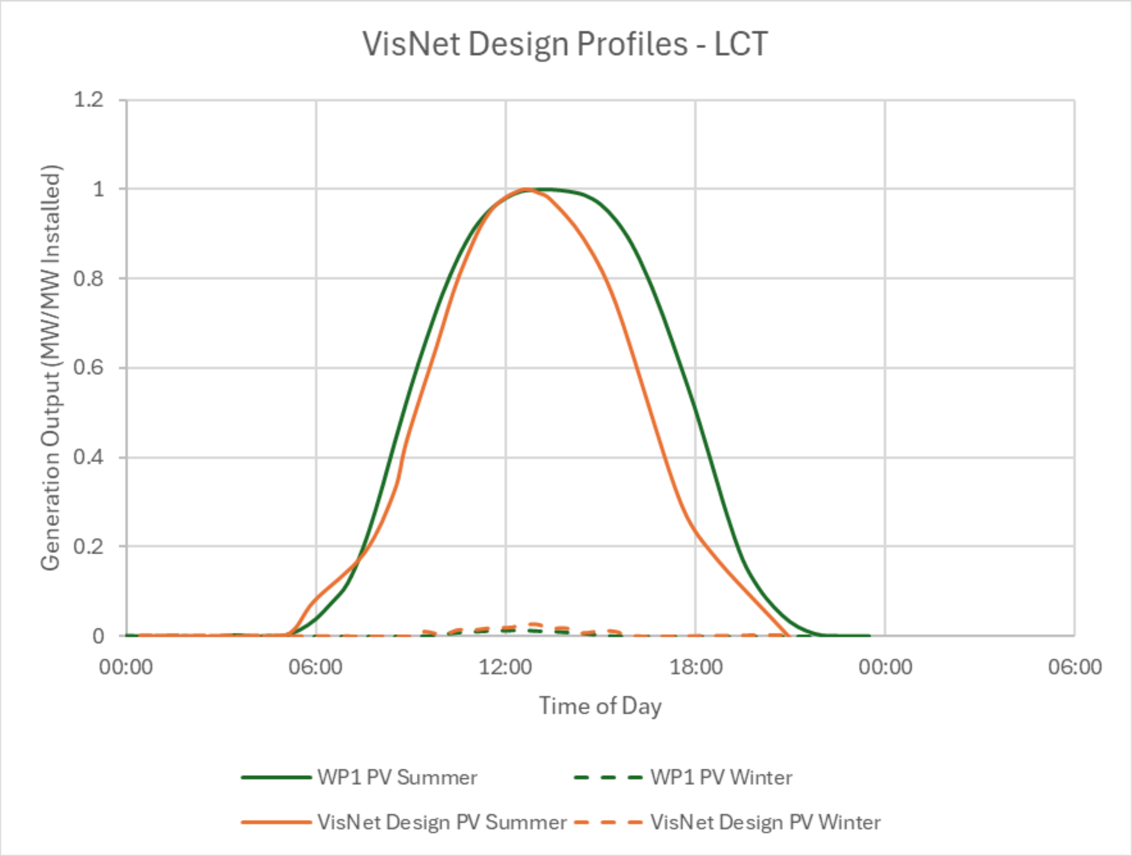

Figure AI.1 Non-diversified PV load profiles used in VisNet Design, which uses established diversity algorithms in the modelling[48]. Models are in alignment with profiles described in WP1.

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[48] ENA, 1981. "Report on Statistical Method for Calculating Demands and Voltage Regulations on LV Radial Distributions Systems", Energy Networks Association, 1981.

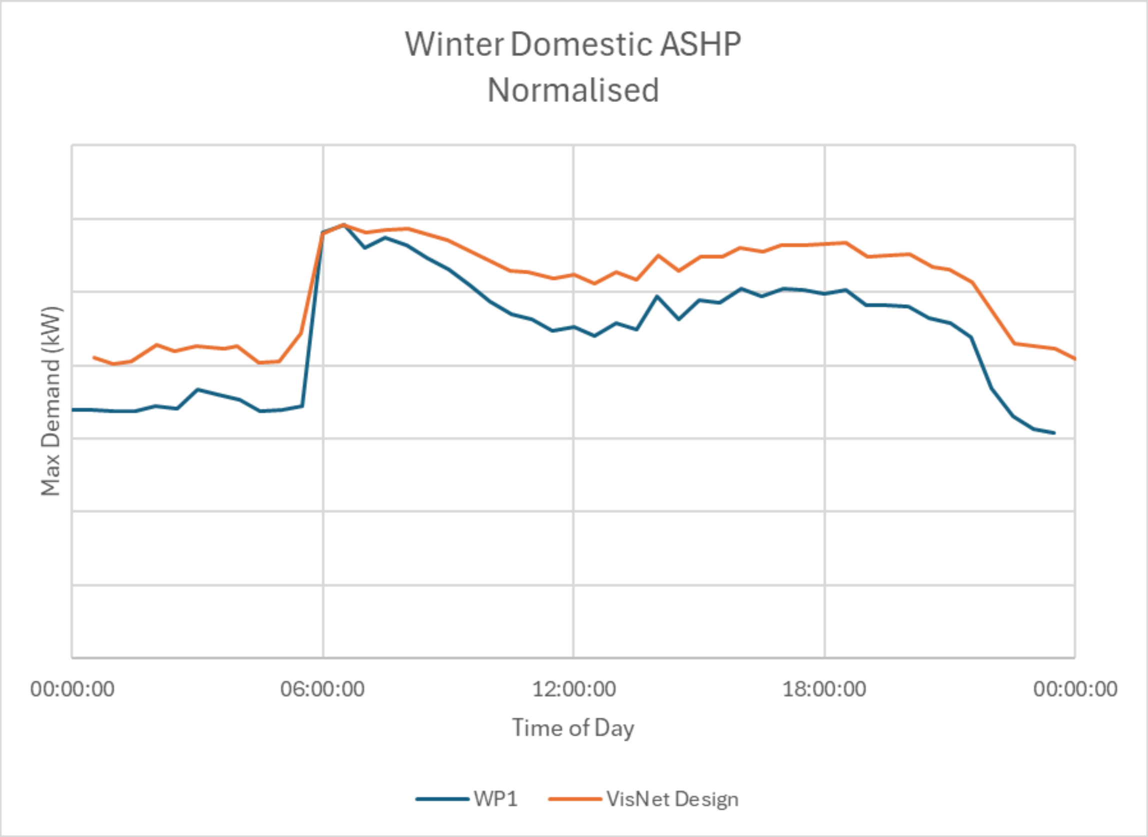

Figure AI.2 Load profile for ASHP in VisNet Design, which uses established diversity algorithms in the modelling. Models are in alignment with profiles described in WP1.

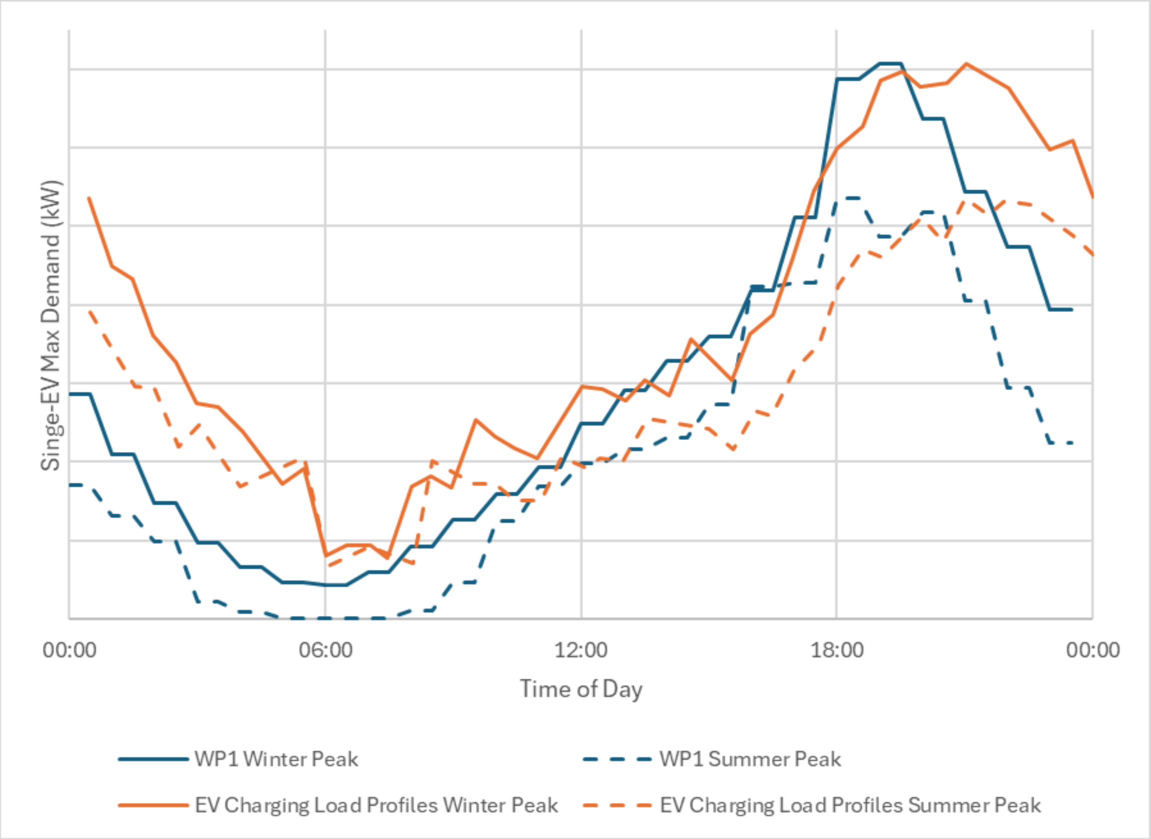

Figure AI.3 Load profile for EV chargers in VisNet Design, which uses established diversity algorithms in the modelling. Models are in alignment with profiles described in WP1.

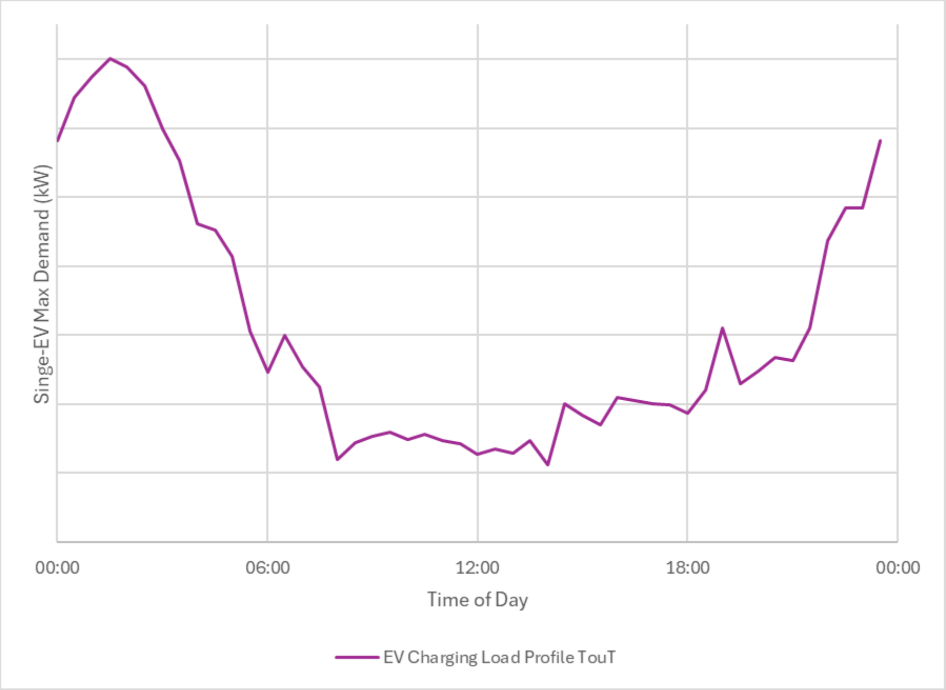

Figure AI.4 Load profile for EV chargers using TouT in VisNet Design.

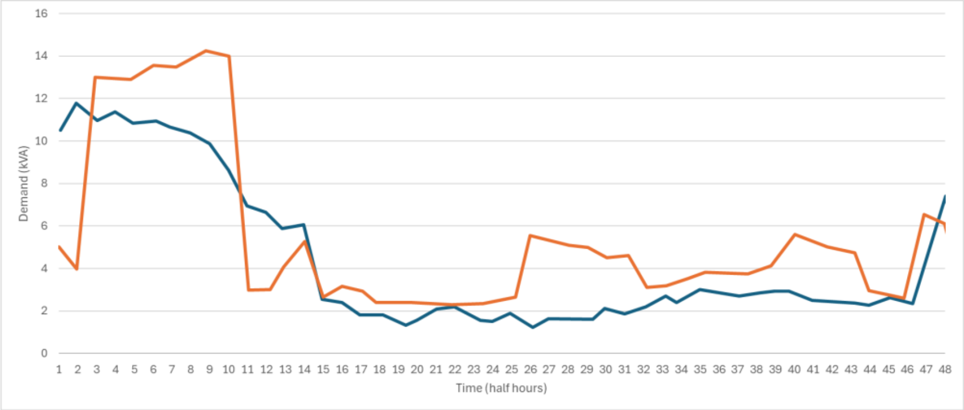

Figure AI.5 Electric resistive storage load profiles in VisNet Design, Economy 7 and Economy 10.

Appendix II Transform LV Interventions

Transform LV Intervention	Term Used Within LV Case Studies
Generator Constraint Management GSR - LV connected generation	Flexible solution
Generator Providing Network Support e.g. Operating in PV Mode - LV	
Permanent Meshing of Networks - LV Urban	Network reconfiguration
Permanent Meshing of Networks - LV Sub-Urban	
Real Time Thermal Rating (RTTR) for H/LV transformers	Operational flexible solution, alleviates thermal constraints
RTTR for LV Overhead Lines	
RTTR for LV Underground Cables	
Switched Capacitors - LV	Flexible solution
Temporary Meshing (soft open point) - LV	
LV Underground network Split feeder	Network reconfiguration
LV New Split feeder	
LV Ground mounted 11/LV Tx	
LV underground Minor works	
LV underground Major works	
LV overhead network Split feeder	
LV overhead network New Split feeder	
LV Pole mounted 11/LV Tx	
LV overhead Minor works	
LV overhead Major works	
Active Network Management - LV	Flexible solution
Local smart EV charging infrastructure, intelligent control devices (LV)	
Dynamic voltage management using online tap changers - LV	
Dynamic voltage management using power electronics - LV	
Network data monitoring - LV	Network visibility
FLEX - LV Connected Generation/Demand	Flexible solution

Appendix III Diversity

Diversity and Low Carbon Technologies

The integration of low carbon technologies like solar PV, EVs, and heat pumps into the network increases both the complexity and the importance of managing diversity, particularly at lower voltage tiers.

- **Solar PV**: With solar PV systems becoming more common, especially at the LV level, the diversity of generation increases. While solar panels on different properties generate electricity during daylight hours, the amount of energy produced can vary depending on location, time of day, weather conditions, and the orientation of panels. This variability introduces a new kind of diversity—generation diversity—into the grid. On sunny days, many solar PV systems may export power back to the grid simultaneously, while on cloudy days, generation is minimal. This is further exacerbated by the generation off-setting load being used within the connected property, which is itself highly variable. Furthermore, the combination of battery storage with solar generation introduces another variable that impacts how a customer is 'seen' by the network. The network must manage this variation, ensuring that it can handle surplus generation during peak sunlight hours while also maintaining supply when generation drops.

- **Electric Vehicles (EVs)**: The adoption of electric vehicles also impacts load diversity. While not every EV owner will charge their vehicle at the same time, clustering of charging patterns—such as after work in the evening—can create significant spikes in demand. Diversity in charging behaviour (different charging times, rates, and patterns) helps to spread out this demand, but as EV numbers increase, the network must be prepared to handle both the peak load from simultaneous charging events and the reduced diversity in charging times as more EVs are adopted. The increasing prevalence of ToUTs directly counters the diversity that would otherwise be expected, as customers choose to move their charging to reduce their own operating costs.

- **Heat Pumps**: Heat pumps add another layer of diversity to the network. Although heat pump usage tends to peak during colder months, the actual demand can vary significantly across properties based on the insulation, heat pump size, and temperature settings. Like domestic electrical appliances, not every heat pump will run at full capacity at the same time, introducing some diversity in load. However, as heat pumps replace traditional heating systems, there is a risk of reduced diversity during cold spells, when many households will require heating simultaneously and the potential for diversity is reduced.

- **Electric Resistive Heating**: Electric resistive storage heating presently has reduced diversity as its use is predicated on the fact that it is turned on during specific overnight periods, and older electric storage heaters have limited ability to change these times. Newer storage heaters are more intelligent and efficient, with the ability to respond to ToUTs, which may increase diversity for this heating type. Standard direct electric heating with no storage will have similar impacts on diversity as heat pumps, with the potential for reduced diversity assumptions during cold spells as households respond to temperature needs.

Diversity Across Voltage Tiers

1. **Low Voltage (LV) Network**
   The LV network benefits from the highest degree of diversity due to the large number of connections. In addition to the staggering of domestic loads, the diversity of generation from rooftop solar PV and varying charging patterns of EVs means that the network experiences high levels of fluctuation in both load and generation. However, because each individual connection—whether a house, solar panel, or EV charger—has a relatively small impact, the network can manage these fluctuations more

easily. Nevertheless, the cumulative effect of multiple homes, EVs, and heat pumps can lead to localised peaks in demand or generation, requiring careful management and capacity planning.

2. High Voltage (HV) Network
   At the HV level, diversity decreases as fewer, larger connections are directly made to the network. Load and generation at this level tend to be more predictable, but the diversity of generation sources (such as medium-sized solar farms or embedded generation) still presents variability that must be managed. The reduced number of connections means that each one has a larger impact, and a loss of diversity could lead to more significant effects on the network. The integration of low carbon technologies at the HV level, such as larger solar farms or fleets of EV chargers, is carefully monitored to balance supply and demand effectively.

3. Extra High Voltage (EHV) and 132kV Network
   The EHV and 132kV networks experience the least diversity in load and generation, as they handle fewer, larger connections. The impact of any single generator or load is significant, and there is little room for the kind of diversity seen at lower tiers. For example, a large wind farm or solar park connected at this level can inject substantial power into the grid, but the variability of renewable generation still requires advanced grid management techniques to ensure voltage stability and prevent overloads. At these levels, diversity is managed through the use of balancing services and grid-scale storage solutions to ensure consistent power supply.

In summary, as voltage tier increases, the number of directly connected customers decreases, leading to reduced diversity in both load and generation. However, the impact of individual connections becomes more significant. Conversely, at lower voltage tiers, greater diversity—due to the large number of small-scale loads and generators—requires more flexible management to maintain grid stability and accommodate the increasing role of low carbon technologies.

At the local level it is important to recognise how the diversity of LCT adoption impacts network management and planning. The local case studies, which examine rural, suburban, and urban networks, illustrate how unique load patterns shape the specific needs and challenges of each archetype. For instance, urban areas may see higher demand diversity from clustered EV charging, while rural areas may face voltage management challenges from dispersed solar PV and lower diversity in heat pump usage during winter peaks. These localised insights are necessary to inform targeted solutions for each network type influencing the selection of conventional upgrades and smart solutions. Ultimately, the case study work underscores the need for tailored strategies to understand local diversity in LCT deployment, ensuring sufficient capacity as LCT adoption continues to grow..

Safer, Stronger, Smarter Networks

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