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Network investment costs of the domestic heat and transport transition in Scotland

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1 Executive summary

The Scottish Government has ambitious targets to achieve net zero, which will require the uptake of low-carbon technologies. Targets include:

- **principal emissions reduction:** 68% reduction in emissions from buildings by 2030 against a 2020 baseline as set out in the Climate Change Plan Update.
- Aiming for over **1 million homes** currently using mains gas to **convert to zero emissions heating by 2030**, a non-statutory target stated in the Heat in Building Strategy.

The heat and transport transition will require reinforcement of electricity distribution networks. Our report assesses network investment costs for domestic heat transition and transport decarbonisation using different rates of adoption of low-carbon technologies. We also assess likely network investment recovery costs and potential impacts on Scottish consumer bills.

1.1 Research methodology

We used Low Carbon Technologies Planner software to inform network reinforcement requirements and calculated associated costs for different future scenarios of heat transition and transport decarbonisation.

Scenarios for uptake of heat pumps and electric vehicles

We defined heat pump and electric vehicle uptake scenarios using scenarios from Distribution Future Energy Scenarios: Steady Progression, System Transformation, Consumer Transformation and Leading the Way.

Network solutions

We explored feasible solutions that can be used to resolve network issues from the uptake of heat pumps and electric vehicles. Associated costs were used to determine the optimal investment profile for representative networks.

To alleviate network constraints, we modelled two sets of solutions:

- **Infrastructure reinforcement solutions** that increase network capacity but do not alter demand. Conventional examples of this are uprating transformers, splitting feeders, reconductoring overhead lines or using higher cross-section sizes for underground cables. Modern solutions can also include smart grid solutions using digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet end user demands.

- **Flexibility solutions** that reduce peak consumption, either by reducing energy consumption or by displacing it from peak times. Examples of flexibility services include demand-side response, energy storage systems, time-of-use tariffs, hybrid heat pumps and smart electric vehicle charging schemes.

1.2 Key findings

The research found that:

- Reinforcing distribution networks across Scotland to accommodate uptake of domestic heat pumps and electric vehicles to 2050 would cost between £1.59bn and £2.48bn discounted capex without flexibility options, or between £1.10bn and £1.60bn discounted capex with flexibility options.

- Current network business plans offer lower investment than some scenarios but are comparable to the Distribution Future Energy Scenarios 'System Transformation' scenario.

- Network investment recovery costs are primarily based on unit consumption. Properties with higher electricity usage will contribute a greater proportion towards network reinforcement costs than properties with lower electricity usage.

- Flexibility solutions have potential to reduce network investment recovery costs by a third as this defers the need for reinforcement.

- Based on the modelled scenarios, maximum annual recovery costs in Scotland range between £7.20 and £23.35 per household, for the full investment timeline until 2050. This is based on a high electricity demand and low network flexibility scenario. For a lower cost investment scenario that includes network flexibility, the cost recovery range is reduced to between £3.75 and £11.81 per household.

- In the short term, during the 2023-2028 charging period, modelled recovery cost per household ranged from £0.82 to £6.07 per year. The variation depends upon region, deployment of network flexibility solutions and consumers' uptake of low carbon technologies.

- Ultimately, the exact translation of recovery costs for these network investments onto consumer bills will depend on the policy decisions by Ofgem. Ofgem’s final determination for the 2023-2028 charging period asserts that there will not be increases to consumer bills associated with decarbonisation.
- The calculated recovery costs may therefore not be reflected directly in increased consumer bills due to other factors, such as expiration of previous network investment recovery costs and regulator policy decisions.

Contents

2 Glossary

ASHP	Air source Heat Pump
AV	Autonomous Vehicle
CT	Consumer Transformation. Scenario of FES and DFES
DFES	Distribution Future Energy Scenarios produced by all DNOs in the UK
DNO	Distribution Network operator
DUoS	Ofgem's acronym for Distribution Use of System
EHV	Extra High Voltage
ENA	Energy Networks Association
ESO	Electricity System Operator
EV	Electric Vehicles
FES	Future Energy Scenarios produced by National Grid ESO
HP	Heat Pumps
HV	High Voltage
LCT	Low Carbon Technologies
LtW	Leading the Way. Scenario of FES and DFES
LV	Low Voltage
RIIO-ED2	Second price control for the electricity distribution networks. This price control runs for five years (2023-2028). This stands for Revenues = Innovation + Incentives + Outputs for Electricity Distribution 2
SP	Steady Progression. Scenario of FES and DFES
SPEN	Scottish Power Energy Networks. DNO in the south of Scotland
SSEN	Scottish and Southern Electricity Networks. DNO in the north of Scotland
ST	System Transformation. Scenario of FES and DFES
V2G	Vehicle to Grid

3 Introduction

The Scottish Government is committed to delivering a just transition and to end Scotland's contribution to climate change in a fair way. Ambitious net zero targets include decarbonisation of heat, which will likely require reinforcement of electricity distribution networks (to enable heat pump deployment).

This report assesses the costs of the heat transition in Scotland considering investments required to upgrade electricity distribution networks, and how these costs would be recovered e.g. through consumer bills. The impact of both heat and transport decarbonisation and how different rates of adoption of low carbon technologies will impact network costs are considered.

Distribution Future Energy Scenarios (DFES) produced by the Scottish Distribution Network Operators (DNOs) Scottish and Southern Electricity networks (SSEN) (Scottish and Southern Electricity Networks, 2021) and Scottish Power Energy Networks (SPEN) (Scottish Power Energy Networks, 2021) were used to assess the impact of different rates of adoption of low carbon technologies, such as heat pumps, on the electricity distribution network. This analysis was refined through regular engagement with the DNOs and the Scottish Government. The outcomes of the analysis provided distribution network investment costs for different scenarios. This was then used to determine network investment recovery costs and how consumer bills could be affected. Network investment recovery costs are the charges required to pay for investments in the network as a result of heat and transport decarbonisation that could be passed on to bill payers. Consumer archetypes were used to represent groups of people with different socio-economic characteristics, which provided information on potential impact on consumer bills for each group.

This report includes three main sections:

- **Research considerations**: The methodology used to calculate network investments is described. The scenarios are described in conjunction with the Scottish Government's decarbonisation targets. Additionally, the software tool is described, including how power networks and reinforcement or flexibility solutions are represented.
- **Network investment costs**: High-level analysis of network investment costs across scenarios for the whole of Scotland is presented in this section. There is also a breakdown of investment at network level, a timeline of investments leading up to 2050, and a comparison of near-term investment against RIIO-ED2 business plans (Scottish and Southern Electricity Networks, 2021), (Scottish Power Energy Networks, 2021) created for each DNO licensed area in Scotland.
- **Network charging and consumer bills**: Overall investments are translated to network charging for individual households, using a methodology which shares assumptions with the Common Distribution Charging Methodology (Ofgem, 2009). Additionally, qualitative analysis of alternative charging mechanisms is presented.

4 Research Considerations

This section provides an overview of the research methodology, scenarios, representation of networks and network solutions that have been considered in this project.

4.1 Research methodology: the LCT Planner

Designing the future electricity network is a challenging task that involves analysing a large and complex set of future predictions in aspects such as heating, transport, efficiency, development of new technologies and many more. DNOs in the UK perform this task yearly so that they can proactively prepare for the future changes in their respective networks.

The LCT (Low Carbon Technologies) Planner is a software tool used to inform network reinforcement requirements and associated costs of large-scale electricity distribution networks considering the uptake of LCTs such as Electric Vehicles (EVs) and Heat Pumps (HPs), whilst minimising the cost to consumers. This is achieved by considering a range of inputs, including future scenarios, network reference models and network solutions, fed into a network modelling tool that produces investment profiles and operating envelopes as outputs. Table 1 outlines the high-level description of the tool. In this chapter we will explain the inputs for our research.

<table>
<tr><th>Inputs</th><th>Processes</th><th>Outputs</th></tr>
<tr><td>1. Forward looking scenarios for the growth of low carbon technologies
Low carbon technologies: solar photovoltaic, electric vehicles, battery storage, heat pumps, others.</td><td rowspan="3">4. Network Modelling Tool “Strategic Electricity Distribution Network Development and Operation”
How much future network investment is required to integrate LCTs in a techno-economic efficient manner
What solutions (i.e. conventional, smart grid and distributed flexibility) to deploy in the future network to integrate LCTs
Where in the network to deploy the solutions
When to invest in the network (i.e. network investment expenditure profile)</td><td>5. Network investment profile
Network augmentation expenditure profile: capital, operational and total expenditures (both gross and discounted)
Cost-estimation of the deployment of solutions to resolve network constraints</td></tr>
<tr><td>2. Parametric reference network model
Networks: representation of real electricity distribution networks</td><td rowspan="2">6. Network operating envelopes
Identification of network constraints, their magnitude, location and likely timing of occurrence
Constraints: thermal due to overloading of circuits; voltage due to voltage rise or drop; and fault level of circuits</td></tr>
<tr><td>3. Network and non-network solutions
Solutions: conventional network, smart grid and distributed flexibility solutions</td></tr>
</table>

Table 1 High level description of the methodology underpinning the LCT Planner

4.2 Scenarios

The electricity distribution in Scotland is covered by two DNOs: SSEN and SPEN. SSEN manages the distribution network in the north of Scotland and SPEN manages the south. Each produce a yearly forecast for electricity generation and consumption for each of their licence areas over the next 30 years. The forecast is part of the DFES used by the authors as an input to the Cost Benefit Analysis that underpins the LCT Planner tool calculations.

DNOs start their DFES production by analysing the yearly Future Energy Scenario (FES) produced by National Grid ESO (National Grid ESO, 2021) for the whole of GB, which includes an overall analysis for all energy vectors. The FES then includes a set of plausible future predictions considering policy targets outlined by the UK Government, the current and future behaviour of the market, the condition of the national energy grid and other factors. Figure 1 presents each of the FES scenarios in terms of speed of decarbonisation and societal change.

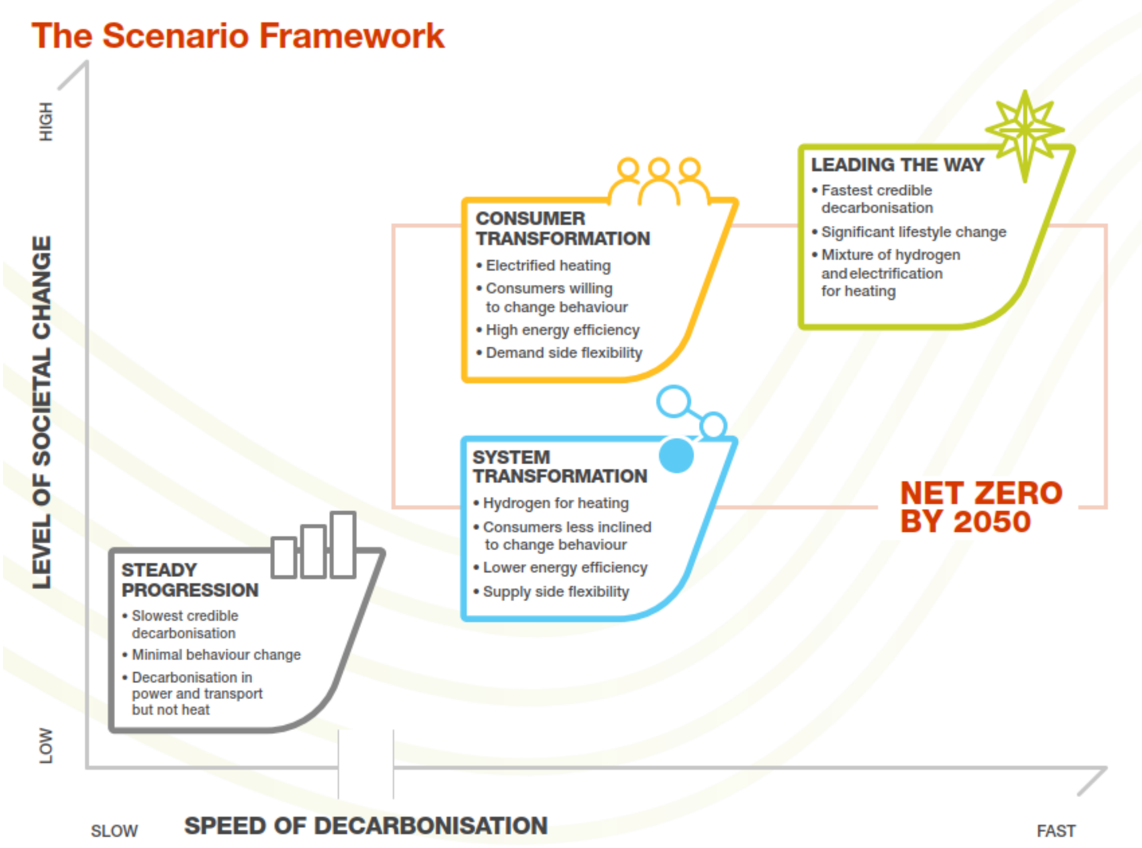

Figure 1 Comparison of all FES and DFES scenarios in terms of societal change and speed of decarbonisation. Source: FES 2021 (National Grid ESO, 2021)

DFES provide forecast information for several technologies and energy vectors for each of the DNOs. To reflect Government strategies and targets for decarbonisation of heat and transport, this report focuses on two major technologies:

- Heat pumps (HPs)
- Electric vehicles (EVs)

The sections below provide general information on overall uptake projections for these technologies in Scotland and how targets set by the Scottish Government are mapped. Furthermore, a high-level description of the networks and flexibility solutions used for this analysis is provided.

4.3 Scottish Government targets

Several policies have been outlined by the Scottish Government with the objective of delivering on climate change targets. These policies cover a broad spectrum of social, economic, environmental, and technological pathways to meet the statutory target of net zero by 2045. The policies of interest for this specific study are related to low-carbon heating and transport.

The Heat in Buildings Strategy (Scottish Government, 2021) outlines the following for low-carbon heating:

> "To meet our net zero target, by 2045 all homes and buildings in Scotland must have significantly reduced their energy use, and almost all must be using a zero-emissions heating system."
>
> "In order to meet our interim climate targets and ensure long-term delivery of our net zero objectives, by 2030 the vast majority of the 170,000 off-gas homes that currently use high emissions oil, LPG, and solid fuels, as well as at least 1 million homes currently using mains gas, must convert to zero emissions heating."
>
> "As set out in the 2021 Programme for Government, to maintain progress towards our statutory emission reduction targets, zero emissions heat installations must scale up to provide a total of at least 124,000 systems installed between 2021 and 2026. The installation rate will need to peak at over 200,000 new systems per annum in the late-2020s – which is above the natural replacement rate for boilers."
>
> "We will require new buildings to use zero direct emissions heating, and to feature high levels of fabric energy efficiency to reduce overall heat demand so that they do not need to be retrofitted in the future. This requirement will apply from 2024 for building warrant applications for new homes."
>
> The updated climate change plan 2018-2032 (Scottish Government, 2020) indicates the following for low-carbon transport: "Phase out the need for petrol and diesel cars and vans in Scotland by 2030."

The modelling undertaken for this study will be reflective of the decarbonisation of heating and targets outlined in the Heat in Buildings Strategy.

4.4 Scenarios for the uptake of Heat Pumps and Electric Vehicles in Scotland

SPEN and SSEN have created their own DFES detailing different future realisations and how these realisations could impact the future operation of the network. Each DNO defines their DFES based on information from National Grid ESO Future Energy Scenarios, interactions with different stakeholders and their local information regarding their distribution networks. Information related to the interaction that each of the DNOs had with their stakeholders with emphasis on heat pumps and electric vehicles is presented in Appendix A. The DFES is then defined by four scenarios, i.e. Steady Progression (SP), System Transformation (ST), Consumer Transformation (CT), and Leading the Way (LtW). The assumptions for all the scenarios are presented in Appendix A. The results from the SP scenario are included in the appendices of this report for reference. They are not analysed in detail given that the scenario represents business as usual with limited action towards achieving Scottish Government targets. This study is being used to determine the impact that proactive actions toward net zero will have on energy networks in the form of investment and how those costs could be recovered from consumers. Therefore, the SP scenario does not fulfil the criteria to be fully analysed in this section.

Figure 2 and Figure 3 have been created using information from each of the DFES scenarios in Appendix A. These figures present the total uptake of heat pumps and electric vehicles in Scotland up to 2050. The target of 1 million homes using zero emission heating by 2030 is achieved only in the LtW scenario, whilst in CT that target is achieved in 2033 and in the ST scenario only in 2041. LtW and CT meet the Scottish Government target of almost all homes and buildings in Scotland using a zero-emissions heating system, however, ST does not meet the target. All scenarios meet the target of a total of at least 124,000 zero-emissions heating systems installed between 2021 and 2026. Although the rate of 200,000 new heating systems per annum in the late-2020s is not met by any of the scenarios, the previous 2045 target is met by LtW and CT as mentioned before.

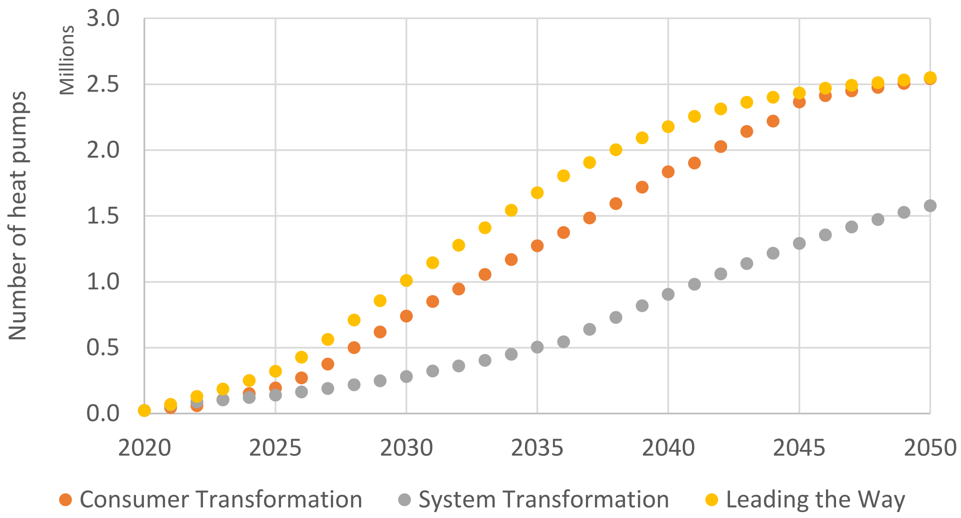

Figure 2 Scenarios for heat pumps uptake in Scotland

The total uptake of electric vehicles has a growing trend for all scenarios from the 2020s to mid-2030s followed by a downward trend at the end of the planning horizon. The downward trend from the late 2030s is the most particular aspect of the uptake. This is caused by a change in consumer behaviours where an increase in public transport use, vehicle sharing, and autonomous vehicles result in an overall decrease of electric vehicles. This is mentioned in the stakeholder feedback and assumptions for the scenarios as set out in Appendix A. The target to phase out the need for petrol and diesel cars and vans in Scotland by 2030 is met by an increased uptake of electric vehicles in all scenarios from 2030 or before as shown in the Figure 3.

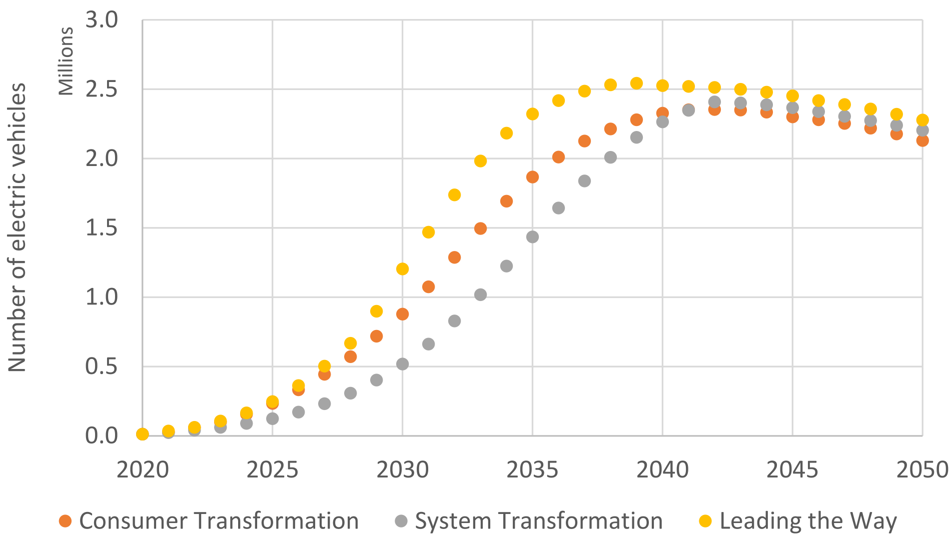

Figure 3 Scenarios for Electric Vehicle uptake in Scotland

4.5 Networks

The LCT Planner tool is capable of allocating LCT penetration levels not only at global or regional levels, but also at the network level. The range of network elements/assets accounted for is shown in in Figure 4.

In each of these categories, representative network elements were developed by analysing datasets from the existing networks of each DNO involved in the original Energy Networks Association (ENA) working group. Full distribution network models were provided by the DNOs in a variety of file formats, each of which was analysed using bespoke data processing techniques to produce a consistent dataset with which to create the representative feeder[1] models.

For each representative feeder, two kinds of loadability are considered:

- Thermal Loadability: the maximum load which can be delivered without exceeding any circuit section ratings but ignoring node voltages.
- Voltage Loadability: the maximum load which can be delivered without exceeding the voltage limits at any node but ignoring the loading on the circuit sections.
- The increased loadability available after various network reinforcement options are considered to give the solution base for the LCT Planner tool.

In this context, feeders are overhead lines and underground cables: Extra High Voltage (EHV) at 33kV, High Voltage (HV) at 11kV and Low Voltage (LV) at up to 1kV. Substations refer to all

[1] Representative feeders are proxy representations of a far larger number of real feeders in a distribution network. Several real feeders (sharing very similar characteristics) can be represented by a single representative feeder and therefore require similar investment solutions. The representative feeders used in this project were developed in an Energy Networks Association project in 2021 for which DNO validation was a requirement, acknowledged by all UK DNOs. “Representative networks”, “representative network elements”, “representative feeder models” and “representative feeder” are used in this report and refer to the same concept as set out above.

assets used to reduce voltage levels and then connect EHV, HV and LV feeders. More detailed information about the networks can be found in Appendix B.

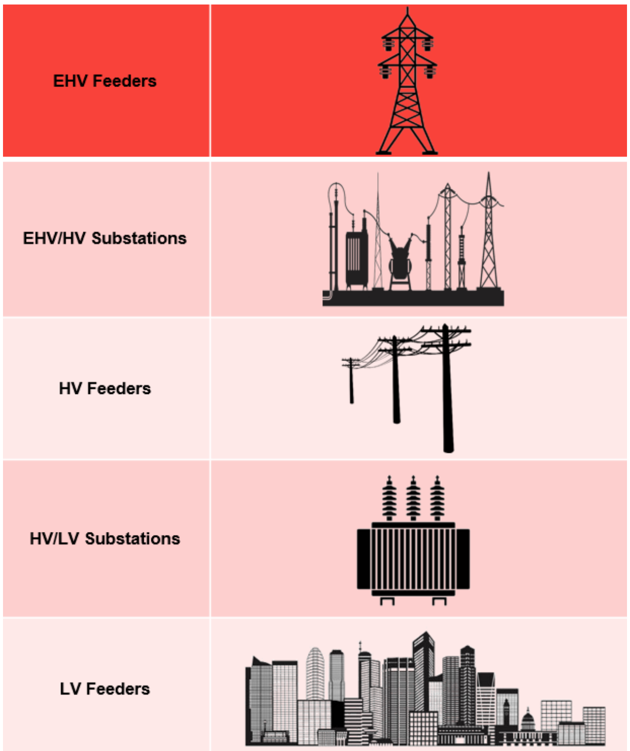

Figure 4 Illustrative definition of network levels

4.6 Network Solutions

It is necessary to explore all feasible solutions that can be used to resolve the identified network issues. The remedial impact of these solutions and their associated costs are then used to determine the optimal investment profile for a representative network. To alleviate network thermal overloads and voltage exceedances, two sets of solutions have been modelled in the LCT Planner tool – ‘Infrastructure reinforcement solutions’ and ‘Flexibility solutions’.

Infrastructure reinforcement solutions: solutions which increase network capacity but do not alter demand. Conventional examples of this are uprating transformers, splitting feeders, reconductoring overhead lines or using higher cross-section sizes for underground cables. Modern solutions can also include smart grid solutions using digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet end user demands.

Flexibility solutions: solutions which reduce peak consumption, either reducing energy consumption or by displacing it from peak times. This category of solutions is under continuous development where new opportunities are coming into the market gradually. Demand side response, energy storage systems, time of use tariffs, hybrid heat pumps and smart electric vehicle charging schemes are examples of flexibility services. National Grid ESO created a program for Winter 2022/2023 to allow consumers to participate in demand flexibility services and although this was an exceptional circumstance caused by the energy crisis in 2022, this shows that flexibility services can be applied at widescale.

The incremental loadability benefits of network solutions were determined by modelling in a power system analysis tool, PowerFactory.

4.7 Research Limitations

Some details regarding domestic connections may not be captured and therefore there may be residual mismatches between the investment cost presented in this study and the real investment cost considering the operational network.

Heating and non-heating electrification (e.g., EV) for industrial and commercial sectors are not considered in this study, since the objective is to determine the cost that domestic consumer will need to pay to upgrade the future electricity distribution network that will allow decarbonising the energy system. Therefore, the investment figures for high and extra high voltage assets could be greater than the figures presented in the following sections. This study captures costs of investment on electricity distribution networks and doesn't consider investment costs on Electricity Transmission networks nor investment costs with other energy vectors infrastructure, such as gas and hydrogen.

5 Network investment costs

This section describes the initial findings for network investment expenditure for the three different scenarios (CT, ST and LtW) in Scotland with the networks and solutions described in the previous sections.

A discount rate throughout the planning horizon of 3.5% was considered for the analysis, in line with HM Treasury guidance from The Green Book (HM Treasury, 2022) with 2022 as base year.

5.1 Analysis for Scotland

An analysis for each of the DNOs' electricity networks, i.e., for SSEN and SPEN, was performed. This identified investment costs that would allow economical and technically feasible operation of the distribution system considering an increase in electricity demand from heat pumps and electric vehicles. The results of the analysis were then combined to produce a single investment figure for Scotland. The investment summary for all scenarios is then summarised in Table 2. The results for each of the DNOs can be found in Appendix C.

LtW is the only scenario that guarantees that all Scottish Government targets are met. However, this ambitious plan requires the highest level of investment among all scenarios. If the measures to incorporate flexibility in the electricity system are not successful, then a discounted cost of £2,477.4 million up to 2050 is expected to upgrade the network so that it can accommodate the total electricity demand. However, if flexibility solutions are fully implemented then the cost is £1,596.4 million. Flexibility for LtW reduces the overall cost of investment by 35%. CT and ST see reductions of around 28% and 30% respectively when flexibility solutions are implemented.

	Flexibility	Consumer Transformation	Leading the Way	System Transformation
Total Investment (£m)	No	2,158.7	2,477.4	1,585.6
	Yes	1,544.6	1,596.4	1,096.9

Table 2 Summary of discounted costs for all scenarios in Scotland for investment period of 2020-2050

The overall investment figures presented above can be split into their components to identify which parts of the electricity network will require most investment compared to others. This investment breakdown is presented in Figure 5 for all scenarios with and without flexibility. It can be seen that most of the investment cost is to upgrade low voltage components, i.e., substations and feeders, in all scenarios. High voltage components are the next greatest cost, and extra high voltage are the smallest proportion. These results can be explained by the large difference in the number of components between low, high and extra high voltage. Upgrading a single low voltage feeder or substation is always cheaper than upgrading a high voltage and/or extra high voltage one. However, the number of LV feeders (75,955) and substations in Scotland greatly outnumber the HV and EHV feeders (4,227 and 528 respectively) and substations. The number of high voltage feeders and substations is greater than the number of extra high voltage feeders and substations.

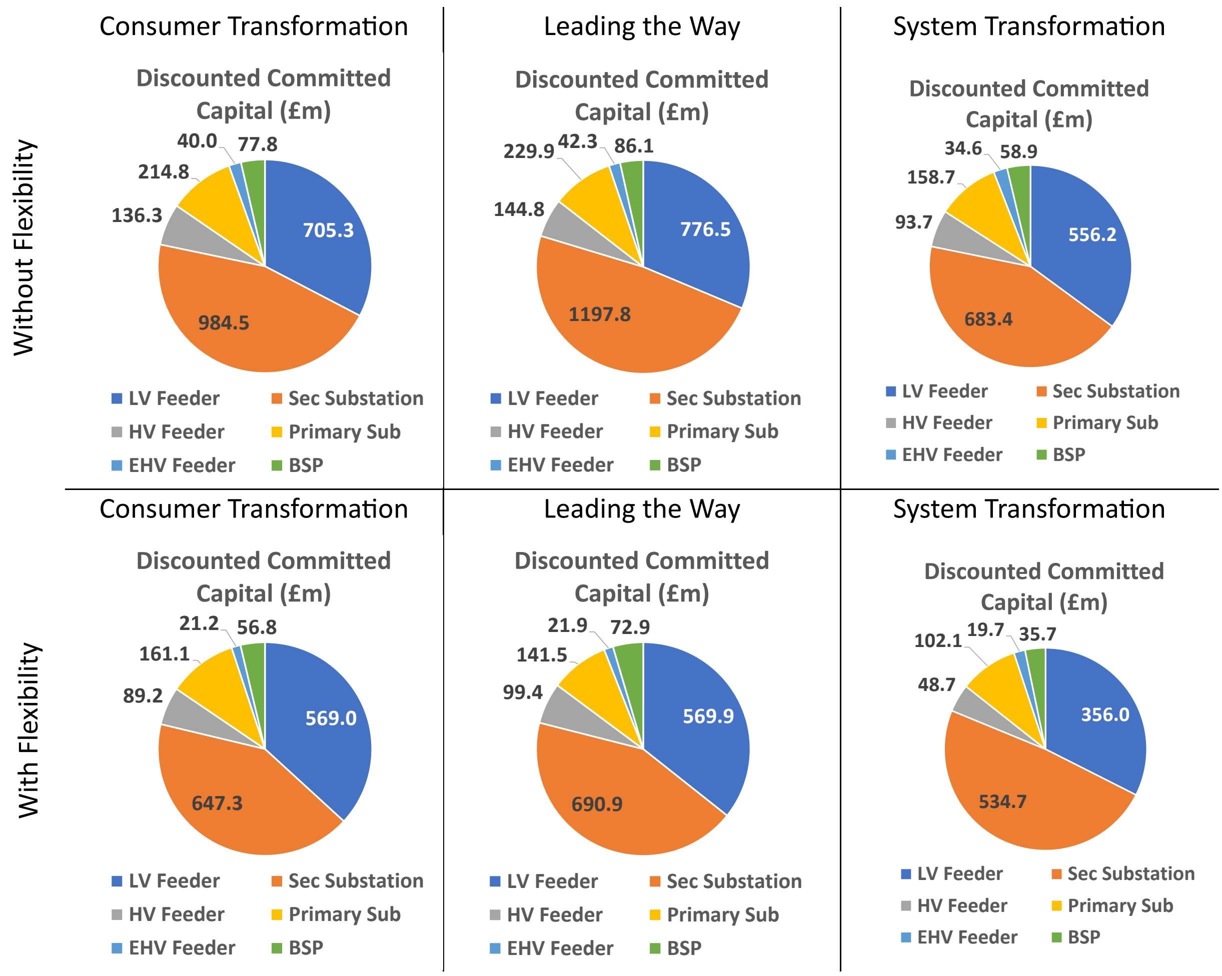

Figure 5 Discounted committed capital for all scenarios in Scotland to 2050

Figure 6 presents the cumulative discounted investment for all scenarios, which defines an investment envelope for the future cost of upgrading the distribution network in Scotland. This shows that the total investment for the LtW scenario without flexibility represents the highest investment throughout the years and System Transformation with flexibility represents the lowest investment cost.

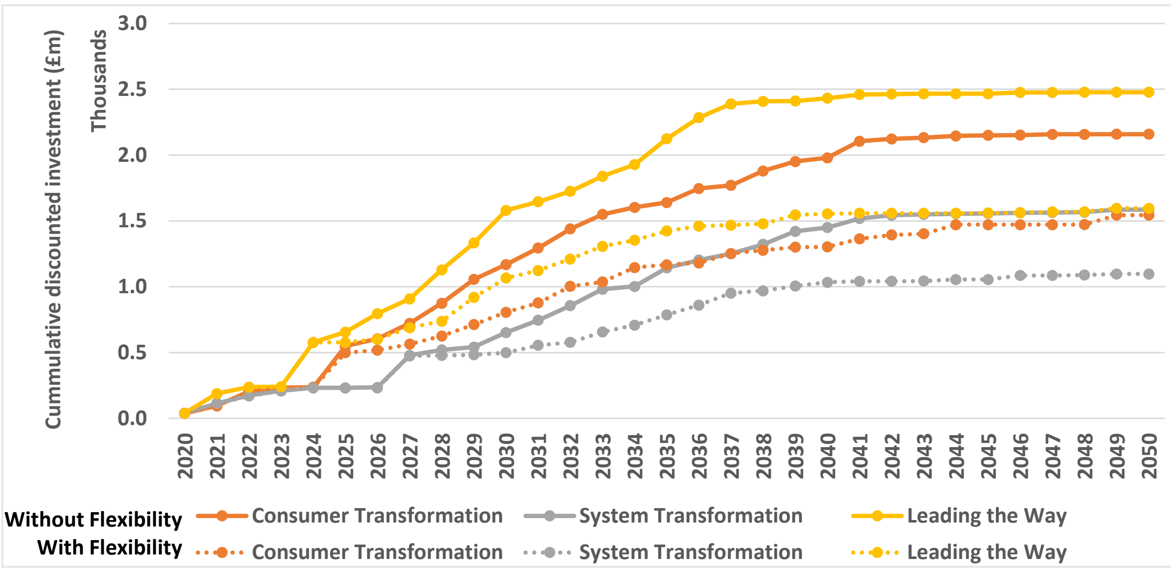

Figure 6 Cumulative discounted investment cost for all scenarios in Scotland

5.2 Comparison with Networks' Business Plans (RIIO-ED2)

Figure 7 shows the modelled investment from the RIIO-ED2 portion (2023-28) of each scenario timeline versus the RIIO-ED2 planned investment for load-related infrastructure builds, published by SSEN and SPEN. The planned investments presented are taken from the final business plans of each network operator and adjusted based upon the final determinations agreed with Ofgem (Ofgem, 2022).

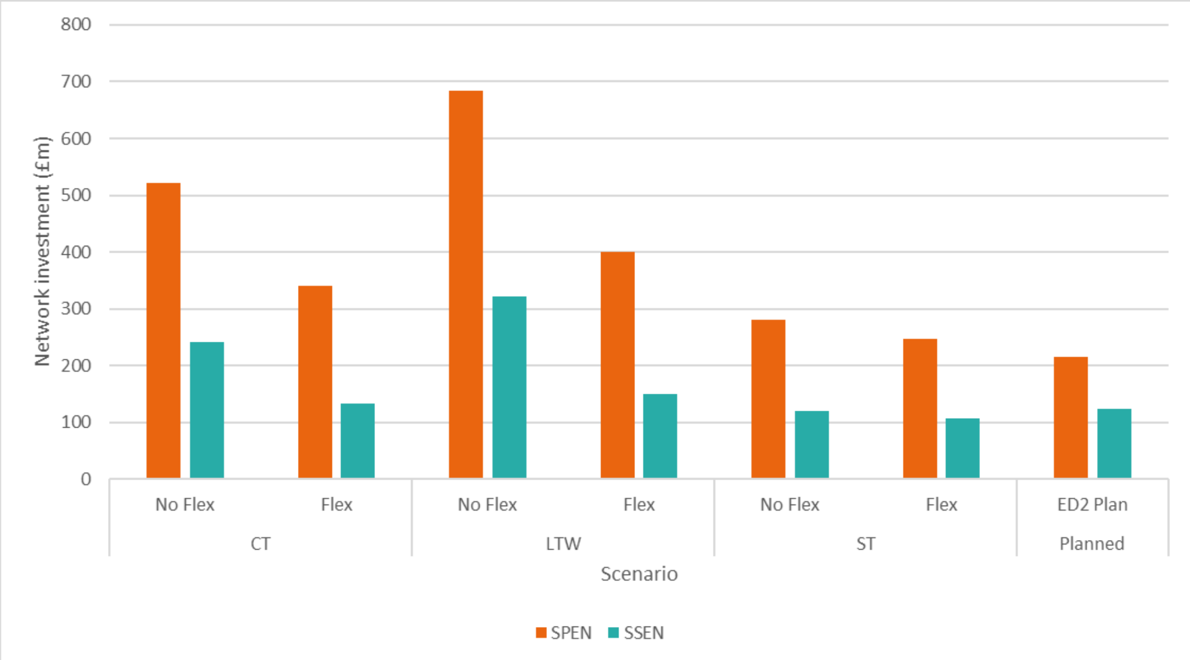

Figure 7 Comparison of ED2 timeline investment for scenarios and published ED2 business plans

Modelled investment and planned expenditures can be compared to provide insights into the scale of investment required compared with planned investment in the next five years. However, modelled investments are subject to various inputs, such as headroom and demand forecasts, associated with each DFES scenario as well as a relatively simple assumption to reinforce at time of requirement. In contrast, the planned expenditure published by the DNOs is subject to many other influences not captured by modelling, such as ability to defer through active network management (ANM), local stakeholder requirements and project financing. It is therefore difficult for the figures to directly agree.

Scenarios without flexibility

- The published RIIO-ED2 plans have a lower investment profile than modelled CT and LtW scenarios, across both DNO network regions.
- The modelled ST investment profile is more comparable to both DNO investment plans, albeit with a shortfall in the SPEN region.

Scenarios with flexibility

- Flexibility options allow for lower modelled network investments, and therefore narrow the gap between published business plans and each modelled scenario.

- CT and LtW modelled investments are comparable to published plans for the SSEN region, but still represent a larger investment for the SPEN region.
- ST modelled investment is comparable in cost for both regions when flexibility options are introduced. This scenario tends to feature a more back-heavy investment profile than the other scenarios, and therefore investments across the RIIO-ED2 period are less affected by introduction of flexibility options.

The modelled investments in both the CT and LtW scenarios are heavily front-loaded, as dictated by the rapid pace of change assumed within the uptake profiles of each. However, real-life investments are more likely to be consistent between regulatory periods, so we compared average yearly investments from modelled scenarios with the published business plans.

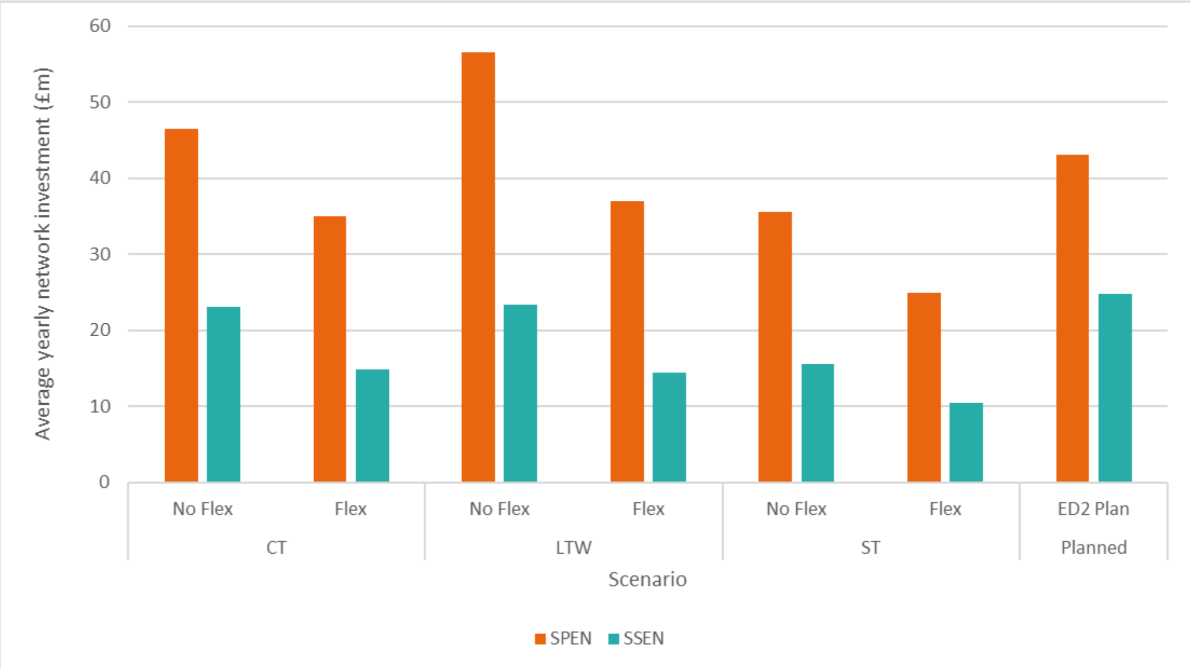

Figure 8 Comparison of yearly average spend across full scenario timelines and ED2 business plans

Figure 8 shows the yearly average investment for each full scenario timeline (2020-2050), with comparative figures for each RIIO-ED2 business plan average yearly spend (2023-2028). The SSEN published business plan has a higher yearly average investment than any of the investment profiles associated with the scenarios in this study. For the SPEN region only two scenarios have a higher yearly average modelled investment compared to the published business plan (LtW and CT without flexibility options).

These comparisons demonstrate the reason for shortfalls within the RIIO-ED2 period demonstrated in Figure 7. Scenarios such as CT and LtW are typically front-heavy in terms of investment, due to the associated demand curves which must be met, with the bulk of investment made before 2040. Therefore, the published business plans for RIIO-ED2 appear to underinvest when compared to the modelled investment profiles associated with these scenarios, despite representing a similar average spend against the whole timeline.

There are multiple differences between our modelling assumptions and the rationale behind funding of network investments in real-life. As an example, the DNOs may be able to obtain additional funding through uncertainty mechanisms during the price control period to manage increases in load related reinforcement. These scenarios represent only one subset of pathways over which the energy system could evolve to 2050 and cannot consider a variety of local factors which will influence decision-making.

6 Network charging and consumer bills

In this section, network investment costs are translated into recovery costs which could be levied on consumer bills.

6.1 Current network charging arrangements

6.1.1 Overview

The current methodology for setting network charges for domestic customers is common across all DNOs and has the following key characteristics:

- Are based on a representative model (known as the "500MW model") that reflects the network configuration and costs in each DNO region.
- Are based on "downstream only" assumptions, which means that charges relate to the voltage of connection and higher network levels only (e.g. HV charges do not include any reinforcement costs relating to the LV network).
- Differ by customer category but are common across a DNO region (e.g. all domestic customers in SSEN's North of Scotland region face the same charges).
- Have consumption-based unit rates (red, amber, green) and a fixed charge component.
- Are charged to suppliers on an aggregate basis for all the supplier's customers within each category. The supplier then chooses how Distribution Use of System (DUoS) costs are charged to their customers, which will depend on the tariff they have (e.g. if a customer is on a single unit rate tariff, then DUoS costs would simply make up a portion of the total unit rate).

Note that charges for customers in the North of Scotland are subsidised through two government schemes (Department for Business, Energy & Industrial Strategy, 2022) to protect them from facing higher charges than in other DNO regions, due to remoteness, geography, and lower customer density. These schemes are:

- The Hydro Benefit Scheme, which protects domestic and non-domestic consumers from high costs of distributing electricity in the North of Scotland by bringing costs down to a level comparable with the next highest cost region, subsidising the additional costs across other licensed areas.
- The Common Tariff Obligation, which ensures electricity suppliers in the North of Scotland are not able to charge comparable domestic consumers different prices solely on the basis of their location within the region.

The methodology is subject to "open governance", which means that any relevant party can propose a modification, which will be assessed by industry and, in most cases, sent to Ofgem for approval.

6.1.2 Implications for bills

The current methodology means that, although the unit and fixed rates might increase, due to electrification of heat (and transport), any difference in how they impact customer bills will be determined by each customer's consumption levels.

It is also important to note that there is no direct link between the components that make up a DNO's allowed revenue (the total amount of revenue they can recover through network charges) and how costs are reflected in network charges. For example, a need for additional LV network reinforcement in a specific area of the DNO network, due to heat pumps being installed, does not necessarily mean that there will be an equivalent increase in LV related costs under the charging methodology.

6.2 Methodology for estimating network charges

6.2.1 Distribution of costs

The LCT tool was used to obtain network reinforcement costs for 3 DFES scenarios, considering both flexibility and non-flexibility optionality, for the SPEN and SSEN regions in Scotland. The aim of this section is to translate this investment into recovery costs which could be levied on domestic electricity bills.

As explained in the previous section, the current charging methodology requires a series of inputs from the DNOs, which are not readily available. Additionally, the methodology does not allow for flexible scenario modelling and does not produce charges that recognise differences between domestic customer groups.

However, there are general principles that underpin the methodology and are likely to continue, which means it is possible to estimate how changes in network reinforcement under different scenarios could impact on domestic customers. An internal version of the charging methodology was developed to achieve this. This shares key assumptions with the Common Distribution Charging Methodology, albeit with simplifications due to availability of data and a focus on the domestic consumer. The detail of the methodology adopted is outlined here:

Step 1: Split investment costs by network level and define appropriate splits across sectors

Different network levels serve different customer demand types, and this is reflected in customers' bills. For this part of the methodology, the process was as follows:

- Split overall investment costs based on network level (LV, LV/HV, HV, HV/EHV, EHV), as per the outputs from the LCT planner.
- Assign the full cost of the LV network level reinforcement to domestic consumers, as LV networks are likely to serve small-scale demand in a downstream only network.

- Use the "network use factors" set out in the charging methodology[2] to define a proportion of investment at higher network levels that should be levied on domestic properties.
- Add together the applicable costs from each network level to create an overall investment recovery cost that may be levied on domestic consumers.

Step 2: Define sub-archetypes of domestic properties based on technology uptake within future scenarios

Households which adopt low carbon technologies (i.e. heat pumps and electric vehicles) will consume greater quantities of electricity per annum. Contribution to network reinforcement recovery is based on unit consumption, it is therefore fair that these types of houses will contribute a higher proportion towards these recovery costs than homes which do not adopt low carbon technologies. Distinctions are therefore required within the methodology created to distinguish between homes with different usage profiles. For this part of the methodology, consumption profiles were defined for sub-archetypes as follows:

- Split existing archetypes within the LCT tool into sub-archetypes, based on the uptake percentages of low carbon technologies across the scenarios.
- Define consumption profiles of each sub-archetype, based on usage of small-power and low carbon technologies where applicable.

Step 3: Define a split of investment costs across sub-archetypes based on annual usage characteristics

The current methodology for network charging is based on unit rates and therefore heavily linked to consumption. Ofgem does not consider locational charging within DNO regions and does not use seasonal charging rates (e.g. summer and winter tariffs). We proportionally split the investment costs between sub-archetypes based on the annual consumption within each defined group across a DNO region.

The number of homes within each group are then considered to create an annual recovery cost for a typical home within each sub-archetype.

LCT Planner Archetypes

The LCT Planner tool contains numerous domestic dwelling archetypes, which represent different power consumption profiles across the overall housing sector. These are taken from the Experian's Mosaic UK customer segmentation (Experian, 2013), created during the Customer Led-Network Revolution (CLNR) project.

More detail about these archetypes, along with alternative archetypes used previously by ClimateXChange, are provided in Appendix D. A subset of six archetypes were required for this work, which are outlined in Table 3.

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[2] Network use factors determine the extent that costs at each voltage level are recoverable from which charges. They are described in the original manual for the underlying model (Energy Networks Association, 2012)

Experian groups	Description	Nomenclature
Alpha Territory	People with substantial wealth who live in the most sought-after neighbourhoods	A
Rural Solitude	Residents of small villages and isolated homes where farming and tourism are economic mainstays	C
Small Town Diversity	Residents of small and medium-size towns who have strong roots in their local community	D
Suburban Mindsets	Maturing families on mid-range incomes living a moderate lifestyle in suburban semis	F
New Homemakers	Young singles and couples in small modern starter homes	H
Terraced Melting Pot	Lower income workers, mostly young, living in inner urban terraces, including some areas of high diversity	N

Table 3 Breakdown of Experian archetypes used by the LCT Planner Tool for Scotland

6.2.2 Charging periods

One factor to consider is the investment framework which DNOs must work within (i.e. RIIO-ED2). Network investments are planned and carried out by DNOs across fixed term price control periods. Therefore, a more realistic assessment of investment profile is to tranche the year-by-year investment profiles created within the LCT Planner into discrete funding periods.

The investments presented within this study are therefore divided into a series of discrete tranches, replicating these planning periods. With only the RIIO-ED2 period currently being defined (2023-28), the authors have taken a position that the following periods will also each be five years in duration, directly following on from the previous one (RIIO-ED3, RIIO-ED4, RIIO-ED5 and RIIO-ED6).

The outputs of the LCT planner tool were also modified to fit the narrative of these charging periods. The unaltered outputs of the LCT planner tend to have large variations in investment between consecutive years. This is partially due to the tool considering that all work is completed within the year in which it is required, with no lead time, and due to uniform headroom assumptions for typical feeders within a particular type. Neither of these assumptions is likely to be reflected in reality, with DNOs spreading investment across five-year periods to manage both resources and also target those assets which are under greatest strain early within the charging period.

Taking these factors into account, the reinforcement solution outputs of the LCT Planner tool modelling were smoothed in preparation for analysis of cost recovery/bill impact. This was accomplished by evenly spreading each investment over a five-year period, effectively beginning works four years before required by the LCT planner. This five-year smoothing is intended to replicate the investment profiles which are more likely when considering the current investment framework used by Ofgem and DNOs.

6.3 Cost recovery and consumer bill impacts

The discounted recovery costs for homes without low carbon technologies, and those with both heat pumps and electric vehicles, are shown in this section. Other sub-archetypes, where only one type of low carbon technology is deployed, will have cost impacts which sit between these in scale. The costs shown represent the anticipated cost impacts due to the network investments modelled in these scenarios, without the influence of policy mechanisms.

Figure 9 and Figure 10 show discounted recovery costs for those households which do not adopt electric vehicles or heat pumps as part of these scenarios. As explained within Section 6.2, households with higher consumption will face a larger cost impact from reinforcement, and so Alpha Territory (A) and Small Town Diversity (D) households consistently have higher modelled recovery costs, regardless of the scenario considered.

Households within the SSEN licence area of North of Scotland also have higher modelled billing impacts than households in the SPEN licence area in Scotland. This is a consequence of the geography of the region, which requires networks to be built in more challenging locations, serving sparser population centres. This is reflected within the network topologies of each region characterised within the LCT Planner. As a result, it is expected that network reinforcement in the SSEN region will be more expensive than an equivalent portfolio of work in the SPEN region. However, the Hydro Benefit Scheme will likely help to mitigate some impact on customers and reduce some recovery costs on the bills of these households.

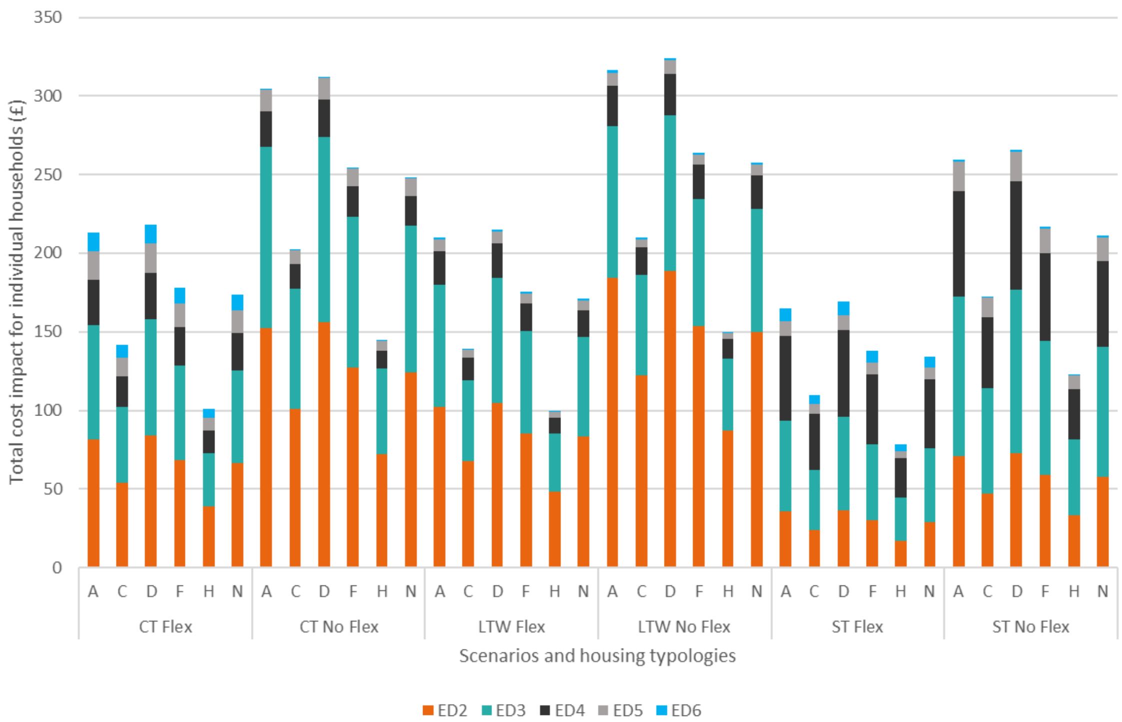

Figure 9 Discounted cost impact for different regulatory periods for households with no LCT technologies (SPEN)

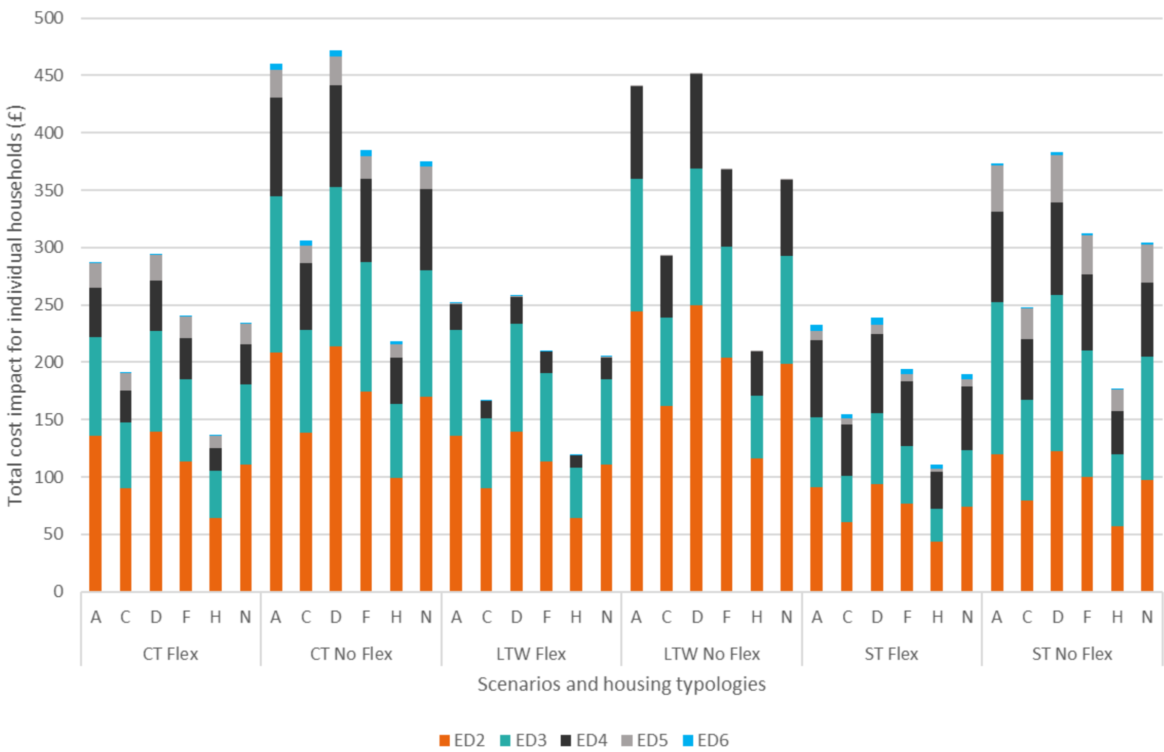

Figure 10 Discounted cost impact for different regulatory periods for households with no LCT technologies (SSEN)

Selected annual household recovery costs for these scenarios are shown in Table 4, for those homes which do not adopt LCTs. These are broken down to show the highest investment cost scenario across the housing portfolio (typically from CT or LtW) and also the highest recovery costs from the ST scenario, which has lower overall investment cost.

Our analysis demonstrates the impact of flexibility solutions on the recovery costs.

Scenario	Full scenario timeline (2020-2050) Annual recovery cost (£)		ED2 timeline (2023-2028) Annual recovery cost (£)	
	SPEN	SSEN	SPEN	SSEN
Highest cost investment scenario[3]	7.20	10.48	4.19	5.56
Highest cost investment scenario[3] with flexibility	4.78	6.53	2.33	3.10
Low investment scenario (ST)	5.91	8.51	1.61	2.73
Low investment scenario (ST) with flexibility	3.75	5.30	0.82	2.08

Table 4 Annual recovery costs for highest consumption households without LCTs

In the SPEN region, the highest recovery cost is for Small Town Diversity households (D) in the LtW scenario, which have an annual recovery cost of £7.20. In the SSEN region, the highest recovery cost is for archetype D households within the CT scenario, at £10.48 per year. These are based on an assumed reclamation period of 45 years for network assets and represent recovery costs over the full investment timeline (2020-2050). The equivalent

[3] LtW in SPEN area, CT in SSEN for full scenario timeline. LtW for ED2 timeline.

maximum annual recovery costs for the low investment scenario (ST) in SPEN and SSEN regions are £5.91 and £8.51 respectively. Introduction of flexibility to the energy system can create savings of around one-third on these recovery costs.

We have also calculated cost recovery for modelled investments which are made during the ED2 period. The highest recovery costs both occur for archetype D households in the LtW scenario, with annual values for SPEN and SSEN regions of £4.19 and £5.56 respectively. In contrast, for the ST scenario, which has a similar investment requirement over this timeline to the published ED2 business plans, annual recovery costs are £1.61 and £2.73 for the SPEN and SSEN regions respectively.

The recovery costs calculated above will be additional to existing network reinforcement charges which are currently reclaiming the costs of previous network reinforcement. The reclamation cost for these works will be removed from consumer bills once they reach the end of the depreciation period. Therefore, the precise change in consumer bills will depend upon not only the costs calculated for future network reinforcement works, but also the removal of costs for previous works.

Ultimately, the exact translation of recovery costs for these network investments onto consumer bills will depend on the policy decisions by Ofgem. Ofgem's final determination for RIIO-ED2 asserts that there will not be increases to consumer bills associated with decarbonisation, quoting measures such as 'strong efficiency challenges and lowering of investor returns' to ensure bills do not increase (Ofgem, 2022).

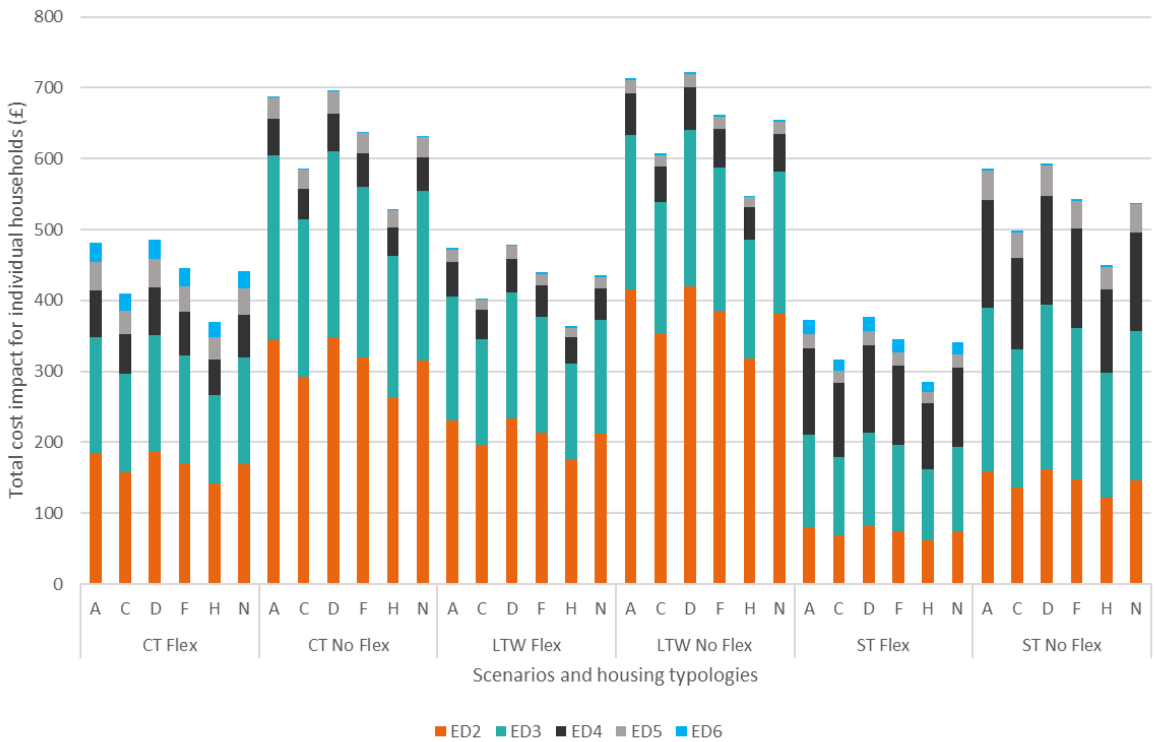

Figure 11 Discounted cost impact for different regulatory periods for households with heat pumps and electric vehicles (SPEN)

Figure 11 and Figure 12 show the corresponding discounted recovery cost distribution for those households which adopt both electrified transport and heating in the scenarios. These households have the highest usage, and therefore higher network recovery costs.

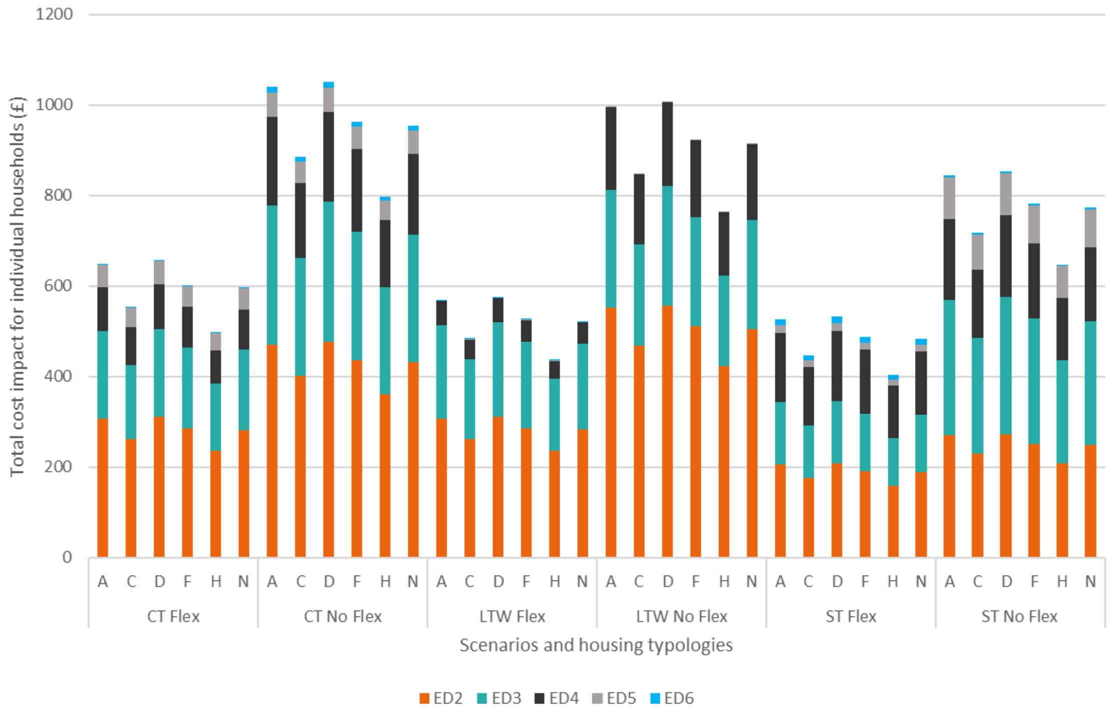

Figure 12 Discounted cost impact for different regulatory periods for households with heat pumps and electric vehicles (SSEN)

Selected maximum recovery costs for scenarios are shown in Table 5. These are representative of the highest consumption household (D) in each case.

	Full scenario timeline (2020-2050) Annual recovery cost (£)		ED2 timeline (2023-2028) Annual recovery cost (£)	
Scenario	SPEN	SSEN	SPEN	SSEN
Highest cost investment scenario[4]	16.04	23.35	9.33	12.38
Highest cost investment scenario[4] with flexibility	10.65	14.55	5.18	6.91
Low investment scenario (ST)	13.17	18.95	3.59	6.07
Low investment scenario (ST) with flexibility	8.36	11.81	1.82	4.64

Table 5 Annual recovery costs for highest consumption households with LCTs

For the SPEN and SSEN regions, the maximum annual recovery costs are £16.04 and £23.35 per household. These are much higher values than for homes with no LCT usage due to higher electricity usage, however these households would be making associated savings on their gas and transport fuel bills.

Scenarios with flexibility options require lower levels of network reinforcement, and therefore have reduced impacts on recovery costs. For the recovery costs discussed above,

[4] LtW in SPEN area, CT in SSEN for full scenario timeline. LtW for ED2 timeline.

utilisation of flexibility solutions corresponds to recovery cost reductions of close to one-third.

For the lower investment ST scenario, equivalent annual recovery costs for the SPEN and SSEN regions are £13.17 and £18.95. With inclusion of flexibility options in this scenario, reduction in recovery costs of around one-third are again achieved.

For short-term consideration, the recovery costs attributed to only modelled investments from the ED2 period are calculated. In the highest cost investment scenario, annual recovery costs in the SPEN and SSEN regions are £9.33 and £12.38 respectively. For the ST scenario, which has a similar investment requirement over this timeline to the published ED2 business plans, annual recovery costs are £3.59 and £6.07 for the SPEN and SSEN regions respectively. Reductions are also achieved through use of flexibility to defer reinforcement.

These recovery costs are only one component of the overall average consumer bill and expiration of previous investment costs and policy mechanisms will also have an influence on actual energy bills.

6.4 Future analysis

The methodology used attempts to capture the key assumptions of the current Ofgem charging methodology, which is based primarily on usage volume for domestic customers. Nevertheless, it is important to caveat that charge sharing mechanisms do currently exist for the SSEN region in Scotland (Hydro Benefit Scheme, Common Tariff Obligation), which should ensure that customers in this region do not pay significantly higher network reinforcement costs than any other DNO licensed area in Great Britain.

It is possible that in future energy systems, alternative charging methodologies might be adopted to encourage behaviour which reduces overall system costs. Financial incentives could be provided in terms of lowered network charging rates for those households which take advantage of flexibility options and reduce network strain during peak events. National Grid ESO also created the Demand Flexibility Service (DFS) which ran from 1 November 2022 until March 2023 and allows some domestic and non-domestic customers to provide demand reduction for a financial incentive. However, this scheme is not yet fully available, with its primary purpose last winter to protect the energy system. There is a more widespread mechanism (RAG charge rates) which attempts to incentivise flexibility on a system level; however, this does not currently reflect location-specific constraints. Changes to reflect location specific flexibility would be most relevant for the scenarios with flexibility optionality considered here, taking the form of managed electric vehicle charging or demand side response linked to heating patterns.

In these cases, there would be a requirement to consider not only units of electricity consumed by domestic customers, but also the local network conditions during which consumption occurs.

There may also be a cost benefit of adapting the current charging methodology to consider seasonal charging. The rationale would be to incentivise flexibility in winter months by introducing higher network charges during this period. This price signal would then reduce the size of peaks on the electricity network, deferring reinforcement. These schemes may be limited by an average customer's ability to provide flexibility in their heating requirement, unless heat pumps can be coupled with local energy storage to provide temporal displacement. Counterbalancing this would be a summer period of low network charge rates since incentivising flexibility is a lower priority under these conditions.

Charging methodologies such as these could create issues relating to fair access:

- Any inclusion of locational pricing will need to be created to guarantee that large discrepancies are not reflected within bills for the most remote customers. This is currently ensured by the Hydro Benefit Scheme and Common Tariff Obligation for North of Scotland, but significant discrepancies could also emerge within southern Scotland (e.g. rural areas where costs may currently be cross subsidised by customers in Glasgow or Edinburgh).

- Seasonal charging could create much larger bills in the winter months, particularly for the most vulnerable customers (those without ability to take advantage of flexibility, or available credit to spread payment burdens). This raises further issues of fairness, and these factors would need to be balanced against the possibility of creating reductions in network reinforcement for the overall system.

- The ability for consumers to provide flexibility, and benefit from reduced network charging, will depend upon ability to engage freely with the energy market. This could be reliant upon household income (ability to purchase required technology), familiarity with technology (access via online applications/smartphones), ease of understanding (facilitated through market aggregators) and the ability to shift demand depending upon the use case (heating has lower potential for flexibility than vehicle charging).

To mitigate fairness issues, any change to the current methodology would most likely need to include caps which prevent bills rising to a large extent for geographical outliers (and conversely, negating significant reductions for those customers with very low network constraint). Implementing caps weakens price signals relating to network reinforcement, and therefore provides a less targeted response, but also ensures that customers are not penalised due to the area in which they live. The key to including these locational signals within the network charging methodology is finding the correct balance between overall system cost reduction and fairness for consumers paying the reinforcement charges.

An alternative solution to using price caps would be to allow one-off payments to those network users most impacted by changes to the charging mechanism. An issue with implementing this is that the system is currently run using a "supplier-hub model", whereby the DNO charges suppliers for all of their customers' aggregate usage, and then the supplier determines the split of costs across its customer base. Under this system, the DNO cannot provide certainty that one-off payments will be targeted in the correct way, since the supplier can redistribute costs. To mitigate this, DNOs would need to play a more direct role in billing of customers, without all costs being translated through energy suppliers, which would be a regulatory/government decision.

7 Conclusions and recommendations

We investigated potential cost impacts of decarbonisation scenarios across Scotland, using a timeline from the present day until 2050. The scenarios align with the DFES for both DNO regions within Scotland.

Total investment in networks from these scenarios indicate that LtW is the most expensive option, with ST being the most affordable. An important factor is the availability of network flexibility options. Using flexibility options allows a LtW scenario to become cost comparable with CT and reduces scenario costs by a significant margin across the board.

	Flexibility	Consumer Transformation	Leading the Way	System Transformation
Total Investment (£m)	No	2,158.7	2,477.4	1,585.6
	Yes	1,544.6	1,596.4	1,096.9

The ST network investment profiles were found to be most comparable with the published business plans for ED2 from both of the DNOs in Scotland. The other two scenarios were only comparable with flexibility options included for one DNO area. Discrepancies between scenarios and the planned spend in each region can be explained by the front-heavy investment profile of CT and LtW, which conclude the majority of investment before 2040.

Households with higher usage characteristics will contribute a larger proportion towards the network investment cost recovery. This will have a larger impact for occupants of homes with poor thermal performance and larger homes, both of which will have a higher-than-average consumption profile throughout the year.

The estimated impact on recovery costs and consumer bills also varies depending upon the assumed usage of low carbon technologies such as electric vehicles and electrified heating. For those homes without LCTs, annual recovery costs of network reinforcements could be up to £7.20 or £10.48 annually for the SPEN and SSEN regions respectively. For homes with both electrified transport and heating, recovery costs could be up to £16.04 to £23.35 annually for the SPEN and SSEN regions respectively. However, these cost recovery values are for a very high investment, low network flexibility scenario and for homes with the highest electricity usage. A low investment scenario with network flexibility solutions deployed resulted in reduced maximum recovery costs of £3.75 to £11.81 annually. Costs vary depending on DNO area and level of uptake of LCT technologies. Generally, usage of network flexibility options can cut recovery costs by about one-third.

Potential recovery costs from network reinforcements during the ED2 period have been calculated based on the investment profiles being most comparable with the ST scenario during this period. For homes without LCTs, maximum annual recovery costs range between £0.82 and £2.73 (depending upon region and availability of network flexibility). For homes with both heat pumps and electric vehicles the maximum recovery cost range is £1.82 to £6.07 annually as a result of investments made during the ED2 period.

While the recovery costs calculated for the SSEN region were higher, cost sharing mechanisms are currently in operation which distribute costs both within and across regions to ensure that these customers are not penalised due to their geographic location.

We recommend a further study is commissioned to investigate the detailed impacts on consumer fairness that alternative charging methodologies could create, particularly when coupled with existing fuel poverty under the current charging methodology.

7.1 Recommendations for further work

- Additional work should also be undertaken to identify specific impacts on vulnerable customers resulting from increased energy bills, including additional network investment recovery costs, and mechanisms which can be used to alleviate financial burden. The archetypes used within this study are broad, and although providing an indication of household income, still encompass a wide variety of socio-economic situations. From a policy perspective, additional study in this area should help to highlight how support can be targeted effectively.
- The authors have provided a charging methodology which is based on the currently used Common Distribution Charging Methodology for domestic consumers that applies the same charges across the year and region. Ofgem has previously done work to consider more granular network charges (e.g. introducing locational and seasonal variation). Although that review has been paused, we recommend the Scottish Government considers the potential impact if such changes were introduced and the trade-off between more cost reflective charges that incentive flexibility where it is most valuable (i.e. where the network is most constrained / most expensive to reinforce) against distributional impacts.
- In considering potential changes to the charging methodology, it would be important to assess the potential impact on the most vulnerable and most geographically isolated customers. Some cost sharing is still inevitable to protect specific customer groups from large bill increases; striking a balance between overall cost reduction and fairness is an important topic to consider. Research in this area would provide the Scottish Government with insights that they can feed into any further review Ofgem does into network charging, and form part of future cost recovery periods beyond RIIO-ED2.

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Appendix A Distribution Future Energy Scenarios (DFES) for SSEN and SPEN

Stakeholder Feedback for SPEN's and SSEN's DFES scenarios

SSEN and SPEN consulted their regional stakeholders during the process of updating their DFES and the stakeholders' views have been incorporated in the update. Tables containing those interactions specifically for HPs and EVs has been extracted from SSEN's and SPEN's DFES reports, with the objective of getting a better understanding of how those interactions influenced the final projections.

Table 6 - Table 9 contain the stakeholder comments and the actions taken from each of the DNO. Those interactions affected the number, geographical distribution, flexibility potential and deployment time of EVs and HPs on different scenarios considered by the DNOs.

Stakeholder feedback provided	How this influenced SSEN's analysis
In the context of Scottish Government's 2030 target for zero carbon heating uptake, stakeholders thought that heat pump deployment would be focussed in new homes, off-gas homes and social housing.	Heat pump uptake is weighted towards these housing types and demographics in the near and medium term.
Local authorities were engaged to understand which authorities had a low carbon heat strategy established or in development. However, this formed a minority of local authorities.	Heat pump uptake is weighted towards local authorities with low carbon heat strategies in the near term.
Scottish Government's Heat in Buildings Strategy policy commitments, targets, and projections, alongside workshop engagement and other published low carbon heat documents.	Scottish Government targets and ambitions for low carbon heating are reflected in all scenarios, and explicitly met in the CT and LtW scenarios.
Islands in the North of Scotland licence area were specifically consulted around their unique heating challenges and drivers. Fuel poverty, energy efficiency and the lack of mains gas were raised as key drivers in the electrification of heat. Hydrogen for heating is also being explored on Shetland and Stornoway.	Heat pump uptake on the islands is high in every scenario, due to being dominantly off-gas. However, uptake may be tempered by high heat demands and poor energy efficiency of the housing stock. This is reflected through the range of the four future scenarios in the analysis.

Table 6 Stakeholder feedback for heat pumps – SSEN DFES report

Stakeholder feedback provided	How this influenced SSEN's analysis
When asked "when might the North of Scotland licence area's EV uptake align with the rest of the UK", stakeholders had mixed views with little discernible trend emerging. The majority of views were that EV uptake in the licence area would align with the GB average before 2030 (predicted to be 2027).	EV uptake rates in the North of Scotland licence area remain behind the national average until the mid-2020s, in doing so also reflecting Scottish Government ambition for high EV uptake.

Stakeholder feedback provided	How this influenced SSEN's analysis
For the uptake of EVs, other feedback was received at a stakeholder workshop focused on the Isle of Wight. The outcome of this for EVs confirmed initial assumptions in the modelling such as the ambition of the net zero scenarios and distribution models.	Confirmed existing assumptions.
In addition to other feedback that confirmed existing assumptions, the Scottish Government provided feedback that public procurement of EVs to decarbonise fleets is ambitious and above average nationally.	The suitability of the scenarios in representing the uptake of fleet vehicles in Scotland was reviewed.
Feedback from industry stakeholders highlighted that the ambitious growth of the net zero scenarios was dependent on the supply of EVs, and that presently supply is not meeting demand as a result of chip shortages, manufacturing limitations and other factors. Furthermore, an additional challenge for the UK is to secure sufficient imports of EVs against the backdrop of high global demand for EVs.	The deliverability and progress achieved towards the scenarios will be reviewed annually. FES 2021 conducted this analysis and found that EV uptake seen last year fell well within the credible range of scenarios.

Table 7 Stakeholder feedback for electric vehicles – SSEN DFES report

Stakeholder feedback provided	How this influenced SPEN's analysis
Consider a more rapid uptake of heat pumps to help achieve the legislated target of 75% carbon reduction by 2030	SPEN has updated the heat pump forecast for the CT scenario to show a faster adoption rate in short to medium term
Air source heat pumps (ASHPs) will not materialise in grade 1 and 2 listed buildings	SPEN has refined their heat pump allocation methodology to exclude these types of buildings. All scenarios have been updated with this refinement.
Heating demand is likely to be less flexible than electric vehicle demand, as there is less appetite to compromise on comfort levels	Stakeholders felt there to be little scope for flexibility from heat pumps. SPEN has slightly increased the range of potential flexibility response, in line with the ESO's 2021 FES.
Strong emphasis on social housing and off-gas grid decarbonisation. Local heat and energy efficiency strategies will reduce the geographical and technological uncertainty on heat decarbonisation	SPEN is proposing to adopt a strategic optimiser role in RIIO-ED2 to provide advice and support to all local authorities, across SPEN network areas, on the development of their heat decarbonisation plans. Ongoing collaboration will work in both directions as this will enable local authorities to make more informed and optimal whole-system choices and will enable SPEN to refine forecasts and deliver their future more efficiently. Stakeholders provided strong support for this proposal during the development of SPEN RIIO-ED2 Business plan
Scotland is likely to see a higher uptake of district heating schemes	SPEN believes their forecast facilitate Scottish Government's 2030 target of at least 6 TWh of heat demand supplied through heat networks

Table 8 Stakeholder feedback for heat pumps – SPEN DFES report

Stakeholder feedback provided	How this influenced SPEN's analysis
Consider a more rapid uptake of electric vehicles to help achieve the legislated target of 75% carbon reduction by 2030.	SPEN has updated the electric vehicle forecast for the SPD LtW scenario to show a faster adoption rate.
By 2050 the number of vehicles is expected to decrease due to autonomous and shared vehicles, and increased home working.	SPEN believes this is an area of great uncertainty. However, their assumptions for autonomous vehicles have been updated in line with the ESO's 2021 FES, other than in LtW scenario
Bus electricity consumption is expected to be around 1.6 kWh/mile.	SPEN have updated their assumptions for electricity consumption for buses in all scenarios. This change has limited impact on peak demand, as most bus charging will occur outside of peak demand periods.
Destination charging at popular tourist spots could be a significant challenge, particularly in remote areas.	SPEN has updated all scenarios to incorporate the contribution from destination charging at popular tourist spots.
The uptake of electric vehicles may see a "hockey stick" around 2025-26 as the second-hand car market picks up	SPEN's EV-Up project considers different socio-economic groups and their likelihood of purchasing new and second-hand cars. Their CT and LtW scenarios already reflect the knee point, so they have not made updates.
Rural areas may see more electric vehicles as there is often a lack of public transport alternative.	SPEN's EV-Up project considers different socio-economic groups and their likelihood of purchasing new and second-hand cars. Their CT and LtW scenarios already reflect the knee point, so they have not made updates.
Smart charging is key to the integration of electric vehicle in the network. The volume of flexibility from smart charging is likely to partly depend on the level of cost savings for electric vehicle owners.	SPEN agrees that smart charging will enable flexibility to connect more electric vehicles. Our flexibility assumptions already captured the potential for considerable peak demand impact reduction due to charging electric vehicles in a more flexible way.
Most car manufacturers do not cover battery degradation within their warranty if the vehicle is used for V2G services. This means V2G flexibility will likely be low. Another barrier is battery technology as battery cycling currently reduces battery life.	SPEN agrees with their stakeholders that V2G capability will be low in the coming decade. They have updated their assumptions in line with the ESO's 2021 FES, which show V2G making an increasing contribution from the 2030s – SPEN has not adjusted this further as they anticipated that rapid improvements in battery technology could mean that warranties and battery degradation may not be such a barrier to V2G over the longer term. SPEN will continue to monitor further technology developments in this area.

Table 9 Stakeholder feedback for electric vehicles – SPEN DFES report

Assumptions for Distribution Future Energy Scenarios

Each of the DFES scenarios for the DNOs above was produced considering a set of assumptions for the future. The assumptions outlined in SSEN's and SPEN's DFES 2021 reports are detailed fully in Table 10 and Table 11.

	Steady Progression	Consumer Transformation	System Transformation	Leading the Way
Electric vehicles	Low uptake of Battery Electric Vehicles	High uptake of Battery Electric Vehicles	Medium uptake of Battery Electric Vehicles	High uptake of Battery Electric Vehicles
		Electric Vehicle uptake is likely to see a knee point around 2025/26 once the second-hand car market develops.	Increased homeworking, an increased use of public transport, and the expected development of autonomous and shared vehicles could drive a reduction in vehicle ownership towards 2050. This scenario reflects this decrease from the late 2030s to early 2040s.	Electric Vehicle uptake is likely to see a knee point around 2025/26 once the second-hand car market develops.
		Increased homeworking, an increased use of public transport, and the expected development of autonomous and shared vehicles could drive a reduction in vehicle ownership towards 2050. This scenario reflects this decrease from the late 2030s to early 2040s.		
Heat pumps	Low uptake of heat pumps	High uptake of heat pumps	Medium uptake of heat pumps	High uptake of heat pumps
		Scottish Government's target of 75% greenhouse gas emission reductions by 2030, could feasibly accelerate heat pump deployment. The CT scenario was updated to consider an increased heat pump uptake in the short and medium term.		

Table 10 Assumptions for SPEN DFES Scenarios

<table>
<tr><th></th><th>Steady Progression</th><th>Consumer Transformation</th><th>System Transformation</th><th>Leading the Way</th></tr>
<tr><td rowspan="4">Electric Vehicles</td><td colspan="4">Across all scenarios, the uptake of EVs is expected to accelerate significantly in the mid-2020s. The overwhelming majority of this uptake is from electric cars, with electric vans, buses and other vehicles growing at a slower rate.</td></tr>
<tr><td colspan="4">The uptake of EVs is expected to accelerate between 2025 and 2035 in all scenarios.</td></tr>
<tr><td rowspan="2"></td><td>Increased EV uptake by 2025 to reflect Scottish Government target, resulting in the licence area not remaining behind the GB average for EV uptake beyond the early- to mid-2020s.</td><td rowspan="2">An increase in the number of hydrogen cars in mid-2040s results in the flattening and then marginal reduction in the uptake of EVs.</td><td>EV uptake begins to slow in the mid-2030s as EV adoption approaches saturation and only the hardest-to-electrify vehicles such as HGVs, remain fuelled by petrol or diesel.

Other factors also contribute to uptake slowing, including a reduction in the total number of vehicles, increased use of AVs and increased use of public transport and active travel.</td></tr>
<tr><td>EV uptake begins to slow in the mid-2030s as EV adoption approaches saturation and only the hardest-to-electrify vehicles such as HGVs, remain fuelled by petrol or diesel.

Other factors also contribute to uptake slowing, including a reduction in the total number of vehicles, increased use of AVs and increased use of public transport and active travel.</td><td>Other factors also contribute to uptake slowing, including a reduction in the total number of vehicles, increased use of AVs and increased use of public transport and active travel.

Many homes opt to have one or no car at all, which results in a decrease in the number of company and private vehicles.</td></tr>
</table>

<table>
<tr><th></th><th>Steady Progression</th><th>Consumer Transformation</th><th>System Transformation</th><th>Leading the Way</th></tr>
<tr><td>Electric vehicles</td><td></td><td>The numbers of EVs reduces from the late 2030s and mid-2040s, respectively. This is the result of societal change and technological development including increased use of public and active travel and the rising number of AVs.

Many homes opt to have one or no car at all, which results in a decrease in the number of company and private vehicles.</td><td></td><td></td></tr>
<tr><td rowspan="3">Heat pumps</td><td colspan="4">Heat pump uptake increases in all scenarios in the near term (2021 - 2025) but remains low in all scenarios except LtW.</td></tr>
<tr><td colspan="4">As a common factor in fuel poverty due to high costs, resistive electric heating reduces in all four scenarios in favour of heat pumps, heat networks, gas network expansion and other more affordable heating systems. However, some installations occur in energy efficient new build properties, especially smaller homes such as flats in the medium term (2025 – 2035)</td></tr>
<tr><td>Scottish and UK Government targets are not met in the medium term (2025 – 2035).</td><td>The Scottish Government’s Heat & Energy Efficiency Scotland result in a significant increase in heat pump deployment in both new and existing homes in the near term (2021 – 2025)</td><td>Scottish and UK Government targets are not met in the medium term (2025 – 2035).</td><td>Very high levels of consumer engagement and green ambition results in high levels of heat pump deployment in the near term (2021 – 2025).</td></tr>
</table>

	Steady Progression	Consumer Transformation	System Transformation	Leading the Way
Heat pumps	Heat pump uptake remains low as Scotland and GB fail to meet their decarbonisation targets in the long term (2035 – 2050). 40% of North of Scotland homes are heated by a heat pump or resistive electric heating by 2050, higher than the GB average, due to increased Scottish Government ambitions and the higher proportion of off-gas homes in the licence area.	The high levels of heat pump uptake seen in the 2030s continues to 2045, as Scotland achieves its 2045 Net Zero goal. By 2050, over 80% of homes are electrically heated under these scenarios, with the remainder heated via low carbon district heat (which may be driven by a heat pump), biofuels or hydrogen. Similarly, the vast majority of non-domestic properties are electrically heated in these scenarios.	Heat pump uptake slows and is replaced by the emergence of hydrogen boilers for domestic heating in the long term (2035 – 2050), which becomes the heating technology for majority of homes that are currently on-gas. However, the high cost of hydrogen also encourages the uptake of hybrid heat pumps with hydrogen boiler back-ups.	The Scottish Government's Heat & Energy Efficiency Scotland result in a significant increase in heat pump deployment in both new and existing homes in the near term (2021 – 2025)
				The high levels of heat pump uptake seen in the 2030s continues to 2045, as Scotland achieves its 2045 Net Zero goal. By 2050, over 80% of homes are electrically heated under these scenarios, with the remainder heated via low carbon district heat (which may be driven by a heat pump), biofuels or hydrogen. Similarly, the vast majority of non-domestic properties are electrically heated in these scenarios.

Table 11 Assumptions for SSEN DFES Scenarios

SPEN and SSEN DFES

SPEN and SSEN released their most up to date DFES in 2021 with their forecast of how electricity generation and demand might evolve during the next 30 years. To do so, the DNO's have reconciled data from the National Grid ESO FES 2021, targets from the Scottish Government and different stakeholders. Figure 13 - Figure 16 present the projections for HPs and EVs for each of the DNOs up to 2050. This data has been used by WSP as the input data for the estimation of the total investment cost for each of the different scenarios.

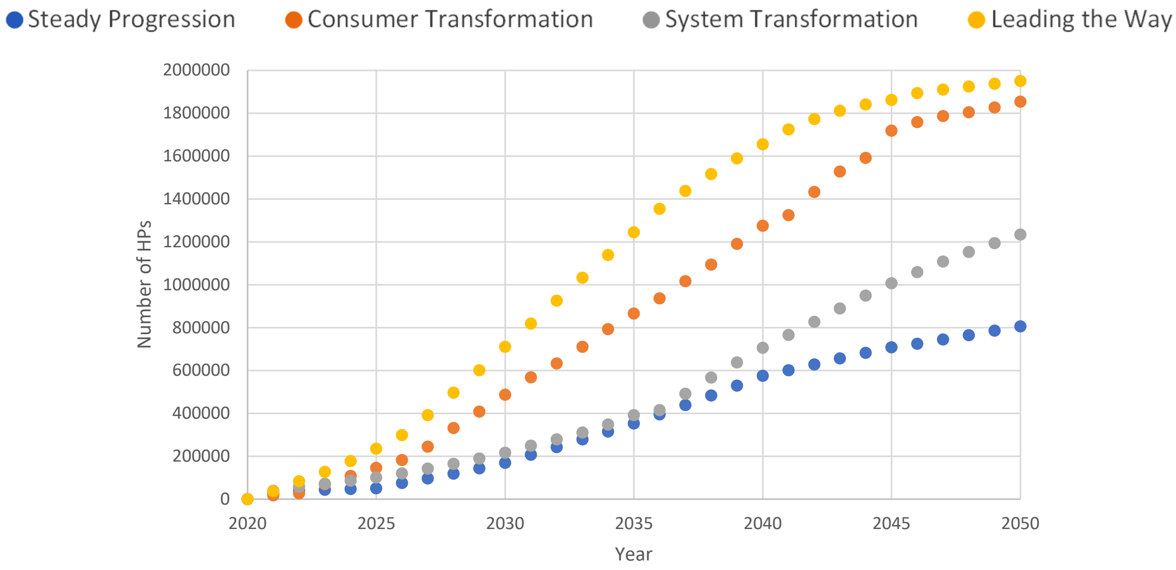

Figure 13 HP uptake for SPEN

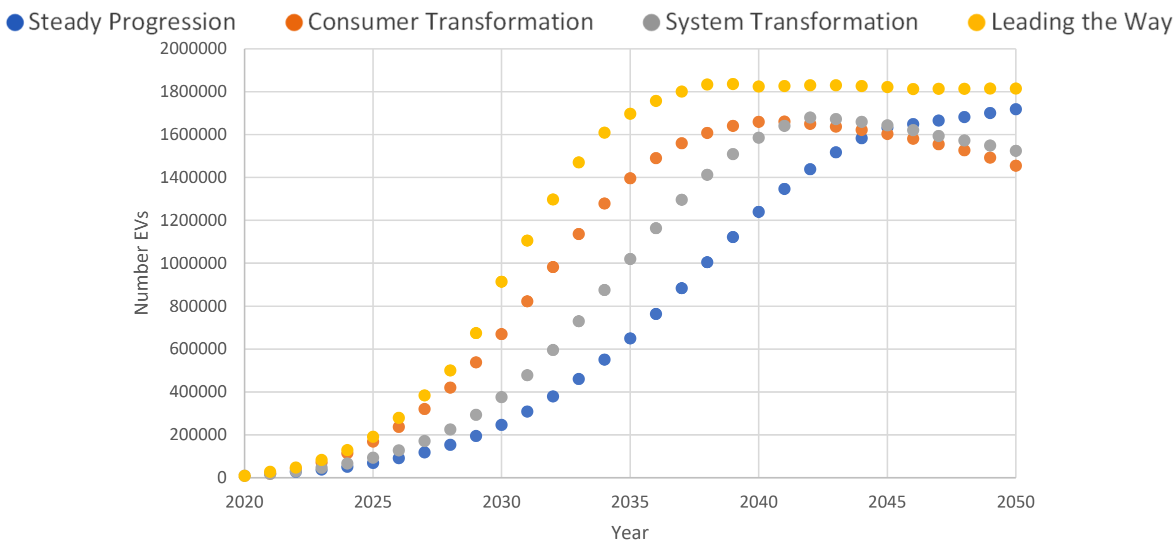

Figure 14 Residential EV uptake for SPEN

Steady Progression Consumer Transformation System Transformation Leading the Way

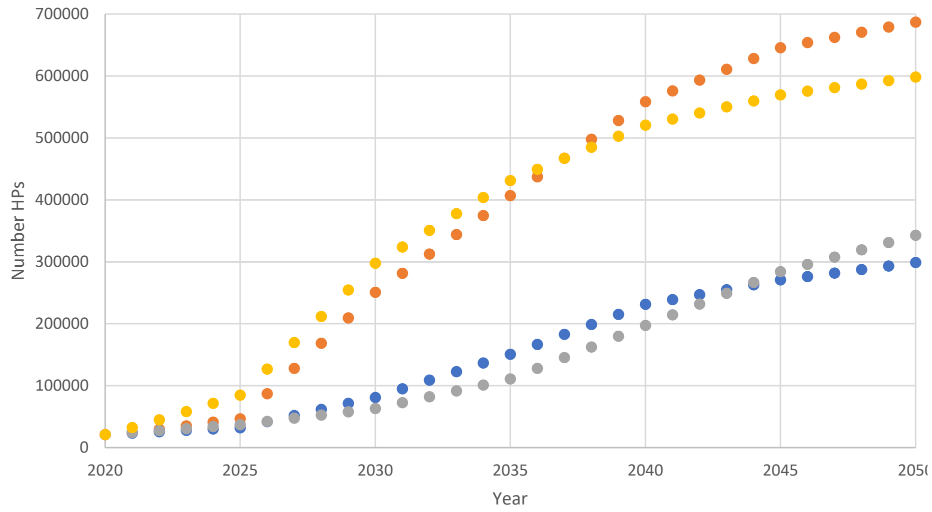

Figure 15 HP uptake for SSEN

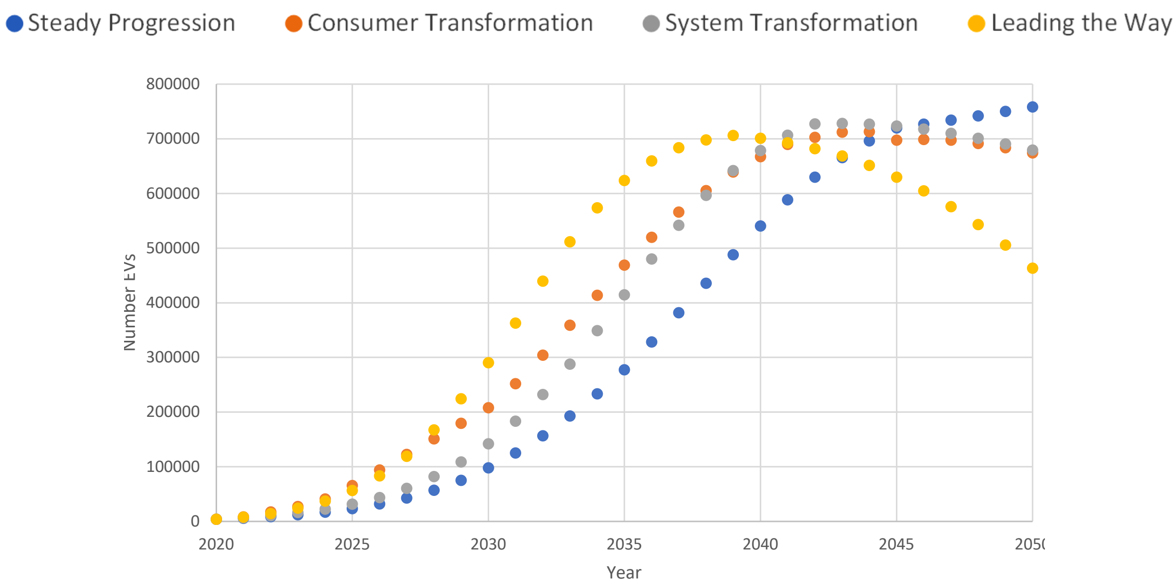

Figure 16 Residential EV uptake for SSEN

Heat pumps uptake vs number of households

The LCT Planner database contains information on representative LV, HV and EHV feeders as well as EHV/HV and HV/LV substations for SSEN and SPEN. Each of those representative feeders and substations contains a specific number of households and domestic vehicles (all technologies). Therefore, the tool relies on the estimation of percentage uptakes per year to properly estimate the number of HPs and EVs on each of the representative feeders.

Therefore, it is necessary to convert the number of HPs and EVs provided in the DFES of each of the DNOs to LCT uptake percentages. The National Records of Scotland has a projection of the number of households from 2018 up to 2043 (National Records of Scotland, 2020). This projection was then further extended to 2050 by creating a polynomial trendline based on the existing data and then projecting the future values using the resulting equation of the trendline. The visualisation of this procedure is shown in Figure 17.

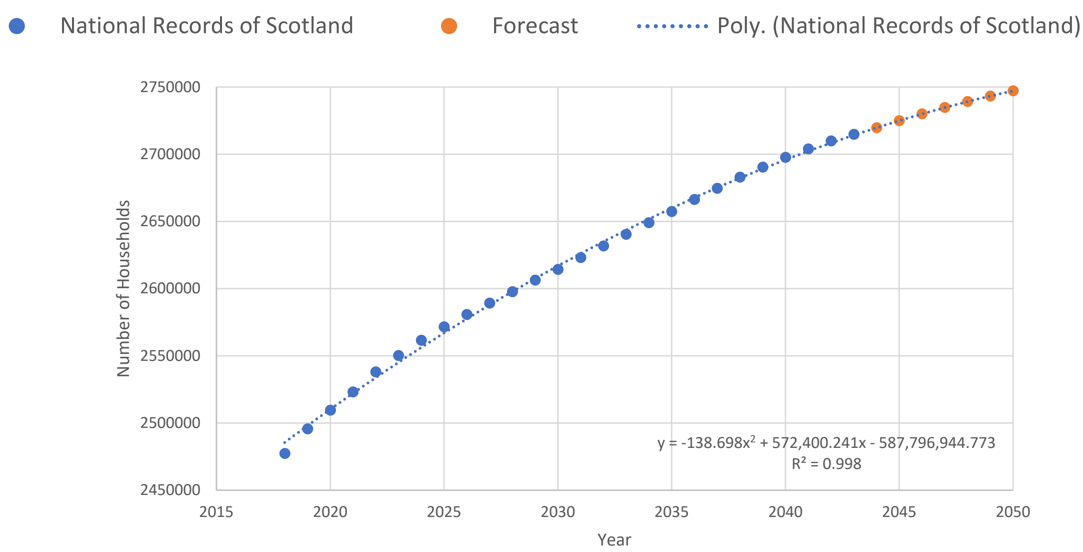

Figure 17 Number of households in Scotland

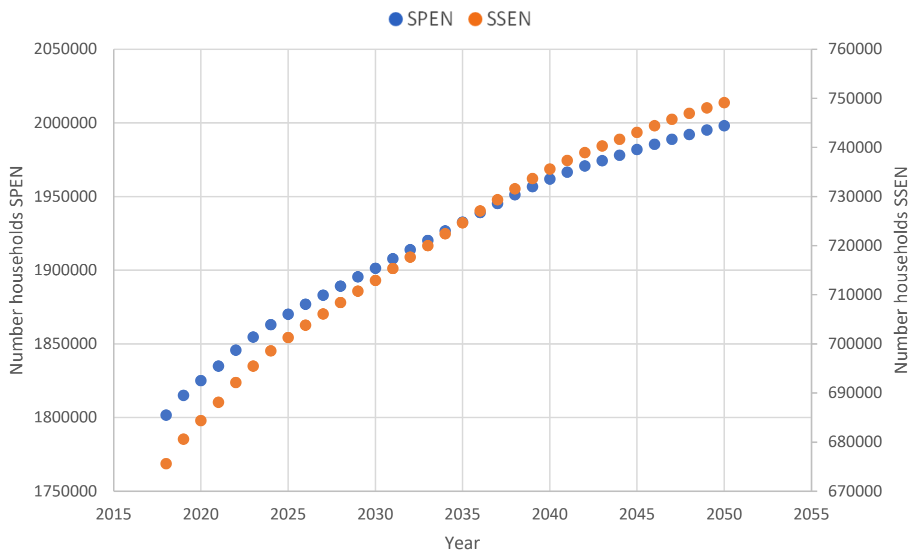

Figure 18 Number of dwellings per DNO

Previous analysis performed by WSP allowed determining that about 72.73% of households belong to SPEN and the remaining 27.27% belong to SSEN. With those values it is possible to determine the total number of households per licensed are using the total number for Scotland. Figure 17 shows the number of households per DNO.

Figure 19 and Figure 20 show the uptake percentage of HPs for SSEN and SPEN considered by WSP.

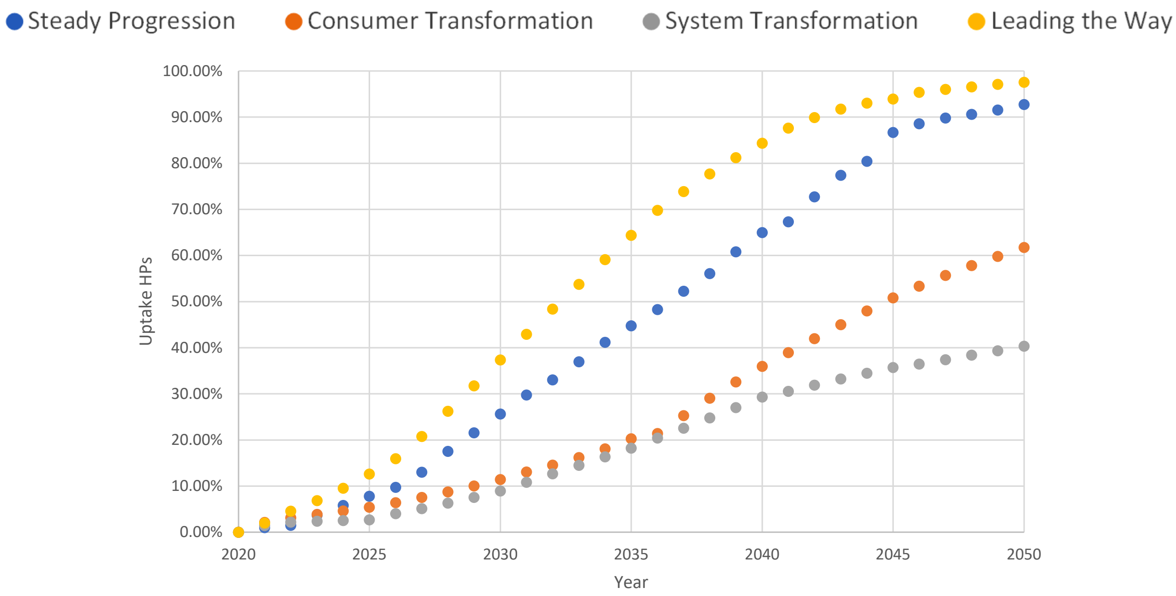

Figure 19 Uptake % of HPs compared to total number of households (SPEN licenced area)

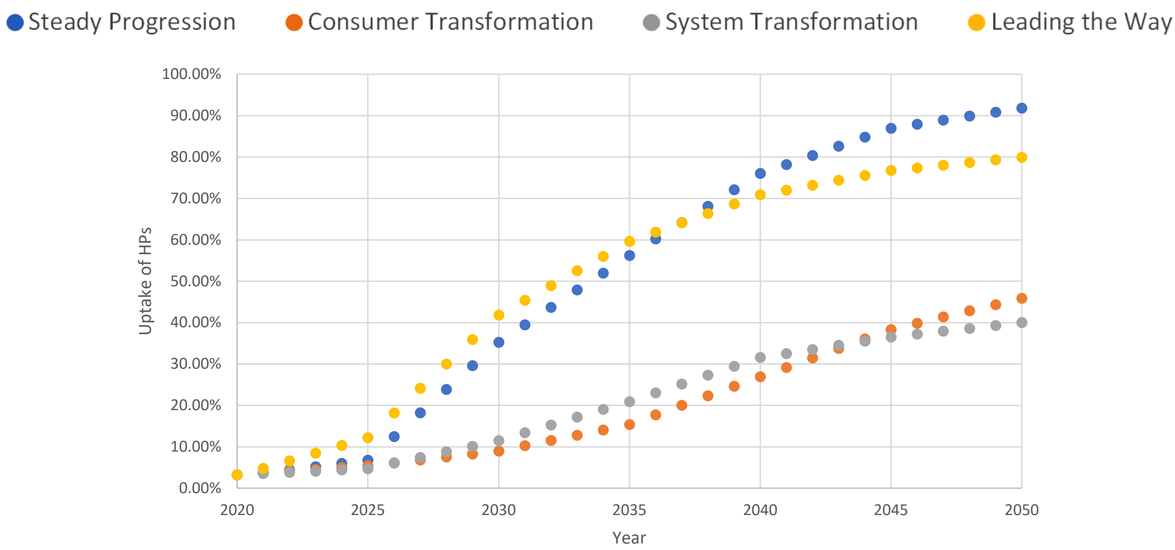

Figure 20 Uptake % of HPs compared to total number of households (SSEN licenced area)

Electric Vehicles uptake vs number of vehicles

A similar approach was taken with the uptake of EVs. The number of vehicles in Scotland was initially determined (Figure 21) and then after this number was separated for SSEN and SPEN. Historical data from Transport Scotland was initially used to forecast the number of vehicles up to 2050. However, it was assumed that petrol and diesel new car sales ban comes into place from 2035, with electric vehicles (EVs) and vans sales banned from 2040. This assumption comes from National Grid ESO FES 2021 for the SP scenario and was also used in the DFES for both DNOs. Based on this there is a slowdown in the number of vehicles from 2035 and a further slowdown from 2040 onwards. The uptake percentages in Figure 23 and Figure 24 were then estimated based on the uptake values obtained from SSEN and SPEN and the forecasted total number of vehicles.

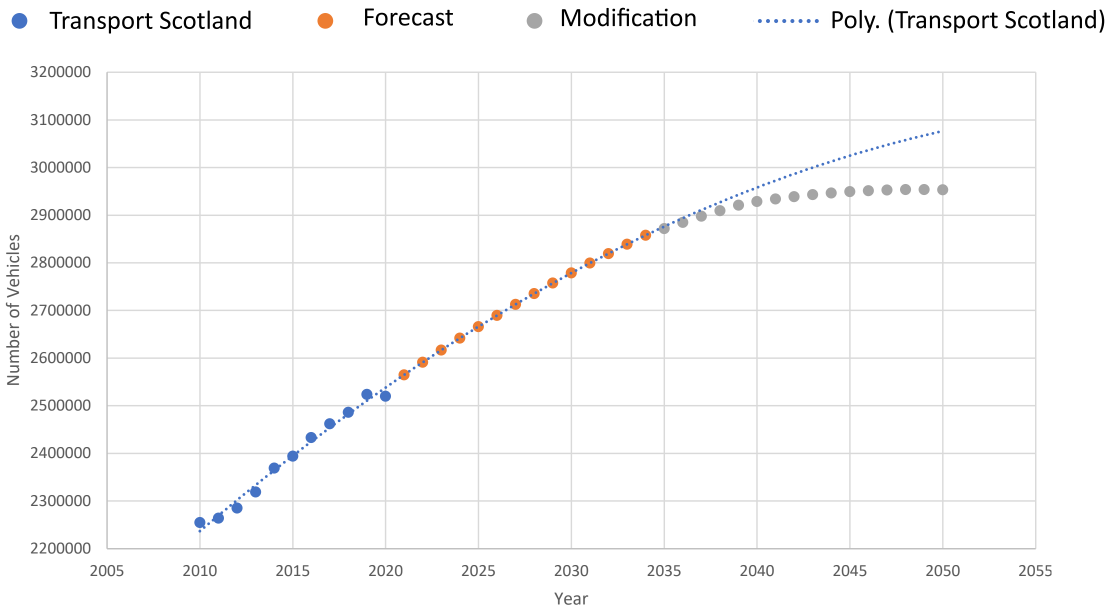

Figure 21 Number of vehicles (all technologies) in Scotland

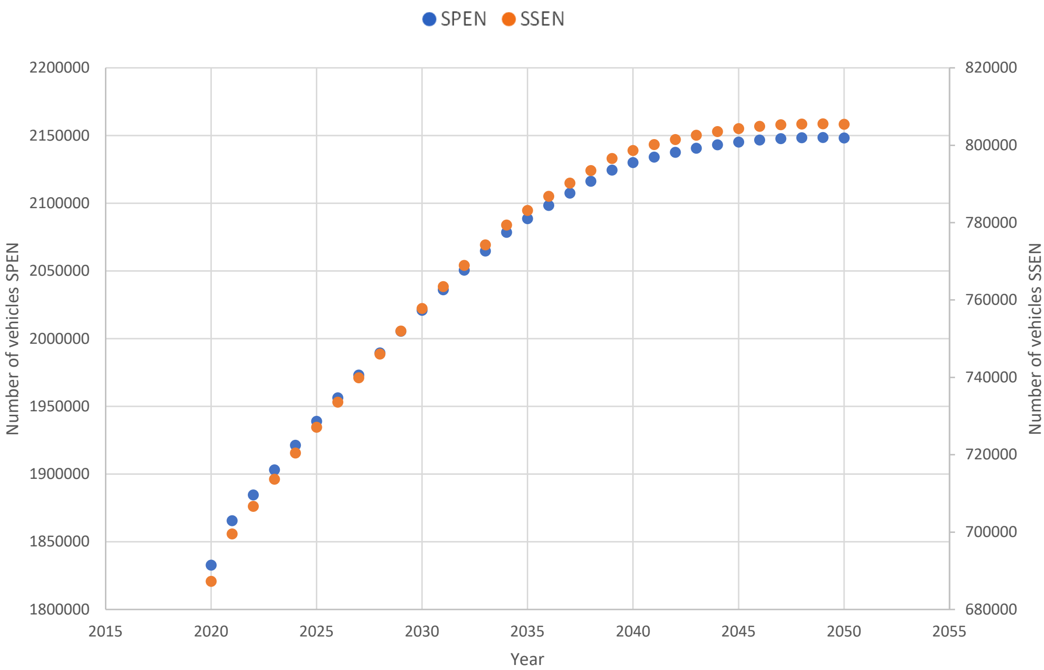

Figure 22 Number of vehicles (all technologies) per DNO

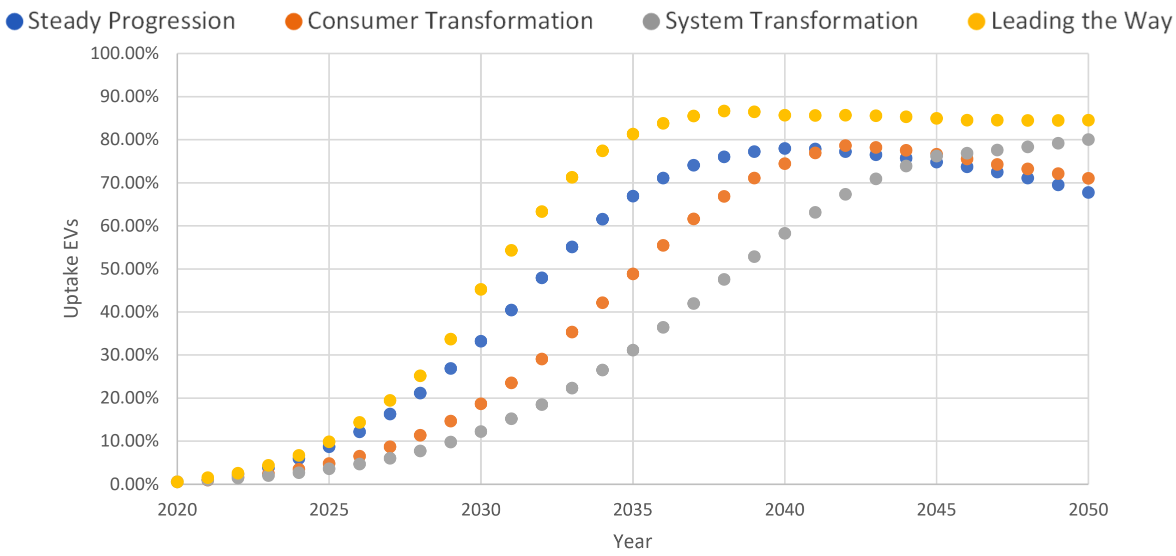

Figure 23 Uptake percentage of EVs compared to total number of vehicles in SPEN licenced area

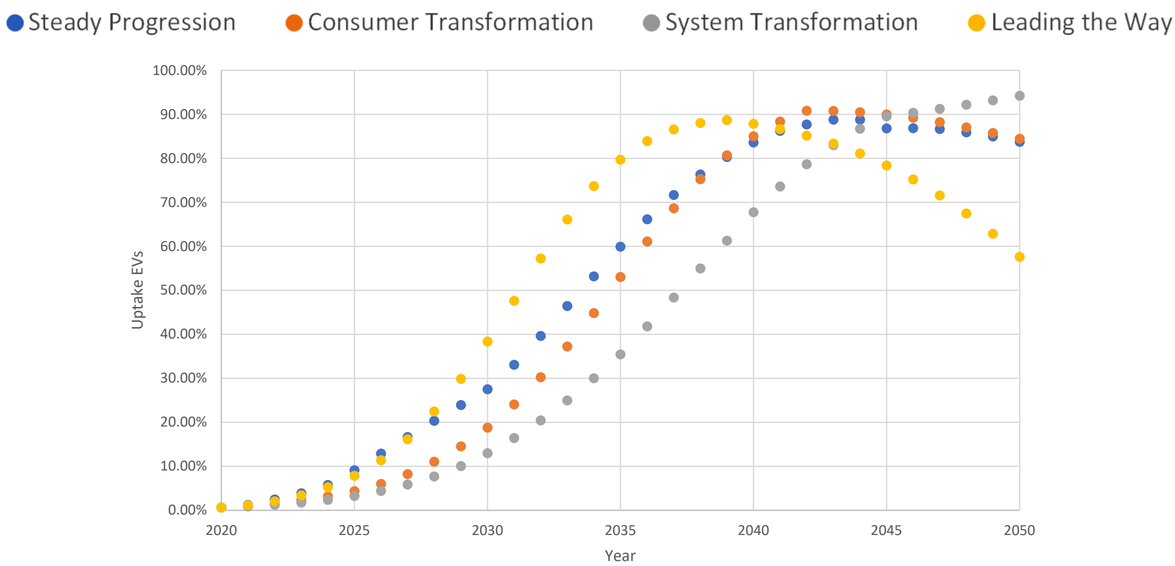

Figure 24 Uptake percentage of EVs compared to total number of vehicles in SSEN licenced area

Appendix B Networks and Solutions in LCT Planner

LCT Planner high level overview

The LCT Planner performs the analysis of long-term optimal investments on electricity distribution networks. The overall architecture of the LCT Planner tool is shown below.

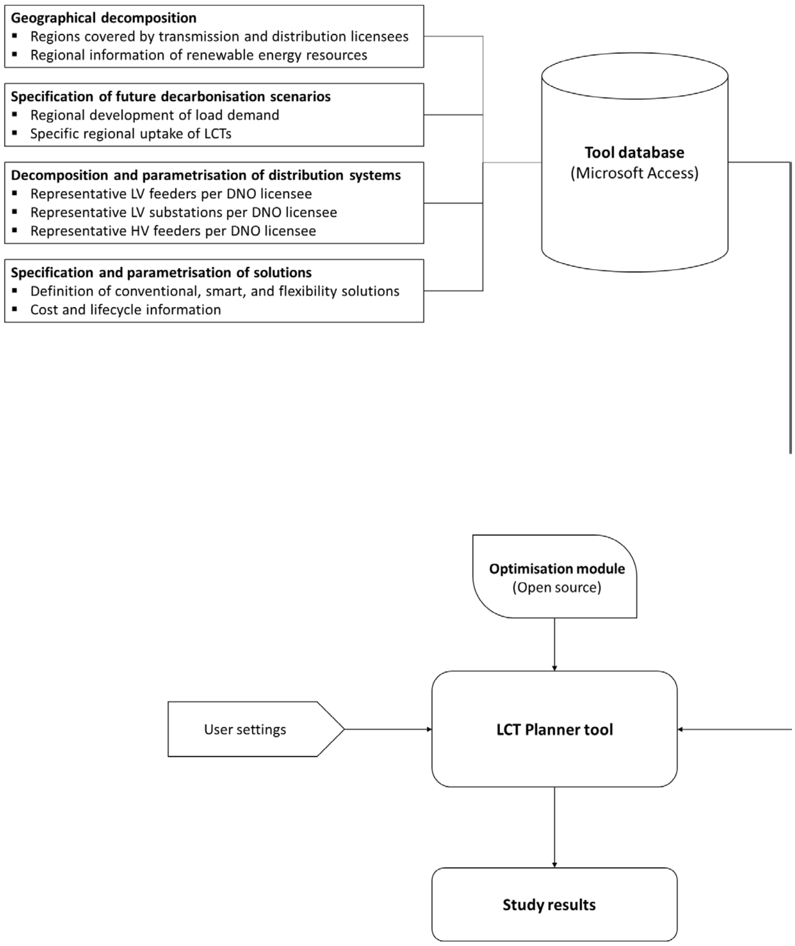

Figure 25 Overall architecture of LCT Planner

There are three major components within this as follows:

- LCT Planner Tool - developed in Visual Basic for Applications using Microsoft Excel as a host application for presenting the user interface custom forms. It contains the code to interact with user, database and solver, runs simulations and provides study results.
- Optimisation Module - which is called on to solve mathematical models generated by the LCT Planner and depends upon the optimisation library 'LP Solve'
- The Database - which holds pre-processed data required to carry out desired techno-economic studies. The database includes, among other things, LCT uptake scenarios for EVs and heat pumps, loading scenarios and solutions and costs for increasing network capacity, as illustrated below. It should be noted that all data in the database can be updated by the user.

Networks Representation

In the LCT Planner tool, representative substations were created by analysing data extracted from each DNO's Long Term Development Statement (LTDS) (Scottish and Southern Electricity Networks, 2022) and (Scottish Power Energy Networks, 2022). A technique known as cluster analysis, which is used in machine learning and pattern recognition, was performed on the processed feeder and substation datasets to produce representative components to be used during the power system analysis phase. It was employed to group together similar feeders using their characteristics (metrics), with dissimilar feeders in other groups. This process yields quantities of each kind of feeder which exist within the UK distribution networks. From these groups of feeders, representative feeders were selected which would be analysed within Power Systems Analysis software. There are Extra High Voltage (EHV), High Voltage (HV) and Low Voltage (LV) representative feeders.

The LCT Planner tool performs cost-benefit analyses using incremental loadability figures pertaining to each feeder class, determined during the development of the tool via power systems modelling in DIgSILENT Power Factory.

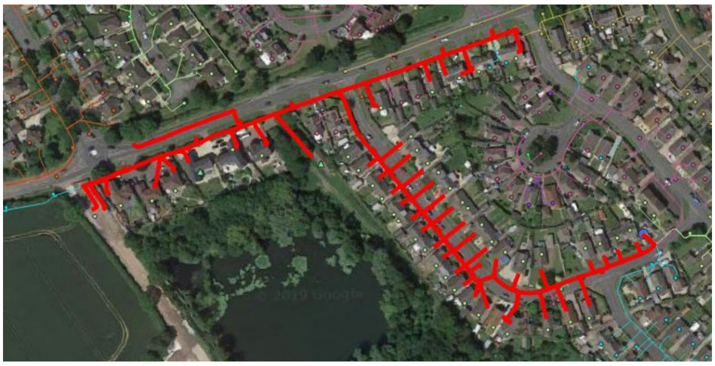

Figure 26 Example LV Representative Feeder

Table 12 contains the breakdown of representative feeders in the LCT Planner tool:

Network element type	Number of representative elements defined
LV feeders	7
HV feeders	10
EHV feeders	7
Secondary substations	7
Primary substations	7
Bulk supply points (BSPs)	7

Table 12 Number of representative elements in the LCT Planner Tool

While these representative network elements provide a detailed decomposition of the network under analysis, significant variation exists within each representative component in terms of the conductor size, material, rating, customers numbers, and so on. Using a single model per representative component would lead to 'all or nothing' type investments, the costs of which would be multiplied by the volume of the component in each region. To avoid this issue, variants of each component are used, which feature the same feeder topology (lengths, conductor size, etc.) or transformer rating but have variations in their customer numbers and initial loading levels. The number of representative feeders for each of the DNOs are shown in the tables below.

Identifier	SPEN	SSEN
LVFT02	6722	2521
LVFT06	4526	1697
LVFT07	27154	10183
LVFT08	10249	3844
LVFT09	2928	1098
LVFT10	3128	1173
LVFT11	532	200

Table 13 LV Feeders quantities for each DNO

Identifier	SPEN	SSEN
HV1	1146	555
HV2	768	176
HV3	83	38
HV4	60	10
HV5	100	41
HV6	77	15
HV7	113	105
HV8	101	76
HV9	152	286
HV10	109	216

Table 14 HV Feeders quantities for each DNO

Identifier	SPEN	SSEN
EHV1	13	16
EHV2	12	34
EHV3	25	161
EHV4	22	15
EHV5	80	137
EHV6	0	0
EHV7	13	0

Table 15 EHV Feeders quantities for each DNO

Infrastructure reinforcement solutions

<table>
<tr><th></th><th colspan="3">Feeders</th><th colspan="3">Substations</th></tr>
<tr><th></th><th>EHV</th><th>HV</th><th>LV</th><th>EHV</th><th>HV</th><th>LV</th></tr>
<tr><td rowspan="5">Solutions</td><td>Overlay</td><td>Overlay</td><td>Overlay</td><td>Extra Transformer</td><td>Upgrade Pole Mounted (PM)</td><td>Extra Transformer</td></tr>
<tr><td rowspan="4">Parallel</td><td>Rebalance</td><td>Split</td><td>New Substation</td><td>Upgrade Ground Mounted (GM)</td><td>New Substation</td></tr>
<tr><td>Split</td><td rowspan="3">On-load Tap Changer</td><td rowspan="3">Upgrade substation</td><td>New Pole Mounted (PM)</td><td rowspan="3">Upgrade substation</td></tr>
<tr><td>Voltage Control</td><td rowspan="2">New Ground Mounted (PM)</td></tr>
<tr><td>Voltage Regulation</td></tr>
</table>

Table 16 Infrastructure reinforcement solutions

Infrastructure reinforcement solutions represent conventional reinforcements which have traditionally been used by electricity network operators for many years. Uprating transformers, splitting feeders, reconductoring overhead lines or using higher cross-section sizes for underground cables are examples of conventional solutions.

Practical aspects of conventional measures such as lead time, life expectancy, capital expenditure, operational cost and future value of assets have been modelled in the LCT Planner and can be updated. This would allow fair comparison between network solutions and flexibility services in the optimisation process. Conventional solutions enhance the capacity of the electricity network where their incremental capability needs to be advised through power system studies and/or expert view. This information is stored in the tool database where users can amend relevant data. It is also possible to add additional solutions to the database subject to supplying associated parameters.

The incremental impact of network solutions is represented through the concept of "Loadability". Loadability is basically a maximum level of demand that can be placed on an electricity network before a compliance issue occurs. Considering that solutions addressing thermal and voltage issues have long lead times and normally require considerable investments, the loadability concept has been limited to two major loadability limits called "Thermal Loadability" and "Voltage Loadability". The first one represents the maximum demand which an electricity network can handle before facing thermal limitations, while the second one shows the same concept but for the case of voltage issues. The LCT Planner determines which one of these loadability limits should be considered depending on the network limits under study. As an example, if voltage loadability of a network is less than its thermal loadability, the optimisation process would explore solutions that can fix voltage issues on their own or as by-product of additional thermal capacity. In other words, the minimum loadability level would be utilised for investment planning, being either thermal or voltage.

Flexibility solutions

Solution	Voltage level	Availability	Intake		Release	
			Time interval	Value in p.u.	Time interval	Value in p.u.
Demand flattening	Extra High	20%	7:00-16:00 17:00-22:00	[-0.2, -0.1] [0.05, 0.25]	N/A	N/A
	High	20%	7:00-16:00 17:00-22:00	[-0.2, -0.1] [0.05, 0.25]	N/A	N/A
	Low	20%	7:00-16:00 17:00-22:00	[-0.2, -0.1] [0.05, 0.25]	N/A	N/A
Demand response	Extra High	20%	17:00-20:00	0.5	21:00-00:00	0.5
	High	20%	17:00-21:00	0.5	12:00-16:00	0.5
	Low	20%	17:00-21:00	0.5	12:00-16:00	0.5
Heat pumps	Extra High	40%	17:00-21:30	1	N/A	N/A

	High	40%	17:00-21:30	1	N/A	N/A
	Low	40%	17:00-21:30	1	N/A	N/A
Electric vehicles charging	Extra High	40%	17:00-20:00	1	21:00-00:00	1
	High	40%	17:00-21:00	1	00:00-04:00	1
	Low	40%	18:00-22:00	1	01:00-05:00	1

Table 17 Flexibility solutions

Table 17 describes the flexibility services that were considered for this study. The flexibility solutions are applied to both representative feeders and substations. The voltage level indicates to which voltage level each flexibility solution is related to. The availability indicates the maximum percentage of the demand, electric vehicles, and heat pumps that could participate in flexibility services. Intake indicates when some flexibility could be purchase and the demand could potentially decrease. Release indicates when the demand that participated in the flexibility services could return to normal operation and perform the activities that would have been performed during the peak time. The time interval indicates when the flexibility service could operate. The value in per unit (p.u.) indicates how much the demand could decrease (positive in intake and negative in release) or increase (negative in intake and positive in release).

- Demand flattening is a flexibility services that allow users to strategically increase their demand during well-known periods of low demand (07:00-16:00) and decrease their demand during periods of peak demand periods (17:00-22:00). In this case, the decreased demand is not expected to be allocated in another time.
- Demand response aims to move the demand from peak demand periods to low demand periods.
- Heat pumps flexibility have a similar behaviour as demand flattening. Forty percent of the demand coming from heat pumps is candidate for flexibility services. The heat pumps could decrease their electricity demand up to 100% during peak time periods. A previous WSP study for ENA (WSP, 2020) used sensitivity analysis to identify that using 40% of heat pump demand for flexibility helps to achieve a reduction in peak demand that could defer the installation of new infrastructure solutions. This could be achieved by either not using the heat pump during peak periods or by switching to an alternative energy vector such as gas or hydrogen.
- Charging of electric vehicles is another good source of flexibility. Electric vehicles could charge during periods of low demand instead of charging during peak time.

Appendix C Results for SSEN and SPEN

Analysis for SPEN

The LtW scenario for SPEN's licenced area is the most expensive in terms of network investment as shown in Table 18 and Table 19. The result is expected as this is the scenario with the highest stress for the network, which is caused by the highest uptake of EVs and HPs of all scenarios. The second most expensive scenario is CT. This scenario has a high uptake of EVs and HPs but not as high as the previous scenario. Furthermore, there is a small decline of EVs around 2040, which helps to decrease the stress in the system when more HPs are being installed. System Transformation has a significantly lower uptake of HPs and a slower EV uptake compared to the previous scenarios. This lower uptake of HPs causes a decreased stress on the network and therefore requires a lower level of investment. The scenario with the lowest investment cost is SP. This is expected as this is the scenario with the lowest uptake of HPs and the slowest uptake of EVs. This scenario shows also how predominant the demand coming from HPs is compared to EVs and how then HPs could be the major drivers of investment cost. This can be concluded by observing the table below and comparing with the uptakes in Figure 19, Figure 20, Figure 23 and Figure 24.

	Flexibility	Consumer Transformation	Leading the Way	System Transformation	Steady Progression
Total Investment (£m)	No	2,337.2	2,733.1	1,881.6	1,776.7
	Yes	1,857.6	1,768.1	1,288.0	1,245.3
Cost per dwelling (£)	No	1,015.0	1,187.0	817.0	772.0
	Yes	807.0	768.0	560.0	541.0

Table 18 Summary of non-discounted costs for all scenarios in SPEN licenced area

	Flexibility	Consumer Transformation	Leading the Way	System Transformation	Steady Progression
Total Investment (£m)	No	1,441.7	1,752.6	1,102.4	972.6
	Yes	1,083.9	1,147.3	773.1	684.9
Cost per dwelling (£)	No	626.0	761.0	479.0	422.0
	Yes	471.0	498.0	336.0	298.0

Table 19 Summary of discounted costs for all scenarios in SPEN licenced area

Figure 27 and Figure 28 show the total non-discounted and discounted investment for all scenarios disaggregated by different type of feeders and substations. The secondary or LV substations are the elements of the system that require the highest level of investment followed by LV feeders for all scenarios. The next biggest expenses are the HV feeders and substations and last come the EHV feeders and substations, with the EHV feeders requiring the least investment.

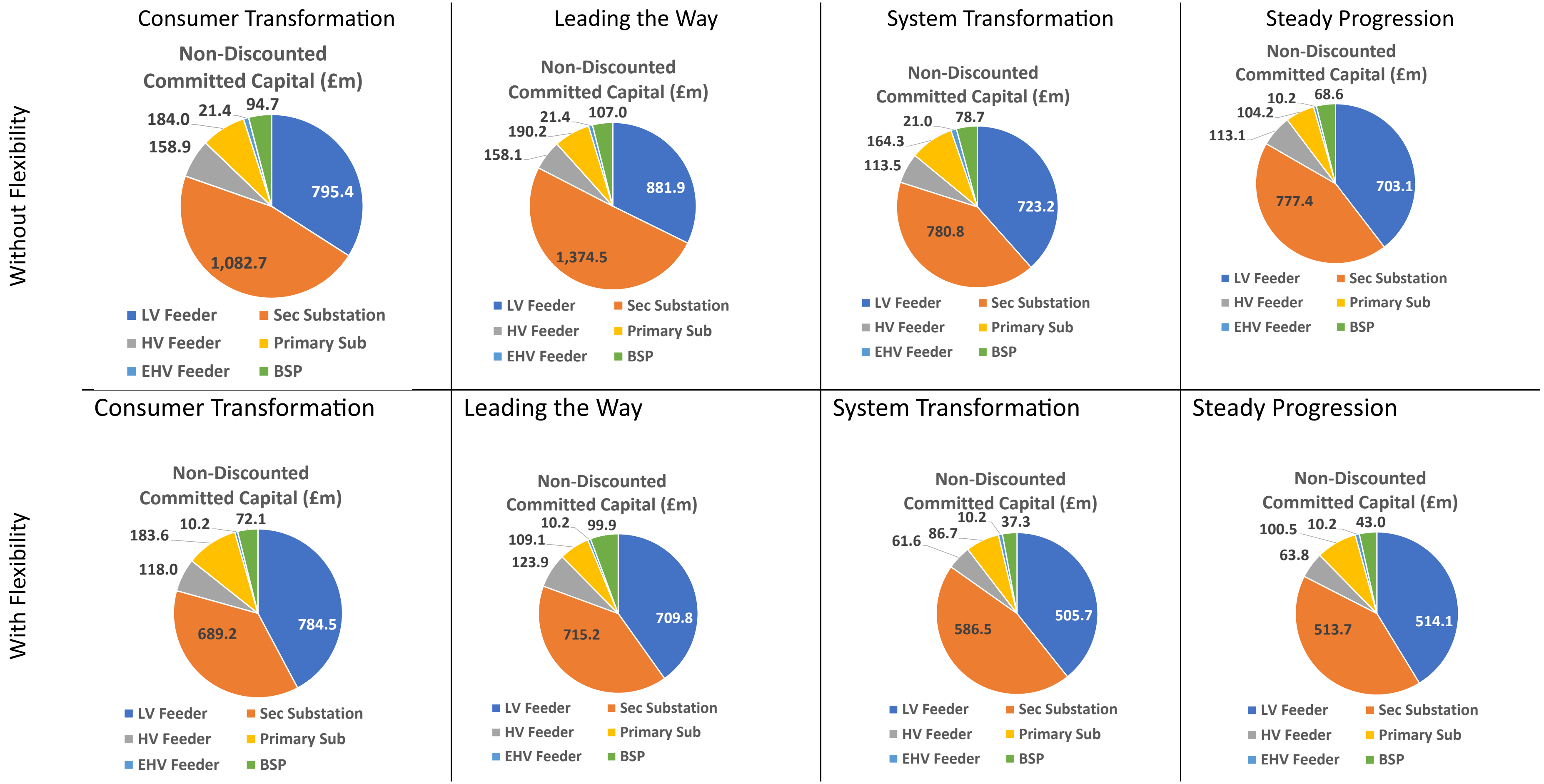

Figure 27 Non-discounted committed capital for all scenarios in SPEN licenced area

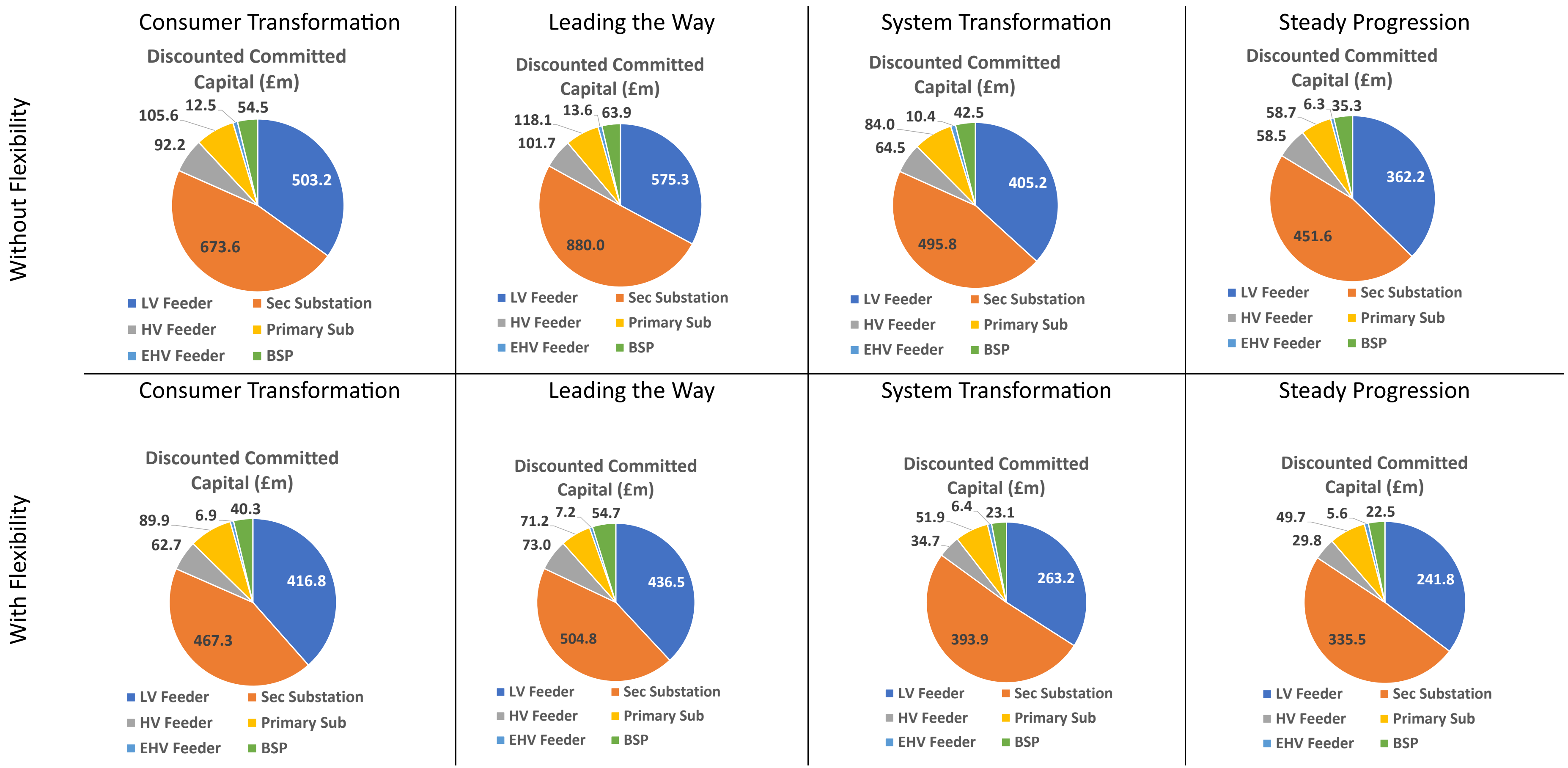

Figure 28 Discounted committed capital for all scenarios in SPEN licenced area

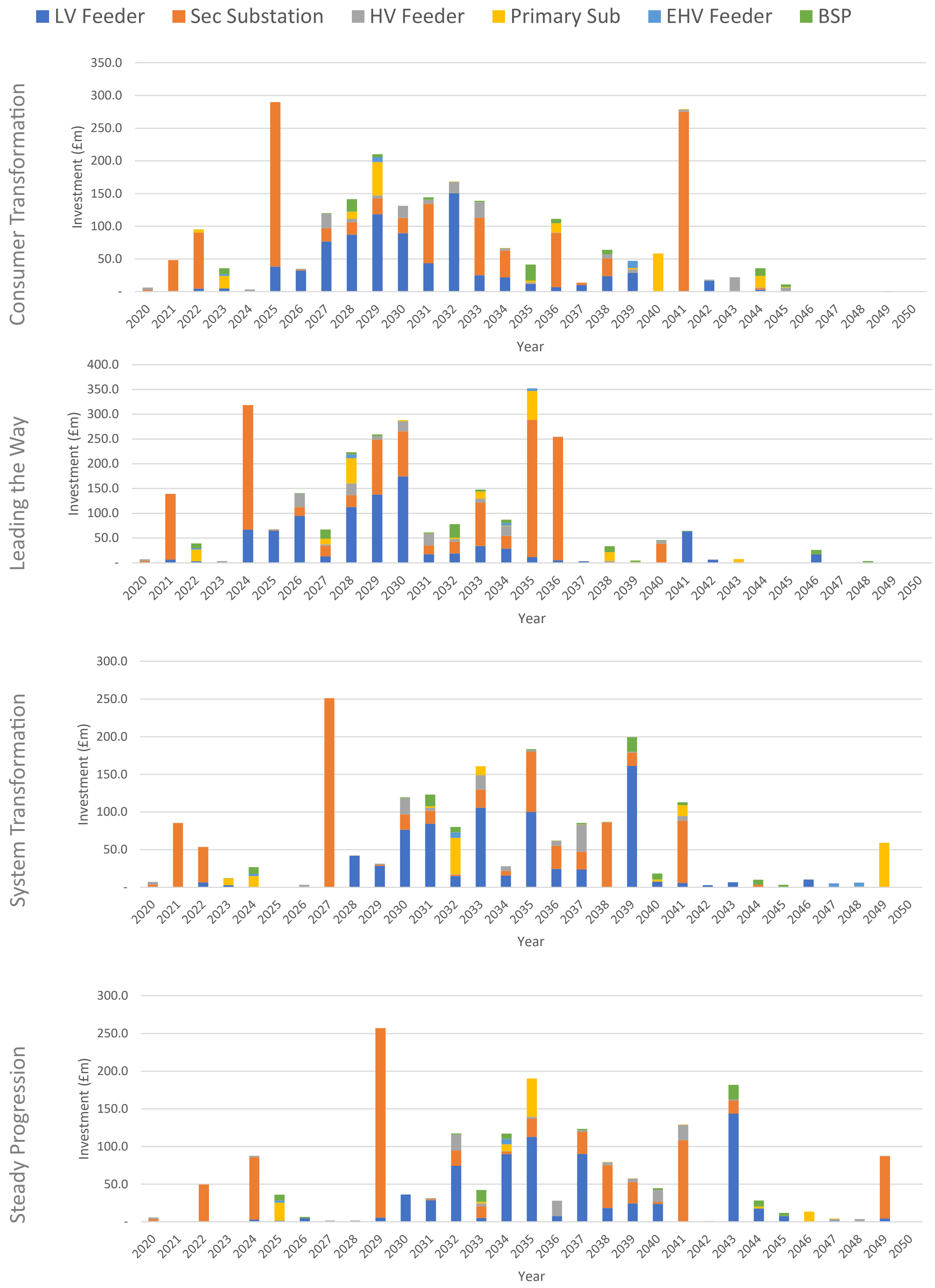

Figure 29 Yearly non-discounted committed capital for all scenarios in SPEN licence area without flexibility

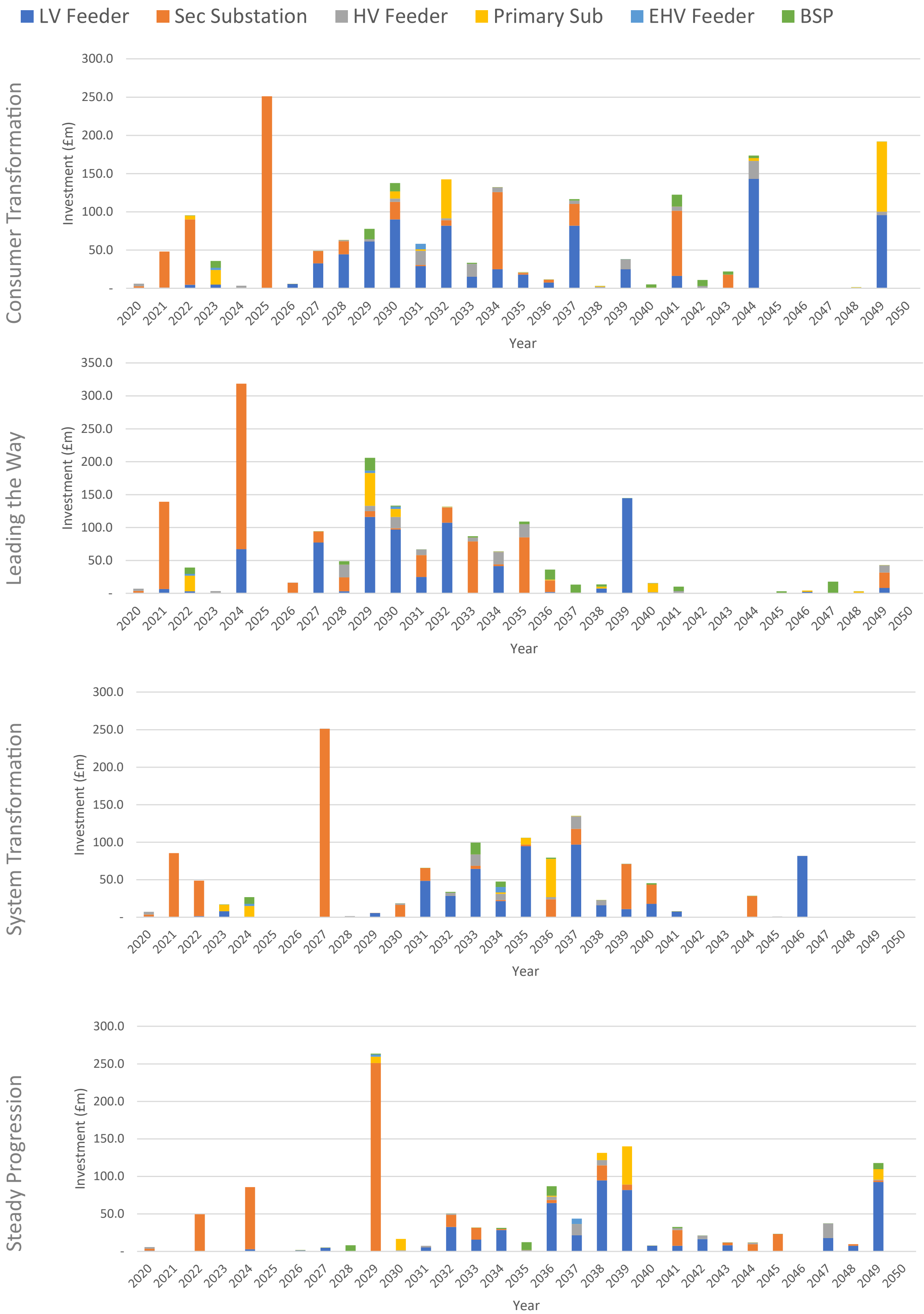

Figure 30 Yearly non-discounted committed capital for all scenarios in SPEN licence area with flexibility

Analysis for SSEN

The CT scenario is the most expensive for SSEN as shown in Table 20 and Table 21, which is caused by having the highest uptake of HPs from 2038 until 2050. Additionally, the uptake of EVs reaches values close to 90% in 2043. The second most expensive scenario is LtW, which has the second largest uptake of heat pumps of all scenarios and has its peak uptake of EVs in 2039. The next most expensive scenario is SP, which has the lowest uptake of heat pumps by 2050. However, this scenario has the highest uptake of EVs by 2050. Finally, the ST scenario requires the lowest investment of them all. This scenario has a slightly higher uptake of heat pumps by 2050 compared to the SP scenario. However, the uptake of EVs is lower in the ST scenario in the last few years, which end up removing the need for additional investments.

	Flexibility	Consumer Transformation	Leading the Way	System Transformation	Steady Progression
Total Investment (£m)	No	1,181.2	1,119.8	822.8	896.9
	Yes	743.5	679.0	535.6	543.1
Cost per dwelling (£)	No	1,369	1,297	953	1,039
	Yes	861	787	621	629

Table 20 Summary of non-discounted costs for all scenarios in SSEN licenced area

	Flexibility	Consumer Transformation	Leading the Way	System Transformation	Steady Progression
Total Investment (£m)	No	717.0	724.8	483.2	491.6
	Yes	460.7	449.1	323.8	317.4
Cost per dwelling (£)	No	831	840	758	570
	Yes	534	520	375	368

Table 21 Summary of discounted costs for all scenarios in SSEN licenced area

Figure 31 and Figure 32 show the total non-discounted investment cost disaggregated by feeders and substations. The bulk of investment is used to adapt LV feeders and substation to the new demand. Another major component is the upgrade of primary or HV substations in the licenced area.

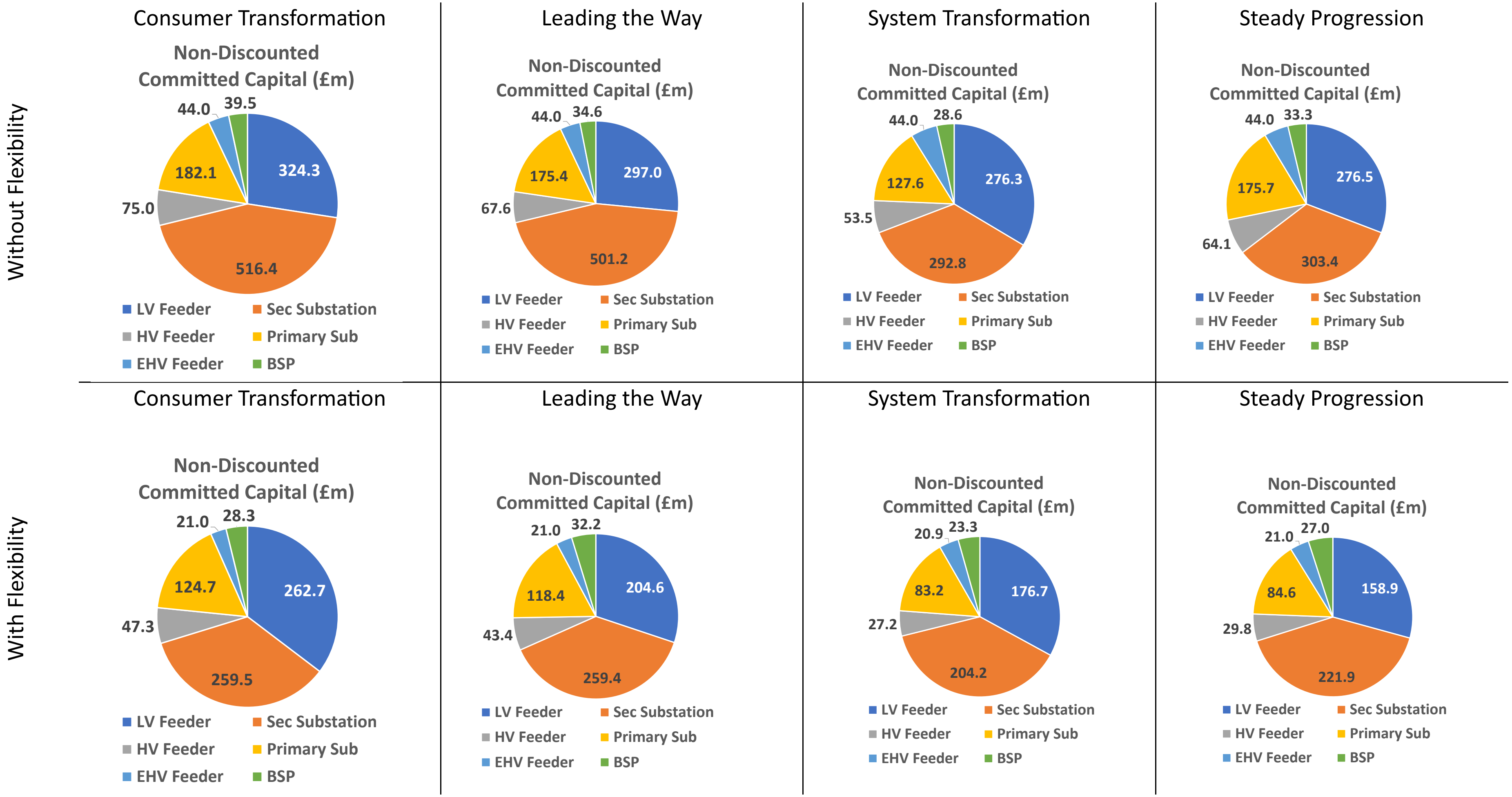

Figure 31 Non-discounted committed capital for all scenarios in SSEN licenced area

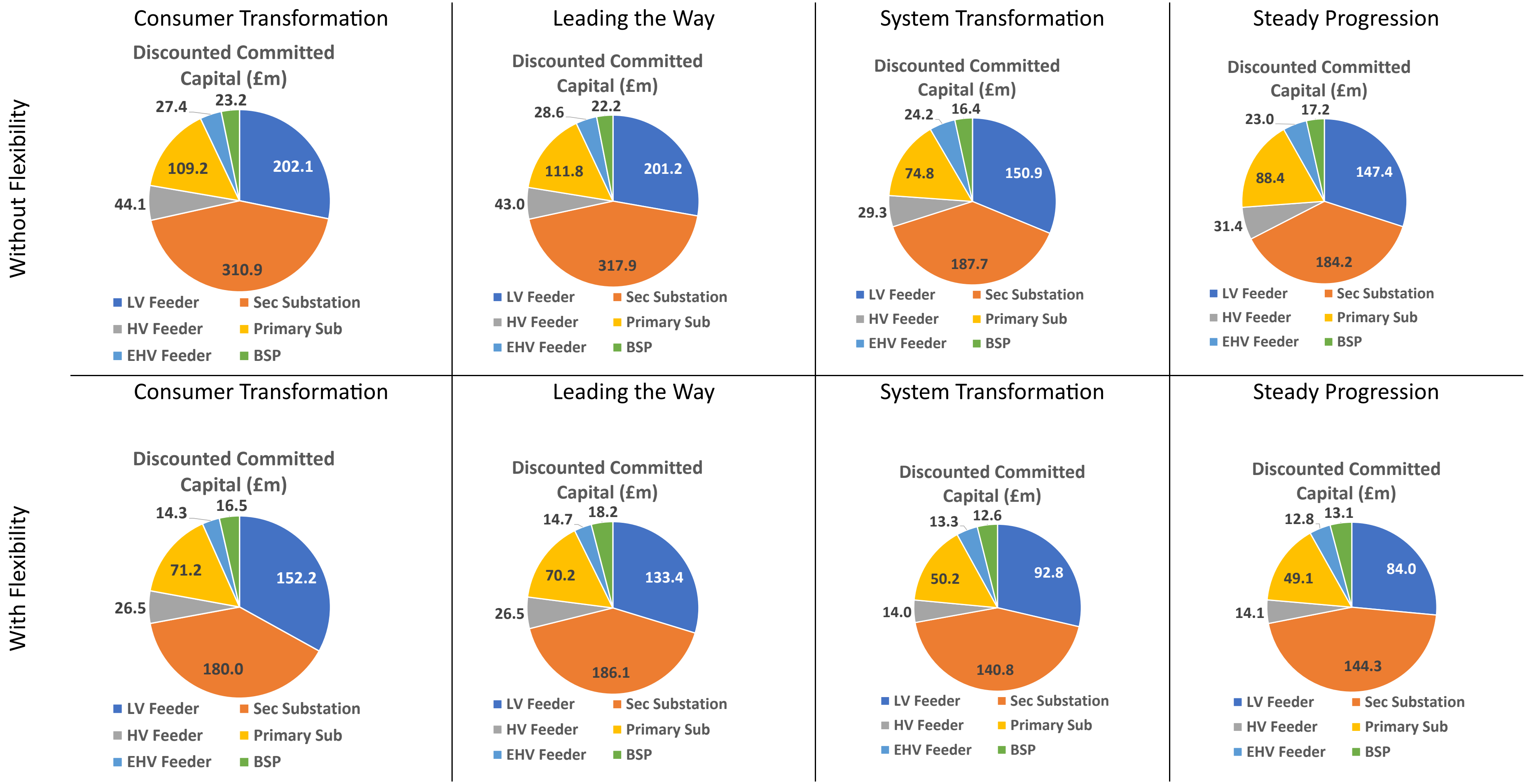

Figure 32 Discounted committed capital for all scenarios in SSEN licenced area

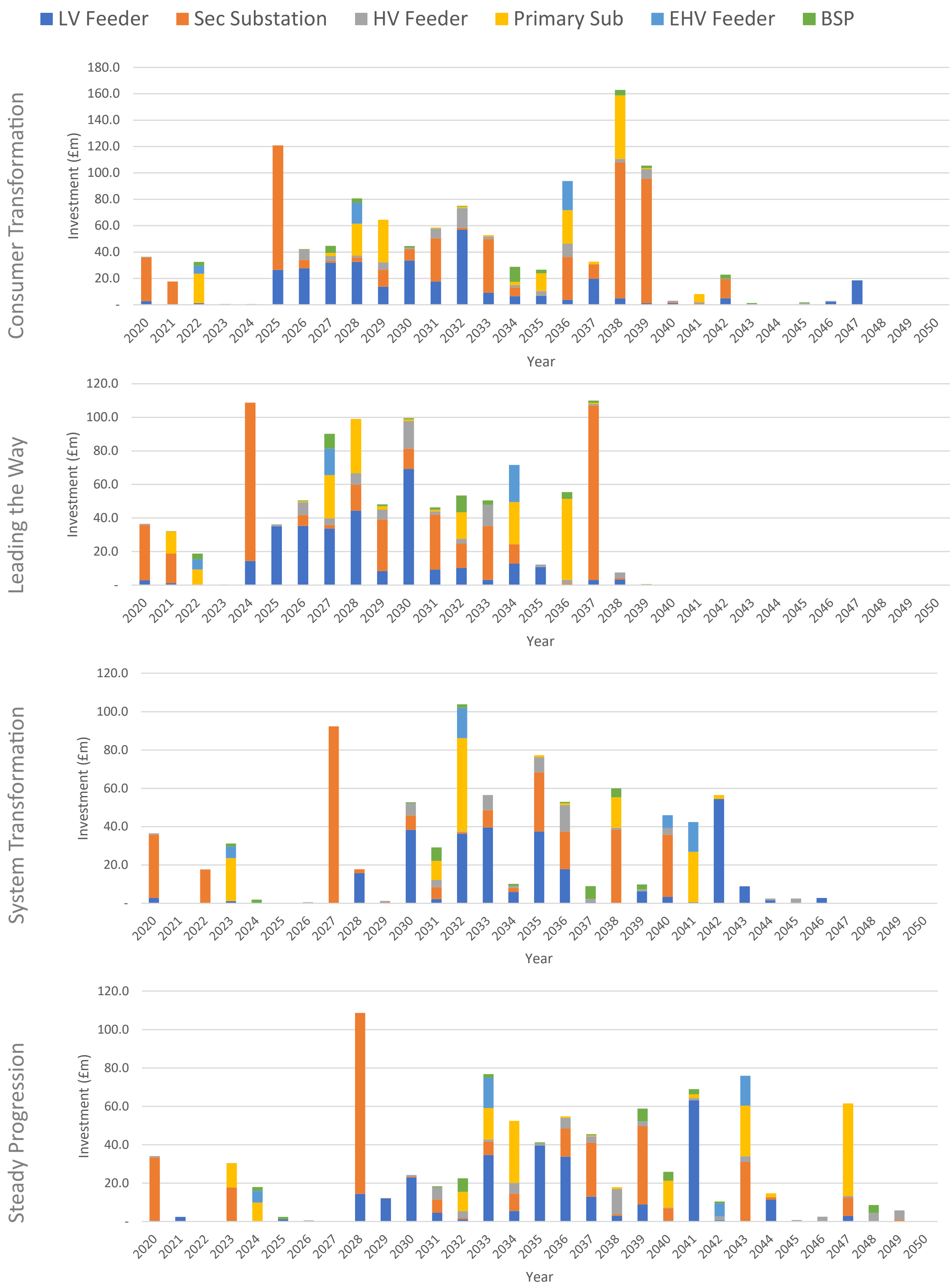

Figure 33 Yearly non-discounted committed capital for all scenarios in SSEN licence area without flexibility

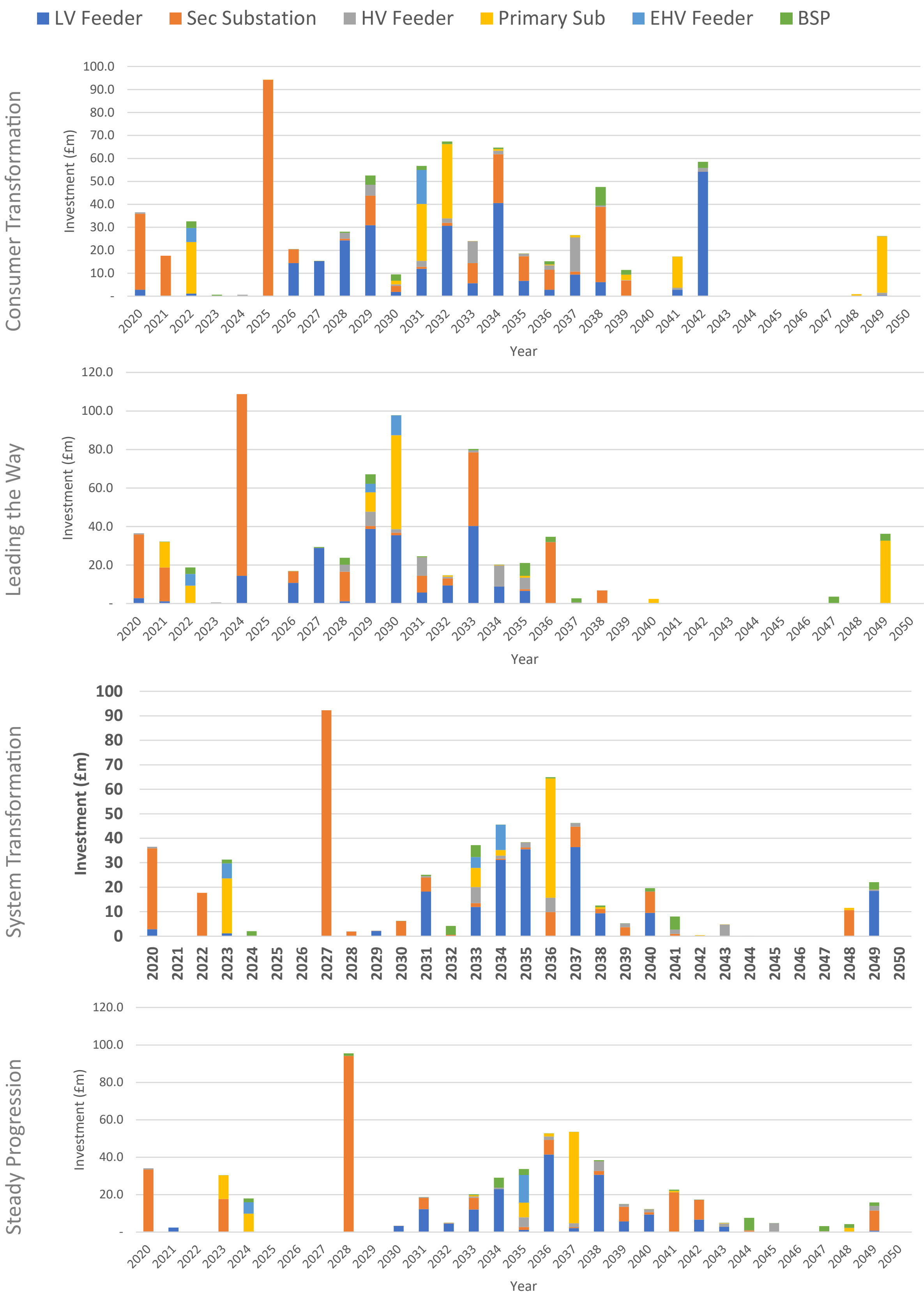

Figure 34 Yearly non-discounted committed capital for all scenarios in SSEN licenced area with flexibility

Appendix D Comparison of LCT planner and CXC archetypes

The LCT planner uses a number of customer archetypes to consider domestic dwellings. These are customer segmentations that help to determine the electric energy consumption of different dwellings based on social and economic metrics. This appendix provides greater detail about the archetypes used in the LCT Planner tool and attempt to link these with the archetypes used by ClimateXChange in previous work.

LCT Planner Archetypes

Archetypes used within the LCT planner tool are taken from Experian's Mosaic UK customer segmentation (Experian, 2013), created during the Customer Led-Network Revolution (CLNR) project. Within the study area considered in this report, a sub-section of six of these archetypes were required.

Within the LCT planner tool, each archetype has a half-hourly electric energy consumption profile, which is used by WSP to estimate the investment cost for each of the feeders considered. To do so, each Low Voltage (LV) feeder was assigned a specific type of archetype as shown in Table 22. This table also shows the number of households that belong to each of the archetypes within the study area.

Archetypes		Feeder Type	Number of Dwellings		
			SPEN	SSEN	Scotland
A	Alpha Territory	LVFT02	155,514	58,324	213,838
C	Rural Solitude	LVFT11	1,234	464	1,698
D	Small Town Diversity	LVFT09	58,517	21,944	80,461
		LVFT10	66,142	24,804	90,946
F	Suburban mindsets	LVFT06	199,258	74,711	273,969
H	New Homemakers	LVFT08	276,057	103,539	379,596
N	Terraced Melting Pot	LVFT07	1,314,118	492,807	1,806,925
Total number of domestic dwellings			2,070,840	776,593	2,847,433

Table 22 Scottish Energy Consumer Archetypes considered in WSP's LCT Planner tool

ClimateXChange Archetypes

The following description was extracted from the report "Domestic energy consumer archetypes: segmentation profiles" (ClimateXChange, 2020):

"Eight Scottish energy consumer archetypes have been developed following an extensive review of existing segmentation approaches and consultation with stakeholders. The archetypes serve as a tool that enables users to take a more detailed review of different consumer issues across the energy sector. It is intended that the archetypes will help enhance understanding of the different experiences and needs of different energy consumers, the different drivers that may exist for households to engage in energy related policies and enable a more considered and nuanced approach to policy design and promotion of energy technologies.”

The archetypes in Table 23 represent a similar market segmentation considered in the Experian Mosaic UK analysis. These groups are also of interest when considering impact of customer bills because of links to previous work undertaken by the Scottish government.

Archetypes		Number of households	Average net income	Main rurality	Long-term illness or disability	Energy market engagement
1	Single low-income renters using electricity for heating	245,000	£18,700	Mixed	42%	8%
2	Urban very low-income single older adults	289,800	£11,600	Urban	43%	24%
3	Switched on wealthier couples and families	597,000	£41,700	Urban	17%	84%
4	Families or younger couples in urban areas	418,700	£19,400	Urban	7%	42%
5	Wealthy rural families	99,300	£42,400	Rural	21%	55%
6	Older urban couples who own their homes outright	320,600	£25,100	Urban	44%	63%
7	Urban social renters with long term health problems	285,400	£17,400	Urban	92%	25%
8	Rural, less affluent older adult households	174,500	£22,800	Rural	30%	30%
All households		2,430,300	£25,100	-	34%	47%

Table 23 Scottish Energy Consumer Archetypes from ClimateXChange. Source: (ClimateXChange, 2020).

Archetype links

The archetypes described above were created with different purposes, using differing metrics to drive the segmentation. As a result, providing a one-to-one matching of customer archetypes is difficult, and it is common to see many archetypes from one group linked to one archetype from another. However, WSP has undertaken a mapping exercise to attempt to link archetypes from different studies. This should aid attempts to relate findings from this study to the CXC archetypes which have previously been used.

CXC archetype	Experian archetype	Rural / urban	Rationale
Single low-income renters using	Terraced Melting Pot	Urban	• Largely reside in terraces, flats, etc in urban environments

CXC archetype	Experian archetype	Rural / urban	Rationale
electricity for heating			• Likely to be a mix of electricity heating vs gas, but expect there to be a high proportion of electricity only heating (and PPM) • Expectation of low-day occupancy
Urban very low-income single older adults	Terraced Melting Pot Small Town Diversity	Urban	• If single and urban, likely to reside in terraces, flats, etc. • Note there is a difference in consumption profile (gas heated) • Segmentation similar to above so the shape of the profile is likely to be the similar
Switched on wealthier couples and families	Alpha Territory	Urban	• Generally wealthy and urban • Large houses driving up the consumption levels
Families or younger couples in urban areas	New Homemakers	Urban	• Low fuel costs and so it is reasonable to assume both archetypes are modern efficient housing. • Consumption profiles are likely to be similar, as both are working families on gas
Wealthy rural families	Rural Solitude Alpha Territory	Rural	• Could face the same issues as Rural Solitude, where locational charges are introduced • Consumption profile may be more akin to others in the Alpha Territory, although they are not on mains gas • Exact conditions depend heavily on geographical circumstances
Older urban couples who own their homes outright	Suburban Mindsets	Urban	• Generally older and urban with reasonable incomes • In both cases, likely to be on mains gas and possibly working lower hours
Urban social renters with long term health problems	Terraced Melting Pot	Urban	• Social housing would generally be in flats, terraces, etc • Consumption profile may not be an exact match, given low levels of employment and possible other health related needs, such as more heating • However, housing stock and likelihood to be on gas, electricity and PPM would be similar
Rural, less affluent older adult households	Rural Solitude	Rural	• Some alignment between these archetypes, although there are likely to be some differences under the Rural Solitude group, such as whether on mains gas or oil/LPG • Both could be badly affected by locational network charges.

Table 24 Mapping of Experian archetypes and ClimateXChange archetypes

If you require the report in an alternative format such as a Word document, please contact info@climatexchange.org.uk or 0131 651 4783.

climate X change

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