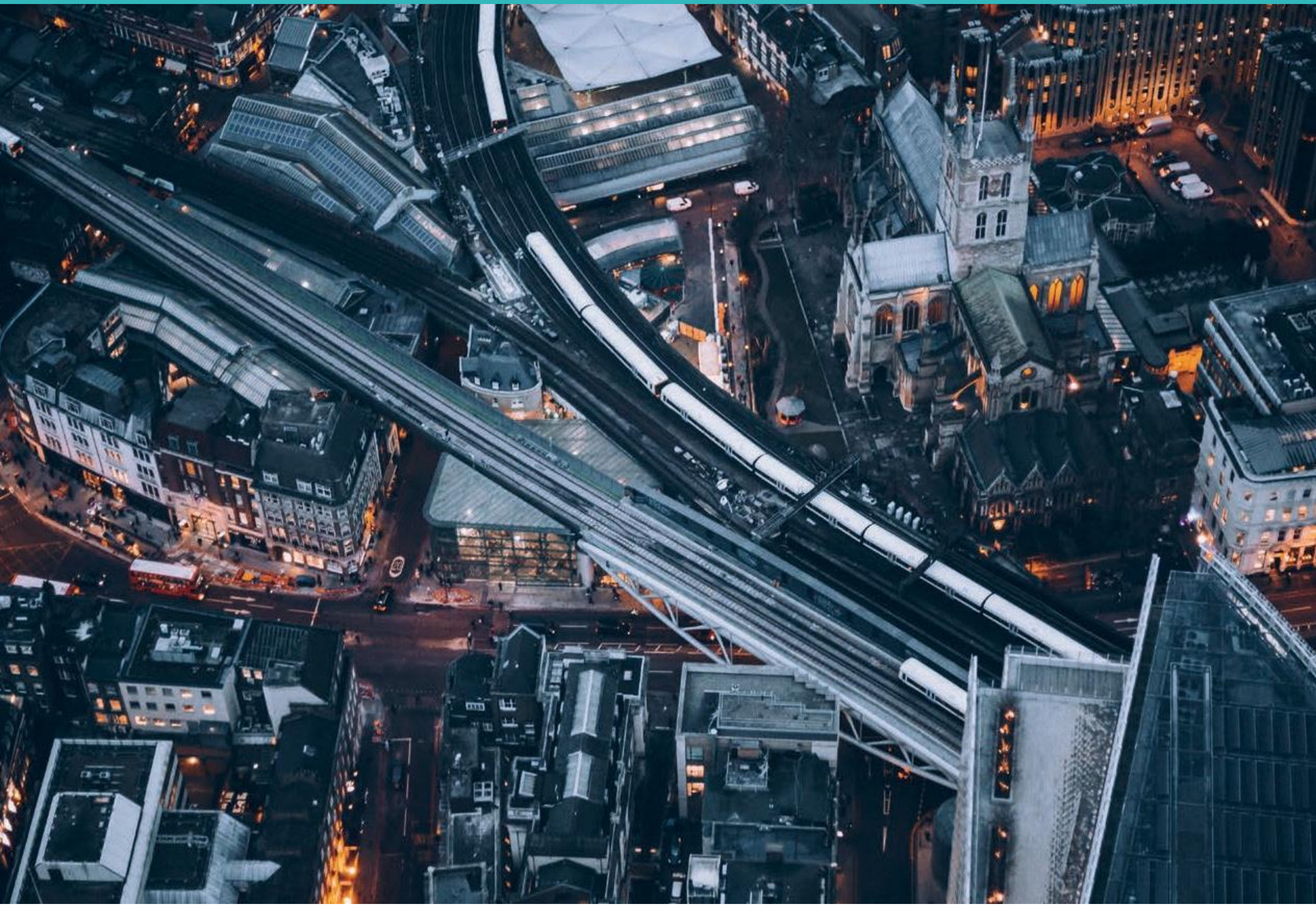

REPORT

EPIC: Evaluation and Learning Report

Prepared for: Western Power Distribution

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technology

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Final Approval

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Executive Summary

Background to the Project

As part of the process to create Distribution Future Energy Scenarios (DFES), gas and electricity utilities consider local and regional factors as well as information from local authority development and decarbonisation plans. Local authorities are consulted and give input to the DFES process. However, the DFES does not wholly adopt or incorporate local authorities' longer term strategic plans, since it is based on national scenarios. The "Energy Planning Integrated with Councils" (EPIC) project has developed and trialled a new process to align plans across energy networks and engage with local authorities. It involved co-creation of energy plans, development of network analysis tools to assess future impacts, creating investment options to ensure networks remain operable and analysing use cases, strategies and scenarios to create a holistic and strategic investment plan. EPIC is a Network Innovation Allowance (NIA) project funded by Western Power Distribution (WPD) and Wales and West Utilities. It is being delivered by a consortium of project partners:

- Regen to support the development of new processes with local authority and to develop the tool to support the creation of the Integrated Investment plan.
- Wales & West Utilities (WWU) to support process development and providing network investment options for the gas network.
- West of England Combined Authority (WECA) to assist with process development, trial area selection etc.
- PSC to develop the HV network analysis automation tool.
- EA Technology to adapt the Network Investment Forecasting Tool (NIFT) and use it to assess WPD's LV networks.
- The local authorities for the trial areas. The trial areas for EPIC are South West Bristol Strategic Planning Area (SPA), Bristol North Fringe SPA, Bath Enterprise Zone SPA.

Scope and Objectives

The objectives of the overall EPIC project, delivered by the project partners were to:

- Develop a standardized process that can be used with different local authorities to create a local energy plan.
- To create energy plans for the three trial areas
- To determine how to reflect the local energy plans in the DFES used for network planning purposes
- To disaggregate the DFES data to support LV and HV planning
- To develop a tool to support automated analysis of HV networks and suggest network remedies
- To analyse the HV and LV networks associated with at least one primary substation in the trial areas and provide a view of the network and non-network solutions under different investment strategies
- To develop a tool to allow the investment plans for electricity networks, gas networks and the local authorities to be compared to identify potential synergies
- To use the tool to create an Integrated Investment Plan in the trial areas.
- To refine the processes to reflect the learning gained during the project.

The purpose of this report is to document the process used and findings in relation to the modelling of the LV network as part of the EPIC process. Outputs from the LV modelling were used in two main ways:

- Determining the level of reinforcement of the LV network required for the various plans, the cost of this, and evaluating different investment strategies, via the Cost Benefit Analysis (CBA) being completed by Regen.
- Passing data on demand on the LV network to the HV Network Assessment Tool (NAT) (developed by PSC) as an input.

This document sets out the key findings from the LV network analysis completed by EA Technology and the lessons learnt for future, similar modelling projects. Further conclusions based on the data outputs from the LV modelling will also be reported by other project partners – for example, at the conclusion of the CBA work by Regen.

Conclusions

Conclusions have been split into three – those relating to the results of the modelling (comparisons between use cases and comparison between primary substation areas) and to the EPIC process and how similar modelling work could be undertaken in the future.

Comparison of Scenarios:

C1. Across the majority of LCT uptake scenarios and primary substation areas the proportion of both LV feeders and distribution transformers with constraints increases through the study period as LCT uptake increases. The size of the increase is highly variable between primary substation areas. In all cases, LV feeder constraints are more common than constraints on distribution transformers.

C2. The graph below compares the proportion of feeders constrained in each of the use cases in 2019 and 2050 (the start and end of the modelling period).

C2.1 In 2019 the level of constraints is very similar between the use cases as LCT adoption and energy efficiency savings increase as the modelling period progresses. The level of constraints in 2019 is artificially high (compared to network conditions today) due to data inaccuracies.

C2.2 The 2050 figures show the level of variation between use cases. The difference between the use cases is generally low, with the largest difference compared to the baseline scenario occurring in the medium energy efficiency scenario, where 41.8% of feeders are constrained in 2050, compared to 44.3% in the baseline scenario.

C2.3 This shows that the level of constraints is relatively insensitive to differences modelled in this project between various use cases. Across all scenarios there is a revolutionary change in levels of electricity consumption – this is consistent with the findings of other modelling work such as the National Grid Future Energy Scenarios. Against this dramatic increase as a result of widespread electrification the variations between scenarios are much smaller.

C2.4 The lack of variability between scenarios can give confidence in investment for net zero – similar investment is needed regardless of the exact scenario/pathway is followed.

C3. The graph below compares the proportion of distribution transformers constrained in each of the use cases in 2019 and 2050 (the start and end of the modelling period).

C3.1 Transformer constraints are much less common in the NIFT results for 2019. As expected they are consistent across the various use cases, with approximately 8% of transformers having a constraint at the start of the modelling period.

C3.2 The EV use cases result in minimal differences in the level of constraints observed in 2050, varying between 10.2 and 10.4%.

C3.3 The heat pump scenarios result in the largest differences between a use case and the baseline scenario. Higher uptake of the flexible profile results in 12.3% of distribution transformers being constrained in 2050, compared to 10.4% in the base case (low uptake of the flexible profile). This increase in constraints may be due to the pre-heating creating a new, higher peak, just prior to the traditional evening peak period.

C3.4 Increased energy efficiency savings result in a small (1%) decrease in the prevalence of distribution transformer constraints.

C4. NIFT was also used to model the interventions required to resolve the network constraints identified. The profile of expenditure was strongly affected by data inaccuracies which cause a large number of apparent constraints in 2019. This modelling could be repeated in the future if the underlying data quality was improved to assess how this has affected the outputs. Across all scenarios, approximately 75% of investment was made in 2019. The profile of investment remained similar across the use cases with a further small peak in investment in 2040. The large investment in 2019 provided substantial additional capacity to accommodate growth in demand due to LCT adoption without requiring further investment. However, this issue was common to all LCT adoption/energy efficiency scenarios and so comparisons between scenarios remain valid. The graph below compares the total investment over the study period between use cases.

C4.1 The variation in total investment between the use cases and the base case is different between the scenario types as follows:

C4.2 EV Scenarios: total capital investment varies very little – between 98.6% and 101.1% of the base case.

C4.3 Heat Pump Scenarios: this is the scenario with the greatest variation compared to the base case. High uptake of the flexible profile increases investment requirements to 109% of the base case. Increased uptake of hybrid heat pumps, which switch demand from the electricity to gas network during the winter and intermediate cool peak periods results in 97% of the baseline level of expenditure.

C4.4 Energy Efficiency Scenarios: a higher level of energy efficiency results in a reduction of capital expenditure – 92% of the baseline amount.

C4.5 Considering all six primary substation areas in aggregate, the 'Fit for the Future' investment strategy (larger initial investments to avoid multiple interventions over the medium term) increases capital expenditure slightly. However, this result varies between primary substation area and is likely to be more strongly affected by the investment requirements in 2019 which are a result of data inaccuracies.

C5. The results presented above consider only the capital investment required for the LV network. These results alongside other metrics have been shared with Regen to all a whole system CBA to be undertaken, and the results of this are reported separately.

C6. The type of solutions which are deployed varies through the study period. The large amounts of capacity created in the baseline year (2019) is made up from conventional solutions, or a mix of a conventional solution with a smart one. In the latter parts of the study period (particularly the 2040s) smart solutions are deployed more widely (around 60% of investment). The use case or investment strategy can result in some changes to the type of interventions deployed.

Comparison of Primary Substation Areas:

C7. In this project six primary substation areas were modelled across the three SPAs. This allowed comparisons to be made between primary substation areas as well as between use cases. The results of the modelling of the level of constraints demonstrated:

C7.1 Broad conclusions about which scenario/use case leads to lower levels of constraints are consistent across multiple primary substation areas. This is particularly true for the EV use cases studied, where the level of difference between scenarios was small across all scenarios and primary substations. The overall conclusion that the level of constraints is relatively insensitive to the EV use cases is valid for all the modelled primary substation areas. The results are more variable for heat pump scenarios. This is perhaps to be expected as the differences in the underlying profiles (e.g. for hybrid vs. non-hybrid heat pumps in winter) is greater than in the EV scenarios. Modelling a subset of primary substation areas is likely to be sufficient to draw conclusions about which scenarios give lower/higher level of constraints.

C7.2 However, to predict the absolute level of constraints for a given network then detailed modelling of that specific is required due to high variability in the results.

C7.3 The variation in the level of constraints comes from a range of factors including the age and condition of the network and the number and type of customers supplied, as this will affect the LCTs likely to be taken up in an area.

C8. The capital investment required was also highly variable between primary substation areas, demonstrated by the graph below, which also compares the investment strategy use case:

C8.1 This demonstrates the variation in capital expenditure between the primary substation areas (from £1.3 million at Cribbs Causeway in the 3 year scenario to £10.4 million at Bedminster in 20 year scenario). This variability comes from both the underlying variability in the level of constraints between primary substation areas, and also differences in the size and type (underground vs. overhead) of the LV network.

C8.2 Figure 54 also shows an example where the conclusion about which use case/scenario leads to the lowest total cost varies between primary substation areas.

C8.3 For the other three use cases (EVs, heat pumps, energy efficiency) the least expensive strategy is consistent across primary substation areas (or very similar across all scenarios). However the absolute difference compared to the baseline can vary – for example expenditure was always higher in the 'high flexible profile uptake' scenario for heat pumps compared to the baseline. However, it varied between 101% and 114% of baseline at Cribbs Causeway and Filton DC respectively.

EPIC Modelling Process:

C9. As discussed above, inaccuracies in the underlying network data resulted in an unrealistically high prevalence of constraints in the base year. This will have affected the total amount of investment predicted to be required and the profile of the investment. Comparisons between the LCT adoption scenarios remain valid, as this issue affects each of these scenarios equally. The availability of accurate, high quality network data for the area to be studied is key. In this project timescales did not allow for an existing model to be updated, resulting in older, less accurate data being used. As digitalisation of network data increases the availability of accurate models of the network should improve.

C10. The EPIC project was completed as a Western Power Distribution NIA project, with local authorities/SPAs which fell within WPD's licence area. It therefore made use of an existing LV modelling and forecasting tool – NIFT. Local authorities in licence areas other than WPD would need to contact EA Technology to discuss whether NIFT could be used to support their analysis. This would incur additional costs, or they would need to follow a different process in order to undertake the modelling of the LV network. The extent to which other LV modelling packages could be used/their suitability would depend on the size of area being modelled, the number of future years and the technologies included.

C11. Differences between the scenarios depend on both the LCT uptake and the differences between the demand profiles for each technology/operating profile (see Section 3.2 and 3.4.1). Greater confidence on the future operating profile for different technologies would increase confidence in the modelling results. This is particularly true in the case of heat pumps, on-street EV chargers as EV adoption increases and domestic energy storage where there is a lack of substantial trial data from which to generate a suitable profile.

C12. The results from this project have shown that conclusions about which use cases results in higher/lower levels of constraints are consistent across primary substations. However, the absolute level of constraints and the required investment was found to vary between primary substation (see Section 6 and 8). The majority of cost and time expended relates to data preparation, initiating analysis runs (e.g. setting up separately for each use case/scenario due to different input data) and post-processing and interpreting the results. Modelling a larger number of primary substations increases the chronological time required to produce results, but this is a 'hands off' process (i.e. NIFT can be left to run all the required substation areas). The costs associated are much more dependent on the number of use cases/scenarios to be modelled, rather than the number of primary substation areas.

C13. Analysis presented in Section 7 shows that with the existing load/generation profiles it is sufficient to model a smaller number of representative days (winter and summer). The worst case network conditions across all constraint types occurs on either the winter or summer day in at least 89% of cases. Reducing the number of days to be modelled would reduce the time required to produce results and the post-processing needed to consolidate the results from multiple representative days.

C14. In order to model the range of technologies and profiles included in the EPIC project a number of changes were made to the NIFT, including the introduction of additional profiles, adding in the ability to vary the energy consumption between years, and differentiating the number of technologies deployed to Class 1 and Class 2 customers. Each of these changes incurred time and costs to develop and test (e.g. ensuring that the correct profile type was used for each variant of the heat pump profile). Consistency in future modelling exercises would decrease the amount of effort which needed to be expended developing and testing new bespoke elements for different local authorities. This could include using a standard agreed set of technology building blocks and operating profiles and ensuring data is presented in the same format each time.

C15. The modelling and post-processing analysis could be streamlined (less time required to produce outputs) if a common set of outputs was agreed in advance, prioritising data which offers the greatest value to local authority stakeholders. At the time of writing the outputs of EPIC have not been presented to the local authorities involved so it is not clear which outputs are of greatest value. Once a set of consistent outputs had been agreed then an analysis template could be produced, for example in PowerBI, which would automate the post-processing from the granular NIFT outputs to the required summary views.

Recommendations

Recommendations for improving the data used for modelling, reducing the modelling workload and updating the datasets and options are given in section 11. This also highlights that the work appears to have a large peak in 2040 and that some long term resource planning may be required to smooth the peak by bringing forward and pushing back work if possible.

Contents

Figures

Tables

Appendices

1. Definitions

ANM	Active Network Management
CBA	Cost Benefit Analysis
DFES	Distribution Future Energy Scenarios
ENA	Energy Networks Association
EPIC	Energy Planning Integrated with Councils
ESA	Energy Supply Area
LCT	Low carbon technology
LV	Low voltage
NAT	Network Assessment Tool
NGFES	National Grid Future Energy Scenarios
NIA	Network Innovation Allowance
NIFT	Network Investment Forecasting Tool
SPA	Strategic Planning Area
ToU	Time of Use
WECA	West of England Combined Authority
WPD	Western Power Distribution
WWU	Wales & West Utilities

2. Introduction to the EPIC project

As part of the process to create Distribution Future Energy Scenarios (DFES), gas and electricity utilities consider local and regional factors as well as information from local authority development and decarbonisation plans. Local authorities are consulted and give input to the DFES process. However, the DFES does not wholly adopt or incorporate local authorities' longer term strategic plans, since it is based on national scenarios. This could lead to different expectations of future energy requirements between the local authority and the utilities. There is also a potential missed opportunity to align plans across energy networks and to take a more holistic and strategic view of future investment options, which could lead to better investment outcomes for both the networks and for regional stakeholders. To close this gap a new process needs to be developed which will not only align planning assumptions but also provide stakeholder input into the way solutions to network constraints are selected. These solutions may involve non-network options such as flexibility services.

The "Energy Planning Integrated with Councils" (EPIC) project has developed and trialled a new process to align plans across energy networks and engage with local authorities. It involved co-creation of energy plans, development of network analysis tools to assess future impacts, creating investment options to ensure networks remain operable and analysing use cases, strategies and scenarios to create a holistic and strategic investment plan. This provides higher resolution visibility of future impacts and better investment outcomes both for the networks and for regional stakeholders.

EPIC is a Network Innovation Allowance (NIA) project funded by Western Power Distribution (WPD) and Wales and West Utilities. It is being delivered by a consortium of project partners:

- Regen to support the development of new processes with local authority and to develop the tool to support the creation of the Integrated Investment plan.
- Wales & West Utilities (WWU) to support process development and providing network investment options for the gas network.
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- PSC to develop the HV network analysis automation tool.
- EA Technology to adapt the Network Investment Forecasting Tool (NIFT) and use it to assess WPD's LV networks.
- The local authorities for the trial areas. The trial areas for EPIC are South West Bristol Strategic Planning Area (SPA), Bristol North Fringe SPA, Bath Enterprise Zone SPA.

There are six core EPIC process stages, illustrated in Figure 1:

I. Opportunity identification and area selection
II. Data Collection
III. Local Energy (requirements) Planning
IV. Network analysis
V. Investment and options appraisal
VI. Local Energy Planning (completion)

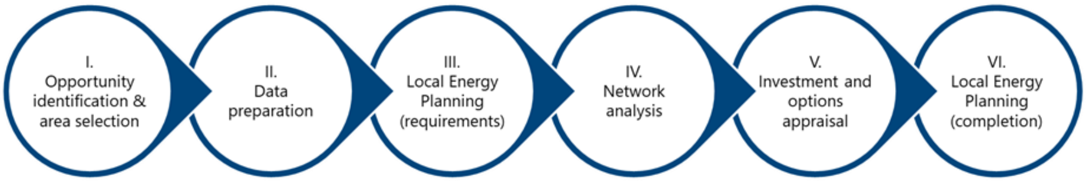


Figure 1 Core EPIC process stages

The NIFT was used for step IV, Network Analysis, and also for step V in which the investment options that could be used to resolve any network issues identified in step IV were proposed using the inbuilt solutions module. Data from local authorities (provided by Regen) was prepared in Step III, as an input to the Network Analysis. The format of this data was set out in WP2 Deliverable D4 (NIFT Specification).

Outputs from the LV modelling was used in two main ways:

- Determining the level of reinforcement of the LV network required for the various plans, the cost of this, and evaluating different investment strategies, via the Cost Benefit Analysis (CBA) being completed by Regen.
- Passing data on demand on the LV network to the HV Network Assessment Tool (NAT) (developed by PSC) as an input.

2.1 Purpose of this document and report structure

This document sets out the key findings from the LV network analysis completed by EA Technology and the lessons learnt for future, similar modelling projects. Further conclusions based on the data outputs from the LV modelling will also be reported by other project partners – for example, at the conclusion of the CBA work by Regen.

The report is structured as follows:

- Sections 2 and 3 provide the context for the project and the modelling which was completed, including an overview of the NIFT tool used for LV modelling;
- Section 4 outlines how the aggregated load from new developments as analysed, as this was completed outside of the NIFT tool.
- Sections 5 to 7 present the results of the analysis of network loading across different representative days, years and scenarios. Section 5 compares the level of constraints between different use cases, Section 6 compares between primary substations and Section 7 analyses how often each representative day results in the worst case network conditions.
- Sections 8 and 9 show the results from the 'solutions module' which was used to determine the optimal combination of interventions/network investment to resolve the constraints. Section 8 looks at both the differences between use cases and between primary substations. Section 9 details how the outputs from the NIFT solution module were used to provide the required inputs for the CBA tool.
- Section 10 summarises the conclusions, learning points and recommendations from the project.

3. NIFT Modelling Overview

3.1 NIFT Modelling Overview

The Low Voltage (LV) modelling in the EPIC project used the NIFT developed by EA Technology for WPD in 2019. The NIFT was originally completed to help WPD generate investment profiles, following from work on the Electric Nation project. NIFT has been used in the intervening time to study the impact of different Low Carbon Technology (LCT) adoption rates on the loading of LV networks as part of WPD's business plan submission for RIIO-ED2.

NIFT is a software tool which combines a number of sophisticated algorithms to predict the impact of LCT uptake over time and across large geographical areas. It does this by:

1. Intelligently distributing LCTs across LV networks according to uptake scenarios.
2. Running DEBUT[1] assessments to measure thermal and voltage impact on LV networks, using network data and demand profiles for each technology.
3. Producing reports which present aggregated results to reveal insights and inform business decisions.

It can also optionally recommend "solutions" where networks become constrained, based on constraint type, magnitude and the expected impact and availability of traditional and smart solutions. This 'solutions module' was used to provide the majority of data for the CBA analysis and is described in more detail below (see Section 8 and 9).

To do this, NIFT combines network data with the number of customers and LCTs. NIFT's network data is built with geospatial and asset information, whilst its scenarios are defined by the number of customers assigned to each profile class, and how many of each LCT are assigned to groups of customers. In the original deployment of the NIFT and subsequent use for ED2 planning, these technology uptake figures were applied to primary substation (mapping to ESA) areas. In the EPIC project technology uptake was modelled at a more local level – the distribution substation.

Figure 2 outlines the interactions made between the NIFT, EA Technology, and WPD to extract insights from the tool.

[1] DEBUT is a load flow analysis engine used to model LV distribution networks. It uses information on the properties of LV networks (ratings, length of feeders etc.) combined with the loads fed from the network to determine the thermal utilisation of cables and transformers and voltage rise and drop along feeders. DEBUT is the load flow engine within WinDEBUT™, which has recently been upgraded to Connect/LV.

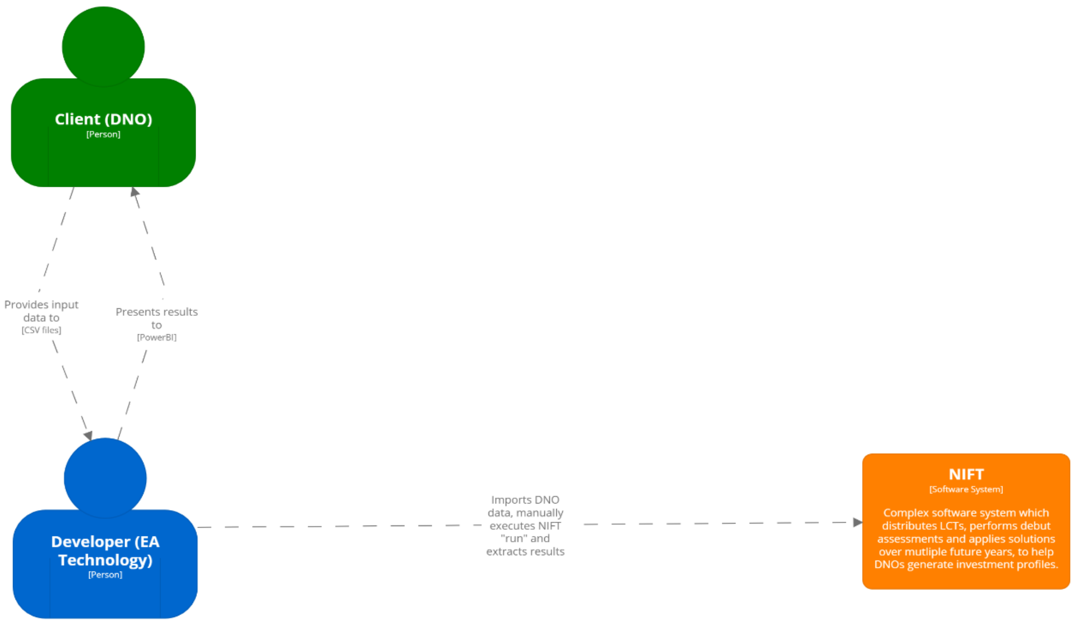


Figure 2 Use of the NIFT tool

In the EPIC project, Regen acted as the 'Client' in some cases, as they provided the technology uptake figures based on their engagement with local authorities. EA Technology loaded this data into the NIFT and conducted the relevant modelling runs. Further details of the scenarios/use cases modelled in EPIC are given in Section 3.4.3, Table 5.

For EPIC, the core power flow analysis engine, DEBUT, was upgraded to that which is used by the Connect/LV (also marketed by EA Technology as ConnectGrid[2]) tool, which has recently been implemented in WPD. This allowed for continuity and consistency of the results from the NIFT when compared to analysis by WPD's own network planners, as well as improved accuracy.

NIFT's results are provided in the form of a series of set tables. These can then be summarised using configurable PowerBI reports to present actionable insights, such as those provided in this report. The high-level inputs and outputs of a NIFT run are summarised in Figure 3.

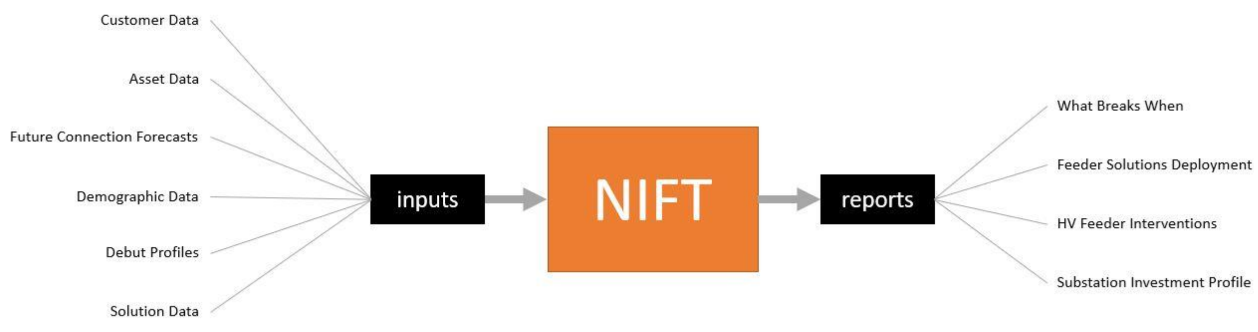


Figure 3 NIFT run inputs and outputs

The sub-sections below give a summary of the data inputs provided for the modelling in the EPIC project, and the data outputs.

[2] ConnectGrid | EA Technology Accessed April 2022

3.2 Data Inputs for EPIC

Figure 3 summarises the data inputs required by NIFT. The table below gives more detail on how each of these were derived, and any changes which were made.

Table 1 NIFT Input Data

Input Data Type	Data Source	Comments
Asset data	WPD	NIFT contains the asset data provided by WPD during development of the Network Assessment Tool as part of the Electric Nation project (circa 2017/18). This data includes network connectivity and asset properties (lengths of feeder, rating of equipment etc.). In the early stages of EPIC the quality of the data for the selected primary areas was reviewed. This showed that the selected primary substation areas were typically above the average quality of data for WPD's four licence areas, based on the cable utilisation, customer count and length of feeders. In addition, the timescales of the project meant that a data refresh was not possible. For this reason no further updates to the asset data held in NIFT were made. This had implications for the modelling results and these are discussed elsewhere in this report.
Customer Data	Provided by WPD during original development of LV Network Assessment Tool/NIFT	The number of customers fed from each LV feeder in each of the eight Elexon profile classes[3] was included in the original data import when NIFT was developed. This data was not updated for the EPIC project. No new Class 1 – 8 customers were assumed to connect to the existing network. New loads came from the allocation of low carbon technologies (LCTs) to existing customers. New developments were modelled separately (not using NIFT) and more detail is given in 4 of this report. Some customers in the data had a profile class of 0. It is likely that these customers a mix of half hourly metered customers (correctly, Class 0) and data errors (e.g. profile class value was NULL). NIFT analyses the profile class of other customers on the same feeder and then allocates those without a profile class to either Class 1 (if the majority of customers on the feeder are domestic) or Class 5.
Future Connection Forecasts	Regen, based on discussions with local authorities	Future connection forecasts in the form of the number of different ty`pes of LCTs were supplied by Regen, based on their discussion with local authorities. These low carbon technologies were assigned to existing domestic (Profile Class 1 and 2) customers. Further details are given in Section 3.4.

[3] Profile Class 1 – Domestic Unrestricted Customers
Profile Class 2 – Domestic Economy 7 Customers
Profile Class 3 – Non-Domestic Unrestricted Customers
Profile Class 4 – Non-Domestic Economy 7 Customers
Profile Class 5 – Non-Domestic Maximum Demand (MD) Customers with a Peak Load Factor (LF) of less than 20%
Profile Class 6 – Non-Domestic Maximum Demand Customers with a Peak Load Factor between 20% and 30%
Profile Class 7 – Non-Domestic Maximum Demand Customers with a Peak Load Factor between 30% and 40%
Profile Class 8 – Non-Domestic Maximum Demand Customers with a Peak Load Factor over 40%
Available from: What are the Profile Classes? - Elexon BSC Accessed January 2022

Input Data Type	Data Source	Comments
Demographic data	N/A	The original deployment of NIFT used demographic data to allocate some LCTs to particular LV feeders using primary substation level uptake figures. For example, primary level uptake of EVs was disaggregated to distribution substations/LV feeders using factors such as affluence and the availability of off-street parking. In the EPIC project NIFT deployment demographic data was not used as projections of LCT uptake were provided for each distribution substation and these LCTs were allocated randomly across LV feeders to existing domestic customers.
Debut Profiles	EA Technology, WPD, Regen	For each of Profile Class 1 – 8 and the LCTs a 'Debut Style' profile is required. These profiles are based on the ACE49 methodology[4]. These Debut style profiles are expressed in terms of the mean demand for a given half hour, p, and another property, q, which represents the deviation from this mean demand in that half hour. Additional Debut profiles were developed for the EPIC project based on the WPD Customer Behaviours Report[5] and EA Technology expertise. In addition, scaled versions of existing profiles were used to allow additional seasons to be modelled. Further details are given in Section 4.4 of WP2 D4 NIFT Specification. In addition to the underlying profiles governing the shape of demand in each half hour profiles are scaled by either an annual energy consumption figure, or maximum power demand. The values used in EPIC were developed by a combination of EA Technology, WPD and Regen. The original version of NIFT did not allow the annual energy consumption or maximum power demand to vary between substations or years. NIFT was further developed as part of the EPIC project to allow the effect of energy efficiency to be modelled.
Solutions Data	EA Technology and WPD Defined between EA Technology and WPD (based on Transform data) during original NIFT development	The majority of the solutions data which defines the cost and benefits of each of a toolkit of 15 solutions was taken from the original NIFT development, which in turn was based on the data in the Transform model. A change was made to the costs and benefits of distribution transformer upgrades and this is detailed in Appendix III. The solutions data is shown in Appendix I.

3.3 Data Outputs from NIFT

Figure 3 summarises the standard data outputs from NIFT. Details of these and the way in which they have been used in the EPIC project are given below:

- **'What Breaks When'**: this table is produced following the load flow analysis of the network. It contains a row for each LV feeder in each of the study years and details key parameters including maximum cable

[4] ENA 1981. "Report on Statistical Method for Calculating Demands and Voltage Regulations on LV Radial Distribution Systems". Energy Networks Association 1981.
[5] Distribution Future Energy Scenarios 2020. Available from : https://www.westernpower.co.uk/downloads-view-reciteme/303103 Accessed January 2022

utilisation, volt drop and volt rise, and the maximum utilisation of the associated distribution transformer supplying the feeder. The report also includes the number of customers and LCTs connected as well as static asset data including the cable rating and feeder length. A 'What Breaks When' table was produced for each representative day (see Section 3.4.2) and for each scenario. These tables are the key input used for the modelling of solutions, as they identify where constraints exist which need to be resolved via network investment. The 'What Breaks When' tables have also been used to produce outputs within this report, such as looking at which representative days lead to maximum cable/transformer utilisation, maximum volt drop or rise.

- Feeder Solutions Deployment Report: this report is generated by the solutions module. It contains a detailed list of the solutions identified to solve the constraints identified in the What Breaks When table. Further details of the operation of the solutions module is given in Section 8.1. Data is reported for each LV feeder, for each year, with columns naming the interventions deployed in each year and whether these relate to the LV feeder in question, other LV feeders fed from the same distribution substation, or the distribution substation itself.
- Substation Investment Profile: also from the solutions module, this report consolidates the data for feeders and reports it against each distribution substation. For each year it reports which solutions are deployed for the first time in the year ('chosen for deployment'), and what solutions are active, having been deployed in previous years. It also reports the capital and operating expenditure (capex and opex) spend in each year (capex for solutions which are chosen for deployment in that year, plus opex for all active solutions, combined into total expenditure (totex).
- HV Feeder Interventions: this report consolidates interventions to list them against each HV feeder for each year. In each year it reports the number of each of the 15 available solutions deployed for the first time on all networks downstream of the HV feeder. It also reports the sum of the opex and capex (gross and discounted) for all solutions which are active on all assets downstream of the HV feeder. This report was not used for the EPIC project.

Both the feeder solutions deployment and the substation investment profile reports have been used in producing the data required for the CBA work, with further details given in Section 8.

In addition, for the EPIC project a bespoke output was produced showing the half hourly load profile for each distribution transformer for each representative day, study year and scenario. This data was used by PSC in the HV model to show the load at distribution substations (i.e. the aggregate LV load supplied by the HV network).

3.4 Profiles, Scenarios and Representative Days

The EPIC project modelled a variety of different LCTs, including variations in operating profile (e.g. EV charging influenced by a Time of Use (ToU) tariff, or 'unabated'). A number of scenarios were included in the project to compare the impact of local authorities strategies, for example, whether EV charging facilities for those without driveways is delivered by distributed, LV connected, on-street chargers, or via larger, HV connected, charging hubs. This sub-section sets outs the profile types, representative days and scenarios included within the LV modelling.

3.4.1 Profiles

A set of input data was provided for each scenario which detailed:

- LCT uptake for each distribution substation, for each profile type in each study year
- The annual energy consumption, or maximum power demand (depending on profile type) for each profile, by primary substation, in each study year.

The following profile types were included within the EPIC modelling:

Table 2 Profiles in NIFT EPIC modelling

Profile	Scaled by	Comments
Class 1 domestic customer	Annual energy consumption	The standard profile for non-electrically heated homes.
Class 2 domestic customer	Annual energy consumption, split by day and night	This profile is used for electrically heated homes which use night storage heaters.
Class 3 commercial	Annual energy consumption	Profile used for small commercial premises (non-half hourly metered) which are not electrically heated.
Class 4 commercial	Annual energy consumption, split by day and night	Profile used for small commercial premises (non-half hourly metered) with electric heating.
Class 5	Maximum power demand (kW)	Profiles for larger commercial/industrial customers. Class 5 to 8 have varying peak load factors
Class 6		
Class 7		
Class 8		
Domestic solar PV	Maximum power output (kW)	
Domestic battery energy storage – for Class 1 customers	Maximum power input/output (inverter rating, kW)	Profiles were derived for the use of domestic energy storage. The operating profile of the storage (times of charge/discharge) were estimated based on likely energy tariffs. Class 1 domestic customers were assumed to charge the battery overnight and discharge during the evening peak, in response to a ToU tariff where electricity is more expensive in the evening peak. Class 2 domestic customers have cheaper electricity supply during seven hours overnight, and a higher rate throughout the day. Storage for Class 2 customers was therefore assumed to charge overnight and discharge for longer in the afternoon/evening period (compared to Class 1 customers).
Domestic battery energy storage – for Class 2 customers	Maximum power input/output (inverter rating, kW)	
Gas hybrid heat pumps	Annual energy consumption	A profile for gas hybrid heat pumps was developed based on the findings of the FREEDOM project. This profile assumed no electrical load from the heat pump in either the winter or intermediate cool 90th percentile demand day, as during these periods the home would be heated using gas.
Unabated heat pump	Annual energy consumption	Electric only heat pump profiles were derived using the WPD Customer Behaviours Report.

Profile	Scaled by	Comments
Flex heat pump	Annual energy consumption	The flex profile assumes higher power demand for the heat pump in the early hours of the morning and afternoon, effectively 'pre-heating' the home, allowing there to be no heat pump demand during the breakfast or evening peak during winter and intermediate cool days. The two profiles are compared in Figure 17. The proportion of homes using the unabated and flex profiles were varied between scenarios, using projections from National Grid Future Energy Scenarios[6] (NGFES).
Off-Street EV Charger, non-ToU	Annual energy consumption	Profiles for off-street EV chargers were derived by EA Technology using data from Electric Nation in a previous project for WPD. The ToU profile was based on the findings of a trial of customers' response to a time of use incentive supported by smart charging and an app. The proportion of homes using the non ToU and ToU profiles were varied between scenarios, using projections from National Grid Future Scenarios (Table CV41 Consumer engagement in smart charging). High and low uptake of ToU tariffs used the 'Consumer Transformation' and 'Steady Progress' scenarios, respectively.
Off-Street EV Charger, ToU	Annual energy consumption	
On-Street EV Charger, non-ToU	Annual energy consumption	Data from existing on-street EV chargers from which to derive a profile was not available, and utilisation of these chargers is likely to change in the future as a greater proportion of homes have an EV. The chargers modelled in EPIC were assumed to be used by drivers who do not have off-street parking, and so would be used in a similar manner to an off-street charger (i.e. with the majority of charging sessions beginning in the evening and the vehicle remaining plugged in until the morning). For this reason the unabated domestic off-street charger profile was used as a proxy. The annual energy consumption increased through the modelling period to reflect increased utilisation as a single on-street charger would serve increasing numbers of EVs (e.g. for multiple houses on a street) in later years (see Table 3).

Debut profiles are scaled by either the annual energy consumption or the maximum power demand/generation output. EPIC included modelling the impact of energy efficiency measures in two scenarios. The energy consumption values used for each scenario (low, medium or high) are shown in Table 5 below.

Energy consumption/power output figures were determined using data from WPD (including previous modelling using the NIFT). Reductions in energy consumption over time were determined by Regen. For some profiles (where data was available) differences were applied between the six primary substation areas. The table below shows the values used for each profile class in the baseline year (2019), 2035 and 2050 in the low energy efficiency scenarios (see Table 5 for further details of scenarios modelled).

[6] National Grid Future Energy Scenarios 2021 data from: https://www.nationalgrideso.com/document/199971/download Accessed January 2022. Data for smart control of heat pumps was not included with the Future Energy Scenarios data. Uptake of Smart White Appliances was used as a proxy. Low uptake of the flex profile corresponded to the 'Steady Progress' scenario. High uptake of the flex profile corresponded to the Consumer Transformation scenario.

Table 3 Energy Consumption Values (existing customers)

Profile	Scaled by Energy Consumption or Max Demand?	Variation in energy consumption/power demand by primary substation?	Data source	2019 value	2035 value	2050 value
Class 1 Domestic Customer	Energy Consumption (single annual total)	Yes	WPD metering data	2,340 to 2,965 kWh	2,224 to 2,817 kWh	2,107 to 2,669 kWh
Class 2 Domestic Customer	Energy Consumption (day and night totals)	Yes	WPD metering data provided annual total, split 30% 'day' and 70% 'night' in baseline year in line with previous modelling.	Day: 1,502 to 1,820 kWh Night: 3,506 to 4,246 kWh	Day: 1,427 to 1729 kWh Night: 3,155 to 3,891 kWh	Day: 1,352 to 1,637 kWh Night: 3,155 to 3,821 kWh
Class 3 Small commercial	Energy consumption (single annual total)	Yes	WPD metering data	19,312 to 40,773 kWh	16,415 to 34,657 kWh	16,415 to 34,657 kWh
Class 4 Small commercial (electrically heated)	Energy Consumption (day and night totals)	Yes	WPD metering data provided annual total, split 34% 'day' and 66% 'night' in baseline year in line with previous modelling.	Day: 12,209 to 36,111 kWh Night: 6,105 to 18,055 kWh	Day: 10,378 to 30,694 kWh Night: 5,799 to 17,153 kWh	Day: 10,378 to 30,694kWh Night: 4,579 to 13,542 kWh
Class 5	Max Demand	No	Consistency with WPD ED2 Modelling in NIFT	101 kW	101 kW	101 kW
Class 6						
Class 7						
Class 8						
Solar PV	Max Generation Output	No	Maximum allowable inverter size for domestic PV under G83	3.6 kW	3.6 kW	3.6 kW

Profile	Scaled by Energy Consumption or Max Demand?	Variation in energy consumption/power demand by primary substation?	Data source	2019 value	2035 value	2050 value
Domestic energy storage	Inverter rating	No		0.5 kW	0.5 kW	0.5 kW
Gas hybrid heat pump (electricity demand)	Energy consumption (single annual total)	No	National Grid Future Energy Scenarios by combining projections for total electricity demand for hybrid heat pumps and the number of hybrid heat pumps per year.	3,972 kWh	2,443 kWh	1,725 kWh
Heat pumps (unabated and flex)	Energy consumption (single annual total)	No	WPD Customer Behaviours Report[22].	4,479 kWh	3,680 kWh	2,998 kWh
Off-street EV charger (non ToU and ToU)	Energy consumption (single annual total)	No	Electric Nation data for baseline, scaled in accordance with WPD Customer Behaviours Report[22]	2,658 kWh	2,289 kWh	2,259 kWh
On-Street EV charger	Energy consumption (single annual total)	No	Assuming low utilisation in early years, increasing as more drivers without off-street parking switch to EVs.	1,329 kWh	7,995 kWh	9,433 kWh

3.4.2 Representative days

In each scenario, five representative days were modelled, in order to see the variation of demand and therefore network constraints (asset utilisation, voltage rise and drop) across different seasons. For example, voltage rise on networks with PV generation is most likely in the summer when generation is highest, and demand lowest.

For each of the profile classes in Table 2 a 'Debut Style' demand profile was used. These profiles are based on the ACE49 methodology[7]. These Debut style profiles are expressed in terms of the mean demand for a given half hour, p, and another property, q, which represents the deviation from this mean demand in that half hour. For a 90% probability of operating within demand, in a random situation during the central winter period, the design demand is:

$$Design\ Demand\ =\ Mean\ Demand\ +\ 1.28\ \times (Standard\ Deviation\ \ -\ Mean) = \ p\ +\ q$$

This 90% probability is generally accepted as the optimal boundary[4], balancing the need to ensure the network is sufficiently robust to avoid regularly exceeding its capacity with efficient use of resources. Alternatively, p – q gives the 10th percentile – used for modelling 'minimum demand' scenarios. Demand and generation figures were combined in the different representative days as shown below.

Table 4 Representative Days and Percentiles Used for Each

Representative Day	Demand Percentile Used	Generation Percentile Used	Season
Winter - Peak Demand Minimum Generation	90	10	Winter
Intermediate Cool – Peak Demand Minimum Generation	90	10	Intermediate Cool
Intermediate Warm – Peak Demand Minimum Generation	90	10	Intermediate Warm
Summer – Peak Demand Minimum Generation	90	10	Summer
Summer – Peak Generation Minimum Demand	10	90	Summer

For each scenario, five representative days were modelled, producing a 'What Breaks When' table and profile of half hourly transformer utilisation for each distribution substation (see Section 3.3). The contribution of the different representative days to determining worse case network conditions is analysed in Section 4.

3.4.3 Scenarios

The scenarios modelled in the EPIC project were devised by Regen and WPD and shaped by the interests of the local authorities. They aimed to test different strategies which local authorities could take in the decarbonisation of local areas. Six different areas of variation were studied:

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

- Strategy for providing EV charging facilities for those without off-street parking: charging could either be provided at distributed, LV connected on-street chargers, or via larger 'hubs' (e.g. council car parks) which would connect to the HV network. The results of this modelling can only be seen by considering the results of both the LV and HV modelling as the strategies switch demand from one voltage level to another.
- Uptake of ToU tariffs/smart charging for domestic EV charging: higher uptake of ToU tariffs may limit the increase in demand during the evening peak and therefore avoid, or delay the need for network investment. The impact of varying uptake of this type of tariff was modelled by comparing the baseline scenario with Run 7.
- Uptake of hybrid heat pumps: as described above, hybrid heat pumps were assumed to heat homes using gas during the 90th percentile demand days in both the winter and intermediate cool seasons. This could limit the additional demand created during existing network peaks and therefore avoid, or delay the need for network investment. The impact of higher uptake of hybrid heat pumps can be seen by comparing the results of the baseline scenario with Run 17.
- Uptake of flexible tariffs/operation for heat pumps: in response to a ToU tariff a heat pump user may decide to reduce the electrical demand for their heat pump during the traditional evening peak by 'pre-heating' the home beforehand. The impact of varying uptake of this type of tariff was modelled by comparing the baseline scenario with Run 15.
- Energy efficiency: the baseline scenario assumed modest 'low' improvements in energy efficiency for existing developments. For example, annual energy consumption for a Class 1 customer was 90% of the 2019 value in 2050. Run 12 was completed for all SPAs and included greater improvements in energy efficiency. For example, consumption by Class 1 customers in 2050 was 80% of the 2019 values. A SPA specific use case was modelled for the North Fringe SPA with higher energy efficiency improvements (Run 29) due to the ambitions of the local authority in this area expressed during the stakeholder engagement phase.
- Investment strategy: when deploying network investment NIFT includes a 'look ahead' period. Investments are chosen which can satisfy constraints for the full look ahead period, to avoid multiple small interventions occurring in a short period of time. As part of the EPIC project two strategies were modelled – a 'just in time' approach with a three year look ahead period, and 'fit for the future' with a twenty year look ahead period. In both cases this was based on the constraints identified in the baseline scenario.

The impact of these different scenarios on network loading and therefore investment required has been analysed both within the LV modelled (reported here) and via the CBA work.

The table below shows the scenarios and run numbers modelled at LV. In each case the variation from the baseline run is shown in **bold**.

Table 5 List of LV Modelling Scenarios in EPIC

Run Number and Scenario	Description
2 ('Just in Time' investment strategy)	The baseline data consisting of: • High uptake of on-street charging (lower uptake of HV connected EV hubs) • High uptake of smart charging for EVs[8] • Low uptake of hybrid heat pumps • Low uptake of the heat pump 'flex' tariff/operation[9] • Low energy efficiency improvements • 3 year look ahead period
2 ('Fit for the Future'[10] investment strategy)	• High uptake of on-street charging (lower uptake of HV connected EV hubs) • High uptake of smart charging for EVs • Low uptake of hybrid heat pumps • Low uptake of the heat pump 'flex' tariff/operation • Low energy efficiency improvements • **20 year** look ahead period
7 (EV High On-Street Low Managed)	• High uptake of on-street charging (lower uptake of HV connected EV hubs) • **Low** uptake of smart charging for EVs[11] • Low uptake of hybrid heat pumps • Low uptake of the heat pump 'flex' tariff/operation • Low energy efficiency improvements • 3 year look ahead period
6 (EV Low On-Street High Managed)	• **Low** uptake of on-street charging (higher uptake of HV connected EV hubs) • High uptake of smart charging for EVs • Low uptake of hybrid heat pumps • Low uptake of the heat pump 'flex' tariff/operation • Low energy efficiency improvements • 3 year look ahead period

[8] Equivalent to 'Consumer Transformation' in the National Grid Future Energy Scenarios.
[9] Equivalent to 'Steady Progress' in the National Grid Future Energy Scenarios.
[10] Run numbers were assigned based on variations in LCT uptake/energy consumption. The 'Just in Time' vs. 'Fit for the Future' use case used the same baseline LCT uptake/energy consumption data – the baseline scenario, Run 2.
[11] Equivalent to 'Steady Progress' in the National Grid Future Energy Scenarios.

Run Number and Scenario	Description
8 (EV Low On-Street Low Managed)	• Low uptake of on-street charging (higher uptake of HV connected EV hubs) • Low uptake of smart charging for EVs • Low uptake of hybrid heat pumps • Low uptake of the heat pump 'flex' tariff/operation • Low energy efficiency improvements • 3 year look ahead period
17 (Heat Pump High Hybrid Low Flex)	• High uptake of on-street charging (lower uptake of HV connected EV hubs) • High uptake of smart charging for EVs • High uptake of hybrid heat pumps • Low uptake of the heat pump 'flex' tariff/operation • Low energy efficiency improvements • 3 year look ahead period
15 (Heat Pump Low Hybrid High Flex)	• High uptake of on-street charging (lower uptake of HV connected EV hubs) • High uptake of smart charging for EVs • Low uptake of hybrid heat pumps • High uptake of the heat pump 'flex' tariff/operation[12] • Low energy efficiency improvements • 3 year look ahead period
12 (Medium energy efficiency)	• High uptake of on-street charging (lower uptake of HV connected EV hubs) • High uptake of smart charging for EVs • Low uptake of hybrid heat pumps • Low uptake of the heat pump 'flex' tariff/operation • Medium energy efficiency improvements • 3 year look ahead period.
29 (High energy efficiency) Specific to the North Fringe SPA, applying to Cribbs Causeway and Filton DC primaries)	• High uptake of on-street charging (lower uptake of HV connected EV hubs) • High uptake of smart charging for EVs • Low uptake of hybrid heat pumps • Low uptake of the heat pump 'flex' tariff/operation • High energy efficiency improvements • 3 year look ahead period.

[12] Equivalent to 'Consumer Transformation' in the National Grid Future Energy Scenarios.

3.5 Study Areas

Three strategic planning areas were included in the EPIC project: Bath Enterprise Zone, South West Bristol and North Filton, shown on Figure 4 below.

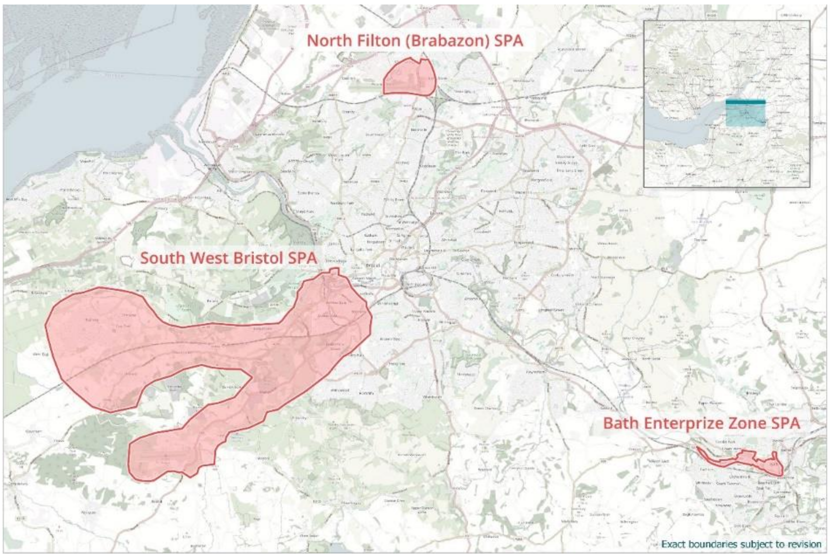


Figure 4 EPIC Strategic Planning Areas

The areas to be modelled in NIFT are defined by Energy Supply Areas (ESAs) – the distribution substations fed from particular primaries.

The following primary substations were modelled for each of the three SPAs:

- Bath Enterprise Zone: Dorchester Street New
- South West Bristol: Bedminster, Bower Ashton, Nailsea
- North Filton: Filton DC, Cribbs Causeway

Modelling of the HV network considered a single primary for each SPA and therefore the CBA considers only a single primary to ensure a fair comparison. For example, the EV charging use case compares the costs associated with strategies using a number of HV connected hubs, compared to LV connected distributed on-street EV chargers. To compare these options the reinforcement costs at HV and LV are required. Costs at HV will relate to a single ESA (supplied by one primary). Therefore, for a fair comparison the costs for the LV network for a single primary should be used (rather than two or three for North Filton SPA and South West Bristol SPA respectively).

This report compares the trends and conclusions between primaries in order to show whether similar trends are observed in all cases, reducing the need to model multiple primaries in the future.

In the modelling of the LV network LCTs are distributed to domestic customers only. The amount of reinforcement as a result of LCT uptake will vary depending on the customer types fed from each primary, amongst other factors. The composition of the customer base for each primary is shown below, both in absolute and percentage terms.

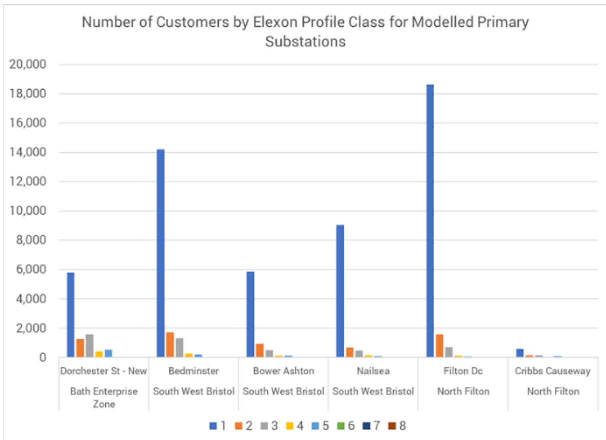


Figure 5 Customer Composition of Six Primaries Modelled - Absolute Number

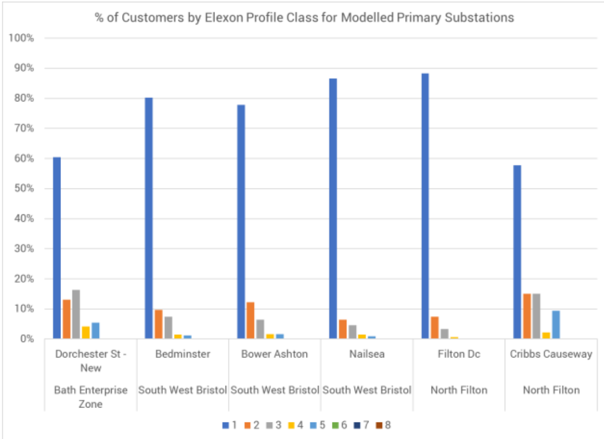


Figure 6 Customer Composition of Six Primaries Modelled - Percentage of Total

The customer composition for the three primaries in the South West Bristol SPA are broadly similar, dominated by Elexon Class 1, with approximately 10% of Elexon Class 2 and very little half hourly metered commercial/industrial (Class 5 – 8). The total number of customers in the three primary areas is 17,702, 7,503 and 10,463 for Bedminster, Bower Ashton and Nailsea respectively. However, in the North Filton SPA there is a significant difference in the customer composition between Filton DC and Cribbs Causeway which may result in different reinforcement requirements and conclusions between the two primaries. In addition the underlying number customers is vastly different – 21,094 at Filton DC (the highest of the six areas modelled) and 996 for Cribbs Causeway.

The size of the LV network also varies between primaries, and is shown in the two graphs below through the number of distribution substations and the number of LV feeders, split by the type of network (underground or overhead).

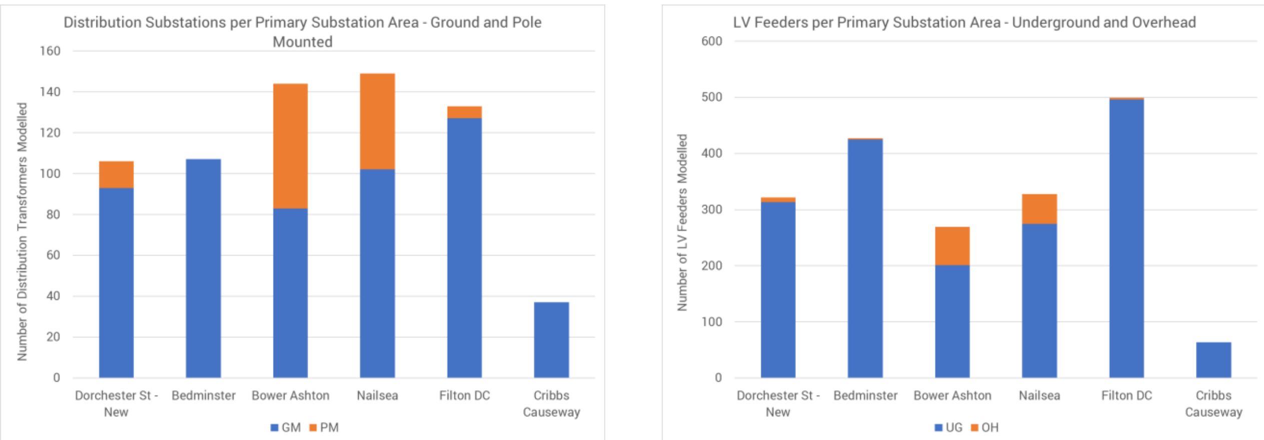


Figure 7 Number of Distribution Substations and LV Feeders in each Primary Substation Area

The Debut profiles (see Section 3.4.1) and customer numbers have been used to estimate the load profile for the LV network in each primary area (aggregated to the primary substation level). This calculation excludes LCTs which are deployed in 2019 – i.e. only profile class 1 – 8 is included. The resulting load profiles are shown below.

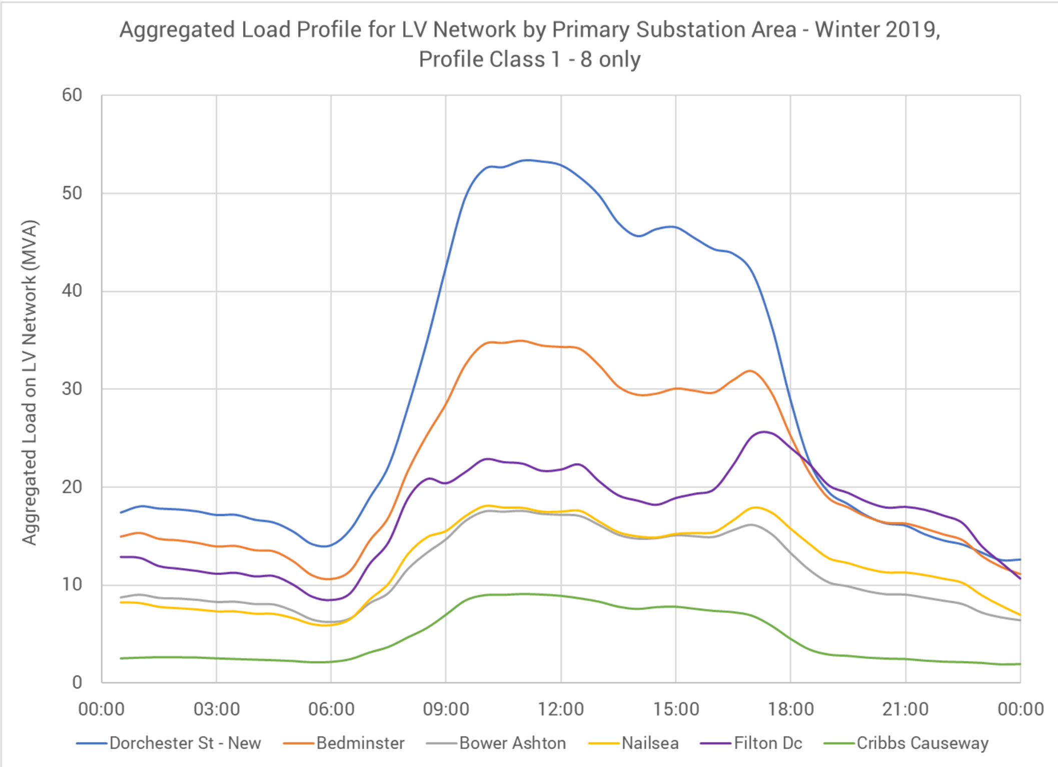


Figure 8 Aggregated LV Demand by Primary Substation Area (Winter, 2019, Profile Class 1 - 8 only)

Of the six primary substation areas, Dorchester St. New has the highest demand. Although the total number of customers is low, Dorchester St. New has a much greater number of commercial and industrial customers with high daytime demand. The pattern in maximum aggregated demand (Dorchester St. New, Bedminster, Filton DC etc.) mirrors the number of non-domestic customers in the primary substation area.

The table below shows the time of maximum demand for the six primary substation areas.

Table 6 Half Hour of Maximum Aggregated Demand

Primary Substation Areas	Half Hour of Maximum Aggregated Demand at LV
Nailsea	10:00
Dorchester St. New, Bedminster, Bower Ashton, Cribbs Causeway	11:00
Filton DC	17:30

The graph below shows the contribution each profile class makes to the demand at the time of peak.

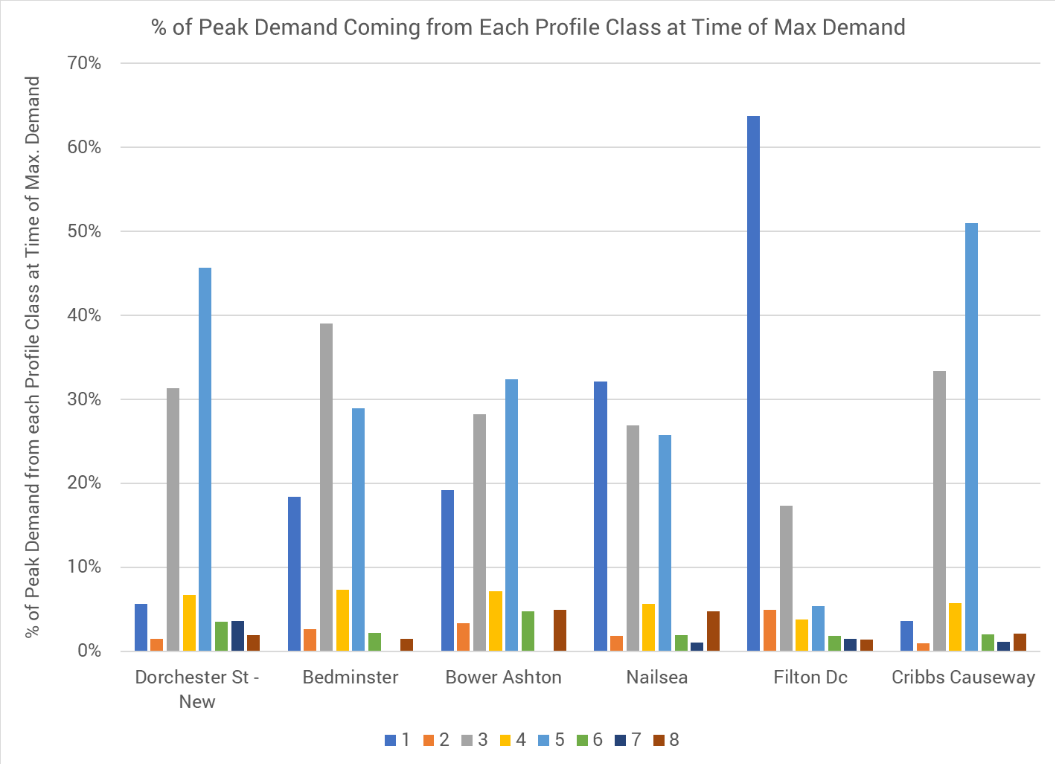


Figure 9 % of Peak Demand from Each Profile Class at Time of Maximum Demand

At the four primary substation areas which have their maximum demand at 11:00, Profile Class 3 and 5 contribute between 61 and 84% of the total demand. Maximum demand across the Nailsea area occurs at 10:00 with domestic customer (Class 1) contributing to this to a greater degree. The composition at Filton DC is markedly different – the peak occurs at 17:30, when demand for commercial and industrial customers has reduced.

Comparisons of the network constraints and resulting investment requirements between primary substation areas are given in Sections 6 and 8.2 respectively.

4. Modeling of New Developments

As described above, NIFT contains the existing distribution network in WPD's licence areas. The impact of LCT uptake was modelled for the existing network by assigning LCTs to existing domestic customers and carrying out power flow analysis to determine network conditions and so any required reinforcement.

During the stakeholder engagement process carried out by Regen new developments were also discussed with the local authorities. It is likely that new developments will involve the construction of a new distribution substation and downstream LV network. The LV network would therefore be designed to accommodate likely uptake of LCTs, rather than requiring subsequent reinforcement due to retrofitting. However, these new LV networks will create additional load on the existing HV network. There was therefore a requirement within the EPIC project to provide aggregated load profiles for the new developments. These load profiles were generated in a separate analysis spreadsheet – outside of NIFT but using the same underlying demand profiles.

4.1 Input Data

Regen supplied data for each predicted new development (a total of 42 across the three SPAs), showing the number of customers of the types listed below in each year from 2019 to 2035:

- Domestic
- Class 3 (small commercial)
- Class 7 (half hourly metered customer with a peak load factor between 30 and 40%)
- Class 8 (half hourly metered customer with peak load factor greater than 40%)
- Domestic PV generation
- Heat pump
- Off-street EV charger
- Domestic energy storage

Each development was assigned a 'dummy substation' ID, such that each dummy substation fed a number of properties and associated LCTs.

The same Debut profiles were used for modelling new and existing developments. However, in some cases the predicted energy consumption per customer was less than for existing customers. This reflects the higher standard of building insulation and other energy efficiency measures likely to be in place for new developments. These numbers were derived based on current planning policy and discussions between the project partners, with WECA providing feedback. The table below shows the input data used in the low, medium and high energy efficiency scenarios.

Table 7 Energy Consumption/Power Demand Assumptions for New Developments

Profile	Scaled by	Low Energy Efficiency (Base)	Medium Energy Efficiency	High Energy Efficiency
Domestic – Class 1 (non-electrically heated)	Annual Energy Consumption (single value)	1320 kWh	880 kWh	770 kWh

Profile	Scaled by	Low Energy Efficiency (Base)	Medium Energy Efficiency	High Energy Efficiency
Domestic Class 2 (includes electric storage heating)	Annual Energy Consumption (day and night values)	Day = 841 kWh Night = 771 kWh	Day = 555 kWh Night = 526 kWh	Day = 496 kWh Night = 386 kWh
Class 3	Annual Energy Consumption (single value)	14,384 kWh	10,416 kWh	8,111 kWh
Class 7 and Class 8	Maximum Power Demand	91 kW	86 kW	81 kW
Solar PV	Maximum Power Output	3.6 kW	3.6 kW	3.6 kW
Domestic Energy Storage	Inverter Rating	0.5 kW	0.5 kW	0.5 kW
Heat Pump	Annual Energy Consumption (single value)	1,000 kWh	670 kWh	500 kWh
Off-street EV Charger	Annual Energy Consumption, varying from 2019 to 2035 based on assumed improvements in EV efficiency[13]	2019 = 2,658 kWh (Electric Nation baseline consumption) 2030 = 2,406 kWh 2050 = 2,259kWh		

Five representative days were modelled, as outlined in Section 3.4.2.

4.2 Data Processing

The input data provided by Regen required some processing in order to determine the number of customers in each profile class, including assumptions such as the type of profile adopted for EV charging (unabated or ToU) and the use of storage heating for new developments. The following assumptions were made:

- Domestic customers were split into Class 1 (non-electrically heated[14]) and Class 2 (night storage heaters) as follows:
    - If fewer than 80% of homes had been allocated a heat pump then 80% of domestic customers were assigned to Class 1 and 20% to Class 2.
    - If more than 80% of homes had been allocated a heat pump then all homes with a heat pump were assigned to Class 1 (for their non- heating demand), with the remainder falling into Class 2.

[13] Figure 47. Distribution Future Energy Scenarios 2020. Available from : https://www.westernpower.co.uk/downloads-view-reciteme/303103 Accessed January 2022

[14] Homes heated using a heat pump are allocated to Class 1 for their underlying 'non-heating' demand and a heat pump was added as a separate profile.

- Domestic energy storage: the import/export profiles for energy storage differ between Class 1 and Class 2 customers (see Table 2). Regen provided an estimate of the total number of domestic energy storage units. These were split into Class 1 and Class 2 using the same proportions as the number of customers in each class. For example:
    - The input data for a given year predicted 224 domestic customers and 7 storage units.
    - There were 132 heat pumps (less than 80% of domestic customers) therefore the 224 domestic customers were split into 179 Class 1 and 45 Class 2 (80/20 split as described above).
    - 3% of customers have storage units (7 out of 224). Therefore 3% of the 179 Class 1 customers have a Class 1 storage profile = 6 (rounded to a whole number), leaving one Class 2 storage unit.
- Input data for heat pumps and EVs were split into the unabated/ToU (EVs) and unabated/ flex (heat pumps) profiles using National Grid Future Energy Scenarios data, in line with those used for existing customers, as follows:
    - Electric Vehicles: the number of EV chargers was split into a number of customers with the non-ToU and ToU profiles according to the NGFES predicted level of consumer engagement in smart charging. High and low uptake of managed charging was equivalent to the 'Consumer Transformation' and 'Steady Progress' scenarios respectively. This predicted the proportion of customers who were assigned to the ToU profile, with the remaining customers allocated to the non-ToU profile. It was assumed that the take-up of ToU profiles would be the same in a given year for both new and existing developments.
    - Heat Pumps: the number of heat pumps was split into a number of customers with the unabated and flex profiles using the NGFES data (Uptake of Smart White Appliances used as a proxy). High and low uptake of the flex profile was equivalent to the 'Consumer Transformation' and 'Steady Progress' scenarios respectively. This predicted the proportion of customers who were assigned to the flex profile, with the remaining customers allocated to the unabated profile. It was assumed that the take-up of two heat pump profiles would be the same in a given year for both new and existing developments.

Regen predicted new developments from 2019 to 2035 as this is the time period for which local authorities could provide data. The study period for EPIC extended to 2050. It was therefore assumed that data from 2035 remained constant until the end of the study period, with only the energy consumption of EVs changing (continuing to decrease slightly due to improvements in vehicle technology, not linked to building fabric).

4.3 Scenarios

Due to the technologies included within the modelling of new developments not all scenarios were relevant to new developments. Five scenarios were modelled, with details given below.

Table 8 List of LV Modelling Scenarios for New Developments

Run Number and Scenario	Included in new development modelling?	Details
2 ('Just in Time' investment strategy)	Yes	

Run Number and Scenario	Included in new development modelling?	Details
2 ('Fit for the Future'[15] investment strategy)	No	Investment was not modelled for new developments. A single set of baseline power demand profiles were produced.
7 (EV High On-Street Low Managed)	Yes	The impact of low uptake of managed charging was modelled, compared to high uptake in the baseline scenario. Only off-street EV chargers were included in the new development data therefore variations based on uptake of distributed on-street chargers vs. charging hubs was not modelled.
6 (EV Low On-Street High Managed)	No	
8 (EV Low On-Street Low Managed)	No	
17 (Heat Pump High Hybrid Low Flex)	No	All heat pumps for new developments were assumed to be electric only. Hybrid heat pumps allow the impact on the electricity network to be limited by using gas during peak demand periods. However, as the network for new homes would be designed including heating demand this fuel switching capability would be of less value.
15 (Heat Pump Low Hybrid High Flex)	Yes	The impact of higher uptake of the flex profile was modelled, compared to low uptake in the baseline scenario.
12 (Medium energy efficiency)	Yes	The impact of improved energy efficiency was modelled.
29 (High energy efficiency) Specific to the North Fringe SPA, applying to Cribbs Causeway and Filton DC primaries)	Yes	

4.4 Outputs

An aggregated load profile was derived for each 'dummy substation' for each study year, giving the load in each half hourly period, for the five representative days for each of the five scenarios in Table 8. In some cases the number of customers connected increased over time as developments grew. The graph below shows an example for a development in South Gloucestershire, showing the winter representative day in two year intervals from 2021 to 2035, as the number of customers grows.

[15] Run numbers were assigned based on variations in LCT uptake/energy consumption. The 'Just in Time' vs. 'Fit for the Future' use case used the same baseline LCT uptake/energy consumption data – the baseline scenario, Run 2.

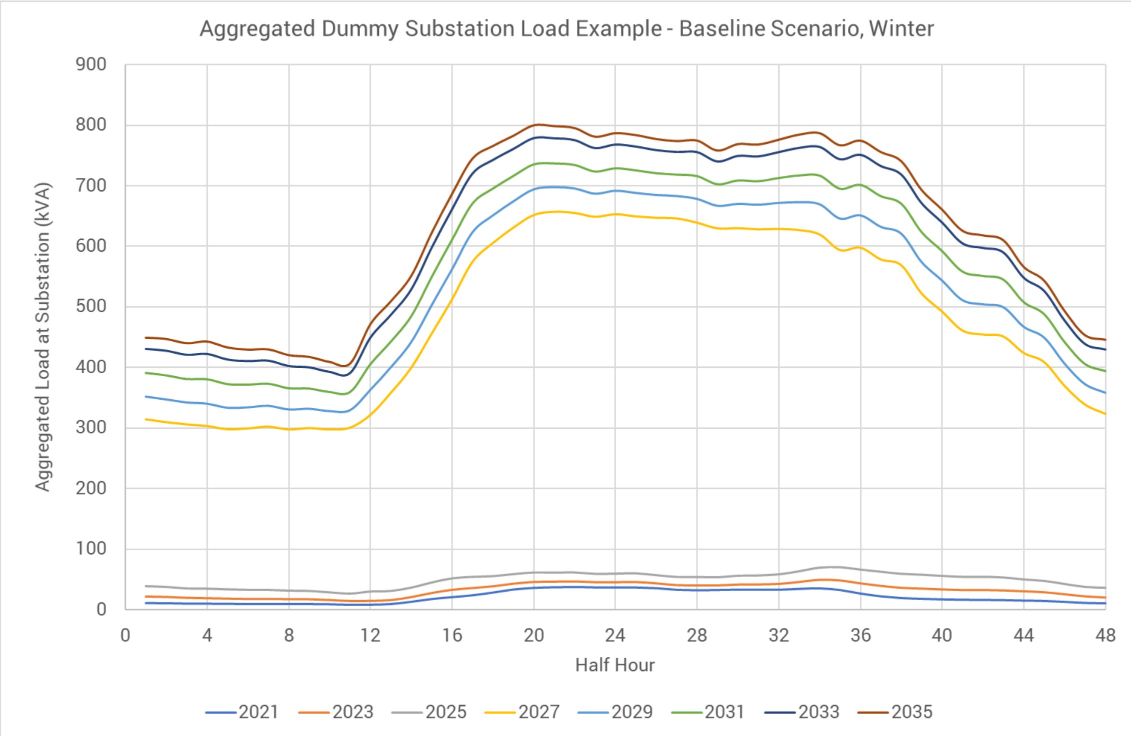


Figure 10 Example of Aggregated Load at a Dummy Substation

This shows a substantial increase in demand between 2025 and 2027, due to increases in customer numbers as follows:

- Domestic customers: 78 to 124
- Heat pumps: 15 to 52
- PV: 17 to 28
- EV chargers: 6 to 13
- Class 7: 0 to 7

The increases in customer numbers between other years are more gradual, as shown by the smaller changes in the aggregated load profile.

The load profiles were supplied to PSC so that the impact of new developments on the HV network could be accounted for.

5. Level of constraints – comparing use cases

5.1 Introduction

Assets are defined as 'constrained' in the NIFT modelling if any of the following conditions are met:

- LV feeders: utilisation of greater than 110%, volt drop of greater than 6%, volt rise of greater than 1.5%
- Distribution transformers: utilisation of greater than 110%

Constraints may already be present on the network in the baseline year due to combinations of existing loading, or low data quality. However, these baseline constraints will be very similar between scenarios and so the modelling still allows the differences between scenarios to be studied.

During the study period demand will tend to increase due to the adoption of LCTs, although in some cases this may be offset to some degree by energy efficiency improvements. The different scenarios modelled in EPIC (see Section 3.4.3) may result in different levels of constraints appearing – for example, there may be more constrained networks when fewer EV drivers adopt ToU tariffs which reward off-peak charging, or fewer constrained networks if the adoption of hybrid heat pumps is higher. The results from the modelling could be used to answer two questions (amongst others):

1. Does use case/scenario A (e.g. high adoption of EV ToU tariffs) lead to lower constraints than use case/scenario B (e.g. low adoption of EV ToU tariffs)?
2. What level of constraints will occur across time in use case/scenario A?

The purpose of this section is to compare the level of constraints seen between scenarios – question 1 above. If the results (which use case/scenario leads to lower constraints) are the same across multiple primary substations then it may be possible to answer question 1 by modelling a limited number of primary substation areas. The answer to question 2 is more likely to be specific to each primary substation area (and indeed vary between distribution substations) and so require more modelling to answer the question for each network in turn. The results for different primary substations are compared in Section 6 to show whether the same trends are observed across multiple primaries.

5.2 EV Scenarios

Two factors relating to EV uptake were varied in the LV modelling:

- **Uptake of on-street EV chargers connected to the LV network:** the baseline scenario and Run 7 had relatively high uptake of distributed, LV connected on-street chargers. In Runs 6 and 8 the uptake of on-street chargers was lower, as in these scenarios it was assumed that a 'hub' model would be adopted by local authorities to provide EV charging for drivers without off-street parking at home. These larger hubs would be connected to the HV network, likely leading to a lower level of constraints on the LV network.
- **Adoption of ToU tariffs by drivers:** Previous work by WPD in the Electric Nation project[16] demonstrated a change in charging behaviour by drivers when they were offered a financial reward for charging outside of the evening peak period, particularly when this was supported by smart charging and an easy to use app. UKPN's Shift project also reported that ToU propositions were effective at reducing demand in the evening peak. Across two trials (Kaluza ToU Distribution Use of System) and ev.energy Flexibility Procurement trails the average diversified peak EV charging demand seen at 20:00 on weekdays was

[16] https://www.westernpower.co.uk/downloads-view-reciteme/64369 Electric Nation Summary Brochure. 2019. Accessed February 2022.

reduced by 79%[17]. ToU tariffs are already being offered to EV drivers which incentivise charging at off-peak times. The level of adoption of these tariffs may affect the impact EV adoption has on the presence of network constraints. High (Baseline and Run 7) and low (Run 6 and 8) levels of adoption of ToU tariffs were modelled. Forecasts from National Grid Future Energy Scenarios were used to set levels of adoption between the two scenarios, with the percentage of drivers who use a ToU tariff in the two scenarios shown below.

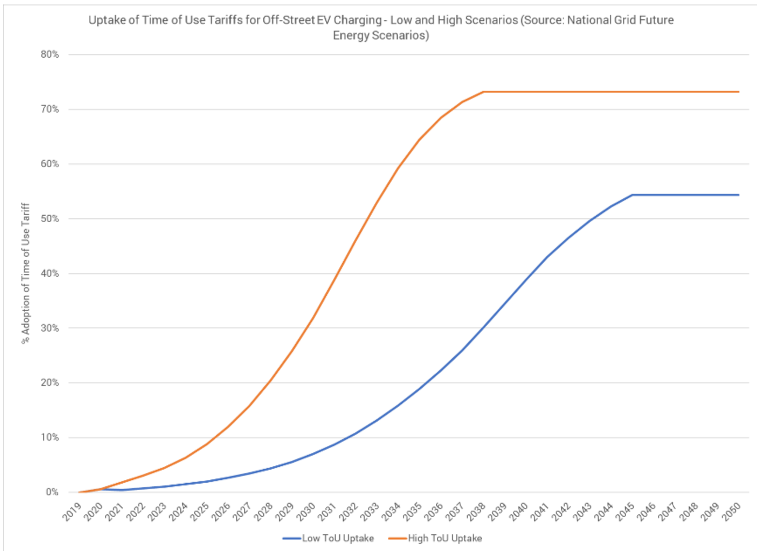


Figure 11 Adoption of Time of Use Tariffs in Low and High Scenarios

Three EV related profiles were modelled at LV:

- Off-Street EV charging: non-ToU and ToU variants, with annual energy consumption varying from 2,658 kWh in 2010 to 2,259 kWh in 2050. This reduction is the result of improvements in vehicle efficiency.
- On-Street EV charging: used the profile shape for non-ToU off-street EV charging, based on the assumption that these two charger types would be used in a similar way as they are predominantly in residential areas. The annual energy consumption increased from 1,329 kWh in 2019 (assuming low levels of utilisation due to low ownership rates of EVs for those without off-street parking) to 9,433 kWh in 2050.

The graphs below shows the total number of each profile deployed across the six primary areas modelled at LV.

[17] UKPN. Project Shift Summary Report – September 2021. Available from: 21236_UKPN_Project-Shift_2021_Final-proof.pdf (ukpowernetworks.co.uk) Accessed May 2022

Figure 12 Uptake of Off-Street (non ToU) Chargers by Scenario

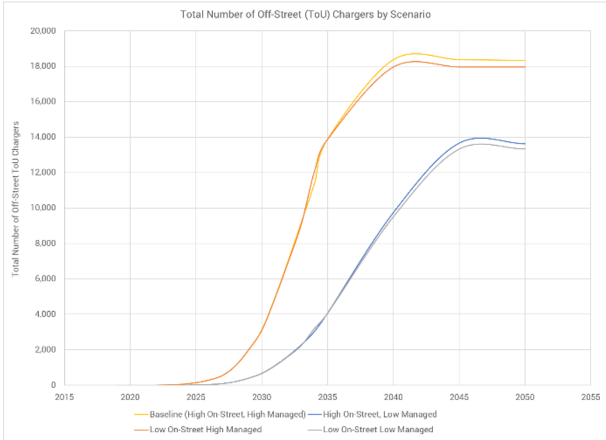


Figure 13 Uptake of Off-Street (ToU) Chargers by Scenario

The total number of off-street chargers increases until a peak of around 25,000 chargers is reached in 2040. The decline in non ToU chargers from the early/mid 2030s (depending on scenarios) is made up for by an increase in ToU chargers, such that the total number of chargers continues to increase.

The number of off-street chargers is independent of the number of on-street chargers (e.g. yellow and orange curves are similar despite being from the low and high on-street charger uptake scenarios). The difference between the yellow/orange and blue/grey curves depends on the level of adoption of ToU tariffs, as shown in Figure 11.

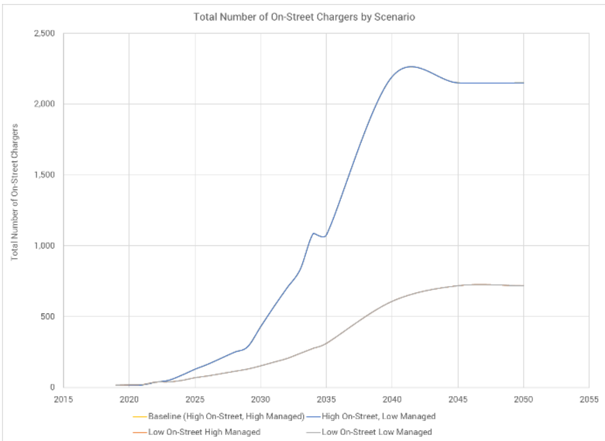


Figure 14 Uptake of On-Street Chargers by Scenario

The uptake of ToU tariffs/management does not affect the number of on-street chargers, therefore the only difference is between the high and low uptake scenarios shown in blue and grey respectively. It is important to note that in the 'low' on-street uptake scenario EV charging load will still be present, but would be delivered by HV connected hubs. For this reason the whole system CBA analysis being completed by Regen is key to comparing the EV scenarios, as this is able to consider costs and benefits from both the LV and HV networks.

In each scenario, for each year, the percentage of feeders which have at least one constraint (cable utilisation, voltage drop or rise) on the worse-case day has been calculated. The graph below shows the results for the four EV scenarios, across all six of the modelled primaries. It should be noted that these are the constraints predicted based on existing data and assuming no interventions occur during the study period. The interventions to be deployed in order to prevent network constraints are analysed in Section 8.

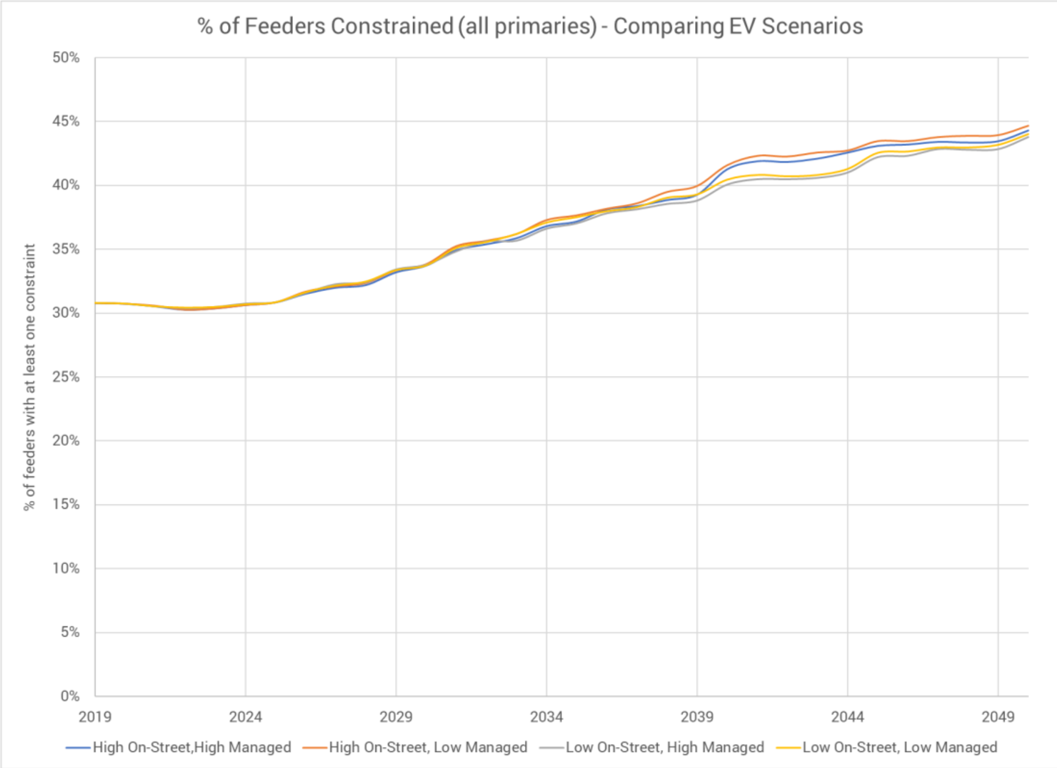


Figure 15 % of Feeders Constrained for all primaries in different EV scenarios

A high level of constraints is observed in the baseline year – before LCT adoption. This is likely a result of data gaps/inaccuracies in the underlying network data. It is high likely to affect all scenarios equally, but is not representative of actual network conditions in the baseline year. The graph shows a general trend in all scenarios of increasing numbers of constraints in the later years. This is as a result of LCT adoption. Comparing the different scenarios the prevalence of constraints is very similar until latter part of the study period (where EV adoption is higher). Even in the later years, the impact of the different EV scenarios is low:

- Comparing the two scenarios with high uptake of on-street EV chargers the largest difference occurs in 2039, with 39.3% of feeders constrained with high uptake of managed charging/ToU tariffs, compared to 39.9% when uptake of these tariffs is low. However the difference between the two scenarios is minimal.
- Lower uptake of on-street chargers results in the greatest difference to the baseline scenario in 2044. In this year 42.6% of feeders have at least one constraint when uptake of on-street chargers is high, compared to 41.0% and 41.3% when uptake of on-street chargers is low (high and low adoption of ToU tariffs respectively).
- The level of constraints is relatively insensitive to either the uptake of on-street charging or the adoption of a ToU tariff, as demonstrated by the small differences in the curves shown in Figure 15. There is a slightly larger difference between the high/low uptake of on-street chargers, compared to the level of uptake of ToU tariffs.

The graph below compares the percentage of distribution transformers which are constrained (have a utilisation > 110%) in each study year in the four EV scenarios.

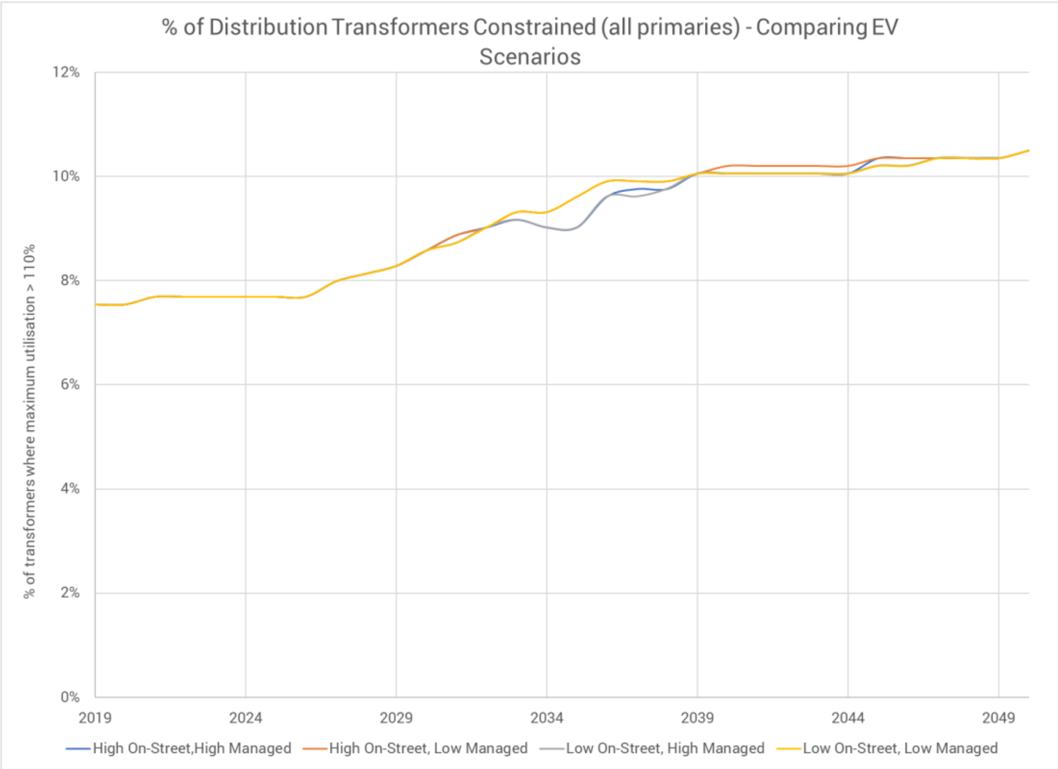


Figure 16 % of Distribution Transformers Constrained (all primaries) - comparing EV scenarios

The overall level of constraints at distribution transformers is lower, although this may be related to data quality issues leading to a higher than expected proportion of LV feeders having constraints in the baseline year. The overall increase in constraints during the study period is also low from 7.5% in 2019 to 10.5% in 2050. Transformer constraints are less sensitive to either the uptake of on-street chargers or ToU tariffs than feeder constraints, shown by the smaller differences between the scenarios in Figure 16.

5.3 Heat Pump Scenarios

Two factors relating to heat pump uptake were varied in the LV modelling:

- Uptake of hybrid heat pumps: hybrid heat pumps are assumed to provide heating using the gas network (rather than electricity) on the peak winter and intermediate cool days, thus limiting the increase in demand on the electricity network. In the baseline scenario uptake of hybrid heat pumps was low, compared to the 'high hybrid heat pump' uptake in Run 17.
- Adoption of flexible heat pump operating profile: two electricity only heat pump profiles were modelled at LV in the EPIC project[18] and are shown below.

[18] Profiles from the WPD Customer Behaviours Report. https://www.westernpower.co.uk/downloads-view-reciteme/303103 Accessed February 2022

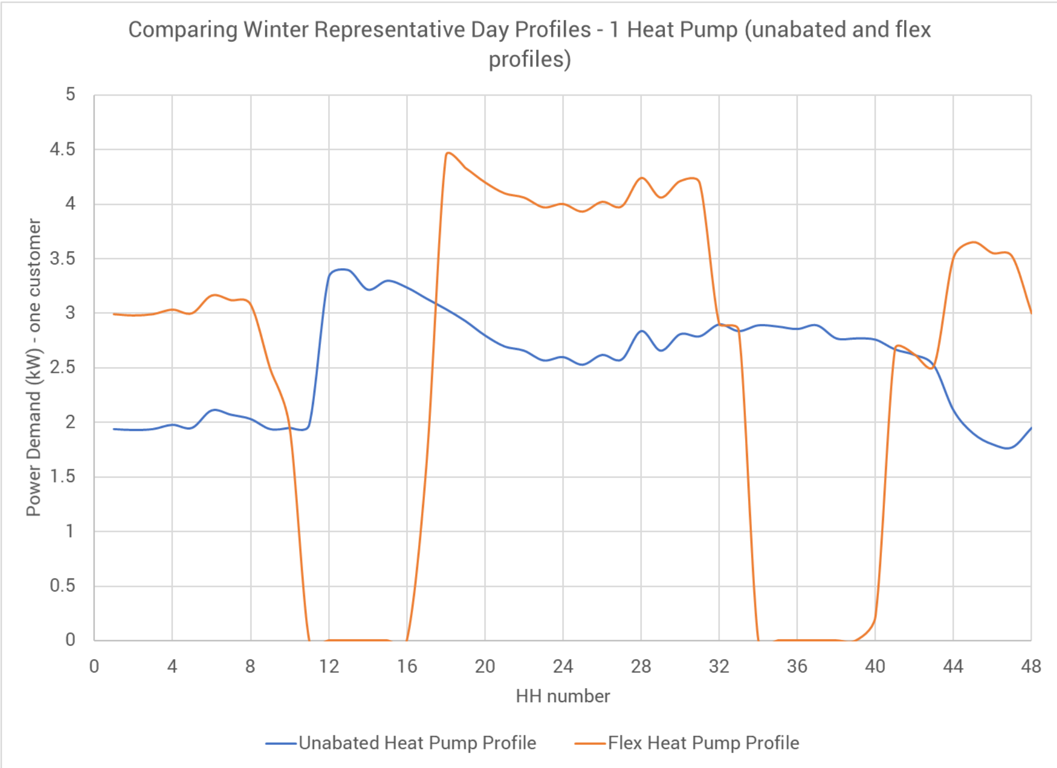


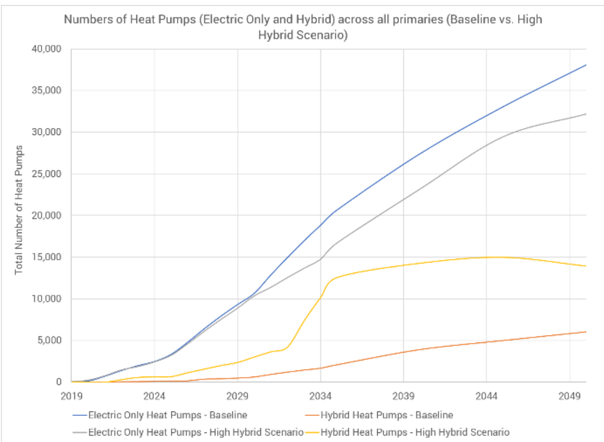
Figure 17 Winter Representative Day Heat Pump Profiles for 1 Customer

The flex profile assumes the heat pump responds to higher prices in periods of traditional network peak demand by pre-heating the home prior to the morning and evening peak. This leads to higher demand during the middle of the day compared to the unabated profile, but no demand during the peak periods on the winter representative day. Two scenarios were modelled – the baseline, assuming low uptake of the flex profile, and Run 15, with high uptake of the flex tariff. In both the baseline and Run 15, uptake of hybrid heat pumps was low.

Two comparisons can therefore be made:

- Comparing the impact of the uptake of hybrid heat pumps – Baseline vs. Run 17 (uptake of the flex profile is low in both cases)
- Comparing the impact of the uptake of the flex profile – Baseline vs. Run 15 (uptake of hybrid heat pumps is low in both cases).

The graphs below show the total number of each of the relevant profiles between 2019 and 2050 in the different runs/scenarios.



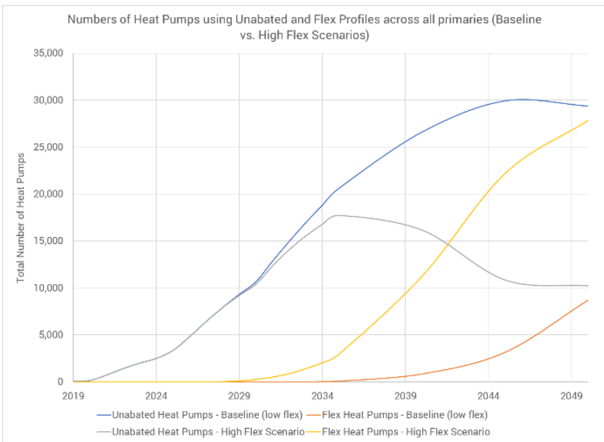


Figure 18 Number of Electric Only and Hybrid Heat Pumps (Baseline and Run 17)

Figure 19 Number of Unabated and Flex Heat Pumps (Baseline and Run 15)

In both the baseline and 'high hybrid' scenarios electric only heat pumps still dominate (blue and grey curves higher than both yellow and orange). The difference between the scenarios is greater in the later years of the study period. The difference in the number of electric only heat pumps deployed in the high hybrid scenario compared to the baseline opens up from 2030 onwards. It is important to note that in the high hybrid uptake scenario the energy demand for heating during the winter evening peak is supplied by the gas network. This may result in lower investment requirements for the LV electricity network. However, the whole system impact (electricity and gas networks) should be reviewed via the whole system CBA analysis being completed by Regen.

Comparing the baseline (low flex uptake) and Run 15 (high flex uptake), uptake of the flexible profile remains low in all scenarios until the early 2030s. In the high flex uptake scenario (Run 15) the flexible profile overtakes the unabated option around 2041.

The graph below compares the percentages of feeders across the modelled areas with constraints over the study period across the three heat pump scenarios.

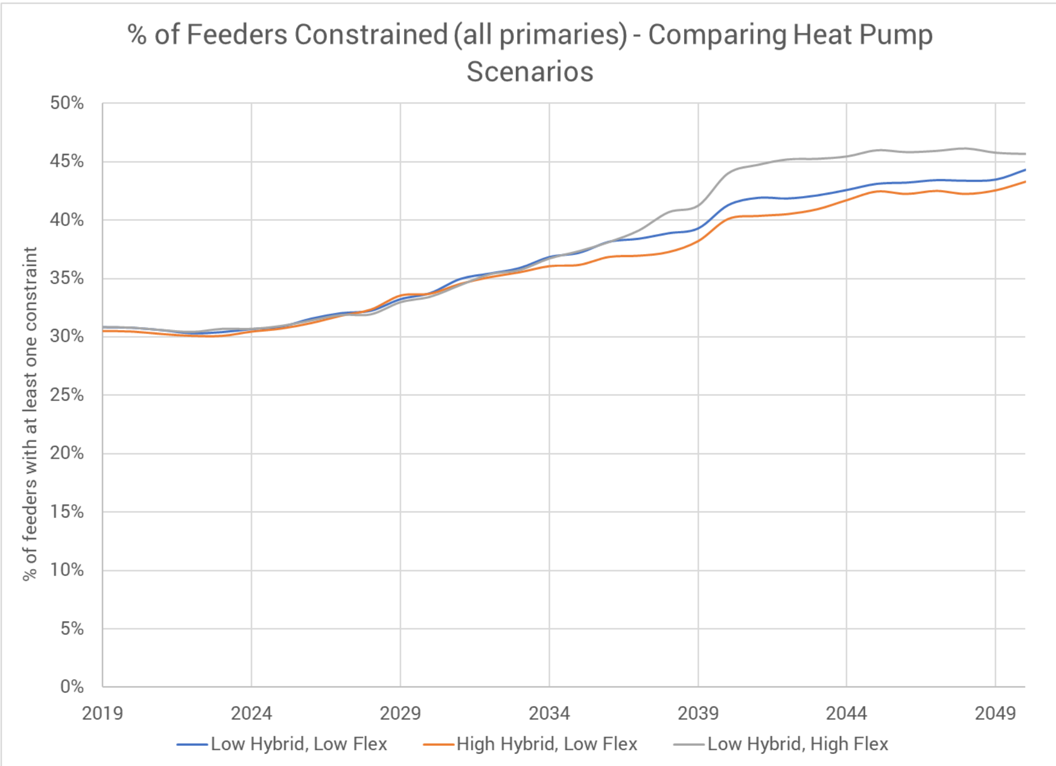


Figure 20 Percentage of Feeders Constrained - Comparing Heat Pump Scenarios

There is minimal difference between the three scenarios until around 2030. Figure 18 and Figure 19 show relatively low uptake of either hybrid heat pumps or the flex profile until after this date. Even in the later part of the study period the scenarios are relatively similar, particularly comparing the baseline (low hybrid uptake, blue) and high hybrid uptake (orange) scenarios. Perhaps counterintuitively, higher uptake of the flex profile leads to a greater proportion of feeders being constrained in the later years. This may be as a result of increased demand for heat pumps either side of the traditional peak which may create new peaks which are sufficient to cause constraints in some networks.

The graph below compares the percentage of distribution transformers which are constrained (have a utilisation > 110%) in each study year in the three heat pump scenarios.

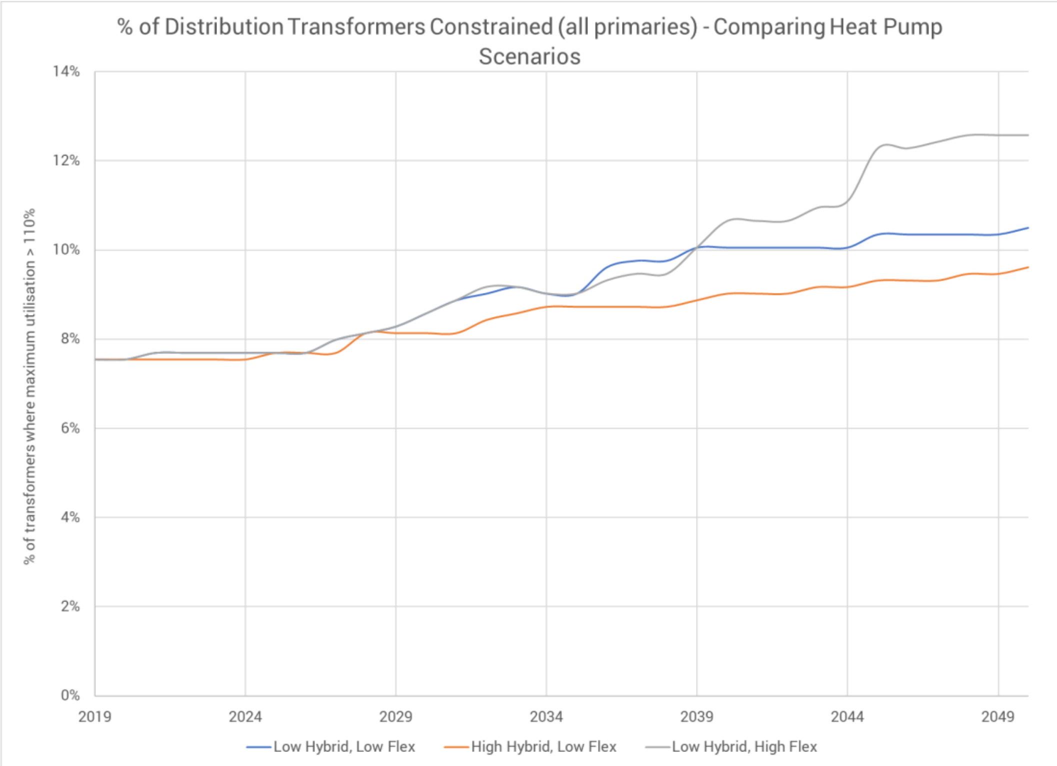


Figure 21 Percentage of Distribution Transformers Constrained across All Primaries - Comparing Heat Pump Scenarios

There are larger differences between scenarios for heat pumps compared to EVs (see Figure 16). The comparison between heat pump scenarios for transformer constraints is similar to that for feeder constraints shown above – higher uptake of hybrid heat pumps compared to the baseline results in slightly fewer constraints, whereas increased uptake of the flex profile increases constraints, particularly in the later study years.

5.4 Energy Efficiency Scenarios

The baseline scenario assumed relatively small improvements in energy efficiency for existing customers. Table 3 shows the energy consumption for each profile type in 2019, 2035 and 2050 in the baseline (low) energy efficiency scenario. For example, for a Class 1 domestic customer in the Bedminster primary area the annual energy consumption decreased from 2,340 kWh in 2019 to 2,107 kWh in 2050 (90% of 2019 value). Local authorities may achieve higher energy efficiency improvements through funding/promotion of retrofit measures, or through investment in local authority housing stock or commercial premises. A 'medium' energy efficiency scenario was modelled for all three SPAs (six primary areas). In addition, for North Filton an SPA specific use case modelled the impact of 'high' energy efficiency improvements. For Class 1 domestic customers energy consumption in 2050 was 90%, 80% and 70% of the 2019 value in the low, medium and high energy efficiency scenarios respectively.

The Debut approach used in the NIFT network modelling scales profiles of demand by either the annual energy consumption or peak power demand (see Table 3). Decreasing the annual energy consumption therefore applies the same reduction to each half hour modelled – i.e. assuming the same reduction applies at all times of day.

5.4.1 Low and Medium Energy Efficiency Use Case – all SPAs

The graph below shows the percentage of LV feeders (across all six primaries) which are constrained in the low (baseline) and medium energy efficiency scenarios.

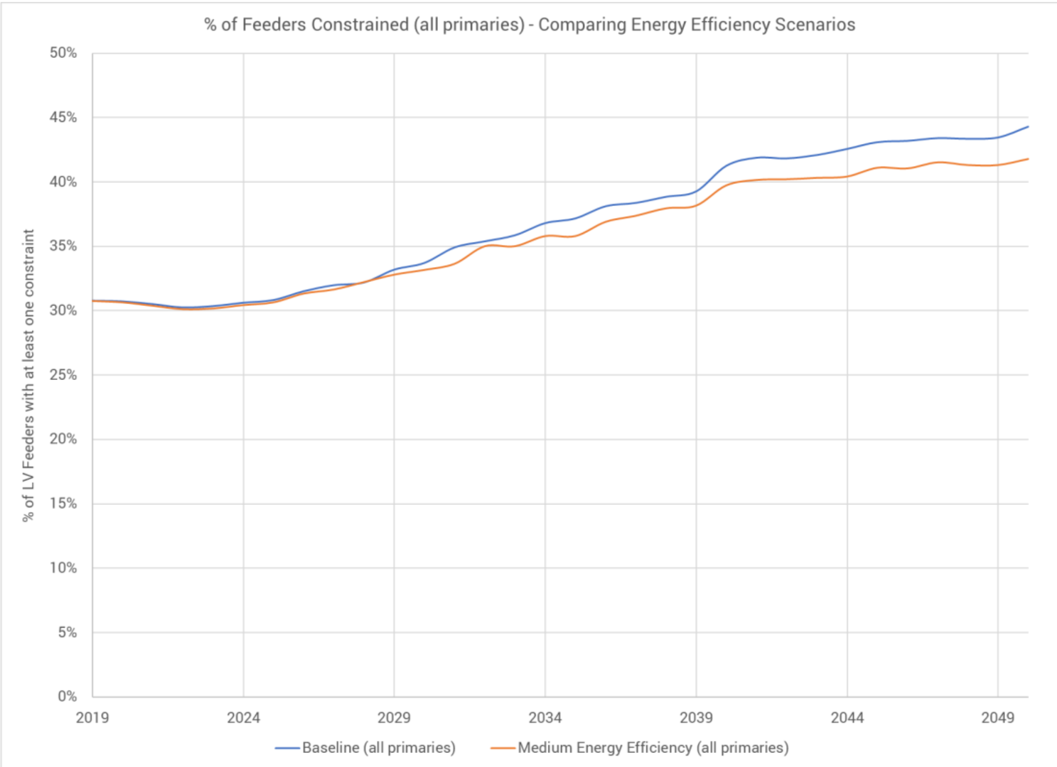


Figure 22 Percentage of Feeders Constrained (all primaries) - Comparing Energy Efficiency Scenarios

Higher energy efficiency only leads to a modest decrease in feeder level constraints – 44% and 42% of feeders are constrained (either due to utilisation, volt drop or rise) in 2050 in the low and medium energy efficiency scenarios respectively. The impact on transformer constraints is similar, with 11% and 9% of distribution transformers constrained in 2050 in the low and medium energy efficiency scenarios respectively.

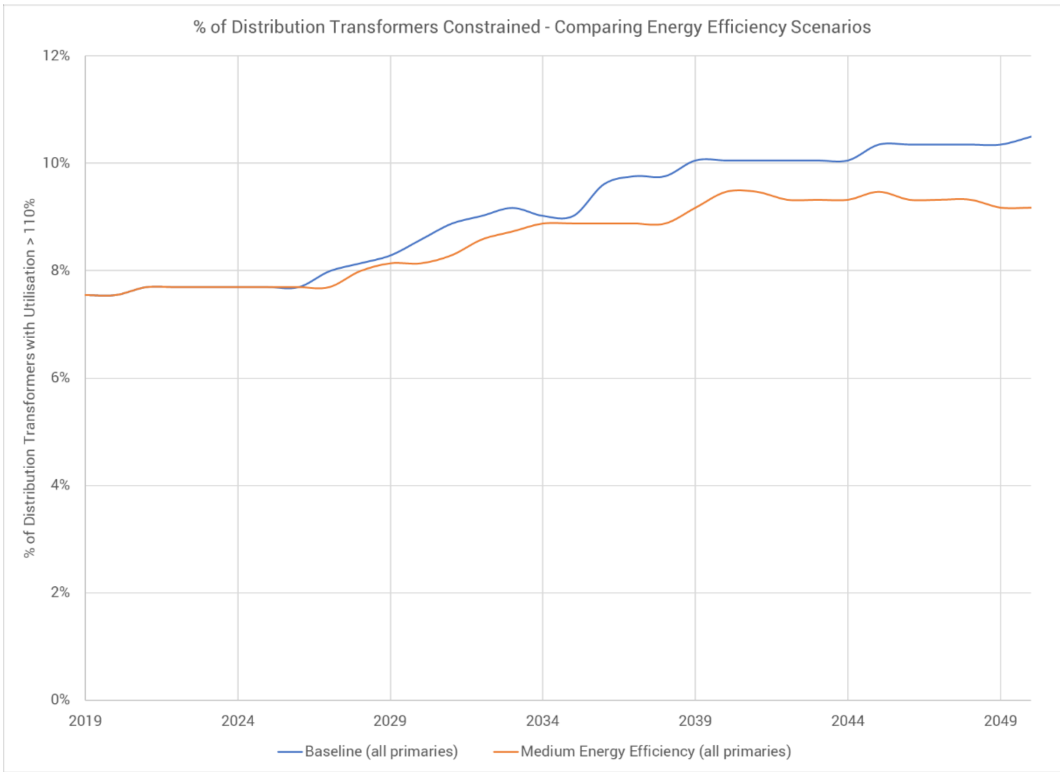


Figure 23 Percentage of Distribution Transformers Constrained (all primaries) - comparing energy efficiency scenarios

5.4.2 North Filton SPA Specific Use Case – High Energy Efficiency

North Filton SPA (Filton DC and Cribbs Causeway primary areas) included a high energy efficiency scenario due to the ambitions of the local authority in this area. The graphs below compare the percentage of feeders constrained for each primary separately, showing the low, medium and high energy efficiency scenarios.

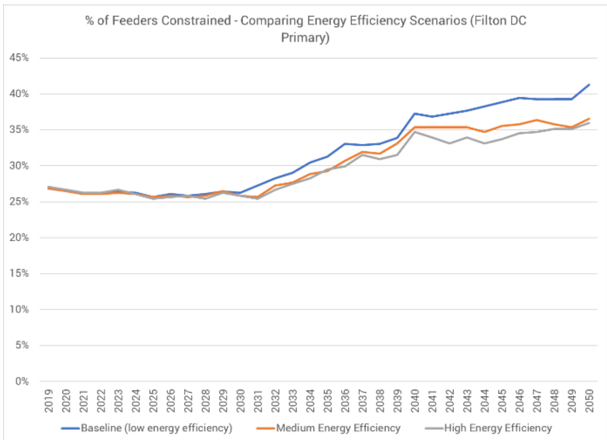


Figure 24 Percentage of Feeders Constrained - Comparing Energy Efficiency Scenarios (Filton DC Primary)

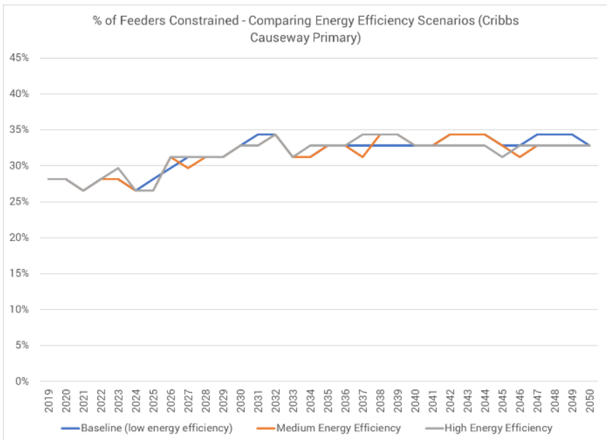


Figure 25 Percentage of Feeders Constrained - Comparing Energy Efficiency Scenarios (Cribbs Causeway Primary)

The customer composition of the two primaries are different (see Figure 5). 96% of customers supplied at LV by Filton DC primary are domestic customers (88% Class 1, 7% Class 2) compared to 73% of those supplied by Cribbs Causeway primary. In the NIFT modelling LCTs were applied to domestic customers only, and it is the increasing adoption of LCTs which causes the number of constraints to increase over time. Across all scenarios for the Filton DC primary area the proportion of feeders which are constrained increases through the study period. Increased energy efficiency limits the decrease with 41%, 37% and 36% of feeders constrained in 2050 in the low, medium and high energy efficiency scenarios respectively. The impact of energy efficiency at Cribbs Causeway is less clear. LCT adoption is lower and so the increase in the proportion of feeders constrained over the study period is lower (from 28 to 33% in the baseline scenario for Cribbs Causeway, compared to 27% to 41% for Filton DC). No energy efficiency improvements were assumed for customers in Elexon Profile Class 5 to 8. These customers make up 9% of LV customers supplied by Cribbs Causeway (whereas Filton DC supplies no customers in these classes at LV). This is an example of how differing customer composition can result in different trends being observed between primaries. This is explored in more detail below.

6. Level of constraints – comparing primary substations

6.1 Introduction

As described above, the LV network fed from six primary substations was modelled as part of the EPIC project, across three SPAs:

- Bath Enterprise Zone: Dorchester Street New primary
- South West Bristol: Bedminster, Bower Ashton and Nailsea primaries
- North Filton: Filton DC and Cribbs Causeway primaries

Modelling additional primary substation areas increases the time required for data preparation, modelling and analysis of results. This section of the report compares the results between different primary substation areas to determine whether it is necessary to model multiple primary substations, or whether the number to be modelled could be reduced whilst still delivering the same level of insights. Section 3.5 compares the different study areas in terms of the customers supplied at LV and the resulting aggregated load profile in 2019.

The purpose of this section is to compare the results between primary substations.

6.2 Variability of Results Between Primary Substation Areas

The data presented in Section 5 shows the proportion of feeders and distribution substations with constraints across the study period for various scenarios. The results for all the primary substations were combined (with the exception of the high energy efficiency SPA specific use case). This has the potential to hide differences in the results between primary substations.

The graphs below show the baseline results. The shaded area represents the spread of results between the primary with the highest level of constraints and that with the lowest in each year. The individual results for a subset of the primaries is shown with orange markers (Nailsea), red crosses (Cribbs Causeway) and purple crosses (Filton DC).

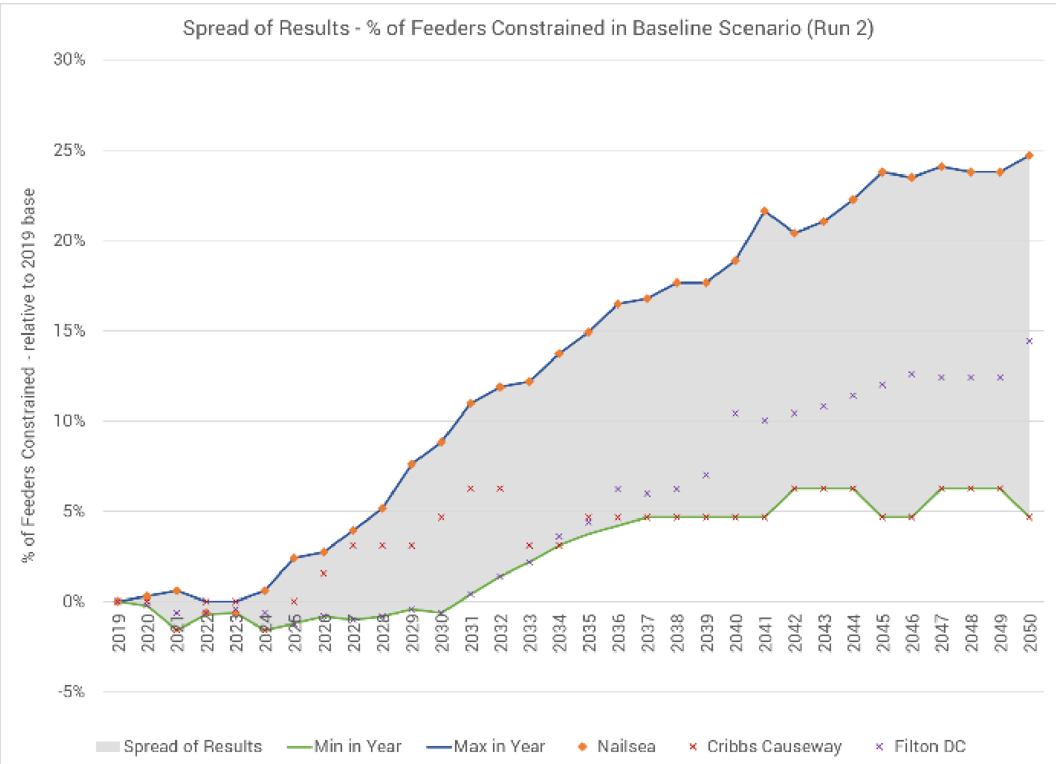


Figure 26 Spread of Results for Feeder Constraints - Baseline Scenario

Figure 26 shows that as the study period progresses the spread of results between the primary with the lowest and highest proportion of constrained feeders increases (widening grey area). Results are shown relative to the 2019 base case for each primary so the differences observed above are due to differences in LCT adoption, rather than the level of constraints already present/identified in the model. The individual data for three primary substations has been included, as these areas demonstrate the variability of results best:

- Cribbs Causeway: has the lowest change compared to its 2019 base across of all the primaries from 2037 onwards (red crosses sit on the minimum line). As shown in Figure 6 Cribbs Causeway has a lower proportion of domestic customers, so LCT adoption in the NIFT will be lower.
- Filton DC: the results for this primary, Bower Ashton, Bedminster and Dorchester St New were broadly similar. Filton DC has an increasing level of constraints through the study period, but not to the extent of Nailsea (see below).
- Nailsea: with the exception of 2022 and 2023 Nailsea has the largest change in the proportion of its feeders which are constrained compared to the 2019 base. However, considering customer composition alone (Figure 5 and Figure 6) it is not clear why the results for Nailsea differ significantly compared to Filton DC.

There a wide range of potential reasons for the variability in results between substations, including:

- Age and condition of the existing network and therefore the available capacity to accommodate LCT load growth
- Number and type of customers: in the EPIC project LCTs on the LV network have only been allocated to domestic customers (Elexon Class 1 and 2). Primary areas which have a lower proportion of domestic customers (e.g. Cribbs Causeway, see Figure 6) are less likely to see investment requirements driven by the uptake of LCTs.

The graph below shows the variation in the level of constraints on distribution substations between primary substation areas, using the same format.

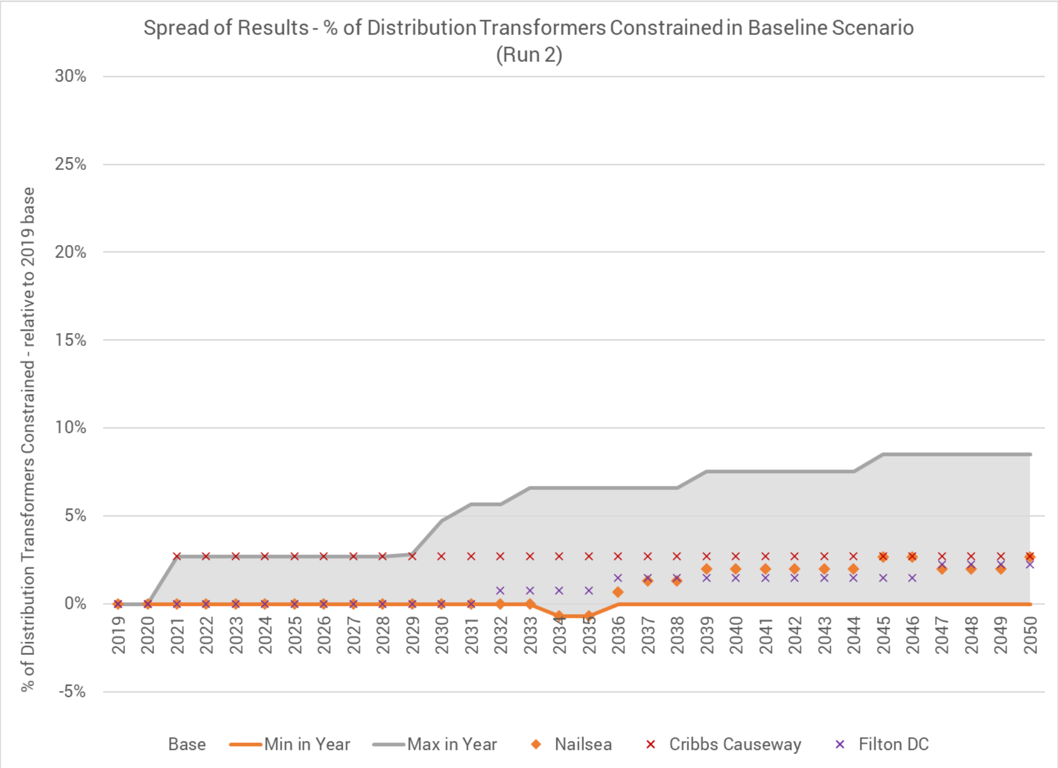


Figure 27 Spread of Results for Distribution Transformer Constraints - Baseline Scenario

The variability between primary substation areas is lower when considering distribution transformer constraints (smaller grey shaded area on Figure 27). However, the trend between primaries differs from the feeder results. For example, Nailsea had the largest increase in feeder level constraints of all the modelled primaries, but the level of distribution transformer constraints was lower.

The above graphs indicate that there is significant variability in the level of constraints which occur between primary substations.

6.3 Variability of Scenario Level Conclusions Between Primary Substation Areas

Sections 5.2, 5.3 and 5.4 compared the level of constraints between different use cases, concluding that there was minimal difference between the scenarios when LCT adoption is at the level modelled within EPIC, particularly in the EV and heat pump scenarios. These conclusions were based on the results for all primary substations combined. In combination with the investment results summarised in later sections and the CBA results this information could be used by local authorities in their planning. For example, the minimal difference between the scenarios may mean that decisions on the optimal policy could be made based on other factors, rather than the required investment in the energy network. However, if results differ between primary substations (i.e. in a particular area the level of constraints does vary considerably between scenarios) it may be necessary to model each primary area in future modelling exercises before making a conclusion.

6.3.1 EV Scenarios

Individual graphs comparing the proportion of feeders which are constrained between the use cases for each primary substation area can be found in Appendix II. For each year the absolute difference between each scenario and the baseline has been calculated for each primary substation. The maximum difference across the study period for each of the scenarios is given below. For example, in 2038 at Dorchester St. New 43.8% of LV feeders were constrained in the baseline scenario. In the high on-street, low managed scenario 44.7% of feeders were constrained a difference of 0.9%. This was the year with the largest difference between the scenarios. This calculation has been repeated for each primary substation area.

Table 9 EV Scenarios - Comparing Use Cases and Primaries (Feeder Constraints)

Primary Substation Area	Maximum Absolute Difference to Baseline across study period		
	High On-Street Low Managed	Low On-Street High Managed	Low On-Street Low Managed
All areas	0.7%	1.6%	1.3%
Dorchester St. New	0.9%	1.2%	1.2%
Bedminster	1.2%	2.1%	2.1%
Bower Ashton	1.3%	3.0%	3.0%
Nailsea	0.6%	0.9%	1.2%
Filton DC	1.4%	1.8%	1.2%
Cribbs Causeway	1.6%	1.6%	1.6%

Shading has been applied to indicate the scenario(s) with the largest difference compared to the baseline (pink fill), smallest difference (green fill) and the middle value (yellow fill). The table above shows:

- Across all primary substations and scenarios the differences between the scenarios are small. The largest difference is a 3.0% decrease in constraints at Bower Ashton in the low on-street scenarios compared to the baseline. The overall conclusion that the level of constraints is relatively insensitive to the EV use cases is valid for all the modelled primary substation areas.
- There are some differences in which scenario has the largest difference compared to the baseline. For example, at Filton DC in the 'Low On-Street, High Managed' scenario in 2040 there is a 1.8% decrease in constraints compared to the baseline and this is the scenario with the largest difference. However, at Nailsea the largest difference to the baseline occurs in 2041 in the 'Low On-Street, Low Managed' scenario. However, as the overall differences between the scenarios are small these differences in which has the greatest difference are relatively insignificant.

The same analysis approach has been applied to constraints on distribution transformers.

Table 10 EV Scenarios - Comparing Use Cases and Primaries (Distribution Transformer Constraints)

Primary Substation Area	Maximum Absolute Difference to Baseline across study period		
	High On-Street Low Managed	Low On-Street High Managed	Low On-Street Low Managed
All areas	0.6%	0.1%	0.6%
Dorchester St. New	0.0%	0.9%	0.9%
Bedminster	0.0%	0.0%	0.0%
Bower Ashton	0.7%	0.0%	0.7%
Nailsea	1.3%	0.7%	1.3%
Filton DC	0.8%	0.0%	0.8%
Cribbs Causeway	0.0%	0.0%	0.0%

As shown in Section 5.2 (specifically Figure 15 and Figure 16) the differences between the scenarios is generally lower when looking at transformer constraints. Again, the differences between the scenarios is minimal for all primary substation areas.

In conclusion the data in Section 6.2 and the graphs in Appendix II show that there is variability in the level of constraints between the primary substation areas and this difference widens as the study period progresses.

6.3.2 Heat Pump Scenarios

The analysis approach shown above was repeated for the heat pump scenarios. Graphs showing the full results for each primary substation area can be found in Appendix II. The table below shows the largest difference in any year between each scenario and the baseline (low hybrid heat pumps, low uptake of the flexible profile).

Table 11 Heat Pump Scenarios - Comparing Use Cases and Primaries (Feeder Constraints)

Primary Substation Area	Maximum Absolute Difference to Baseline across study period	
	High Hybrid Low Flex	Low Hybrid High Flex
All areas	1.6%	3.4%

Primary Substation Area	Maximum Absolute Difference to Baseline across study period	
	High Hybrid Low Flex	Low Hybrid High Flex
Dorchester St. New	4.0%	1.6%
Bedminster	1.4%	4.2%
Bower Ashton	5.9%	4.3%
Nailsea	2.4%	1.8%
Filton DC	3.1%	6.7%
Cribbs Causeway	4.7%	3.1%

Shading has been applied to indicate the scenario(s) with the largest and smallest difference compared to the baseline (pink and green fill respectively). The table above shows:

- The degree of variability between the heat pumps scenarios and the baseline is greater than the EV scenarios. The level of constraints is more sensitive to the type of heat pumps deployed and how electric only heat pumps operate. For example, at Bower Ashton in 2037 in the high hybrid, low flexible profile uptake scenario 35% of feeders are constrained, compared to 41% in the baseline (low hybrid, low flexible profile uptake). For Filton DC in 2041 44% of feeders are constrained in the low hybrid, high flexible profile uptake scenario, compared to 37% in the baseline scenario. The differences between the EV scenarios described above are smaller (in the region of 0 – 3%).
- Appendix II shows the graphs of the level of constraints for each primary substation. While broadly it is true for all primary substation areas that constraints are more widespread in the high flexible profile uptake scenario, and lower when hybrid heat pump uptake is higher (compared to the baseline). The extent to which this is true is variable between primary substation areas – compare for example Bower Ashton and Nailsea shown below.

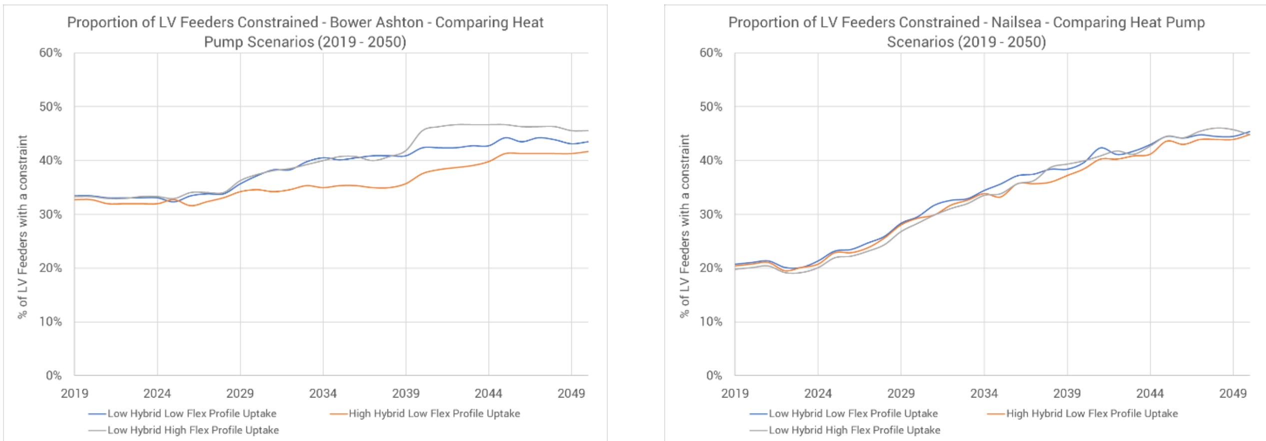


Figure 28 Comparing Feeder Level Constraints (Heat Pump Scenarios) - Bower Ashton and Nailsea

The difference between scenarios is greater at Bower Ashton than Nailsea (also evident from Table 11).

- Figure 28 also illustrates that the growth in constraints through the study period varies between primary substation areas. The rate of increase is much lower at Bower Ashton compared to Nailsea.

The same analysis approach has been applied to constraints on distribution transformers.

Table 12 Heat Pump Scenarios - Comparing Use Cases and Primaries (Distribution Transformer Constraints)

Primary Substation Area	Maximum Absolute Difference to Baseline across study period	
	High Hybrid Low Flex	Low Hybrid High Flex
All areas	1.2%	2.2%
Dorchester St. New	3.8%	1.9%
Bedminster	0.0%	3.7%
Bower Ashton	1.4%	2.8%
Nailsea	2.7%	2.7%
Filton DC	0.8%	2.3%
Cribbs Causeway	2.7%	0.0%

This shows similar results to the feeder constraints (albeit that distribution transformer constraints are lower, as shown in Figure 20 and Figure 21):

- The heat pump scenarios are more variable compared to the baseline than the EV scenarios; and
- The scenario with the largest change compared to the baseline varies between primary substation area.

6.3.3 Energy Efficiency Scenarios

The analysis approach shown above was repeated for the energy efficiency scenarios. Graphs showing the full results for each primary substation area can be found in Appendix II. The table below shows the largest difference in any year between the low and medium energy efficiency scenarios for all primary substation areas, and the low, medium and high scenarios for Filton DC and Cribbs Causeway (North Filton SPA).

Table 13 Energy Efficiency Scenarios - Comparing Use Cases and Primaries (Feeder Constraints)

Primary Substation Area	Maximum Absolute Difference to Baseline across study period	
	Medium Energy Efficiency	High Energy Efficiency
All areas	2.5%	
Dorchester St. New	2.5%	
Bedminster	3.7%	
Bower Ashton	2.9%	
Nailsea	1.2%	
Filton DC	4.7%	5.3%
Cribbs Causeway	1.6%	1.6%

Increased levels of energy efficiency reduces the level of constraints at all primary substation areas. However, the difference varies between areas – from 1.2% at most at Nailsea, to 4.7% at Filton DC.

6.4 Summary

At start of Section 5 two questions were posed, which may be solved through the kind of detailed modelling undertaken in the EPIC project, as follows:

1. "Does use case/scenario A (e.g. high adoption of EV ToU tariffs) lead to lower constraints than use case/scenario B (e.g. low adoption of EV ToU tariffs)?
2. What level of constraints will occur across time in use case/scenario A?"

In this section it has been demonstrated that broad conclusions can be made about which scenario/use case leads to lower levels of constraints which are consistent across multiple primary substation areas. This is particularly true for the EV use cases studied, where the level of difference between scenarios was small across all scenarios and primary substations. The overall conclusion that the level of constraints is relatively insensitive to the EV use cases is valid for all the modelled primary substation areas. The results are more variable for heat pump scenarios. This is perhaps to be expected as the differences in the underlying profiles (e.g. for hybrid vs. non-hybrid heat pumps in winter) is greater than in the EV scenarios. Modelling a subset of primary substation areas is likely to be sufficient to draw conclusions about which scenarios give lower/higher level of constraints.

However, if quantitative, absolute results showing the level of constraints on a particular network are required (i.e. the answer to question 2) then this can only be obtained through modelling of the network in questions due to high variability in the results. This is evident in Figure 26 and the graphs in Appendix II.

7. Contribution of Representative Days to Network Constraints

As described in Section 3, five representative days were modelled in NIFT to reflect different load/generation profiles through the seasons. For the majority of profiles included within the modelling, demand is highest in winter, followed by intermediate cool, intermediate warm and summer, with the following key exceptions:

- PV generation: highest output in summer, followed by intermediate warm, intermediate cool and winter.
- Hybrid heat pumps: no demand in winter or intermediate cool (heating demand supplied by gas). Demand highest in the intermediate warm season, followed by summer.
- Heat pump flex profile: no demand 5:30 to 8:00 and 17:00 to 19:30 during winter or intermediate cool days. The heat pump flex profile has greater demand in the early hours of the morning and middle of the day/early afternoon, effectively pre-heating the home to avoid using electricity for heating during peak demand times.

The 'What Breaks When' tables report network conditions (transformer and LV feeder utilisation, volt drop and volt rise) for each asset in each study year, with a separate table for each representative day. LCT uptake increases from the base year (2019) to the end of the study period (2050). Each modelling run was performed separately, increasing the time required to derive results. Network investment is driven by the worst case conditions. The time expended in producing the outputs could be reduced by modelling fewer representative days, if there was sufficient certainty that this would capture the worst case scenario.

For each transformer and LV feeder the season in which the maximum transformer utilisation, cable utilisation, volt drop and volt rise occurs has been determined, in the base year (2019) and when LCT adoption is highest (2050). The results for the baseline scenario are shown below.

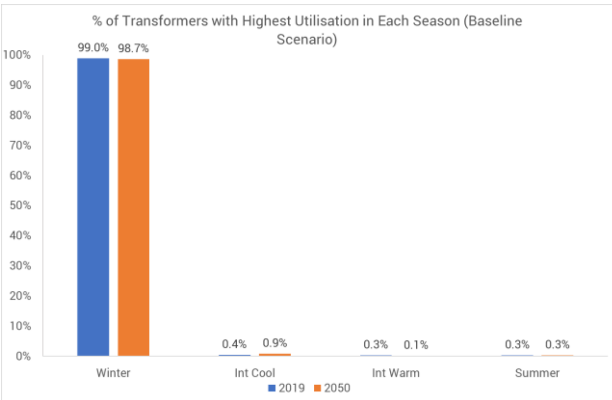


Figure 29 % of Transformers with Highest Utilisation in Each Season (Baseline)

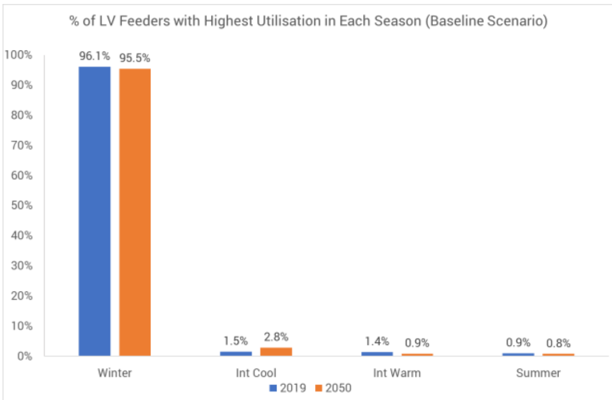


Figure 30 % of LV Feeders with Highest Utilisation in Each Season (Baseline)

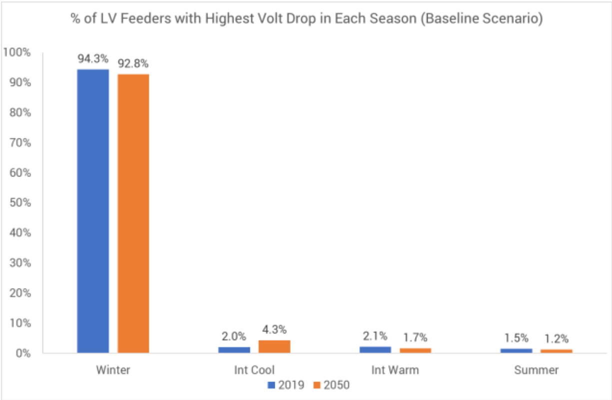


Figure 31 % of LV Feeder with Highest Volt Drop in Each Season (Baseline)

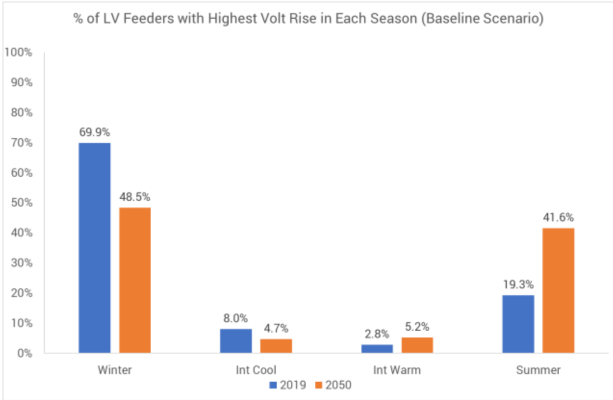


Figure 32 % of LV Feeder with Highest Volt Rise in Each Season (Baseline)

These figures show that, with the current profiles, modelling only the winter and summer representative days would determine the worst case network conditions in the vast majority of cases, as follows:

- Transformer Utilisation: 99.3% (2019) and 99.0% (2050)
- Feeder Utilisation: 97.1% (2019) and 96.3% (2050)
- Volt drop: 95.8% (2019) and 94.0% (2050)
- Volt rise: 89.2% (2019) and 90.0% (2050)

Two of the scenarios (see Table 5 for full details) may alter this trend, as they include a greater take up of profiles with a different seasonal pattern of demand:

- Run 17 (heat pump use case – high hybrid, low flex profile uptake): this run has a higher uptake of hybrid heat pumps which do not contribute to demand on the electricity network on winter and intermediate cool days, as they are assumed to operate on gas during these periods.
- Run 15 (heat pump use case – low hybrid, high flex profile uptake): this run has higher uptake of the 'flex' profile for non-hybrid heat pumps. The flex profile has increased demand during the early morning and middle of the day/early afternoon, and no demand in the traditional evening peak during winter and intermediate cool.

The analysis presented in Figure 29 to Figure 32 was repeated for Run 17 (high hybrid heat pump uptake) and Run 15 (high uptake of the flex profile). Run 17 showed the largest change to the seasonality of network constraints and so is shown below.

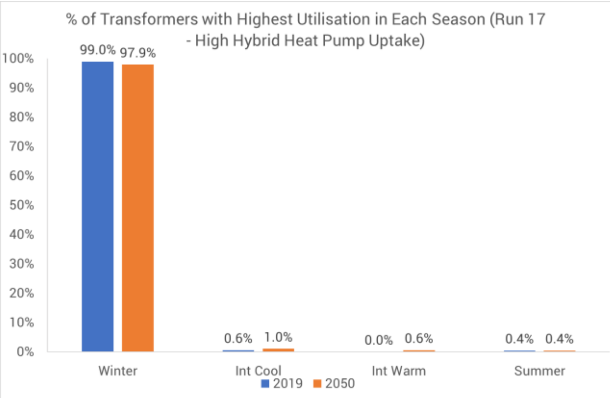


Figure 33 % of Transformers with Highest Utilisation in Each Season (Run 17)

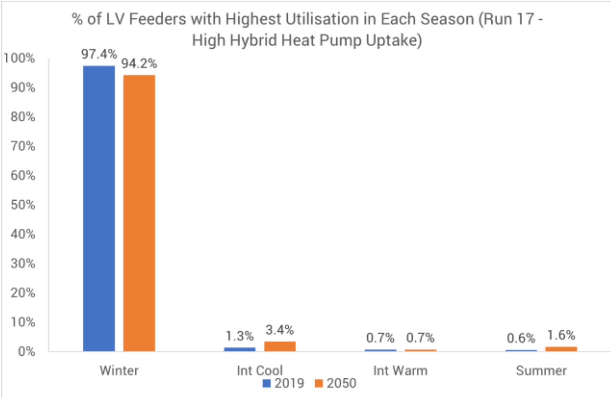


Figure 34 % of LV Feeders with Highest Utilisation in Each Season (Run 17)

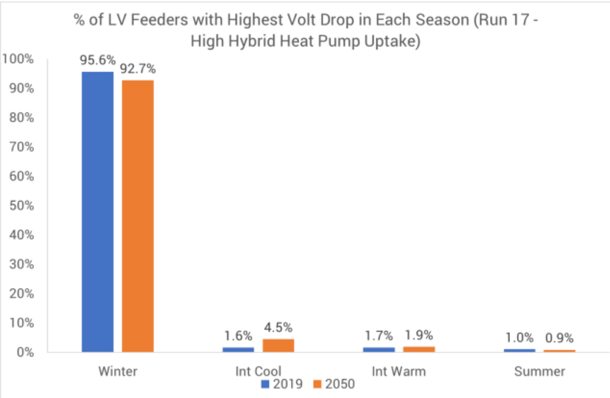


Figure 35 % of LV Feeder with Highest Volt Drop in Each Season (Run 17)

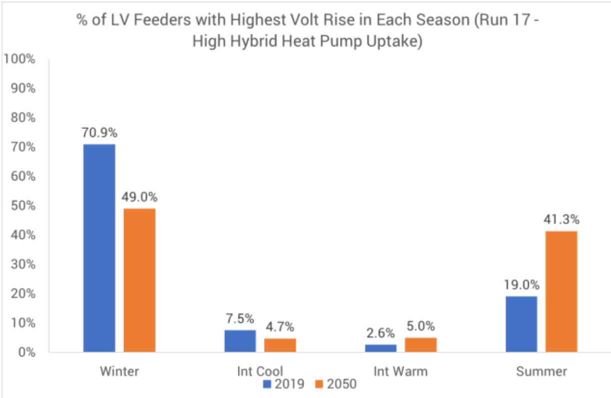


Figure 36 % of LV Feeder with Highest Volt Rise in Each Season (Run 17)

While this shows a slight change compared to the baseline scenario (an increase in maximum network constraints occurring in the intermediate seasons), modelling the winter and summer representative days only would still predict the vast majority of worse case scenarios when LCT uptake is highest in 2050, as follows:

- Transformer Utilisation: winter and summer representative days account for 98.3% of worse case scenarios in 2050 (compared to 99% in the baseline)
- Feeder Utilisation: winter and summer representative days account for 95.8% of worse case scenarios in 2050 (compared to 96.3% in the baseline)
- Volt Drop: winter and summer representative days account for 93.6% of worse case scenarios in 2050 (compared to 94.0% in the baseline)
- Volt Rise: winter and summer representative days account for 90.3% of worse case scenarios in 2050 (compared to 90.0% in the baseline)

The majority of the Debut profiles used within the EPIC project have highest demand in winter, and highest generation in summer. The results above, showing the vast majority of constraints occurring in either winter or summer are to be expected. The level of uptake of profiles with different seasonality in Runs 17 and 15 was not sufficient to alter this pattern substantially. In the absence of updated Debut profiles with different seasonality the modelling work could be reduced to cover winter and summer representative days only without materially affecting the results. Modelling of the shoulder seasons would only become necessary if the demand/generation output would exceed that seen in winter and summer.

8. Network Investment

The previous sections have presented the results of the analysis of network conditions and constraints. Network investment in the form of reinforcement or other smart interventions is required in order to solve the constraints. NIFT includes the ability to determine the solutions required to solve the constraints, and the resulting expenditure.

The following sections describe the functionality of the NIFT solutions module and how it was used in the EPIC project. They provide an overview of the results in terms of the profile of expenditure and how this differs between scenarios and describe the methodology used to generate the inputs required for the cost benefit analysis (CBA) work being completed by Regen. Changes made to the NIFT solutions module for the EPIC project are given in Appendix III.

8.1 NIFT Solutions Module

As described in Section 3.1 NIFT uses data on the LV network (network configuration, asset ratings, existing customers, etc.) and projections of LCT uptake to determine network conditions in future years. Network conditions (cable utilisation, volt drop and rise for each LV feeder, and transformer utilisation for each distribution transformer) are reported for each representative day/season in the 'What Breaks When' table (see Section 3.3). Without first establishing the network conditions it is not possible to identify the investment needed to address these constraints. In EPIC network conditions were modelled for five separate representative days[19], as detailed in the LV Specification Report (Deliverable WP2 D4). This therefore shows where and when constraints exist throughout the study period (2019 – 2050) as the network conditions are compared to allowable values. An additional step was introduced for the EPIC project so that the worst-case conditions were taken from the various representative days (e.g. transformer and cable utilisation and volt drop likely to come from the winter representative day due to cold weather, volt rise likely to come from the summer representative day due to low demand and high PV output). Section 7 explores which representative days led to the worst case network conditions.

The 'Solutions Module' from NIFT was used to determine the reinforcement required to resolve the constraints for the existing LV network. Connections for new developments were not modelled in the solutions module as it is assumed these are constructed with sufficient capacity and will not require reinforcement during the study period.

The diagram below shows the process flow for the solutions module at a high level:

[19] Winter, Intermediate Cool, Intermediate Warm, Summer (maximum demand, minimum generation) and Summer (minimum demand, maximum generation).

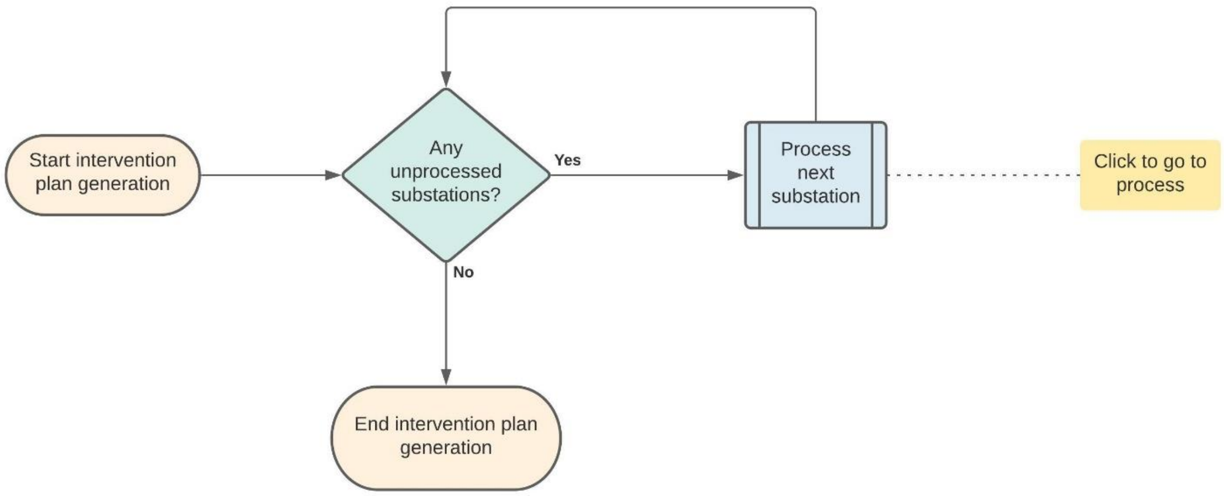


Figure 37 High Level Process for Solutions Module

The intervention plan can be generated once the 'What Breaks When' table has been generated for each run, as this table is required to identify the constraints to be solved. The Solutions module processes each substation within the study area in turn, until all substations have been processed.

The process for each substation is shown below:

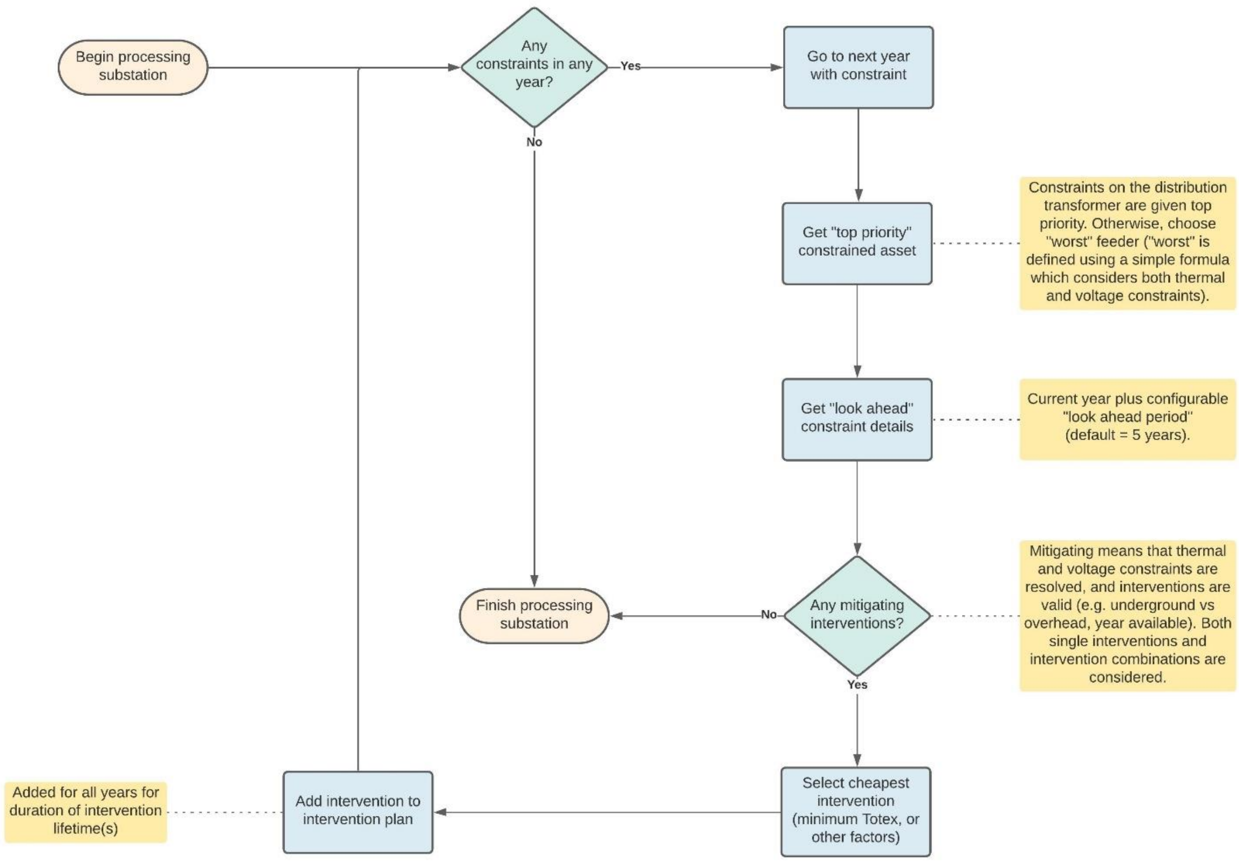


Figure 38 Substation by Substation Processing in Solutions Module

The process can be summarised as follows:

- Review the 'What Breaks When' table for each distribution transformer and all associated feeders downstream. Determine whether constraints (thermal or voltage) exist in any of the modelled years. If none exist, then the solution module moves to the next unprocessed substation as the process is complete because no reinforcement is required.
- Where a constraint exists, the module identifies the year in which it occurs and the asset with the highest priority with a constraint. Distribution transformers take highest priority above individual feeders. If the constraints are only at a feeder level, then the 'top priority' asset is identified by considering the relative magnitude of the constraints.
- The module then 'looks ahead' to review the network condition over the following years. For example, if a look ahead period of 5 years is set then a solution will be identified which is able to meet the modelled demand for the next five years, rather than just solving the constraint in the year it first appears. The look ahead period was varied to compare two approaches – 'just in time' (look ahead period of three years) compared to 'fit for the future' (look ahead period of twenty years), see Table 5.
- At this stage the assets which are constrained and the size of constraint over a given time period have been identified for the substation. The tool then proceeds to identify suitable 'mitigating interventions' from the available solution set. The solution set for EPIC is summarised in Appendix I. A list of candidate interventions is produced – i.e. interventions that a) are suitable for the asset type in question, b) are able to resolve the identified constraint and c) are available in the year required. Interventions may be deployed on their own, or where appropriate combined. The candidate list of solutions has a series of properties associated with each, including:
    - Capital expenditure to deploy
    - Operational expenditure
    - Resultant total expenditure (totex)
    - Solution life-time
    - Network benefits – thermal benefits for transformers and cables/OHL and voltage head and legroom released
- The suitable (i.e. available at the time necessary, solves the constraint for the duration of the look ahead period and compatible with the network type) intervention with the lowest totex expenditure is selected and added to the intervention plan.
- The substation is processed until no constraints remain. For example, if the process outlined above first applies a solution in 2025 with a 15 year lifetime then a new intervention would be required for 2040 onwards (assuming the loading level remains high enough to require it). Interventions with longer lifetimes would be more likely to solve the constraints identified for the entirety of the study period (2020 - 2050).

Two reports produced by the solutions module were used in the EPIC project:

- Feeder Solution Deployment Report: a detailed list of the solutions identified from the process reported above. Data is reported for each LV feeder, for each year, with columns naming the interventions deployed in each year and whether these relate to the LV feeder in question, other LV feeders fed from the same distribution substation, or the distribution substation itself.
- Substation Investment Profile Report: this report consolidates the data for feeders and reports it against each distribution substation. For each year it reports which solutions are deployed for the first time in the year ('chosen for deployment'), and what solutions are active having been deployed in previous years. It also reports the capex and opex spend in each year (capex for solutions which are chosen for deployment in that year, plus opex for all active solutions, combined into totex – total expenditure).

These outputs have been used to produce the data summaries included within this report (see Section 8.2) and also combined with the 'What Breaks When' Table to produce the majority of the inputs required for the CBA tool (see Section 9). A set of reports (Feeder Solutions and Substation Investment Profile) were generated for each of the use cases/scenarios shown in Table 5.

8.2 Comparing Investment Between Use Cases

The investment required is a function of the level of constraints which occur. This section compares two aspects of the expenditure:

- The profile of capital expenditure over time, and the total amount across the study period
- The type of solutions which are deployed – traditional network reinforcement and 'smart' solutions such as Active Network Management (ANM)

For all the sections below it should be noted that there is significant capital investment predicted in 2019. This is as a result of the modelled constraints which occur in the base year (2019). In most cases this is likely to be due to data inaccuracies. In reality expenditure in 2019 would be much lower. When comparing investment between scenarios with variations in energy consumption or LCT adoption this affects all scenarios equally as the base data is very similar (due to low levels of LCT uptake in 2019 across all scenarios).

8.2.1 'Fit for the Future' vs. 'Just in Time'

The level of constraints and therefore related expenditure/investment varies depending on LCT adoption and changes in energy consumption. Three areas have been studied – EV charging, heat pump adoption and energy efficiency, as described in Section 5. In addition, two investment strategies were studied as part of the EPIC project:

- 'Just in Time': in this scenario investments are made considering short term needs only. The solutions module used a 'look ahead' period of three years. As described in Section 8.1 the solutions module selects a solution which resolves constraints for the entire duration of the look ahead period. For example, if a constraint was identified in 2020 then a solution would be chosen that provides enough capacity to meet the requirements until 2023.
- 'Fit for the Future': in this scenario investments were chosen looking further into the future, with a look ahead period of twenty years. For example, if a constraint was identified in 2020 then a solution would be chosen that provides enough capacity to meet the requirements until 2040. This could lead to greater initial investment as more expensive solutions may be required to provide sufficient capacity. However, it may ultimately result in lower expenditure and less disruption if multiple interventions are avoided.

The constraints from the baseline scenario were used to generate a set of investments for the 'Just in Time' (3 years) and 'Fit for the Future' (20 years) variations – i.e. the only difference in this use case is the investment strategy, rather than the level of constraints.

The graph below compares the total investment for each primary substation area across the study period between the two investment strategies.

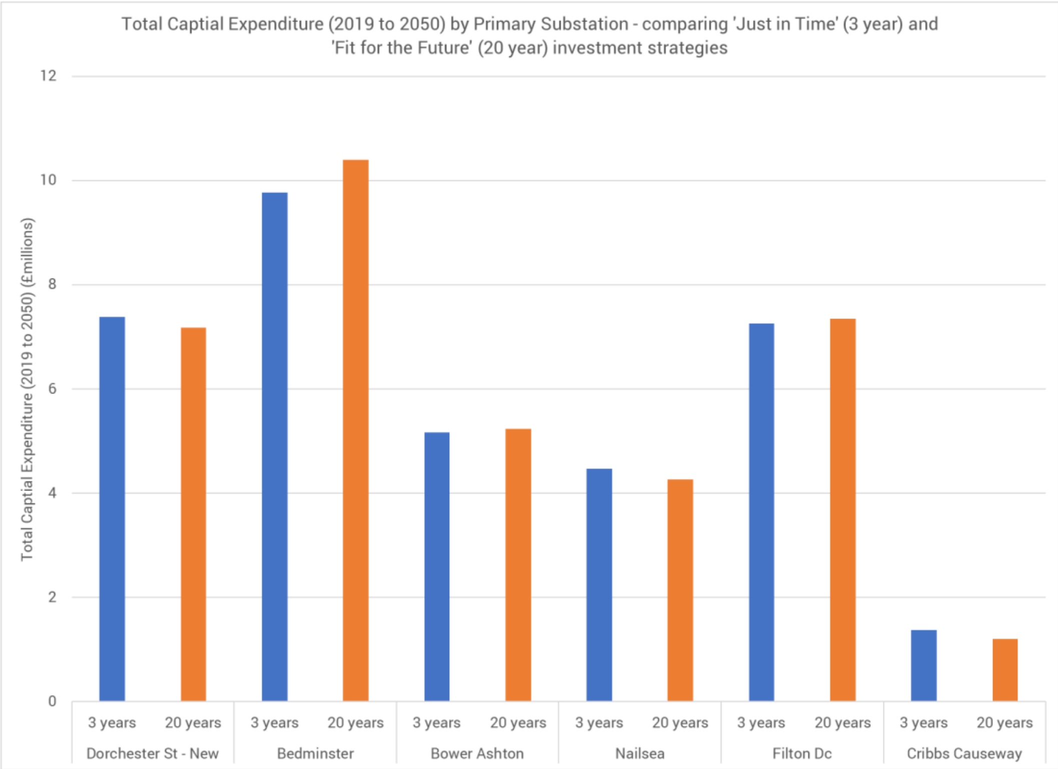


Figure 39 Comparing Total Investment by Primary Substation for Different Investment Strategies

The table below also provides a summary of the data, the strategy resulting in the lowest total expenditure has a green fill.:

Table 14 Comparing Total Investment by Primary Substation for Different Investment Strategies

Primary Substation	Total Investment – 'Just in Time' (£millions)	Total Investment – 'Fit for the Future' (£millions)	% Difference
Dorchester St New	£7.385	£7.175	-2.8%
Bedminster	£9.770	£10.398	+6.4%
Bower Ashton	£5.171	£5.237	+1.3%
Nailsea	£4.466	£4.260	-4.6%
Filton DC	£7.257	£7.345	+1.2%
Cribbs Causeway	£1.375	£1.198	-12.8%

This shows that the cheapest strategy is not consistent between the modelled primary substation areas. Based on these results it is not possible to determine which is the most cost efficient strategy to adopt in all cases.

This is in contrast to the results of the HV modelling tool which suggested that by upgrading the network to the capacity required in 2050 repeated investments could be avoided for 5% of distribution transformers and one of the primaries could avoid an interim replacement of primary transformers.

Given that the long term forecasts for electricity demand are for significant increases due to LCT deployment the risk of stranded assets is relatively low compared to the potential for future savings in capex and easing of resource constraints by adopting policies that provide higher levels of network capacity at an earlier stage. Therefore it is recommended to carry out further analysis to determine how DNO planning processes can be adjusted to include a long term capacity requirement assessment and cost benefit assessment of oversizing assets in the short term to meet long term needs.

The investment over time (total capital expenditure across modelled period for all six primary substations areas) is shown below.

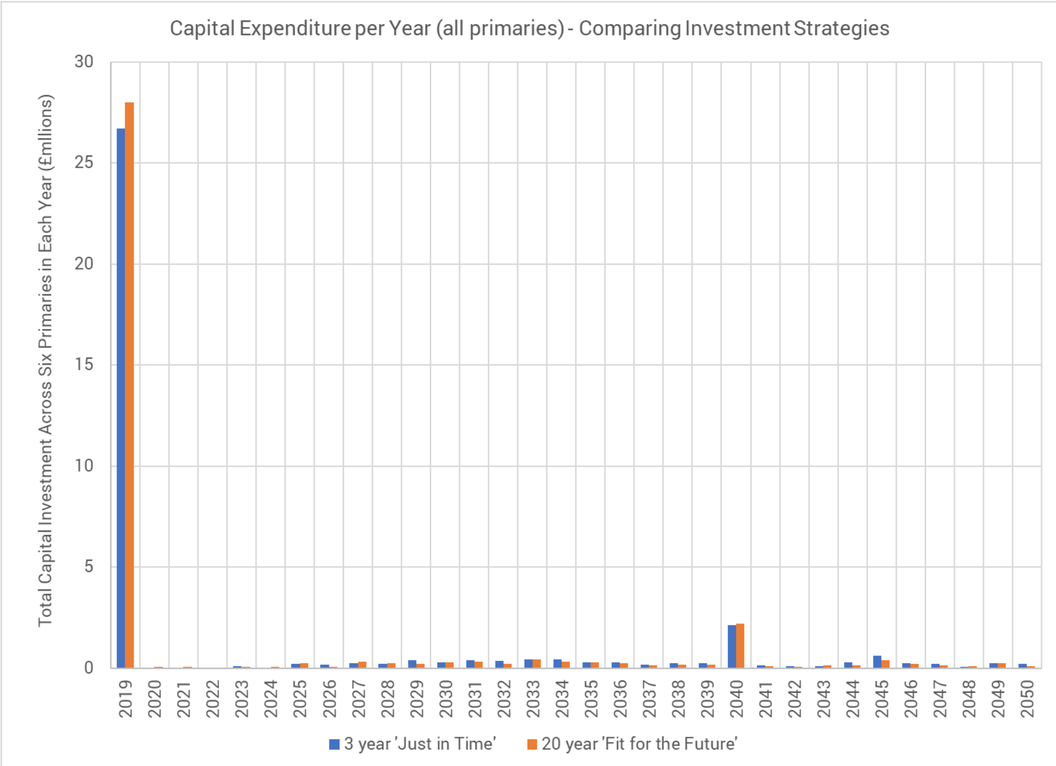


Figure 40 Total Capital Expenditure per Year - comparing Investment Strategies

The level of constraints identified in 2019 (likely as a result of data quality issues) results in large amounts of expenditure in the base year – 75% and 79% of the total across the study period for the 'Just in Time' and 'Fit for the Future' strategies respectively. This investment creates significant capacity above that which is immediately required, even with a short look ahead period. This leads to low investment needs throughout the 2020s and 2030s as this spare capacity is sufficient to accommodate LCT adoption (i.e. the large investment in 2019 is effectively modelling a "fit for the future" strategy for the early years of the analysis even when a 3 year look ahead period is selected). The table below summarises the spending in each modelled decade for the two scenarios:

Table 15 Profile of Investment in Each Decade - Comparing Investment Strategies

	% of Total Investment Throughout Period	Average Investment per Year	Max. Annual Investment in Period
Base year (2019)	Just in Time = 75% Fit for the Future = 79%	Just in Time = £26.68 million Fit for the Future = £27.99 million	N/A
2020 – 2029	Just in Time = 4% Fit for the Future = 4%	Just in Time = £0.134 million Fit for the Future = £0.130 million	Just in Time = £0.387 million Fit for the Future = £0.312 million
2030 – 2039	Just in Time = 9%	Just in Time = £0.308 million	Just in Time = £0.433 million

	% of Total Investment Throughout Period	Average Investment per Year	Max. Annual Investment in Period
	Fit for the Future = 7%	Fit for the Future = £0.252 million	Fit for the Future = £0.424 million
2040 – 2050	Just in Time = 12% Fit for the Future = 11%	Just in Time = £0.392 million Fit for the Future = £0.345 million	Just in Time = £2.116 million Fit for the Future = £2.184 million

It can be seen that as impact of the 2019 investment wanes in the 2030's and 2040's and the percentage of total investment and average investment per year are lower for the Fit for the Future strategy suggesting that there may be benefits for this approach but that the large investment in 2019 has impacted the results.

The type of solutions chosen has been analysed. NIFT has a 'toolbox' of 15 different solutions (see Appendix I), including both conventional and 'smart' solutions, categorised as shown below:

Table 16 Categorisation of Solutions – smart and conventional

Smart Solutions	Conventional Solutions
• Dynamic Network Reconfiguration - LV • D-FACTS - LV connected STATCOM • EAVC - LV circuit voltage regs • RTTR for HV/LV transformers • Active Network Management - LV	• LV UG network Split feeder • LV New Split feeder • LV GM 11/LV Tx • LV UG Minor works • LV UG Major works • LV OH network Split feeder • LV OH network New Split feeder • LV PM 11/LV Tx • LV OH Minor works • LV OH Major works

NIFT can either deploy solutions in isolation, or by combining multiple solutions if this offers the required capacity uplift at lowest overall totex cost. Each solution (or combined solution) has been categorised as either 'all conventional', 'all smart' or 'mixed' (where multiple solutions are deployed and the combination includes both smart and conventional elements). The breakdown of investment spending on each type of intervention for the baseline 'Just in Time' and 'Fit for the Future' investment strategies are shown below.

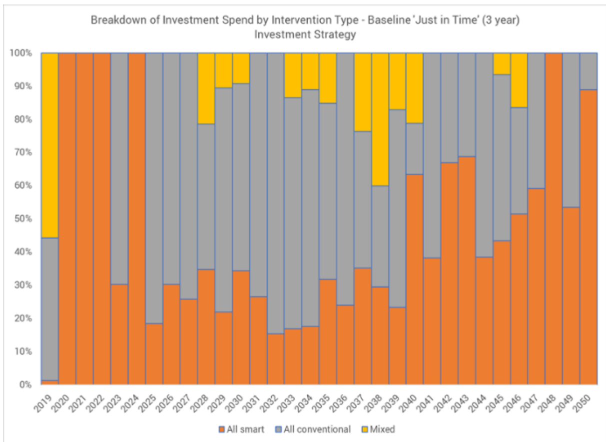


Figure 41 Breakdown of Solution Types by Proportion of Investment - Baseline 'Just in Time'

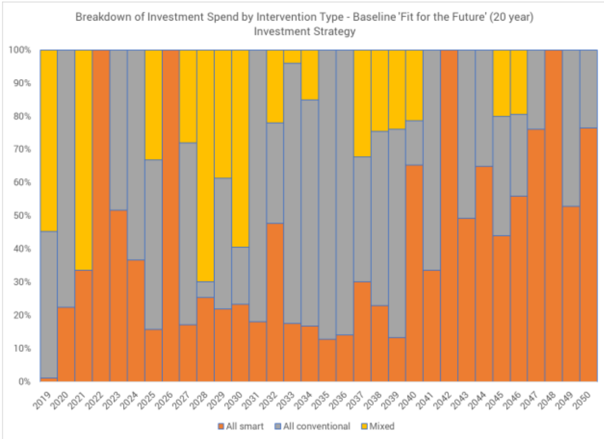


Figure 42 Breakdown of Solution Types by Proportion of Investment - Baseline 'Fit for the Future'

In 2019, solutions which are either entirely conventional, or include conventional elements make up a total of 99% of the total investment amount for both investment strategies. Looking at the absolute number of interventions (rather than capital expenditure), 62% of interventions are conventional, 30% mixed and 8% smart, for both investment strategies. Although 8% of interventions are smart, they only account for 1% of the capital investment as these interventions tend to be cheaper.

The table below looks at the breakdown of investment by intervention type in the different phases of the study period for the two intervention strategies:

Table 17 Type of Interventions Selected - Comparing Investment Strategies

	% of Total Investment on Conventional Solutions	% of Total Investment in Smart Solutions	% of Total Investment in Mixed Solutions
Base year (2019)	Just in Time = 43% Fit for the Future = 44%	Just in Time = 1% Fit for the Future = 1%	Just in Time = 56% Fit for the Future = 55%
2020 – 2029	Just in Time = 64% Fit for the Future = 38%	Just in Time = 30% Fit for the Future = 26%	Just in Time = 6% Fit for the Future = 36%
2030 – 2039	Just in Time = 65% Fit for the Future = 64%	Just in Time = 24% Fit for the Future = 21%	Just in Time = 11% Fit for the Future = 16%
2040 – 2050	Just in Time = 29% Fit for the Future = 22%	Just in Time = 59% Fit for the Future = 62%	Just in Time = 12% Fit for the Future = 15%

The greatest differences between the two investment strategies occur in the 2020s. Under the 'Just in Time' strategy the majority of investment is conventional only (64%). Mixed interventions make up only 6% of expenditure. Under the 'Fit for the Future' strategy the spend on smart interventions is similar (30% 'Just in Time', 26% 'Fit for the Future'), but a much greater proportion of investment is made in mixed interventions. It may be the case that as greater capacity increases are required under the 'Fit for the Future' strategy (to ride through increases in demand until the 2040s) smart solutions are deployed alongside conventional ones to provide this additional capacity boost. A much greater proportion of investment is allocated to smart solutions in the 2040s compared to earlier in the study period (59% 'Just in Time', 62% Fit for the Future'). The increases in capacity required under either strategy may be smaller than earlier in the study period as a large proportion of LCT adoption has already occurred[20].

The data quality issues which give rise to large amounts of investment in 2019 may be affecting the conclusions drawn from comparing the two investment strategies. Large amounts of investment is allocated in 2019 under either investment strategy due to apparent widespread constraints. The extent of these constraints means that even under the 'Just in Time' strategy large uplifts in capacity are needed, with high deployment of conventional solutions and a large proportion of the total investment. In the absence of these 2019 constraints it is likely that the investment profile would be more incremental and tied more closely to LCT adoption. The additional capacity deployed in the 'Just in Time' strategy would be lower than in 'Fit for the Future' (only enough capacity for the following three years, rather than twenty), and may therefore require multiple interventions on the same asset.

8.2.2 EV Scenarios

As described in Section 5.2 four EV scenarios were modelled, which varied the level of uptake of distributed, LV connected on-street chargers (high/low) and ToU tariffs which incentivised drivers to charge overnight, away from the traditional evening peak (high/low uptake). In all four EV scenarios a three year look ahead period was used – the 'Just in Time' investment strategy. Figure 43 compares the total expenditure required for the LV network across the study period between the four EV scenarios at each of the six primary substation areas.

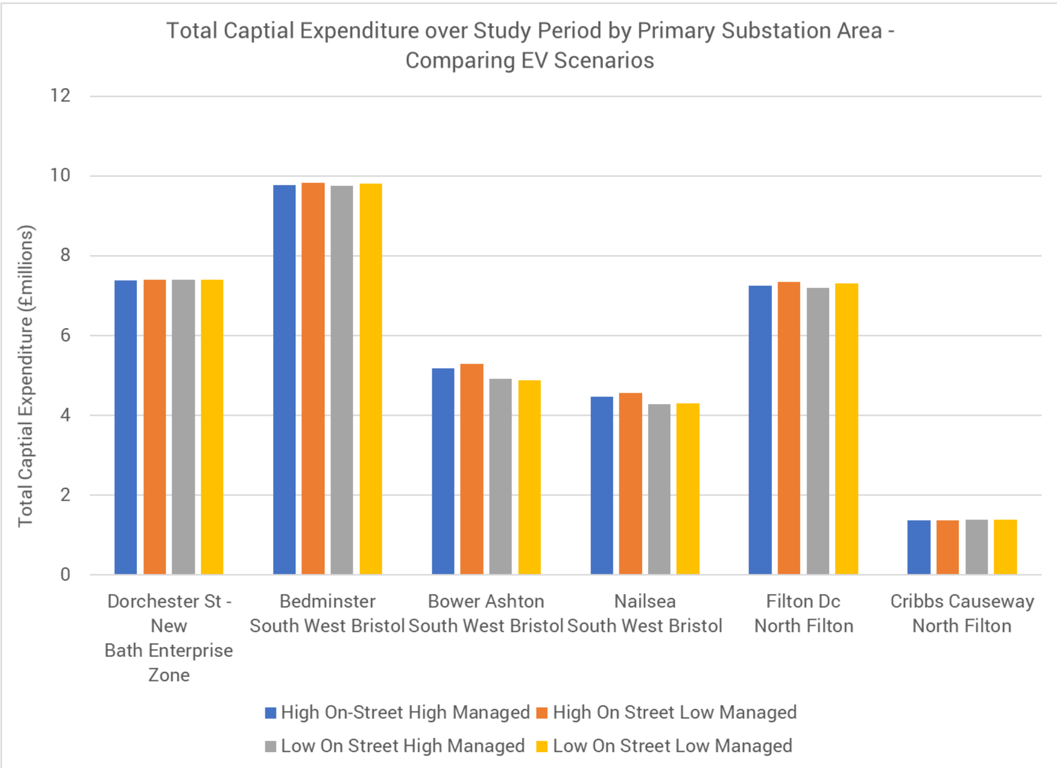


Figure 43 Total Capital Expenditure by Primary Substation Area (EV Scenarios)

This shows that while there is considerable variation in total expenditure between primary substation areas, there are only very minor differences in expenditure between the four scenarios. Costs may vary between primary substation areas due to differences in the level of constraints over the study period. Potential reasons

[20] EV chargers and heat pumps are responsible for the majority of LCT load growth. Figure 12 to Figure 14 shows EV chargers reaching a peak or a plateau by 2040 under the Baseline scenario. Figure 18 shows that by 2040 72% of electric only and 65% of hybrid heat pumps have already been deployed in the Baseline scenario.

for differences in underlying constraints are discussed in Section 6.2. In addition the resulting cost of interventions to resolve constraints could vary depending on two further factors:

- Type of network. The costs associated with reinforcement vary significantly between underground and overhead line networks. For example, the capital expenditure to split a feeder is £35,600 and £11,900 for underground and overhead networks respectively. For a given set of interventions the capital expenditure would be lower for overhead line networks. Bower Ashton and Nailsea have a greater proportion of their LV feeders which are overhead (25% and 16% respectively, compared to a maximum of 3% from the other four areas). A greater proportion of the distribution transformers for these two networks are pole mounted (42% and 32% respectively).
- Size of LV network: as shown in Figure 7 the number of distribution substations and LV feeders in each primary substation area varies. Cribbs Causeway has a significantly smaller LV network than either of the other five areas, which is likely to contribute to the lower investment values shown above. Bedminster and Bower Ashton supply a similar composition of customer (based on Elexon profile class), but have very different investment requirements. The LV network associated with Bedminster primary area includes 107 distribution substations and 427 LV feeders, compared with 144 distribution substations and 269 LV feeders in the Bower Ashton area. If investment is mainly driven by feeder level constraints (likely, given the comparison between the proportion of feeders and transformer constrained presented in Section 5.2) then this may contribute to the lower investment requirements at Bower Ashton compared to Bedminster, particularly when considered in conjunction with the fact that Bower Ashton has a higher proportion of its network pole mounted compared to Bedminster (25% vs. 0%).

The variation between both primary substations and across the EV scenarios is summarised in the table below.

Table 18 Comparing Investment for EV Scenarios and Primary Substation Areas

Primary Area	Total Capex Across Study Period High On-Street Charging, High ToU Adoption (Baseline)	High On-Street Charging, Low ToU Adoption as a % of Baseline	Low On-Street Charging, High ToU Adoption as a % of Baseline	Low On-Street Charging, Low ToU Adoption as a % of Baseline
Dorchester St New	£7.385 million	100.3%	100.2%	100.2%
Bedminster	£9.770 million	100.6%	99.9%	100.4%
Bower Ashton	£5.171 million	102.3%	95.1%	94.2%
Nailsea	£4.466 million	102.2%	95.9%	96.5%
Filton DC	£7,257 million	101.2%	99.3%	100.6%
Cribbs Causeway	£1.375 million	100.0%	100.4%	100.4%

The largest differences (compared to the baseline) are an increase of 2% in costs in the 'High On-Street, Low Managed' scenario (Bower Ashton and Nailsea primaries), and a decrease of 6% in the 'Low On-Street Low Managed' scenario (Bower Ashton primary). However, the expenditure for the high/low on-street options shown above should be considered for the electricity system as a whole. When deployment of on-street LV connected chargers is lower then a higher uptake of HV connected charging hubs has been modelled in the HV model. This may shift investment from the LV network to HV. The whole system impact of all scenarios is modelled within the CBA work being completed by Regen and reported separately.

The graph below shows the profile of expenditure for the four EV scenarios (total expenditure for all six modelled primary substation areas).

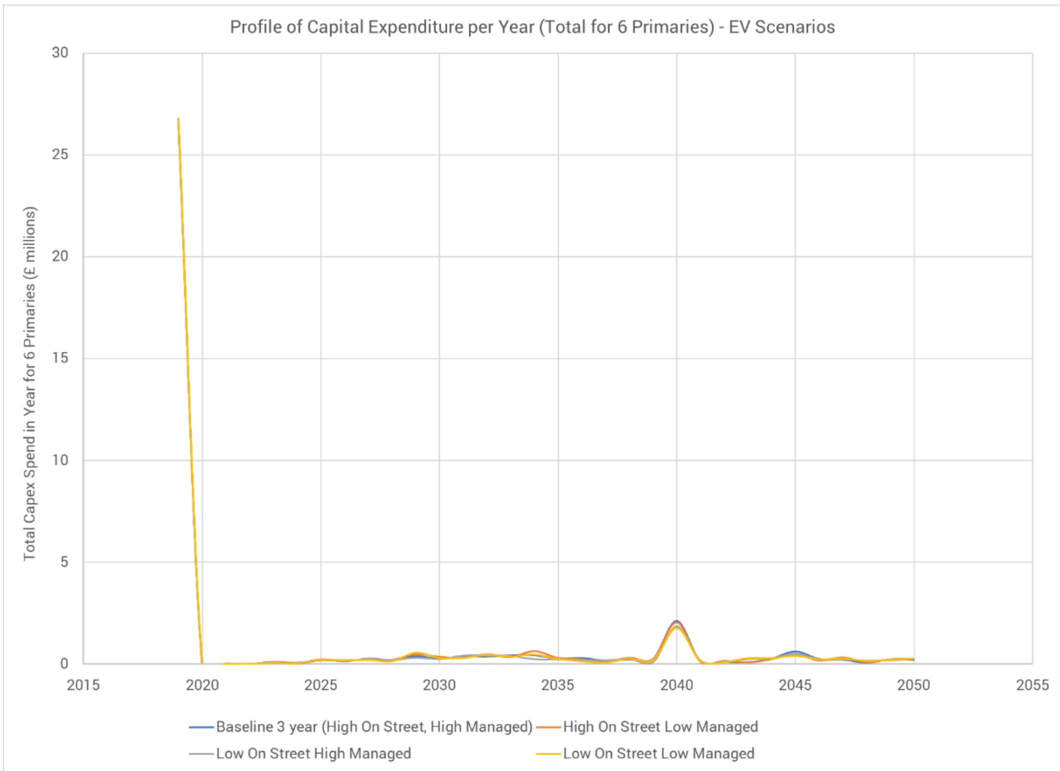


Figure 44 Profile of Capital Expenditure - EV Scenarios

This illustrates the issue created by the relatively high proportion of assets appearing to have constraints in 2019. Approximately 75% of expenditure occurs in 2019. This investment increases the capacity of the network, likely providing a 'buffer' against increasing demand from LCT uptake during the early part of the study period. The profile of investment is very similar between the four scenarios. Average annual investment from 2020 onwards varies between £262,900 (Low On-Street Charging, High ToU adoption) and £294,400 (High On-Street Charging, Low ToU adoption). There is a small further peak in investment for all four EV scenarios in 2040 with investment between £1.775 and £2.118 million. This temporary peak in investments would be difficult to resource so it is recommended that DNOs continue to produce long term investment plans aside from those that have been created for ED2 planning. It is likely that there would be benefit in reducing the peak workload by bringing work forward, especially as the peak is present under all the scenarios that have been examined.

The type of interventions chosen has been analysed using the approach outlined in Section 8.2.1 above.

Table 19 Type of Interventions Selected - Comparing EV Scenarios

	% of Total Investment on Conventional Solutions	% of Total Investment in Smart Solutions	% of Total Investment in Mixed Solutions
Base year (2019)	High On-St. High ToU: 43% High On-St. Low ToU: 43% Low On-St. High ToU: 43% Low On-St. Low ToU: 43%	High On-St. High ToU: 1% High On-St. Low ToU: 1% Low On-St. High ToU: 1% Low On-St. Low ToU: 1%	High On-St. High ToU: 56% High On-St. Low ToU: 56% Low On-St. High ToU: 55% Low On-St. Low ToU: 55%

	% of Total Investment on Conventional Solutions	% of Total Investment in Smart Solutions	% of Total Investment in Mixed Solutions
2020 – 2029	High On-St. High ToU: 64% High On-St. Low ToU: 64% Low On-St. High ToU: 62% Low On-St. Low ToU: 64%	High On-St. High ToU: 30% High On-St. Low ToU: 27% Low On-St. High ToU: 32% Low On-St. Low ToU: 27%	High On-St. High ToU: 6% High On-St. Low ToU: 10% Low On-St. High ToU: 6% Low On-St. Low ToU: 9%
2030 – 2039	High On-St. High ToU: 65% High On-St. Low ToU: 64% Low On-St. High ToU: 61% Low On-St. Low ToU: 61%	High On-St. High ToU: 24% High On-St. Low ToU: 22% Low On-St. High ToU: 30% Low On-St. Low ToU: 28%	High On-St. High ToU: 11% High On-St. Low ToU: 13% Low On-St. High ToU: 9% Low On-St. Low ToU: 11%
2040 – 2050	High On-St. High ToU: 29% High On-St. Low ToU: 34% Low On-St. High ToU: 35% Low On-St. Low ToU: 36%	High On-St. High ToU: 59% High On-St. Low ToU: 58% Low On-St. High ToU: 55% Low On-St. Low ToU: 57%	High On-St. High ToU: 12% High On-St. Low ToU: 7% Low On-St. High ToU: 10% Low On-St. Low ToU: 7%

This shows a similar change in the type of interventions chosen across the study period as that outlined in Section 8.2.1 for the baseline 'Just in Time' scenario:

- Conventional or mixed solutions accounting for the overwhelming majority of investment in the base year.
- Increased investment in smart solutions during the middle of the study period, but conventional reinforcement options still dominating.
- Smart solutions dominating in the final decade of the study period once EV adoption has reached a peak, reducing the additional reinforcement required each year.

Comparing between scenarios there are minimal differences in the type of solutions chosen. The greatest difference is an increase in smart solutions (decrease in conventional) in the 2030s for scenarios with lower deployment of LV connected on-street chargers. This may be a result of slightly lower amounts of additional capacity being required compared to the scenario where a large number of LV connected chargers are deployed. This follows through to the CBA analysis by Regen that also suggests little variation between the whole system costs for the EV charging scenarios.

8.2.3 Heat Pump Scenarios

As described in Section 5.3 the heat pumps scenarios analysed the impact of hybrid heat pump uptake and the impact of a flexible profile for electric only heat pump operation. Two comparisons can therefore be made:

- Comparing the impact of the uptake of hybrid heat pumps – Baseline vs. Run 17 (uptake of the flex profile is low in both cases)
- Comparing the impact of the uptake of the flex profile – Baseline vs. Run 15 (uptake of hybrid heat pumps is low in both cases).

In all the heat pump scenarios a three year look ahead period was used – the 'Just in Time' investment strategy. Figure 45 compares the total expenditure required for the LV network across the study period between the three heat pump scenarios at each of the six primary substation areas.

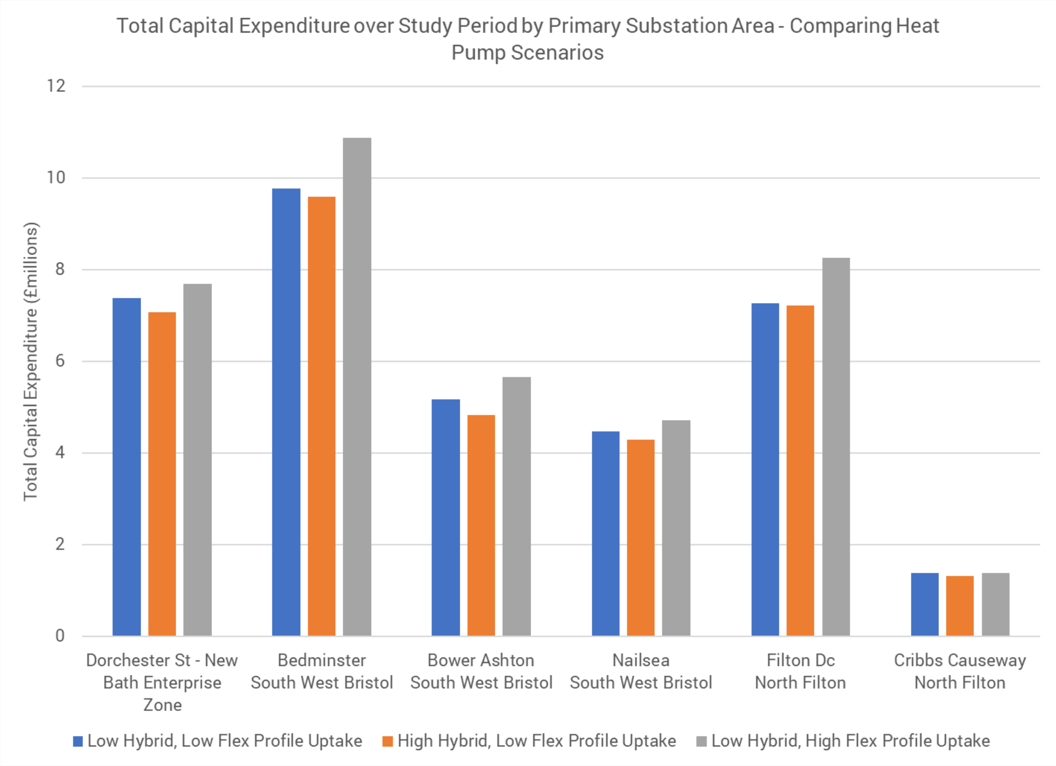


Figure 45 Total Capital Expenditure by Primary Substation Area (Heat Pump Scenarios)

As for the EV scenarios the required investment varies substantially between primary substation areas and the possible reasons for this variation are outlined above. The variation between scenarios for each primary substation area is slightly greater than between EV scenarios, particularly with respect to the 'low hybrid heat pumps, high flex profile uptake' scenarios. The variation between both primary substations and across the heat pump scenarios is summarised in the table below.

Table 20 Comparing Investment for Heat Pump Scenarios and Primary Substation Areas

Primary Area	Total Capex Across Study Period Low Hybrid Heat Pumps, Low Flex Profile Uptake(Baseline)	High Hybrid Heat Pumps, Low Flex Profile Uptake as a % of Baseline	Low Hybrid Heat Pumps, High Flex Profile Uptake as a % of Baseline
Dorchester St New	£7.385 million	95.6%	104.0%
Bedminster	£9.770 million	98.1%	111.4%
Bower Ashton	£5.171 million	93.2%	109.4%
Nailsea	£4.466 million	95.9%	105.3%
Filton DC	£7,257 million	99.5%	113.8%
Cribbs Causeway	£1.375 million	95.2%	100.5%

The largest differences (compared to the baseline) are an increase of 13% in costs for the high flexible profile uptake scenario at Filton DC, and a decrease of 7% in the high hybrid scenario at Bower Ashton. The increase in costs for the higher uptake of the flex profile is a little counterintuitive. A similar pattern was observed when considering the prevalence of constraints in the heat pump scenarios (see Section 5.3). The flexible profile has higher demand immediately before the evening peak as heat pump demand increases to 'pre-heat' the home, to allow the heat pump to switch off during the traditional peak. It may be that this increase in demand is sufficient to create a new, slightly earlier peak which results in the need for greater reinforcement.

When considering the change in expenditure for the high hybrid heat pump scenarios a whole system approach is needed which also considers any additional expenditure required for the gas networks. Hybrid heat pumps reduce the additional demand on the electricity network by using gas to provide heating on peak winter days. This could therefore place additional demand on the gas network. The results of whole system analysis in EPIC are reported separately by Regen and Wales and the West Utilities. Early indications show that the uptake of hybrid heat pumps does not require additional reinforcement in the gas network as many of these customers would have already had gas boilers anyway and increases are offset by reductions of gas consumption in the same area by customers moving from gas to non-hybrid heat pumps.

The graph below shows the profile of expenditure for the three heat pump scenarios (total expenditure for all six modelled primary substation areas).

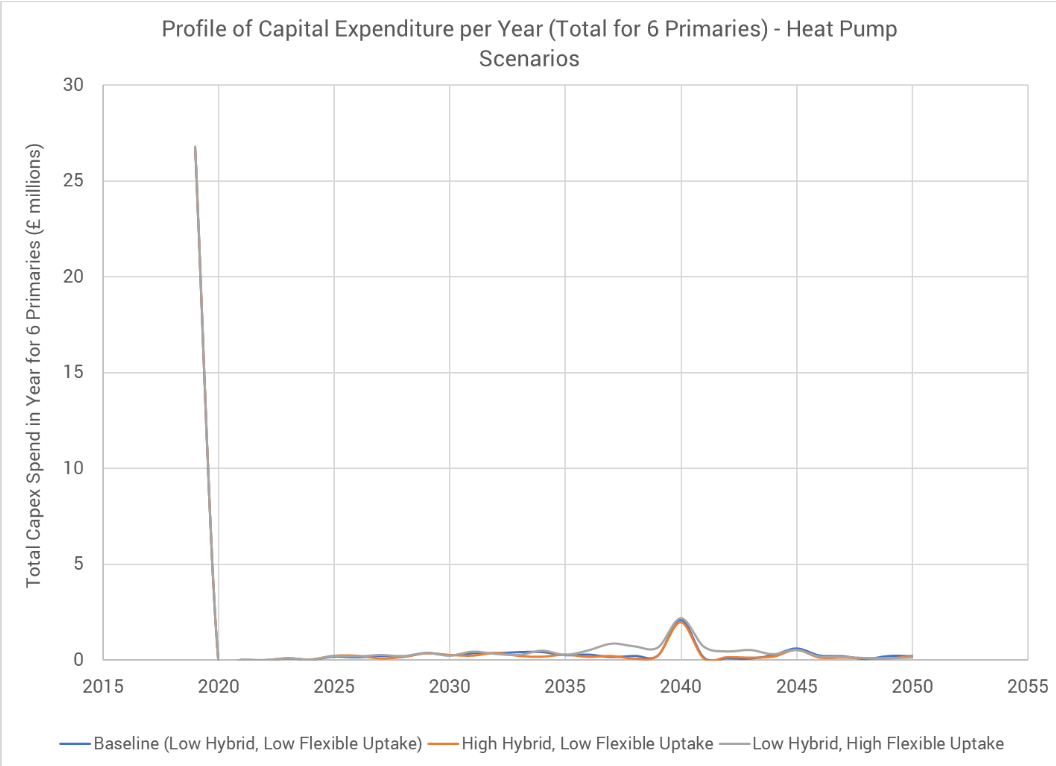


Figure 46 Profile of Capital Expenditure – Heat Pump Scenarios

In common with the previous scenarios, approximately 75% of expenditure occurs in 2019 in all the heat pump scenarios. This investment increases the capacity of the network, likely providing a 'buffer' against increasing demand from LCT uptake during the early part of the study period. The profile of investment is similar between the three scenarios. Average annual investment from 2020 onwards varies between £242,900 (High Hybrid, Low Flexible Uptake) and £379,100 (Low Hybrid, High Flexible Uptake). There is a small further peak in investment for all three heat pump scenarios in 2040 with investment between £1.990 and £2.185 million. Once again this peak in 2040 would add to the resource requirements of the 2040 peak relating to EV triggered interventions highlighting the need to view long term investment requirements for resource planning.

The higher total capital expenditure in the 'high flexible uptake' scenario (grey curve) occurs in the late 2030s and early 2040s. This is to be expected as the uptake of the flexible profile begins to increase rapidly from 2035 (see Figure 19). In the period from 2035 to 2045 the total capital investment is:

- Low Hybrid, Low Flexible Profile Uptake: £4.55 million

- High Hybrid, Low Flexible Profile Uptake: £4.16 million
- Low Hybrid, High Flexible Profile Uptake: £7.76 million

The type of interventions chosen has been analysed using the approach outlined in Section 8.2.1 above.

Table 21 Type of Interventions Selected - Comparing Heat Pump Scenarios

	% of Total Investment on Conventional Solutions	% of Total Investment in Smart Solutions	% of Total Investment in Mixed Solutions
Base year (2019)	Low Hybrid Low Flexible: 43% High Hybrid Low Flexible: 43% Low Hybrid High Flexible: 43%	Low Hybrid Low Flexible: 1% High Hybrid Low Flexible: 1% Low Hybrid High Flexible: 1%	Low Hybrid Low Flexible: 56% High Hybrid Low Flexible: 56% Low Hybrid High Flexible: 56%
2020 – 2029	Low Hybrid Low Flexible: 64% High Hybrid Low Flexible: 62% Low Hybrid High Flexible: 66%	Low Hybrid Low Flexible: 30% High Hybrid Low Flexible: 32% Low Hybrid High Flexible: 24%	Low Hybrid Low Flexible: 6% High Hybrid Low Flexible: 6% Low Hybrid High Flexible: 9%
2030 – 2039	Low Hybrid Low Flexible: 65% High Hybrid Low Flexible: 64% Low Hybrid High Flexible: 58%	Low Hybrid Low Flexible: 24% High Hybrid Low Flexible: 28% Low Hybrid High Flexible: 23%	Low Hybrid Low Flexible: 11% High Hybrid Low Flexible: 8% Low Hybrid High Flexible: 19%
2040 – 2050	Low Hybrid Low Flexible: 29% High Hybrid Low Flexible: 29% Low Hybrid High Flexible: 37%	Low Hybrid Low Flexible: 59% High Hybrid Low Flexible: 60% Low Hybrid High Flexible: 49%	Low Hybrid Low Flexible: 12% High Hybrid Low Flexible: 11% Low Hybrid High Flexible: 15%

This shows a similar change in the type of interventions chosen across the study period as that outlined in Section 8.2.1 for the baseline 'Just in Time' scenario, and EV scenarios (Section 8.2.2). Comparing between the heat pump scenarios there are minimal differences in the type of solutions chosen, particularly looking the impact of hybrid heat pump uptake. Increased uptake of the flexible profile requires greater use of conventional or mixed solutions in the later part of the study period.

8.2.4 Energy Efficiency Scenarios

As described in Section 5.4 two levels of energy efficiency improvements were modelled across all six primary substation areas. In addition, a high energy efficiency scenario was modelled for the North Filton SPA (Filton DC and Cribbs Causeway primary substation areas). In all the energy efficiency scenarios a three year look ahead period was used – the 'Just in Time' investment strategy. Figure 47 compares the total expenditure required for the LV network across the study period between the relevant energy efficiency scenarios for each of the six primary substation areas.

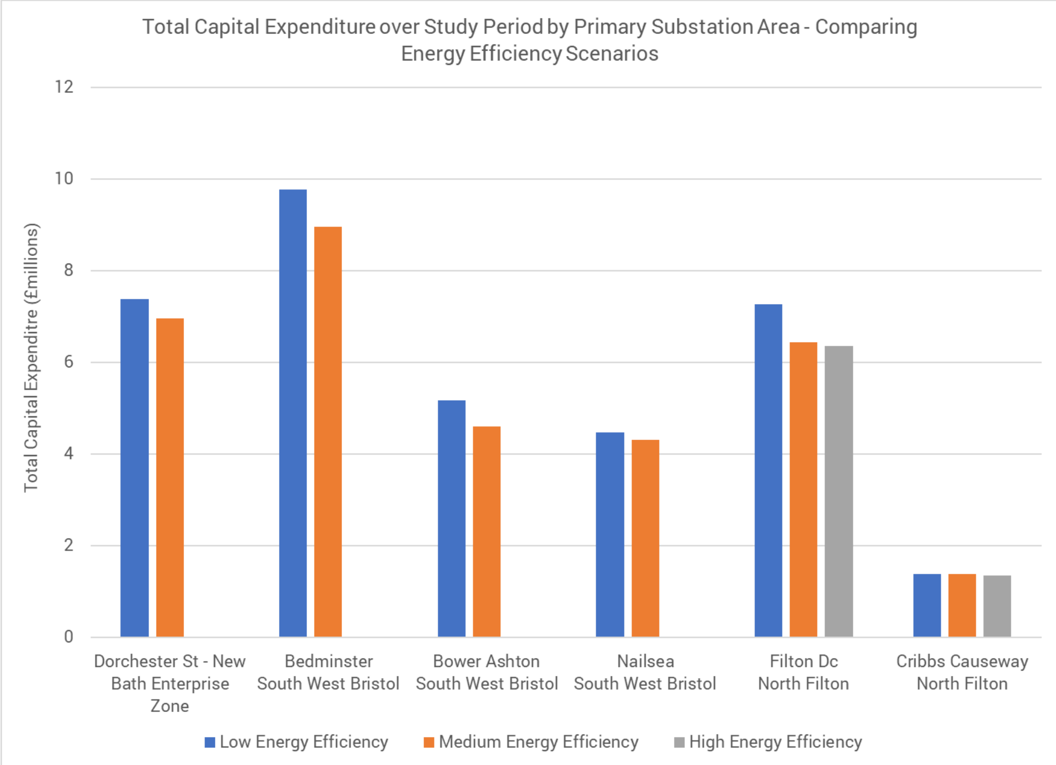


Figure 47 Total Capital Expenditure by Primary Substation Area (Energy Efficiency Scenarios)

As for the other use cases the required investment varies substantially between primary substation areas and the possible reasons for this variation are outlined above. In addition the level of energy efficiency savings which could be made varied by profile class and therefore this would lead the customer composition in the area to have an impact on the difference between energy efficiency scenarios. For example, no energy efficiency savings were assigned to Profile Classes 5 to 8, therefore primary substation areas with a greater proportion of customers in these classes would see lower reductions compared to one with very few Class 5 to 8 customers. This applies to Dorchester Street and Cribbs Causeway (see Section 3.5).

The variation between both primary substations and across the energy efficiency scenarios is summarised in the table below.

Table 22 Comparing Investment for Energy Efficiency Scenarios and Primary Substation Areas

Primary Area	Total Capex Across Study Period Low Energy Efficiency (Baseline)	Medium Energy Efficiency as a % of Baseline	High Energy Efficiency as a % of Baseline
Dorchester St New	£7.385 million	94.1%	N/A – SPA specific use case
Bedminster	£9.770 million	91.6%	
Bower Ashton	£5.171 million	88.9%	
Nailsea	£4.466 million	96.4%	
Filton DC	£7.257 million	88.6%	87.6%
Cribbs Causeway	£1.375 million	99.8%	97.6%

The medium energy efficiency scenario provides savings of up to 11% compared the baseline low energy efficiency scenario at both Bower Ashton and Filton DC. The additional savings in the high energy efficiency scenario are minimal (88.6% vs. 87.6% of baseline for Filton DC, a difference of £69k and 99.8% vs. 97.6% of baseline for Cribbs Causeway, a difference of £30k).

The graph below shows the profile of expenditure for the low and medium energy efficiency scenarios (total expenditure for all six modelled primary substation areas). Due to the minimal differences between the medium and high scenarios shown above the profile of capital expenditure for the high scenario is not shown.

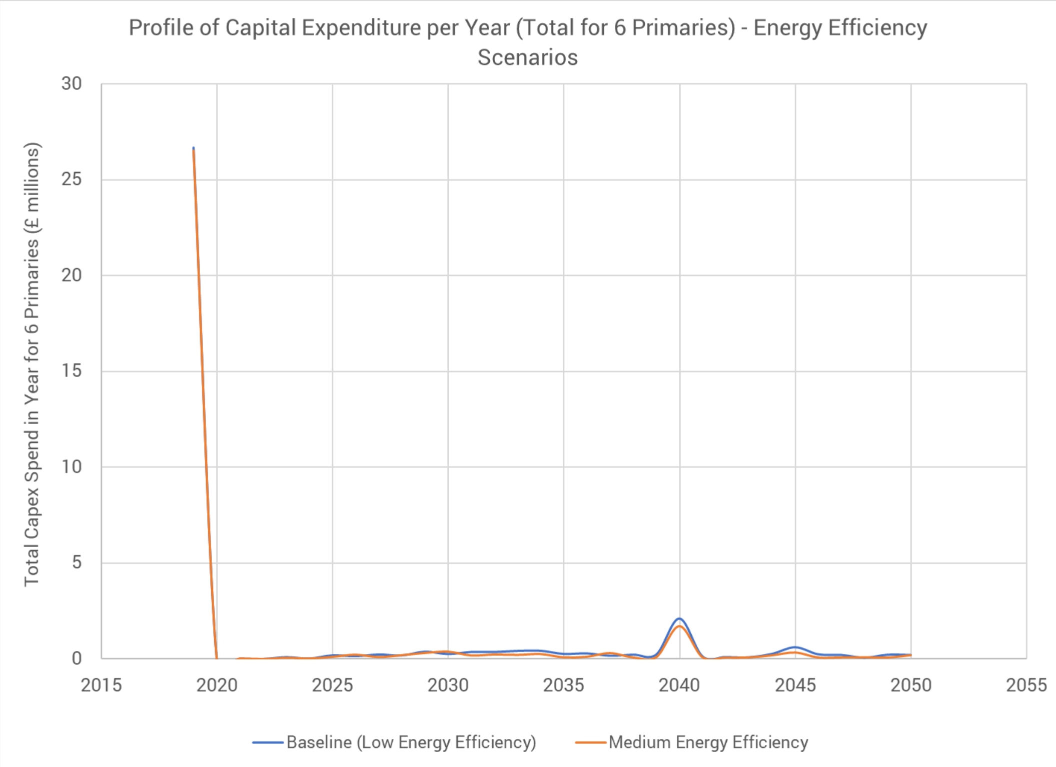


Figure 48 Profile of Capital Expenditure – Energy Efficiency Scenarios

In common with the previous scenarios, approximately 75% of expenditure occurs in 2019. The profile of investment is very similar between the two scenarios. Average annual investment from 2020 onwards is £195,500 and £281,900 for the medium and low energy efficiency scenarios respectively. There is a small further peak in investment in 2040 - £1.71 and £2.12 million for the medium and low energy efficiency scenarios respectively.

The type of interventions chosen has been analysed using the approach outlined in Section 8.2.1 above. Results are presented separately for all six primary substation areas, and Filton DC and Cribbs Causeway only (North Filton SPA).

Table 23 Type of Interventions Selected - Comparing Energy Efficiency Scenarios (all six primary substation areas)

	% of Total Investment on Conventional Solutions	% of Total Investment in Smart Solutions	% of Total Investment in Mixed Solutions
Base year (2019)	Low Energy Efficiency: 43% Medium Energy Efficiency: 44%	Low Energy Efficiency: 1% Medium Energy Efficiency: 1%	Low Energy Efficiency: 56% Medium Energy Efficiency: 55%
2020 – 2029	Low Energy Efficiency: 64% Medium Energy Efficiency: 69%	Low Energy Efficiency: 30% Medium Energy Efficiency: 31%	Low Energy Efficiency: 6% Medium Energy Efficiency: 0%

	% of Total Investment on Conventional Solutions	% of Total Investment in Smart Solutions	% of Total Investment in Mixed Solutions
2030 – 2039	Low Energy Efficiency: 65% Medium Energy Efficiency: 50%	Low Energy Efficiency: 24% Medium Energy Efficiency: 36%	Low Energy Efficiency: 11% Medium Energy Efficiency: 13%
2040 – 2050	Low Energy Efficiency: 29% Medium Energy Efficiency: 21%	Low Energy Efficiency: 59% Medium Energy Efficiency: 72%	Low Energy Efficiency: 12% Medium Energy Efficiency: 8%

- In common with other use cases, there is no variation between scenarios for the baseline year. Investment in the base year is due to constraints which appear (some due to data quality issues) with existing loading. There is very little difference in LCT adoption or energy consumption between scenarios in 2019, therefore the investments chosen are also very similar.
- In the later part of the study period (2030 onwards) the medium energy efficiency scenarios result in a greater proportion of investment being made in smart solutions, with the majority of the decrease coming from conventional solutions.

Table 24 Type of Interventions Selected - Comparing Energy Efficiency Scenarios (Filton DC and Cribbs Causeway – North Filton SPA)

	% of Total Investment on Conventional Solutions	% of Total Investment in Smart Solutions	% of Total Investment in Mixed Solutions
Base year (2019)	Low Energy Efficiency: 26% Medium Energy Efficiency: 26% High Energy Efficiency: 26%	Low Energy Efficiency: 1% Medium Energy Efficiency: 1% High Energy Efficiency: 1%	Low Energy Efficiency: 72% Medium Energy Efficiency: 72% High Energy Efficiency: 72%
2020 – 2029	Low Energy Efficiency: 67% Medium Energy Efficiency: 83% High Energy Efficiency: 83%	Low Energy Efficiency: 18% Medium Energy Efficiency: 17% High Energy Efficiency: 17%	Low Energy Efficiency:15% Medium Energy Efficiency: 0% High Energy Efficiency: 0%
2030 – 2039	Low Energy Efficiency: 57% Medium Energy Efficiency: 32% High Energy Efficiency: 50%	Low Energy Efficiency: 23% Medium Energy Efficiency: 39% High Energy Efficiency: 39%	Low Energy Efficiency: 20% Medium Energy Efficiency: 29% High Energy Efficiency: 11%
2040 – 2050	Low Energy Efficiency: 30% Medium Energy Efficiency: 15% High Energy Efficiency: 2%	Low Energy Efficiency: 58% Medium Energy Efficiency: 78% High Energy Efficiency: 92%	Low Energy Efficiency: 12% Medium Energy Efficiency: 7% High Energy Efficiency: 6%

Comparing Table 23 and Table 24, particularly in the base year shows the variation in the type of investments between primary substation areas. When considering investment across all six primary areas, 43%, 1% and 56% of investment is made in conventional, smart and mixed solutions respectively. Looking at Filton DC and Cribbs Causeway only, 26%, 1% and 72% of investment is made in made in conventional, smart and mixed solutions.

There are some differences between the scenarios in the North Filton SPA:

- In the 2020s, the medium and high energy efficiency scenarios have a greater proportion of investment made in conventional interventions, with minimal investment in mixed solutions. Adding a smart solution to a conventional one tends to increase the capacity released beyond that offered by the conventional solution alone. The medium and high energy efficiency scenarios reduce the level of constraints (see Section 5.4.2) and so conventional solutions alone are more likely to be sufficient.

- In all scenarios, investment in smart solutions is highest in the final decade of the study period. In the high energy efficiency scenario 92% of investment was assigned to smart solutions.

8.3 Summary

The modelling of capital investment has shown:

- High levels of investment in 2019 across all scenarios, likely to due to data issues which cause a relatively high proportion of LV feeders to appear constrained in the base year (i.e. before LCT adoption). This leads to around 75% of the total investment occurring in 2019. This will affect the EV, heat pump and energy efficiency scenarios equally. However, it may alter the results of the comparison between investment strategies.
- The differences in total expenditure and the profile of investment over time are similar between the various use cases. However, in some cases the use cases require analysis of whole system costs (i.e. including the HV electricity network and/or the gas network) to make a fair comparison.
- There are large variations in the amount of capital investment required for the six different primary substation areas. Modelling a subset of the primaries would give results which could be extrapolated to predict the investment needed in other areas.
- The type of solutions which are deployed varies through the study period. The large amounts of capacity created in the baseline year (2019) is made up from conventional solutions, or a mix of a conventional solution with a smart one. In the latter parts of the study period (particularly the 2040s) smart solutions are deployed more widely (around 60% of investment). The use case or investment strategy can result in some changes to the type of interventions deployed.

9. Cost Benefit Analysis Inputs

As part of the EPIC project Regen are completing a Cost Benefit Analysis to compare the different scenarios. For example, comparing the whole system costs and benefits of approaches which use a greater proportion of HV connected EV charging hubs, compared to more distributed on-street EV chargers connected to the LV network.

This analysis is being undertaken by Regen using the ENA Whole System CBA tool and includes both the LV and HV networks, modelled by EA Technology (using NIFT) and PSC respectively. The purpose of this section is to give a short overview of the outputs from NIFT in relation to network reinforcement and detail how these outputs were post-processed to produce the inputs required for the CBA tool. The results of the CBA are reported by Regen separately.

9.1 CBA Inputs

The following metrics relating to the LV network were provided for the CBA analysis:

- Capex (£): capital expenditure on reinforcement. The capex spend occurs during the year in which reinforcement occurs
- Opex (£): operational expenditure relating to reinforcement. A constant amount of opex is spent in all years for which a solution is operational.
- Feeder length for roadworks (km): the length of feeders which have interventions that would involve roadworks.
- Count of interventions requiring roadworks: the number of interventions deployed in each year which would require roadworks.
- Capacity Index (feeders) (kVA): the sum of the difference between feeder rating (including increases due to reinforcement) and feeder utilisation, for all feeders in each primary area.
- Capacity index (transformers) (kVA): the sum of the difference between each distribution transformer's cyclic rating (including increases due to reinforcement) and maximum utilisation, for all distribution transformers in each primary area.
- Losses (MWh): the estimated losses on LV feeders based on the annual energy demand and a fixed % factor.

NIFT analysis is carried out at either the distribution transformer or LV feeder level. For the purposes of the CBA analysis each metric was aggregated up to the primary transformer level, for each year. For example, the capex spend on all substations and LV feeders was summed for each of six primaries in the study are (Bedminster, Nailsea, Filton DC, Cribbs Causeway, Bower Ashton and Dorchester Street New).

The sub-sections below detail how these metrics were derived.

9.1.1 Capex and Opex

As described in Section 8.1 the 'Substation Investment' Report from the NIFT solution module reports the gross capex and opex spend for each distribution substation in each year. The gross capex is the amount associated with any solutions deployed for the first time in each year. A detailed analysis of the capital expenditure for the LV network and how this varies is presented in Section 8 of this report. The capex and opex for each solution are defined within the Solutions Templates and was agreed with WPD. A copy of the solutions template can be found in Appendix I. A standard set of figures were used to reflect those applied in the Transform model[21].

[21] https://eatechnology.com/resources/projects/investment-in-smart-grids/ Accessed January 2022

Gross opex is the total opex associated with all operational solutions, for their lifetime. For example, ANM has a lifetime of 15 years and an annual opex cost of £516. Therefore, any substations with ANM active incur an opex spend of £516 in each year for 15 years from installation.

Gross capex and opex spend was reported for each distribution substation in each year. For the purposes of the CBA analysis this was aggregated to give a total for each primary substation area in each year, using a mapping between distribution substations and their associated primary.

9.1.2 Roadworks

Reinforcement of the electricity network may require roadworks (e.g. to excavate an underground cable and replace it). Roadworks are disruptive to society due to increased traffic congestion, noise etc. The CBA tool therefore includes a societal cost associated with roadworks.

The solution module within NIFT identifies which solutions are applied to each individual feeder, from a 'toolkit' of 15 solutions. It can also apply a combination of solutions (e.g. where combining two solutions results in a lower totex expenditure to solve the constraint identified by the model). Only a subset of the solutions would require roadworks and this was defined as follows:

Table 25 Solutions and Roadworks

Solution	Requires Roadworks
Dynamic Network Reconfiguration – LV	✗
D-FACTS – LV connected STATCOM	✗
EAVC – LV circuit voltage regulators	✗
RTTR for HV/LV transformers	✗
LV Underground network split feeder	✓
LV underground network New Split feeder	✓
LV Ground mounted 11/LV Tx	✗
LV underground minor works	✓
LV underground major works	✓
LV overhead network split feeder	✗
LV overhead networks New Split feeder	✗
LV Pole mounted 11/LV Tx	✗
LV overhead minor works	✗
LV overhead major works	✗
Active Network Management - LV	✗

The feeder solution deployment report specifies which interventions are deployed for the first time on each feeder in each year. The length of each feeder is also held within NIFT (data supplied by WPD at the time of NIFT's original development). Two metrics were derived from this data:

- The total length of feeders with associated roadworks: the sum of the length of all feeders in each primary substation area with interventions which require roadworks, in each year. It is important to note that the length of the feeder is given – rather than the length of roadworks required (e.g. if only a section of the feeder would require excavations, rather than the full length).
- A count of the number of feeders with associated roadworks

9.1.3 Capacity Index

Reinforcement will often create more capacity than the amount strictly needed in the short term. This therefore creates additional spare capacity on the network which is available for other parties to connect – thus creating a benefit. The aim of the capacity index metric is to capture this benefit. The capacity index reflects thermal capacity only. However, where interventions deployed due to a voltage constraint are applied and have a thermal benefit this increase in available capacity is captured.

Each solution has a set of defined benefits, expressed as a percentage of the original asset rating/allowable value, as follows:

- Transformer thermal benefit: the percentage increase in the allowable thermal utilisation of a transformer. NIFT allows a utilisation of 110% before reinforcement is required. As an example, a new pole or ground mounted distribution transformer increases the allowable utilisation by 80% - therefore the new allowable utilisation is 190% of the cyclic rating.
- Cable thermal benefit: the percentage increase in the allowable thermal rating of feeders. This benefit applies to the feeder on which the intervention is applied (see cross-feeder benefits below).
- Voltage headroom benefit: the additional percentage increase in voltage headroom (i.e. increasing the allowable voltage rise, as the intervention would mean the voltage rise would in practice be within the statutory limits). This benefit applies to the feeder on which the intervention is applied.
- Voltage legroom benefit: the additional percentage increase in voltage legroom (i.e. increasing the allowable for voltage drop). This benefit applies to the feeder on which the intervention is applied.
- Cross-feeder thermal benefit: some interventions applied to an individual feeder also provide benefits to other feeders fed from the same transformer. The cross-feeder thermal benefit captures this.
- Cross-feeder voltage headroom benefit: as above, for voltage headroom.
- Cross-feeder voltage legroom benefit: as above, for voltage legroom.

Through discussion between the project partners the capacity index was defined as a measure of the spare capacity on the network, calculated in all years. The capacity index (a measure of spare capacity) will decrease due to increased loading (e.g. due to connection of EV charging and heat pumps), and increase due to the deployment of interventions/reinforcement.

Two metrics were calculated at LV; feeder capacity index and transformer capacity index (reported separately). In both cases, the capacity index is the sum (for all LV feeders or distribution transformers associated with a primary transformer) of the difference between the maximum allowable thermal utilisation and the actual utilisation.

LV Feeder Capacity Index Calculation

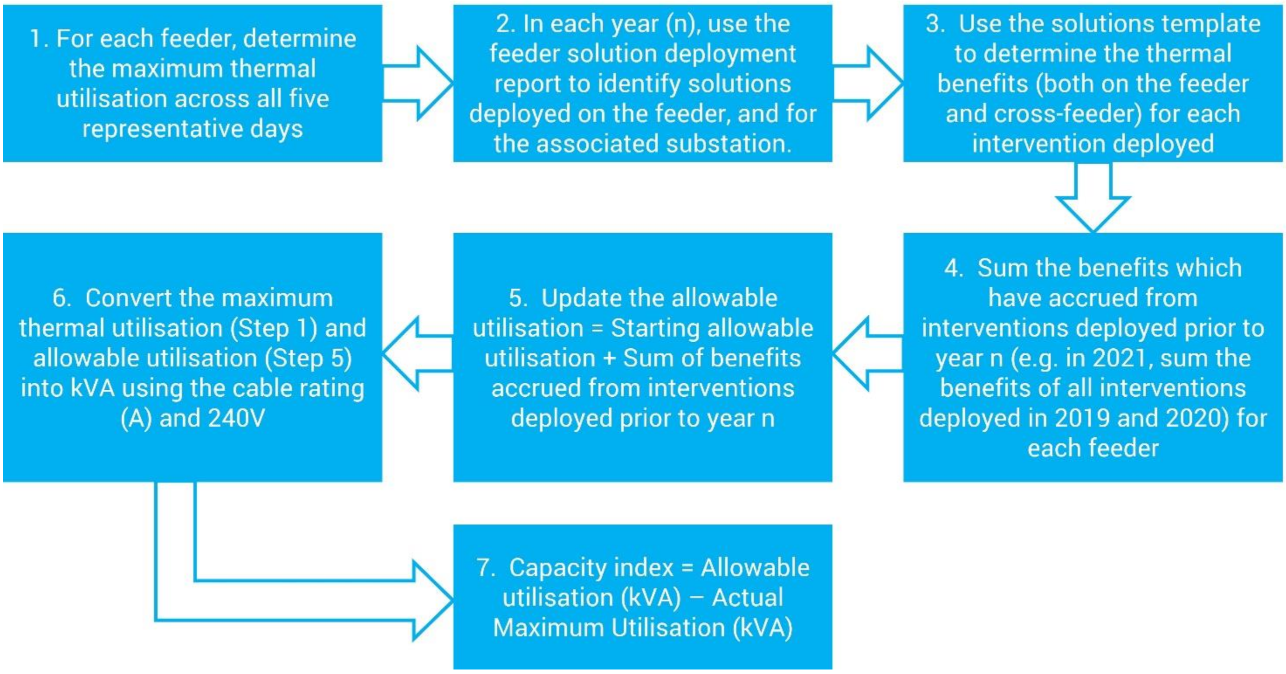


Figure 49 Capacity Index Calculation Steps – LV Feeders

Figure 49 shows the calculation steps for each LV feeder. Solutions can be deployed either 'for feeders' or 'for substation'. The benefits that accrue to feeders are calculated from these, as follows:

- 'Deployed for feeder':
  - Allowable utilisation on the feeder on which the intervention is deployed increases by the cable thermal benefit.
  - Each feeder also receives the sum of the cross-feeder thermal benefits for all solutions deployed on the other feeders fed from this substation which have been 'deployed for feeder'.
- 'Deployed for substation':
  - All feeders fed from the substation increase their allowable thermal utilisation by the cross-feeder benefit defined in the solution templates.

A theoretical example is given below to illustrate the calculation of allowable utilisation:

- The substation has three feeders, ID A, B and C. In 2019 due to high utilisation (>110% of rating) on feeder C 'LV underground minor works' is deployed ('for the feeder'). This solution has a cable thermal benefit of 100% and a cross-feeder thermal benefit of 25%. From 2020 onwards, the allowable utilisation of feeders A and B = 110 + 25 (cross feeder benefit of intervention on feeder C) = 135%. The allowable utilisation of feeder C = 110 + 100 = 210%.
- Later, in 2030, the load has increased further, and the utilisation of the distribution transformer is now too high, so Active Network Management (ANM) is deployed 'for the substation'. The cross-feeder thermal benefit of ANM is defined as 3%. Therefore from 2031 onwards the allowable utilisations are:
  - Feeders A and B = 110% (starting allowable) + 25% (cross-feeder benefit from minor works on feeder C in 2019) + 3% (cross-feeder benefit of ANM deployed for the substation) = 138%
  - Feeder C = 110% (starting allowable) + 100% (cable thermal benefit from minor works in 2019) + 3% (cross-feeder benefit of ANM deployed for the substation) = 213%

Distribution Transformer Capacity Index Calculation

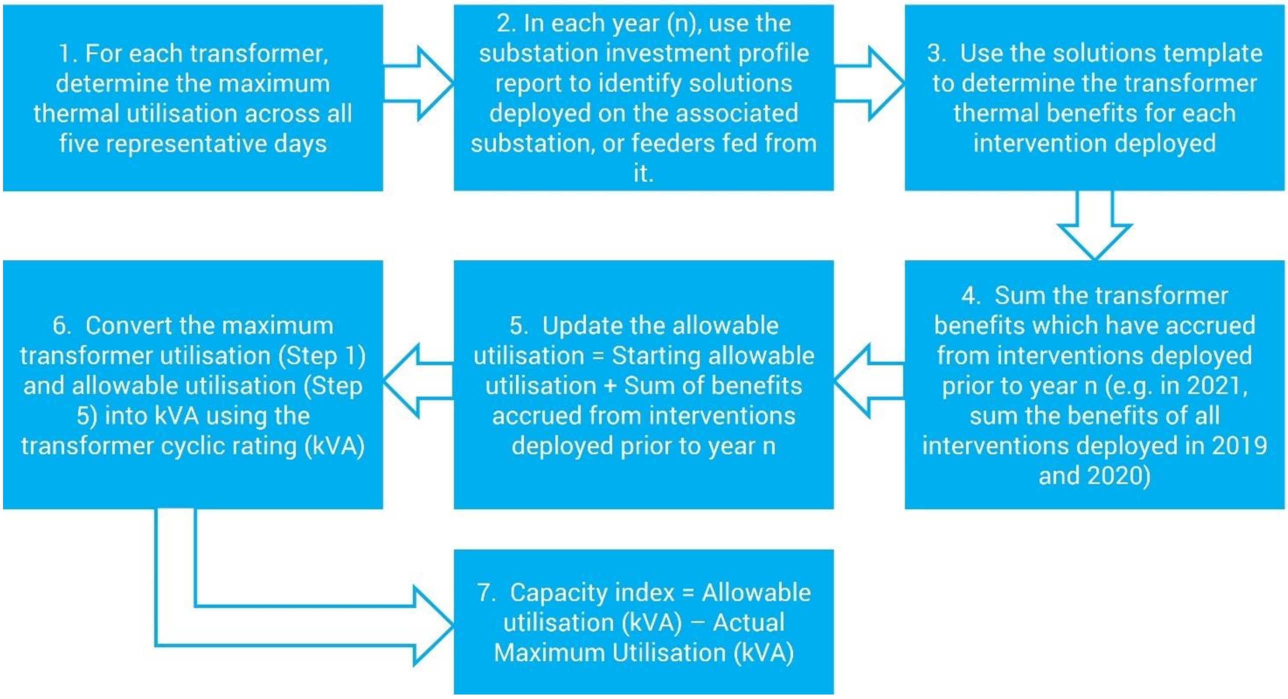


Figure 50 Capacity Index Calculation Steps – Distribution Transformers

9.1.4 Losses

Losses occur on the distribution network which are broadly proportional to the energy transferred. A simple analysis was conducted for the EPIC project based on the following assumptions:

- The effect of interventions on the impedance of the distribution network was not taken into account
- Losses were assumed to be 1.06% of the delivered energy, based on a recent losses investigation project completed by WPD[22] with Loughborough University. This accounts for losses on LV feeders only (losses in the distribution transformer were included in the HV model).

The annual energy demand for each distribution substation was determined as follows:

- Number of customers in each profile class/Low Carbon Technology (LCT) type
- Annual energy consumption for each profile class/LCT type.

Data sources/assumptions are detailed below:

Table 26 Losses Calculation Data Input

Data Point	Sub-Group	Source/Data manipulation used
Customer Numbers	Existing customers in Elexon Class 1 - 8	Data in NIFT from its original development showing the number of customers per LV substation in each profile class
	Connections of LCTs	Regen scenario definition data showing the number of each LCT type deployed in each year in each year

[22] https://www.westernpower.co.uk/downloads-view-reciteme/51418 Accessed January 2022.

Data Point	Sub-Group	Source/Data manipulation used
Energy Consumption per Annum	Profiles which were scaled using a single annual energy consumption figure (Elexon Class 1 and 3 plus heat pumps and EV chargers)	Regen/EA Technology value for annual energy consumption as applied in the NIFT modelling. These figures were varied in the 'low/baseline', 'medium' and 'high' energy efficiency scenarios. No manipulation required.
	Profiles scaled with day and night figures for annual energy consumption (Elexon Class 2 and 4)	Regen/EA Technology value for annual energy consumption as applied in the NIFT modelling. These figures were varied in the 'low/baseline', 'medium' and 'high' energy efficiency scenarios. Sum the day and night consumption to give the total
	Profiles scaled by maximum power demand: Elexon Class 5, 6, 7 and 8	WPD metering data was used to analyse the average annual energy consumption for customers in each profile class fed from each primary.
	Profiles scaled by maximum power demand: PV generation	Generation output of 3,700kWh per annum based on Energy Savings Trust estimate. Negative figure used as PV output decreases network load.
	Profiles scaled by maximum power demand: energy storage	Not included in losses calculation as the storage is assumed to have a net zero energy consumption (i.e. ignoring round trip losses).

The total energy demand for each distribution substation was calculated (the sum of number of customers x per customer annual energy consumption across all profile classes). This was then aggregated up to the primary substation level and multiplied by 1.06% to give an estimate of the annual losses (MWh) on LV feeders.

10. Conclusions

Conclusions have been split into three – those relating to the results of the modelling (comparisons between use cases and comparison between primary substation areas) and to the EPIC process and how similar modelling work could be undertaken in the future.

Comparison of Scenarios:

C1. Across the majority of LCT uptake scenarios and primary substation areas the proportion of both LV feeders and distribution transformers with constraints increases through the study period as LCT uptake increases. The size of the increase is highly variable between primary substation areas. In all cases, LV feeder constraints are more common than constraints on distribution transformers.

C2. The graph below compares the proportion of feeders constrained in each of the use cases in 2019 and 2050 (the start and end of the modelling period).

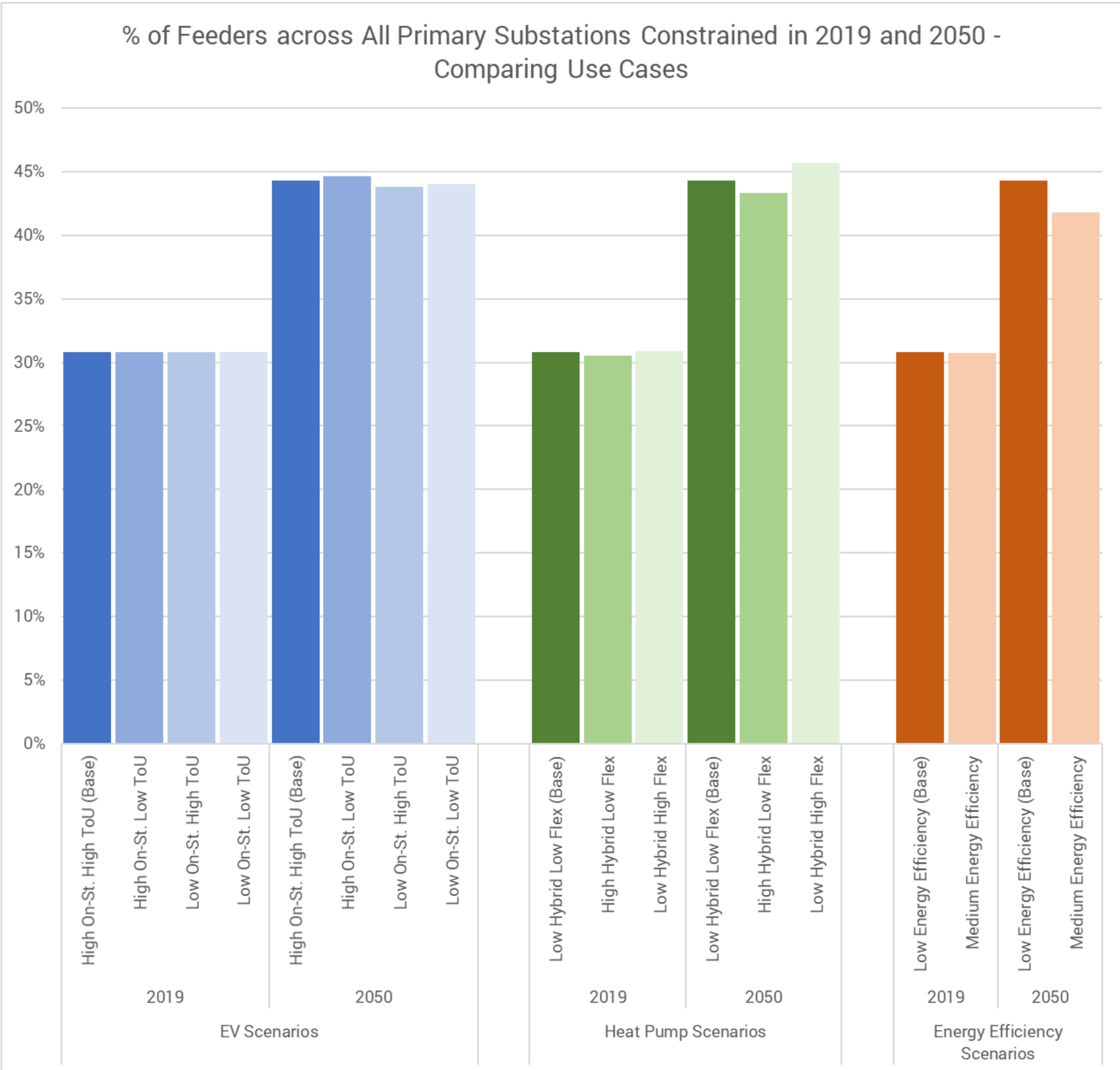


Figure 51 Proportion of LV Feeders Constrained in 2019 and 2050 (all primary substation areas) comparing use cases

C2.1 In 2019 the level of constraints is very similar between the use cases as LCT adoption and energy efficiency savings increase as the modelling period progresses. The level of constraints in 2019 is artificially high (compared to network conditions today) due to data inaccuracies.

C2.2 The 2050 figures show the level of variation between use cases. The difference between the use cases is generally low, with the largest difference compared to the baseline scenario occurring in the medium energy efficiency scenario, where 41.8% of feeders are constrained in 2050, compared to 44.3% in the baseline scenario.

C2.3 This shows that the level of constraints is relatively insensitive to differences modelled in this project between various use cases. Across all scenarios there is a revolutionary change in levels of electricity consumption – this is consistent with the findings of other modelling work such as the National Grid Future Energy Scenarios[23]. Against this dramatic increase as a result of widespread electrification the variations between scenarios are much smaller.

C2.4 The lack of variability between scenarios can give confidence in investment for net zero – similar investment is needed regardless of the exact scenario/pathway is followed.

C3. The graph below compares the proportion of distribution transformers constrained in each of the use cases in 2019 and 2050 (the start and end of the modelling period).

[23] Future Energy Scenarios 2021 estimates annual electricity demand in 2020 was 294TWh. In 2030 this was predicted to increase to between 309 and 340TWh (depending on scenario) and between 459 and 702TWh by 2050. National Grid Future Energy Scenarios 2021. “Key Statistics in 2030 and 2050”. Accessed June 2022.

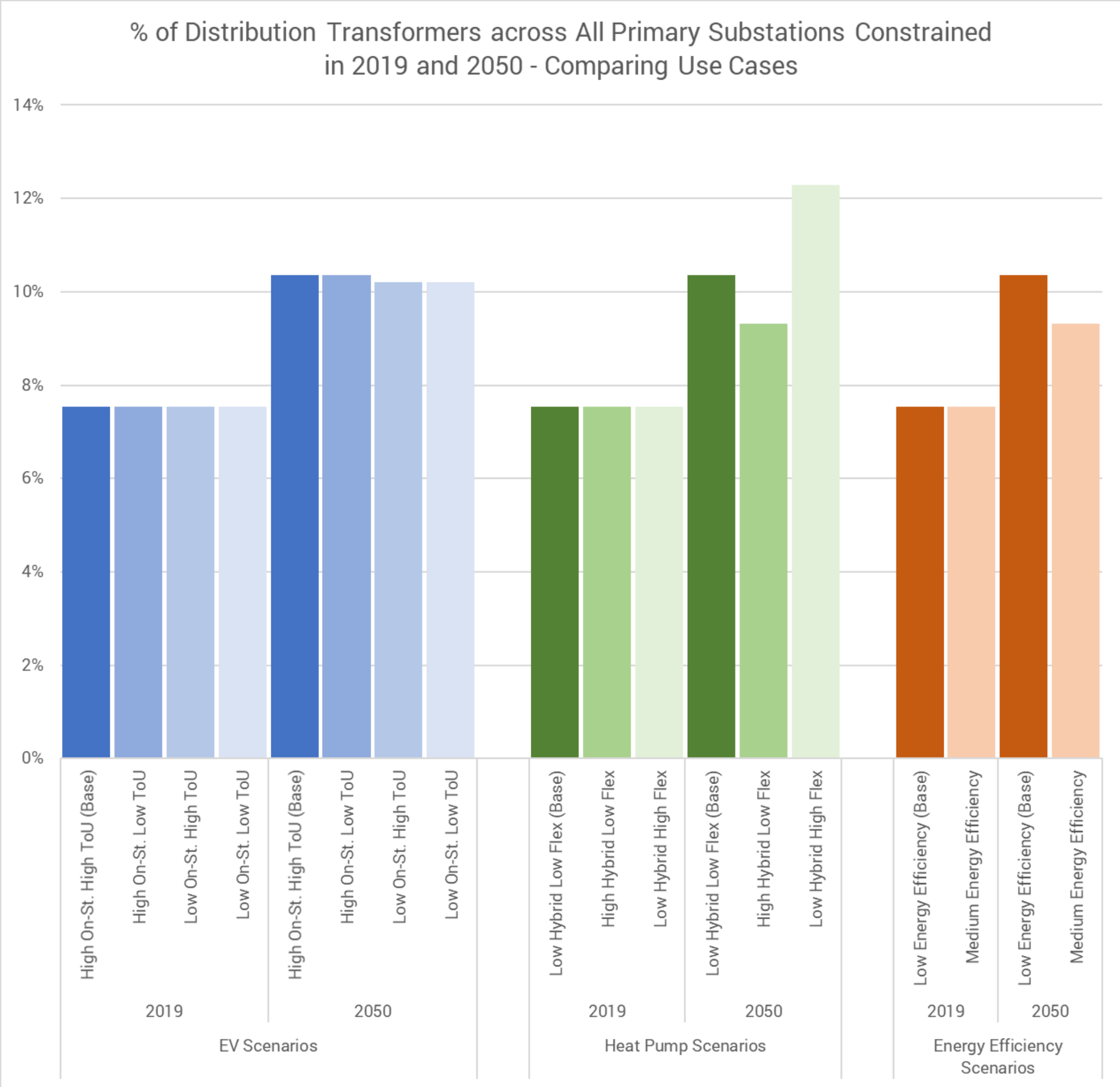


Figure 52 Proportion of Distribution Transformers Constrained in 2019 and 2050 (all primary substation areas) comparing use cases

C3.1 Transformer constraints are much less common in the NIFT results for 2019. As expected they are consistent across the various use cases, with approximately 8% of transformers having a constraint at the start of the modelling period.

C3.2 The EV use cases result in minimal differences in the level of constraints observed in 2050, varying between 10.2 and 10.4%.

C3.3 The heat pump scenarios result in the largest differences between a use case and the baseline scenario. Higher uptake of the flexible profile results in 12.3% of distribution transformers being constrained in 2050, compared to 10.4% in the base case (low uptake of the flexible profile). This increase in constraints may be due to the pre-heating creating a new, higher peak, just prior to the traditional evening peak period.

C3.4 Increased energy efficiency savings result in a small (1%) decrease in the prevalence of distribution transformer constraints.

C4. NIFT was also used to model the interventions required to resolve the network constraints identified. The profile of expenditure was strongly affected by data inaccuracies which cause a large number of apparent constraints in 2019. This modelling could be repeated in the future if the underlying data quality was improved to assess how this has affected the outputs. Across all scenarios, approximately 75% of investment was made in 2019. The profile of investment remained similar across the use cases with a further small peak in investment in 2040. The large investment in 2019 provided substantial additional capacity to accommodate growth in demand due to LCT adoption without requiring further investment. However, this issue was common to all LCT adoption/energy efficiency scenarios and so comparisons between scenarios remain valid. The graph below compares the total investment over the study period between use cases.

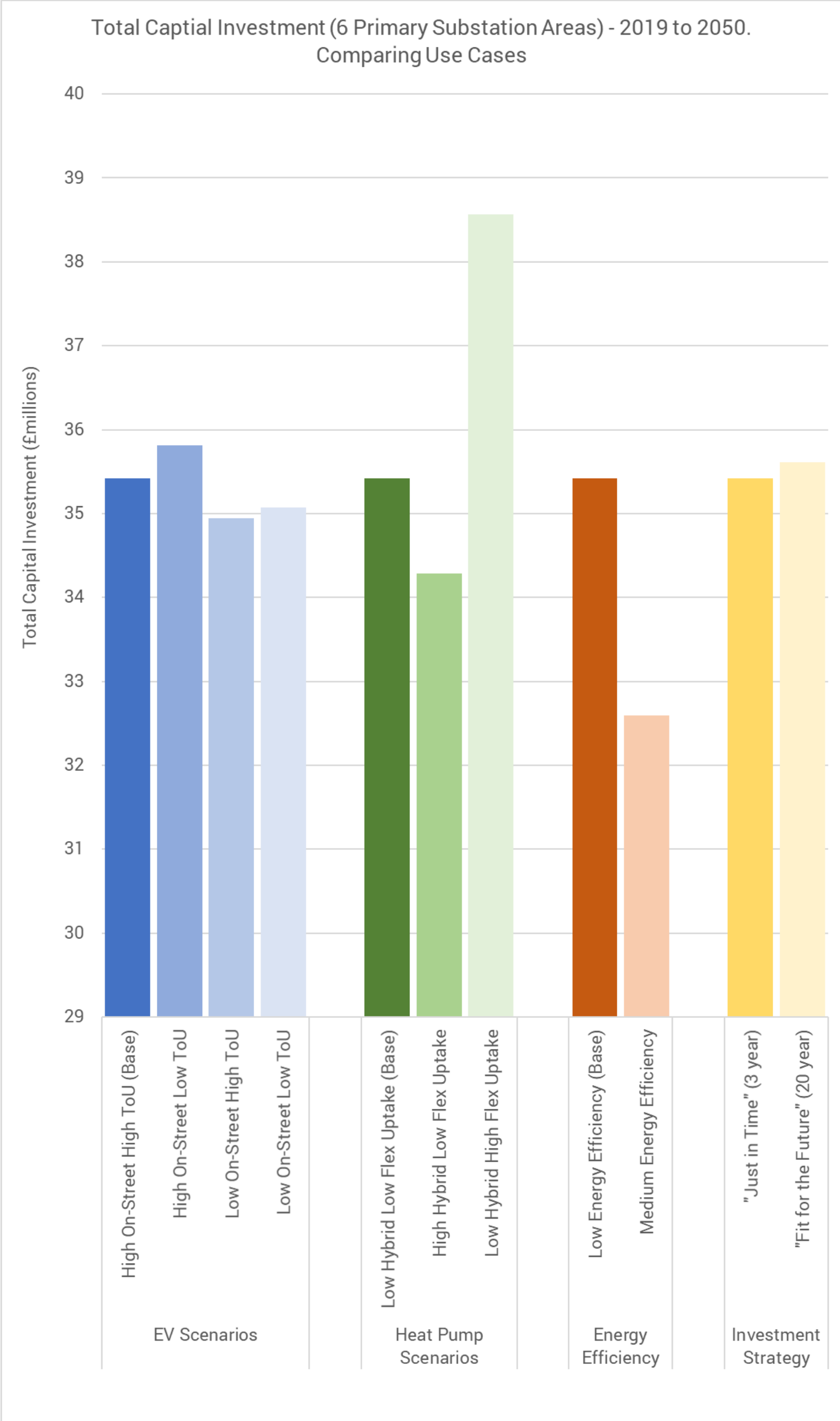


Figure 53 Comparing Total Capital Investment between Use Cases

C4.1 The variation in total investment between the use cases and the base case is different between the scenario types as follows:

C4.2 EV Scenarios: total capital investment varies very little – between 98.6% and 101.1% of the base case.

C4.3 Heat Pump Scenarios: this is the scenario with the greatest variation compared to the base case. High uptake of the flexible profile increases investment requirements to 109% of the base case. Increased uptake of hybrid heat pumps, which switch demand from the electricity to gas network during the winter and intermediate cool peak periods results in 97% of the baseline level of expenditure.

C4.4 Energy Efficiency Scenarios: a higher level of energy efficiency results in a reduction of capital expenditure – 92% of the baseline amount.

C4.5 Considering all six primary substation areas in aggregate, the 'Fit for the Future' investment strategy (larger initial investments to avoid multiple interventions over the medium term) increases capital expenditure slightly. However, this result varies between primary substation area and is likely to be more strongly affected by the investment requirements in 2019 which are a result of data inaccuracies.

C5. The results presented above consider only the capital investment required for the LV network. These results alongside other metrics have been shared with Regen to all a whole system CBA to be undertaken, and the results of this are reported separately.

C6. The type of solutions which are deployed varies through the study period. The large amounts of capacity created in the baseline year (2019) is made up from conventional solutions, or a mix of a conventional solution with a smart one. In the latter parts of the study period (particularly the 2040s) smart solutions are deployed more widely (around 60% of investment). The use case or investment strategy can result in some changes to the type of interventions deployed.

Comparison of Primary Substation Areas:

C7. In this project six primary substation areas were modelled across the three SPAs. This allowed comparisons to be made between primary substation areas as well as between use cases. The results of the modelling of the level of constraints demonstrated:

C7.1 Broad conclusions about which scenario/use case leads to lower levels of constraints are consistent across multiple primary substation areas. This is particularly true for the EV use cases studied, where the level of difference between scenarios was small across all scenarios and primary substations. The overall conclusion that the level of constraints is relatively insensitive to the EV use cases is valid for all the modelled primary substation areas. The results are more variable for heat pump scenarios. This is perhaps to be expected as the differences in the underlying profiles (e.g. for hybrid vs. non-hybrid heat pumps in winter) is greater than in the EV scenarios. Modelling a subset of primary substation areas is likely to be sufficient to draw conclusions about which scenarios give lower/higher level of constraints.

C7.2 However, to predict the absolute level of constraints for a given network then detailed modelling of that specific is required due to high variability in the results.

C7.3 The variation in the level of constraints comes from a range of factors including the age and condition of the network and the number and type of customers supplied, as this will affect the LCTs likely to be taken up in an area.

C8. The capital investment required was also highly variable between primary substation areas, demonstrated by the graph below, which also compares the investment strategy use case:

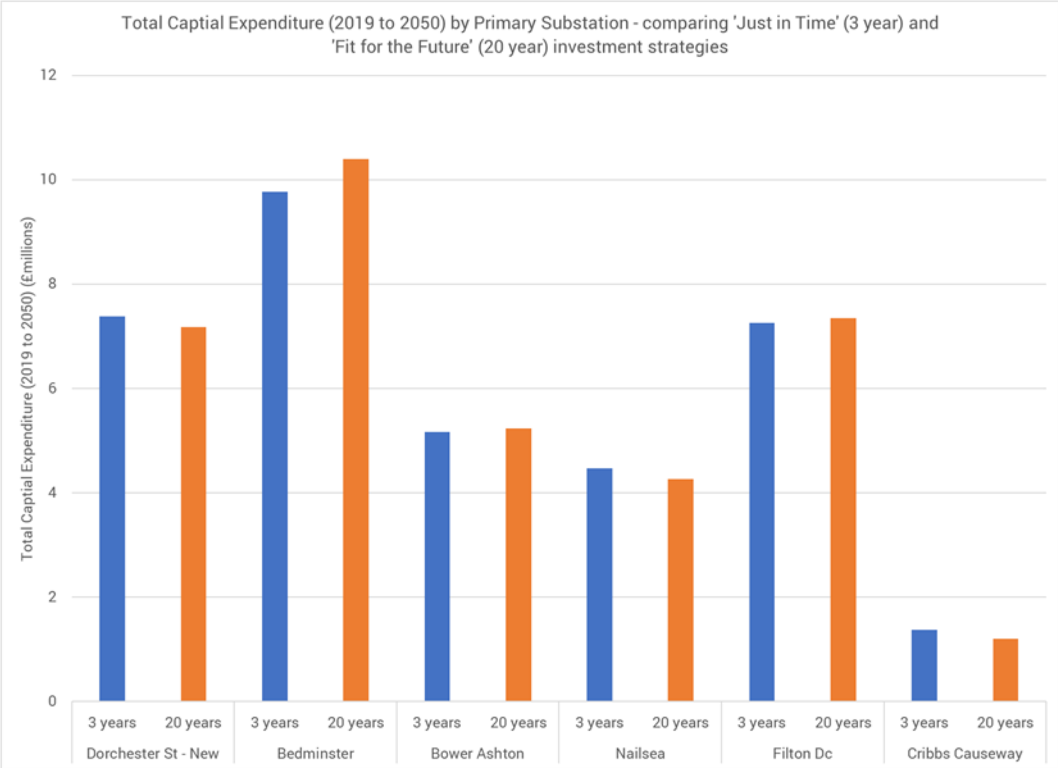


Figure 54 Total Capital Investment - Comparing Primary Substation Areas and Investment Strategy

C8.1 This demonstrates the variation in capital expenditure between the primary substation areas (from £1.3 million at Cribbs Causeway in the 3 year scenario to £10.4 million at Bedminster in 20 year scenario). This variability comes from both the underlying variability in the level of constraints between primary substation areas, and also differences in the size and type (underground vs. overhead) of the LV network.

C8.2 Figure 54 also shows an example where the conclusion about which use case/scenario leads to the lowest total cost varies between primary substation areas.

C8.3 For the other three use cases (EVs, heat pumps, energy efficiency) the least expensive strategy is consistent across primary substation areas (or very similar across all scenarios). However the absolute difference compared to the baseline can vary – for example expenditure was always higher in the 'high flexible profile uptake' scenario for heat pumps compared to the baseline. However, it varied between 101% and 114% of baseline at Cribbs Causeway and Filton DC respectively.

EPIC Modelling Process:

C9. As discussed above, inaccuracies in the underlying network data resulted in an unrealistically high prevalence of constraints in the base year. This will have affected the total amount of investment predicted to be required and the profile of the investment. Comparisons between the LCT adoption scenarios remain valid, as this issue affects each of these scenarios equally. The availability of accurate, high quality network data for the area to be studied is key. In this project timescales did not allow for an existing model to be updated, resulting in older, less accurate data being used. As digitalisation of network data increases the availability of accurate models of the network should improve.

C10. The EPIC project was completed as a Western Power Distribution NIA project, with local authorities/SPAs which fell within WPD's licence area. It therefore made use of an existing LV modelling and forecasting tool – NIFT. Local authorities in licence areas other than WPD would need to contact EA Technology to discuss whether NIFT could be used to support their analysis. This would incur additional costs, or they would need to follow a different process in order to undertake the modelling of the LV network. The extent to which other LV modelling packages could be used/their suitability would depend on the size of area being modelled, the number of future years and the technologies included.

C11. Differences between the scenarios depend on both the LCT uptake and the differences between the demand profiles for each technology/operating profile (see Section 3.2 and 3.4.1). Greater confidence on the future operating profile for different technologies would increase confidence in the modelling results. This is particularly true in the case of heat pumps, on-street EV chargers as EV adoption increases and domestic energy storage where there is a lack of substantial trial data from which to generate a suitable profile.

C12. The results from this project have shown that conclusions about which use cases results in higher/lower levels of constraints are consistent across primary substations. However, the absolute level of constraints and the required investment was found to vary between primary substation (see Section 6 and 8). The majority of cost and time expended relates to data preparation, initiating analysis runs (e.g. setting up separately for each use case/scenario due to different input data) and post-processing and interpreting the results. Modelling a larger number of primary substations increases the chronological time required to produce results, but this is a 'hands off' process (i.e. NIFT can be left to run all the required substation areas). The costs associated are much more dependent on the number of use cases/scenarios to be modelled, rather than the number of primary substation areas.

C13. Analysis presented in Section 7 shows that with the existing load/generation profiles it is sufficient to model a smaller number of representative days (winter and summer). The worst case network conditions across all constraint types occurs on either the winter or summer day in at least 89% of cases. Reducing the number of days to be modelled would reduce the time required to produce results and the post-processing needed to consolidate the results from multiple representative days.

C14. In order to model the range of technologies and profiles included in the EPIC project a number of changes were made to the NIFT, including the introduction of additional profiles, adding in the ability to vary the energy consumption between years, and differentiating the number of technologies deployed to Class 1 and Class 2 customers. Each of these changes incurred time and costs to develop and test (e.g. ensuring that the correct profile type was used for each variant of the heat pump profile). Consistency in future modelling exercises would decrease the amount of effort which needed to be expended developing and testing new bespoke elements for different local authorities. This could include using a standard agreed set of technology building blocks and operating profiles and ensuring data is presented in the same format each time.

C15. The modelling and post-processing analysis could be streamlined (less time required to produce outputs) if a common set of outputs was agreed in advance, prioritising data which offers the greatest value to local authority stakeholders. At the time of writing the outputs of EPIC have not been presented to the local authorities involved so it is not clear which outputs are of greatest value. Once a set of consistent outputs had been agreed then an analysis template could be produced, for example in PowerBI, which would automate the post-processing from the granular NIFT outputs to the required summary views.

11. Recommendations

A number of recommendations can be made as a result of the EPIC project, relating to the overall process and modelling approach, and also future innovation projects.

R1. Feedback gained from the local authorities which participated in the EPIC project could be used to standardise the analysis – using a common set of data inputs and reporting. This would reduce the time required to generate input data, run multiple simulations and manually analyse and comment on the outputs.

R2. The time taken to prepare, complete and analyse the results is much more dependent on the number of use cases/scenarios modelled, rather than the total number of substations. Where possible the number of scenarios should be minimised in order to reduce the costs involved.

R3. The availability of accurate, high quality network data for the area to be studied is key. In this project timescales did not allow for an existing model to be updated, resulting in older, less accurate data being used. As digitalisation of network data increases the availability of accurate models of the network should improve, and this should be a pre-requisite for future modelling.

R4. Differences between use cases are due to variations in the uptake levels of different technologies and also assumptions made about the profile of demand. For example, in this project, higher uptake of the flexible heat pump profile has resulted in higher investment requirements for the majority of primary substations, when compared to the baseline. This is due to differences in the underlying demand profiles (see Figure 17). As knowledge about the operation of new technologies increases then this may provide the opportunity to improve the assumptions which underpin this analysis. It is therefore recommended that in future innovation projects the opportunity is taken to collect the analyse the data to improve the profiles available for LV network analysis. This would benefit macro level modelling such as that undertaken in EPIC or for business planning purposes, and LV network design on a more local level.

R5. Unless there are large changes in the seasonality in demand (i.e. such that highest demand no longer occurs in winter, and highest generation in summer) then future modelling could reduce the number of representative days modelled and still cover the worst case scenario in the vast majority of cases (see Section 7).

R6. Amendments were made to the solution module as part of EPIC. This altered the way in which upgrades to distribution transformers were made and how the benefits of this were applied. This upgrade resolved a significant issue and it is therefore recommended that any future automated analysis to determine future levels of investment uses this modified approach.

R7. The solutions data used in EPIC was based on Transform, and the cost and capabilities of technology at the time (shown in Appendix I). Future modelling exercises may wish to re-evaluate the solutions which are deployed, the benefits they offer and the costs involved as more innovative solutions are developed and mature.

R8. Across all use cases and investment strategies the network investment profile over the study period showed a small increase in reinforcement requirements occurring in 2040. This temporary peak in investments would be difficult to resource so it is recommended that DNOs continue to produce long term investment plans aside from those that have been created for ED2 planning. It is likely that there would be benefit in reducing the peak workload by bringing work forward, especially as the peak is present under all the scenarios that have been examined.

Appendix I Solution Set for EPIC

Table AI.1 Solution Set for EPIC

Name	Capex	Opex	Lifetime (years)	Capex and Opex Optimism Bias	Totex (£)	UG Feeder Compatible	OH Feeder Compatible	Ground Mounted Tx Compatible	Pole Mounted Tx Compatible	Tx_Thermal Benefit (%)	Cable Thermal Benefit (%)	Volt Headroom Benefit (%)	Volt Legroom Benefit (%)	Cross Feeder Cable Thermal Benefit (%)	Cross Feeder Volt Headroom Benefit (%)	Cross Feeder Volt Legroom Benefit (%)
Dynamic Network Reconfiguration - LV	£15,495	£1,549	15	1.5	£50,012	✓	✓	✓	✓	5	10	3	5	0	0	0
D-FACTS - LV connected STATCOM	£30,990	£1,240	20	1.3	£63,190	✓	✓	✓	✓	5	10	15	15	0	0	0
EAVC - LV circuit voltage regs	£12,396	£496	20	1.3	£25,276	✓	✓	✓	✓	0	0	10	10	0	0	0
RTTR for HV/LV transformers	£2,066	£207	15	1.3	£5,779	✓	×	✓	×	10	0	0	0	0	0	0
LV UG network Split feeder	£35,638	£356	45	1.1	£48,021	✓	×	✓	✓	0	100	1	3	0	0	0
LV New Split feeder	£39,202	£392	45	1.1	£52,823	✓	×	✓	✓	0	80	1	2	0	0	0
LV GM 11/LV Tx	£16,308	£163	45	1.1	£21,974	✓	×	✓	×	80	0	1	6	0	1	6
LV UG Minor works	£118,795	£1,188	45	1.1	£160,070	✓	×	✓	✓	100	100	1	10	25	0.4	2.4
LV UG Major works	£296,987	£2,970	45	1.1	£400,176	✓	×	✓	✓	500	500	1	15	125	0.4	6
LV OH network Split feeder	£11,879	£119	45	1.1	£16,007	×	✓	✓	✓	0	100	1	3	0	0	0
LV OH network New Split feeder	£13,067	£131	45	1.1	£317,608	×	✓	✓	✓	0	80	1	2	0	0	0
LV PM 11/LV Tx	£14,255	£143	45	1.1	£19,208	×	✓	×	✓	80	0	1	6	0	1	6
LV OH Minor works	£23,759	£238	45	1.1	£32,014	×	✓	✓	✓	100	100	1	10	25	0.4	4
LV OH Major works	£148,493	£1,485	45	1.1	£200,087	×	✓	✓	✓	500	500	1	15	125	0.4	6
Active Network Management - LV	£5,165	£517	15	1.5	£16,671	✓	✓	✓	✓	10	10	3	3	3	1.2	1.2

Appendix II Results of Constraint Analysis for Individual Primary Substation Areas

EV Scenarios

Feeder Constraints

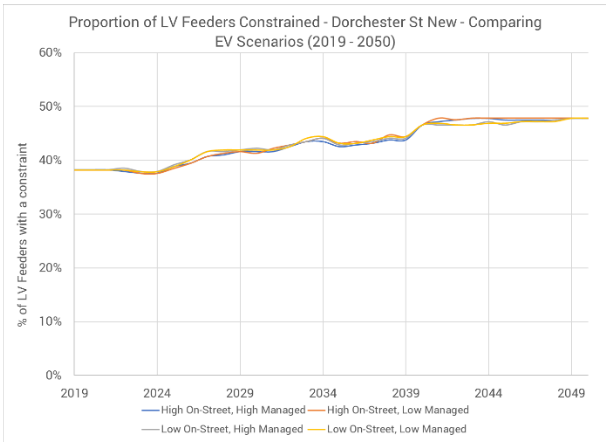


Figure AII.1 Dorchester St. New - Feeder Level Constraints (EV Scenarios)

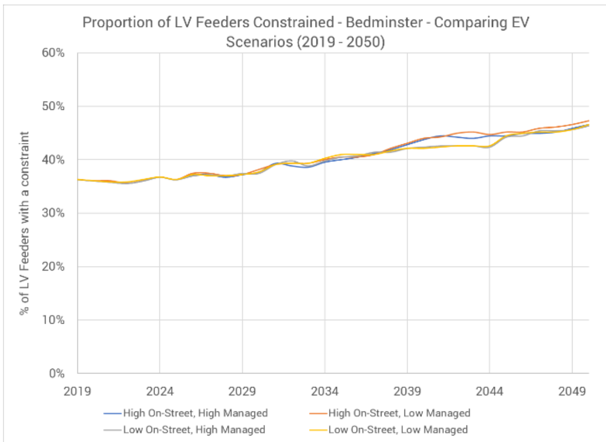


Figure AII.2 Bedminster- Feeder Level Constraints (EV Scenarios)

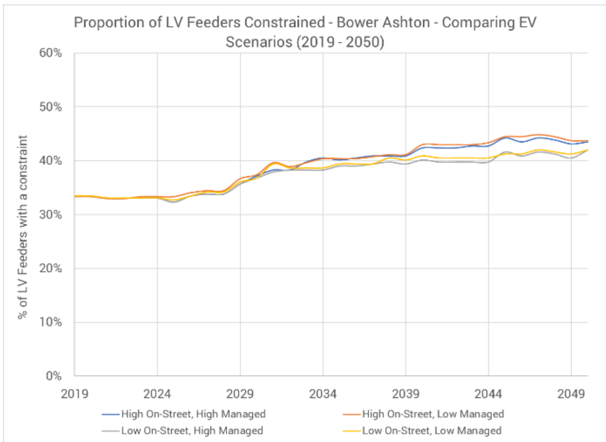


Figure AII.3 Bower Ashton - Feeder Level Constraints (EV Scenarios)

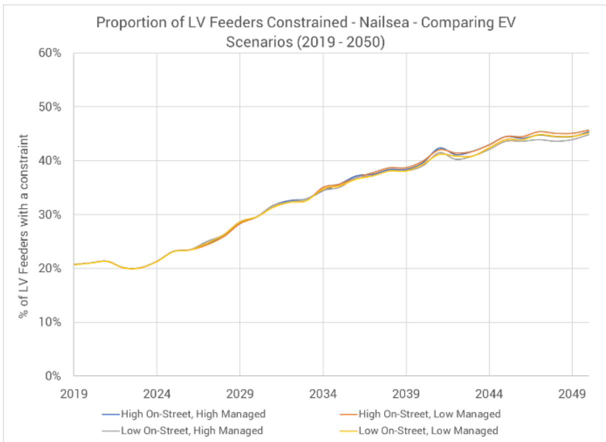


Figure AII.4 Nailsea - Feeder Level Constraints (EV Scenarios)

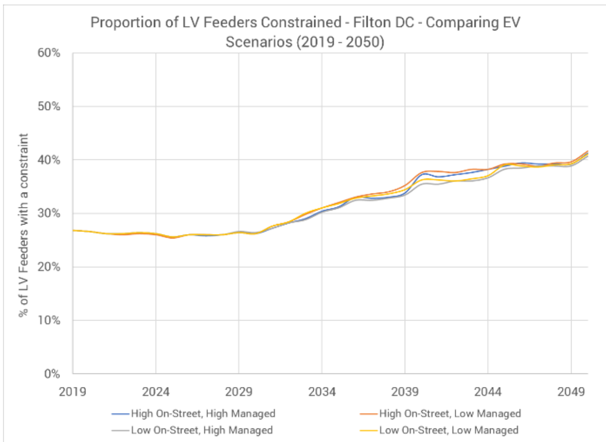


Figure AII.5 Filton DC - Feeder Level Constraints (EV Scenarios)

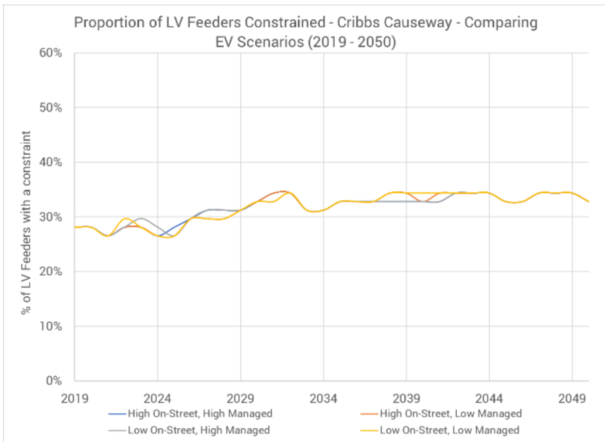


Figure AII.6 Cribbs Causeway- Feeder Level Constraints (EV Scenarios)

Heat Pump Scenarios

Feeder Constraints

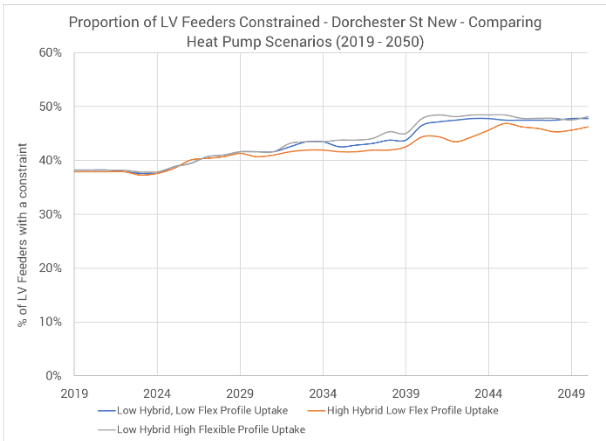


Figure AII.7 Dorchester St New - Feeder Level Constraints (Heat Pump Scenarios)

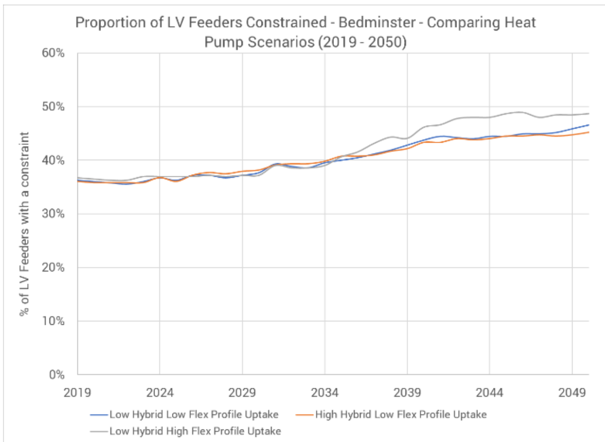
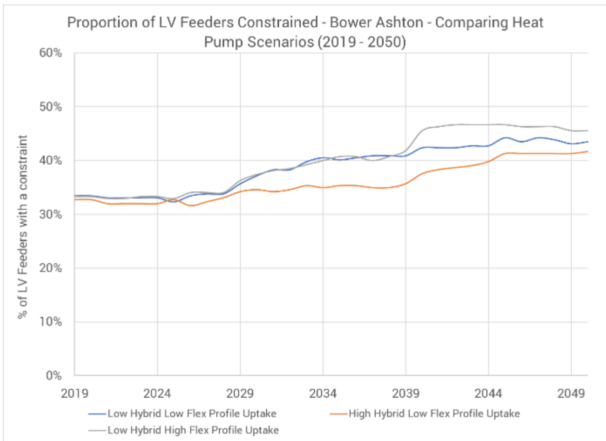


Figure AII.8 Bedminster - Feeder Level Constraints (Heat Pump Scenarios)



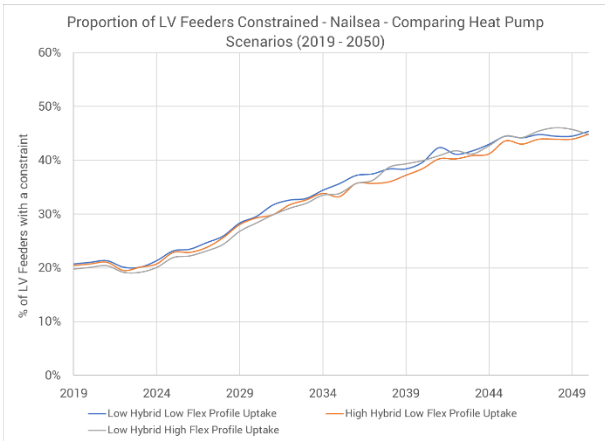


Figure AII.9 Bower Ashton - Feeder Level Constraints (Heat Pump Scenarios)

Figure AII.10 Nailsea - Feeder Level Constraints (Heat Pump Scenarios)

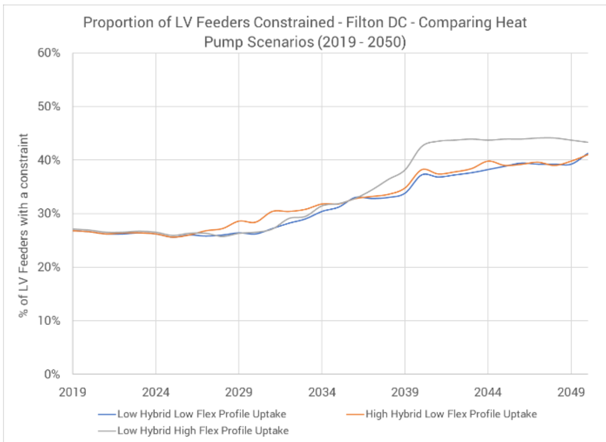


Figure AII.11 Filton DC - Feeder Level Constraints (Heat Pump Scenarios)

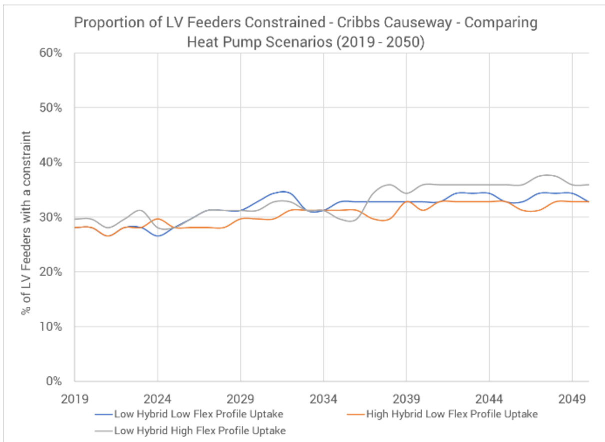


Figure AII.12 Cribbs Causeway - Feeder Level Constraints (Heat Pump Scenarios)

Energy Efficiency

Feeder Constraints

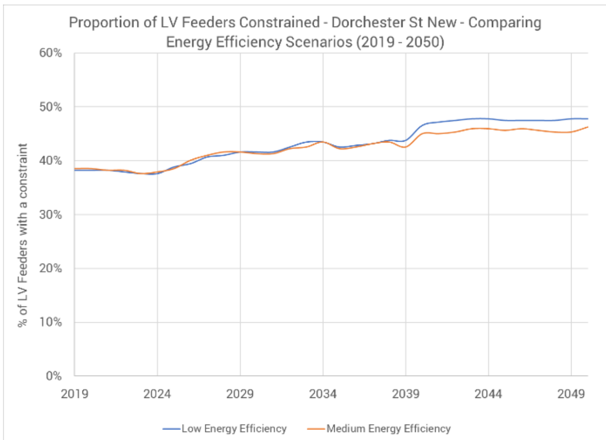


Figure AII.13 Dorchester St New - Feeder Level Constraints (Energy Efficiency Scenarios)

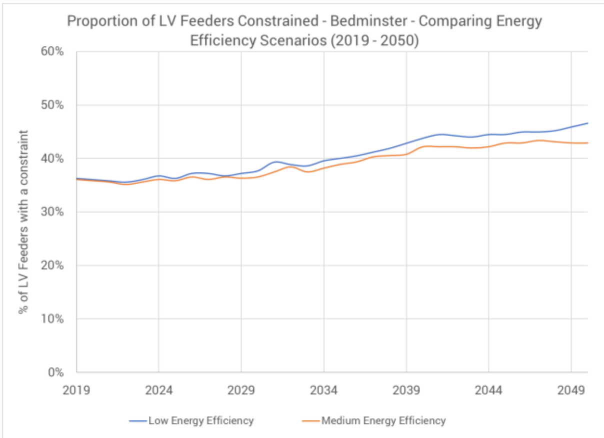


Figure AII.14 Bedminster- Feeder Level Constraints (Energy Efficiency Scenarios)

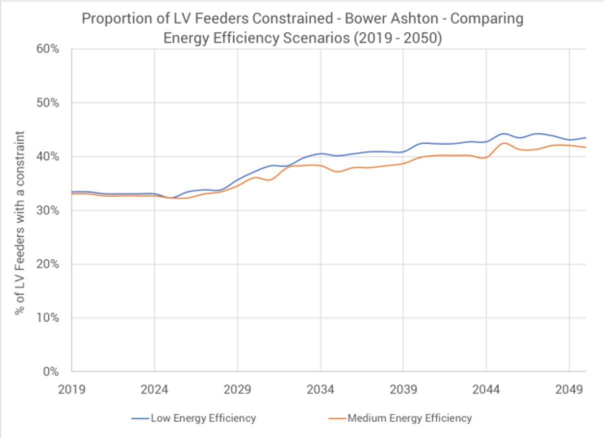


Figure AII.15 Bower Ashton - Feeder Level Constraints (Energy Efficiency Scenarios)

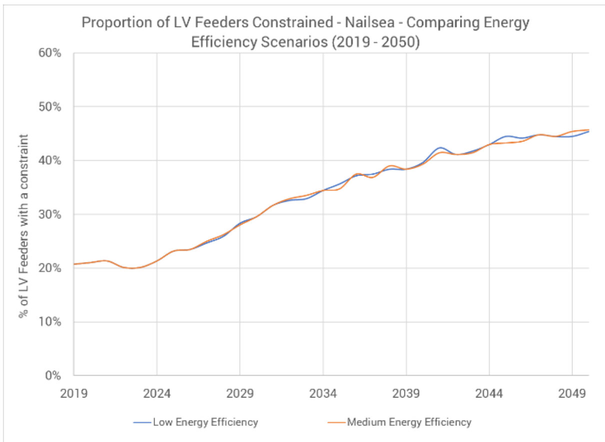


Figure AII.16 Nailsea - Feeder Level Constraints (Energy Efficiency Scenarios)

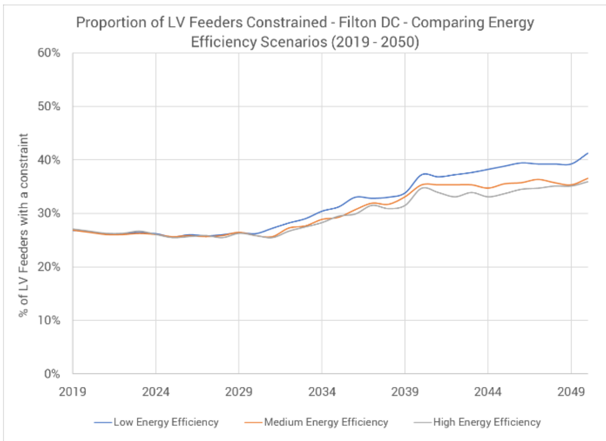


Figure AII.17 Filton DC - Feeder Level Constraints (Energy Efficiency Scenarios)

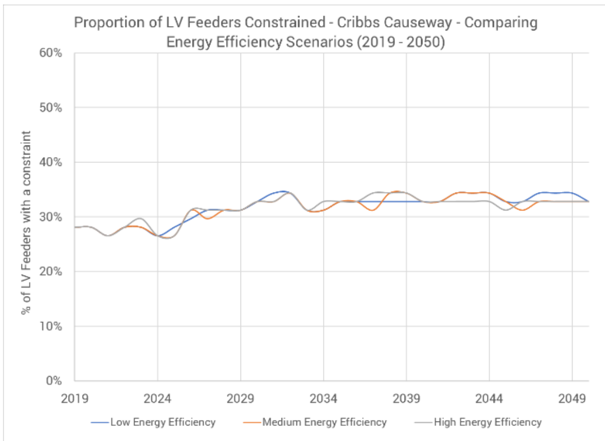


Figure AII.18 Cribbs Causeway - Feeder Level Constraints (Energy Efficiency Scenarios)

Appendix III Amendments to the Solutions Module for EPIC Project

The solutions module in NIFT was deployed for the first time in the EPIC project. Previous applications of the NIFT for WPD used only the data from the 'What Breaks When' tables. A change to the solutions module and solution properties was required in order to improve the accuracy of the results. This sub-section describes the issue and how it was resolved.

The solutions module was developed based on the Transform model used by UK DNOs and Ofgem. This adopts a 'feederised' approach whereby modelling, including solutions, was applied at an LV feeder level, as data was not available to link feeders to their associated distribution transformers. The cost of solutions were therefore given at a per feeder level, assuming an average of four feeders per substation. This 'feederisation' negatively affected the deployment of two solutions of the fifteen included in NIFT: the replacement of ground and pole-mounted transformers. Other solutions were not affected as they related to individual feeders, rather than the substation transformer.

Due to the feederised approach the cost and benefits for transformer replacement (ground mounted shown) were initially as follows (NB the values are below are per LV feeder so the capex for transformer replacement at the distribution substation assumed to have 4 feeders would be 4 x £4,077):

- Capex: £4,077
- Opex: £41
- Totex (over a 45 year lifetime): £5,493
- Transformer thermal benefit: additional 80% allowable utilisation
- Voltage headroom benefit (on feeder the transformer was 'deployed for'): 1%
- Voltage legroom benefit (on feeder the transformer was 'deployed for'): 6%
- Cross-feeder voltage headroom benefit[24]: 0.4%
- Cross-feeder voltage legroom benefit: 2.4%

Voltage constraints were relatively common on the modelled LV networks in 2019. The 'feederised' costs resulted in transformer replacement being extensively deployed as it represented the most cost efficient way to resolve voltage issues, due to the ranking below (showing options for a pole mounted network). The second cheapest solution was nearly three times as expensive as transformer replacement and offered a lower increase in the allowable voltage legroom.

Table AIII.1 Solutions, costs and voltage benefits (default NIFT template, pole mounted networks)

Solution	Totex	Voltage Headroom Benefit	Voltage Legroom Benefit
Pole mounted 11/LV Tx	£4,802	1%	6%
LV overhead network split feeder	£16,007	1%	3%

[24] When a solution is deployed on/or a particular feeder the feeder on which it is deployed gains the larger voltage headroom and legroom benefits (1% and 6% respectively for this example). All other feeders supplied from the same substation gain the cross-feeder voltage benefits.

Solution	Totex	Voltage Headroom Benefit	Voltage Legroom Benefit
Active Network Management (LV)	£16,671	3%	3%
LV overhead network new split feeder	£17,608	1%	2%
EAVC – LV circuit voltage regulators	£25,276	10%	10%
LV overhead minor works	£32,014	1%	10%
Dynamic network reconfiguration (LV)	£50,012	3%	5%
D FACTS – LV connected STATCOM	£63,190	15%	15%
LV overhead major works	£200,088	1%	10%

Voltage constraints were often present on multiple feeders from the same substation, and as the 'cross-feeder' benefits were low (0.4% and 2.4% headroom and legroom respectively, compared to 1% and 6% on the feeder the transformer had been deployed 'for'), multiple new transformers would be deployed to solve the voltage constraints of each feeder in turn. This had two detrimental effects:

- Full costs would only be captured if four 'feederised' transformer replacements were deployed (otherwise a fraction of the total cost would be included);
- Allowable transformer utilisation could increase beyond realistic values. Each transformer replacement increased the allowable transformation utilisation by a further 80%, from a starting value of 110%. Therefore on a substation where two transformer upgrades had been selected (to address voltage issues on two feeders for example) the allowable utilisation would be 110% (starting value) + 80% (benefit from first transformer replacement) + 80% (second transformer replacement = 270%

This does not accurately represent the costs and benefits of transformer replacement and does not align with network investment in practice. Instead, the transformer is deployed at a substation level, incurring the full cost (not a 'feederised' figure) and all feeders receive the same voltage benefits.

The 'feederisation' of transformer benefits and costs were removed by making the following changes:

- Capex and opex increased to remove feederisation (multiply through by four to remove the 'four feeders per transformer' conversion):
  - Ground mounted costs: increased from £4,077 (capex) and £41 (opex) to £16,308 (capex) and £163 (opex). Totex increased from £5,493 to £21,974
  - Pole mounted costs: increased from £3,564 (capex) and £36 (opex) to £14,255 (capex) and £143 (opex). Totex increased from £4,802 to £19,208.
- Cross feeder benefits increased to reflect all feeders receiving the same benefit – i.e. an increase of 1% in allowable voltage headroom and 6% voltage legroom on all feeders fed from the same substation.

In practice the result was that a transformer upgrade was typically deployed for the feeder with the highest priority constraint (the largest constraint). The cross-feeder benefits resolved the voltage issues present on other feeders, in many cases removing the need for further interventions within the same year. Where a new transformer was deployed due to high utilisation of the distribution transformer then the full cost of the transformer replacement was incurred rather than the 'feederised' figure (a quarter of the total) from the original solutions properties. This upgrade resolved a significant issue and it is therefore recommended that any future automated analysis to determine future levels of investment uses this modified approach.

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