Local Energy Oxfordshire

July 2022 | Version 1

Local Energy System Modelling: Osney Island Smart and Fair Neighbourhood Case Study

Local Energy Oxfordshire

Local Energy Accelerating Net Zero

Report Title:	***Local Energy System Modelling:*** ***Osney Island Smart and Fair Neighbourhood Case Study***
Lead Authors:	
Organisations:	Low Carbon Hub, SSEN

Funded by:

Context

The UK Government has legislated to reduce its carbon emissions to net zero by 2050. Meeting this target will require significant decarbonisation and an increased demand upon the electricity network. Traditionally an increase in demand or distributed generation on the network would require network reinforcement. However, technology and the ability to balance demand on the system at different periods provide opportunities for new markets to be created, and new demand to be accommodated through a smarter, secure, and more flexible network.

The future energy market offers the opportunity to create a decentralised energy system, supporting local renewable energy sources, and new markets that everyone can benefit from through providing flexibility services. To accommodate this change, Distribution Network Operators (DNOs) are changing to become Distribution System Operators (DSOs).

Project Local Energy Oxfordshire (LEO) is an important step in understanding how new markets can work and improving customer engagement. Project LEO is part funded via the Industrial Strategy Challenge Fund (ISCF) who set up a fund in 2018 of £102.5m for UK industry and research to develop systems that can support the global move to renewable energy called: Prospering from the Energy Revolution (PFER).

Project LEO is one of the most ambitious, wide-ranging, innovative, and holistic smart grid trials ever conducted in the UK. LEO will improve our understanding of how opportunities can be maximised and unlocked from the transition to a smarter, flexible electricity system and how households, businesses and communities can realise the benefits. The increase in small-scale renewables and low-carbon technologies is creating opportunities for consumers to generate and sell electricity, store electricity using batteries, and even for electric vehicles (EVs) to alleviate demand on the electricity system.

Project LEO seeks to create the conditions that replicate the electricity system of the future to better understand these relationships and grow an evidence base that can inform how we manage the transition to a smarter electricity system. It will inform how DSOs function in the future, show how markets can be unlocked and supported, create new investment models for community engagement, and support the development of a skilled community positioned to thrive and benefit from a smarter, responsive and flexible electricity network.

Project LEO brings together an exceptional group of stakeholders as Partners to deliver a common goal of creating a sustainable local energy system. This partnership represents the entire energy value chain in a compact and focused consortium and is further enhanced through global leading energy systems research brought by the University of Oxford and Oxford Brookes University consolidating multiple data sources and analysis tools to deliver a model for future local energy system mapping across all energy vectors.

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Executive Summary

Introduction

The Osney Bridge Street secondary substation feeds around 300 homes and half a dozen businesses on Osney Island. It is a typical example of a substation at the grid edge where both domestic and non-domestic customers are increasingly looking to connect Low Carbon Technologies (LCTs).

At the start of one of the place-based trials under LCH's Smart and Fair Neighbourhood (SFN) projects called Osney Supercharge in January 2022 there were 16 existing PV systems installed and a couple of Air Source Heat Pumps (ASHP) and EV chargers. The interest in the concept of increasing the level of renewable generation at the local level and looking to match the demand of residents to that local generation (including the existing community-owned Osney Lock Hydro 50kW scheme) meant that 30 of the 300 households expressed an interest in participating in the project within 2 weeks of the project being launched. SSEN's Business as Usual (BaU) team raised concerns that there might be voltage rise issues on the Low voltage feeder that would prevent them giving permission for the householders to connect their PV systems to the grid. Hence, the SSEN innovation team created a power system model for Osney Island to identify where these grid constraints might occur.

Background to the Task

For historical reasons, maintaining and updating the record of service cables and customer supply points in the LV network has not been at all a critical requirement for DNOs, especially given the large number of nodes and cables in this part of the network. Hence, the existing Geographic Information System (GIS) data for Osney Bridge secondary substation available to the BaU teams had the majority of the supply points and service cables missing. The SSEN innovation team developed a workflow for building models for LV networks in a way that makes a more efficient use of the GIS data available to SSEN BaU teams and incorporates external datasets to augment the data where required.

Analysing the impact of low-carbon technologies on LV networks and estimating the network capacity can quickly become complex to manage because of the different scenarios, settings, and results. With the Power System Analysis (PSA) tool chosen, PowerFactory, it was possible to organise the project into different study cases, operational scenarios and network variations, to facilitate the analysis. It was also possible to use this approach to see the impact of using different sources of data input on the outcomes predicted by the model. A key finding of relevance to future decision making by the BaU teams was the importance of accurate allocation of phase connection for domestic households. Initial modelling was carried out assuming a sequential allocation of phase connections down a feeder. However, a survey was carried out on Osney Island with a phase identification unit in a single day which was used to determine the phase a customer is connected to wirelessly without the need to enter the property. This showed that for 3 of the 5 feeders on Osney Island rather than an even 33% spread across the phases one of the phases had around 40% of homes connected to a single phase, with some of the individual phases having as low as 24% of homes connected to that phase. As described below, it was possible to compare the model predictions between assuming an even and sequential allocation of domestic connections down a feeder with actual known phase connections.

Modelling Results

Analysis of the modelling outputs indicated several important features specific to the implementation of the Osney Supercharge project. These findings also have wider implications for the way in which future connection requests for LCTs at the grid edge at the scale of domestic and SME (Small and Medium-sized Enterprises) are considered by BaU teams.

Firstly, the analysis of the base case network (i.e. before any future installations of LCTs under the Osney Supercharge project) with no generation but maximum demand identified that there were some feeders (in particular the longest Bridge Street East feeder) where the current network is at risk of seeing low voltage events where the voltages at individual customers towards the ends of the feeder dropped below the optimum range specified by SSEN. In these cases, when the installed PV systems are generating, the extent of the low voltage issues was reduced, and furthermore installation of additional PV systems on these feeders would be of benefit to the local energy system. Communicating case studies such as these where Distributed Energy Resources (DERs) can be part of building up the resilience of the energy system is important in changing the mindsets and systems in moving from a centralised to a decentralised energy system.

At the same time these same feeders experiencing potential low voltage issues can be identified in local area energy plans (LAEPs) as areas which would be a lower priority for the installation of additional high demand LCTs such as Air Source Heat Pumps and EV chargers unless they can be balanced by additional local generation.

When the future PV installations under Osney Supercharge were added to the energy system modelled (an additional 17 PV systems and an additional 27 PV systems were considered) as would be expected the no generation and maximum demand scenario did not change significantly. By contrast, the initial analysis of the worst case scenario for high voltage issues, maximum generation but only 50% demand, using a sequential allocation of phase connection for domestic properties, the modelling indicated that there would be high voltage issues on the South Street feeder. This is the feeder that Osney Lock Hydro is also connected to. However, once the actual phase connection was established with a field survey using a phase identification unit and fed into the model this showed that voltages were expected to remain well within the voltage bands specified by SSEN throughout the length of the feeder for the South Street feeder.

Whereas, for West Street on the basis of an even sequential distribution of phases no concerns were raised on potential voltage issues. However, when actual phase connection data mentioned above was input into the model this indicated that new DERs potentially could result in a phase imbalance on one of the 3 phases. Hence, the modelling identified the areas where field monitoring of voltages would be most useful to see if there were any high voltages at times of peak PV production.

This illustrates that robust decisions on the potential impact of connecting LCTs at the grid edge can only be made on the basis of sufficient information such as having a full picture of all the households connected to a feeder and actual phase connections of the households looking to install PV systems. In an energy system area with a high proportion of domestic customers who will be single phase connections, this study has shown that the true phase connectivity is a critical piece of information before robust decisions can be made.

Future Projection and Change

Looking forward, an important question to consider across our networks is “What is the minimum set of data, and accuracy, needed to produce results that can be used for decision making on whether and where to install a particular LCT, and whether there is a requirement for any limits in terms of total power import/export”. To answer these questions SSEN has already commenced further work on refinements of the network model to incorporate smart meters, time-series modelling, local feeder reconfiguration, and LV monitoring to calibrate model outputs. This will allow us to identify other factors (in addition to the importance of using accurate phase connection data which we identified in this first stage) which are the most important in order to make informed decisions on what elements of the network infrastructure will need to be reinforced and when.

Now that the base energy system model is in place it provides an ideal platform to model future scenarios of the steps required for Osney Island to reach Net Zero. It will allow us to assess what level of LCT adoption can be managed within the existing network infrastructure through priority siting and dynamic control.

Working back from net zero scenarios for the Island will allow us to establish the network infrastructure required for net zero. This could enable Osney Island to be the first legacy secondary substation area in the UK to have a network upgrade plan that works back from a network infrastructure that meets the requirements of net zero, rather than working forward in incremental steps to avoid acute network constraints.

Important Modelling and Data Limitations Disclaimer

It’s worth noting that the results and conclusions from these initial studies, while very valuable and directionally informative, are based on a network model that has not been completely fully validated with all of the ideally required data from the real world e.g. true LV network connectivity and precisely accurate customer consumption and diversity profiles.

All of the results and conclusions in this report can be further improved by incorporating additional and improved data from e.g. smart meters and further field investigations - these types of data will likely be available to the DNO in the near future.

SSEN innovation team would therefore advise that the results of the preliminary studies in this report should not be used to make any customer/community investment or connection decisions until the results of such additional work is completed.

Glossary of Terms Used in This Document

CIM – Common Information Model

GIS – Geographical Information System

LCTs – Low Carbon Technologies

PSA – Power System Analysis

SFN – Smart and Fair Neighbourhoods

SLD – Single Line Diagram

UPRN – Unique Property Reference Number

1 Background

In the next few decades the UK has to respond to the threat of climate change. Gas and petrol will be phased out. There will be a huge shift to using electric cars, and heating homes using heat pumps. This transition to Net Zero will create increased demand. The local electricity network as currently configured will not be able to cope.

One of the biggest challenges faced by the current energy system identified by The International Community for Local Smart Grids (ICLSG), convened by Oxford University and coming out of Project LEO, is the lack of visibility of the Low Voltage (LV) network. The energy systems not just in the UK but worldwide from Australia, New Zealand, Japan, and across Europe have been put in place to provide monitoring and visibility of the High Voltage (HV) network for a centralised electricity distribution network. The instantaneous use and constraints at the grid edge in the LV network are largely invisible to network operators which means that decisions about how to manage the connection new DERs onto the network which needed as part of the transition have to be based on conservative estimates. This in turn results either in over specified and costly infrastructure upgrades, or large areas of the country where connection of DERs are restricted because of potential grid constraints.

Osney Island is a small neighbourhood in West Oxford and is where one of the place-based trials under LCH's Smart and Fair Neighbourhood (SFN) projects called Osney Supercharge is located. It includes a 50kW hydro generation scheme, with an associated 9kW solar installation, owned by Osney Lock Hydro Limited, a community benefit company. There are also solar installations on Osney rooftops and nearby at the community centre and on the university estate. The local community has a high level of interest and engagement with energy and could be an exemplar in getting a high percentage of its 300 households installing Low Carbon Technologies (LCTs) if the local energy system can allow them to play their role. Initial discussions with SSEN's business as usual team indicated that even just 10% of the population engaging by adding PV and batteries to their homes could cause problems to the local grid. Hence, Osney Island is an ideal example to work through the sort of challenges that will be faced at the grid-edge by communities across the UK.

In terms of the energy system assets on Osney Island at the start of Osney Supercharge this consisted of:

- A ground mounted secondary substation (Osney Bridge Street – 800kVA) serving the whole Osney island with approx. 300 customers via 5 LV feeders (figure 1)
- An 'anchor generator' in Osney Lock Hydro (50kW) and its PVs (9kW)
- 15 households that already have rooftop solar PV – one or two also with storage/heat pump/EVs
- SSEN has LV monitoring equipment at the secondary substation (i.e., all the feeders are monitored for voltage/current/power)

Figure 1. Satellite view of the Osney Island in Oxfordshire. The secondary substation is highlighted by the green circle, the Osney Lock Hydro in yellow circle (image from Google Earth).

2 Objectives

As part of Osney Supercharge initially 30 residents expressed an interest in installing PV systems and batteries for their homes. While it was known (see section 4) that there was sufficient headroom at the 800 kVA substation to install these systems since historically the maximum loading was 300 kVA, SSEN's business as usual (BAU) team raised concerns that there might be voltage rise issues that would prevent them giving permission for the householders to connect their PV systems to the grid.

Hence, it was identified as a priority for SSEN's innovation team to work with LCH to develop a detailed energy system model to investigate the severity of the potential voltage rises from installation on additional domestic PV systems.

3 Scope of the modelling

The scope of the energy system modelling work was to:

- Develop a reproducible and semi-automated workflow that allows SSEN to scale LV modelling capabilities to other parts of the network

- Assess present conditions of this particular LV network
    - Loading of secondary transformer and LV feeders
    - Phase imbalance across the 3 phases of the electricity network supply
    - Voltage ranges (min/max) at head/end of feeders
    - Existing installations of low carbon technologies (LCTs)
- Estimate network capacity for installing additional LCTs
    - amount of additional generation allowed in kW (e.g. rooftop solar PV, storage)
    - amount of additional demand allowed in kW (e.g. EVs and heat pumps, storage)

4 LV network design and modelling

The starting point for the LV network is what is known as secondary substations, which can be pole-mounted (typical in rural areas) or ground-mounted (typical in urban or suburban areas), and serve to step down the voltage from 11kV to 400V. Domestic and small commercial customers are supplied via service cables, which branch out from the LV mains (also known as LV feeders). Typically, domestic customers are connected via a single-phase service cable, whereas commercial customers with a larger power requirement usually have a three-phase service cable.

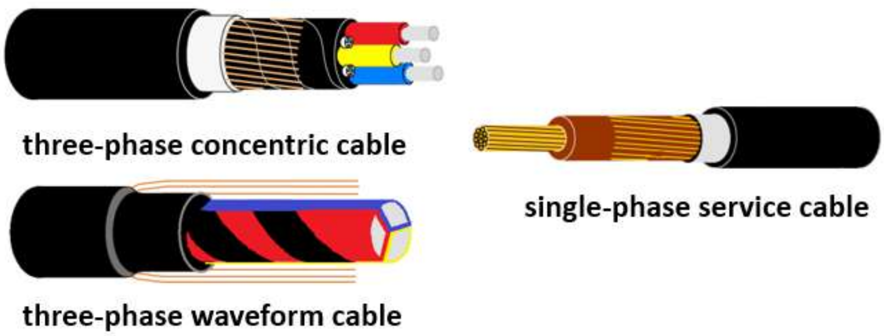


Figure 2. Illustration of a three-phase and a single-phase cable. Image taken from SSEN standard documentation: PR-NET-NPL-001 and TG-NET-NPL-013.

The nominal voltage for single-phase connections is 230 V, and 400 V for three-phase connections. These are subject to (as detailed in ESQCR and ENA EREC P28) a maximum voltage rise of +10% (1.1pu) and a maximum voltage drop of -6% (0.94 pu).

The network capacity can be thought of as the amount of demand and/or generation that can be connected to the network, under existing network conditions, without having an adverse impact on the power quality, or the reliability of the supply in the network. In other words, new connections should take place without overloading the network components and whilst maintaining the voltage within the allowable threshold. While most of the time the network capacity is linked to the overall substation capacity (i.e. the thermal limit of the transformer and thus its ability to accept connections), having enough capacity at the substation is not the only factor that should be considered when analysing whether LCTs can be connected to a particular LV network. Other factors, which might be thought of as "localised network capacity", need to be considered as well, including: the voltage profile of the feeder, the thermal capacity of other parts of the feeder, phase imbalance and customer distribution, etc. Some of the factors affecting the network capacity are:

- Loading of the secondary transformer and the individual LV feeders
- Voltage profile along the feeders, in particular:
  - at the head of the feeder, and
  - at the end of the feeder
- Amount of phase imbalance

In general, too much demand can result in exceedance of the thermal limits or a drop in the voltage at the far end of the LV feeders, however a very low demand paired with very high levels of PV generation (e.g., during the peak of summer) is also not ideal, as it can cause higher voltage ranges on LV feeders.

In the case of Osney Island, while the headline analysis showed there was plenty of substation capacity available at the Osney Bridge Street secondary substation (figure 3), SSEN was concerned that the addition of PV and batteries to 30 homes might cause unacceptable voltage rise issues. While 30 installations was the maximum expected under Osney Supercharge from the initial interest expressed, it still represents just 10% of the 302 homes connected to the Osney Bridge substation. This helps to illustrate the challenges faced in enabling homes in the UK to reach out net zero targets.

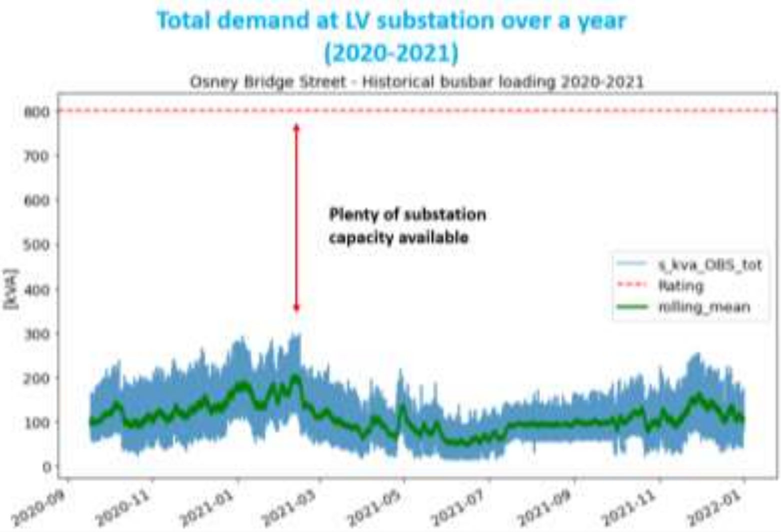


Figure 3. Osney Bridge Street Secondary Substation – Historical data – Rating: 800kVA

SSEN recognises that similar to the case of Osney Island, there are many areas where customers want to connect LCTs and they might face similar challenges. Hence, one of the motivations for this piece of work was to develop a workflow or process for building models for LV networks that could be scaled to other areas. To reduce the amount of manual work required to build a network model, an extract from SSEN's GIS database was used as a starting point for the model development process. The extract was in a format according to the Common Information Model (CIM) standard[1], version 15.

While there are several Power System Analysis (PSA) tools available, only some of them have the functionality to import CIM files. DIgSILENT PowerFactory, one of the PSA tools used at SSEN, can import and export CIM files, and thus it was chosen for creating the network model of the Osney Island. Although the CIM format is a standard language, there are different versions and profiles, and this can create some compatibility problems when importing/exporting between different tools. For this reason, a series of pre-processing steps were needed to make the CIM extract from SSEN's GIS database compatible with DIgSILENT PowerFactory. Figure 4 shows an overview of the model development workflow.

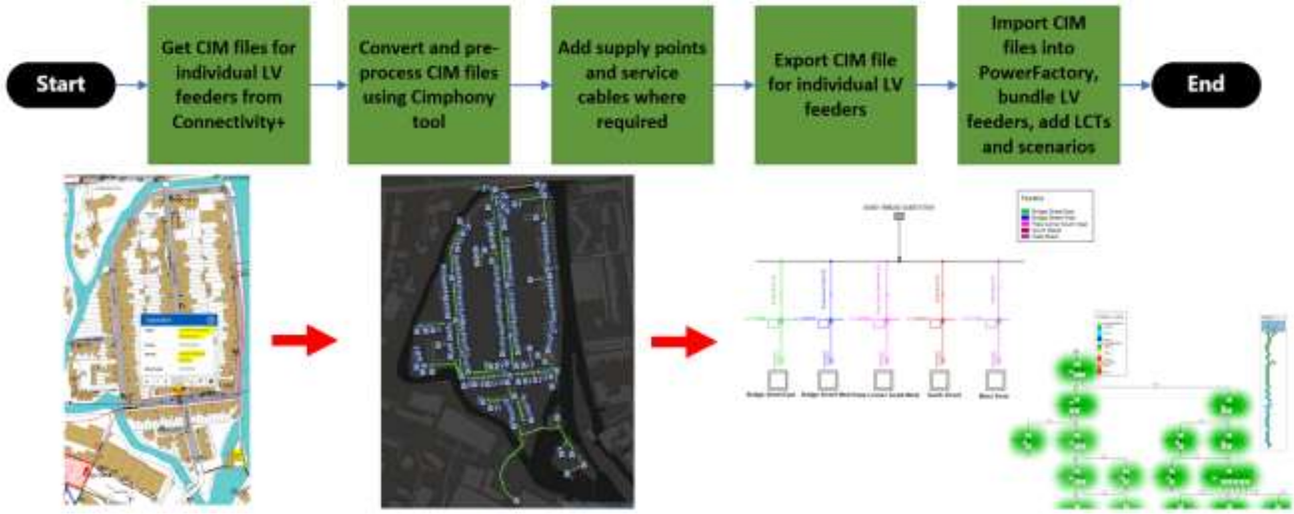


Figure 4. Network model development workflow

One of the tasks of the pre-processing was to validate that the cable information (e.g. cable rating and impedance) in the CIM extract was accurate. Another step involved merging the LV feeders together to form the Osney Bridge Street substation, as the LV feeders typically come in individual CIM extracts.

5 Network connectivity challenges

For historical reasons, maintaining and updating the record of service cables and customer end points (supply points) in the LV network GIS data has not been a critical requirement for DNOs,

[1] The Common Information Model (CIM) is a standard developed by the electric power industry to allow the exchange of information about an electrical network (from: https://en.wikipedia.org/wiki/Common_Information_Model_(electricity)).

especially given the large number of nodes and cables in this part of the network; this is managed through load diversity assumptions made for LV networks.

However, this has changed in the last few years with the increasing number of Low Carbon Technologies (LCTs) connected to the LV network, making it increasingly important to maintain accurate records of the network that can then be used to build network models suitable for power flow studies.

One of the challenges for creating detailed models of the LV network is the need to protect personal data and the accompanying rules under GDPR. This was particularly the case in the Osney SFN given that the majority of the customers in this part of the network are domestic, and therefore some of the data points, such as the individual addresses, are classed as personal data. This also creates complexities when sharing the data with external collaborators and contractors.

The extract from SSEN's GIS database (Electric Office – EO) showed that for this area the majority of supply points and service cables for the 300 homes were not modelled (figure 5). For the historical reasons stated above this was not an unusual or problematic situation, however, it does highlight the challenges faced going forwards in being able to assess the potential impact of LCTs on the LV network.

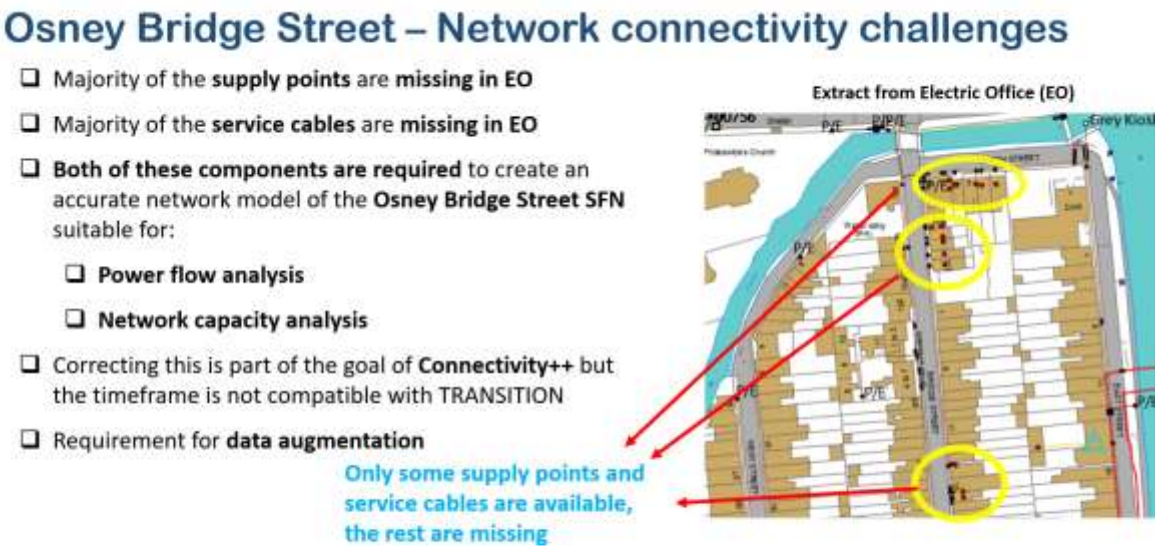


Figure 5. Incomplete data for supply points and service cable modelling in the GIS database

One of the approaches trialled during this work was to use external datasets and a nearest-distance algorithm to augment the network data from the CIM extracts. In particular, we used Unique Property Reference Numbers (UPRNs)[2] as a proxy for missing supply points. The UPRN allowed us to pseudonymise the customer data and avoid the use of addresses. Also, to add another layer of data protection, the name of the supply points were anonymised.

[2] A Unique Property Reference Number (UPRN) is a unique numeric identifier for every addressable location in Great Britain, the UPRN database is provided by Ordnance Survey. Contains OS data © Crown copyright and database right 2021. From: https://www.ordnancesurvey.co.uk/business-government/products/open-uprn

As part of the workflow, we created new supply points where they were missing in the power system model and in the model connected them to the nearest LV feeder in the network using a standard service cable type (single core concentric 35mm aluminium cable). An overview of the process is given in figure 6 and figure 7 shows a comparison of the initial and final state of the network model in a GIS format.

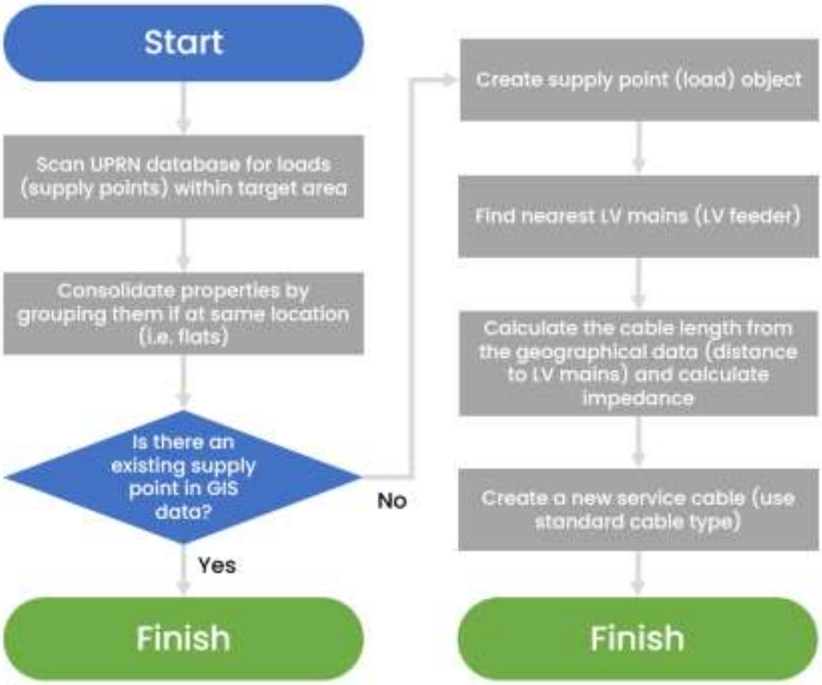


Figure 6. Workflow for creating supply points from UPRNs

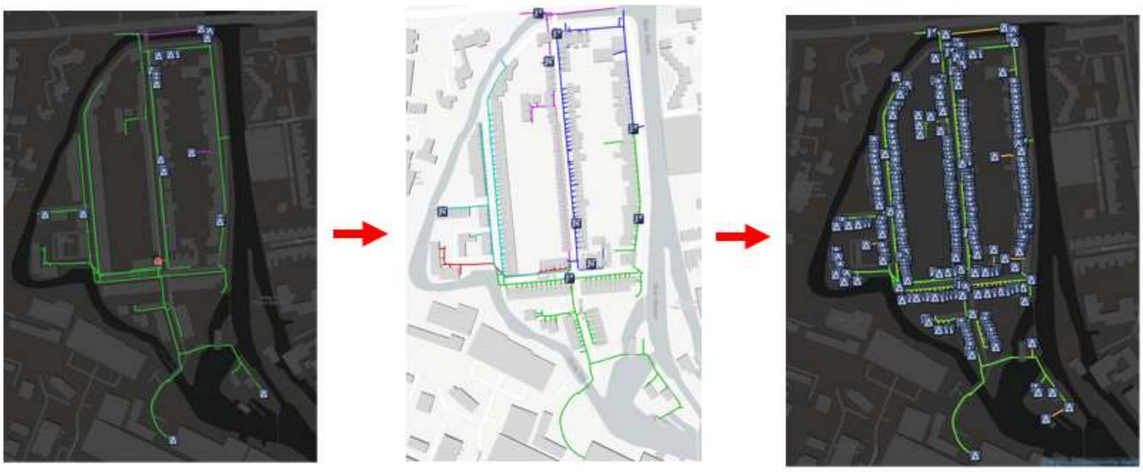


Figure 7. Data augmentation using UPRNs as a proxy for supply points in the network model and the creation of service cables

It is worth noting that the PowerFactory PSA tool only allows importing CIM files with a CGMES profile[3], which is aimed at balanced three-phase systems. For this reason, all the network elements are modelled as three-phase systems, this includes the LV mains and service cables, as well as the terminals and loads. In reality, the majority of the customers in LV networks are supplied via single-phase service cables.

6 Network loading challenges

Once the network connectivity in the model was complete, including all the new supply points and service cables, the next steps were to allocate the customers to a particular phase and to assign a demand value. The demand could be based on the customer characteristics, such as profile class (e.g., domestic, non-domestic), the building type and total area, or it could be based on historical data, either from LV monitoring or from smart meters.

From analysis of the SSEN customer database, it was clear that the majority of customers in the Osney Island LV network are domestic customers (ELEXON class 1 and 2), with a few non-domestic customers (ELEXON class 3, 4 and 6). This is illustrated in figure 8.

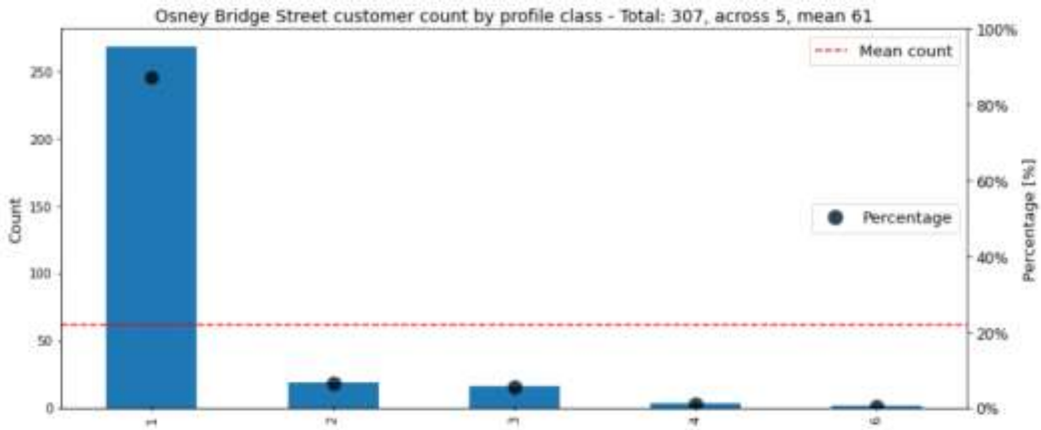


Figure 8. Customers in Osney Island by profile class

Because the majority of the customers are domestic (i.e. single phase, as opposed to 3-phase connected), it was evident that representing the phasing information would be important, as this might give a more accurate view of the problems to be expected in the network. While the supply points are modelled as three-phase components due to the limitations of the CIM CGMES profile (mentioned above at the end of Section 5), to overcome this and accurately represent the single-phase connection of residential loads, the domestic customer demand (active and reactive power) is assigned to only one of the phases and the rest are set to zero. For the larger commercial loads (usually 3-phase connected), the demand was assumed to be split equally across the phases.

[3] This is just a limitation of the data that came in CIM import format, PowerFactory itself internally allows for single phase, 3 phase, and unbalanced condition modelling.

For the initial stages of this work, the demand values applied in the model were based on the type of customer (domestic or commercial), the usage of the building (e.g., office, restaurant, pub) and the area of the building, which was measured using Google Earth. All residential customers were assumed to have non-electric heating and a mean maximum demand of 2.25kW, according to SSEN's standard documentation. The diversity of the loads was modelled using a random uniform distribution between 0.5kW and 2.25kW. For commercial customers the typical maximum demand was calculated based on the area, for instance:

- A pub is considered to have a typical maximum demand of 60W/m^2

It was assumed that all the loads have an inductive power factor of 0.95 (i.e., lagging).

Two levels of sophistication were used for allocating the domestic customers to their respective phase:

A. Initially, in the absence of any real-world specific evidence or data, a uniform allocation of the phase based on the distance from the substation following the sequence A, B, C (i.e., the customer closest to the substation will be assumed to be connected to phase A, the next customer to phase B, and so on).
B. It was later possible to compare the impact of having actual correct phase connection data since actual phase of each household connection was identified during a site visit by an SSEN engineer using a Phase Identification Unit (PIU) manufactured by HAYSYS (Products - HAYSYS Limited Direction Finder Finding Phase Identification LV Substation Monitoring). These devices can be used to determine the phase a customer is connected to, and it can do that wirelessly. Hence, there is no need to enter the property and no need to dig cables out. HAYSYS compares the electric field at the substation with the meter at the properties and maps the phase each property is connected to on this basis.

The modelling impact of being able to include the correct evidence based phase connectivity assumption is discussed in section 8.

The solar PV generation was assumed to have the same phase connectivity as the customer on which it its modelled (i.e., if a residential customer connected to phase A has a solar PV installation then this generator is also connected to phase A). Existing installations were assumed to have a peak generation of 3.36kW, future installations were assumed to be 2.5kW.

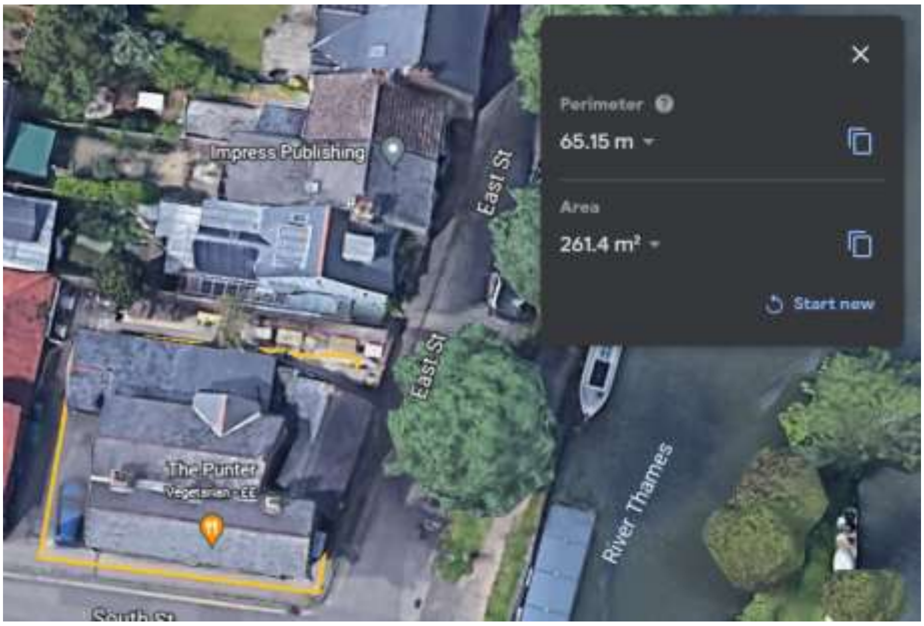


Figure 9. Illustration of the area measurement tool available in Google Earth

It is worth noting that for this initial stage of the modelling work, only single deterministic snapshot point in time was the focus of the modelling analysis, a more comprehensive study could incorporate the effect of load profiles (i.e., timeseries across a wider range of conditions) to obtain broader insights. Also, no smart meter data was available to SSEN for this part of the network at the time of conducting the analysis (even though evidence from the field indicated that at least half of the participants had SMETs 2 smart meters). It is envisaged that smart meter data (aggregated at a 5 property level) will be available in the very near future to DSOs as the penetration of smart meters increases.

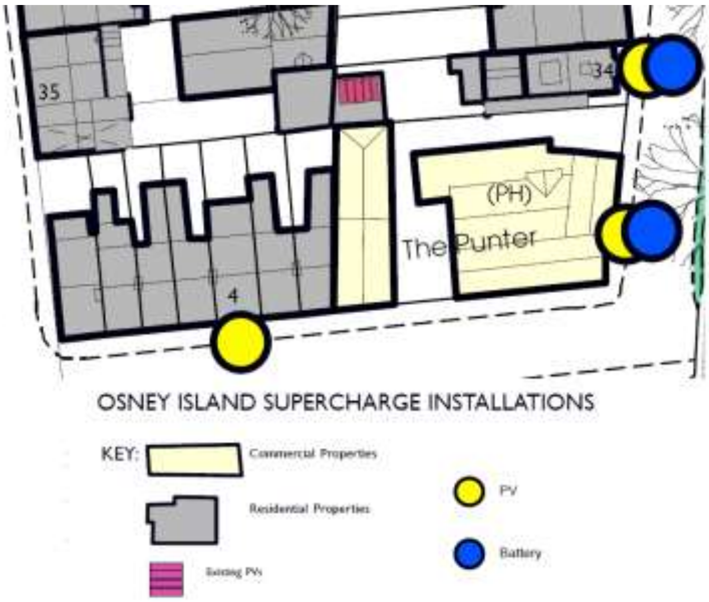


Figure 10. Sample from planning map provided by LCH with existing and future installations – indicative/rough locations only

7 PowerFactory model overview and benefits

Historically, there has been very little monitoring carried out of devices in LV networks, in part due to the predictability of the loads. It is also because of the large number of substations and feeders at this voltage level, would make it prohibitively expensive to deploy monitoring on the entire LV network. Because of this lack of monitoring data, assumptions are needed for some of the parameters of the network model.

This means that when analysing the impact of low-carbon technologies on LV networks and estimating the network capacity, it can quickly become complex to manage the different scenarios, settings, and results. Using the PowerFactory PSA tool it was possible to organise the project into different study cases, operational scenarios and network variations, to facilitate the analysis. Operational scenarios are used to store the demand parameters for the different loads and generators, whereas the network variations are used to represent the network at present and future installations. This feature is also used to differentiate between the customer phase connectivity allocation methods we tested in the study (see Section 6, i.e. assumed to be sequential ABC versus the field-based monitoring actual connection data).

Given that for the Osney Bridge secondary substation we had LV monitoring in place, the initial voltage at the transformer LV busbar was set to 1.065pu for all the study cases which was based on average voltage obtained from LV monitoring data. Secondary transformers usually have off-load tap changers so it was assumed that no active control of the voltage is possible at that point in the network[4]. Figures 11 and 12 illustrate the PowerFactory model set up at the substation and LV feeder levels respectively.

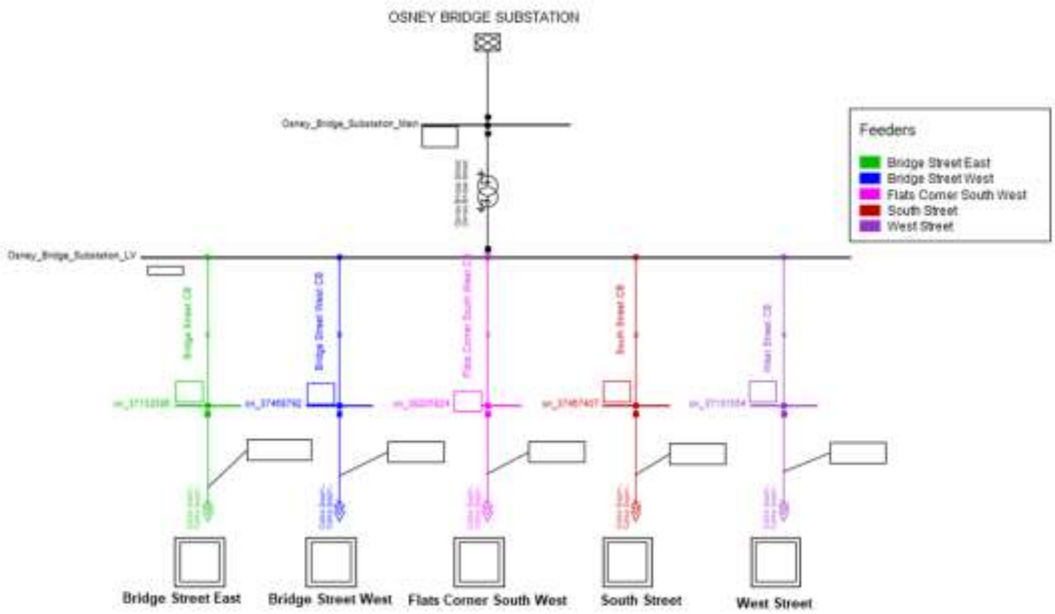


Figure 11. Overview of PowerFactory model at the substation level

[4] Upstream control of network voltage at the Primary 33/11kV substation would be present

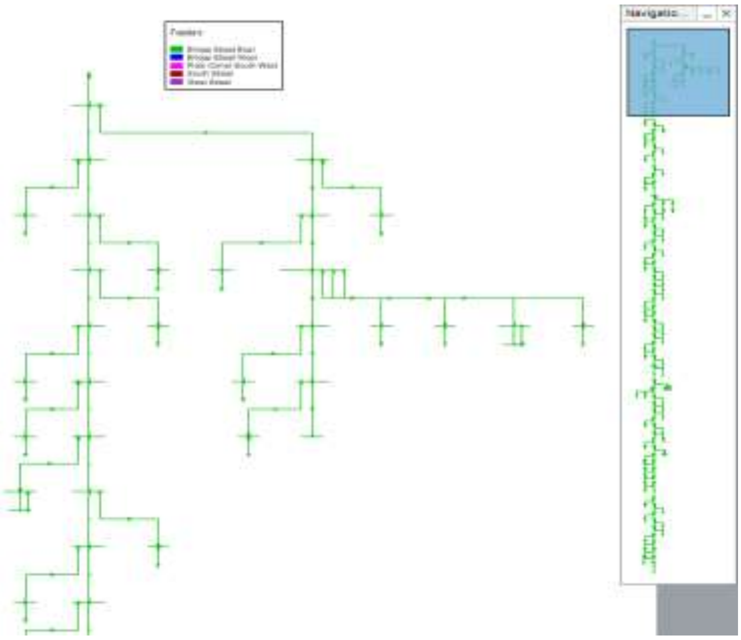


Figure 12. Overview of one of the LV feeders SLD in PowerFactory

Another benefit of PowerFactory PSA tool is that it has useful capabilities to make it easier to visualise the network model, for example by displaying the Single Line Diagram (SLD) of each individual feeder, as well as the results. The voltage across the network can be visualised in the SLD directly as a heatmap to make it easier to spot potential voltage issues linked to clusters of LCTs. An example of this is provided in figure 13. Finally, when looking specifically at the voltage, PowerFactory can easily produce voltage profiles, which plot the voltage with respect to the distance from the substation, making it easier to spot unacceptable voltage rises/drop. All these features were used to analyse the results coming from the Osney Bridge network model and are included in the following sections.

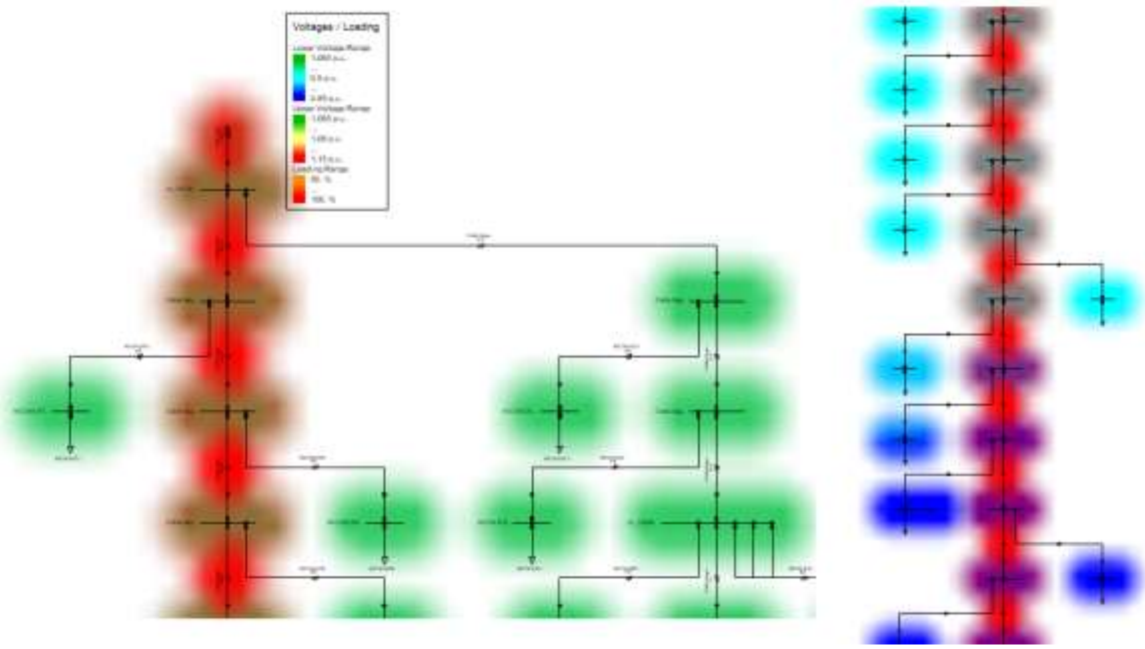


Figure 13. Example of the heatmap tool in PowerFactory for both voltage and loading.

8 Base case results with sequential phase allocation – Existing LCTs installed prior to Osney Supercharge

Two time period conditions were analysed as part of the modelling study, the base case of existing installations and the future installations as part of Osney Supercharge.

In terms of low-carbon technologies (LCTs), the base case considers the fact that some of the customers had rooftop solar PV already installed before the start of the Osney Supercharge project in January 2022, also the base case considers the Osney Lock Hydro, a run-of-river hydro generator with a 50kW capacity. The hydro generator exports most of the time during winter but very rarely during summer.

While a few of the participants in the Osney Supercharge trials have EVs and heat pumps, the first phase of this modelling work looked only at the impact of the solar PV installations. SSEN is aware that there is high interest in the area for installing additional solar PV generators, as well as batteries, to potentially establish a local energy market in the near future.

The base case included the 16 solar PV installations that had already been installed on Osney Island before the start of the Osney Supercharge project. These PV installations were located across all feeders and with particular clusters in the Flats in the SW corner of Osney Island and also on South Street. The modelling considered 2 scenarios:

- Loads at maximum demand with no solar PV generation (evening peak demand) – to make sure the voltage drop in the network was within acceptable limits;
- Loads at 50% of maximum demand with max solar PV generation (midday peak generation with low demand) – to check that the voltage rise lay within acceptable limits.

In the following plots in figures 14 to 22, the PowerFactory simulation, used these assumptions on loading, and generated the voltage profiles. In these graphs the vertical axis represents the voltage in per unit values, and the horizontal axis represents each of the terminals' distance from the secondary substation infeed in km. In the absence of generation, it is expected that the voltage will decrease in value with increasing distance from the terminal to the infeed.

In the first scenario (figure 14) with no solar or hydro generation on the Island, all the feeders are modelled to stay within the voltage drop limits with the exception of the longest feeder for Bridge Street East. The modelling indicated that the end of the Bridge Street East feeder which runs around to the north section of East Street is already at risk of low voltage levels. Hence, for the Bridge Street East feeder rather than additional DERs being viewed as a threat to network resilience in fact the addition of PV in combination with batteries might provide a network benefit in reducing the chances of low voltage issues. This is likely to be a challenge only increasing with time as Bridge Street East would provide the most significant challenge for the addition of additional domestic demand from heat pumps and EVs in the absence of installing additional local generation:

Osney Bridge Street – Max demand, no generation

Voltage profile for all feeders

- Overall voltage drop in all feeders
- All feeders stay within limits except for **Bridge Street East**
- Max voltage drop in Bridge Street East of 0.85pu (longest feeder)

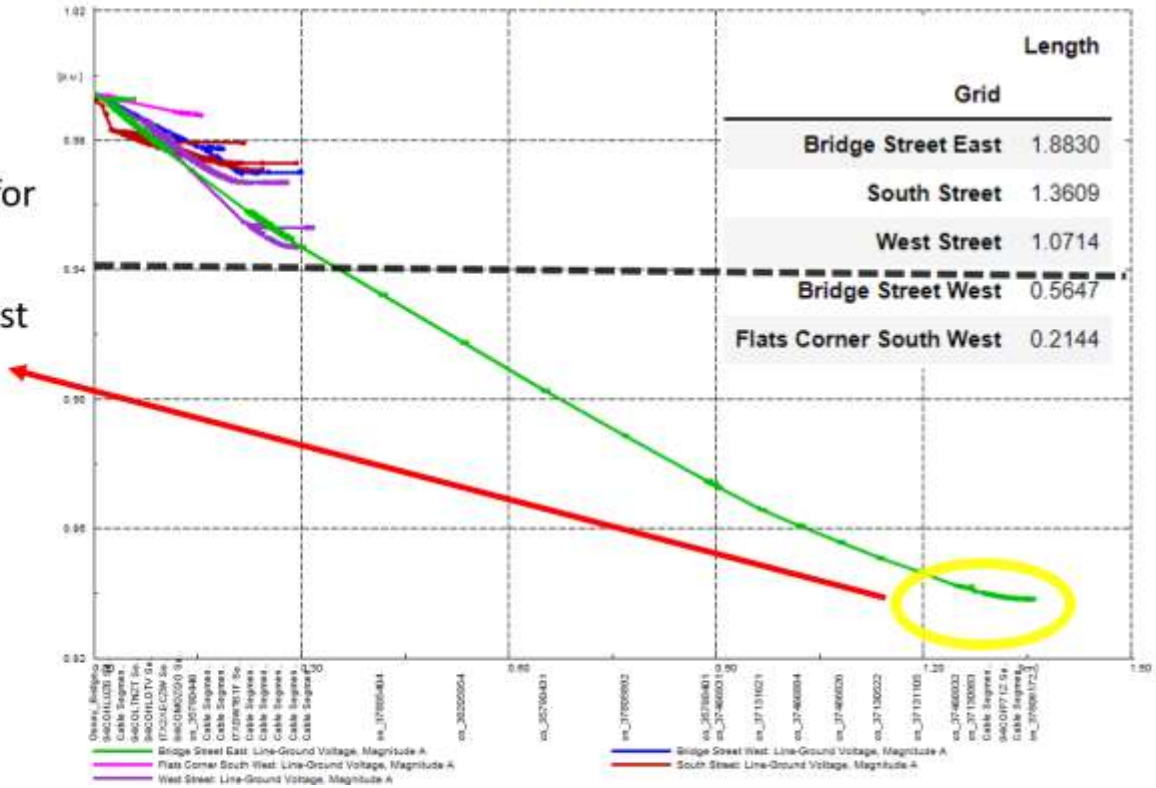


Figure 14. Voltage profile - Base case with maximum demand and no generation

Therefore, the first outcome from the modelling exercise was a recognition that this level of modelling could identify areas in the network where encouraging people to install PV and batteries could be used to overcome potential low voltage issues.

To see whether there were other areas of the Osney network that might suffer from high voltage issues if additional PV systems were installed we modelled a scenario with maximum generation and 50% demand which is regarded as the worst-case scenario for potential voltage rises with the existing solar PV installed on Osney Island (i.e., when the demand is low and the generation is at a maximum). Looking across all three phases in the initial modelling based on sequential phase allocation seemed to indicate that it was the South Street feeder with Osney Lock Hydro connected to it which might have higher voltages, though still well below the 1.1 pu limit – see figure 15.

Hence, despite initial concerns expressed on the potential network implication of installing additional PV and battery systems on Osney Island by the business as usual (BAU) team before the detailed energy system modelling was carried out the conclusions from the base case analysis were:

- Spreading solar PV across all feeders might be best for the network
- Installation for solar PV in Bridge Street East might be most suitable given the length of the feeder and existing voltage drop and would likely to be beneficial for network resilience by reducing low voltage issues at times of PV generation.
- For large demand loads such as EVs it might need smart mitigation strategies in Bridge Street East, especially at the end of the feeder
- Batteries could have a beneficial impact on regulating voltage drop/rise especially if installed close to (or in conjunction with) solar PV or EVs

Osney Bridge Street – Low demand, max generation

Voltage profile for all feeders

- Significant voltage rise in South Street
- Voltage drop in Bridge Street East of 0.94pu (longest feeder)

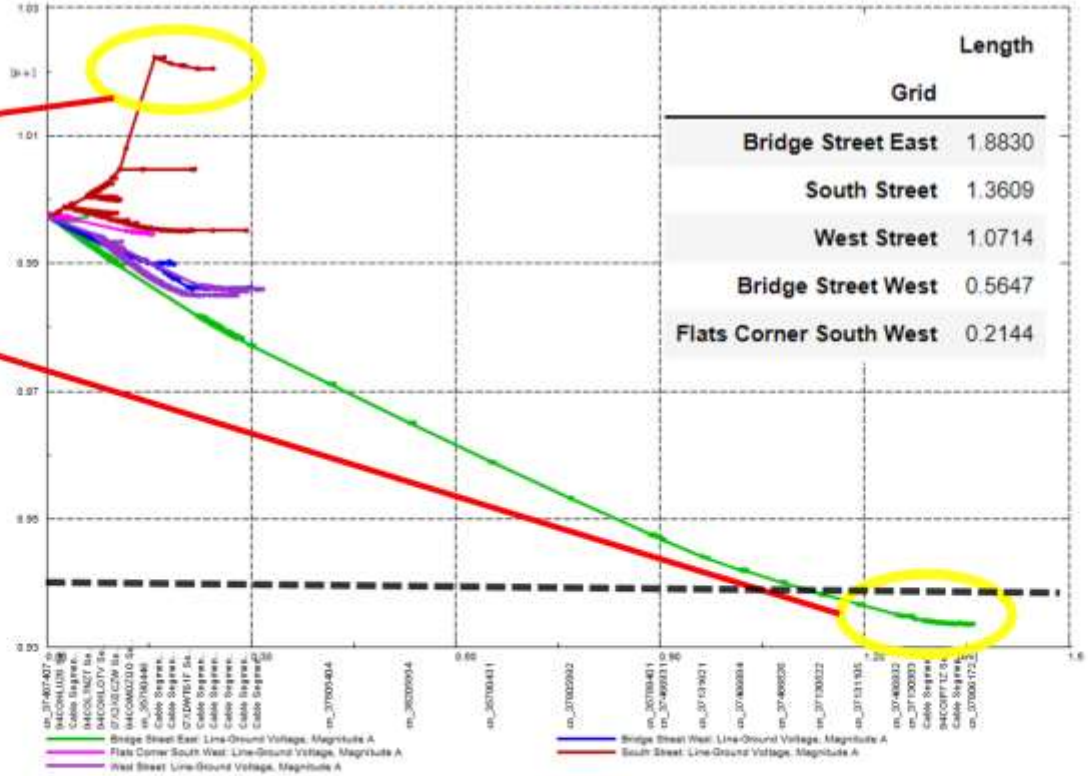


Figure 15. Voltage profile - Base case with maximum generation and low demand

9 Future installations results

The future installations options included the 16 solar PV installations that had been installed before the start of Osney Supercharge and then what the effect would be of adding an additional 17 or 27 future PV installations. No account was taken in the energy system model of whether the PVs were installed in conjunction with batteries. Similar to the base case, the future options were considered for two extreme load cases:

- Loads at maximum demand with no solar PV generation (evening peak demand) – to make sure the voltage drop in the network is acceptable
- Loads at 50% of maximum demand with max solar PV generation (midday peak generation with low demand) – to make sure the voltage rise is acceptable

Unsurprisingly, with no generation there was little impact on the Osney Island energy system with the long Bridge Street East feeder facing potential voltage drops (figure 16)

When maximum generation with 50% demand was modelled using the scenario of uniform allocation of phases then this showed that the low voltage issues on the Bridge Street East feeder were solved by the addition of the additional PV. A useful example of where additional of DERs can provide solutions to network issues – see figure 17.

Osney Bridge Street – Max demand, no generation

Voltage profile for all feeders

- Overall voltage drop in all feeders
- All feeders stay within limits except for **Bridge Street East**
- Max voltage drop in Bridge Street East of 0.85pu (longest feeder)

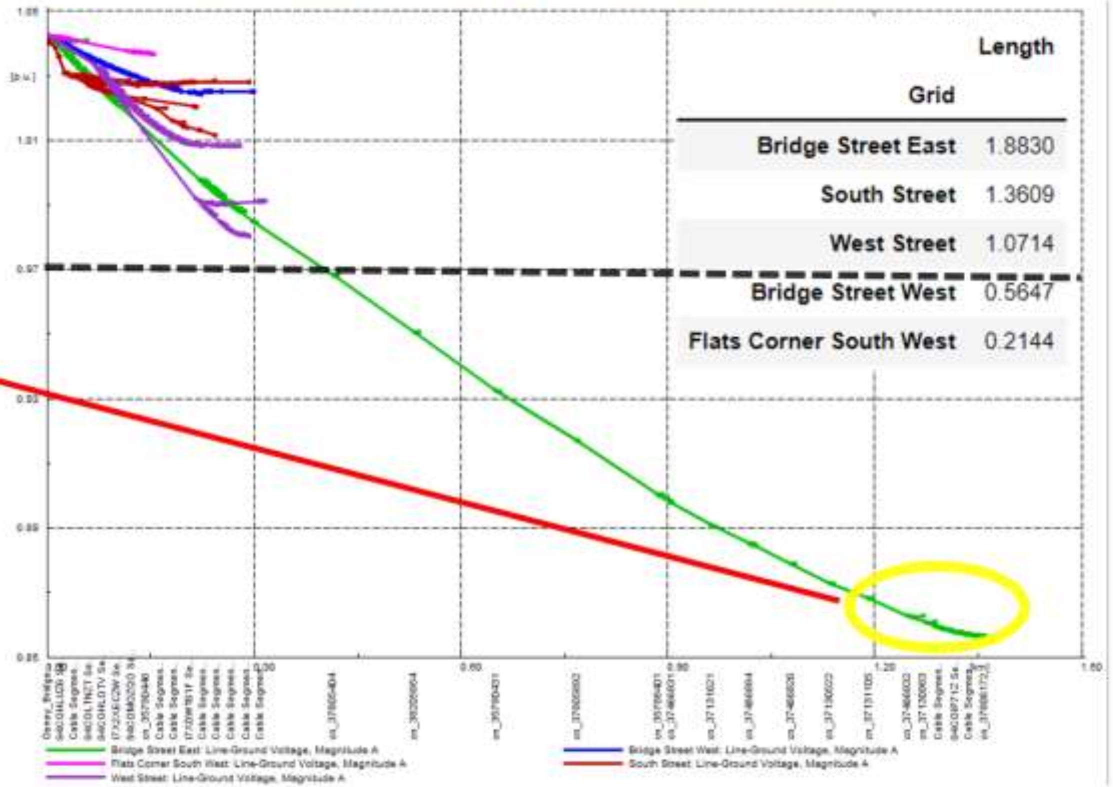


Figure 16. Voltage profile - Future case with maximum demand and no generation

Osney Bridge Street – Low demand, max generation

Voltage profile for all feeders

- Significant voltage rise in South Street
- Voltage drop in Bridge Street East of 0.97pu (longest feeder)

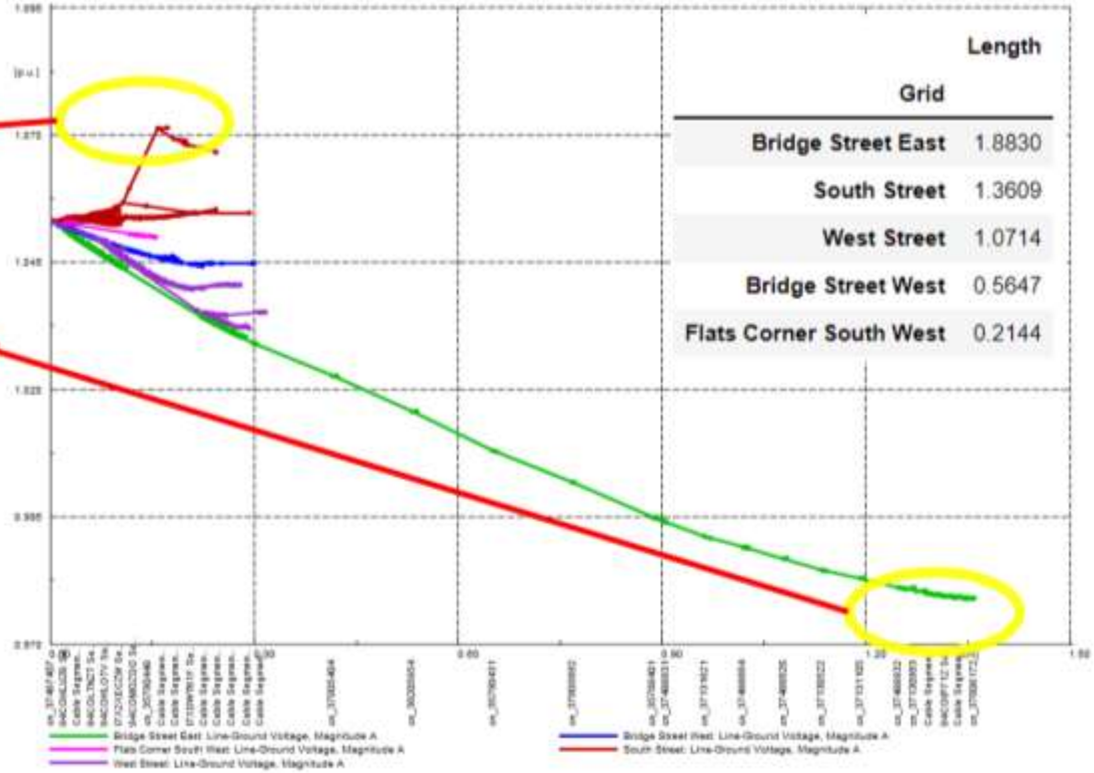
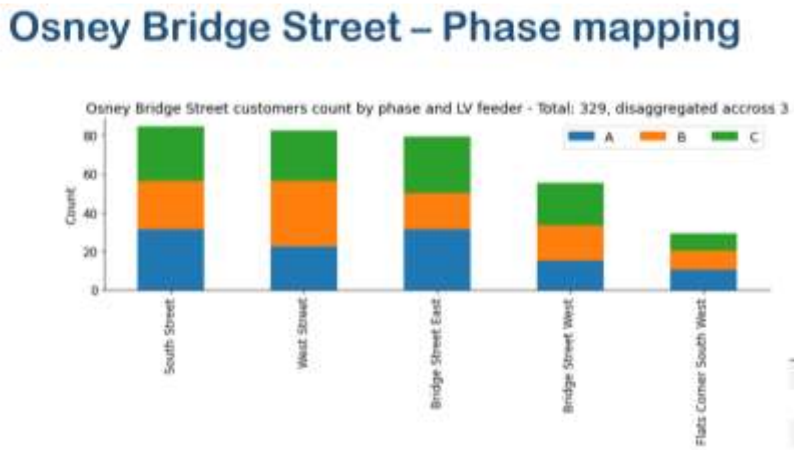


Figure 17. Voltage profile - Future case with maximum generation and low demand across all three phases assuming sequential phase allocation

A concern raised using the sequential allocation of phases the modelling indicated that additional PV would exacerbate the higher voltages seen on the South Street feeder getting closer to SSEN high voltage thresholds.

However, once the field survey data was collected (Figure 18) this was then incorporated in to the energy system model.



Phase_assigned	A	B	C	Total_cols
Grid				
Total	109	106	114	329
South Street	31	25	28	84
West Street	22	34	26	82
Bridge Street East	31	19	29	79
Bridge Street West	15	18	22	55
Flats Corner South West	10	10	9	29

Figure 18. Results of the field survey of phase connection showed that for 3 of the 5 feeders there were single feeders with around 40% of the homes connected to a single phase and some phases with as low as 24-27% of the homes connected to that phase.

Once the correct customer phase connectivity data was incorporated into the model this indicated that South Street was not likely to suffer high voltage issues. In addition to the HAYSYS phase measurements, initially we assumed the solar PV installed at a number of locations were single phase. This was later on corrected to be three-phase where real-world evidence indicated that to be the case.

Instead, this modelling with accurate customer phase allocation highlighted that there was the potential for a significant voltage rise to be observed in West Street (above 1.06pu) (Figures 19 & 20) even though there are only 4 modestly sized PV systems on the West Street feeder. This illustrates the fact that voltage issues are localised and can be influenced significantly by whether Distributed Energy Resources (DER) are distributed across the phases in a balanced way. Hence, adding new DERs have a disproportionate effect on some feeders over others and this can only be determined by detailed energy system models that are informed by real data and evidence from the field.

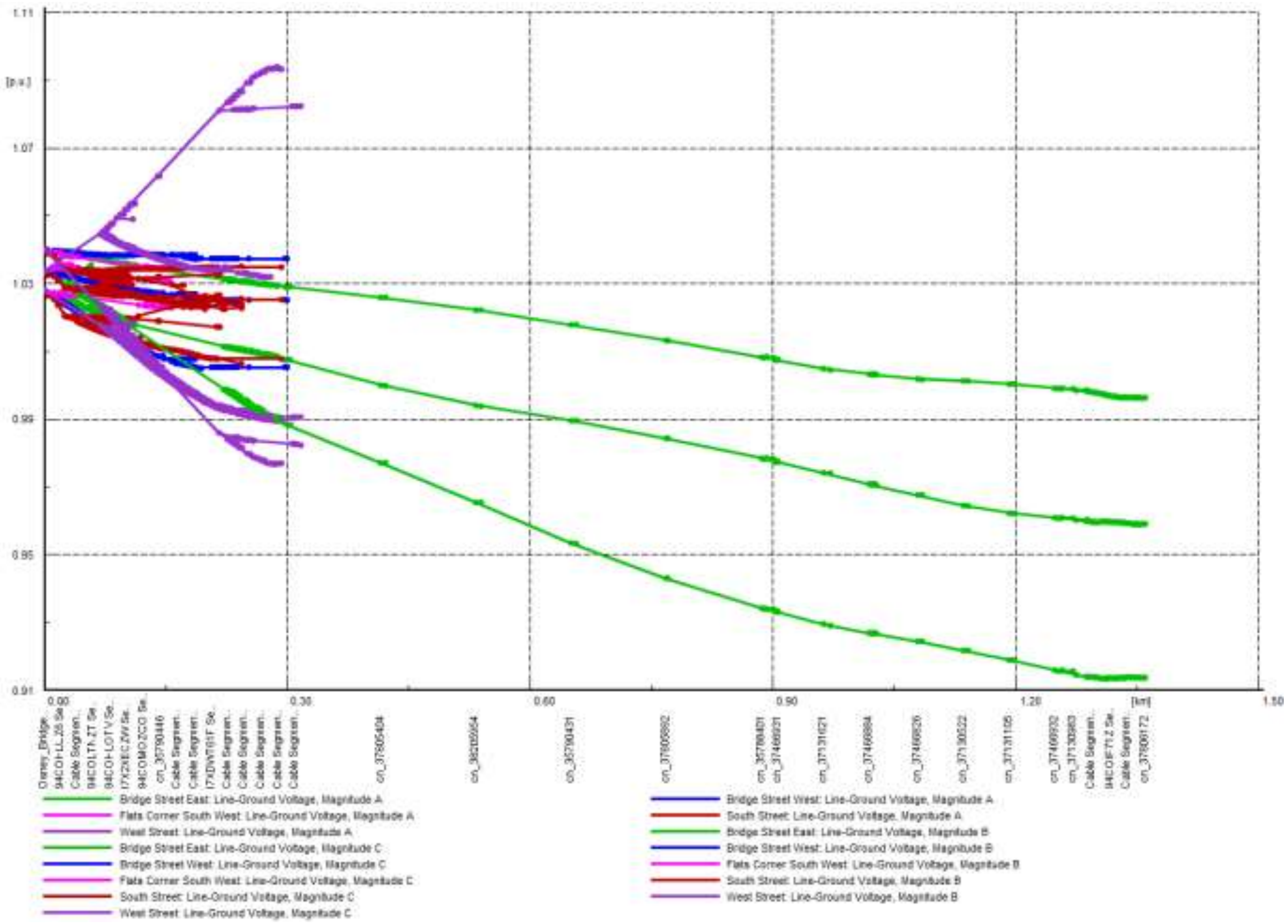


Figure 19. Voltage profile - Future case with maximum generation with 17 additional PV systems. The equivalent plot to figure 17 except here actual ground-truthed (rather than assumed sequential) phase connections were used in the energy system model

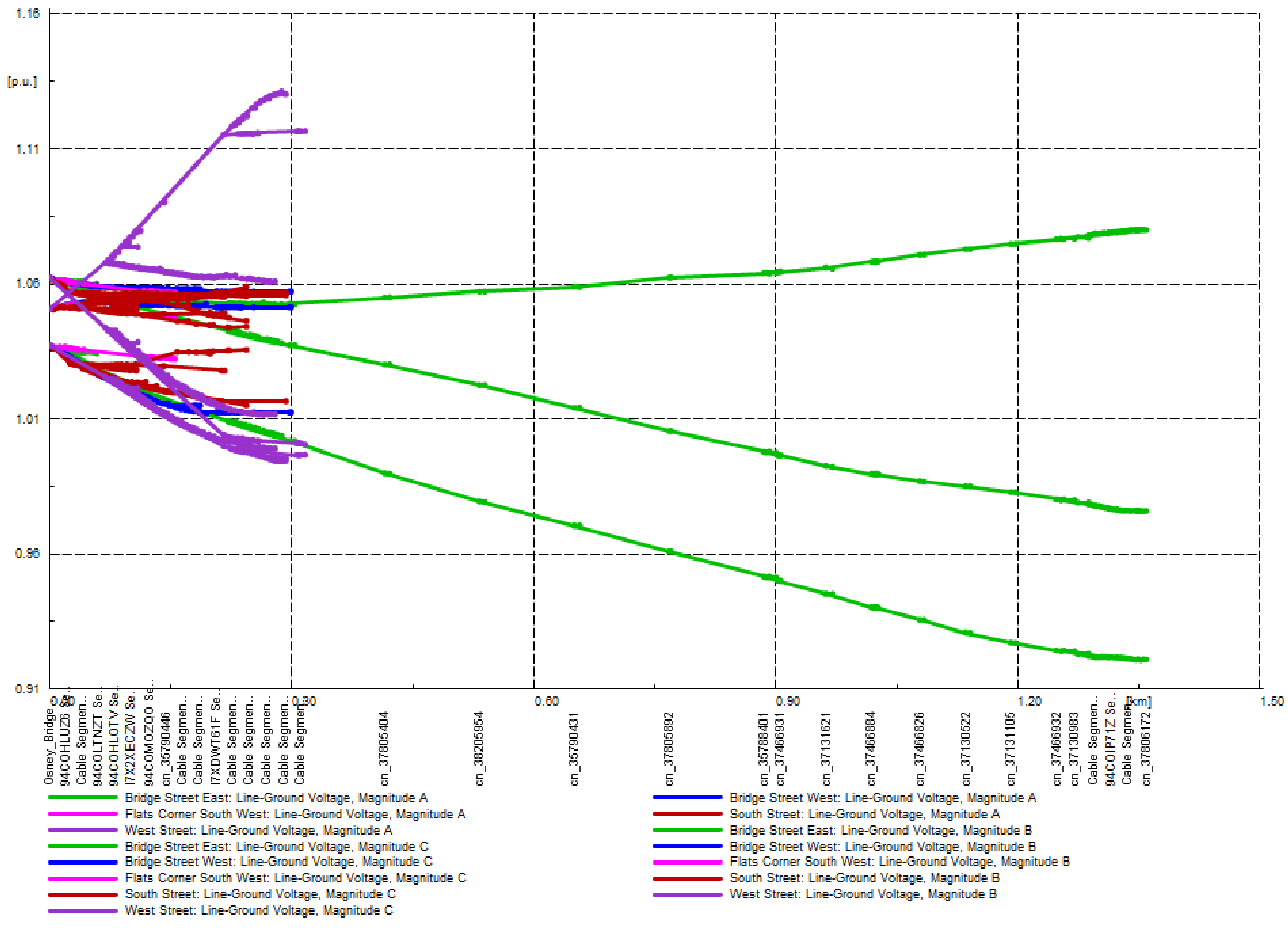


Figure 20. Voltage profile - Future installations case with maximum generation from 27 additional PV systems with ground-truthed phase connections.

With the additional 27 PV installations, the worst-case scenario for the solar PV (i.e., when the demand is low and the generation is at a maximum) resulted in a more pronounced voltage rise in West Street (above 1.1pu compared to 1.06pu without the additional 6 PV systems on West Street).

By contrast in Bridge Street East the low voltage issues have been resolved by the addition of PV systems on this long feeder.

Further detailed modelling of West Street (Figures 21 & 22) shows that of the 3 phases it is only one of the phases that is predicted to experience these high voltage issues. This again highlights the importance of ground-truthed accurate information on which phase each domestic property is connected to.

By contrast, the detailed modelling carried out using the accurate customer phase connectivity data for South Street showed that the potential concerns highlighted for high voltage issues in South Street from the maximum number of PV systems that could have been installed under Osney Supercharge would not be expected to materialise.

Due to the concentration of solar PV installation in the West Street feeder, some of the phases can see a very high voltage rise (outside of the allowable range) when solar PV is generating at peak and demand is low – this is a potential problem. One of the ways to avoid extreme voltage rises would be to spread the solar PV installations across multiple feeders, and across the different phases (i.e., avoiding clusters such as in West Street).

Conversely, solar PV installations in Bridge Street East might be most suitable given the length of the feeder and the existing voltage drop towards end of feeder. For large demand loads, such as EVs and heat pumps, it might be best to avoid Bridge Street East, especially the end of the feeder as the increased demand might worsen the voltage drop.

While this initial stage focused on solar PV installations, LCH is also considering deploying batteries. From the results, given that the network issues tend to occur when there is a lot of generation coupled with low demand, batteries could have a beneficial impact if installed close to (or in conjunction with) solar PV, and are able to store the surplus generation from solar PV for use later in the day.

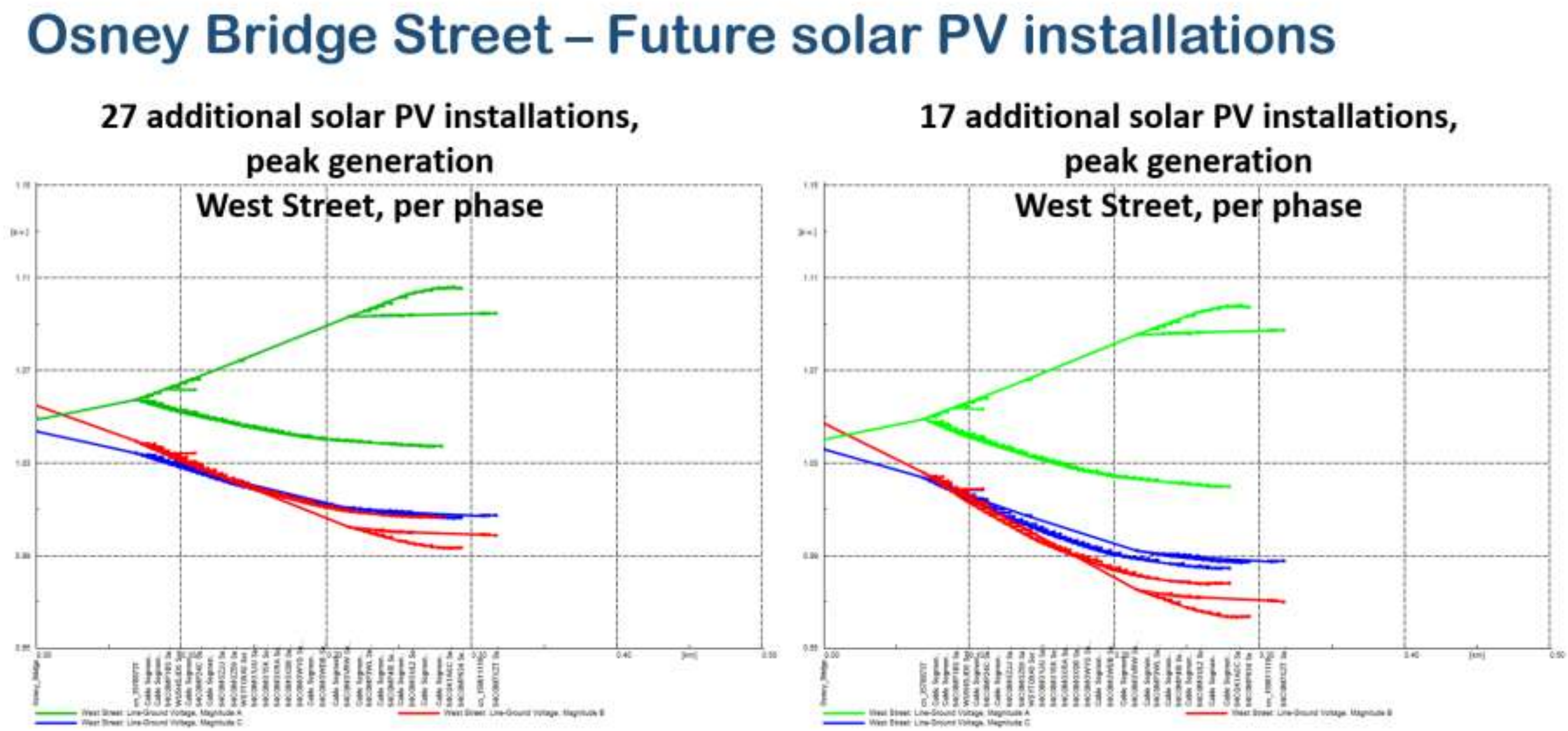


Figure 21. Voltage profile – Detailed modelling of West Street feeder with ground-truthed phase connections.

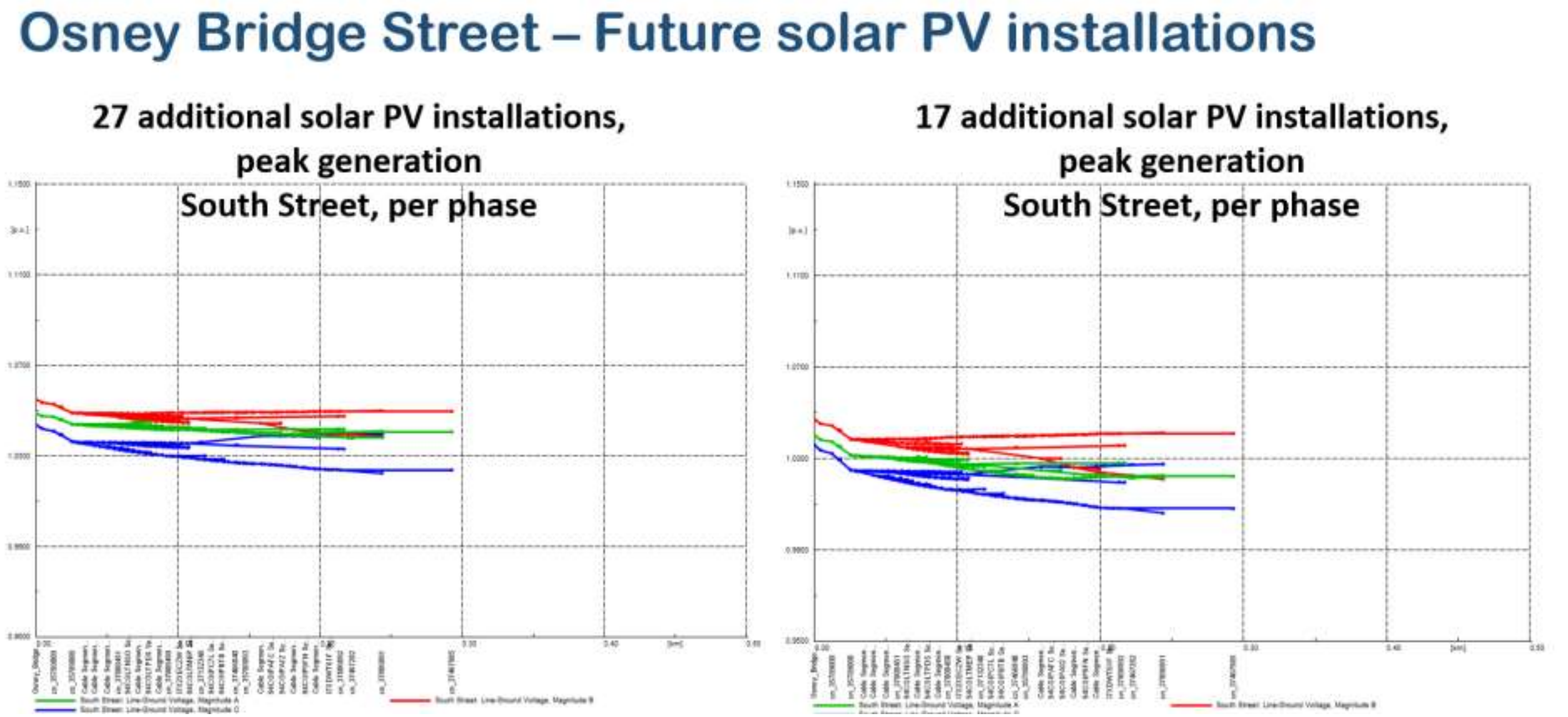


Figure 22. Voltage profile – Detailed modelling of West Street feeder with ground-truthed phase connections.

Important Modelling and Data Limitations Disclaimer

It's worth noting that the results and conclusions from these initial studies are based on a network model that has not been completely fully validated with all of the ideally required data on the network from the real world. For example, the exact LV network configuration has not been possible to validate in the timeframe of this study (e.g. where and how the LV network normally-open/switching points are configured in this area, impacting which customers are precisely on which LV feeders). Furthermore, the specific demand consumption and generation patterns of individual customers were not available, and hence broad-brush assumptions were derived based on the detailed steps outlined in the sections above.

All of these results in this report can be further improved by incorporating data from the actual/true demand and generation profiles, as well as locational voltage measurements by smart meters, combined with deeper investigations from the field on the network connectivity. This type of additional and improved data will likely be available to the DNO in the near future, to be able to then update the assumptions used in the PowerFactory model studies.

SSEN would not advise the preliminary conclusions of the studies in this report to be used to make any customer/community investment or connection decisions until the outcomes of such additional work is completed.

10 Key learnings

As part of this piece of work, SSEN explored the development of a workflow for building models for LV networks in a way that makes more efficient use of the GIS data available to SSEN and incorporates external datasets to augment the data where required.

One of the key learnings for SSEN involved testing the CIM functionality for modelling LV networks and understanding the data requirements, end-to-end processing and conversion required to make these extracts compatible with PowerFactory, the PSA tool chosen for the analysis.

Another key learning was the implementation of Python scripts for the automation of data input in PowerFactory, the creation of scenarios and the analysis of the results.

SSEN expects that these learnings can be used to further support customers looking to connect LCTs in other areas of the LV network and to serve as a starting point for the subsequent design of a local flexibility market in Osney Island.

11 Conclusions and next steps

Carrying out the detailed energy system modelling for Osney Island was invaluable in being able to identify the limited number of areas where installation of LCTs on the Island could potentially cause minor network issues at the level of adoption of PV and batteries by 10% of the population.

The modelling also highlighted that in other parts of Osney Island there is a potential benefit to actively encouraging the installation of both PV and battery systems to help keep the network within optimum voltage limits.

Evidence and real data from the field that was provided by the LCH SFN having the interaction with the individual households adding LCTs provided a visibility of the changes on the load on the LV network which is not normally accessible. That combined with the field-based engineering validation work carried out via the HAYSYS Phase Identification Unit (PIU) to identify which phase each household is connected to has provided a more detailed energy system model than is available anywhere else in the SSEN network.

This project serves to highlight the critical importance of an accurate picture of which phases households (and any businesses on single rather than 3-phase) are connected to. In the absence of actual data obtained from the HAYSYS device an assumption of sequential phase connection would have led decision-makers to view the South Street feeder as having potential grid constraints for further connection of PV systems. However, the modelling including actual phase connections served to illustrate that in reality South Street was likely not facing any such constraints.

By contrast the real world data identifying the phase imbalance across West Street spotlighted the need for the phase imbalance of DER connections to be addressed to prevent potential future grid constraints that would result from installing additional PV systems on one of the 3-phases on the West Street feeder.

Looking forward an important question to consider across our networks is “What is the minimum set of data, and accuracy, needed to produce results that can be used for decision making on whether and where to install a particular LCT, and whether there is a requirement for any limits in terms of total power import/export”. For example, do decision makers have to have complete information on: a minimum phasing of connections across the network area in question and supply point and service cable connectivity? Where are the areas that we can make assumptions on inputs to the network model and still be able to make robust decisions?

To answer these questions SSEN has already commenced further work on refinements of the network model to incorporate smart meter, time-series modelling, and LV monitoring to calibrate model outputs. This will allow us to identify other factors (in addition to the importance of using accurate phase connection data which we identified in this first stage) which are the most important in order to make informed decisions on what elements of the network infrastructure will need to be reinforced and when.

Now that the base energy system model is in place it provides an ideal platform to model future scenarios of the steps required for Osney Island to reach Net Zero. It will allow us to assess what level of LCT adoption can be managed within the existing network infrastructure through priority siting and dynamic control.

By working back from net zero scenarios for the Island also allows us to establish the network infrastructure required for net zero. This could enable Osney Island to be the first secondary substation area in the UK to have a network upgrade plan that works back from a network infrastructure that meets the requirements of net zero, rather than working forward in incremental steps to avoid acute network constraints.

Appendix A: Indicative location of existing and possible future solar PV systems

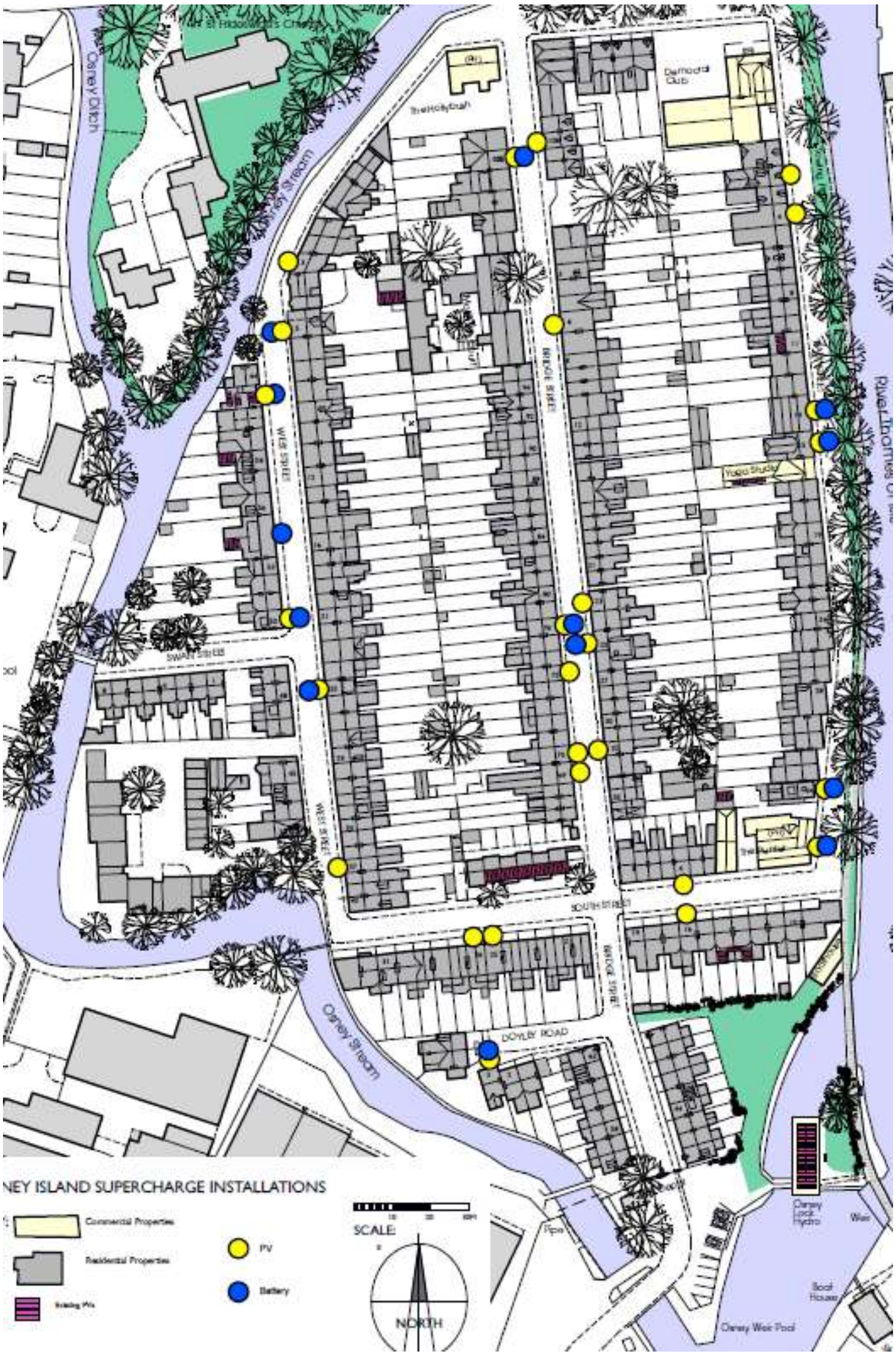


Figure 23. Planning diagram provided by LCH – indicative/rough locations only