WESTERN POWER DISTRIBUTION

INNOVATION

NEXT GENERATION NETWORKS

LOSSES INVESTIGATION

CLOSEDOWN REPORT

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Contents

Executive Summary

Distribution Network Operators have an obligation to operate efficient and economic networks. As such the effective management of distribution losses is important. This project aimed to further our understanding of technical losses on the high voltage (HV) and low voltage (LV) distribution network and provide information to subsequently help us manage them in a cost effective manner. The project should also be seen in the wider current context that anticipates, at least the medium term, existing network utilisation (and consequential losses) will rise with greater adoption of low carbon technologies (e.g. vehicle charging).

The project approach has been to install monitoring on 22 HV and LV feeders, and then to develop methods of assessing technical losses on non-monitored HV and LV feeders using minimal additional monitoring. The monitored feeders provided corroborated actual feeder loss information to further our understanding of technical losses, and acted as a control group for testing alternative methods of assessing losses.

A key outcome of the project has been that methods have successfully been developed to assess losses on HV and LV feeders that require no more monitoring information than is available through business-as-usual channels. These methods are based on power flow calculations for individual feeders, using feeder-specific topology and high time-resolution load models over a one year period. These methods have been calibrated against the monitored feeders, and agree well with losses calculated using the full monitoring data.

In addition, the developed methods have been successfully applied to over 75% of the HV and LV feeders in the East Midlands license area, involving over 71,000 network and load feeder models. The project has therefore demonstrated the feasibility of widespread feeder-specific assessment of losses and has created detailed information characterising losses on HV and LV feeders in the East Midlands.

On average, mean HV feeder losses were found to be 1.47% of delivered power, and LV feeder losses were assessed as 1.06% of delivered power. A significant spread in the level of loss was seen between individual feeders. For HV feeders, results potentially point to higher loss feeders that can be reviewed with a view to reducing loss levels.

For LV feeders, the project has provided further evidence that WPD’s recent policy of installing larger capacity LV mains reduces losses by approximately 17% (compared to previous custom and practice) with an increase in the life-time costs of the installed cable of only 1%, taking installation costs into account.

This demonstrates that DNOs can use business-as-usual data to assess technical HV and LV losses. From such a baseline (assessing losses of real HV and LV feeders), the impacts of future load growth can be tracked. The effects of changes in network planning policies on losses and their associated costs can also be quantified.

The project has spent £1.98m, 80% of its budgeted value excluding contingency, and deduced the learning set out in this report.

1 Project Background

Distribution Network Operators have an obligation to operate efficient and economic networks. As such the effective management of distribution losses is paramount. Previous estimates put the annual losses at between 5.8% and 6.6% of energy delivered[1] (for all voltage levels) worth approximately £900 million across the UK. Approximately two thirds of this loss (£640 million) occurs after transformation down to 11kV.

Some improvements with clear cost benefits across the network are being rolled out, as outlined in WPDs Losses Strategy; however these have limits due to a lack of detailed understanding in the variation of losses across our network. As such, reductions in losses on existing network cannot be targeted on a feeder specific basis and the network cannot be fully optimised. Without a detailed baseline characterisation of losses on individual feeders, it is also difficult to track changes in losses as future demand grows, such as with the uptake of electric vehicles, or to quantify the benefits of changes in the network planning policy.

The Losses Investigation NIA project aimed to:

1. Quantify technical losses on samples of LV and HV network through the application of load monitoring equipment; and
2. Establish loss assessment approaches, using a minimum necessary additional information set, which can be widely applied to HV and LV networks.

The project started in April 2015, and was originally due to be complete by December 2017, reporting March 2018. The project has been extended (see Section 6), with field and analysis work completed in January 2019, and decommissioning, reporting and dissemination work completing by the end of April 2019.

Key phases to the project were:

1. Project mobilisation, partner selection and establishment of appropriate project agreements;
2. Initial laboratory testing of proposed load monitoring equipment, and establishment of loss assessment methodologies and calculations;
3. Field testing of proposed equipment, installation, data collection, and assessment methods for one pilot HV network, and one pilot LV feeder;
4. Installation of monitoring to selected HV and LV feeders;
5. Assessment of Losses on monitored HV and LV feeders;
6. Development of loss assessment methods for HV and LV feeders, using minimum additional information sets; and
7. Demonstration of the loss assessment methods for HV and LV feeders.

[1] "Management of Electricity Distribution Network Losses" IFI report

2 Scope and Objectives

This project aimed to further our understanding of technical losses on the distribution network and help us target them in a cost effective manner. The project was focused on technical losses on the HV and LV networks; losses in the following areas were not included: above the HV feeder circuit breaker; beyond the meter, and non-technical losses.

Objective	Status
Understand technical losses on the LV and HV network	✓
Determine the minimum information to accurately predict network losses	✓

Table 1 – Status of Project Objectives

3 Success Criteria

The established success criteria reflected the basic project approach. Each criterion has been successfully completed, and they are shown in Table 2. Further substantiation of this is contained in Section 5 and in Section 9.

Success Criteria	Status
1) Construction of fully monitored HV and LV networks	✓
2) Measurement of network losses on monitored feeders	✓
3) Accurate modelling of losses with full information	✓
4) Several models with limited data sets created and tested	✓
5) Conclusion on level of information needed to accurately predict losses	✓

Table 2 – Status of Project Success Criteria

4 Details of Work Carried Out

The project approach has been to:

- Install monitoring to 22 HV and LV feeders;
- Calculate and analyse loss results from recorded data for the monitored feeders;
- Establish and demonstrate methods of assessing losses on non-monitored feeders, testing the methods against data and results from the monitored feeders; and
- Apply the loss assessment method to a large proportion of the HV and LV feeders in the East Midlands license area.

The following sections describe what has been done against each of the above elements, and include details of how it has been done.

4.1 Monitoring on HV and LV feeders

4.1.1 HV feeders

Monitoring has been installed on 11 HV feeders in the Milton Keynes area of WPD's East Midlands license area. These feeders provided examples of short highly loaded cable feeders serving urban feeders with commercial and industrial loads, sub-urban mixed domestic and commercial serving feeders, and longer overhead rural feeders largely serving domestic loads. The upstream power flow on the monitored feeder is measured at a 33/11kV Primary Substation, and the downstream power flows are monitored with equipment installed at each of the Distribution Substations served by the feeder. An overview of the installed monitoring arrangement for HV feeders is shown in Figure 1. The downstream sensors (established Lucy GridKey LV substation monitoring devices) are installed on the LV side of the distribution transformers. The end-to-end losses measured in this trial therefore include the 11 kV feeder cable and the 11 kV to LV Distribution Substations.

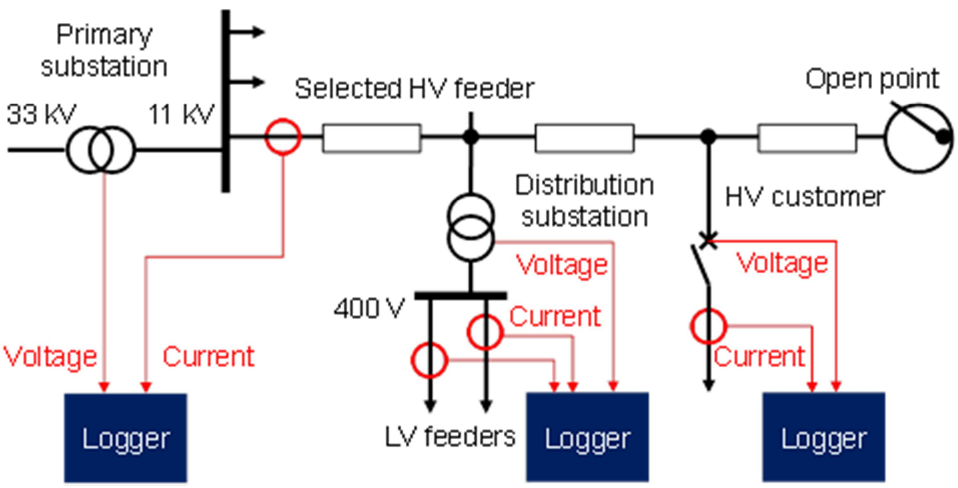


Figure 1 Schematic of HV feeder monitoring

The Lucy GridKey devices are all based on the MCU520 type, utilising split ring CT with integral burden resistor for the Primary and HV monitors, and Rogowski coils for the distribution substation monitors. The GridKey loggers record the following quantities for each feeder and for each phase:

- Busbar current amplitude
- Feeder current amplitude, mean, minimum and maximum
- Phase angle
- Line-to-neutral voltage amplitude
- Active power
- Reactive power
- Active energy
- Reactive energy
- Active harmonic content
- Reactive harmonic content

Values are averaged over 1 minute period. The current averaging uses an RMS algorithm to determine the current amplitude of individual waveform cycles, but the averaging over a 1-minute period then uses an arithmetic mean of these RMS values. The GridKey does not provide any voltage phase information.

All of the GridKey loggers are re-synchronised once per day to a GPS clock source. However, the timing accuracy between the synchronisation events depends on the internal clock so slight timing differences can remain.

The Primary Substation monitoring is provided by a new HV variant of Lucy Gridkey's substation monitoring equipment. This was developed by Lucy GridKey specifically for the project and features a segregated power supply that is independent of the voltage monitoring inputs. A schematic of the connection arrangements for monitoring of an 11kV primary feeder is shown in Figure 2.

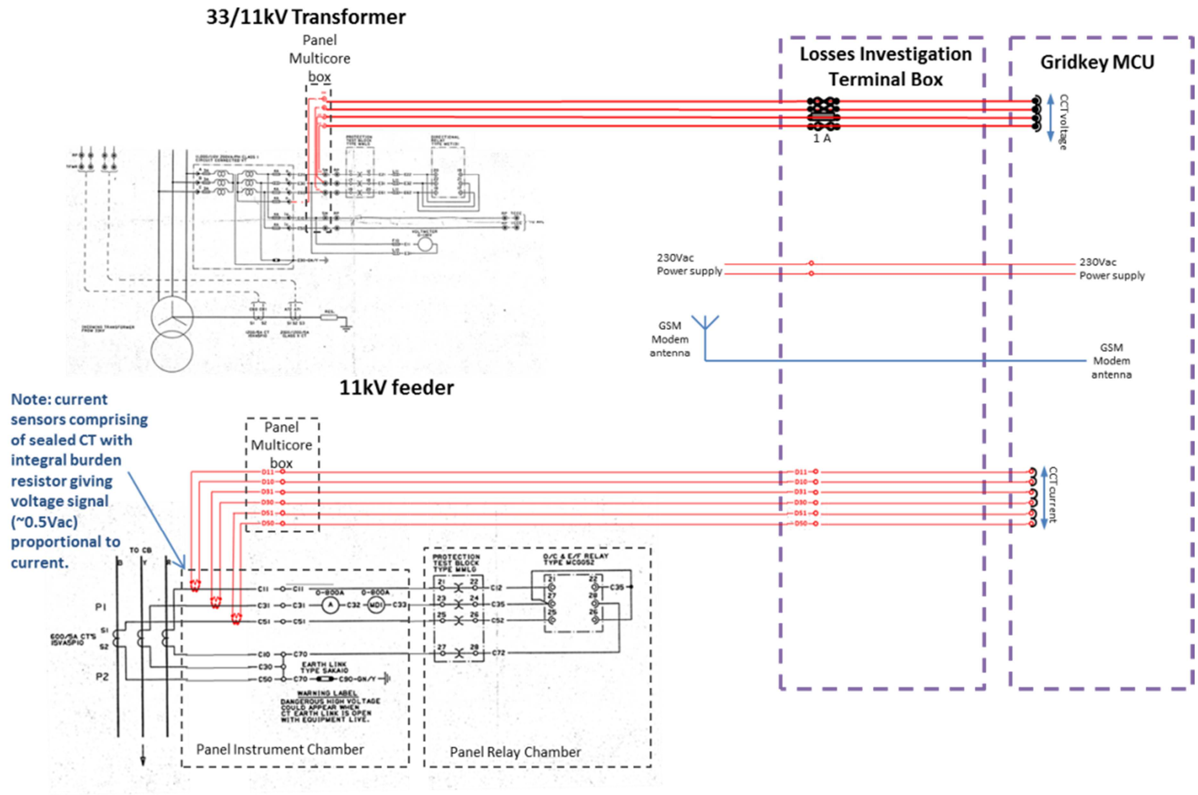
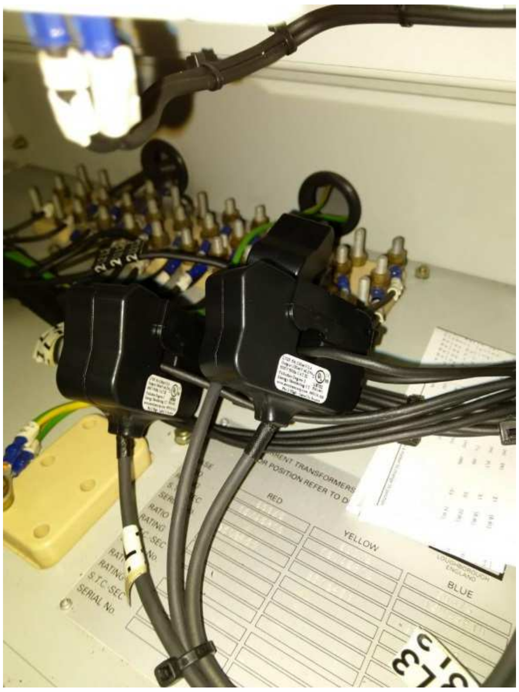


Figure 2 Schematic of monitoring at 11kV primary feeder

Examples of equipment installed at a primary substation are shown in Figure 3.

GridKey HV monitor



Current sensors on monitored 11kV feeder.

Figure 3 11kV primary feeder monitored installed equipment

The HV Lucy GridKey monitor was also used at HV customer connections; a schematic of connection is shown in Figure 4.

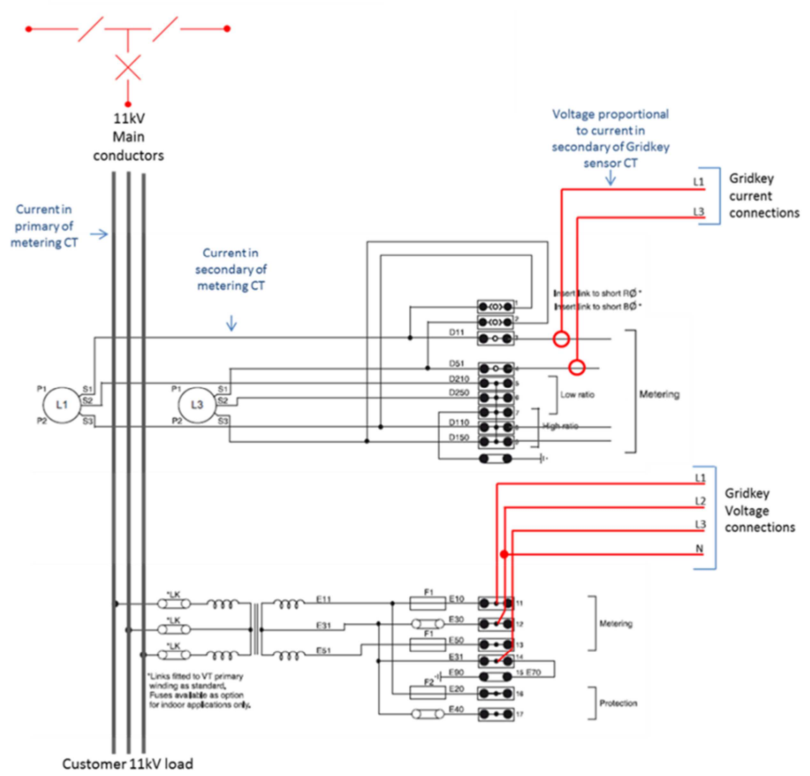


Figure 4 Schematic of monitoring at HV customer connections

Monitoring at distribution substations utilised the established Lucy GridKey MCU520 LV monitoring devices. Work was undertaken to further develop the mounting and connection arrangements for monitoring pole-mounted transformers. Examples of installed overhead equipment are shown in Figure 5.

Lucy GridKey MCU 520 monitor at a pole mounted transformer

Internal arrangements of pole mounted transformer monitoring cabinet

Figure 5 Pole mounted distribution transformer monitoring installed equipment

An example of a monitored HV feeder network is shown in Figure 6 consisting of 23 network nodes, with node 0 (not labelled) being the Primary Substation.

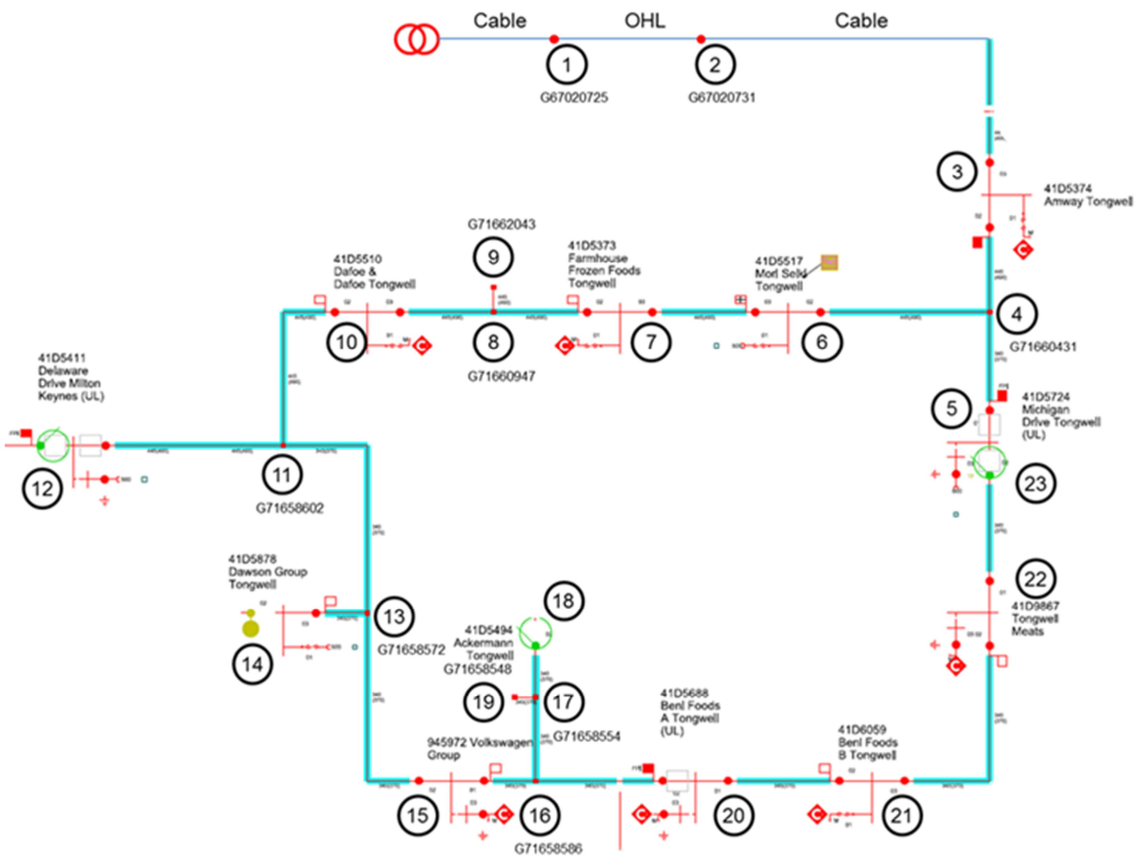


Figure 6 Amway Tongwell HV feeder

Nodes 1 to 17 represent either Distribution Substations or junction nodes in the HV cable. Normal Open Points, where the feeder inter-connects with another HV feeder, are shown in green. In some cases, such as node 3, the Distribution Substation is supplied by the monitored feeder. Conversely, the Distribution Substation at node 10 is on the opposite side of the Normal Open Point and so is served by a different HV feeder.

Instrumentation for this feeder was therefore required at the Primary Substation, and at all of the Distribution Substations served by the feeder. There were a number of occasions during the monitoring programme when the network configuration was temporarily changed and the feeder may have supplied other Distribution Substations that were not fitted with instrumentation. These ‘outage’ periods were detected by the consistency tests described below, and removed from the analysis.

A summary of monitored HV feeders is shown in Appendix A.

4.1.2 LV feeders

The monitored LV feeders are located in the Isle of Man and monitoring undertaken in collaboration with Manx Utilities Authority (MUA). MUA provided an ideal partner for this work due to their vertically integrated structure (including distribution, metering and supply), with network design and assets representative of UK distribution networks. These feeders provided examples of domestic cable feeders, commercial and industrial cable feeders, and overhead feeders, largely serving domestic customers. Upstream power flow to the LV feeders is monitored on the LV side of the distribution transformers (using established Lucy GridKey Distribution Substation monitoring), and smart meters (of a type not previously used in the Isle of Man) are installed at each customer point of connection to monitor downstream power flow. The monitoring included public lighting (either as individual lights or groups of lights) and other utility connections such as water pumps and telecoms cabinets). An overview of the installed monitoring arrangement for LV feeders is shown in Figure 7.

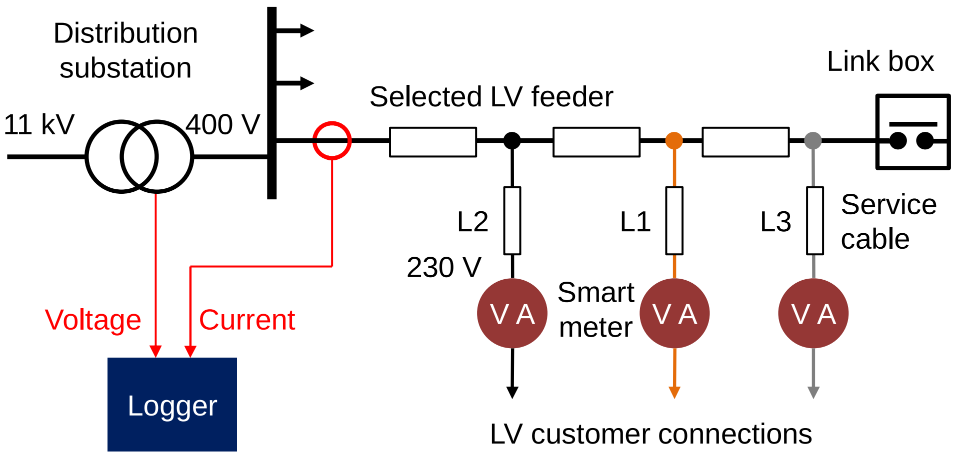


Figure 7 Schematic of LV feeder monitoring

Measurements at customer locations used EDMI meters. For three-phase supplies Mk10A meters were used, as either whole current meters, or for higher demands with CTs. For single phase supplies, Mk7C meters were used. The meters were configured to record the following quantities:

- Current amplitude, mean, minimum and maximum;
- Voltage amplitude;
- Phase angle;
- Active power;
- Reactive power;
- Apparent power;
- Current THD; and
- Voltage THD.

The clocks of the EDMI meters were synchronised to a GPS clock reference once per day when data was downloaded. This uses a different process to the GridKey logger so timing offsets can still occur.

An example of a meter installed at commercial premises is shown in Figure 8. In this instance, the three-phase project meter has been installed in series with the existing revenue meter.

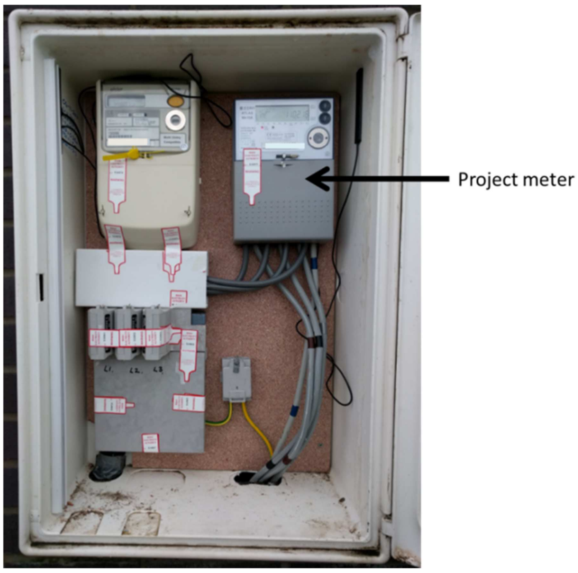


Figure 8 Installed three-phase meter at commercial premises

The measurement data is stored as one minute averages within the monitoring equipment and then collected periodically by GPRS-based data connections. For the smart meters, the number of measurement points (e.g. power, voltage, current, averages, maximums, minimums etc.) and the selected time resolution of the measurement data defines the volume of data collected and requiring transmission. This volume is constrained by the memory size within the instruments and the time/resource needed to download the data. For both the HV and LV feeders, resolution of 1 minute has been selected, so as to minimise any errors in estimating the losses due to under-sampling the time variation of the demand. The number of meter measurements points has been consequentially selected to make maximum use of device memory.

A further point to note is that the power measured at the customer connection point is that which is delivered to the customer, excluding the self-consumption of the billing meter. Accordingly, the internal circuit of the meter has a connection to the power supply that is upstream of the current measurement sensor. The meter therefore correctly measures the energy delivered to the customer. However, the small amount of energy needed to power the meter is not included. The consequence of this is that the internal power requirements of meters must be appropriately taken into account when calculating feeder losses.

Figure 9 shows an example LV feeder. This feeder has a GridKey logger at the Distribution Substation and EDMI meters at each downstream customer connection. For the purposes of the trial, the set of customer connections include public lighting circuits (not normally metered) in order to ensure that all current entering or leaving the feeder were monitored.

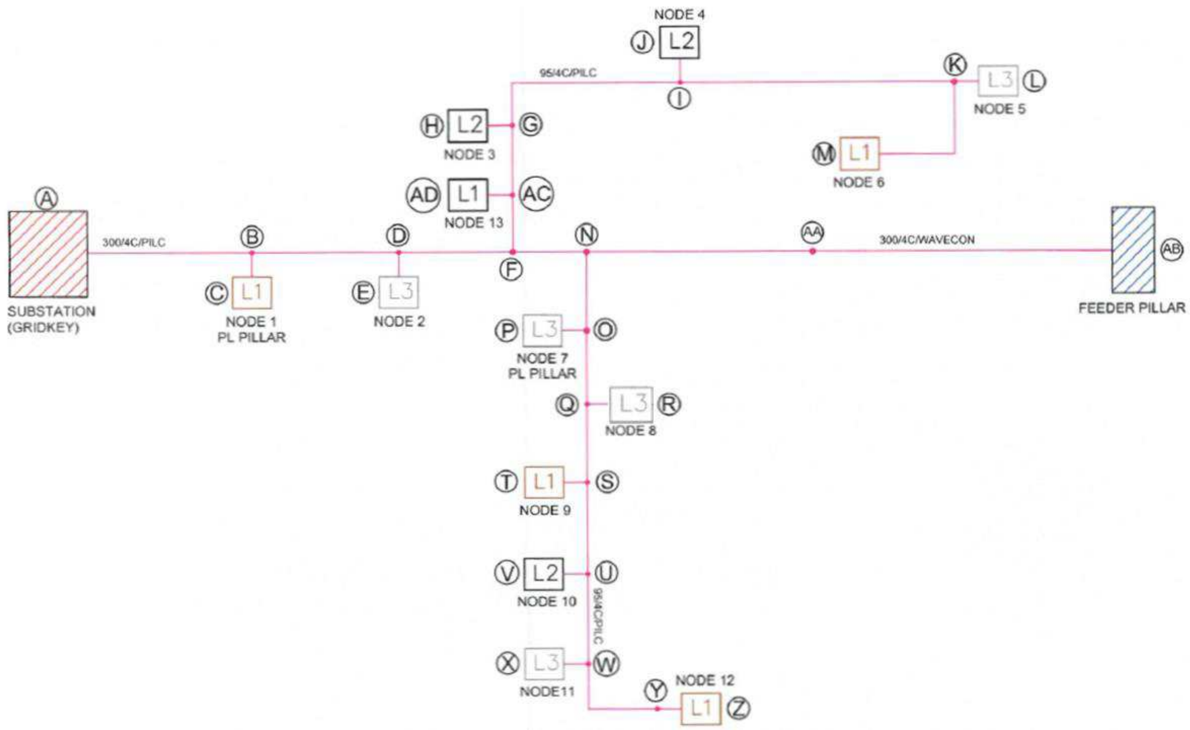


Figure 9 Pilot LV feeder

Data describing the network topology, branch lengths and cable types was compiled from network records. These network records were manually checked for the monitored feeders to ensure the accuracy of the loss analysis. The phase allocations of single-phase meters on the LV feeders were also checked and verified using the current consistency tests described below in Section 4.2.2 (Page 17).

A summary of monitored LV feeders is shown in Appendix A.

4.2 Calculation of losses for monitored HV and LV feeders

4.2.1 Calculation methods

The collected data from monitored feeders has been forwarded to Loughborough University for analysis of the losses. Two loss analysis methods have been used on monitored feeders:

- calculation of the losses based on the power difference between the single upstream power flow and the total downstream power flows on the network; and
- calculation of the losses using an I^2R method primarily based on current measurements at each downstream point on the networks. Additional information is needed for use with the I^2R method in order to specify the resistance of each network branch and to define the connection topology such that the currents on the un-monitored branches within the network can be calculated. The load losses and no-load losses of the transformers must also be specified.

The power difference method has the advantage that the network can be treated as a 'black box' function and no knowledge of the internal impedances or transformer functions is required. The power difference method also naturally takes account of the power drawn by the meters. However, there is consequently no visibility of the breakdown of losses within the network and so this method cannot be used directly to apportion losses to different cable branches or to the load-losses and no-load losses of the transformers.

Further disadvantages of the power difference method are that the calculated losses have been found to be highly dependent on: the measurement tolerances of the current and voltage sensors used in the measurement equipment; and synchronism of measurement time periods across different instruments.

The power difference method is also highly sensitive to errors if one or more nodes are omitted from the monitoring installation. If such circumstances were not recognised, then the unmonitored demand would appear as a contribution to the technical losses.

The alternative I^2R approach is to measure the current at feeder entry and exit points and then to use knowledge of the network topology and the impedances to calculate the losses. The current is measured at each of the downstream nodes and the voltage is measured at the upstream node. The currents in each of the network branches that are internal to the network are then solved using a forward/backward sweep power flow method. For HV feeders, this method includes a model of the distribution transformer in which the additional currents due to the shunt impedances are added. The method for LV feeders takes account of the power drawn by customer meters (for LV feeders). The losses can then be calculated using an I^2R calculation for each cable set and transformer for HV feeders, and for each cable and meter set (for LV feeders).

One limitation of the I^2R approach is that an average value of current (over the one minute monitoring periods) is used to calculate loss power. Given that power is a current squared relationship, variation of current from a constant nominal average value during the one minute period will lead to an under-estimate of loss power. The error due to this effect is lower in upstream branches of the network where the supplied demand is more aggregated and where the current variation is less spikey. The selection of a one minute resolution aims to minimise this error, within the practical constraints imposed by the capabilities of the logging instruments and the communications links for data transfer. With the 1 minute measurement resolution, the impact of this effect in the more heavily loaded network branches is likely to be less than 3% of the mean losses for LV feeders and less than 1% of the mean losses for the HV feeders. The impact will be greater in cables where the demand is less aggregated, although the magnitude of the losses in these cables is lower than in the heavily loaded branches.

Further details on loss metrics, measurement tolerances, time synchronism, metering losses, the application of the two methods to HV and LV feeders, and validation against IPSA (for HV feeders) and DEBUT[2] (for LV feeders) are given in Appendix B.

[2] DEBUT is EA Technology's LV network design software. WinDEBUT™ is the "Windows" desktop interface to the underlying DEBUT software.

4.2.2 Consistency check

HV feeder current consistency checks

The current at the substation can be obtained from the Gridkey measurement data and also by calculating the sum of the currents measured at each Distribution Substation. This summation is computed as an output from the load flow analysis in which the measured currents and voltages for each load are phase-rotated so as to be consistent with the voltage phase differences along each branch of the network.

The measured and calculated Primary Substation currents agree closely and the comparison is shown in Figure 10 as the percentage difference between the calculated and measured values, agreeing to within ±1%.

This successful consistency check demonstrates: that the current monitoring includes all entry and exit points on the network; and that measurements between different instruments agree to within the tolerances of the individual instruments. It is worth noting that this consistency test proved extremely useful during monitoring installation and commissioning, with examples shown in Section 9.1.

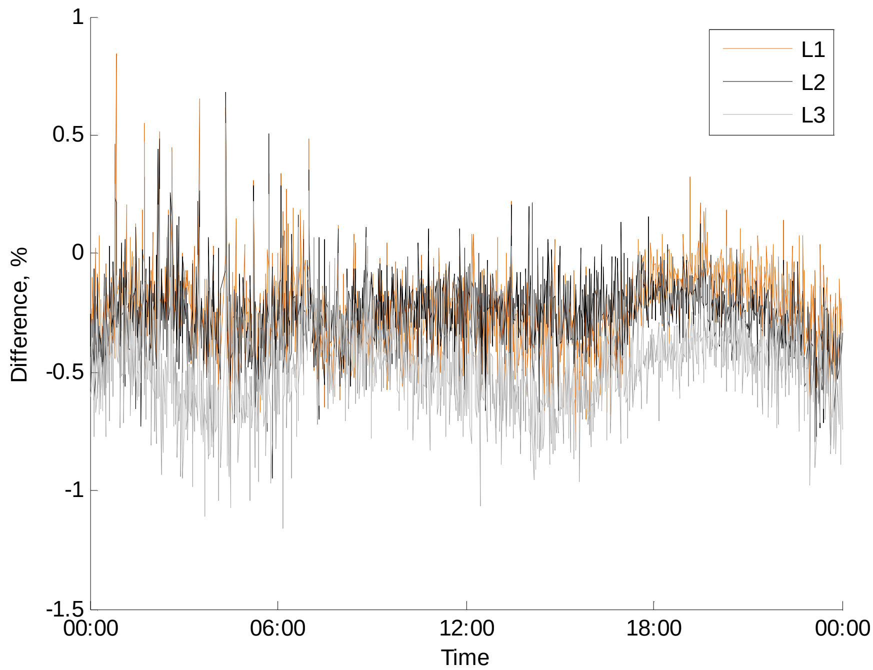


Figure 10 Difference between calculated and measured substation current, 28th March 2016

HV feeder voltage consistency checks

The voltages at the Distribution Substations can be obtained from the GridKey measurements and can also be calculated from the power flow analysis. These are compared here in terms of the percentage difference between the calculated and measured voltages, as shown in Figure 11. This shows an example of the voltage differences measured on the LV side of the distribution substation on the Woodlands feeder. The voltage differences for other nodes and other days are similar.

Over the full set of Distribution Substation nodes, the calculated LV voltages differ by a range of 0% to 0.6% from the measured LV voltages. These voltage consistency checks demonstrate that the calculated voltages agree to within the expected measurement tolerances for the primary substation and distribution substation GridKey loggers.

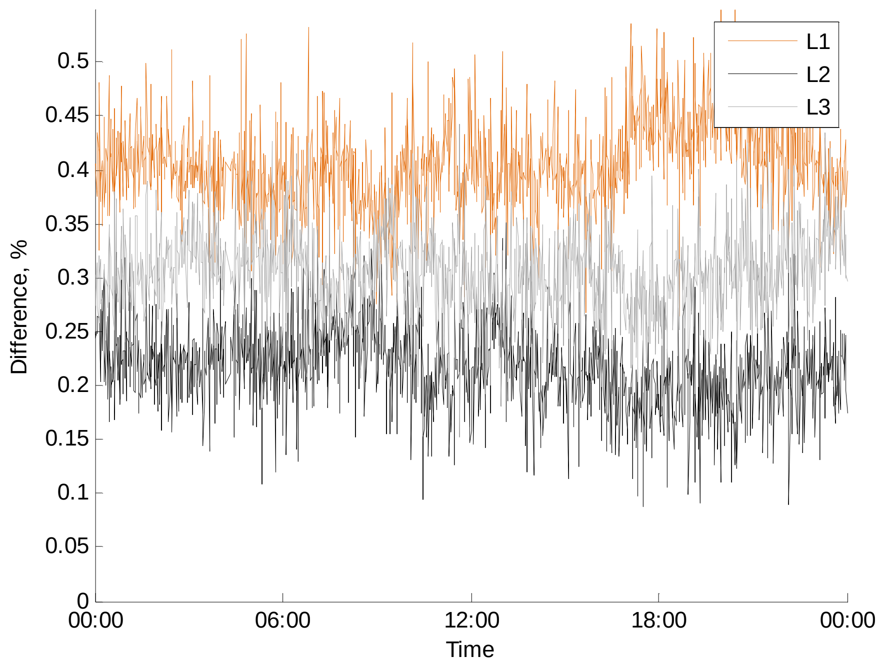


Figure 11 Difference between calculated and measured Distribution Substation voltage on Woodlands feeder, 28th March 2016

LV Feeder current consistency checks

As with the HV consistency analysis, the current at on the LV side of the distribution transformer can be obtained from the GridKey measurement data and also by calculating the sum of the currents measured at each smart meter for the loads.

This comparison of measured and calculated currents has been used to detect any loads on the network that have been omitted from the instrumentation, or alternatively, loads that have been included in the instrumentation but were in reality served by other feeders on the far side of a link disconnection box. The comparison also allows for the phase allocation of single-phase loads to be verified. If this is not configured correctly in the network model then the calculated current will be less than the measured current on one phase, but higher on another.

The measured and calculated substation currents for each phase are shown for a 24 hour period in Figure 12. The plots show that the calculated and measured currents generally agree to better than 1%, although there are greater differences for periods when the demand is rapidly varying. This is to be expected if the instruments are not synchronised exactly. For example, a load switching on for a period of 1 minute could appear as a single spike in one measurement period or could appear with a reduced amplitude and spread over two adjacent measurement samples. If the calculated current spike is slightly delayed relative to the measured current, this would create a negative difference between the currents on the leading edge and a positive difference to follow, as seen towards the left of Figure 12.

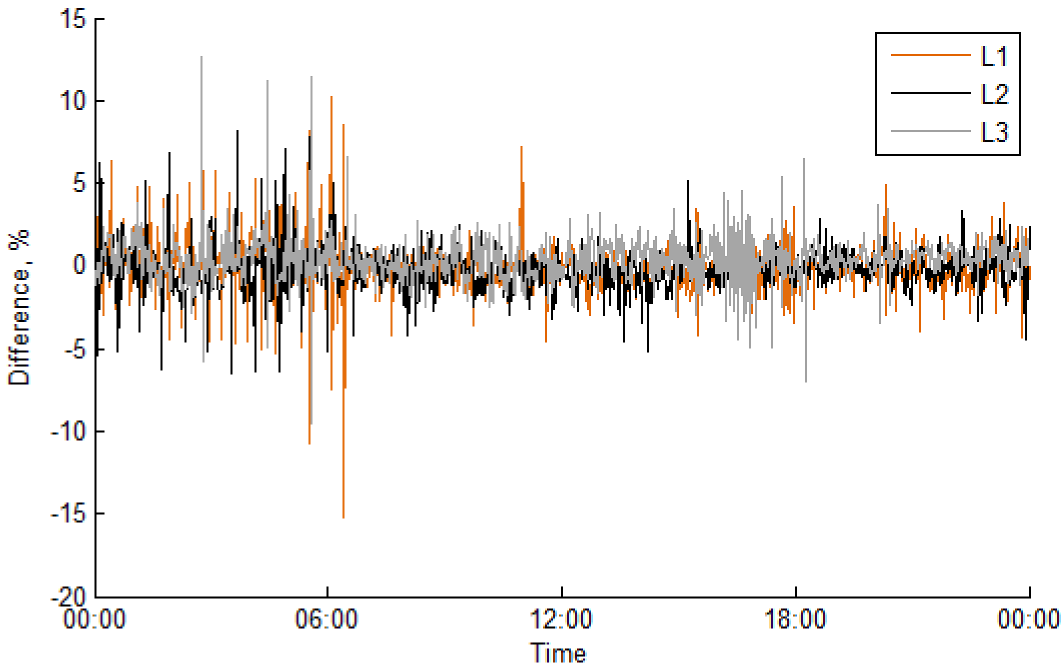


Figure 12 Difference between calculated and measured substation current phases L1, L2 and L3

LV feeder voltage consistency checks

The voltages at the customers' points of connection can be obtained from the EDMI meter measurements and can also be calculated from the power flow analysis. These are compared here in terms of the percentage difference between the calculated and measured voltages, as shown in Figure 13. This shows the voltage differences for a customer on phase L1 at the end of the Pilot trial feeder on 27th March September 2017.

In general the voltage differences are within 1% and so consistent with the expected range based on the instrumentation tolerances.

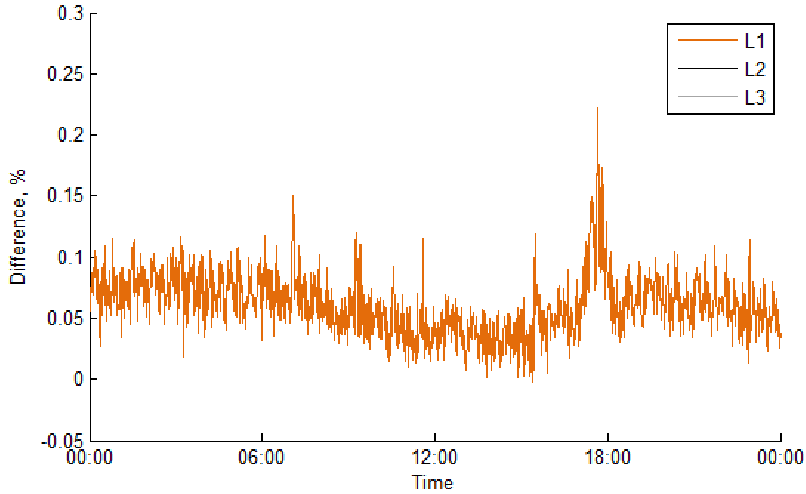


Figure 13 Difference between calculated and measured substation voltages for a load on phases L1

4.2.3 Demand for monitored feeders

HV feeder demand at Distribution Substations

Losses vary as the magnitude of the demand varies, but also depend on whether the demand occurs on substations that are near to the Primary, or towards the end of the feeder. The monitoring results show significant differences between the demands at each distribution substation, as indicated in Figure 14. (The substations numbers in this figure correspond to the node locations shown in Figure 6.) This plot also highlights the differences in reactive power observed for each substation. Notably, there are a number of substations where the mean reactive power is negative.

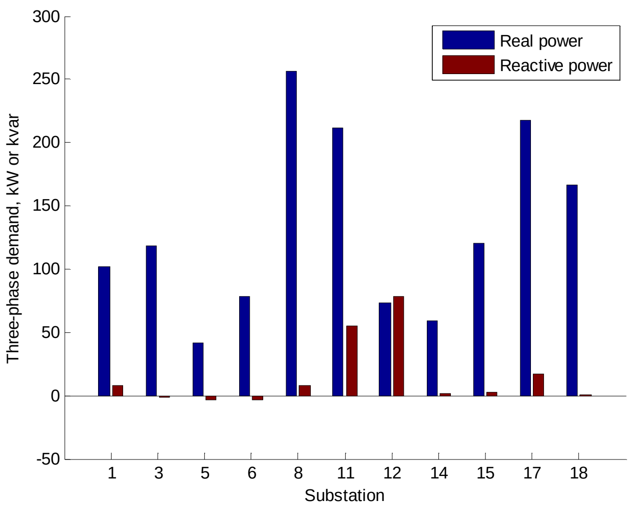


Figure 14 Mean demand for Distribution Substations on Woodlands HV feeder

LV feeder demand at customer meters

A similar plot is shown in Figure 15 for the load connections on the LV feeder. Again, there is significant variation in the mean demand for different customers. There are also a number of loads with a negative mean reactive power (capacitive) demand.

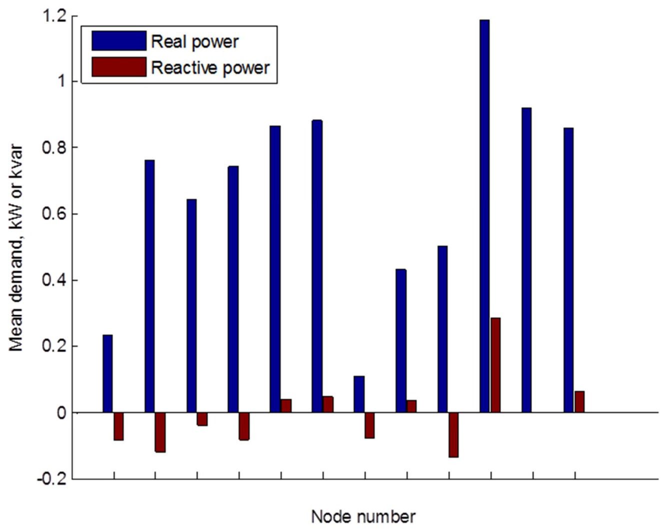


Figure 15 Mean demand for meter connections on Pilot LV feeder

4.2.4 Losses for monitored feeders

HV feeder losses

Losses were calculated using the power difference and I^2R methods for all the monitored feeders using 1-minute sample periods. The power difference results are more vulnerable to measurement sensor tolerances. These tolerances can cause losses to be consistently over- or under-estimated depending if, for example, the current sensor at the Primary Substation reads too high. The power difference results are also more widely spread due to the slight timing differences between the GridKey loggers. Note: differences between the two assessment methods are believed to be associated with measurement sensor tolerances because current balances were achieved, as discussed in Appendix B.4.

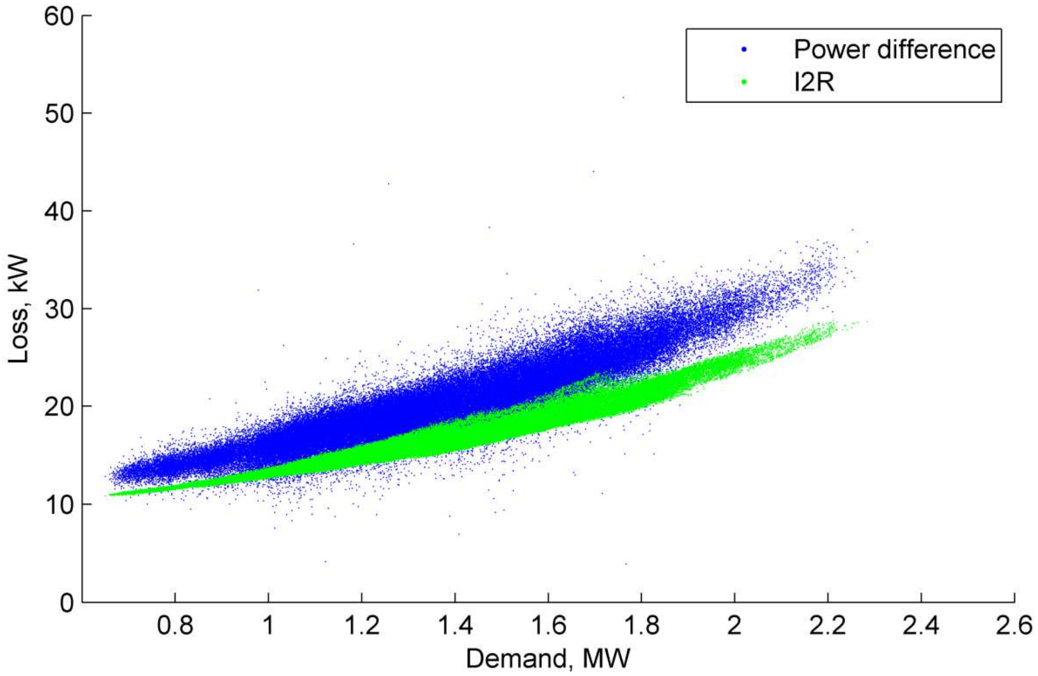


Figure 16 Loss vs demand for 1-minute samples on Woodlands HV feeder

The mean losses over 1 –year measurement duration have been summarised for the monitored feeders, showing the breakdown between cable losses and transformer losses, as in Table 3.

Analysis method	I^2R	Power difference
Mean primary demand, MW	1.19	1.19
Mean network input power, MW	1.19	1.19
Loss power, kW	15.0	17.9
Loss percentage, %	1.26	1.51

Feeder Component	Losses, kW	% of total
HV feeder losses	2.6	17.1
Substation load losses	3.0	20.0
Substation no-load losses	9.4	62.9

Table 3 – Mean losses over 1-year measurement for Woodlands HV feeder

LV feeder losses

Losses calculated at the 1-minute resolution for the LV feeders show a much greater spread for the power difference method. The LV demand has much more spikey characteristic than the HV demand and so is more affected by timing differences between the monitoring instruments. This can cause negative losses to be indicated where power is recorded as being supplied in one sample period and delivered in a later period.

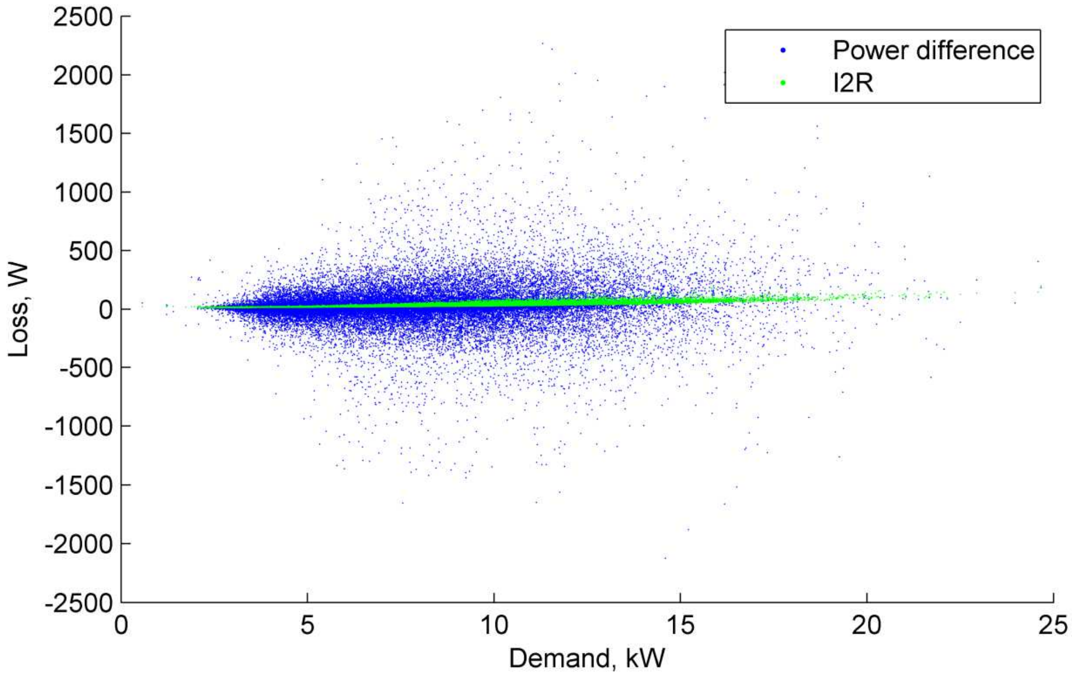


Figure 17 Loss vs demand for 1 minute samples on Pilot LV feeder

The mean losses over 1 –year measurement duration for the pilot LV feeder are shown in Table 4. The results show the loss contributions in mains cables, service cables, and due to the self-consumption of the meters. In this particular example there are only 13 customers and large cable sizes so the means losses are very low. More generally, the losses in the cables are higher than those due to metering.

Analysis method	I^2R	Power difference
Mean substation demand, kW	7.73	7.45
Mean network import power, kW	7.89	7.61
Loss power, W	31.4	23.7
Loss percentage, %	0.40	0.31

Feeder Component	Losses, kW	% of total
LV main cables	8.7	27.8
Service cables	8.4	26.7
Public lighting cables	0.0032	0.01
Metering	14.3	45.5

Table 4 – Mean losses over 1-year measurement for Pilot LV feeder

4.3 Methods for assessing losses on non-monitored HV and LV feeders

The methods developed for calculating losses at a regional scale, typically for a full operating license area, are referred to here as Loss Assessments. The requirements are different for HV and for LV feeders and so there is both an HV loss assessment method and an LV loss assessment method.

Both of these methods are implemented in software tools. The HV loss assessment software consists of a tool written in Python that acts as a data handling interface to the business-as-usual data sources and also implements the network discovery algorithm. A further HV feeder assessment tool is written in Matlab that performs the power-flow analysis. The LV loss assessment software combines all of these three functions into Python code.

4.3.1 HV feeders

An outline of the finalised assessment method is shown in Figure 18 where inputs to the process are shown in blue and the output (estimated losses) in green. Bold lines indicate time-series data for the demand and loss analysis which has a half-hourly time resolution.

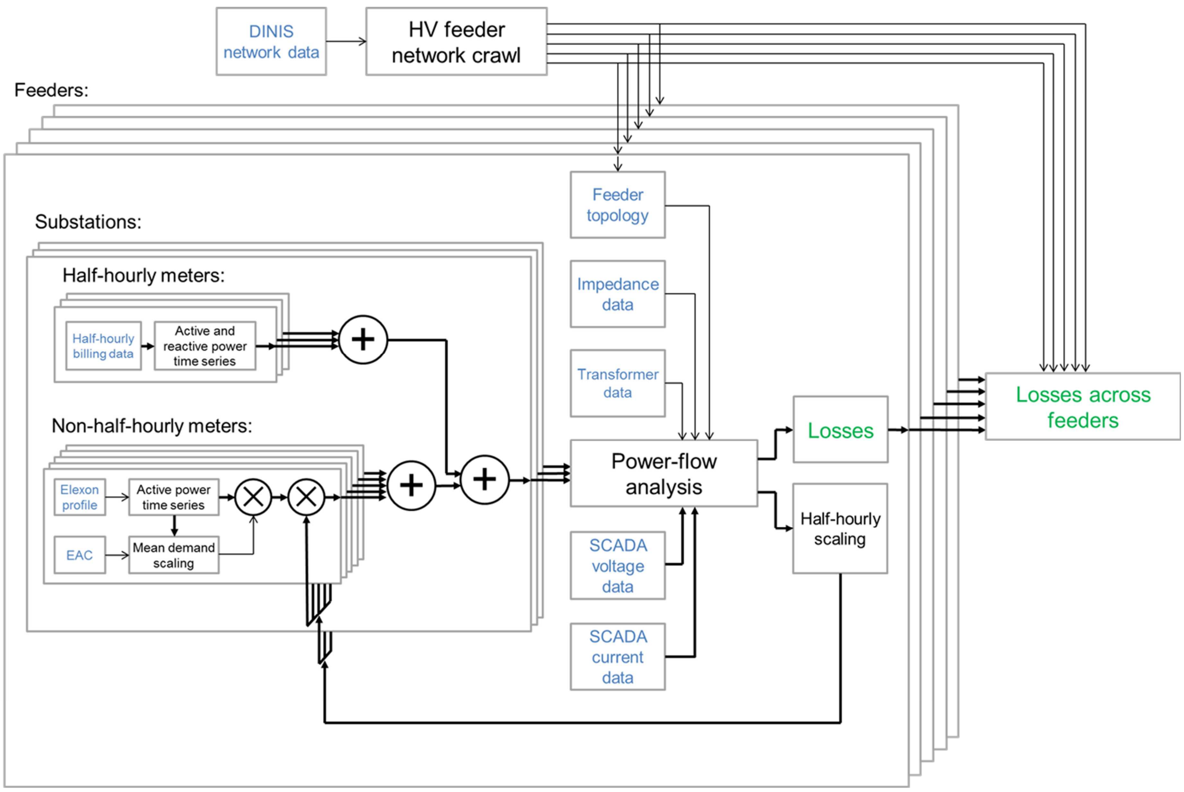


Figure 18 Outline of HV feeder loss assessment method

In summary, for each HV feeder, the loss assessment method combines network topology data with demand data in order to run a power-flow analysis from which the individual feeder losses are calculated. These individual feeder results are then collated so that loss characteristics of the overall HV feeder set can be examined and identified.

A network data file for the East Midlands region is analysed, and individual HV (11kV and 6.6kV) feeders are identified. The loss assessment software uses a network data file exported from the business-as-usual (BAU) HV power flow analysis tool DINIS. This file covers the entire East Midlands region. The loss assessment software builds a representation of the network from the nodes and branches described in the DINIS export file. Branch data is taken from the DINIS data, and transformer data is taken from the asset management data. These built feeders are tested to confirm they are radial; any that are not are excluded from further stages of analysis.

The demand data is based on a time-series with half-hour periods; using known meter data where this is available (for half-hourly meters), and using estimated demands for the non-half-hourly meters. The estimated non-half-hourly demand is based on an Elexon profile, selected according to the profile class for each customer, and scaled according to the estimated annual consumption (EAC). It is recognised that losses calculated with half-hourly demand data will be systematically lower than loss calculations with a higher time resolution. However, the use of half-hourly data was found to have a minimal impact on the calculated losses at HV.

The power-flow analysis gives an initial estimate of the losses and of the total current, aggregated from all of the distribution substations that would be expected at the primary substation. This estimated primary substation current is compared to the measured data that is available from the SCADA current monitoring at the primary. For any individual half-hour period, this will differ from the initial demand estimate based on the scaled Elexon profiles. This is expected as the demands for individual customers will differ from the Elexon profiles that are averaged over many customers and for the half-hour period on many days. In order to allow for this variation, the non-half-hourly demands are scaled for each half-hour period such that the total predicted current at the primary agrees with the measured data. There is no information here to determine which particular customers have a demand that is above or below the average profile and so a common scaling factor is applied to all of the non-half-hourly demands. The total non-half-hourly demand therefore retains an appropriate proportion at each substation (according to the number of customers, their EACs and their profile class), but is also scaled such that the combined demand at the primary substation from the power-flow analysis is consistent with the SCADA monitoring.

The power-flow analysis uses a modified forward/backward sweep algorithm that accommodates the requirement for the predicted primary current to match with the measurements, and also takes into account the additional power imported into the network to allow for the losses. The sum of the half-hourly demand, the estimated non-half-hourly demand, and the losses, are then consistent with the measured demand at the primary substation.

Although the process described above would ideally be applied for all feeders, it has been found that there are a number of cases where the match between the load model and the SCADA data appears unreliable. In this case, the half-hourly scaling cannot be applied and the non-half-hourly demand is based simply on the Elexon profiles.

The phase allocations for single-phase customers are not known and so the HV loss assessment method makes an assumption that the demand of three-phase substations is balanced. However, the power-flow performs a full unbalanced analysis to allow for single-phase HV branches where the demand is assumed to be connected between the red (L1) and blue (L3) phases. This approach has been adopted as comparisons for the project HV trials showed minimal differences if the losses were calculated with balanced demands rather than unbalanced demands. It is recognised that the use of balanced demands will tend to under-represent losses but the impact appears low relative to the much more dominant factors relating to the level of demand, the location of the demand along the feeder, and the lengths and impedances of the cables.

The fundamental loss assessment methods were initially developed and tested using generalised data from the monitored feeders. The assessment methodology was then iteratively extended to handle and operate with large numbers of HV/LV feeders. Pre-processing and storage of power flow input data, and arrangement and storage of power flow analysis for post-processing analysis were progressively developed and tested using larger and larger input data sets.

The HV loss assessment software consists of an application written in Python that handles the pre-processing of the business-as-usual data and compiles a model of the network topology, the branch impedances and the demand data to be applied at each connection point. The feeder selection screen for this software is shown in Figure 19 and Figure 20. A second set of tools written in Matlab then performs the power-flow analysis for each feeder and collates a set of results for feeders throughout the license area.

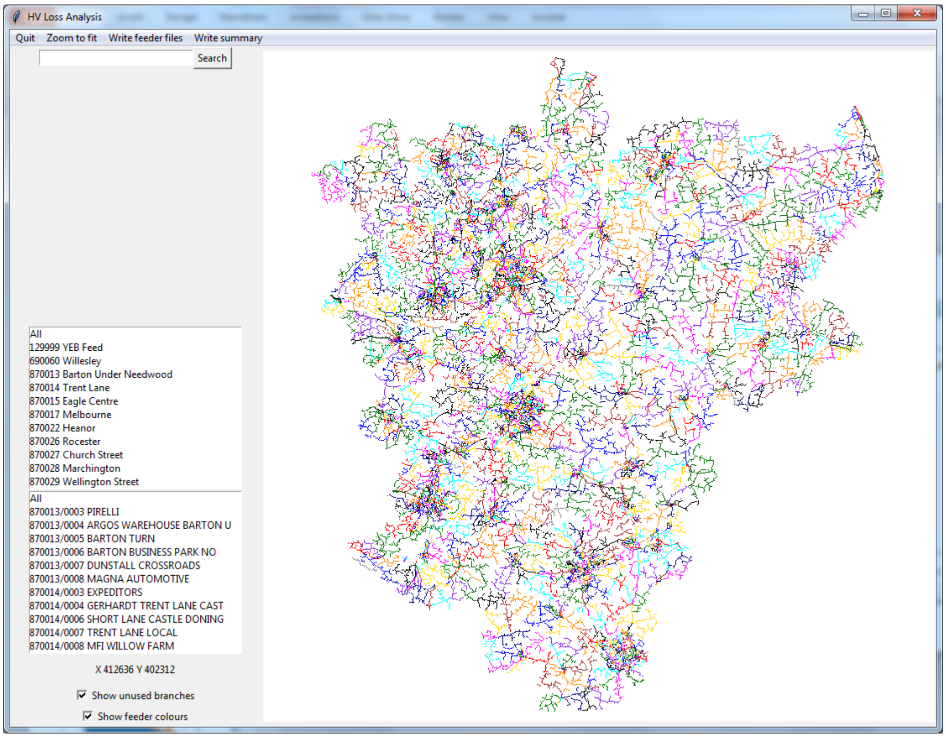


Figure 19 HV loss assessment software Python interface showing East Midlands area feeders

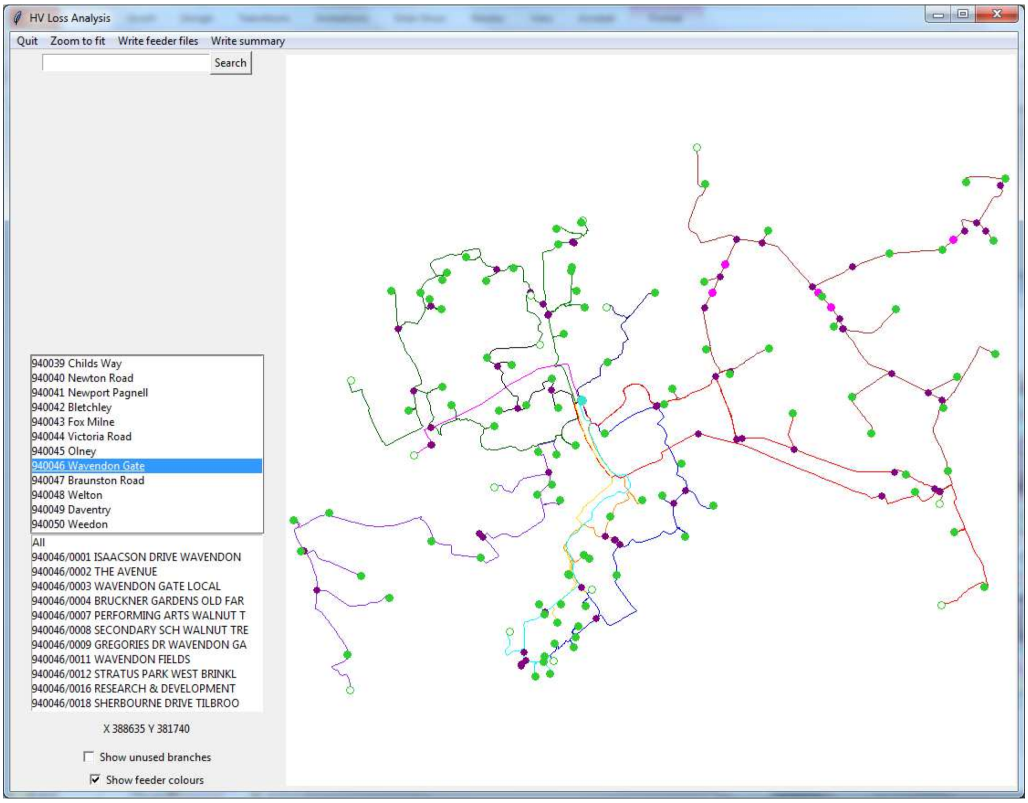


Figure 20 HV loss assessment software Python interface showing feeders for a single primary substation

Learning from the development of the HV method is described in Section 8.2, example output and conclusions from applying the method are included in Section 9 (Project Outcomes).

Further details on specific aspects of data used and the method employed are contained in 0.

4.3.2 LV feeders

An outline of the method for assessing losses on LV feeders is shown in Figure 21 where inputs are shown in blue text and the output (losses) in green. The bold lines indicate time-series data in which each sample represents a 1-minute period. However, the time-series are sub-sampled with only one 1-minute period included for each half-hour. This reduces the computational resources required which would otherwise be prohibitive when processing all of the LV feeders in the East Midlands area.

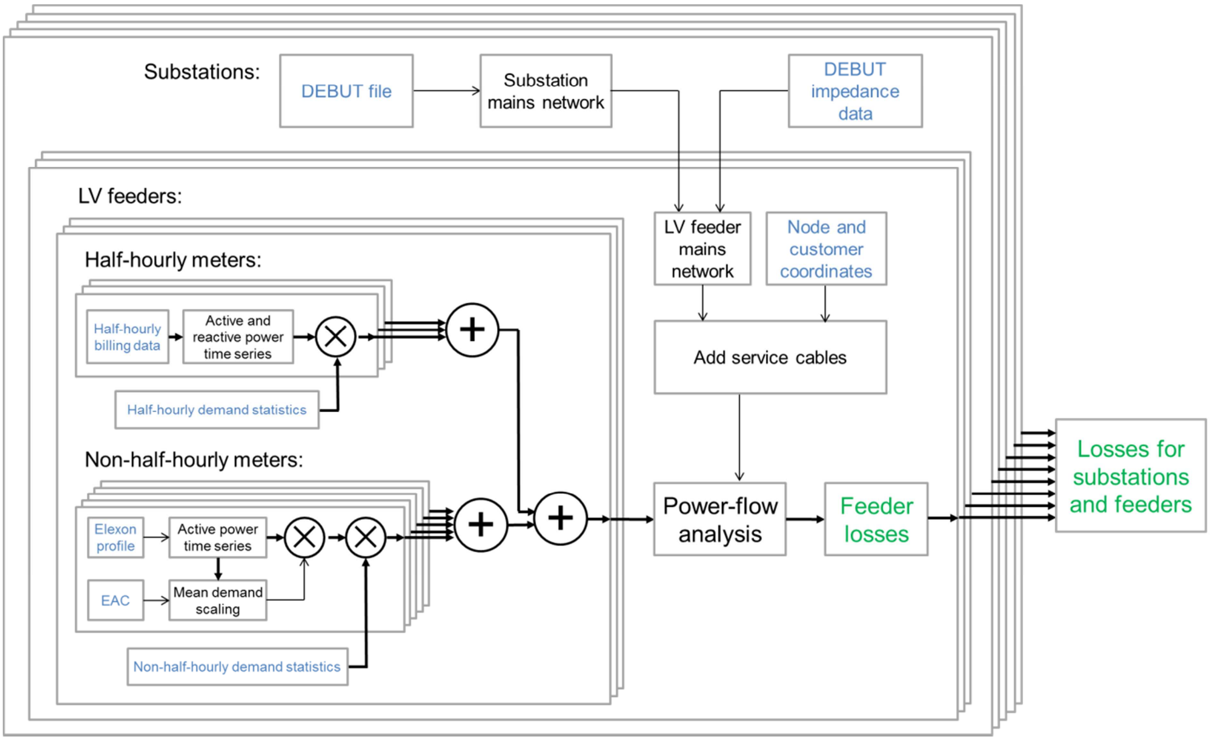


Figure 21 Outline of LV feeder loss assessment method

The LV loss assessment method uses the same approach as for the HV loss assessment. Network topology information is provided by a set of DEBUT files, one for all of the LV feeders at each substation. These network files have been provided to WPD by EA Technology as an output from the Electric Nation innovation project. The network files are accompanied by additional data describing the locations of loads that are connected to each feeder. Only the mains cables are included in the DEBUT file so the loss assessment software creates a set of service cables that connect the load locations to the feeder mains. The phase allocations for single-phase loads are unknown and so a random selection is made.

The demand data is initially constructed in the same manner as for the HV loss assessment method. Half-hourly data is used for connections where this is available. For non-half-hourly metered loads, an individual nominal demand profile is initially constructed from the appropriate Elexon profile, scaled according to the individual load EAC.

The demand data and network data are then used in a power-flow analysis so that the losses can be calculated using the I^2R method.

There are three key differences between the LV and HV loss assessment methods:

- There is no feeder-specific measurement data available for the LV loss assessment method. The HV loss assessment method made use of SCADA voltage and current data measured at the primary substation which acts as the upstream node in the power-flow analysis. The distribution substations have no equivalent measurement. An estimated source voltage must be assumed within the power flow analysis.
- Although the impacts of unbalance and high-resolution time variation were shown to have minimal impact on the HV loss assessment, this is not the case for LV. As noted above, there is also no SCADA current measurement available to add temporal variation to demands calculated based on the Elexon profiles which are statistically correlated between loads. The LV loss assessment method therefore uses statistical techniques to diversify the half-hourly demand estimates. These statistical techniques allow for variation in the demands of individual loads relative to the average profiles, and also for the stochastic variation within half-hourly periods. The variations are applied to individual loads on different phases and will therefore also create unbalances. For three-phase loads, only the total demand is known and so a statistical method is used to allocate the demand to the individual phases.
- In the HV loss assessment method, the combined reactive power from all of the non-half-hourly metered loads at a substation was assumed to be zero. This approximation is appropriate when the demand of all of the loads at a substation is aggregated, but is not valid when the demand model relates to individual loads. Reactive power of half-hourly metered loads is known, but is unknown for individual non-half-hourly loads. A further statistical model is therefore used to include reactive power.

As a consequence of the use of statistical methods in the LV demand model, and also the need to approximate the phase allocations of single-phase customers, there is a greater degree of uncertainty in the loss assessment for LV feeders than for HV feeders. The level of uncertainty reduces with the level of demand aggregation since variations in individual loads from the average profiles have much less impact relative to the combined load from many customers. The network model is also known more accurately for HV feeders and unbalance has minimal impact on the losses. For LV feeders, the losses can be highly dependent on individual customer demands.

Considering the processes described above (to produce a functional regional-scale set of LV network models, and associated load model suitable for an annual loss assessment), the LV feeder results are considered to be highly representative of the LV feeder losses for the population, but reliance on the results for an individual feeder to be a perfect representation of that particular feeder should be approached with caution. Comparisons between the losses for the LV monitored feeders using the full monitoring data set, and the loss assessment method show that the results for individual feeders can be a very good approximation.

As with the HV assessment method, the core LV loss assessment methods were initially developed and tested using generalised data from the monitored feeders. This was then iteratively extended to handle and operate with large numbers of LV feeders. Pre-processing and storage of power flow input data, and arrangement and storage of power flow results for post-processing analysis were progressively developed and tested using larger and larger input data sets.

The LV loss assessment software is an application written in Python that:

- Imports the network and demand data
- Creates network and demand models
- Performs the power-flow analysis for each feeder
- Displays results for each feeder
- Collates results for multiple feeders in the license area

Some example screen-shots from the software are shown in Figure 22 to Figure 26 for substation 941916, where the mains cables follow the network topology defined by the Electric Nation DEBUT file and the service cables added by the loss assessment software are shown in grey. Figure 22 shows the three feeders associated with the substation.

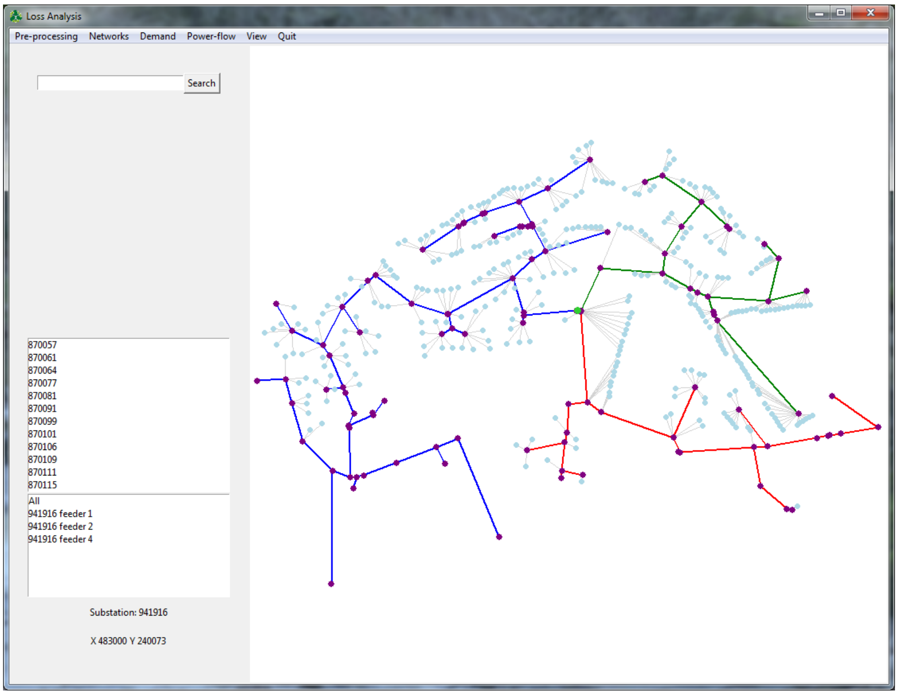


Figure 22 LV loss assessment software Python interface showing LV feeders for substation 941916s

Figure 23 focuses on feeder 1 from this substation and shows the results of the phase assignment algorithm for single-phase meter connections.

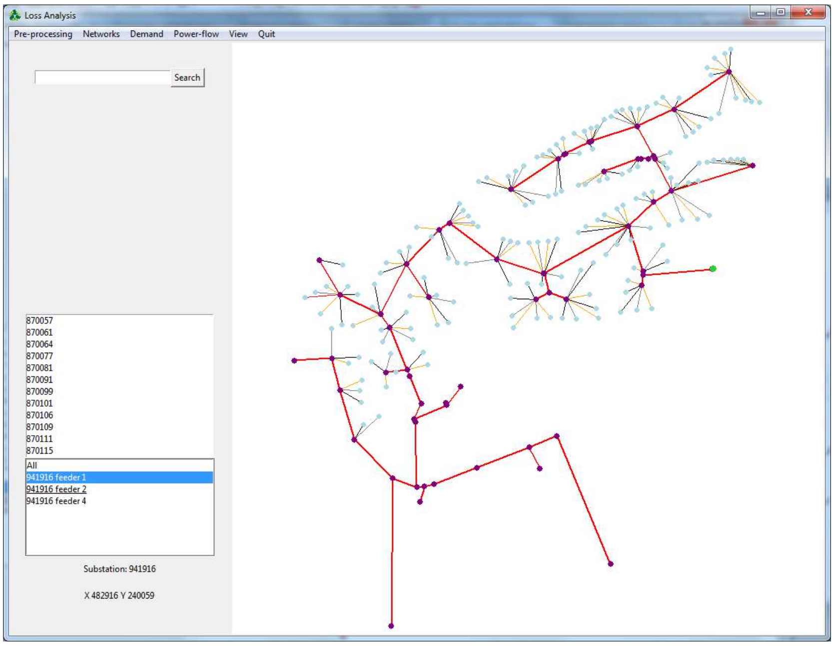


Figure 23 LV loss assessment software Python interface showing losses for substation 941916 feeder 1 (colour scale with highest losses in red, lowest losses in pale yellow)

Figure 24 shows results from the power-flow analysis with losses in each branch indicated by a heat map colour scale. Losses are significantly higher in the branch leading to the substation.

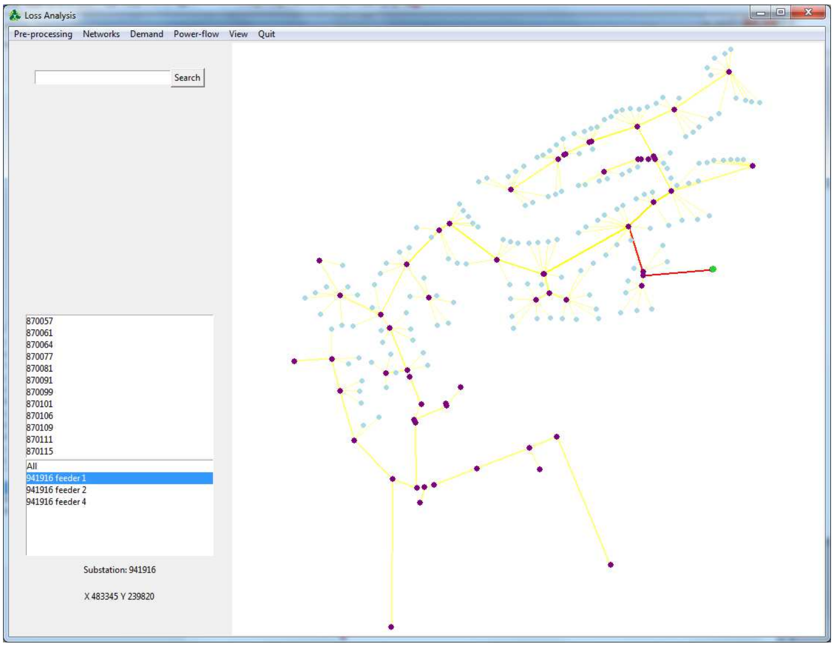


Figure 24 LV loss assessment software Python interface showing phase allocations for substation 941916 feeder 1 (L1 to L3 use standard colouring, three-phase shown in red)

In Figure 25 the heat map colour scale indicates the level of unbalance, calculated here as the ratio of the RMS zero sequence current to the RMS positive sequence current. Unbalance is greatest at the edges of the network and becomes less as the level of aggregation increases towards the substation.

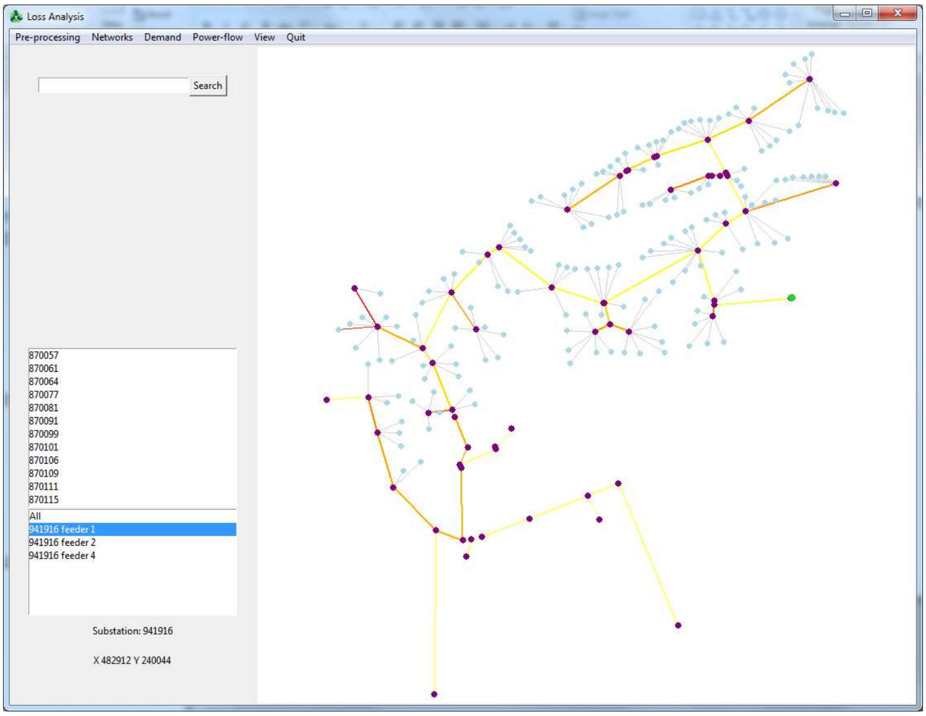


Figure 25 LV loss assessment software Python interface showing unbalances for substation 941916 feeder 1 (ratio of mean zero sequence current to mean positive sequence current, red indicates ratios near 1)

Figure 26 shows a plot of the loss per unit length vs. distance from the substation. This plot combines all parallel branches into a single linear distance from the substation and shows the significant higher losses for the first branch. The losses of the mains cables reduce as the distance from the substation increases. Losses in the service cables, shown in orange, are similar at all distances from the substation (for similar loads and service cable lengths) and, in this example, are a relatively small proportion of the total losses.

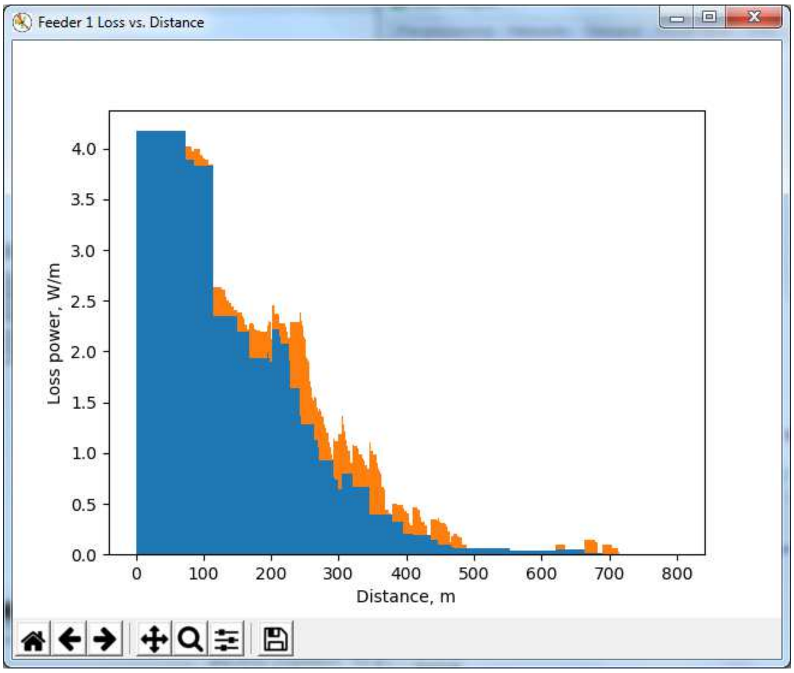


Figure 26 LV loss assessment software output showing cable loss power per unit length vs distance for feeder 1 (mains cable losses in blue, service cable losses in orange)

Learning from the development of the LV method is described in Section 8.3 (Lessons Learnt), with example output and conclusions from applying the method included in Section 9 (Project Outcomes).

Further details on specific aspects of data used and the method employed for LV feeder assessments are contained in Appendix E.

4.3.3 Comparison of loss assessment method results to calculated losses for monitored feeders

Loss results using the calculations based on the full monitoring data for the monitored HV and LV feeders have been successfully compared with results using the developed loss assessment methodology described above. This has been done as an integral part of developing the methodologies. The results of these comparisons are described in the outcomes section of the report (Section 9.2, Page 56).

5 Performance Compared to Original Aims, Objectives and Success Criteria

The project aims have been to further our understanding of technical losses on the distribution network and provide information to subsequently help us target them in a cost effective manner. Supporting these aims, specific project objectives and success criteria were established at inception. Table 5 and Table 6 provide an overview of how the project has successfully performed against these objectives and success criteria.

Objective	Commentary
Understand technical losses on the LV and HV network	The project has developed understanding of technical losses on HV and LV feeders from two sources: the analysis of collected data from the 22 monitored feeders; and from analysis of the loss assessments that have been completed on approximately 75% of the HV and LV feeders in the East Midlands region. This understanding includes: magnitude of feeder technical loss, and variation in loss over time (including daily, monthly and annually); peak loss versus mean loss; drivers of HV feeder loss; and drivers of LV loss.
Determine the minimum information to accurately predict network losses	Having considered the information used to establish technical losses on the project's monitored feeders, the project has determined the minimum information that is required as a foundation for processing to produce accurate assessments of losses on both HV and LV feeders. This established minimum information set is based on existing business-as-usual data. The project has also demonstrated the use of this minimum information, with project established processing routines, on approximately 2,130 HV and 69,256 LV feeders in the East Midlands region.

Table 5 – Commentary on Project Objectives

The success criteria have been met as evidenced in Table 6 below.

Project Success Criteria	Commentary
Construction of fully monitored HV and LV networks	**Construction of monitoring was completed on 11 HV and 11 LV feeders.** All required monitoring was installed on 11 HV feeders. This included monitoring at 7 primary substations, 58 pole-mounted transformers 18 HV-customer supply substations and 116 ground-mounted transformer distribution substations. All required monitoring was installed on 11 LV feeders. This includes an operating set of 300 single phase meters, 46 three-phase meters, 13 ground-mounted LV feeder monitors and 2 pole-mounted LV feeder monitors.
Measurement of network losses on monitored feeders Accurate modelling of losses with full information	**Extensive and accurate loss-related measurements and calculations have been completed for all monitored HV and LV feeders.** The loss calculations have been completed based on full monitoring data and complete recorded knowledge of the monitored networks. Accuracy was tested through current and voltage consistency tests on monitoring data, and the use of both power difference and I^2R based assessments of loss. An overview of the Loss assessments for each of the monitored feeders is shown in Appendix C.
Several models with limited data sets created and tested	**The development and demonstration of method and processes to estimate HV and LV feeder losses has been completed.** Various approaches to estimating feeder specific losses have been considered and tested. As a finalised approach was established (power flow assessment of individual HV and LV feeders using load models representing a complete year), several iterations of load model development occurred to establish an acceptable match between modelled loss assessments for the monitored feeders, and the calculated losses of the monitored feeders using the full monitoring data.
Conclusion on level of information needed to accurately predict losses	**Conclusions have been reached on the level of information required to assess losses on actual HV and LV feeders.** The information required is based on business-as-usual data, and the conclusions are set out in Section 9.4. These conclusions have been implemented in a scale demonstration of the developed loss assessment methods, resulting in assessments of approximately 2,130 HV and 69,256 LV feeders in the East Midlands region.

Table 6 – Commentary on Project Success Criteria

6 Required Modifications to the Planned Approach

While the planned project approach did not change throughout project delivery, the planned timescales were modified.

The approach remained as:

1. Project mobilisation including the establishment of appropriate project agreements;
2. Install monitoring to 22 HV and LV feeders, providing corroborated actual feeder loss information and acting as a control group for testing alternative methods of assessing losses
3. Development of loss assessment methods for HV and LV feeders, using minimum additional information sets; and
4. Demonstration of the loss estimate methods for HV and LV feeder, beyond the monitored feeder set.

Project timescales were extended due to:

- Longer than planned periods required to establish project agreements with all parties. The final agreement was signed 8 months after project initiation.
- Introduction of a single trial HV monitored feeder and a single trial LV monitored feeder to prove instrumentation and measurement approaches and de-risk monitoring implementation phase.
- Construction of both HV and LV feeder monitoring has taken longer than planned. For HV this has been due to additional time required to identify an acceptable solution for monitoring pole-mounted transformers. For LV this is due to additional time required to identify and agree contracts for monitoring of LV feeders. The additional time allowed for at least full 12 months of data capture to take place for each feeder.
- The developed methods of feeder loss assessment involving significantly greater volume and complexity of network and load data processing than was originally anticipated.

These changes were considered and approved through internal governance arrangements.

7 Project Costs

Activity	Budget (£k)	Actual (£k)
HV Feeder monitoring	£1,007	£840
LV Feeder Monitoring	£496	£232
Analysis	£425	£507
Project Design & Project Management	£417	£395
Contingency	£235	£0
Total	£2,580	£1,974

Table 7 – Project Costs

Overall, the project was delivered for approximately 84% of budget (excluding contingency). HV feeder monitoring, LV feeder monitoring and Project Design and Project Management came in under budget, with analysis work extending to 119% of its original budgeted value.

LV feeder monitoring was delivered for significantly less than the budgeted amount due to utilisation of meters from a previous innovation project, reduced volumes, and a close working relationship established with project partners Manx Utilities. This use of meters from a previous innovation project, and the effective working relationship with Manx Utilities led to significantly lower meter installation costs, data and meter management costs, and decommissioning costs than was originally budgeted.

The HV feeder monitoring was delivered for less than budget due to installation of lower volumes than budgeted.

Analysis work extended compared to budget due to the introduction of a monitoring pilot phase, and principally due to significantly higher data complexity and higher data volumes than was originally anticipated.

8 Lessons Learnt for Future Projects

This section presents learning that arose during the project associated with establishing the monitoring on 22 HV and LV feeders, and the development and scale implementation of assessment methods for non-monitored HV and LV feeders.

Key conclusions on the outcomes from analysis of the monitored feeders and on the results arising from implementing the loss assessment methods across the East Midlands are presented in Section 9.

Knowledge dissemination activities are also noted in this section.

8.1 Monitoring and calculating losses for HV and LV feeders

Pilot Approach

- The introduction of phased testing and implementation was successful in reducing project risk at an early stage with limited implementation cost, and in minimising re-work during the roll-out of monitoring to the selected feeders. However, this did affect original project timescales.

Instrumentation

- The EDMI meters, although typically deployed as energy supply billing meters, have been successfully configured to act as instrumentation meters at 1 minute resolution. The developed configurations collect one minute data averages for a wide range of parameters (29 parameters in the case of a three-phase meter), but retain this data for a relatively short period of time on a first-in-first-out basis (21 days) and the quantity of data that requires transmitting on a daily basis takes material periods of time over GPRS connections (three or more minutes, depending on the efficiency of the data collection approach).
- A further sensor type was adopted for use with the MCU520 in collaboration with Lucy GridKey. The need for this sensor arose from the existing Rogowski coil sensors not being suitable for the use over screened sections of HV single phase cables, or for three-phase HV cables. The alternative sensor is a revenue grade hinged split-CT with integral burden resistor to provide a voltage signal proportional to current, and is used to measure current in a CT secondary. These sensors were used at primary substations and at HV customer connections. In some instances, the GridKey MCU520 was also used in a two-wattmeter configuration, where the unmeasured current value is calculated as the vector sum of the two measured phases, flowing in the reverse direction. The use of a new current sensor type necessitated a revision of the MCU520 firmware.

- Accuracy tests of the logging instruments for LV feeders have demonstrated slight differences in the active and reactive power as recorded by the EDMI smart meter, the Lucy GridKey loggers, and an Outram PM7000 used as a high-resolution reference. When values recorded by multiple instruments are compared, a zero offset needs to be applied to the EDMI reported active and reactive power. None of the instruments has been found to be operating outside of their specified accuracy tolerances, but the small observed differences have the potential to affect loss calculations, particularly using the power difference method.
- The time resolution of the measurement data has been found to introduce inaccuracies into the loss calculations for periods when the phase angle of the load currents is rapidly changing. This occurs rarely, but causes errors in the calculations when the direction of active power flow changes within the 1-minute measurement averaging periods, such as when cloud cover variations affect the net output from substations with solar PV generation. The error arises because the current is represented in the analysis as a vector with the amplitude given by the measured average current amplitude, and the phase angle given by the measured average complex power. This differs from the average current vector if the phase angle changes.
- Measurements of the current amplitude by the Lucy GridKey loggers are also affected by the use of signed current amplitude data in the averaging algorithm. A negative sign is applied to the current amplitude to indicate reverse power flow. The aggregation of a period with both forward and reverse active power flow can therefore result in the average current amplitude being recorded as zero.
- Self-consumption of monitoring devices has been considered. Meter self-consumption was tested and the results incorporated into the loss calculations for monitored LV feeders, and also in the wider assessment of LV feeder losses. For the meters used, this was found to be 1.1W/1.5VAr per meter. This is consistent with manufacturer's data, and with wider assumptions about meter self-consumption. The self-consumption current due to the Lucy GridKey loggers (at substations in the LV trial and at primary and distribution substations in the HV trial) is very small relative to the measured loads and so has been neglected.
- The 1-minute loss calculations using the power difference have a greater spread due to residual differences in the clocks of each meter and the Lucy GridKey logger. Calculating the mean loss over a 10- minute period removes much of this spread, and gives results that are more closely in agreement with the results from the I^2R method.
- Although the GridKey loggers do not explicitly provide current distortion data, the current, complex power and voltage fields can be post-processed to indicate the current amplitude at the fundamental frequency. This allows for the impact of harmonics on LV feeder losses to be assessed. The post-processing method cannot be applied for the HV feeder loss analysis as the harmonic distortion cannot be inferred after the current data for each LV feeder has been combined in the GridKey busbar current calculation.

8.2 HV feeder loss assessment methodology

The HV loss assessment method uses network data exported from DINIS. Routines to import this proprietary-format data were successfully established. The following points of learning were established associated with network data during this development process:

- Reviews of examples of feeder loss estimates (testing results) identified that the DINIS data contains network simplifications at some substations which may create topology inaccuracies. These may be identified as network loops that do not actually exist, or through inconsistencies between the resulting electrical network and the underlying branch metadata (e.g. sudden changes in feeder references in apparently continuous branches). Tests of network data integrity have been found to be essential in establishing a level of confidence in the loss assessment, and feeders with uncertain topologies have been excluded from the set of results.
- A consequence of adopting these consistency tests is that the small number of networks which genuinely have a meshed topology are excluded from the analysis.
- The development of routines to apply these consistency tests to the network data for the purpose of feeder loss assessment is a significant amount of work.
- The cable resistances used by the DINIS software tool are around 5% lower than those estimated using finite element analysis. This difference is likely to be due to the omission of AC resistance effects in the DINIS cable definitions data. There are many different cable types used across the WPD networks and it has not been possible to develop finite element models for every variation.
- An approximation method has therefore been used to correct the input DINIS cable data and allow for the AC resistance effects. Although the results vary for different cable types, a reasonable approximation is given by applying a correction that is proportional to the phase conductor cross-sectional area, giving an 11% increase in the resistance for 300 mm^2 conductors.
- Omitting the cable admittances has a negligible impact on the estimated loss values.

A demand model has been constructed for each HV feeder based on the combined demands of each of the recorded customers connected either at LV via distribution substations/pole mounted transformers, or as an HV customer connection. This approach gives loss results that are specific to each HV feeder and represents the best available estimate of the actual distributed energy on an HV feeder.

- For the monitored HV feeders, this approach has generally been found to give good agreement to the substation demand measured using the Lucy GridKey monitoring instrumentation.
- However, in some cases, there are errors in the MPAN-feeder allocation. This affects the estimated losses, particularly where these are more heavily loaded half-hourly metered connections. In one of the HV trials feeders, differences between the BAU meter data and the project meter data accounted for a change in the estimated losses of 15%. More generally, minor differences in recorded MPAN-feeder allocation data caused a much lower impact.

- As described in Section 4.3.1, aggregated non-half hourly data is modified by actual SCADA data to improve the accuracy of the load model, where the SCADA data is found to be reliable. The test for reliability of match between load model and SCADA data was set at ±20%. If the match is outside this limit then the non-half-hourly demand is based simply on the Elexon profiles.
- The demand model uses a half-hourly time resolution. For the HV feeders, the use of half-hourly data was found to have a minimal impact on the losses which are under-estimated by less than 5% compared to calculations with the full 1-minute measurement resolution.
- Detailed phase allocation data for single-phase loads is not available but analysis of the trials feeders has also shown that there is minimal impact on the loss estimates if the demand is assumed to be balanced.
- The unbalance due to single-phase branches of the HV feeder network or from single-phase transformers does have an impact on losses and has been taken into account in the modelling. The BAU data does not generally indicate which phases are used in connecting single-phase transformers or branches and so a worst-case assumption has been adopted that all are connected between the red (L1) and blue (L2) phases.
- Loss estimates for individual substation transformers are more highly dependent on the accuracy of the customer assignments than loss estimates for the combined HV feeder. The loss results have been used to compile a list of transformers with higher-than-average losses, but it is recognised that some of these examples will be cases where the load model is incorrect.
- The HV loss assessment could be improved if more detailed data were to be available relating to the load supplied to IDNO connections. This would resolve an inconsistency in the power balance which arises when the total power supplied to the feeder at the primary is not equal to the sum of the delivered power and losses, due to the unknown demand supplied to individual IDNO connections.

The assessed losses for the distribution transformers use input data specifying the rated copper losses and iron losses.

- These parameters are not available from BAU data for most transformers and so values have been approximated using averaged known data from transformers elsewhere on the network with the same rated power, number of phases and, where possible, for the same decade of manufacture. For configurations where there are no suitable transformers to act as a reference, values for the next available higher rated power are adopted.
- There are minor impacts on the estimated transformer load losses if the tap settings are not accurately known. Typically the transformers are assumed to be on a tap setting of 2, as has been found to be the case for most of the transformers on the HV trial, but the transformer load losses would be under-estimated if transformers were actually on tap 1 or over-estimated if a higher tap setting were used.

- The model assumes constant power loads, and also assumes a constant voltage and current at the primary, and so inaccurate tap setting data causes no error to the estimated HV cable losses or to the transformer no-load losses.
- The assessment method would also be unaffected if single-phase transformers were to be modelled as three-phase transformers. This data is mostly available and so for most feeders this concern does not arise in practice.

8.3 LV feeder loss assessment methodology

The LV loss assessment method uses network data that originates in the business-as-usual (BAU) GIS system. The following points of learning were established associated with network data during this development process:

- The accuracy of the load location data has a significant impact on the reliability of the network models. Errors in the locations of individual non-half-hourly metered loads mostly have little impact, but the loss results can be unrealistic if loads with high consumption are incorrectly placed on small-size cable branches.
- Many instances where loads are incorrectly placed in the model can be detected by consistency checks that ensure that the rated current of the network branches is appropriate for the connected loads, and that the worst-case voltages are within accepted ranges.
- There is a risk that networks with genuinely high losses, and where the demand has increased significantly over time and is no longer consistent with the feeder design guidelines may be eliminated from the results. However, a number of cases have been manually checked and the consistency checking process has been found to operate correctly.
- Errors in the network data are more prevalent for feeders dominated by commercial loads. These feeders often have fewer loads and so errors in individual load location records can have a more significant impact. In addition, customer addresses may be different to the physical locations of meters. In some cases, location data does not specify individual premises within industrial estates and so the geographical resolution may be less accurate than for domestic properties.
- As with the HV network data, the cable impedances are quoted using DC resistances. An approximation method has therefore been designed to allow for the AC resistance effects.

The demand model for LV feeders uses the same approach as for HV feeders, using half-hourly meter data where this is available, and Elexon profiles scaled according to the estimated annual consumption for non-half-hourly metered loads. As for the HV loss assessment, this approach gives loss results that are specific to each feeder and represents the best available estimate of the demand. However, a number of additional aspects need to be taken into account when this approach is used for LV feeders as the demand is much less aggregated:

- The ongoing process of introducing half-hourly meter data for connections with Elexon profile classes 5 to 8 will improve the accuracy of the demand model used for loss assessment. In the near term, if a new MPAN is assigned as part of this process, there is a risk that demand may be recorded with both an Elexon profile and with half-hourly billing. Care is needed to prevent duplication of loads.

- The demand specified by meter data or estimated annual consumption (EAC) is in terms of power rather than current. An accurate calculation of the losses therefore requires an appropriate estimate of the voltage such that the current can be calculated. No monitoring data is available from most distribution substations and so an assumption is required. Based on LV feeders monitored in the Milton Keynes trials, a mean voltage of 245 V has been adopted.
- Whilst it is often recognised in the literature that unbalance can arise if there are different numbers of single-phase meters on each phase, or that they have different demands, the trials have demonstrated that there can be a high level of unbalance associated with three-phase meters. These can be the dominant loads on an LV feeder, especially for commercially-biased feeders. It is unclear from half-hourly billing or EAC data whether the recorded demand should be shared equally between the three phases, or whether the demand may occur only on one phase. A number of examples of significantly unbalanced three-phase connections have been observed.
- On average (over longer periods and across all feeders), the LV feeder measurements from the Milton Keynes trial are approximately balanced, with a slightly higher demand on L1. The phases have active power demand shared in ratio L1: 34.8%, L2: 32.3%, and L3: 32.9%. While there may be practical issues associated with LV service joint installations that tend to bias connections to one phase, these results suggest that this does not cause a significant systematic bias to the balancing of the system as a whole. The LV loss assessment method has therefore aimed for the long-term mean demand to be balanced overall across phases, but retaining the unbalance that is due to short-term variations in the demand.

  The LV demand model needs to take account of demand variations between customers, and also the variation within the half-hourly periods used by meter data and the Elexon profiles. The impacts of unbalance and reactive power also need to be included. Without allowing for these additional factors, losses on the LV trial feeders would be under-estimated by 22%.

8.4 Knowledge dissemination activities

The project has produced detailed six month progress reports describing the work undertaken, learning and outcomes. These are available from the WPD's website (https://www.westernpower.co.uk/innovation/projects/losses-investigation).

Details of the work up to and including Pilot Phase implementation and monitored feeder result assessment were presented at LCNI 2017.

A similar but longer form presentation of material and learning from the work up to and including Pilot Phase implementation and monitored feeder result assessment was presented at November 2017 WPD losses Strategy Consultation event in Birmingham.

Findings from the project were disseminated at WPD's June 2019 Balancing Act event.

This Closedown report and the associated appendices also form an important element of knowledge dissemination.

To date. two papers have been submitted based on work relating to this project:

> A. Urquhart, M. Thomson, C. Harrap, 'Accurate determination of distribution network losses', 24th International Conference & Exhibition on Electricity Distribution (CIRED) 2017, available with open access at: http://digital-library.theiet.org/content/journals/10.1049/oap-cired.2017.1076 .
>
> A. Urquhart, M. Thomson, C. Harrap, 'Impacts of reactive power and harmonics on LV network losses', 25th International Conference & Exhibition on Electricity Distribution (CIRED) 2019, accepted for conference publication in June 2019.

9 The Outcomes of the Project

In summary, the outcomes of the project are:

- Losses have been successfully calculated for periods of up to 24 months for 22 HV and LV feeders using monitoring data at all network entry and exit points. Assessment of this data provided insight into key drivers of losses on actual feeders.
- Methods have successfully been developed to assess losses on HV and LV feeders that require no more monitoring information than is available through business-as-usual channels. These methods bring diverse data sets together in an innovative combination of network GIS data, load location records, load data and SCADA monitoring data.
- With the approaches developed under this project, HV and LV feeder technical loss assessments have been undertaken at a regional scale. The collated results of these region scale assessments provide a number of insights:
    - This bottom-up assessment of technical losses indicates mean HV feeder losses of 1.47% of delivered power, and LV feeder losses of 1.06% of delivered power.
    - For individual feeders, losses vary significantly over the course of a day, a week and seasonally, and mean losses vary significantly between individual feeders.
    - Further breakdown of results indicates: HV feeder losses are split 37% in feeder conductors, and 63% in HV/LV transformers; and LV feeders are split 54% on mains conductors, 30% on services, and 16% on meters.
    - The cost of losses on some HV feeders is significant, allowing high loss feeders to be considered for possible mitigation action, including the movement of normal open point (NOP) positions. Cost beneficial retrospective mitigation action on individual LV feeders is significantly more challenging due to the lower cost of losses per feeder and the much larger number of feeders.
    - Loss assessments provide further evidence of the benefit of recent WPD policy changes on future LV system design. Higher-loss distribution transformers can be identified (though further checks are required) with the potential for some cost beneficial mitigating action.
- A summary of the business-as-usual data that has been used to generate loss assessments has been produced.

Details and discussion of these outcomes are presented in the following sections.

9.1 Conclusions on Losses on monitored HV & LV feeders

9.1.1 Successful calculation of losses for monitored feeders

Losses have been successfully calculated for periods of up to 24 months for 22 HV and LV feeders using monitoring data at all network entry and exit points. Ongoing loss assessment for the monitored feeders started in March 2016 with the completion of monitoring installation on the first HV feeder. Monitoring was in place for the final LV feeder in September 2017. An overview of monitored feeders is presented in Appendix A, and examples of the long term data monitoring are shown in Appendix C.

9.1.2 Routine loss analysis for monitored feeders

Routine analysis of monitoring data for HV feeders typically provides a range of information. Examples of this include:

- Mean HV Feeder exit point demands. This format of chart is particularly able to show the extent to which an HV feeder's load might be dominated by a specific substation. Figure 27 shows a fairly typical HV feeder loading, while Figure 28 shows an extreme point loading on a feeder. The feeder associated with Figure 28 is a high loss HV feeder, where the load is concentrated at one substation which is located at the end of the HV feeder.

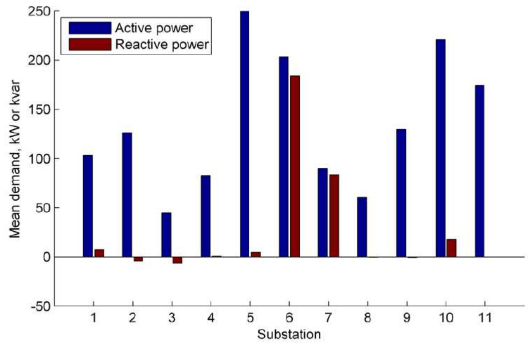


Figure 27 Period mean feeder exit point demands (Woodland HV Feeder March 2017)

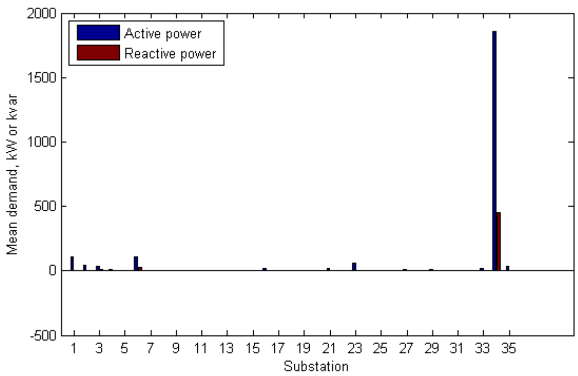


Figure 28 Period mean feeder exit point demands (890058)

- Confirmation that all of the power entering or leaving the feeder has been monitored, such that the sum of boundary node currents equals zero.

  This examples shows a trace from HV feeder monitoring commissioning, where it was found that monitoring data was not enabled on one LV feeder at one distribution substation This was rectified and a broadly balanced trace results thereafter.

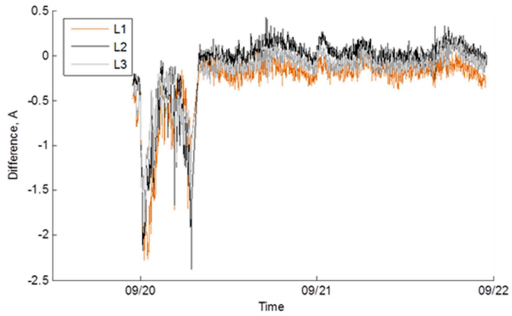


Figure 29 HV current balance example

- Visibility of HV Feeder loss over month-long assessment periods (1 min resolution, calculated through I^2R and power difference methods). The charts are also available with Y-axis expressed in terms of percentage loss.

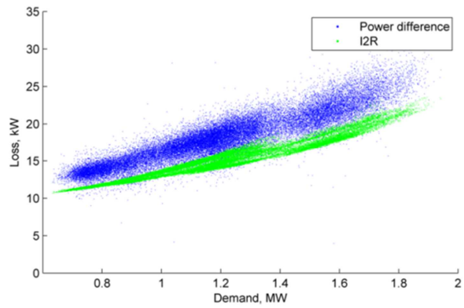


Figure 30 Period data for Woodland HV Feeder (September 2018)

- Portrayal of long term trends of HV feeder mean daily loss, including: total feeder loss; phase conductor loss; transformer load loss; and transformer no-load loss.

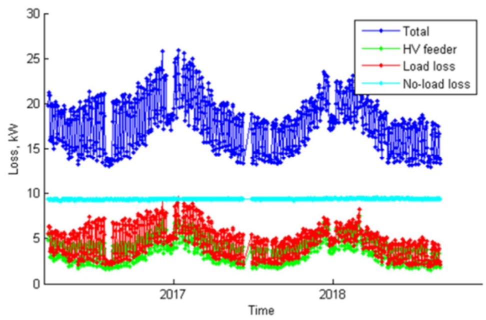


Figure 31 Trend data for Woodland HV Feeder (to September 2018)

Similarly for LV feeders, examples from long term monitoring include:

- Confirmation that aggregate "exit" point currents are balanced with "entry" point current measurements.

  The first example shows an LV commissioning trace where a street lighting feed (on L3) was not initially monitored.

  The second example shows the residual currents on L1 following an new load being connected approximately 12 months after monitoring commenced.

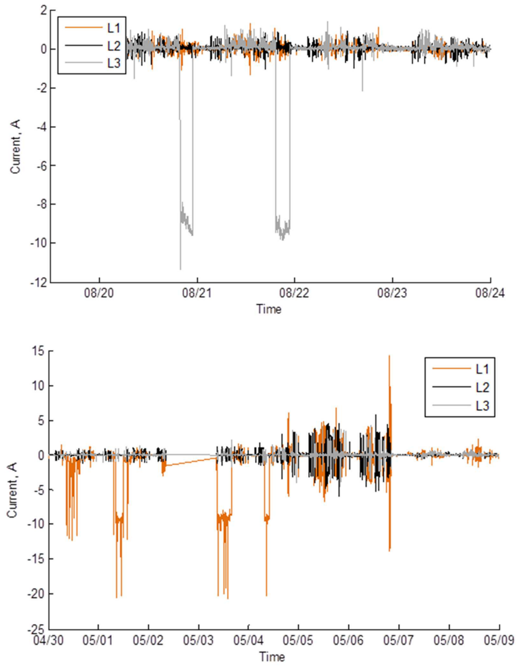


Figure 32 LV current balance examples

- Visibility of feeder loss over month-long assessment periods, (shown here with losses averaged over 10-minute periods to smooth out the effects of residual timing offsets between the 1-minute measurements samples), calculated through I^2R and power difference methods. Charts are also available with Y-axis expressed in terms of percentage loss.

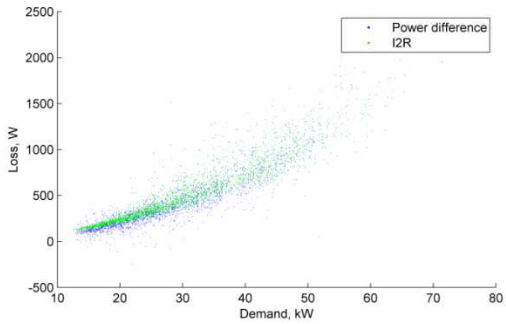


Figure 33 Period data for Dom#3 LV Feeder (August 2018)

- Portrayal of long-term trends for feeder mean daily loss showing variations across weeks and seasons.

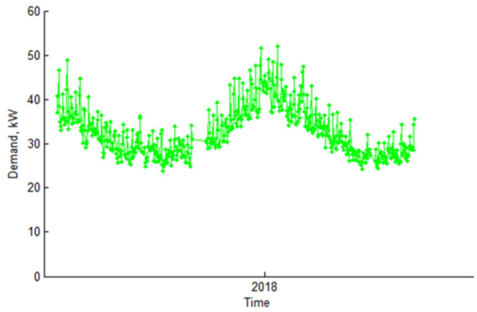


Figure 34 Trend data for Dom#1 LV Feeder (to August 2018)

9.1.3 Insights into drivers of losses from monitored feeders

Unbalance

Unbalance between the demands on each phase can occur on a persistent basis where there are different mean demands on each phase, and also as a short-term unbalance as customers on each phase switch appliances on and off.

Figure 35 shows 1 minute loss versus load samples for the LV pilot feeder over a 1 month period of time. The samples are colour coded according to the degree of unbalance, where unbalance is quantified as the ratio between the zero sequence and positive sequence currents.

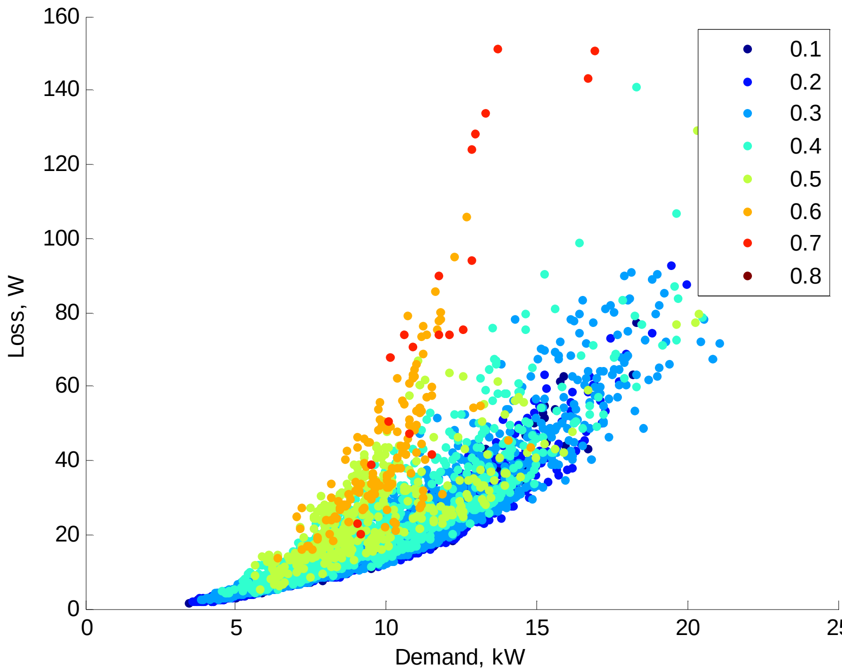


Figure 35 Loss vs. demand with colour indicating unbalance factor

From this example it can be seen that high loss samples (those samples that that above the general trend line) are often associated with higher levels of unbalance. Although these orange and red highlighted samples are eye-catching, they are a small minority of the total number of samples.

Losses for the eleven LV trials feeders with a “virtual” balancing of demand are shown in Figure 36. On average, the total losses (including metering, which is unaffected by the balancing) reduce by approximately 13% and a similar reduction applies to losses only in the mains cables.

The impact of balancing varies between feeders; some feeders have reductions in losses of up to 40%. However, within the set of trials feeders the greatest loss reductions due to balancing occur where the demand and losses are relatively low. The commercial feeders Peel A and Peel B have much greater losses with minimal unbalance. The loss reduction if these feeders were balanced is less than 5%.

The impact of unbalance has also been tested for the LV feeders in the Milton Keynes trial, using results from the LV loss assessment methods. Using balanced demands in place of the predicted unbalanced demand data causes the estimated total losses to be reduced by 13%. There is a greater reduction of 22% for the losses in the mains cables.

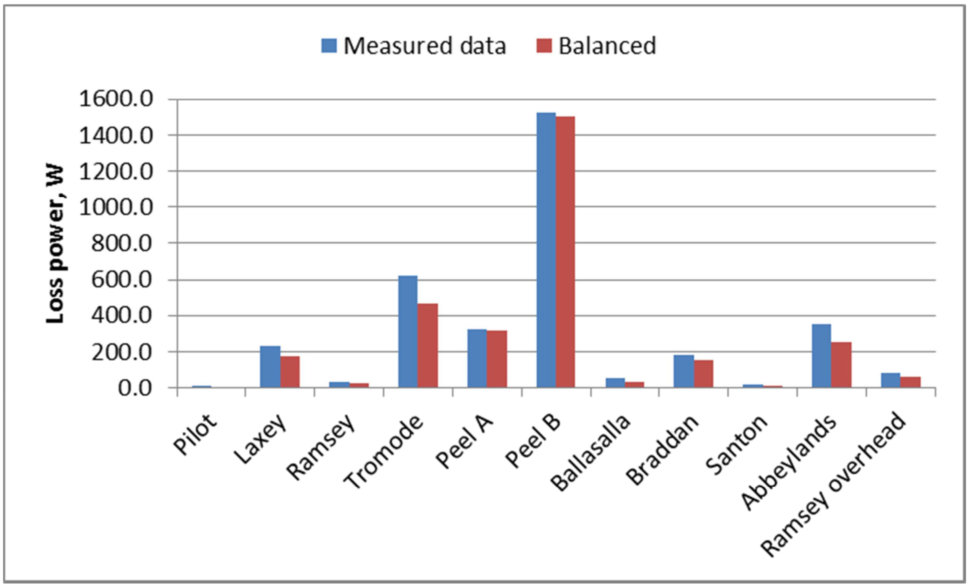


Figure 36 LV feeder mains losses calculated from measurement data and with balanced demand data

A similar comparison for the HV trials feeders shows minimal impact due to unbalance. Losses for feeders where all of the transformers are three-phase are reduced by only 2% if the demand and network are assumed to be balanced. However, the impacts of unbalance may be more significant than this on rural feeders where single-phase transformers and single-phase feeder sections occur.

Reactive power

Losses calculated for the eleven LV trials feeders with only the active power demand included are shown in Figure 37. The losses for the trials are dominated by the Peel B commercial feeder. This has a high reactive power and so losses are significantly reduced by omitting reactive power for the loss calculations on this feeder.

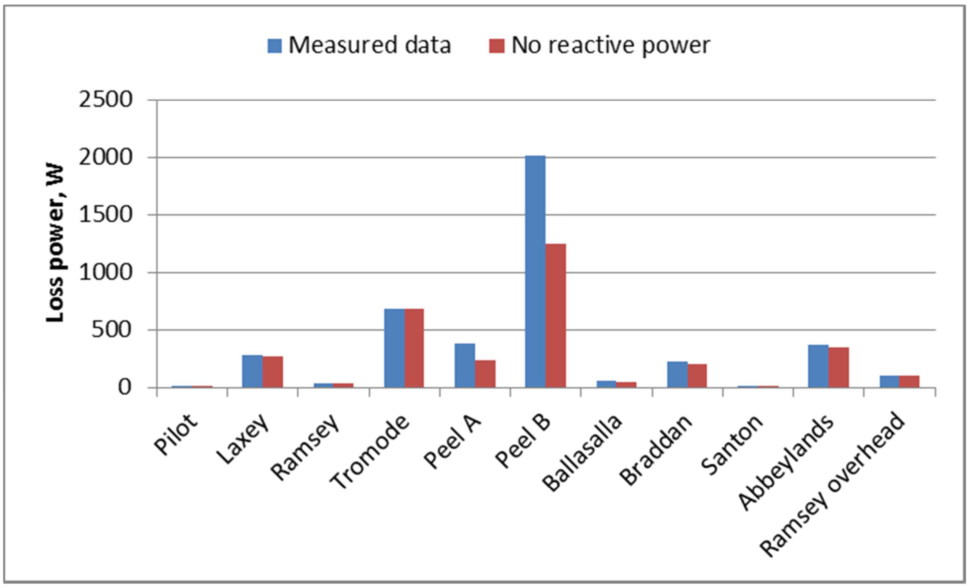


Figure 37 LV feeder mains losses calculated with and without reactive power

Figure 38 shows probability distributions of reactive power measured at LV substations on the Milton Keynes trial feeders. These distributions show measurements of the reactive power for a given level of active power. The reactive power is expressed as a ratio relative to the active power. Typically, the reactive power is either low (relative to the active power), or otherwise likely to be around 80% of the active power or, to a less extent, near to 40% of the active power. Each of these peaks has as a narrower spread as the active power level increases.

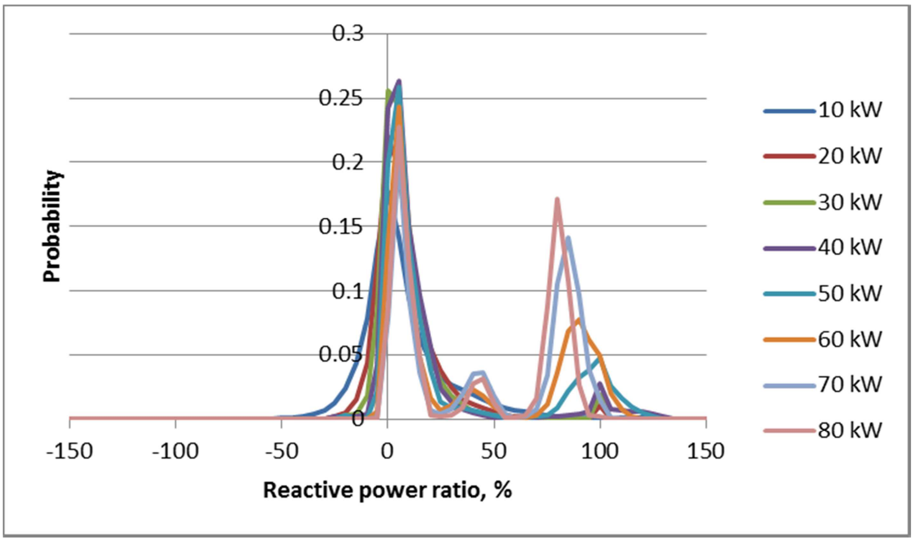


Figure 38 Probability distribution of reactive power for LV feeders

For the LV feeders in the Milton Keynes trial, results from the loss assessment method show a 5% reduction in the cable losses if reactive power is removed from the demand predictions. This estimate is partially dependent on the statistical model used to include reactive power for the non-half-hourly meters, but also makes use of the known reactive power data for the half-hourly meters, typically those with the highest level of demand. This would suggest that there is scope to make significant reductions in losses for specific LV feeders, such as the commercial feeders included in the LV trials. In these examples, the total demand on the feeder is largely due to one or two customers and so the majority of the reactive power might be removed by fitting power factor correction at only these customer connections. An automated process could be developed to analyse half-hourly billing data and so identify the customer connections where power factor correction would have a significant impact on the demand currents. This process would cover an increasing number of customers as non-half-hourly metered customers with Elexon Profile Classes five to eight move towards half-hourly billing being readily available.

There is minimal impact on the losses of HV feeders if reactive power is removed. This was demonstrated for the HV trial feeders, where mean load-related losses (HV cable losses and transformer load losses) were reduced by only 1% (of the loss value), although the losses were reduced by 7% (of the loss value) on one feeder with two substations serving large commercial loads. This comparison for HV feeders is shown in Figure 39.

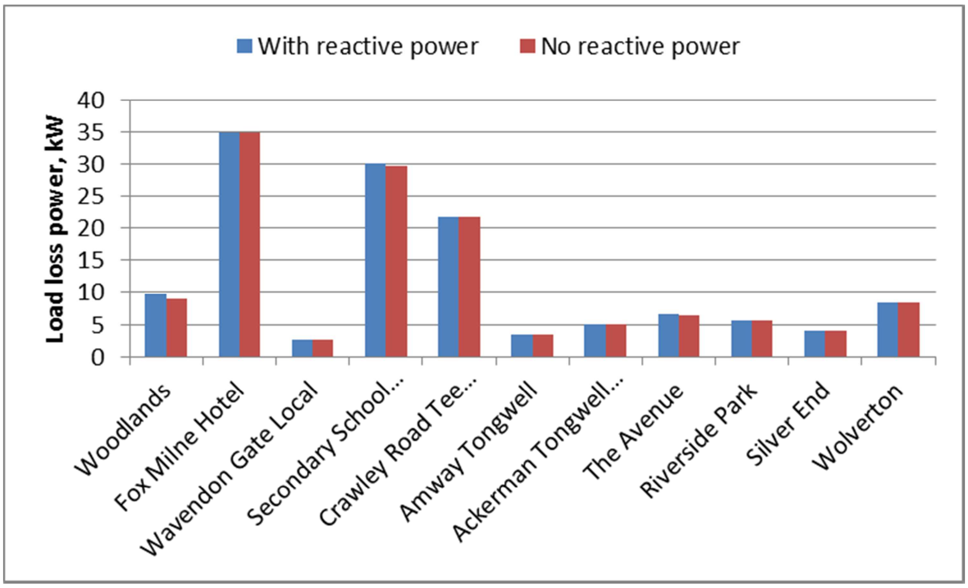


Figure 39 HV feeder mains losses calculated with and without reactive power

Harmonic distortion

Loss calculations for the eleven LV trials feeders are shown in Figure 40. The mean losses for all feeders are reduced by only 2% if harmonics were to be cancelled, suggesting that harmonic distortion is not a significant cause of losses. However, there are greater differences for some feeders with up to a 9% reduction in losses for the Ballasalla feeder, which has a relatively low level of demand. Feeders with greater losses are less affected by harmonics.

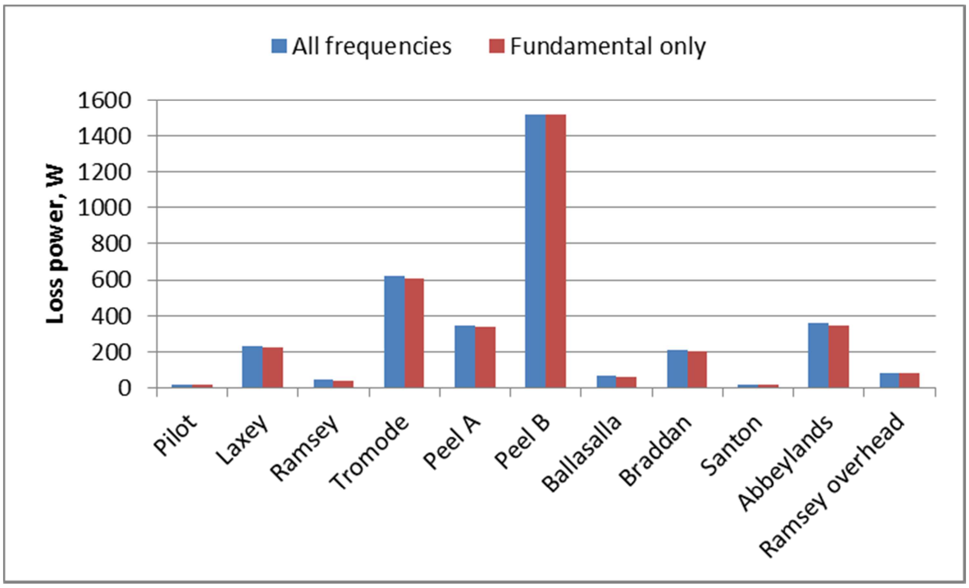


Figure 40 LV feeder cable losses calculated from measurement data using RMS current amplitude and fundamental current amplitude

It has not been possible to present conclusive evidence for the impacts of harmonic distortion on the HV feeders due to the lack of THD information in the GridKey logger data.

9.2 Conclusions on the developed loss assessment methods

9.2.1 Minimum additional information required to assess losses

In line with the project objectives, methods have been developed to assess technical losses on non-monitored HV and LV feeders. The results from these assessment methods have been compared against the calculated values using the full monitoring data. Based on this work it is concluded that **the losses for models of individual feeders can be assessed using business-as-usual data, without the need for any additional monitoring to be installed**.

- Monitored feeders were fitted with extensive (but reasonably practicable) instrumentation to provide high time-resolution voltage and current monitoring data from which a calculation of feeder losses could be made. These "measured" losses were successfully used as a control set to validate the accuracy of loss assessment methodologies.
- Assessment results from the developed methods have been successfully validated for the monitored feeders by comparing loss calculations using "full" monitoring data and knowledge of the networks, with the loss assessments arising from the application of the developed method.
- Whilst not perfect, the method provides assessment of feeder-specific losses that are within 10% of values from the loss calculation using full monitoring data for all but one feeder (which showed agreement to within 20%).

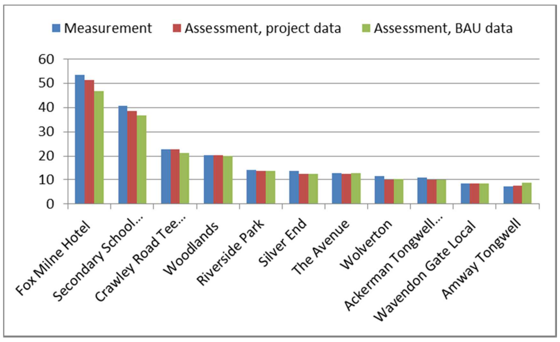


Figure 41 Loss results comparison for monitored HV feeders

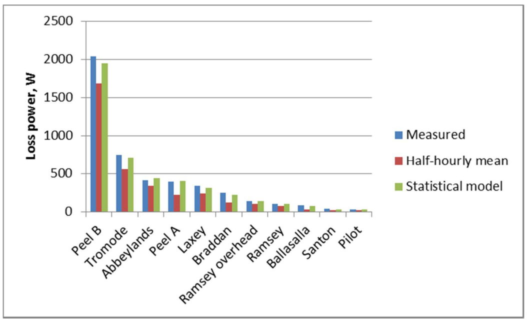


Figure 42 Loss results comparison for monitored LV feeders

- The loss assessments methods for HV and LV feeders indicate the same rank order of feeders with high losses as in the loss calculations from monitoring data. This allows the high-loss feeders to be identified from the loss assessment results.

9.2.2 Feasibility of assessing HV and LV feeders at regional scale

It has been demonstrated that **the developed methods of assessing HV and LV feeders can be applied at regional scale**. This demonstration resulted in 2,130 HV feeder network-load model combinations (75% of East Midlands region), and 69,256 LV feeder network-load model combinations (76% of East Midlands region). Each feeder has a network model based on the recorded feeder topology and cable types; and a feeder-specific load model representing a one year period, with 17,520 half-hour periods for HV feeders and 17,520 representative one-minute periods for LV feeders. This required over 1.25 billion power flow solutions per complete HV/LV assessment run.

Sample results from this at-scale application have been reviewed, and for both HV and LV feeders, it has been found that inaccuracies in input data (e.g. in the location data of small proportions of the loads per LV feeder/LV substation) can lead to unrepresentative feeder loss assessments. Therefore **screening of both HV and LV loss results has been successfully undertaken to remove assessments that are potentially unreliable**. For HV feeders, this involves comparison of modelled aggregate distribution substation loads with installed transformer capacity; for LV feeders, tests of LV branch current versus cable ratings, and modelled voltages at service points versus operating limits are used.

- Figure 43 shows a scatter plot of 2130 individual assessed HV feeders for mean annual feeder loss versus mean feeder import power. The red highlighted feeders are generally those with high losses that have been investigated and found to have errors in the demand data.
- Review of individual examples shows this is due to misallocation of MPANs to distribution substation/transformer.

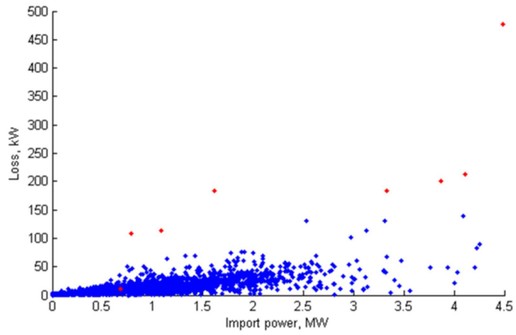


Figure 43 HV feeder loss assessment results, with potentially unreliable results highlighted

- It is clear that the majority of potentially unreliable results are consistent with the general trend, suggesting that the method is generally tolerant of a level of MPAN misallocation.

- Figure 44 shows a filtered scatter plot of HV feeder assessments, with the identified potentially unreliable assessments removed. In this chart, a number of outlying results are highlighted in red.
- These highlighted outlying results have been examined in detail, and all have been found to be realistic representations of the actual feeders, with credible explanations of why losses are either high or low.

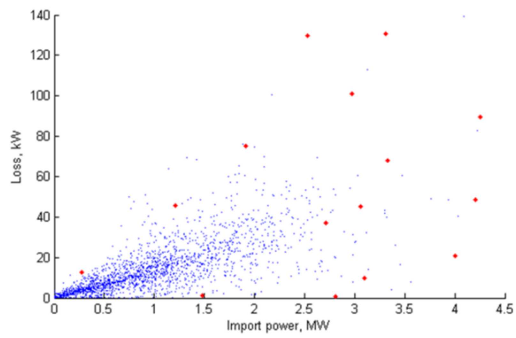


Figure 44 Filtered HV feeder loss assessment results, with outliers highlighted

- Figure 45 shows a scatter plot of individual assessed LV feeders for mean annual feeder loss versus mean feeder import power. The red assessment points represent LV feeder assessments where one or more branches have a modelled current above the branch rating, and therefore are regarded as an unreliable assessment. There are 1,399 such points, 1.9% of assessed feeders. The olive-green assessment points represent feeders where one or more connection points on the network are modelled with voltages below operating limits. There are 3,281 such points, 4.4% of assessed results.
- Examples of both current and voltage model alarms have been investigated, and in all examined cases issues have been found with the recorded geographic location of loads.
- Figure 46 shows 69,256 filtered LV feeder loss assessment results, where individual results are overlaid by multiple other results. Figure 47 shows the same result set with loss shown as a percentage.

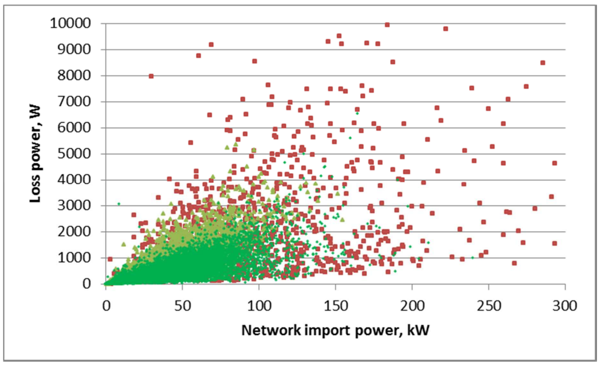


Figure 45 LV feeder loss assessment results, with potentially unreliable results highlighted

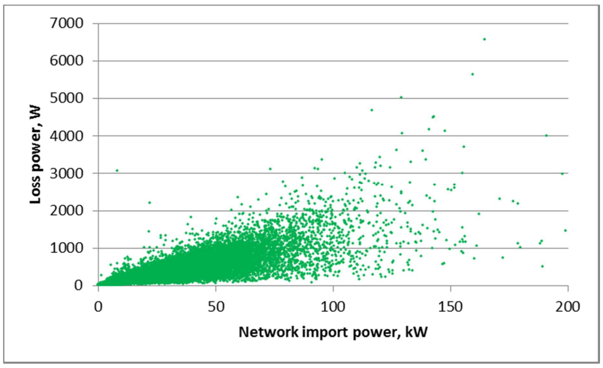


Figure 46 Filtered LV feeder loss assessment results, loss power vs. demand

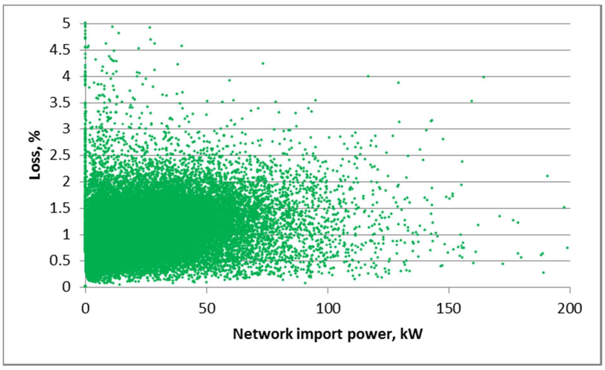


Figure 47 Filtered LV feeder loss assessment results, loss percentage vs. demand

9.3 Conclusions on HV and LV feeder assessment results

9.3.1 Mean levels of loss and variations between individual feeders

Mean levels of loss have been established for over 75% of HV and LV feeders in the East Midlands region based on feeder specific load/network models:

- Overall, the HV feeder losses (including the feeder conductor losses and the LV transformers) are estimated to be 30.4MW. This equates to 1.57% of the 1.93GW power delivered from the primary substations, and 1.47% of the 2.06GW power to the HV network from primary substations plus embedded generation. This loss figure is likely to be lower than for other regions with more rural feeders or older transformers.
- Total losses for the LV feeders are estimated to be 14.1 MW. This equates to 1.06% of the 1.31 GW delivered by distribution substations. The network import power at LV is estimated as 1.32 GW. This figure is similar to the power delivered from distribution substations and reflects the fact that there is less embedded generation connected at LV for which a net export can be identified from the business-as-usual data. For example, domestic PV generation appears 'behind the meter' and causes the customer EAC to be reduced without being visible as generation.

9.3.2 Variations in loss between feeders, and for any one feeder over time

Behind these mean values lies significant variation in the level of loss that occurs on any individual feeder over time, and between individual feeders. This applies to both HV and LV feeders.

Variation in individual feeder loss over time

For individual feeders, losses vary significantly over the course of a day, a week and seasonally.

Figure 48 shows an example of variations in loss for a single HV feeder over the course of a month. The plot shows a broadly quadratic shape, as would be expected. The chart tends towards a vertical axis off-set representing transformer no-load loss. The chart shows relatively little variation of loss for similar levels of load; however, there is evidence of two loss/load curves representing different operating conditions at different times (weekdays versus weekends).

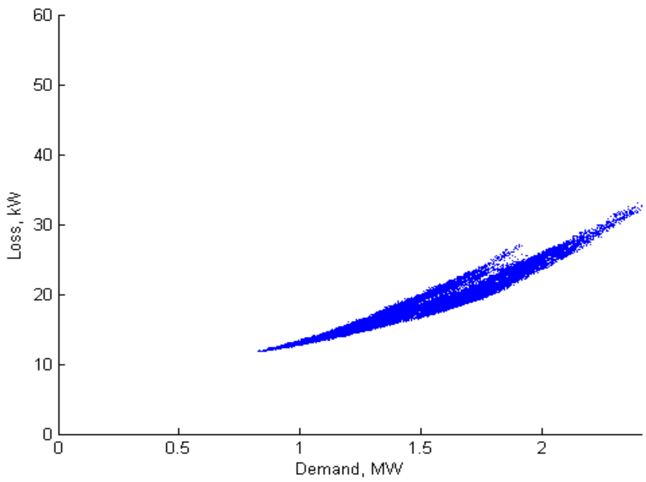


Figure 48 Sample monitored HV feeder loss vs load plot, 1 minute loss/load points using I^2R calculation method

Contrasting this, Figure 49 shows a single LV feeder, with a large spread of loss/load points.

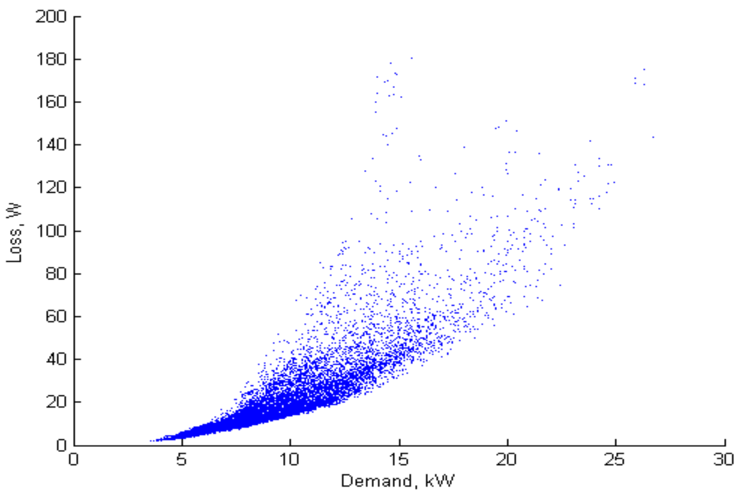
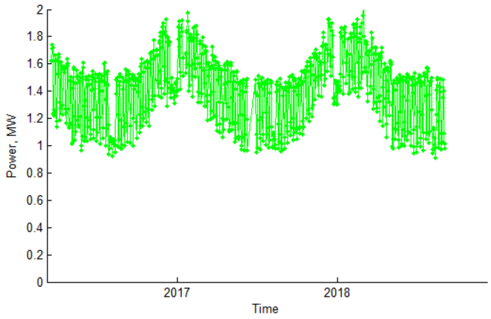


Figure 49 Sample monitored LV feeder loss vs load plot, 1 minute loss/load points using I^2R calculation method

Whilst this shows eye-catching samples out at around 27kW/170W, the vast majority of loss/load points occur in the load range 2-15kW and less than 30W loss, with significant numbers of loss/load points overlaying each other in this region. It is therefore necessary for a load model to have representative time varying loads at different positions along the feeder losses to reproduce the diversity of load/loss points that occur on a feeder, and their relative frequency.

Figure 50 shows two HV monitored feeders that have similar peak loads, but very different weekday to weekend variations, and very different weekday winter peaks to weekday summer peaks.



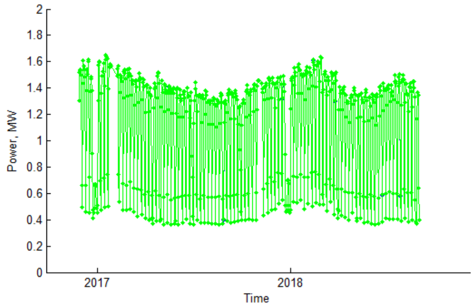


Figure 50 Sample monitored LV feeder loss vs load plot, 1 minute loss/load points using I^2R calculation method

Therefore a comprehensive load model is necessary to appropriately weight the losses that occur at different periods throughout a year.

Variation of loss between feeders

Figure 51 shows the loss load scatter plot for the assessed 2,130 HV feeders, and Figure 52 shows the same for the 69,256 LV feeders.

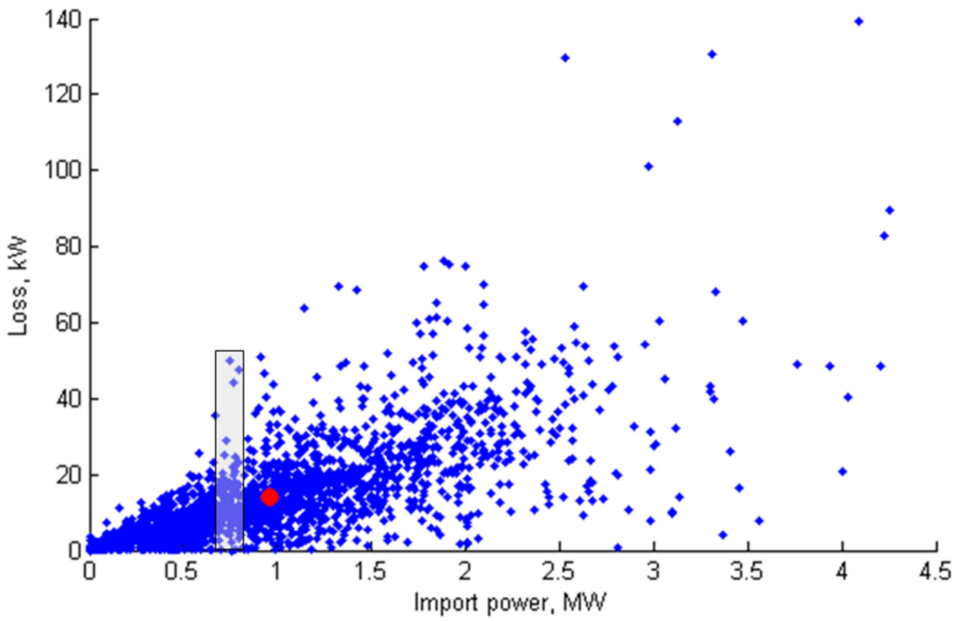


Figure 51 Loss vs. network import power for HV feeders showing mean feeder loss-load point in red

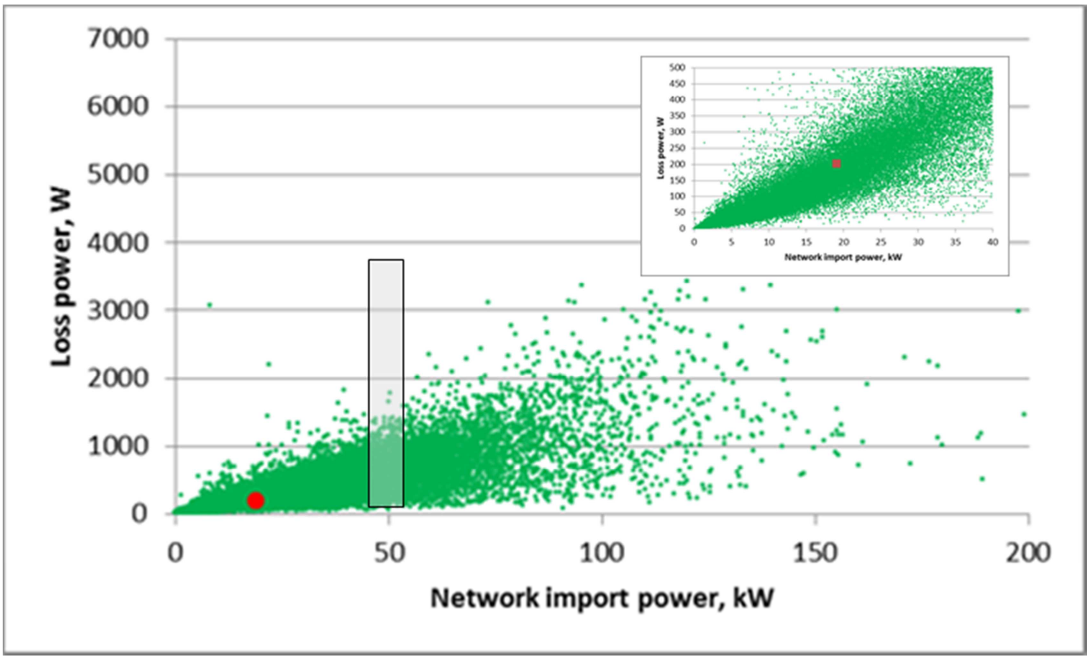


Figure 52 Loss vs. network import power for HV feeders showing mean feeder loss-load point and an indicative trend line

This variation in loss per feeder is expected, with an underlying increase in feeder losses occurring with increasing feeder load. In addition to this, significant variation is also seen to losses for feeders for similar loads (grey box around HV feeders with approximately 0.75MW mean load in Figure 51, and around LV feeders with approximately 50kW mean load in Figure 52). Reviews of example feeders with such variation in loss for similar loads find variation in the following factors:

- feeder impedance (length and cross sectional area) – feeders with increased length or reduced cross-sectional area are seen to have a higher loss;
- numbers of distribution transformers (HV feeders only) – similarly loaded feeders with higher numbers of transformers tend to have higher no-load losses;
- load factor – lower load factor tends to increase loss;
- location and relative magnitude of the load along the feeder (both by static connection and by dynamic changes in the relative magnitude of connected loads over time) – feeders that have dominant loads towards the end of the feeder have a higher loss than more even dispersed load feeders; and
- Reactive power – typically feeders with half hourly metered industrial loads having higher reactive power tend to have higher losses.

These factors appear in combination for individual feeders, and were not necessarily all particularly notable, or all biased to either increase or decrease losses from a nominal average, e.g. a particular feeder may have higher than nominal mean loss (given its load) due to long length and high number of transformers (tending to drive up losses) , but the overall load is biased towards the start of the feeder where higher load edge-of-town substations dominate overall feeder load (tending to reduce losses for the level of load).

One further way of considering this variation in loss for HV feeders is to categorising the feeders as urban[3], semi-urban[4], semi-rural[5] and rural[6]. This characterisation is shown in Figure 53, where it clearly identifies that the rural feeders (tending to have longer length, smaller cross-section and higher numbers of transformers) tend to have higher losses for similar levels of load.

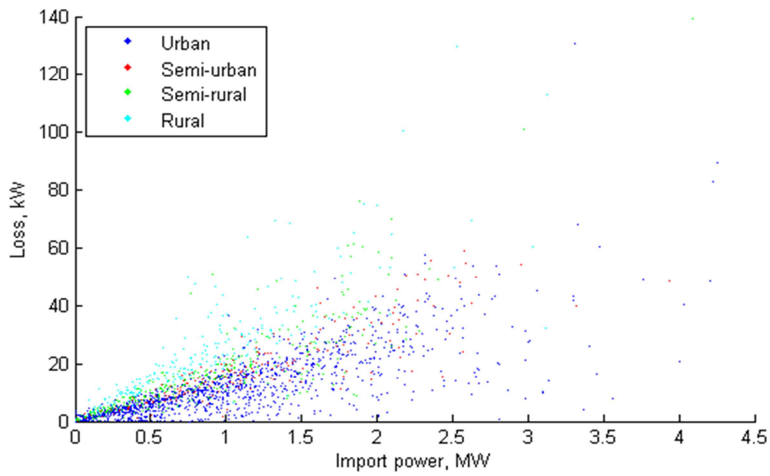


Figure 53 Loss vs. network import power coloured for feeder type

This trend is also seen in the level of no-load transformer loss that exists in rural versus urban HV feeders (Figure 54).

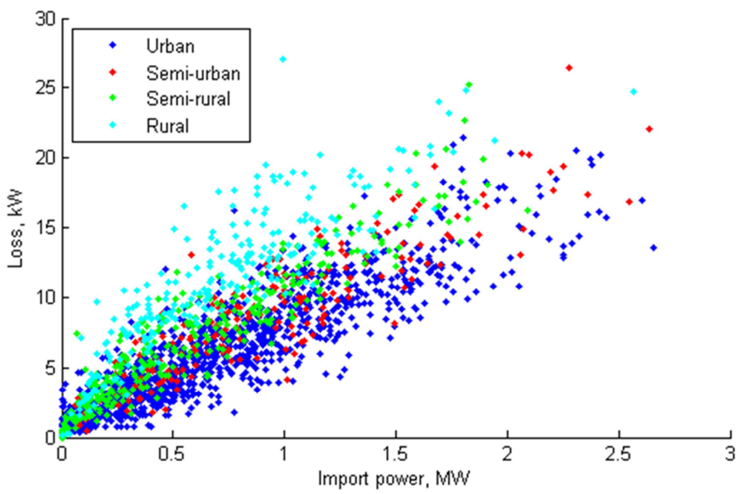


Figure 54 Transformer no-load loss vs. import power

[3] No overhead;
[4] Proportion overhead is > 0% and <= 20% of the feeder
[5] Proportion overhead is > 20% and <= 50% of the feeder, or > 50% and <= 80% and with total feeder length < 19 km
[6] Proportion overhead is > 50% and <= 80% and with total feeder length >= 19 km, or proportion overhead is >= 80%

Differences in loss relating to other feeder characteristics were also examined for operating voltage (6.6kV versus 11kV). Figure 55 shows line losses for assessed HV feeders (6.6kV feeders marked in red), and no significant trend towards 6.6kV feeders having higher losses can be seen.

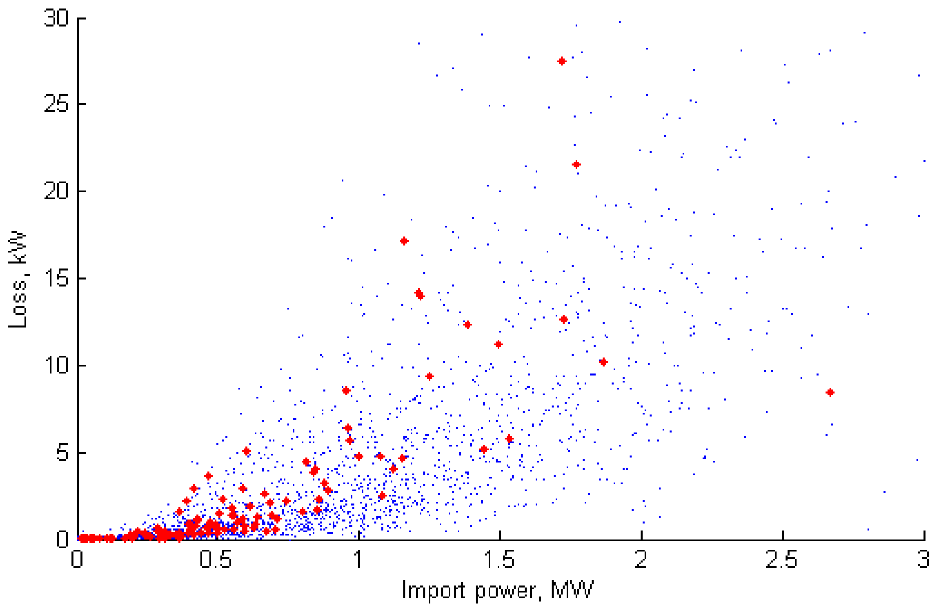


Figure 55 Line loss vs. network import power coloured for voltage (blue: 11 kV, red 6.6 kV)

The diversity of loss/load points occurring on individual feeders, and the differences of mean losses existing between different feeders provides insight into both the variation and the complexity of loss at a regional scale. As a result, a list of around 110 high loss HV feeders in the East Midlands is available to consider the economic potential of measures to reduce losses. This diversity of feeder loss also reinforces the need to take individual feeder network and load characteristics into account when assessing losses.

9.3.3 Breakdown of loss within feeders

On average, for HV feeders 37% of HV feeder losses occur in the feeder lines (cables and overhead lines); and 63% of HV feeder losses are due to distribution transformers (25% of transformer losses are load losses; and 75% are no-load losses). Significant variation occurs around these average values, as demonstrated in Figure 56, where the mean feeder losses are colour coded according to the proportion of line losses as a percentage of total feeder loss. This suggests that feeders with high line loss are generally associated with outlying loss values (both high and low).

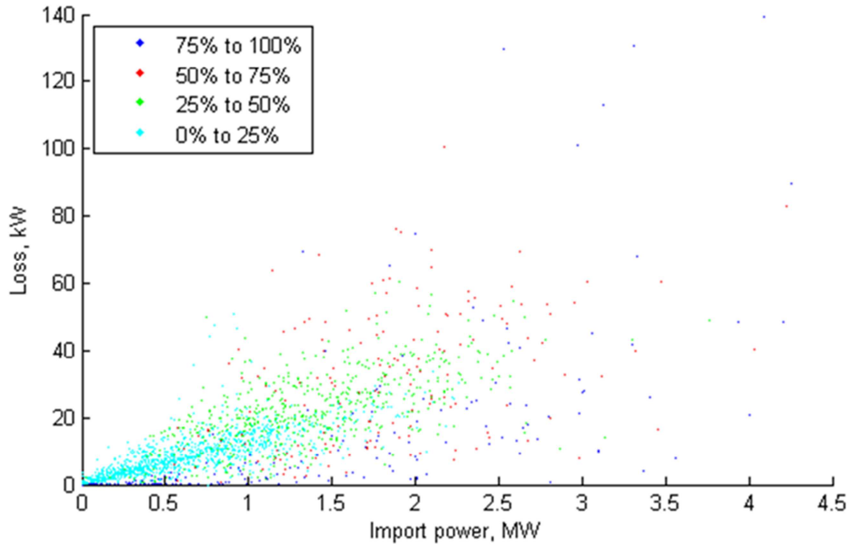


Figure 56 Loss vs. network import power coloured for proportion of losses due to HV cable load losses

It is worth noting that HV line losses are generally greatest in the first branch connected to the primary substation as this carries the aggregated current from all of the distribution substations. The overall results set therefore also provides a list of the first branches with the highest losses, separated into different categories according to the resistance of the cable or overhead line. This list may be used to consider if there is any economic merit in addressing specific instances.

Given that this assessment of loss indicates around 47% of HV losses are associated with transformer no-load losses, selective replacement of transformers by newer designs with lower no-load losses may be a possible means of mitigating a proportion of the existing HV feeder losses. It also suggests potential for a review of policy associated with new transformer standards. The results provide a list of substations for which the age and rated power of existing transformers indicates that the no-load losses may be higher than average, and where the benefits from replacement may be greatest.

On average for LV feeders 84% of LV feeder losses occur in the feeder cables (61% of the losses are in mains cables, and 39% of the losses are in service cables). 16% of LV feeder losses are due to standing losses of meters. A graphical illustration of the breakdown of losses between mains and services for an individual feeder is shown in Figure 57.

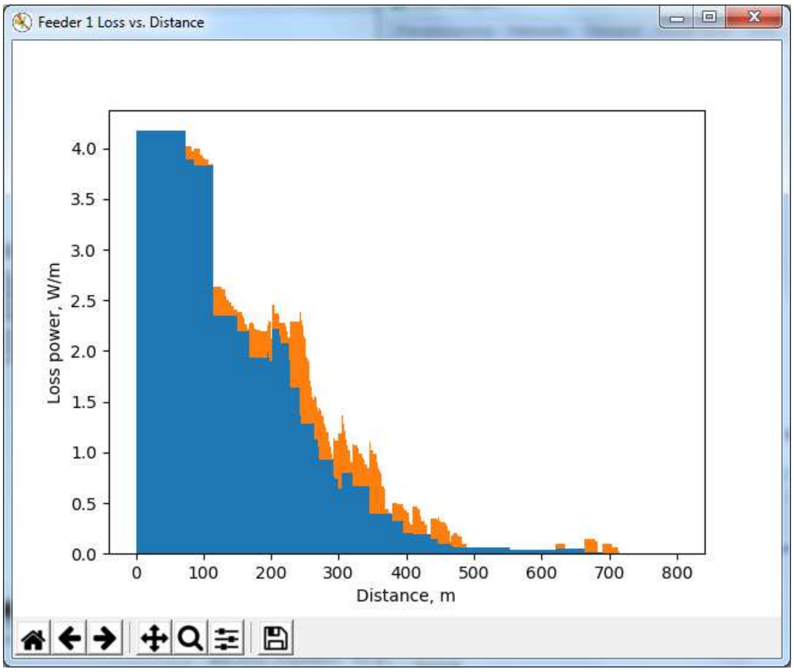


Figure 57 LV loss assessment software output showing cable loss power per unit length vs distance for feeder 1 (mains cable losses in blue, service cable losses in orange)

9.3.4 Cost of losses on feeders

Having assessed the mean loss power for both HV and LV feeders, it is then possible to translate the loss power to cost of losses[7] to provide an indicative annual cost of technical losses per feeder (Figure 58, HV and Figure 59 LV).

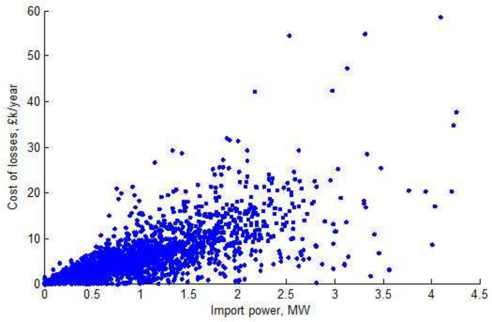


Figure 58 Indicative annual cost of HV feeder technical losses

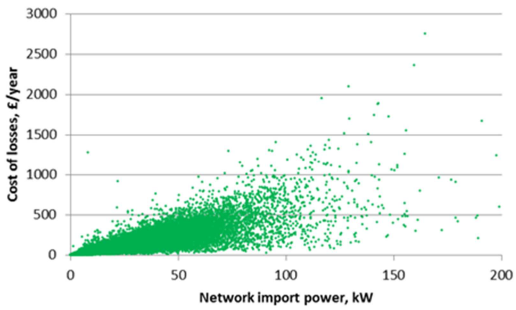


Figure 59 Indicative annual cost of LV feeder technical losses

These same results can also be presented as histograms of the numbers of feeders versus annual cost of feeder losses (Figure 60 for HV and Figure 61 for LV).

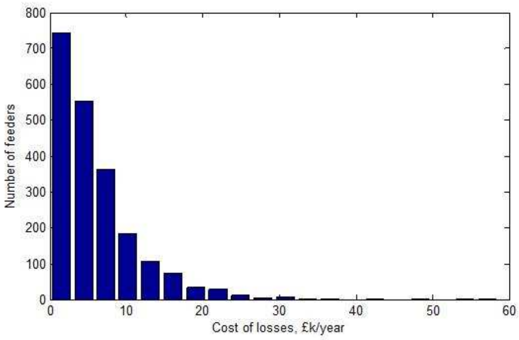


Figure 60 Histogram of number of HV feeders versus annual cost of feeder losses

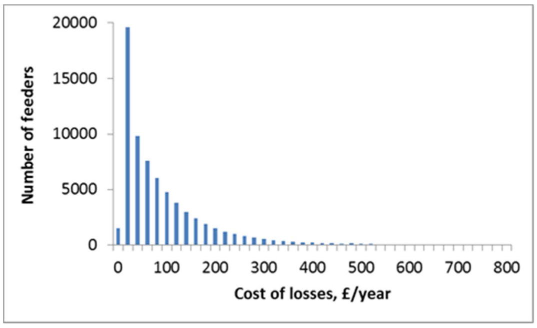


Figure 61 Histogram of number of LV feeders versus annual cost of feeder losses, curtailed at £600/year representing 99% of all losses

HV Feeders

Considering HV feeders, it is clear from the charts that there are a small number of feeders that do have high annual costs of losses. As discussed in Section 9.2.2 and shown in Figure 44 (Page 57), these outlying results have been examined in detail, and all have been found to be realistic representations of the actual feeders, with credible explanations of why losses are either high or low outlying results.

Based on data behind the histogram shown in Figure 60, there are approximately 110 HV feeders with an annual cost of losses above £17k. If a reduction of 10% of losses could be achieved on all 110 feeders, an annual cost saving of £265k might be achievable. This illustration is provided to demonstrate the successful achievement of the project aim to help target losses in a cost effective manner.

[7] The cost of these losses is calculated using the OFGEM cost of losses of £48.42/MWh.

Mitigating HV feeder losses through re-positioning normal open points

Limited illustrative work was carried out to assess one example of how losses could be reduced on HV feeders, through the re-positioning of normal open points (NOPs).

Several of the monitored HV feeders are interconnected at NOPs which break the meshed construction of the HV network into radially operated feeders. In cases where the monitored feeders had common NOPs it is possible to simulate the losses that would have occurred if the open point had been moved to different positions on the network, thereby transferring load from one feeder to another. A summary of the findings is presented in Table 8.

Feeder	Average reduction in Losses by change to a preferred static NOP (using measured load data)	Average reduction in Losses with a change to a dynamically positioned NOP	Estimated annual Cost savings	Estimated annual reduction in CO2e emissions (tonnes)	Average reduction in Losses by change to a preferred static NOP (using estimated load data)
Amway Tongwell	14.7% (6.55kW to 5.59kW)	14.9%	£405	3.0	7.7kW to 7.3kW (10.8kW to 10.0kW for load model with known incorrect customer info)
Wavendon Gate	15.9% (43.3kW to 36.4kW)	No further improvement	£2,892	21.2	47.4kW to 40.0kW (47.2kW to 40.4kW for load model with known incorrect customer info
Newport Pagnell	3.9% (36.1kW to 34.7kW)	No further improvement	£599	4.4	Not examined

Table 8 – Summary of results from investigation of potential to reduce project HV feeder losses by moving NOPs

Estimated annual cost savings from (NOP-change) loss reductions, for three of the feeders being considered by the losses Investigation project, are £405, £2,892 and £599. This suggests:

- Modest per feeder savings are possible, though care would have to be exercised in the amount of investment/expenditure that would be economically viable to achieve the benefits (e.g. feeder identification/assessment/modelling and implementing any mitigating network automation/fault passage indication required);
- Over large numbers of feeders the cumulative savings might be material; but

It should be noted that:

- This is not a saving to a DNO, but a saving to end consumers through further optimising network operation;
- Altering NOPs will change the available capacity on the feeders involved, and will change the numbers of customer connected to a feeder; however,
- Adverse changes to customer numbers on a feeder may occur, and might be mitigated through post-fault automated switching schemes based on fault passage indicators.

This investigation also suggested that the improvement arises through a change from the existing NOP to a preferred static NOP, i.e. there is little further benefit arising from having a dynamic NOP position that changes over peak/off-peak, weekday/weekend or summer/winter periods.

Further work is required to assess the economic feasibility of reducing losses on these feeders, and this is beyond the scope of this project.

LV Feeders

Similar consideration has been given to LV feeders. Examination of data behind Figure 61 indicates the highest 0.5% loss LV feeders have annual costs with an average of approximately £450 per feeder. This is very significantly lower than the annual cost of losses for individual HV feeders, suggesting measures to address individual feeder losses would have to have a low implementation cost for them to be economically efficient. A simple illustration is that if a 10% improvement in losses was achieved on a feeder with annual loss costs of £450, the cost of such measures is limited to around £960[8] per feeder for economic viability. This suggests that works to LV network that were aimed at mitigating losses alone are unlikely to be economic, and therefore the cost of losses should be considered as other triggers for action on individual LV feeders occur (e.g. capacity limitations following sufficient uptake of low carbon technologies such as vehicle charging).

[8] Approximately £960 total annual cost of loss; based on 10% loss reduction; gives (£448x0.1x21.40) £959 benefit. 21.4 factor based on: operational life of 40 years, and a discount rate of 3.5% is applied to costs; over the 40-year life, a cost benefit of £1/year will provide a total of £21.40 lifetime cost benefit.

9.3.5 Supporting evidence for loss-inclusive LV policy changes

Ahead of this project concluding, the WPD Losses Strategy introduced an updated design policy for new LV feeder mains. This design policy avoids the use of tapering in the mains cable selection, and also specifies an uprated size of either 185 mm^2 or 300 mm^2 Waveform cable. One significant output of this project is the provision of more extensive evidence supporting this change. This design policy has been coded into the LV loss assessment software to quantify the reduction in losses arising from this policy (compared to continuation of pre-existing taping and sizing of LV cables), and the impact on costs.

The impact of this policy has been assessed as follows:

- If the existing cable is in the first mains branch, defined as being from the distribution substation to the first mains junction, then the branch is upgraded to 300 mm^2 Waveform cable. Mains branches that are downstream of the first mains junction are upgraded to 185 mm^2 Waveform cable. If any of the mains branches already have a resistance that is lower than the cable selected for upgrading then the existing cable type is retained.
- There is no change to service cables in this model.
- For each mains branch, the difference in losses with the upgraded cable type is then recorded, together with the lifetime cost impact[9].

This assessment shows a 17% reduction in losses for networks with the new-build policy compared to their existing construction. There would be a net increase in costs as the increased capital cost of the cables is not fully offset by reductions in the lifetime cost of losses. However, the total cost increases by only 1% when the installation costs are taken into account.

It should be noted that these figures are indicative of the loss reductions that could be achieved on new feeders, using the existing feeders as a guide to the network designs that are likely to be required. There is no indication that it would be cost-effective to upgrade existing cables solely from the perspective of losses. However, if cable replacement is required for other reasons then adopting the larger cable sizes specified in the Losses Strategy will reduce losses.

The rule-based approach for cable type selection defined in the Losses Strategy allows for a simple design policy that aims to reduce losses. A further exercise in looking to optimise cable size selection based on existing load suggested that a cost neutral solution might achieve a loss reduction of around 7%. The “loss-inclusive” LV design policy achieves higher loss reductions, with a small cost penalty, and also allows for higher capacity for future demand growth.

[9] The cost benefit is given by reduction in the cost of losses over the lifetime of the cable, minus the increased capital cost of installing the upgraded mains cable. The lifetime cost of losses is based on parameters given in WPD document SD1H, where cables are assumed to have an operation life of 40 years, and a discount rate of 3.5% is applied to costs. Over the 40-year life, a cost benefit of £1/year will provide a total of £21.40 lifetime cost benefit. The cost of losses is assessed at £48.42/MWh

9.4 Conclusions on information required to assess HV & LV feeder losses

As described in Section 4.3, Appendix C, and Appendix E, this project has developed "bottom-up" methods of assessing technical losses on HV and LV feeders at a DNO regional scale. In addition, as set out in Section 9, it has been concluded that no additional information (beyond existing business-as-usual data) is required to assess HV and LV network losses.

The data that has been used to assess the HV and LV feeder losses are listed here.

Network modelling data:

- HV network power-flow analysis system files – note these are ultimately derived from the WPD's GIS and asset record systems.
- Distribution transformer data
- LV network files from WPD/EA Technology's Electric Nation Project – note that these are derived from the WPD's asset record system.
- LV customer location and MPAN data.

Load modelling data:

- LV Profile Class 1-4 and NHH profile class 5-8 customers: MPAN, EAC, Profile class, LV feeder reference, and distribution substation.
- Statistical load probability distributions drawn from individual LV connections – derived from project work in the Isle of Man.
- Statistical load probability distributions drawn from LV feeder monitoring – derived from project work in Milton Keynes.
- LV and HV half-hourly metered customers: MPAN, half-hourly energy data, LV feeder reference (LV customers only), and distribution substation reference.
- HV feeder current measurements at primary substations.

10 Data Access Details

This project has principally been concerned with the development of the capability to assess HV and LV technical losses on an existing electricity distribution network, requiring minimal additional monitoring information. The methods of achieving this are extensively set out in Section 4 (what has been done, and how it has been done) and Section 8 (lessons learnt), plus the supporting appendices. The intellectual property associated with this is identified in Section 11.

Data associated with the project has been archived. Requests for data should be made via:

www.westernpower.co.uk/Innovation/Contact-us-and-more/Project-Data.aspx)

11 Foreground IPR

Foreground intellectual property (IP) has been developed under this project. The IP is described as: an assemblage of techniques that have been developed for assessing losses on individual HV and LV feeders, such that the predicted losses can be demonstrated to give an accurate representation of actual losses. The techniques combine multiple business-as-usual datasets, with operational measurement data and with statistical models derived from project measurements.

The intellectual property rights (IPR) are held jointly between Western Power Distribution, and Loughborough University.

In keeping with the intent of NIA funded projects to facilitate knowledge transfer, this Closedown Report contains an extensive description of these methods, allowing a third party to consider if they might wish to replicate the techniques that have been developed. Any party wishing to discuss a licence for the use of this IP should please contact WPD using the details contained in Section 14. Licenses to UK DNOs would be on a standard royalty free NIA IPR basis. It should be noted that the IPR relates to methods for application to a third parties own data.

12 Planned Implementation

The HV and LV loss assessment methods have already been implemented on a wide scale, covering all of the HV and LV feeders within the East Midlands license area for which valid data is available.

The HV loss assessment has generated inputs to WPD identifying a number of pole-mount transformers that are expected to have high no-load losses due to their age. These could potentially be replaced by new transformers with amorphous core technology and substantially lower no-load losses. Work undertaken under this project will contribute to identifying appropriate replacement candidates.

WPD is also making preparations to apply the developed loss assessment methods described in this report to the West Midlands, the South West and South Wales networks. The purpose of this would be to complete an initial assessment of the technical losses for all WPD networks. The results of this work will be reported in future Losses Strategy documents.

In addition, WPD is also preparing to undertake loss mitigation work using higher loss HV feeders that have been identified under this project. The results of this work will be reported in future Losses Strategy documents.

13 Other Comments

None.

14 Contact

Further details on replicating the project can be made available from the following points of contact:

Future Networks Team
Western Power Distribution,
Pegasus Business Park,
Herald Way,
Castle Donington,
Derbyshire
DE74 2TU
Email: wpdinnovation@westernpower.co.uk

Glossary

Abbreviation	Term
BaU	Business as usual
CSA	Cross sectional area
DG	Distributed Generation
DNO	Distribution Network Operator
DUKES	Digest of UK Energy Statistics
EAC	Estimated Annual Consumption
EATL NAT	EA Technology's Network Assessment Tool, produced as part of the Electric Nation project.
EDMI	Meter design and manufacturing company.
Elexon	The not-for-profit company fulfilling the role of the Balancing and Settlement Company within the UK wholesale electricity market
GB	Great Britain
GIS	Geographic information system
GPRS	General Packet Radio Service, the mobile data service on 2G and 3G cellular communications systems.
GPS	Global Positioning System
GWh	Gigawatt hour
HH	Half Hourly
HV	High Voltage
I^2R	Loss assessment approach based on I^2R
IPR	Intellectual Property Register
LCT	Low Carbon Technologies
LV	Low Voltage
MPAN	Meter Point Administration Number
NHH	Non Half Hourly
NIA	Network Innovation Allowance
PICAS	Paper insulated corrugated aluminium sheath cable
PILCSWA	Paper insulated lead covered steel wire armoured cable
MUA	Manx Utilities (Manx Utilities Authority)
RMS	Root mean square
SCADA	Supervisor Control and Data Acquisition
VAr	Volt-ampere reactive
WPD	Western Power Distribution
XLPE	Cross-linked polyethylene cable

WESTERN POWER DISTRIBUTION

INNOVATION

NEXT GENERATION NETWORKS

LOSSES INVESTIGATION

CLOSEDOWN REPORT

APPENDICES

Contents of Appendices

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Appendix A Overview of monitored feeders

Feeder	Overview
Pilot feeder *- 940037-02 (Marlborough Street: The Woodlands)*	*UG2A, 4.8km.* *11 GM Subs.*
940043-03 (Fox Milne: Fox Milne Hotel)	UG2B, 13.3km. 16 GM Subs.
940046-03 (Wavendon Gate: Wavendon Gate Local)	UG1B, 2.1km. 8 GM Subs.
940046-08 (Wavendon Gate: Secondary School Walnut Tree)	UG2A, 8.5km. 13 GM Subs, 2 HV sites.
940041-10 (Newport Pagnell: Howard Way Tee Crawley Road)	UG1A, 3.8km. 3 GM Subs, 3 HV sites.
940041-08 (Newport Pagnell: Amway Tongwell)	MA1A, 19% OH, 2.4km. 4 GM Subs, 7 HV sites.
940041-09 (Newport Pagnell: Ackerman Tongwell Tee Aldrich Drive)	MB1A, 29% OH, 8.3km. 7 GM Subs, 4 PM sites.
940041-04 (Newport Pagnell: Riverside Park)	MA2A, 10% OH, 8.6km. 12 GM Subs, 2 HV sites, 7 PM sites.
940046-02 (Wavendon Gate: The Avenue)	MB2A, 37% OH, 12.0km. 8 GM Subs, 2 HV sites, 11 PM sites.
940036-11 (Wolverton: Energy from Waste RMU C))	MC1B, 76% OH, 15.7km. 7 GM Subs, 1 HV site 14 PM sites.
940045-04 (Olney: Silver End Olney)	OH1B, 87% OH, 23.9km. 8 GM Subs, 22 PM sites.

Table 9 Overview of HV monitored feeders

Feeder	Overview
Pilot feeder – around Douglas	*277m u/g mains cable* *187m u/g service cable* *13 – 1ϕ*
Dom#1	770m u/g mains cables 1054m u/g service cables 57 - *1ϕ*
Dom#2	431m u/g mains cables 742m u/g service cables 53 - *1ϕ + 2 – 3 ϕ*
Dom#3	794m u/g mains cables 885m u/g service cables 57 - *1ϕ*
I&C#1A	383m u/g mains cables 159m u/g service cables 9 - *3ϕ*
I&C#1B	408m u/g mains cables 189m u/g service cables 3 - *3ϕ* + 16 - 1ϕ
I&C#2	426m u/g mains cables 357m u/g service cables 6 - *1ϕ + 12 - 3ϕ*
I&C#3	484m u/g mains cables 118m u/g service cables 8 - *1ϕ +11 - 3ϕ*
OH#1	89m u/g mains, 289m OW mains 183m u/g, 114m o/h services 19 – *1ϕ*
OH#2	368m u/g mains, 546m ABC, 173m OW mains 488m services 28 - *1ϕ + 4 - 3ϕ*
OH#3	337m u/g mains, 393m OW mains 882m services 47 - *1ϕ + 1 - 3ϕ*

Table 10 Overview of LV monitored feeders

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Appendix B Calculation of losses for monitored feeders

Appendix B.1 Application of loss calculation methods to HV feeders

Method	Power difference	I^2R
Inputs required for the analysis	• Distribution Substation active power • Primary Substation active power	• Distribution Substation current amplitude and phase angle relative to voltage • Primary Substation HV voltage amplitude • Network topology data • Cable length data • Cable impedance data • Transformer impedances and losses
Loss calculation	• Active power into the network at the Primary Substation minus active power out of the network at all of the Distribution Substations	• Power flow calculation to determine current phasors, throughout the network then I^2R to determine loss • The phase angles between the three-phase voltages are not measured and so are assumed to be 120°
Outputs from the analysis	• End to end losses, including cables and transformers as one	• End to end losses • Apportioned losses in cables and transformers
Information not required in loss calculations	• Expected values of cable impedances and transformer impedances • Recorded current and voltage	• Distribution Substation voltage amplitudes • Primary Substation current amplitude and phase angle • Recorded power measurements
Consistency tests	• Equivalence to loss calculation using I2R method	• Equivalence to loss calculation using power difference method • Comparison of predicted Primary Substation current amplitude and phase angle with measured value • Comparison of predicted Distribution Substation LV voltages with measured values

Table 11 – Application of loss calculation methods to HV feeders

Appendix B.2 Application of loss calculation methods to LV feeders

Method	Power difference	I^2R
Inputs required for the analysis	• Customer node active power • Distribution Substation active power	• Customer node current amplitude and phase angle relative to voltage • Distribution Substation LV voltage amplitude • Network topology data • Cable length data • Cable impedance data
Loss calculation	• Active power into the network at the Distribution Substation minus active power out of the network at all of the customer nodes	• Power flow calculation to determine current phasors, throughout the network then I^2R to determine loss • The phase angles between the three-phase voltages are not measured and so are assumed to be 120°
Outputs from the analysis	• End-to-end losses in all cables sections together	• End to end losses • Apportioned losses in LV feeders mains and service cables
Information not required in loss calculations	• Expected values of cable impedances • Recorded current and voltage	• Customer node voltage amplitudes • Distribution Substation current amplitude and phase angle • Recorded power measurements
Consistency tests	• Equivalence to loss calculation using I^2R method	• Equivalence to loss calculation using power difference method • Comparison of predicted Distribution Substation current amplitude and phase angle with measured value • Comparison of predicted customer node voltage with measured values

Table 12 – Application of loss calculation methods to LV feeders

Appendix B.3 Loss Metrics

Three phase power measurements
The demand and losses are presented in this report in terms of the total power in all three-phases.

For analysis of LV feeders, where a neutral conductor exists, it would be possible to specify the power per phase as the product of the line-to-neutral voltage and the phase current, but losses in the neutral arise due to the balance of currents and are not clearly attributed to any one phase.

A similar difficulty arises for HV feeders, but where there is no physical neutral the line-to-neutral voltages depend on the arbitrary choice of a neutral voltage. If this neutral voltage is defined by the star-point of a voltage transformer network, it may differ from neutral voltages elsewhere, such as at the primary substation.

These complexities are resolved by considering demand and loss powers as the total across all three phases.

Percentage Losses
Losses are presented here using several different metrics in order to facilitate comparison with other studies and also with standard industry practice.

For a conventional power flow direction, there is a power input $P_{\text{in,sub},t}$ at time t at the upstream substation. For each downstream connection k, there is a power output of $P_{out,t,k}$. If there is embedded generation on the feeder, then individual downstream values of $P_{out,t,k}$ may be negative, and if there is an upstream power-flow from the entire feeder then $P_{\text{in},t}$ will also be negative.

Values of power are defined as being positive for power-flow in the downstream direction.

The mean active input power $\bar{P}_{\text{in}}$ supplied into the feeder over N_{t} time samples is:

$$\bar{P}_{\text{in}} = \frac{1}{N_{\text{t}}} \sum_{t=1}^{N_{\text{t}}} P_{\text{in,sub},t}$$

The mean loss power $\bar{P}_{loss}$ is given by the difference of the mean input power and the mean output power at N_k downstream distribution points:

$$\bar{P}_{loss} = \frac{1}{N_t} \sum_{t=1}^{N_t} \left(P_{in,t} - \sum_{k=1}^{N_k} P_{out,t,k} \right)$$

The mean losses can also be presented as a percentage loss of the input power to the network:

$$\text{Percentage loss} = 100 \times \bar{P}_{loss}/\bar{P}_{\text{in}}$$

If the feeder has embedded generation, and if this generation supplies most of the demand on the feeder, then the mean power input from the upstream substation could be very low (and theoretically could be zero). The percentage loss, as shown above could then be very high, suggesting that the network is operating inefficiently. An alternative metric which describes the efficiency of the network better in such cases uses the total power imported into the network to characterise the demand.

The mean network import power from the upstream substation and from each of the N_k downstream connections given by:

$$\bar{P}_{\text{import}} = \bar{P}_{\text{import,sub}} + \sum_{k=1}^{N_k} \bar{P}_{\text{import},k}$$

where the mean powers at the substation consider only positive values, such that

$$\bar{P}_{\text{import,sub}} = \frac{1}{N_{\text{t}}} \sum_{t=1}^{N_{\text{t}}} \max\left[P_{\text{in,sub},t}, 0\right]$$

and the mean powers at downstream connections only include power flowing upstream

$$\bar{P}_{\text{import},k} = \frac{1}{N_{\text{t}}} \sum_{t=1}^{N_{\text{t}}} \max\left[-P_{\text{out},t,k}, 0\right]$$

The percentage loss is then calculated relative to the network import power

The loss power could be calculated for the feeder overall, or alternatively for specific loss mechanisms, e.g. cable losses, transformer load losses, transformer no-load losses, or LV metering.

Careful interpretation is needed for the transformer losses, where they are expressed relative to the network import power of the HV feeder, or of the power input at the primary substation, since some of this power may be delivered to HV customer connections and does not pass through a distribution transformer. This includes substations where the distribution transformer is managed by an Independent DNO (IDNO). The results in this report show transformer losses as a percentage of the network import power to the feeder, but the percentage losses of power that passes through transformers would be higher.

Appendix B.4 Vulnerability to measurement tolerances

The need for the I^2R method arises partly as a means of investigating the breakdown of the total losses but mostly due to the vulnerability of the power difference method to tolerances in the measurement sensors. As described below, this limits the effectiveness of the power difference method when the magnitude of the losses is small compared to the measurement tolerances of the current and voltage sensors.

A simple example could be considered for a feeder network in which the actual losses are 1% of the delivered power. The power recorded by each logging instrument is calculated based on the product of the measured current and voltage, both of which are subject to measurement tolerances. If the combined effect of both the current and the voltage measurement tolerances gives a ±2% accuracy tolerance, then the calculated losses will have an accuracy of approximately ±4% relative to the input power. If the input power is measured to be 2% higher than the actual value and all of the output powers are measured to be 2% lower than the actual value, then the loss could appear to be 5%. Similarly, if the input power is measured to be 2% lower than the actual value, and all of the output powers are measured to be 2% higher than the actual value, then the loss could appear to be -3%. Depending on the sensor errors, the power difference method can therefore indicate a negative loss of power.

Where there are many downstream nodes in the network with similar power demands, if the measurement errors are independent and if the measured values are symmetrically distributed about the actual values, then the combined impact of tolerances on the measured output power would be expected to average to zero. However, the upstream input power to the network is measured by only one instrument (unless others are provided for redundancy) and so the power difference calculation for the example above would then give loss results in the range of 1% to +3% of the input power to the network.

Experience from lab tests of the measurement equipment has demonstrated that the measurement tolerances are mostly determined by the calibration of the sensors and the positioning of the current sensors around the conductors. Since the calibration and positioning remain constant over time (unless the sensors are moved), the errors appear more as constant offsets than as random perturbations on each measurement sample and so the benefits from longer-term averaging are reduced.

If it is known that the network has no embedded generation, then it would be possible to discount negative loss figures. However, if the results from several similar networks are averaged so as to obtain a more representative loss figure than provided by one feeder alone, then this truncation of the range of values introduces a positive bias into the loss estimates. Again assuming an independent and symmetrical distribution of measurement errors at the upstream nodes on all of the feeders, the average losses tend towards the actual value if the full range of calculated values is retained for each feeder.

Loss calculations using the I^2R method are less sensitive to the impact of measurement tolerances. The I^2R calculation of losses in each cable branch is equivalent to the current in the branch multiplied by the voltage difference along the cable. This is approximately independent of the absolute voltage at the upstream terminal of the cable (other than for second order effects such as the voltage dependency of the transformer magnetising current) and so errors in the upstream voltage measurement have minimal impact on the estimated losses. The method is affected by errors in the current measurement and a ±1% error in the current amplitude will result in an error of approximately ±2% on the square of the current. However, this error factor is applied to the estimated loss power, rather than to the input power (as with the power difference method), such that the losses estimate ranges between 0.98% and 1.02% of the input power.

Clearly, this method also relies on the accuracy of the impedances used in the calculation. If these were known to a tolerance of ±5% then the RMS error margin for the example described here increases from ±2% to ±5.4%. The loss estimates would then range between 0.95% and 1.05% of the input power to the network.

The key benefit of the I^2R method is therefore that the tolerances apply directly to the measurements that vary in proportion (linearly or as a quadratic) to the loss estimate. This contrasts with the power difference method where the tolerances apply to all of the delivered power rather than just the power differences.

Appendix B.5 Synchronisation of different instruments

In principle, the GridKey loggers and EDMI meters used in the trials instrumentation are synchronised to clock references. This seeks to avoid errors that would occur due to timing differences between the instruments if free-running internal clocks were to drift.

The GridKey loggers are re-synchronised to the time server-sourced time reference once per day. However, residual differences in the timing can still occur due to clock drift within the 24 hour period between resets, and due to differences in the round-trip communications in the GPRS wireless modems. These remaining time differences are not known to have any negative impact on the trials analysis.

The EDMI meters could be synchronised to the clock timing of the PC used for daily data collection, and this PC clock is in turn synchronised via Network Time Protocol to a GPS reference. For most of the trials duration, the EDMI meter clocks were re-synchronised each day, but this process was disabled for some months due to concerns about an interaction causing errors with the data collection process. It was also noted that the clock synchronisation process did not always operate correctly, in some cases requiring a lower level reset of the meters.

The LV trials, incorporating the EDMI and GridKey loggers, were therefore more subject to timing errors than the HV trials which used GridKey loggers throughout. Timing differences are also more critical for the LV trials than for the HV trials as the demand is much less aggregated and so has a more spikey profile. The demand current can change significantly within seconds and so timing differences between the meters, or between the meters and the GridKey logger, can have a significant impact.

The power difference method is more vulnerable to timing errors than the I^2R method. Considering the example of the LV trials, if the EDMI meters at the customer connections have an advanced timing reference with respect to the GridKey logger at the substation, then a spike in the demand will appear to arrive later when the time-stamps are aligned in the data analysis. In the 1-minute period with the rising edge of the demand current, this will indicate a higher loss than actually occurred, as less of the power delivered to customers will appear within the sample interval of the power output from the network. Conversely, in the 1-minute period with the falling edge of the demand spike will appear to have a lower loss than actually occurred as the output will include the delayed energy missing from the earlier samples. This apparent delayed energy can cause the power difference results to appear negative.

Timing differences also affect the results of the I^2R analysis but to a much lesser extent. When the current in the network is calculated, based on the sum of the measured currents at the downstream nodes, errors will be introduced if the meter timing was incorrect. However, variations in the demand at each downstream node can mostly be considered to be independent over short time-scales (seconds or minutes). Measurements of demand with timing errors therefore represent a scenario that could plausibly have occurred, even if this was not the exact demand profile that occurred in reality. The losses are therefore representative of the actual losses and not systematically over- or under-estimated.

An example showing the variation of loss vs. demand for the LV pilot feeder is shown in Figure 62, with each point representing a 1-minute sample period. The results for the power difference method have a significantly greater spread than the results for the I^2R method although both sets of points have a similar mean for the same level of demand. As described in Appendix B.4, results from the power difference method can be negative.

The impact of timing differences can be mitigated by averaging the loss results over blocks of consecutive samples. This reduces the errors in the 1-minute results where timing differences can cause power to appear to be delayed from one sample to the next. Results with 10-minute averaging of the loss results are shown in Figure 63. The power difference results here still have a greater spread than the I^2R results but the range is much reduced (approximately by a factor of 10 for 10-minute averaging). The averaging reveals the similarity between the power difference and I^2R results, and allows an offset between the results from the two methods to be observed. This offset is consistent with the impacts of measurement sensor tolerances.

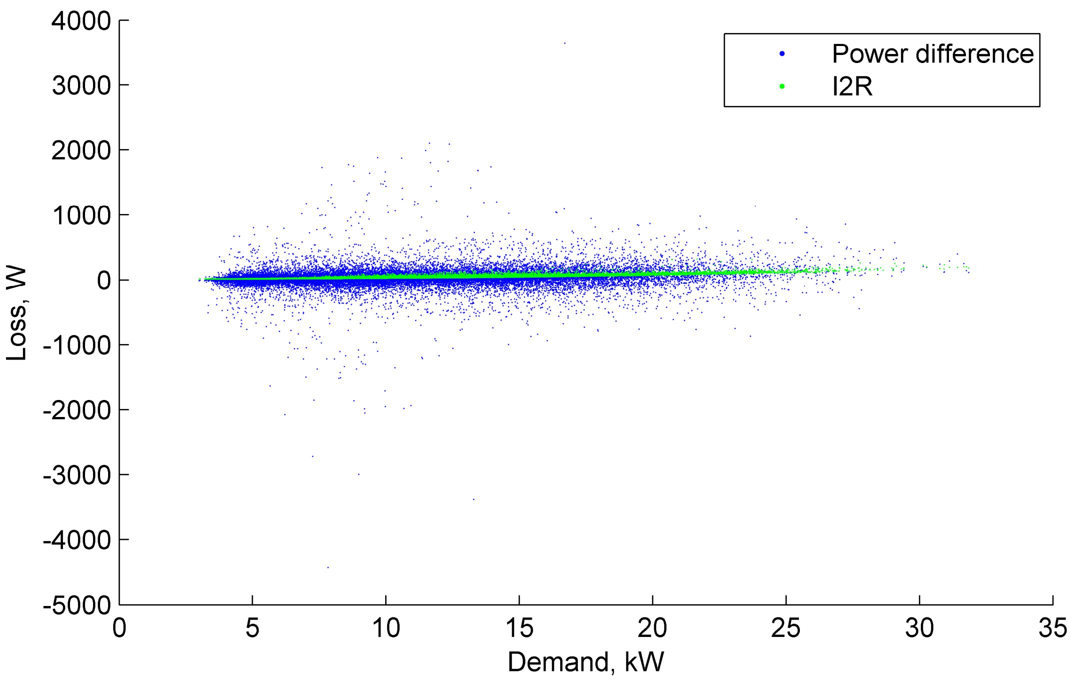


Figure 62 Loss vs demand per 1-minute sample for LV Pilot feeder

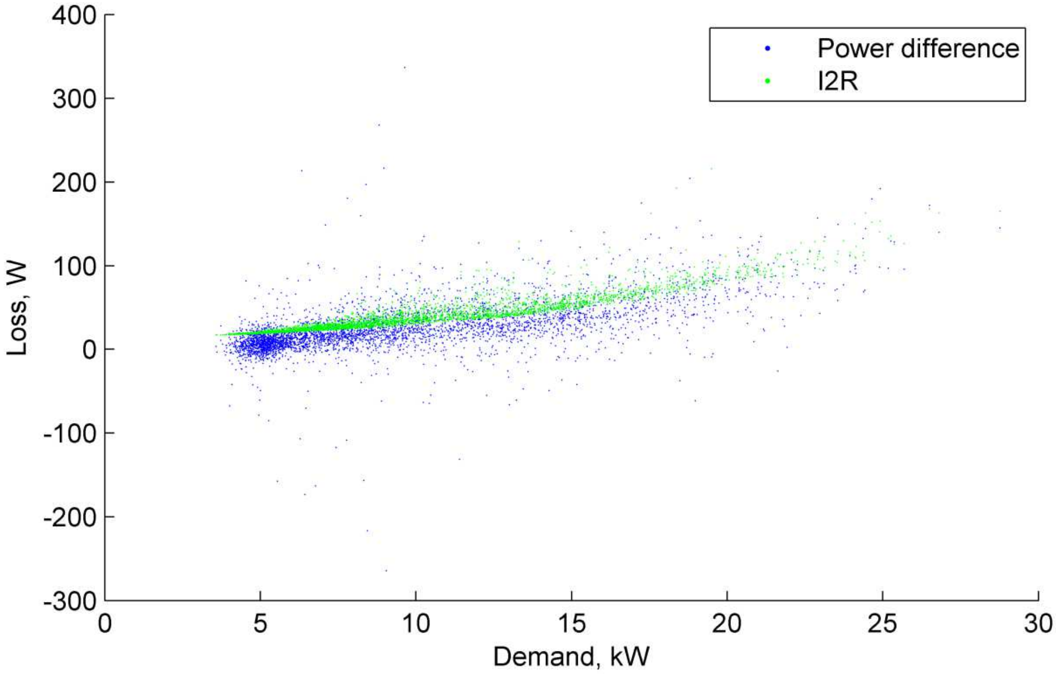


Figure 63 Loss vs demand per 1-minute sample for LV Pilot feeder with 10-minute averaging of the loss results

Appendix B.6 Metering Losses

The LV feeder losses described in this report include a contribution due to the power consumed in the metering installed at each customer connection. A loss power of 1.1 W per meter has been used, based on measurements of monitoring meters. This loss power is added to the cable losses from the I^2R loss calculation in order to determine the total feeder losses. For many feeders, particularly domestic feeders with many customers, the losses due to metering represent a significant proportion of the total losses, as indicated in Figure 64.

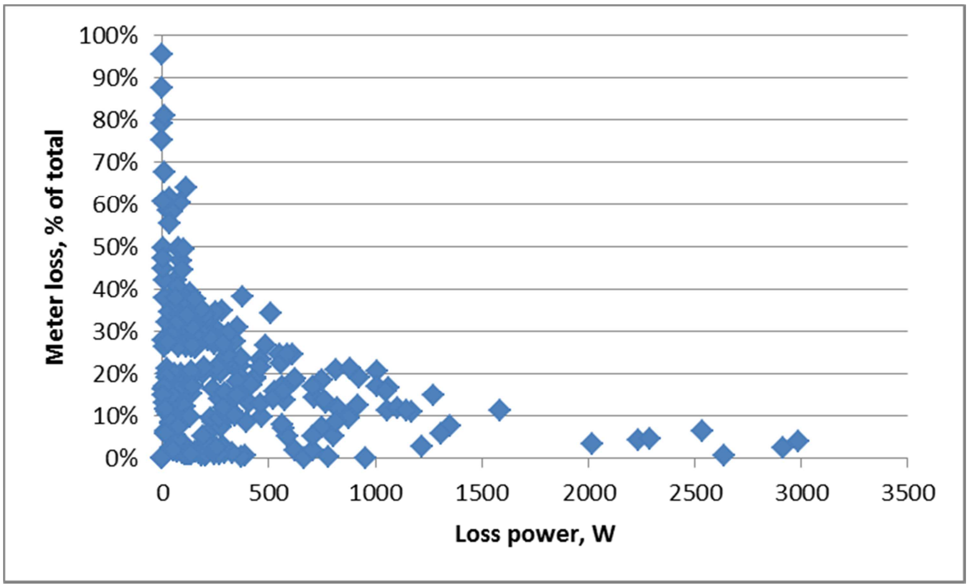


Figure 64 Metering loss as a proportion of the total loss power for LV feeders in Milton Keynes trial.

The EDMI Mk7C and Mk10A meters used for the trials are compliant to BS EN 62053-21 and BS EN 62053-23, both of which specify the power consumption as 2W for voltage measurement and for the power supply. These standards date from 2003, before the development of smart meters. An exception is noted for multi-function meters for which the voltage circuit power consumption is specified in BS EN 62053-61:1998. This allows up to 3 W for a single-phase 'multi-energy meter', defined as a meter that measures multiple energy quantities (watt-hours, VAr-hours etc.). The consumption of a 'multi-function meter' may be up to 5 W, where this relates to meters that provide additional functions such as time switching or ripple control. However, it is also noted that communication devices and functions not related to energy metering and billing, such as voltage and current or harmonic analysis, are outside the scope of the standard.

A summary of smart meter losses has been provided by Ofgem[10] suggesting a total loss of between around 5 W for a single-phase smart meter, allowing for the communications modem and an in-house-display.

[10] Ofgem, "Energy efficiency directive: An assessment of the energy efficiency potential of Great Britain's gas and electricity infrastructure," 2015.

The datasheet for the EDMI meters quotes a burden of 10 VA per phase for the voltage measurement and 0.5 VA per phase for the current measurement. The Mk7C meter datasheet also specifies a burden of 0.5 VA per phase in the current circuit. This differs from the allowance for the current circuit in BS EN 62053-21 which is defined as 5.0 VA at 'basic current' for directly connected meters. This appears to leave the actual voltage circuit power consumption poorly defined for the Mk7C meter.

Further data provided by EDMI for the Losses Investigation quotes a loss of 1.1 W per meter, either single-phase or three-phase. A series of tests were then conducted in conjunction with Manx Utilities in order to verify this loss value. The tests confirmed this loss of 1.1 W and also indicated a reactive power contribution of +1.5 VA at 50 Hz. The meters were also found to introduce harmonic distortion to the current, with a total reactive power of 2.76 VA if this is also included.

The loss analysis therefore represents each customer meter as a load of 1.1 + 1.5 VA for calculations at 50 Hz, which is consistent with the values provided by the manufacturer. However, the standards allow for other smart meters to consume a significantly higher power and this may affect LV feeder losses in the future.

Appendix C Monitored feeders loss assessments

Appendix C.1 HV feeders

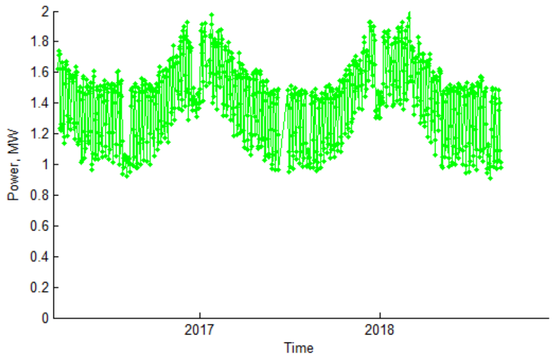


Figure 65 Long term mean daily feeder demand (Woodlands HV feeder)

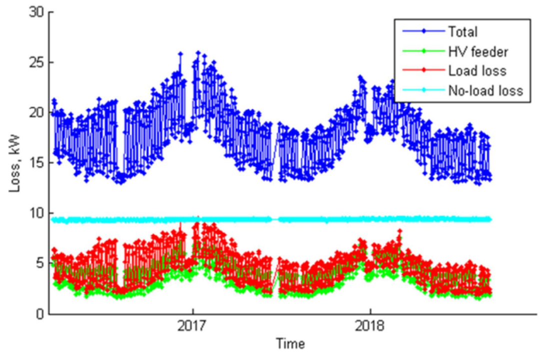


Figure 66 Long term mean daily (I^2R) loss (Woodlands HV feeder)

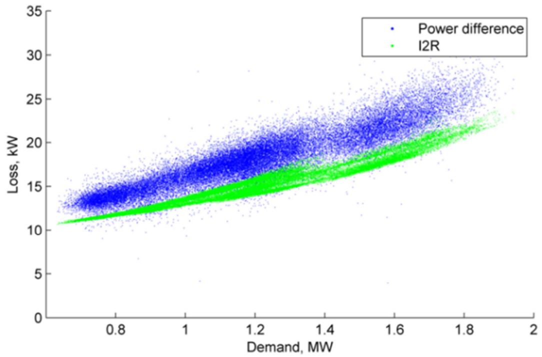


Figure 67 Aug 2018 Loss, kW vs demand (Woodlands HV feeder)

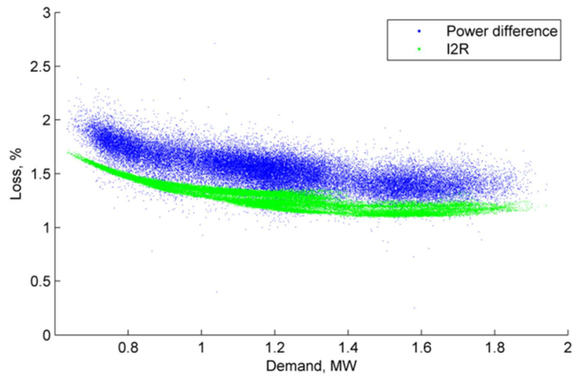


Figure 68 Aug 2018 Loss, % vs demand (Woodlands HV feeder)

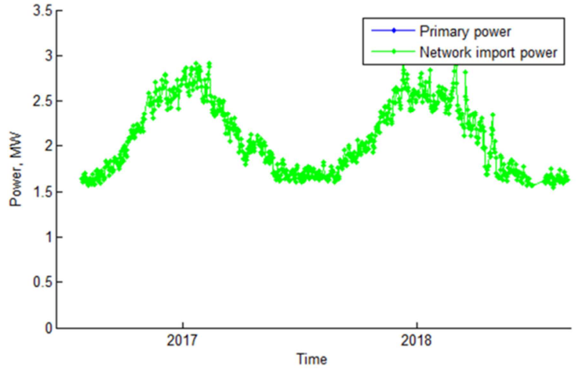


Figure 69 Long term mean daily feeder demand (Fox Milne Hotel HV feeder)

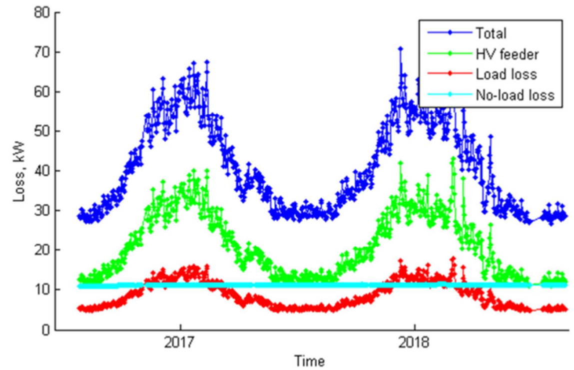


Figure 70 Long term mean daily (I^2R) loss (Fox Milne Hotel HV feeder)

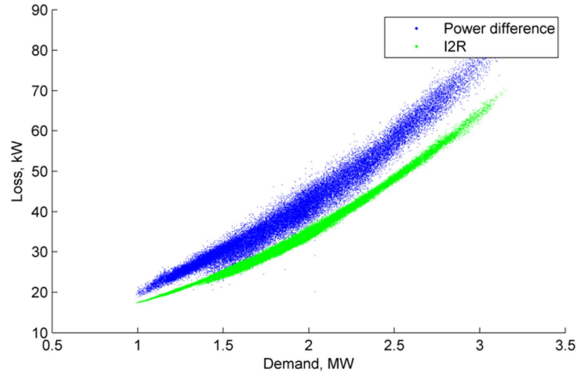


Figure 71 May 2017 Loss, kW vs demand (Fox Milne Hotel HV feeder)

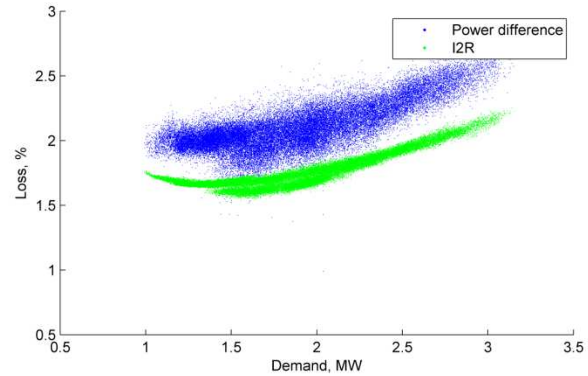


Figure 72 Aug 2017 Loss, % vs demand (Fox Milne Hotel HV feeder)

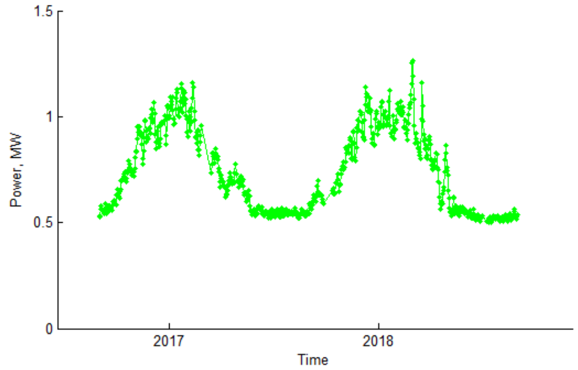


Figure 73 Long term mean daily feeder demand (Wavendon Gate Local HV feeder)

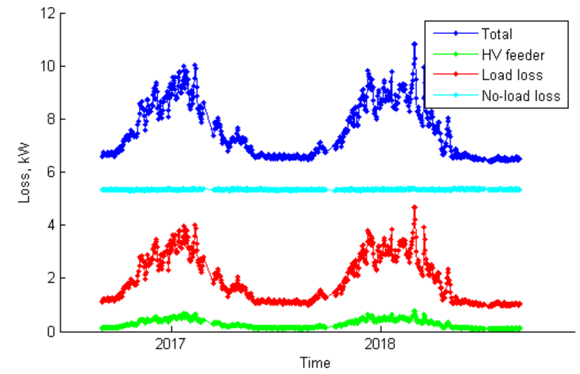


Figure 74 Long term mean daily (I^2R) loss (Wavendon Gate Local HV feeder)

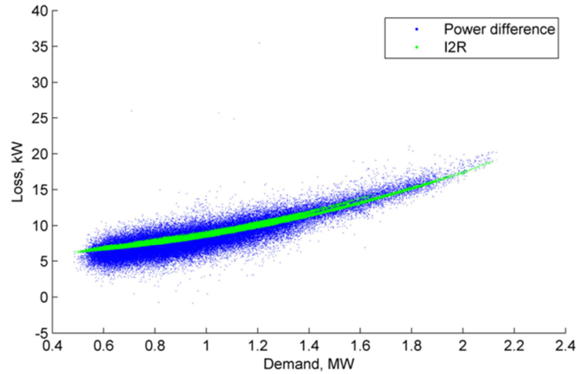


Figure 75 Mar 2018 Loss, kW vs demand (Wavendon Gate Local HV feeder)

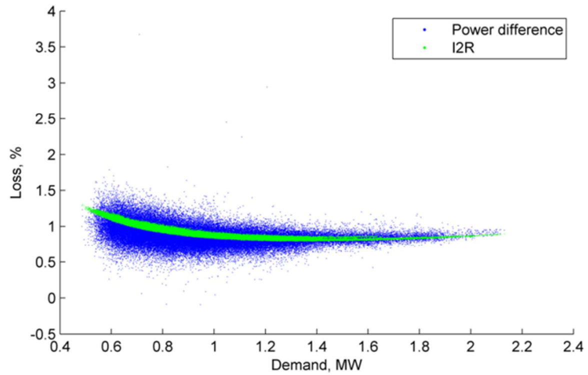


Figure 76 Mar 2018 Loss, % vs demand (Wavendon Gate Local HV feeder)

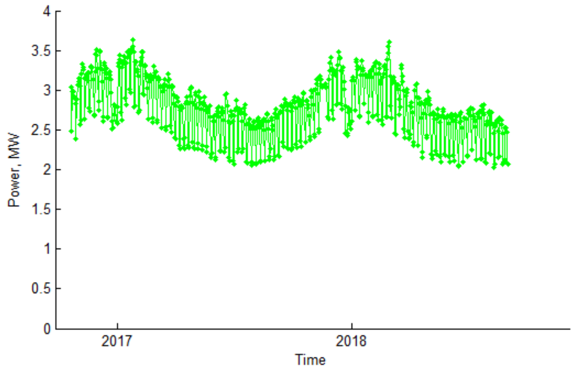


Figure 77 Long term mean daily feeder demand (Secondary School Walnut Tree HV feeder)

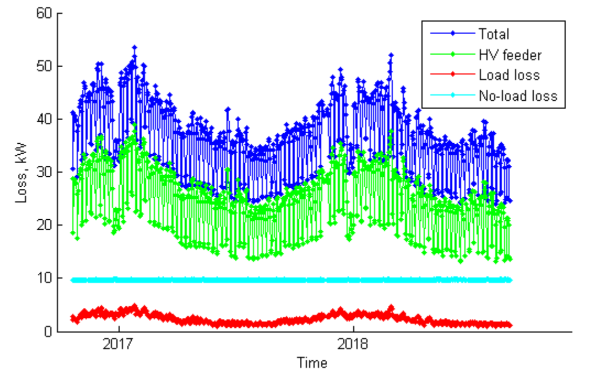


Figure 78 Long term mean daily (I^2R) loss (Secondary School Walnut Tree HV feeder)

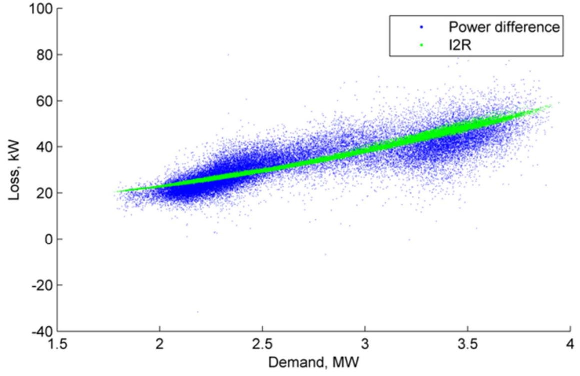


Figure 79 May 2017 Loss, kW vs demand (Secondary School Walnut Tree HV feeder)

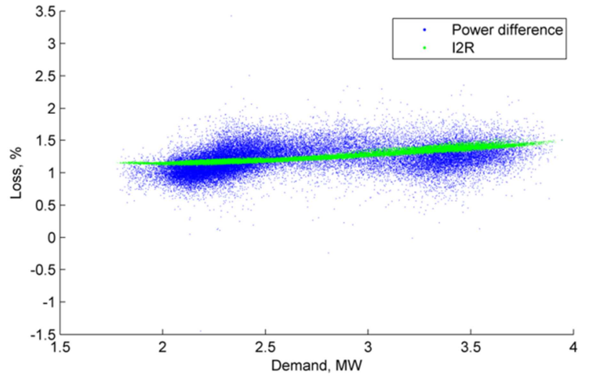


Figure 80 May 2017 Loss, % vs demand (Secondary School Walnut Tree HV feeder)

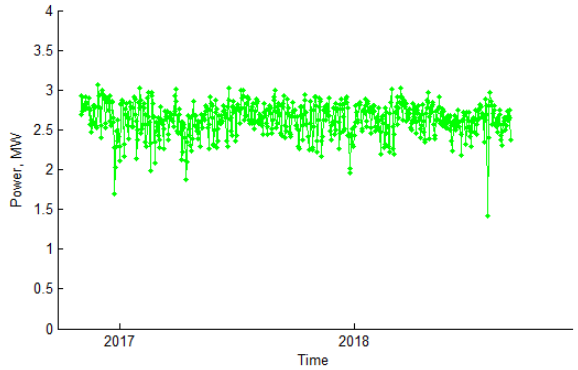


Figure 81 Long term mean daily feeder demand (Crawley Road Tee Howard Way HV feeder)

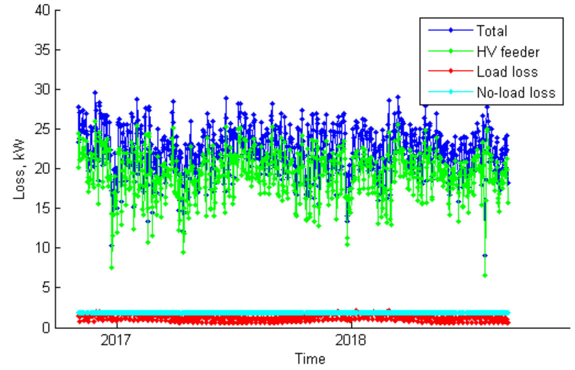


Figure 82 Long term mean daily (I^2R) loss (Crawley Road Tee Howard Way HV feeder)

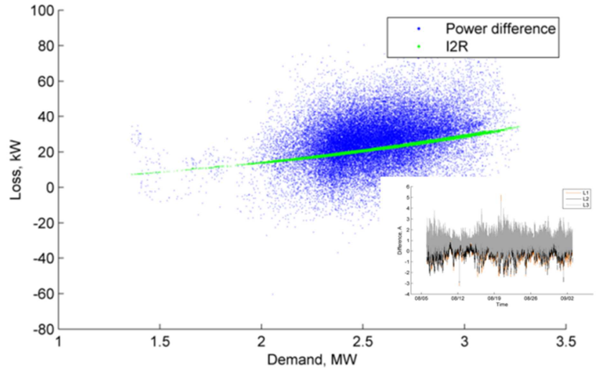


Figure 83 Aug 2018 Loss, kW vs demand (Crawley Road Tee Howard Way HV feeder)

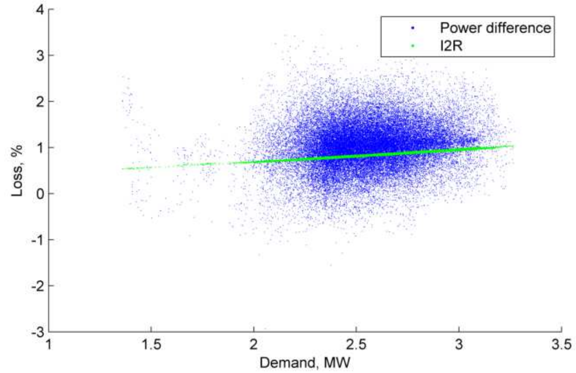


Figure 84 Aug 2018 Loss, % vs demand (Crawley Road Tee Howard Way HV feeder)

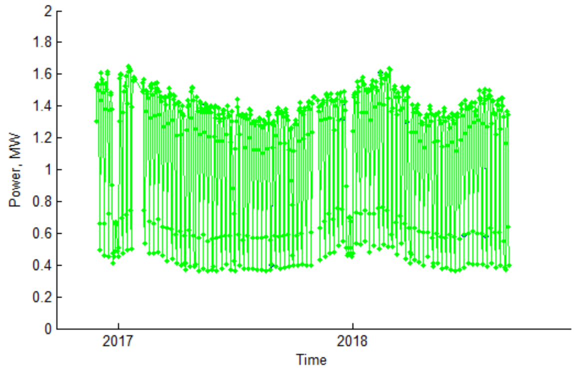


Figure 85 Long term mean daily feeder demand (Amway Tongwell HV feeder)

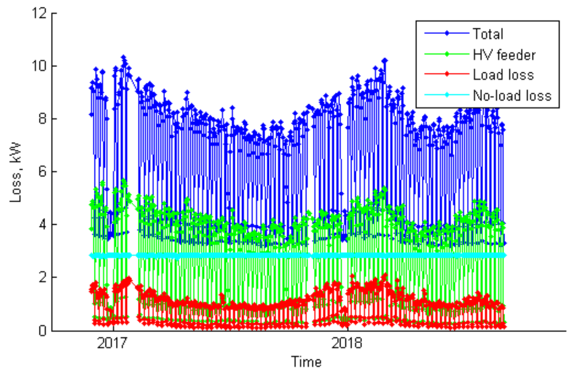


Figure 86 Long term mean daily (I^2R) loss (Amway Tongwell HV feeder)

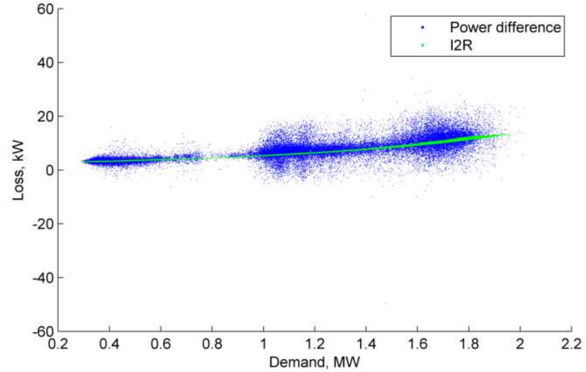


Figure 87 Aug 2018 Loss, kW vs demand (Amway Tongwell HV feeder)

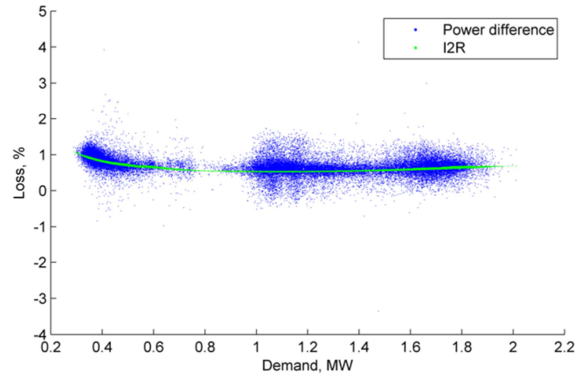


Figure 88 Aug 2018 Loss, % vs demand (Amway Tongwell HV feeder)

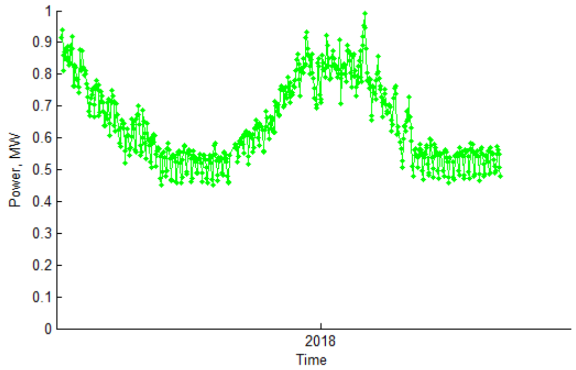


Figure 89 Long term mean daily feeder demand (Ackerman Tongwell Aldrich Drive Tee HV feeder)

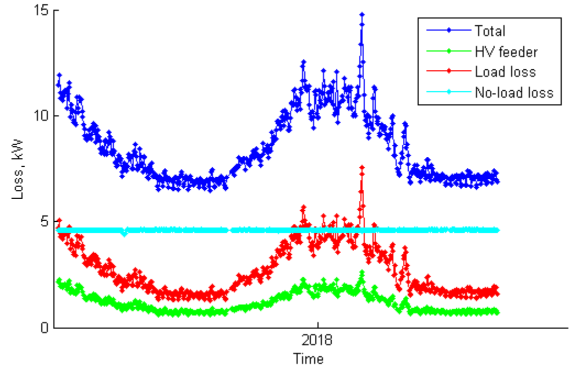


Figure 90 Long term mean daily (I^2R) loss (Ackerman Tongwell Aldrich Drive Tee HV feeder)

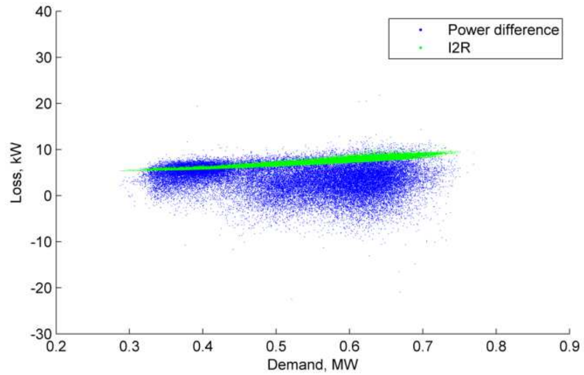


Figure 91 Aug 2018 Loss, kW vs demand (Ackerman Tongwell Aldrich Drive Tee HV feeder)

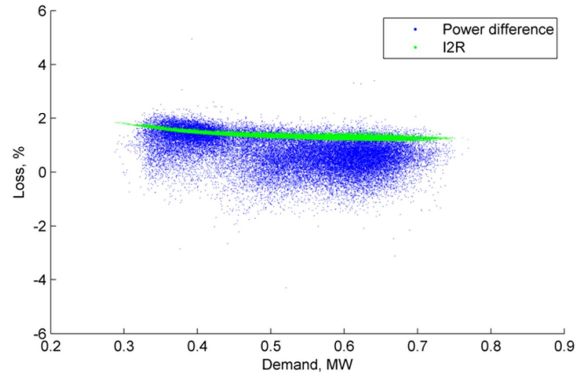


Figure 92 Aug 2018 Loss, % vs demand (Ackerman Tongwell Aldrich Drive Tee HV feeder)

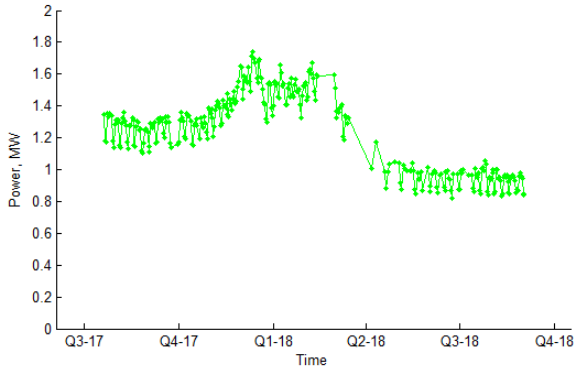


Figure 93 Long term mean daily feeder demand (The Avenue HV feeder)

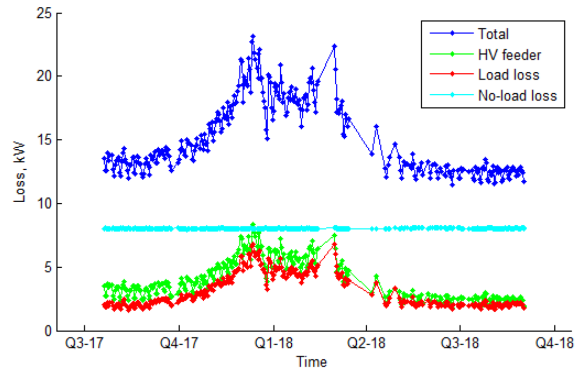


Figure 94 Long term mean daily (I^2R) loss (The Avenue HV feeder)

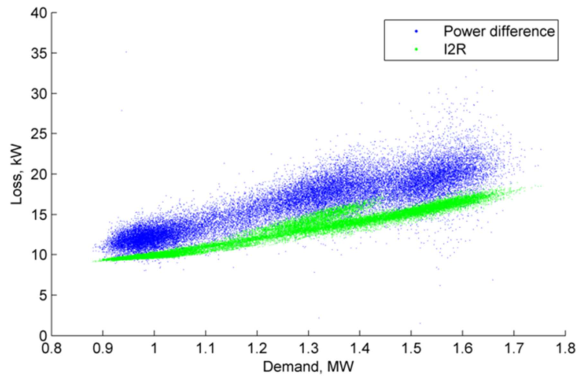


Figure 95 Sep 2017 Loss, kW vs demand (The Avenue HV feeder)

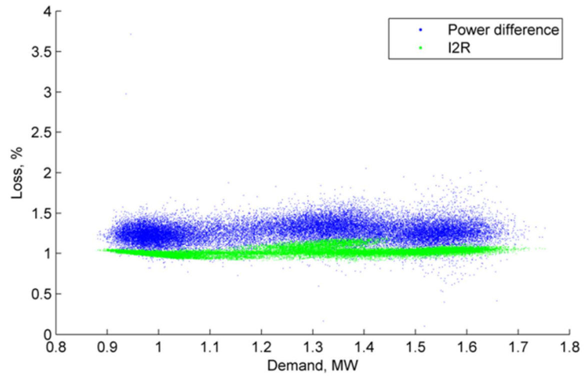


Figure 96 Sep 2017 Loss, % vs demand (The Avenue HV feeder)

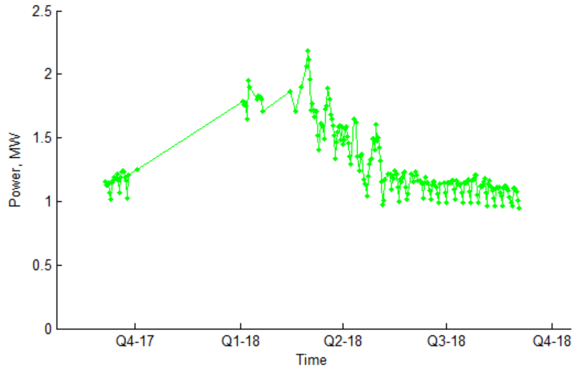


Figure 97 Long term mean daily feeder demand (Riverside Park HV feeder)

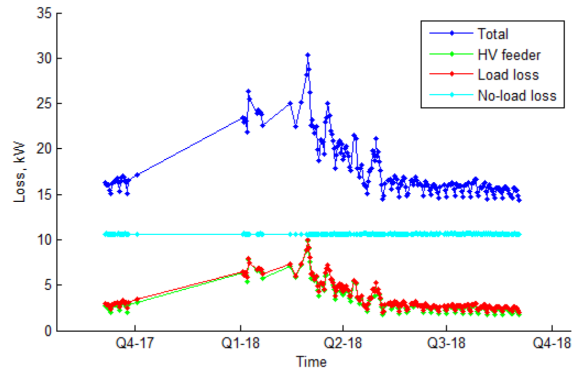


Figure 98 Long term mean daily (I^2R) loss (Riverside Park HV feeder)

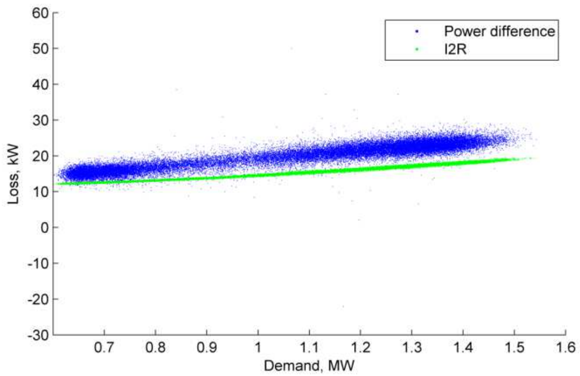


Figure 99 Aug 2018 Loss, kW vs demand (Riverside Park HV feeder)

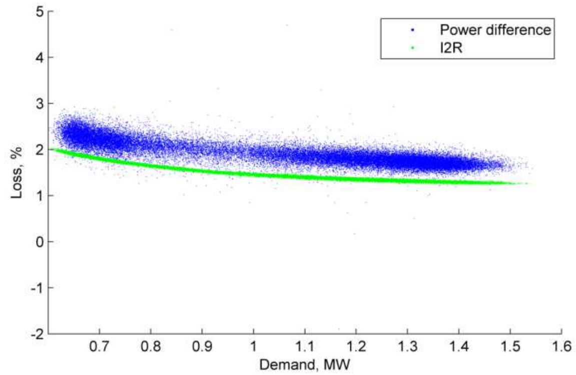


Figure 100 Aug 2018 Loss, % vs demand (Riverside Park HV feeder)

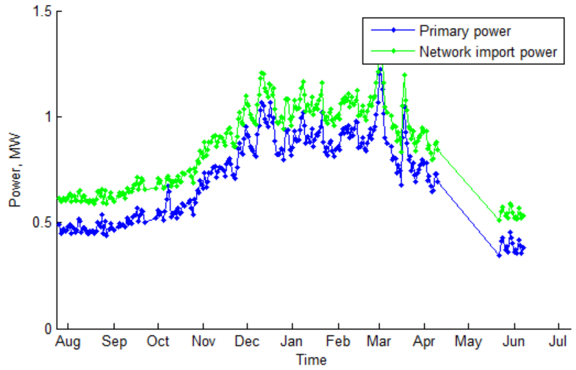


Figure 101 Long term mean daily feeder demand (Silver End HV feeder)

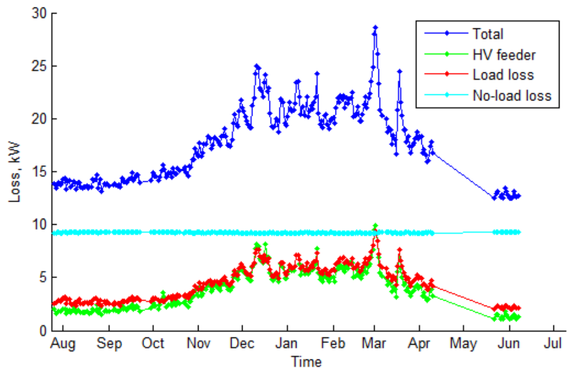
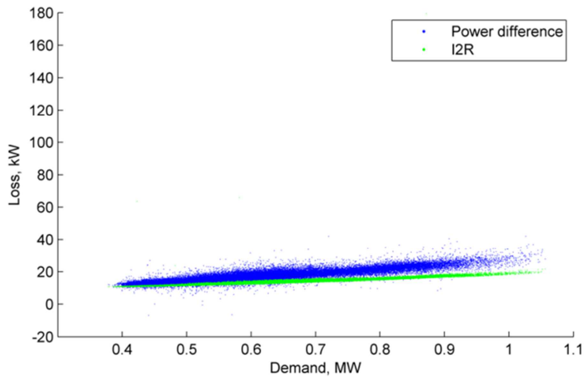


Figure 102 Long term mean daily (I^2R) loss (Silver End HV feeder)



n/a

Figure 103 Jul/Aug 2017 Loss, kW vs demand (Silver End HV feeder)

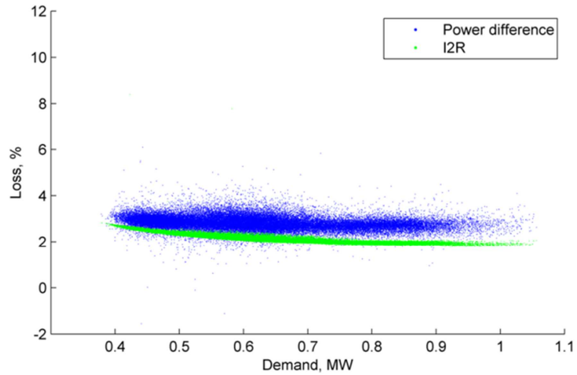


Figure 104 Jul/Aug 2017 Loss, % vs demand (Silver End HV feeder)

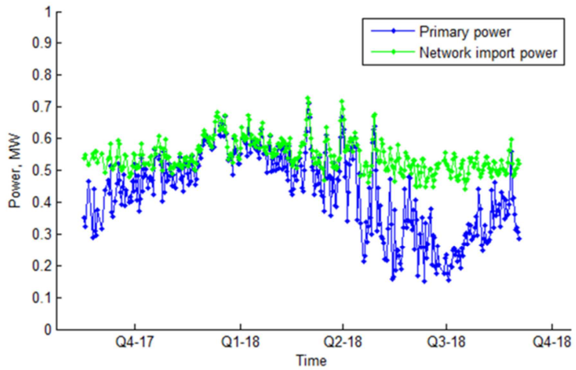


Figure 105 Long term mean daily feeder demand (Wolverton HV feeder)

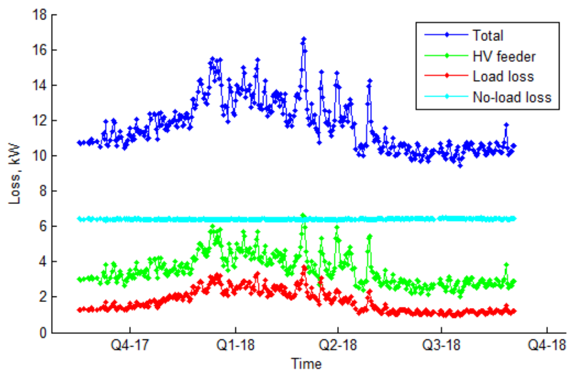


Figure 106 Long term mean daily (I^2R) loss (Wolverton HV feeder)

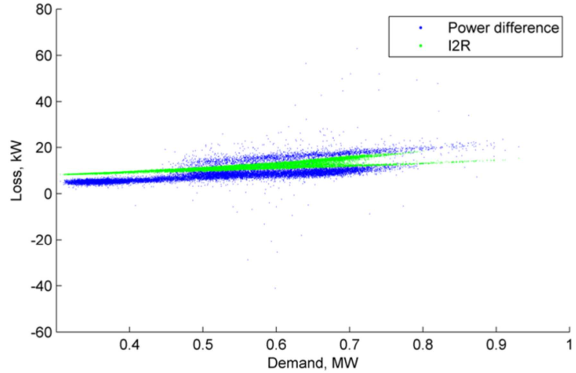


Figure 107 Aug 2017 Loss, kW vs demand (Wolverton HV feeder)

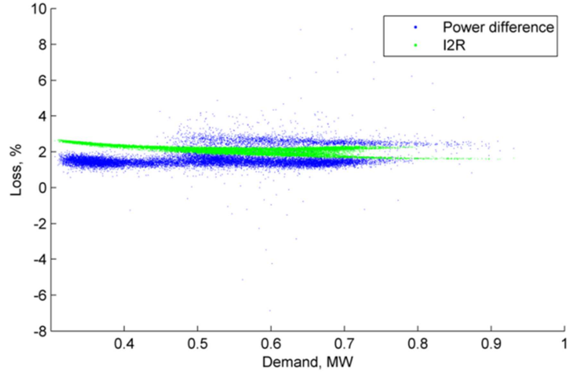


Figure 108 Aug 2017 Loss, % vs demand (Wolverton HV feeder)

Appendix C.2 LV feeders

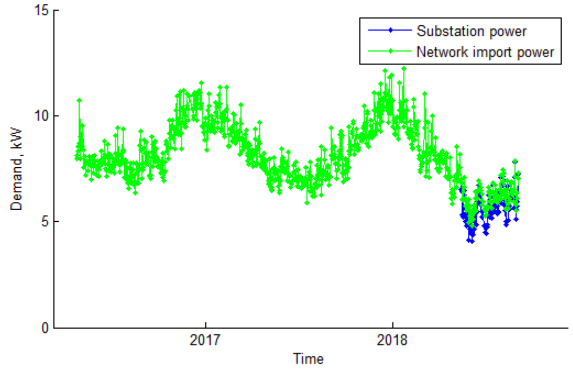


Figure 109 Long term mean daily feeder demand (Domestic Pilot LV feeder)

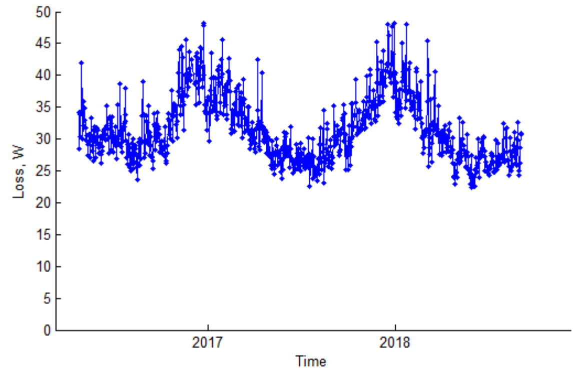


Figure 110 Long term mean daily (I^2R) loss (Domestic Pilot LV feeder)

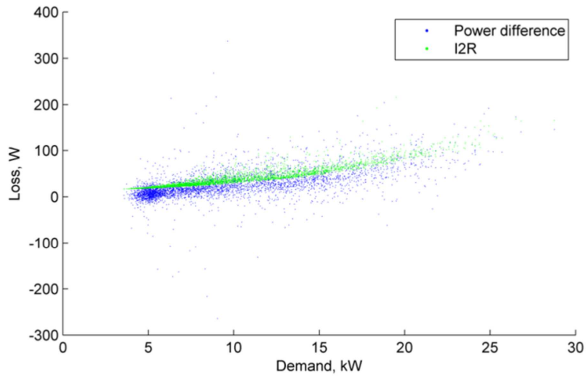


Figure 111 Jan 2018 Loss, kW vs demand, 10 min. av. (Dom. Pilot LV feeder)

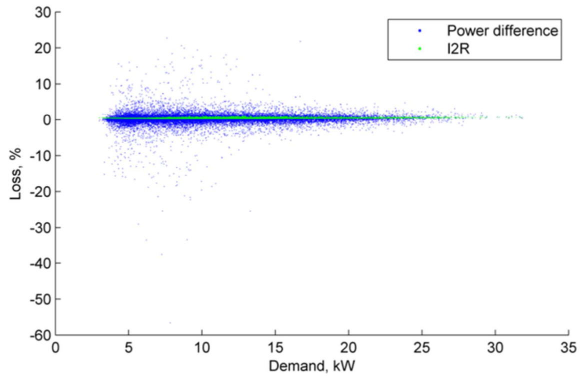


Figure 112 Jan 2018 2017 Loss, % vs demand, 1 min. av. (Dom. Pilot LV feeder)

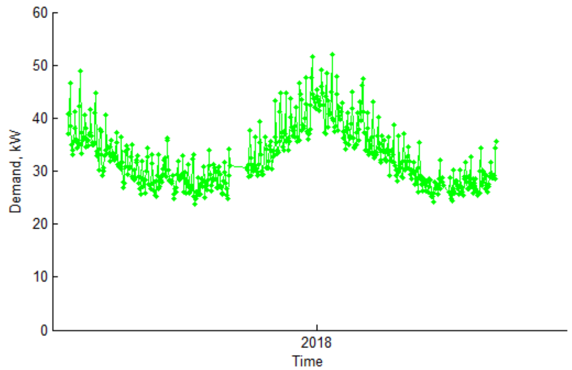


Figure 113 Long term mean daily feeder demand (Laxey Dom. LV feeder)

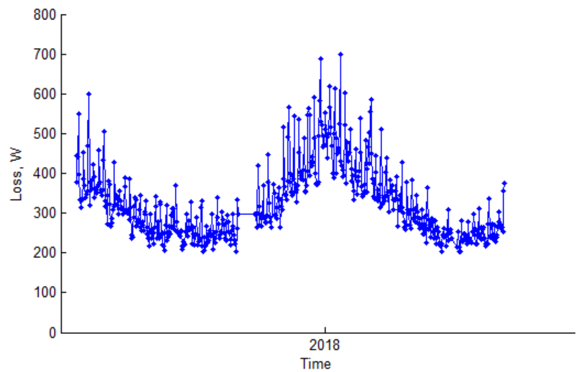


Figure 114 Long term mean daily (I^2R) loss (Laxey Dom. LV feeder)

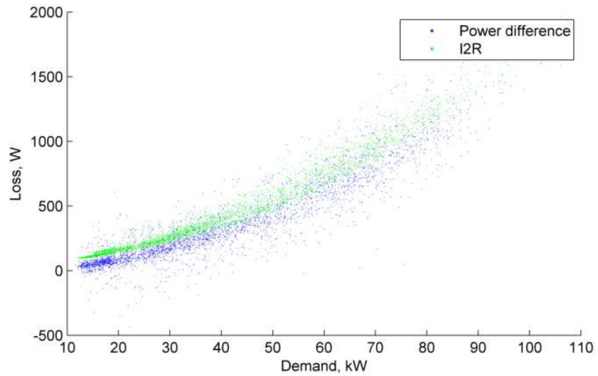


Figure 115 Jan 2018 Loss, kW vs demand, 10 min. av. (Laxey Dom. LV feeder)

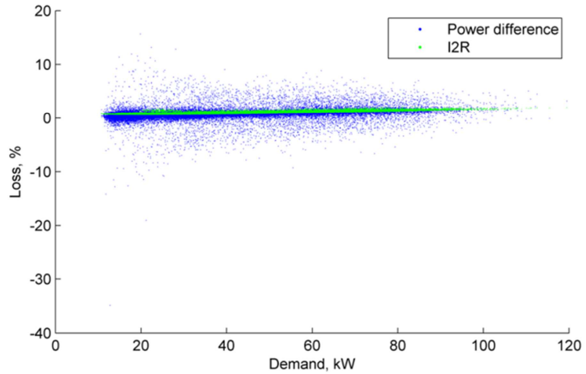


Figure 116 Jan 2018 Loss, % vs demand, 1 min. av. (Laxey Dom. LV feeder)

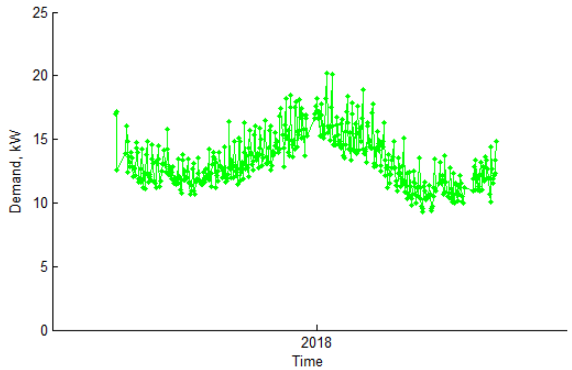


Figure 117 Long term mean daily feeder demand (Ramsey Dom. LV feeder)

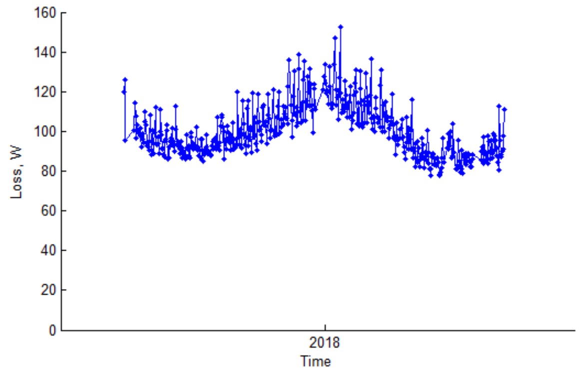


Figure 118 Long term mean daily (I^2R) loss (Ramsey Dom. LV feeder)

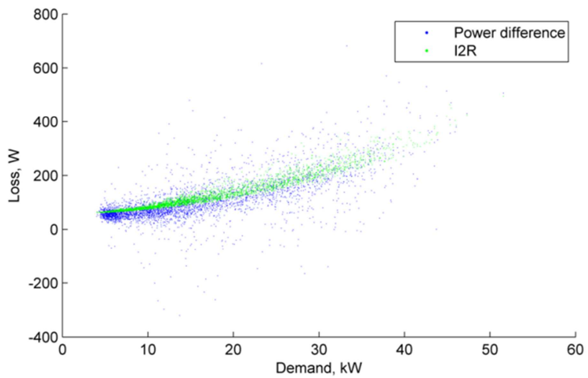


Figure 119 Aug 2018 Loss, kW vs demand, 10 min. av. (Ramsey Dom. LV feeder)

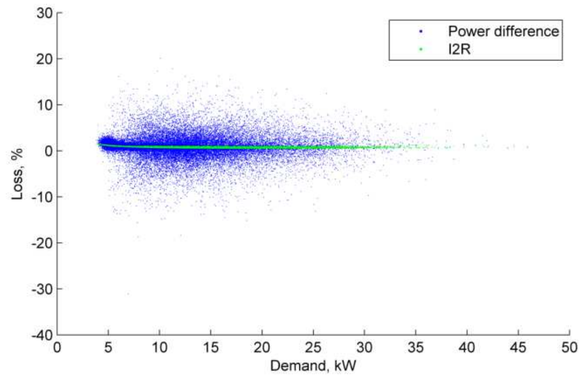


Figure 120 Aug 2018 Loss, % vs demand, 1 min. av. (Ramsey Dom. LV feeder)

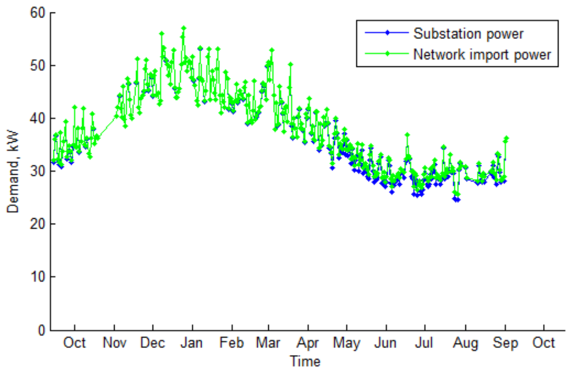


Figure 121 Long term mean daily feeder demand (Tromode Dom. LV feeder)

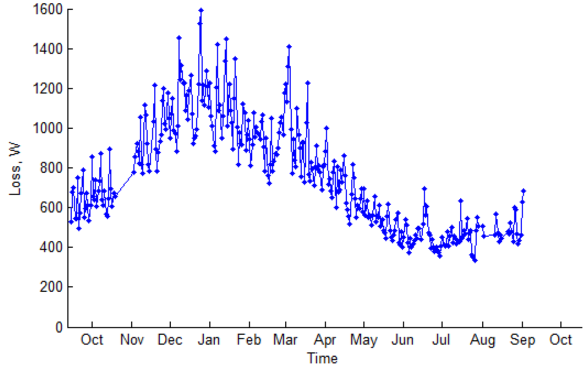


Figure 122 Long term mean daily (I^2R) loss (Tromode Dom. LV feeder)

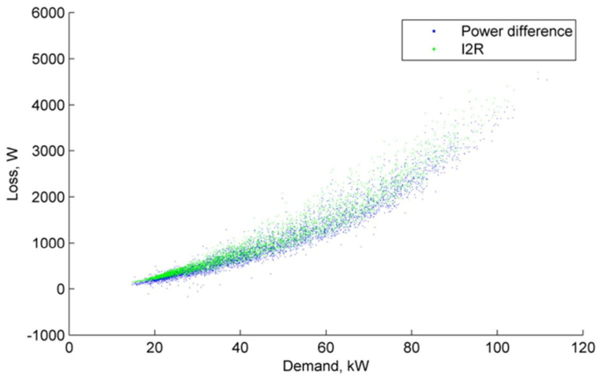


Figure 123 Jan 2018 Loss, kW vs demand, 10 min. av. (Tromode Dom. LV feeder)

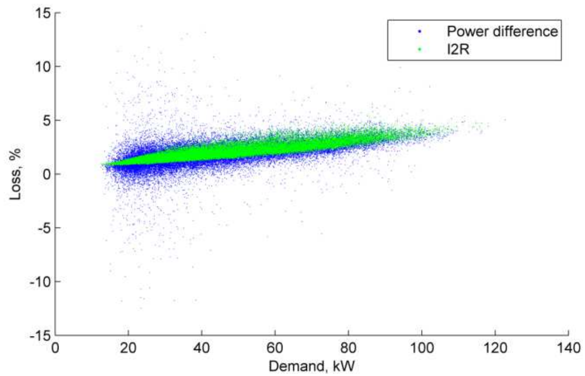


Figure 124 Jan 2018 Loss, % vs demand, 1 min. av. (Tromode Dom. LV feeder)

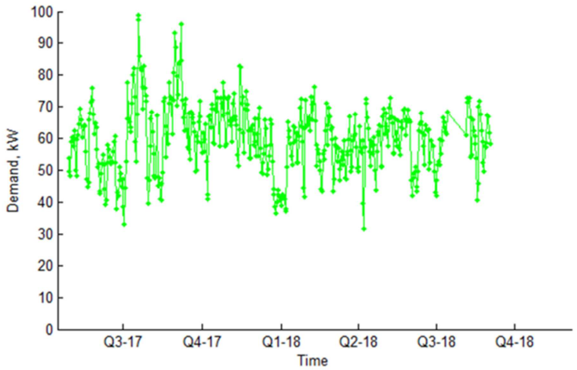


Figure 125 Long term mean daily feeder demand (Peel A I&C LV feeder)

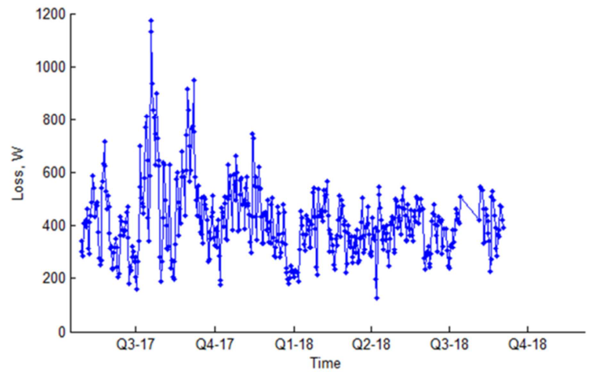


Figure 126 Long term mean daily (I^2R) loss (Peel A I&C LV feeder)

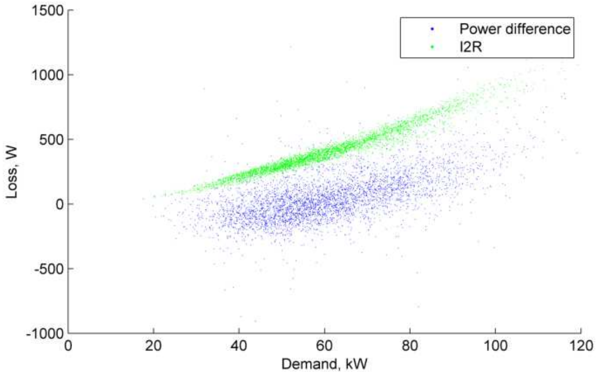
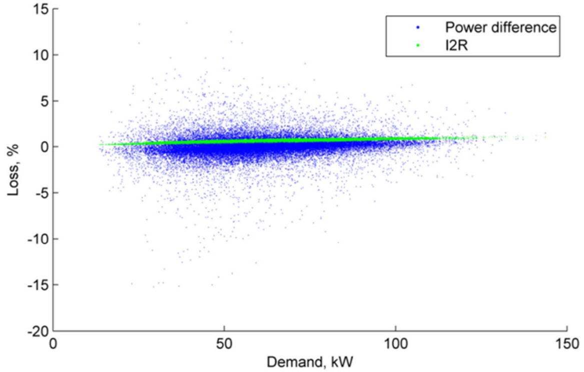


Figure 127 Jan 2018 2017 Loss, kW vs demand, 10 min. av. (Peel A I&C LV feeder)



n/a

Figure 128 Jan 2018 Loss, % vs demand, 1 min. av. (Peel A I&C LV feeder)

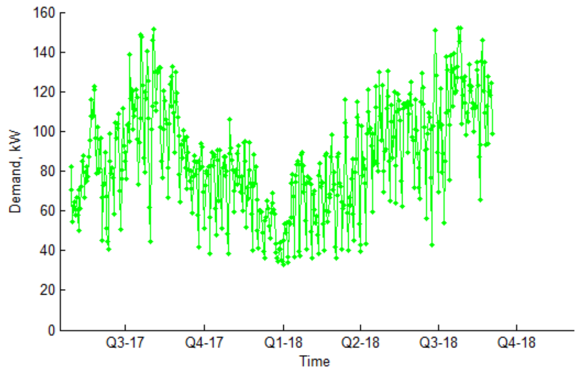


Figure 129 Long term mean daily feeder demand (Peel B I&C LV feeder)

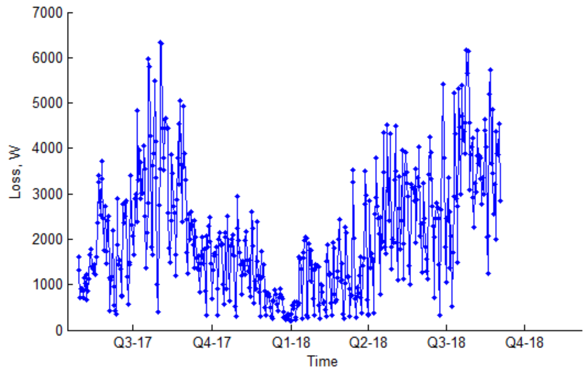


Figure 130 Long term mean daily (I^2R) loss (Peel B I&C LV feeder)

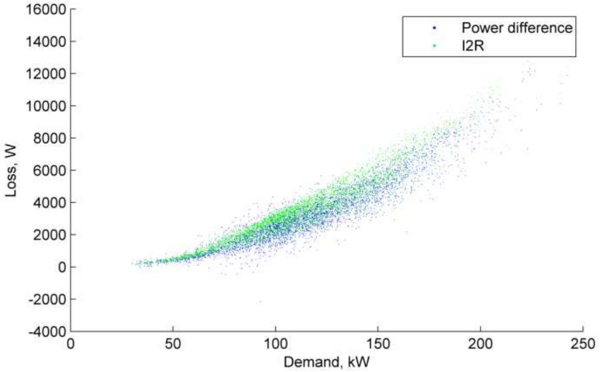


Figure 131 Aug 2018 Loss, kW vs demand, 10 min. av. (Peel B I&C LV feeder)

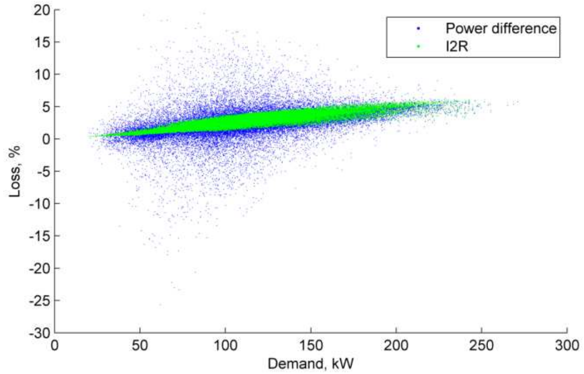


Figure 132 Aug 2018 Loss, % vs demand, 1 min. av. (Peel B I&C LV feeder)

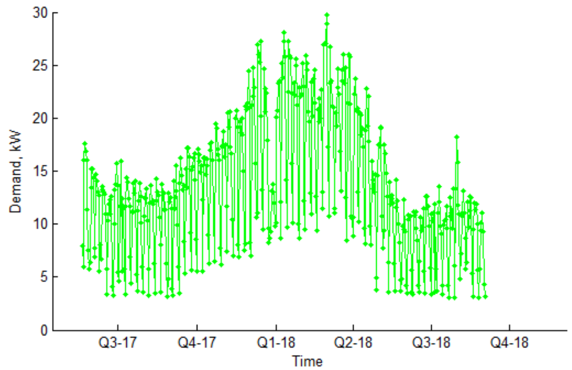


Figure 133 Long term mean daily feeder demand (Ballasalla I&C LV feeder)

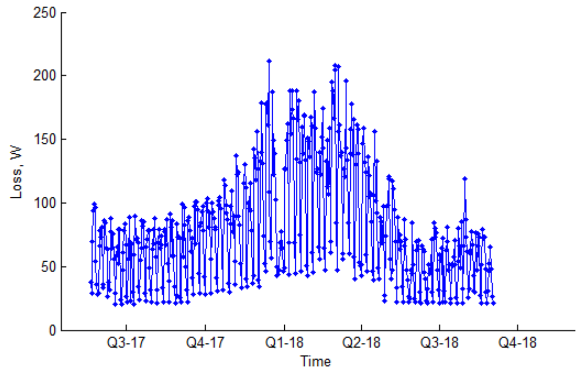


Figure 134 Long term mean daily (I^2R) loss (Ballasalla I&C LV feeder)

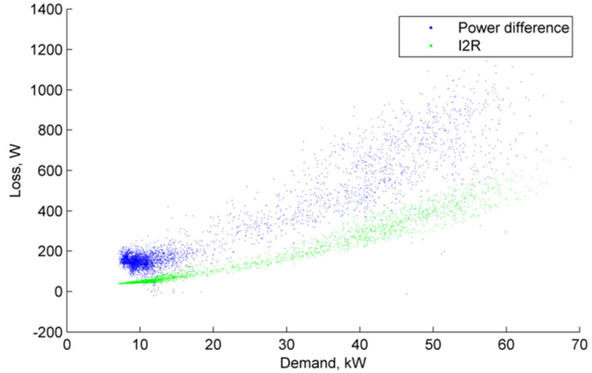


Figure 135 Jan 2018 Loss, kW vs demand, 10 min. av. (Ballasalla I&C LV feeder)

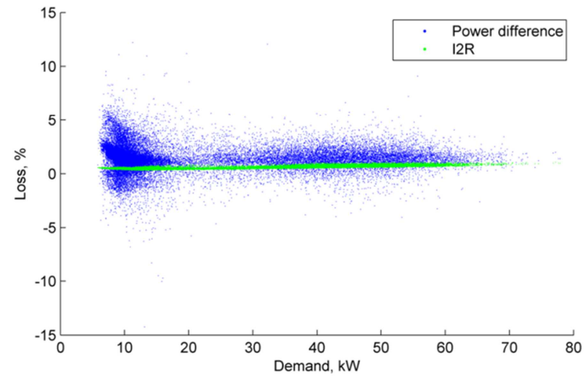


Figure 136 Jan 2018 Loss, % vs demand, 1 min. av. (Ballasalla I&C LV feeder)

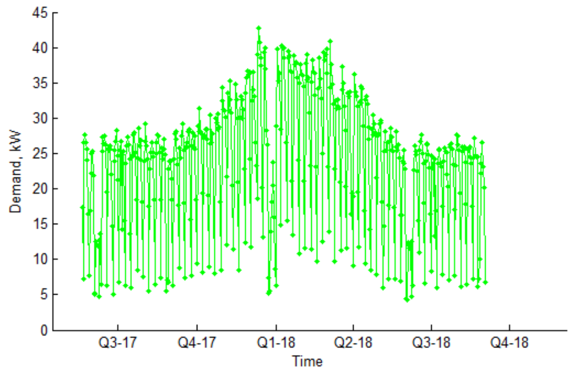


Figure 137 Long term mean daily feeder demand (Braddan I&C LV feeder)

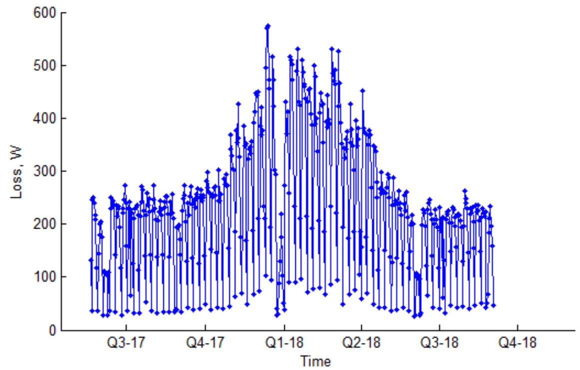


Figure 138 Long term mean daily (I^2R) loss (Braddan I&C LV feeder)

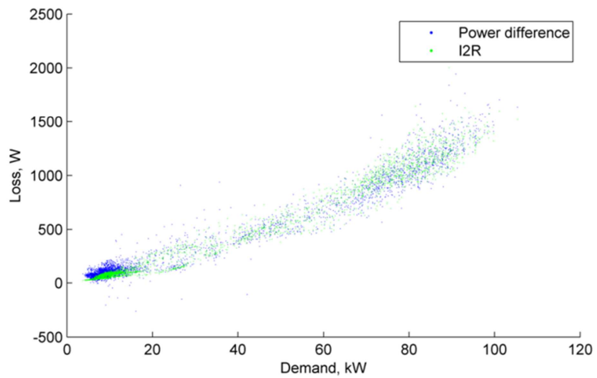


Figure 139 Jan 2018 Loss, kW vs demand, 10 min. av. (Braddan I&C LV feeder)

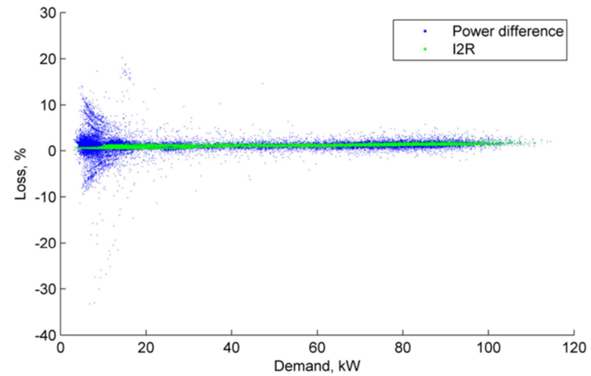


Figure 140 Jan 2018 Loss, % vs demand, 1 min. av. (Braddan I&C LV feeder)

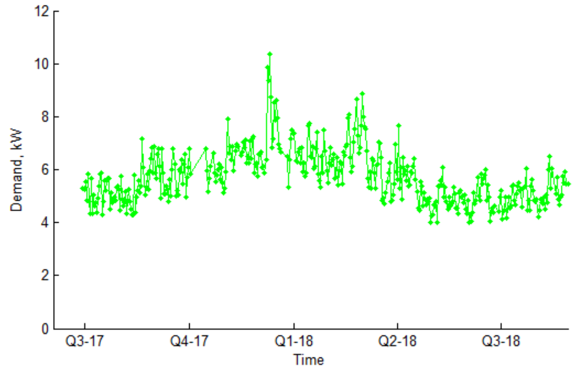


Figure 141 Long term mean daily feeder demand (Santon OH LV feeder)

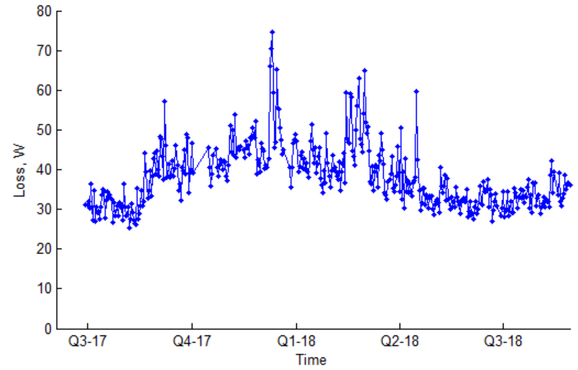


Figure 142 Long term mean daily (I^2R) loss (Santon OH LV feeder)

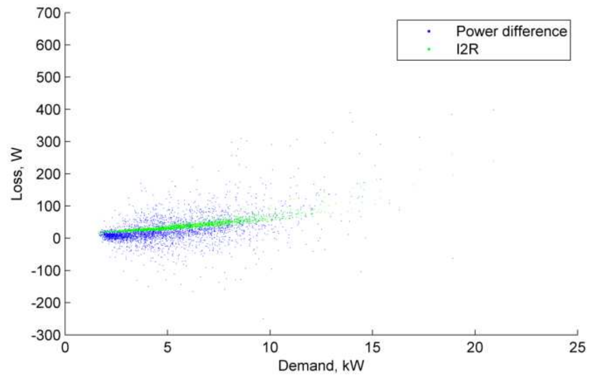


Figure 143 Aug 2018 Loss, kW vs demand, 10 min. av. (Santon OH LV feeder)

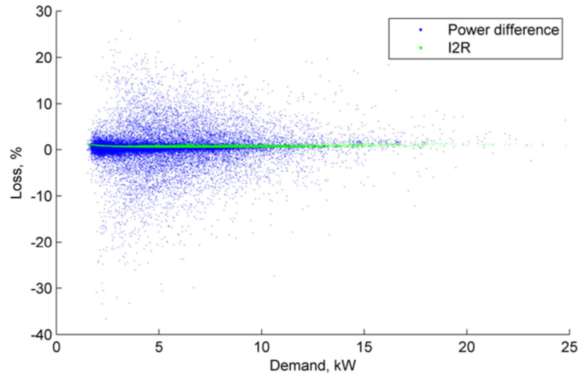


Figure 144 Aug 2018 Loss, % vs demand, 1 min. av. (Santon OH LV feeder)

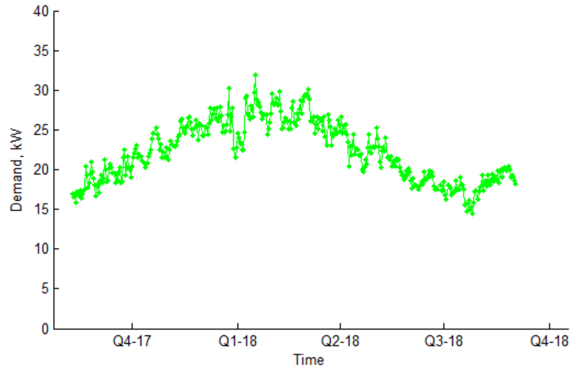


Figure 145 Long term mean daily feeder demand (Abbeylands OH LV feeder)

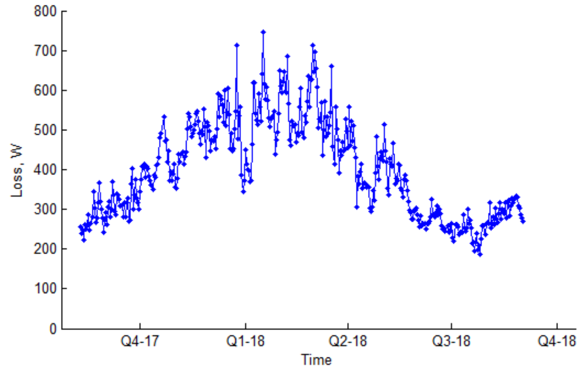


Figure 146 Long term mean daily (I^2R) loss (Abbeylands OH LV feeder)

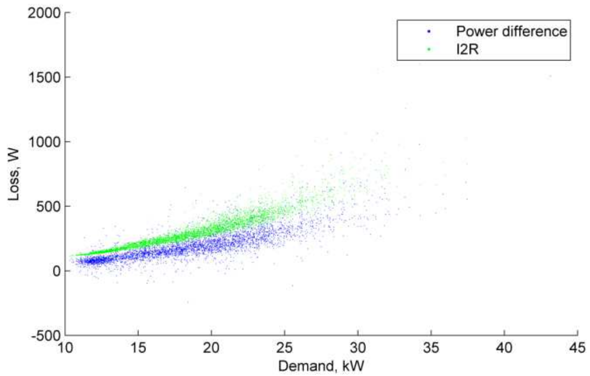


Figure 147 Aug 2018 Loss, kW vs demand, 10 min. av. (Abbeylands OH LV feeder)

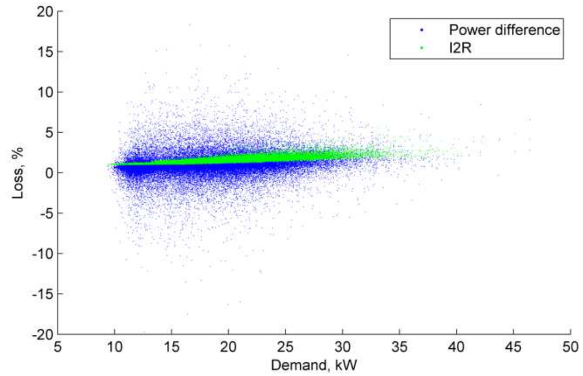


Figure 148 Aug 2018 Loss, % vs demand, 1 min. av. (Abbeylands OH LV feeder)

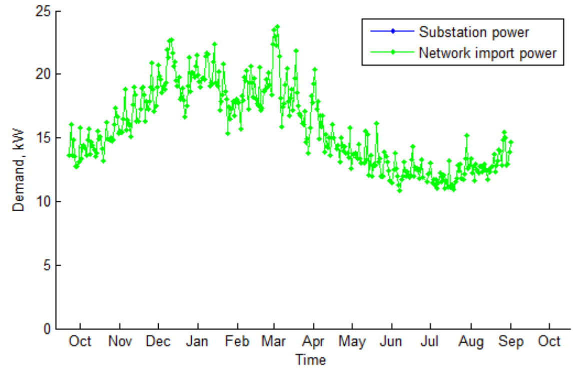


Figure 149 Long term mean daily feeder demand (Ramsey OH LV feeder)

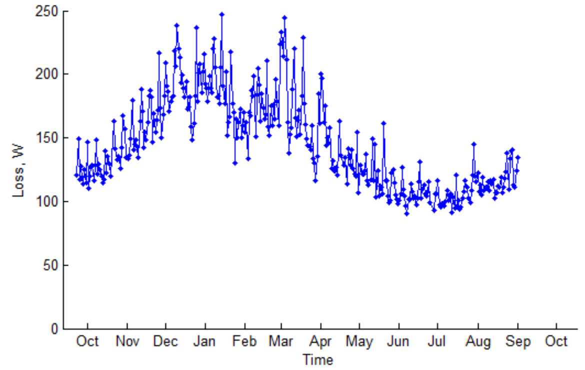


Figure 150 Long term mean daily (I^2R) loss (Ramsey OH LV feeder)

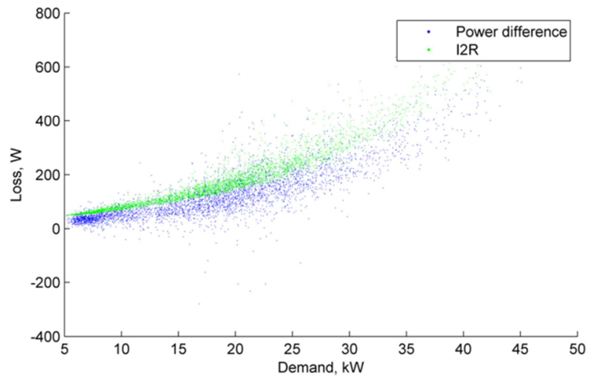


Figure 151 Jan 2018 Loss, kW vs demand, 10 min. av. (Ramsey OH LV feeder)

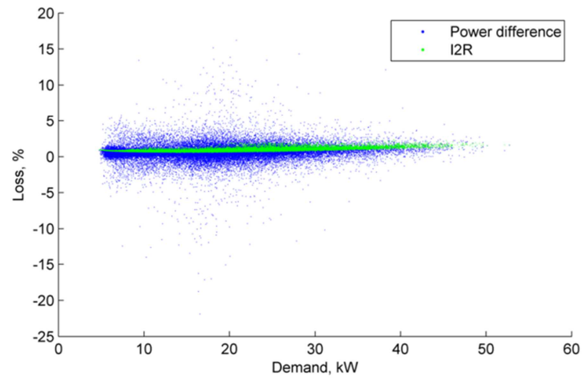


Figure 152 Jan 2018 Loss, % vs demand, 1 min. av. (Ramsey OH LV feeder)

Appendix D HV feeder loss assessment method and input data

Appendix D.1 Network topology data

The loss assessment software uses a network data file exported from the DINIS power system analysis/network planning tool. This file contains all of the HV feeders in the East Midlands region.

The input data to DINIS originates from data in the WPD GIS (EMU) database. The EMU data provides a geographic representation of the feeders and is formed into an electrical model when the DINIS input file is created. The creation of this electrical model involves a number of assumptions being made, for example that cables are considered to be electrically connected when their end points are located within a fixed proximity. There are a number of scenarios when this automated process omits some level of detail in the connectivity and so the data provided in DINIS must be considered to be an approximation to the actual network topology. The network data exported from DINIS, as used for the loss assessment, contains these approximations.

The loss assessment software builds a representation of the network from the nodes and branches described in the DINIS export file. Nodes that act as primary substations are identified. For each primary, the software then 'crawls' through the network of nodes and branches to identify the HV feeders, terminating either when the tree structure of branches has no further connections, or when the end nodes act as normal open points to feeders served from other primaries.

A key requirement of the losses assessment software is that the identified feeders must be radial. Although there are a few scenarios where feeders are actually operated in a mesh topology, it has been found that loops in the identified feeders generally occur when the underlying data in DINIS does not adequately represent the actual geographic data. Feeders with loops are therefore excluded from the loss analysis as the results would be unreliable. Feeders are also excluded from the analysis if the feeder identifiers attached to each branch (derived from the original geographic data) are not consistent with the structure identified by crawling through the node and branch topology.

The loss assessment software supports the analysis of feeders at 11 kV or 6.6 kV. A small number of feeders with interposing transformers, and therefore mixed voltages, are excluded.

Table 13 shows the number of feeders available for final assessment as consistency tests are undertaken on the full original set.

Analysis Stage	Feeders	Availability
Feeders referenced in DINIS EDF file	2832	100.0%
Feeders not discovered in DINIS network topology	92	3.2%
Feeders discovered in DINIS network topology	2740	96.8%
Feeders with apparent non-radial topology	456	16.1%
Feeders passing network consistency tests	2284	80.6%
SCADA name not known	5	0.2%
SCADA name found	2279	80.5%
Mixed 11/6.6kV Voltage	22	0.8%
Voltage OK	2257	79.7%
Transformers missing	14	0.5%
Transformers found	2243	79.2%
Transformers with phase error	102	3.6%
Transformers with phase OK	2141	75.6%
SCADA data available for less than 7 days	2	0.1%
SCADA data available for at least 7 days	2139	75.5%
Power-flow not converged	1	0.0%
Power-flow converged	2138	75.5%
Excluded results	8	0.3%
Included results	2130	75.2%

Table 13: Feeder-specific results for East Midlands region HV feeders

Note: eight results were investigated manually at the end of the process due to input errors creating unrepresentative results.

The data file is not populated with information to indicate how single-phase network branches are connected and so it is assumed that these are always connected between the red and blue phases. This represents the most onerous loss case.

The network branches listed in the DINIS file refer to a library of cable types that are defined in a separate line code file (‘TlTab.Type’). These line codes include the cable impedance, admittance, number of phases, and nominal voltage.

Appendix D.2 Cable Impedance Data

The impedances for the cables used in the project HV trial feeders have also been calculated using a finite element model (FEM) simulation so as to take account of AC resistance effects. This more detailed impedance data is not used in the loss assessment analysis, such that the process can be applied using only BAU data, and also as there are many cable types and sizes, each of which would require the construction of a bespoke model.

The resistances of underground cables from the FEM simulations are typically higher than the values specified in the DINIS line code file. It has therefore been assumed that the DINIS file contains DC resistance values rather than AC resistances at 50 Hz. The resistances are compared in Figure 153 which shows the ratio between the positive sequence resistance from the FEM modelling and the positive sequence resistance specified in the DINIS line code file (after conversion from per unit values). The plot also shows an approximation function that gives a close match to the observed points, given by:

$$\mathrm{r_{ac}} = \mathrm{r_{dc}} \times \left(1 + \frac{0.11}{300} \cdot \mathrm{A_{Cu}}\right)$$

where $\mathrm{r_{ac}}$ and $\mathrm{r_{dc}}$ are the AC and DC resistances and $\mathrm{A_{Cu}}$ is the equivalent copper cross-sectional area of the conductor in mm^2. For copper conductors this is the actual cross-section, whereas for aluminium conductors the conductor area is divided by a factor of 1.6.

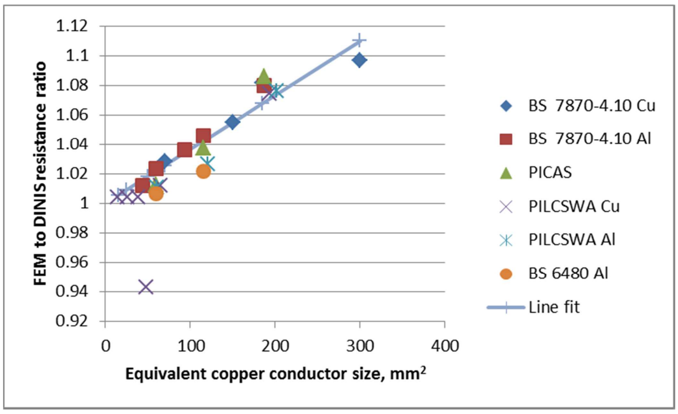


Figure 153 AC resistance scaling for underground cables.

Therefore, the positive sequence resistance values from the line code file have been uplifted to better reflect AC resistances at 50Hz.

Appendix D.3 Meter assignment to substations

The list of customer connections associated with each substation is specified in a data file extracted from WPD's asset record system CROWN. For each MPAN, this data provides the normally-supplying distribution substation reference number and also gives the Elexon profile class and EAC for non-half-hourly metered customers.

This data file also specifies the normally-supplying primary substation and HV feeder to which the distribution substation is connected. It has been found that these fields do not always coincide with the primary and HV feeder numbers for the network topology originating from the EMU database (as used to obtain the DINIS network data file). Where inconsistencies have been investigated, it appears that the EMU database is more current and so disparities between the network data and the primary and HV feeder numbers from the CROWN database have been ignored.

Appendix D.4 Half-hourly meters

Half-hourly data has also been obtained from BAU data for MPANs in the East Midlands region over a 1-year period from 1st July 2016 to 1st July 2017. This provides four-quadrant power data and so gives a time series of the net active and reactive power demand. The demand is assumed to be zero if readings are absent for some of the period (e.g. at the beginning or end of the period).

Some MPANs with half-hourly data also have a defined profile class and/or EAC. The loss assessment software treats these MPANs as half-hourly throughout. MPANs with no half-hourly data and with either the profile class or EAC undefined are omitted.

Appendix D.5 Non-half-hourly meters

The demand for non-half-hourly meter is formed by constructing a time series from the appropriate Elexon profile over the 1-year period defined above, and then re-scaling this for each meter according to the customer EAC. The reactive power is set to zero (for unity power factor), based on project experience with the LV feeder trials in the Isle of Man where a number of domestic customers were found to have both imported and exported reactive power.

Appendix D.6 Time Resolution of load model

It is recognised that losses calculated with half-hourly demand data will be systematically lower than loss calculations with a higher time resolution. The impact of this was investigated, through averaging the 1 minute resolution input data to periods of 2, 5, 10 and 30 minute periods, and then re-calculating losses using these averaged values. As expected, calculated losses were lower with longer average periods as seen in Figure 154. This shows the resulting loss ratio from using lower time resolution (longer averaging periods) for the 11 monitored HV feeders. The loss ratios are based on the total losses for the HV feeder, including the transformer load-losses and no-load losses.

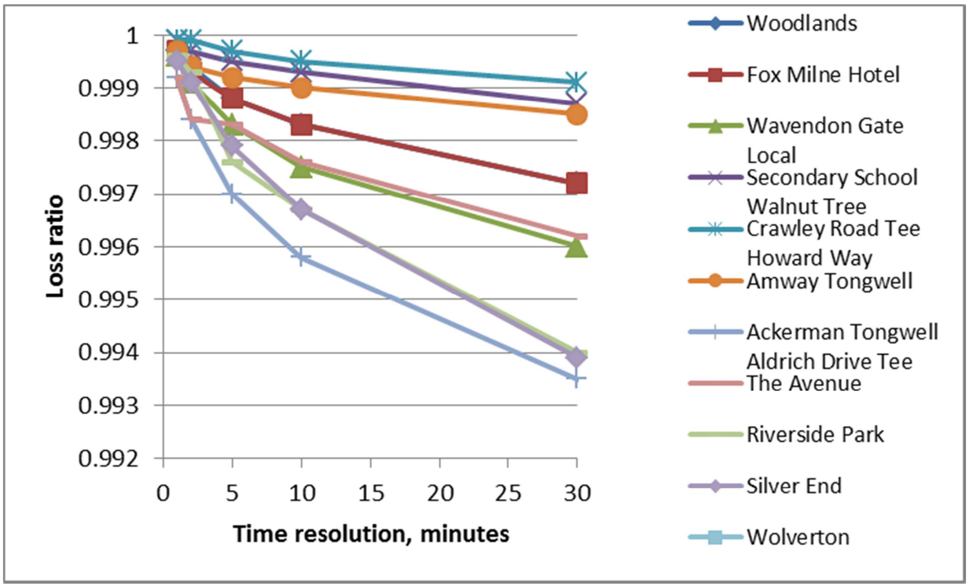


Figure 154 Impact of measurement time resolution for HV feeders

Because the HV input data was already significantly aggregated, the impact of modelling load at 30 minute (compared to 1 minute) resolution is negligible. The HV loss assessment method therefore uses half-hourly data with no further correction applied for time variation within the half-hour periods.

However, although the 1-minute resolution used by the measurement instrumentation is clearly more than adequate for the calculation of losses, the availability of 1-minute data has proved to be essential for other aspects of the analysis, in particular where erroneous data values needed to be removed (typically with outages of only a few minutes), or where the measured and calculated currents at the primary were compared such that any outfeeds from the feeder not included in the instrumentation could be detected.

Appendix D.7 Transformer Data

The power-flow analysis for the HV loss assessment uses input data for each distribution transformer to specify the rated power, number of phases, percentage impedance, and the copper and iron losses. The asset data available from WPD's CROWN system generally only provides the rated power and the number of phases, but impedance and loss data is available only for some transformers, most of which are located in the South West or South Wales regions. Averaged loss and impedance values from these transformers have therefore been used as approximated figures for the majority of transformers for which data is not available.

Separate average values have been formed according to the rated power, number of phases, and decade of manufacture, although an average of all manufacture years is used when no data is available for a particular decade. There are also a number of transformer ratings for which there is no data in any year and so losses for these transformers are taken from the nearest higher transformer rating with a valid average figure. An impedance of 4.73% has been used as a default where no transformer data was available for the required rating or phase type.

There are also some transformers for which the records of the number of phases is unclear and so it has been assumed that transformers are three-phase if the rated power is 30 kVA or above. In a few cases the number of phases is known but not the rated power. In this case, a rating of 500 kVA is assumed for three-phase transformers and 16 kVA for single-phase transformers.

The loss calculations are relatively insensitive to differences in the assumed transformer tap settings. Actual tap positions are not available from asset data and so a default of tap 2 (+2.5%) has been assumed, based on experience from the project trial substations in the Milton Keynes area, giving a transformer ratio of 11,275V to 433V.

There is also no information to determine the phase connections of single-phase transformers. A worst-case option is therefore assumed where all single-phase transformers are connected between the red and blue phases.

Appendix D.8 SCADA current and voltage data

The SCADA monitoring at the primary substation provides half-hourly measurements of voltage and of the current on each of the HV feeders.

The current data includes only the amplitude of the current, with no phase information, and so there is an ambiguity whether a feeder has imported or exported power. The measurement is made on only the yellow phase and so there is also no information to indicate the level of unbalance.

The data generally includes multiple voltage measurements for each primary. Typically, in normal operation, these might be from a pair of transformers and the two sets of values appear to differ only due to measurement noise. However, in some cases, one of the values may be zero or other values that are clearly out of the accepted operating range. This could occur for short periods if one of the transformers has been switched out for maintenance, or if there are longer-term changes to the switch-boards at the primary. To resolve this, the loss assessment software makes a selection on a half-hourly basis of whichever voltage measurement is nearest to the nominal voltage for the feeder. If none of the measured voltages are within 10% of the nominal voltage then the half-hour period is marked as invalid and not included in the loss assessment calculations.

Appendix D.9 SCADA channel mapping

In order to use the SCADA data, the loss analysis software needs to be provided with the name of the primary and HV feeder, as used in the SCADA records, and corresponding to the reference number of the primary and feeder in the DINIS data. The names used in the SCADA system frequently differ slightly from the names used in the EMU database (and therefore by DINIS) and so this name mapping is not always obvious or easily resolved by the loss analysis software. A data file has therefore been established to act as a lookup such that the software can find feeder data in the SCADA system. There are primaries for which the naming has changed at some point within the 1-year period used for the loss assessment. In this case the loss analysis results are omitted for the period when no valid SCADA data can be found.

Appendix D.10 Scaling of Non-Half-Hourly Demand

Provided that the SCADA measurement data appears to be valid, these measurements are used to scale the non-half-hourly demand applied at each of the distribution substations such that the total demand from each HV feeder is consistent with the measurement at the primary, as shown in Figure 18 (Page 25).

If the demand on the feeder is dominated by non-half-hourly customers then it is assumed that the feeder imports power from the primary substation (since the Elexon profiles contain no generation). If the feeder is dominated by half-hourly meters then the current magnitude should be closely consistent with the magnitude of the net complex power supplied to the feeder, with the feeder either importing or exporting in accordance with the half-hourly demands.

The algorithm used to find the non-half-hourly demand scaling also allows for the more general case where there is a mixture of both half-hourly and non-half-hourly meters. It is also necessary to allow for either the half-hourly or non-half-hourly customers to have embedded generation, and also for the case where the assumed power factor for the non-half-hourly demand may not be consistent with the measurement data.

The scaling algorithm proceeds as follows. The power-flow analysis calculates separate complex phasors for the estimated current at the primary substation due to the half-hourly and the non-half-hourly demand. The method then uses two different approaches, depending on whether the estimated primary current amplitude due to the half-hourly demand alone is greater or less than the measured current amplitude.

Two examples of the case where the amplitude of the primary substation current from half-hourly (HH) demand is less than the measured current at the primary are shown in Figure 155 and Figure 156.

The most typical example is shown in Figure 155 where the current phasors for both the half-hourly and the non-half-hourly current contributions represent active power being imported into the feeder. In this example the non-half-hourly (NHH) current contribution requires scaling up such that the amplitude of the total current phasor will be consistent with the measured amplitude. The difference between the scaled and un-scaled NHH current is illustrated in red as the ‘correction’ current.

Figure 156 shows an example where the half-hourly current contribution represents generation and power is exported from the feeder. The Elexon profiles do not include generation and so the NHH current contribution opposes the HH current. Although it would be possible to apply a substantial positive scaling to the NHH current, it is also possible that some of the substations have embedded generation, giving a negative NHH current. The algorithm selects whichever scaling factor is closest to unity.

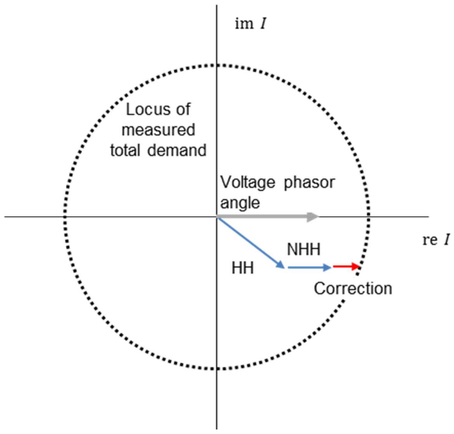


Figure 155 Corrections applied to non-half-hourly demand where the amplitude of the primary substation current due to half-hourly demand is less than the measured current at the primary, and with half-hourly, with non-half-hourly demand as loads.

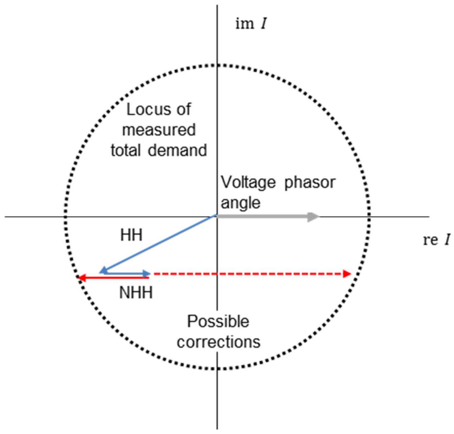


Figure 156 Corrections applied to non-half-hourly demand where the amplitude of the primary substation current due to half-hourly demand is less than the measured current at the primary, with half-hourly demand as generation.

A different approach is needed where the amplitude of the primary substation current from half-hourly (HH) demand is greater than the measured current at the primary. This case is shown in Figure 157 where there is no real-value scaling for the NHH current that will give a total current with an amplitude that lies on the same circle as defined by the current measurement. The algorithm therefore selects a scaling such that the total current will have the same phase angle as the HH current contribution alone. This gives a complex-valued scaling factor with both amplitude and phase.

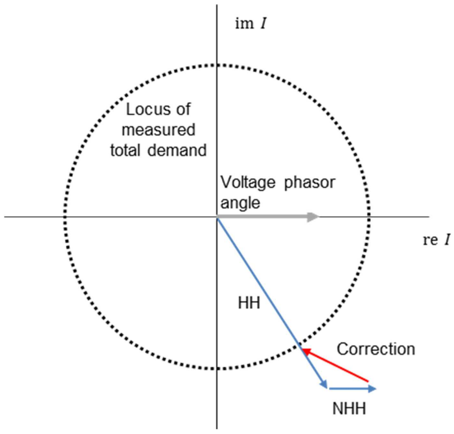


Figure 157 Corrections applied to non-half-hourly demand where the amplitude of the primary substation current due to half-hourly demand is greater than the measured current at the primary.

The use of these two approaches allows for a consistent scaling factor to be found in all cases, including the case where the assumption that the non-half-hourly demand has a unity power factor does not allow for a consistent solution, and also allows for the possibility that either the HH or NHH current contributions could include generation.

Appendix D.11 Power Flow Analysis

A power-flow analysis is used to calculate the losses for the given network and demand data. This analysis runs with half-hourly resolution for 1-year period from 1st July 2016 to 1st July 2017, with each half-hour included provided that the SCADA data is available. The power-flow analysis uses a forward-backward sweep method, and modified so as to allow for the inclusion of the scaling factors, as described above.

Conventionally, the forward-backward sweep algorithm uses input data to determine the current at each load (in accordance with the node voltage and the assumed load model) and the voltage at the upstream node (in this case the primary substation). Initially, all of the currents are assumed to be zero and so the voltage at the loads is equal to the primary substation voltage. The current at the upstream node is then calculated, and then the branch currents are used to calculate a revised estimate of the voltage at each load. This process continues iteratively until the change in node voltages falls below a defined threshold.

For the loss assessment method, the total load current is given by the super-position of the current for the half-hourly meters and the current for the non-half-hourly meters. The current for the half-hourly meters can be calculated from the load demand and from the load voltage, but the currents for the non-half-hourly meters are subject to a scaling factor which is not yet known. However, the modified backward sweep differs from the conventional method in that the SCADA monitoring provides the primary substation current as input data, rather than this being an output from the calculations. This additional data can be used to linearly scale the currents for non-half-hourly demand so as to match the required primary substation current. The forward sweep then follows the conventional method and uses the branch currents to calculate the voltages at each node.

Once the forward-backward sweeps have converged, the losses in each branch and the load losses in the transformers are determined using an $\mathrm{I}^2\mathrm{R}$ calculation. No-load losses for the transformers (dependent on the load voltages) are also calculated. For the power-flow analysis, the sum of these losses is also consistent with the difference between the power input to the network at the primary substation and the power output at each of the loads. (This is not the case for the measurement data analysis, where a method using the $\mathrm{I}^2\mathrm{R}$ calculation plus estimated transformer no-load losses has been found to be more reliable than a power difference method.)

Appendix D.12 Selecting to Use Non-Half-Hourly Scaling

Loss assessments using the process described above have been found to be relatively tolerant to errors in the incorrect assignment of customer meters to substations on the same HV feeder. Provided that the total demand is scaled correctly, the demand from a meter assigned to the wrong substation on a feeder will still be represented in the branches near to the primary where most of the cable losses occur, and errors in the transformer load losses generally have less impact.

Ideally, if the customer EAC data is accurate and in the absence of measurement errors, then the mean of the demand correction power summed over the 1-year period will be zero. In practice, this is never the case as the EAC is only an estimate, and the time period for which it applies is not aligned with the 1-year period used in the loss assessment.

Measurement errors also affect the results. If the SCADA current monitoring has a 5% accuracy class (allowing for both the sensors and for current transformers), then the overall demand may be scaled higher or lower than would be expected based on the EAC values.

Despite these risks, good agreement has been found between the estimated and measured losses for the feeders in the HV losses trials in Milton Keynes. However, if the SCADA data itself is invalid, then using this to create the scaling factors introduces errors into the loss assessment. Most of the HV feeders have short periods for which the open points have been reconfigured, either for maintenance or in the case of a fault. There are then likely to be either more (or fewer) substations on the feeder than are normally connected and the current measured at the primary substation will not be consistent with the demand for the substation connections recorded in the network data. In this case the SCADA current measurement is not at fault, but the modelling is subject to a limitation that short-term re-configurations are not included.

If the network is re-configured to include additional substations, then the SCADA current data will be higher than would be expected for the substations that are normally connected. The scaling algorithm will then scale any non-half-hourly demand from the normally connected substations, so as to match the measured current. Both the cable losses and the transformer load losses may exceed their normal expected ranges. However, the periods with network re-configurations are usually relatively short and so the erroneous values have a low impact on the overall loss assessment.

There are also HV feeders for which the SCADA data appears to contain errors. This might be found where the current is either permanently or intermittently stuck at a zero value, or where the current sensors has not been appropriately configured, giving either incorrectly scaled readings, or in some cases readings with a non-linear operating range. If these errors persist throughout the 1-year loss assessment period then the impact on the results can be significant. In this case, it is likely that a better loss estimate would be provided by using the Elexon profiles without scaling the demand to match the SCADA data (although still scaling the demand for each customer according to their EAC).

The loss assessment software runs the analysis both with and without the scaling process. The results with scaling are used by default, but the results without scaling are used if:

- Any of the distribution substations on an HV feeder has a mean loading that is more than 25% above the rated power for the transformer
- The SCADA data is zero for more than 5% of the 1-year period.
- The demand correction power is more than ±20% of the power imported into the network (where the power imported into the network is calculated with no scaling applied).

If the feeder has no non-half-hourly meters then no scaling factor is required.

Appendix D.13 Output data

The results from the loss analysis are stored as a table of losses, also showing the breakdown of losses between HV cables and transformer load-losses and no-load losses. This also shows the cost of losses based on the value of lost energy of £48.42/MWh.

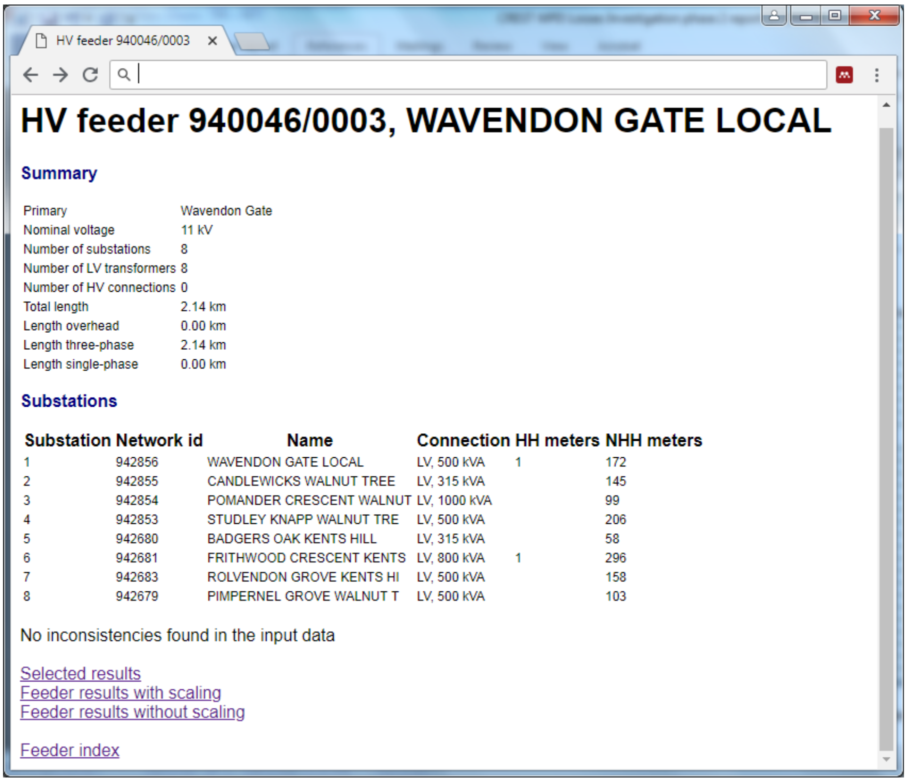
The tables also provide a list of the feeders with the highest losses, allowing investment action to be prioritised towards feeders that give the greatest reductions in losses and costs. In most cases, the losses for these feeders are dominated by HV cable losses, with a much smaller proportion being due to transformer losses.

Two separate lists also show the distribution substations with the greatest load and no-load losses. Although transformer losses are generally lower than the HV cable losses, investments to replace individual transformers may in some cases be cost-effective, particularly for older transformers that may have higher losses.

It should be noted that the load losses, which vary significantly between substations, are an output from the loss analysis using the demand data. These results are sensitive to errors in the meter assignment record data which may show customer meters being connected to the incorrect substations. Abnormally high load losses may therefore indicate an error in the records, which could be corrected for a revised iteration of the loss analysis.

The no-load losses vary with voltage (determined by the SCADA monitoring) but otherwise depend mainly on the limited set of input data used to define the rated iron losses. For most substations, a high no-load loss therefore indicates that, based on the age, rating and number of phases, the transformer is similar to others for which a high iron loss rating has been recorded. More accurate information can then be obtained by checking the manufacturer’s rating plate on the transformer casing where the loss values not included in the records might be found.

Detailed results for each feeder are accessed via HTML pages. A summary page provides the feeder topology, details of the substations and distribution transformers, and also the numbers of customer meters connected at each substation. There are linked pages containing the results of loss analysis with scaling, and without scaling, and also a page showing the selected loss analysis (either with- or without scaling). Examples of these pages are included in Figure 158 and Figure 159.



HV feeder 940046/0003

HV feeder 940046/0003, WAVENDON GATE LOCAL

Summary

Primary	Wavendon Gate
Nominal voltage	11 kV
Number of substations	8
Number of LV transformers	8
Number of HV connections	0
Total length	2.14 km
Length overhead	0.00 km
Length three-phase	2.14 km
Length single-phase	0.00 km

Substations

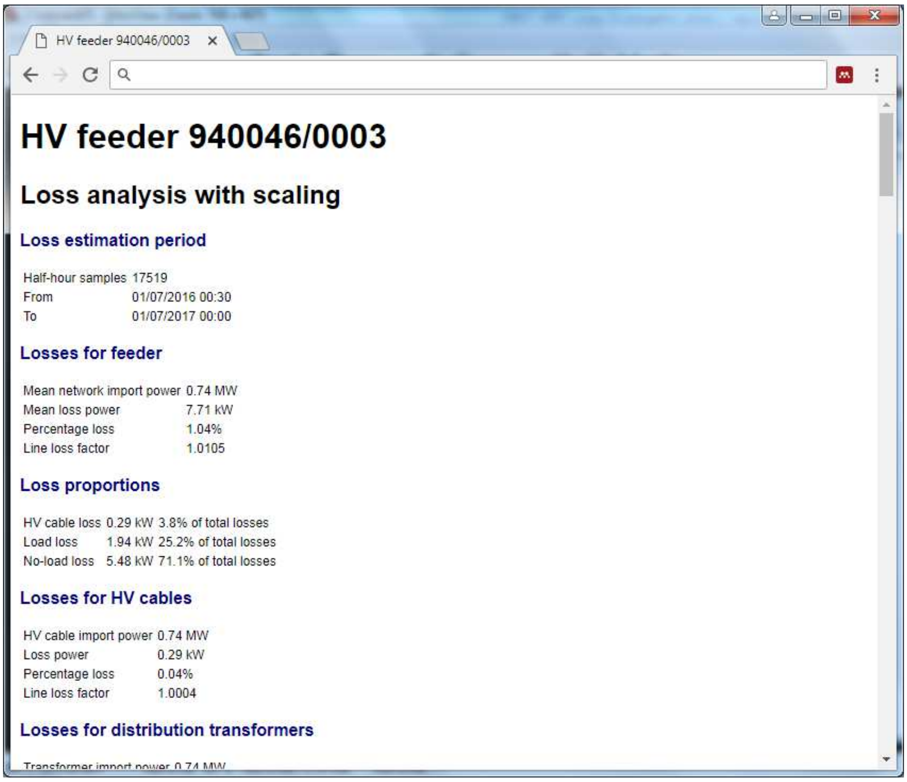
Substation	Network id	Name	Connection	HH meters	NHH meters
1	942856	WAVENDON GATE LOCAL	LV, 500 kVA	1	172
2	942855	CANDLEWICKS WALNUT TREE	LV, 315 kVA		145
3	942854	POMANDER CRESCENT WALNUT	LV, 1000 kVA		99
4	942853	STUDLEY KNAPP WALNUT TRE	LV, 500 kVA		206
5	942680	BADGERS OAK KENTS HILL	LV, 315 kVA		58
6	942681	FRITHWOOD CRESCENT KENTS	LV, 800 kVA	1	296
7	942683	ROLVENDON GROVE KENTS HI	LV, 500 kVA		158
8	942679	PIMPERNEL GROVE WALNUT T	LV, 500 kVA		103

No inconsistencies found in the input data

Selected results
Feeder results with scaling
Feeder results without scaling

Feeder index

Figure 158 - Example of feeder details HTML page.



HV feeder 940046/0003

HV feeder 940046/0003

Loss analysis with scaling

Loss estimation period

Half-hour samples	17519
From	01/07/2016 00:30
To	01/07/2017 00:00

Losses for feeder

Mean network import power	0.74 MW
Mean loss power	7.71 kW
Percentage loss	1.04%
Line loss factor	1.0105

Loss proportions

HV cable loss	0.29 kW	3.8% of total losses
Load loss	1.94 kW	25.2% of total losses
No-load loss	5.48 kW	71.1% of total losses

Losses for HV cables

HV cable import power	0.74 MW
Loss power	0.29 kW
Percentage loss	0.04%
Line loss factor	1.0004

Losses for distribution transformers

Transformer import power 0.74 MW

Figure 159 - Example of feeder results HTML page.

Appendix D.14 Validation against IPSA

The HV loss assessment uses power-flow analysis code written in Matlab. The cable loss calculations in this software have been validated against an equivalent model in the IPSA software tool from TNEI. Loss analysis results for the Amway Tongwell HV trials feeder were used for this test.

The IPSA model consists of an IPSA network file together with Python scripts that configure a series of demand snapshots and run the power-flow analysis. For each half-hourly time step, the script reads input demand data from an Excel file, configures the appropriate demand at each network load, runs the power-flow analysis, and then writes the losses for each branch into Excel output files.

The comparison required that both software models used equivalent input data to define the demand and to describe the network topology and line impedances. The IPSA model uses a balanced power-flow analysis based on positive sequence currents. The impedances were therefore configured such that the line impedance for each branch was equal to the positive sequence impedance exported from the Matlab model. The demand data time series was also configured to be identical for both the IPSA and Matlab models.

A number of simplifications were also applied to the Matlab model such that the analysis would be equivalent to the IPSA model.

- A fixed voltage of 11 kV was used throughout.
- The Matlab code was run in a balanced mode such that the results would be equivalent with the IPSA calculations, which use only the positive sequence mode.
- The Matlab code was amended to be consistent with the Excel spreadsheet such that the total outfeed power at all of the distribution substations was scaled to be consistent with the input current at the primary substation. This approximation neglects the losses when scaling the demand profiles.
- The four LV distribution substation loads were configured to connect to the HV feeder at 11 kV. The losses in these transformers are therefore not included. The modification was required (instead of just neglecting the transformer losses) as the distribution substations are defined as constant power loads and so would otherwise draw a higher current due to the reduced per unit voltage on the LV side of the transformers. This modification also omits the additional currents due to the shunt impedance of the transformers.
- The current due to the cable admittance was omitted.

The two models were compared for losses on a selected day of 14th December 2016. Both models estimated the HV cable losses as 110.1541 kWh. It is assumed that any differences beyond this level of accuracy relate to limitations of the numerical precision used in exporting the output data.

This verification demonstrates that the power-flow analysis from the two models is equivalent to a high degree of precision.

Appendix D.15 Potential causes of estimation inaccuracy

This section describes a number of potential causes of inaccuracy in the loss estimates. Where possible, these inaccuracies have been addressed by checking for consistency between multiple BaU databases, but some possible errors remain.

Network changes

The loss assessment for the East Midlands region uses a DINIS file exported in November 2017. Clearly, there will be network changes since this time, and there would also have been changes in the network configuration over the 1-year period for which the losses were estimated. The loss assessment results are therefore recommended as an indicator of feeders with high losses. The network configuration for these high loss feeders can then be re-checked when evaluating possible loss mitigation actions.

It is also possible that there are errors in the network data. However, the loss assessment method carries out a number of consistency tests to ensure that the identified HV feeders are consistent with the geographic feeder data in the EMU database.

Customer meter assignments

It has been found that some of the database records for customer meters show that they are connected to either the incorrect substation or HV feeder. Eight feeders have been excluded from the analysis for this reason but it is likely that there are other cases where this has not been detected. Undetected meter assignment errors are likely to cause load losses to be incorrectly recorded, with some transformers having additional load and others having an under-estimated load. Provided that the meters are recorded on the correct HV feeder, an error in the substation assignment has less of an impact on the HV cable loss calculation as the highest losses occur where the full feeder current is aggregated together.

Missing cable data records

Some of the branches in the DINIS network file are defined with a default cable type that has an impedance value of zero. In most cases these branches are short jumper cables at substations, but there are a few with much longer sections of cable having zero impedance.

Substations for independent DNOs (IDNOs) are increasingly being connected to HV feeders. In many cases the IDNO is responsible for the distribution transformer and for the downstream network to the customers. WPD generally has limited information for these loads and so these meters are omitted from the demand model.

There is no impact to the transformer loss metrics for the IDNO transformer itself as these losses are not within scope of the losses managed by WPD. However, there are other impacts to the loss assessment, depending on whether the SCADA measurements are used for scaling the non-half-hourly demand. If so, then the load losses on other distribution transformers will be over-estimated as the non-half-hourly demand at the other substations will be scaled up so that the total current matches the measurement at the primary. The HV cable loss estimate will also be affected, although the aggregated current in the branch nearest at the substation, typically with the highest losses, will be effectively unchanged. If the non-half-hourly demand is not scaled, then the IDNO substation demand is simply omitted and the HV cable losses will be under-estimated.

SCADA current measurement accuracy

Where SCADA data is used to scale the non-half-hourly demand, the results are clearly sensitive to the accuracy of the SCADA current readings. These may be specified as class 5 accuracy (±5%) although comparisons with separate measurements using GridKey loggers on the project HV trial feeders have generally shown much closer agreement.

If all of the demand is non-half-hourly metered then a 5% error in the current reading would give approximately 10% error in the loss power.

Missing transformer records

The loss assessment software assigns a distribution transformer to a substation if a record can be found in the list of transformers exported from the CROWN database. If a substation has no transformer listed in this data, then it is assumed to be an HV customer connection point and so there is a risk that transformer losses will be under-estimated if transformer records are missing. The loss assessment software therefore excludes any feeders with a substation that has a non-zero load rating specified in the DINIS file, but for which no transformer can be identified. Other differences between the transformer rated power and the DINIS file load rating are ignored as the CROWN transformer database has been treated as more reliable than the load ratings in the DINIS file.

It is possible that further missing transformers have not been detected, particularly as there are some substations with non-half-hourly customers connected, assumed to be at LV, but where there are no records for the distribution transformer. Although this causes the transformer losses to be under-estimated, there is negligible impact to the HV cable losses.

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Appendix E LV Feeder loss assessment method and input data

Appendix E.1 LV network topology data

The DEBUT files created for the Electric Nation project are based on business-as-usual geographic cable data from WPD's geographic information system (GIS). These DEBUT files are available (where the data conversion has been successful) for all of the WPD license areas. The network data in the DEBUT files overcomes two key limitations with the raw business-as-usual data:

- The geographic data does not always provide a complete model of the electrical connectivity. The DEBUT files are created using an algorithm that identifies end nodes of cables that are potentially geographically separate but that should be joined in an electrical model of the network
- Whilst the load records include a field specifying the feeder number to which each load is connected, the corresponding feeder numbers are not included in the geographic cable data. Numbers are therefore assigned to feeders in the electrical model based on the feeder numbers of the load groups that are in closest proximity. This process is most reliable when there are large numbers of domestic customers. However, there is a greater chance of errors when a feeder has a small number of commercial loads. Errors in the load location data can then cause feeders to be wrongly identified and the model may therefore connect loads to the wrong mains cables. Such errors are tested for.

A total of 91,138 LV feeders are listed in the CROWN database export file that lists customer meter MPANs for the East Midlands. Of this total, 74,156 feeders are included in the DEBUT files available from the WPD Electric Nation project. There are no network data for the remaining 16,982 feeders, either because there is no network file for the associated distribution substation, or because the LV feeder is not included in the network for the substation.

A loss estimation simulation is therefore possible for 74,156 feeders. The power-flow analysis converges successfully for nearly all of these feeders, but does not converge for 220 feeders. Feeders with poor convergence have been found to have high demands assigned to high resistance branches, either due to the cable type having a high resistance, or in some cases where mains branches are very long. In all of the cases examined, the input data relating to the demand location has been found to be incorrect. It is therefore correct to exclude these feeders from the results as they do not represent a realistic feeder configuration.

Although some feeders with very high loads that are incorrectly placed will fail to converge, there are other examples where the customer locations are incorrect but where the load is still within the range for which a power-flow solution can be created. A further set of consistency tests has therefore been applied to remove results for which the current and voltage characteristics would not be consistent with the planning rules used to design LV feeders. Unfortunately there is no clear distinction between customer loads that appear to be incorrectly located, and customer loads that may genuinely be inappropriate for the feeder cable to which they are connected. This situation could arise where demands have increased since the network was installed.

Feeder results are therefore classed as valid if:

The peak current in each branch is below the current rating for the cable
This comparison uses a peak current that is the maximum half-hourly mean current over daily profiles calculated for each of the 15 Elexon season-day types. This follows the same approach as used by DEBUT where the worst-case winter-day profiles are used for comparison against the cable ratings.

The minimum node voltage for any customer connection is above 217 V
This ensures that the network is approximately compliant to the voltage supply requirements. There is no further averaging applied in this case, requiring voltages to be within accepted tolerances for each 1-minute sample.

After applying these additional tests, a total of 69,256 feeders are considered to have valid results. Table 14 shows the number of LV feeders available for final assessment as consistency tests are undertaken on the full original set.

Analysis Stage	Feeders	Availability
Feeders referenced in East Midlands CROWN MPAN file	91,138	100.0%
Feeders with no network data	16,982	18.6%
Feeders with network data	74,156	81.4%
Feeders not converged	220	0.2%
Feeders converged	73,936	81.1%
Feeders removed	4,680	5.1%
Feeders accepted	69,256	76.0%

Table 14: Feeder-specific results for East Midlands region HV feeders

Appendix E.2 Service cables

The DEBUT files do not define the service cables between customer locations and the feeder mains. These have been assigned by assuming a straight line connection between the MPAN location and the nearest junction point on the mains cable. The service cable junctions are therefore not known and so it is assumed here that services attach to the nearest known junction in the mains. This simplified algorithm is expected to result in longer service cables than in reality. However, the use of a straight-line route rather than a route following road layouts will tend to under-estimate the lengths. . The impact of this approximation has been investigated using the known network data of the Isle of Man trials feeders as a case study.

The service cable assignment algorithm takes account of co-located meters (such as in a block of flats) sharing a common service cable to the feeder main. It is assumed that service cables may be shared for non-half-hourly meters with Elexon profile classes 1 to 4. Meters with the higher profile classes (5 to 8) and half-hourly meters therefore all have an individual service cable.

Service cable connections are assigned in order of their distance from the nearest feeder main, starting with the shortest distance. Subsequent service cables are connected directly to the main if they are within 3 m of the nearest mains junction, or to an existing meter location if they co-located to within 3 m of this and the service cable is to be shared. Services are only connected to existing meter locations if the destination meter is itself directly connected to the main, thus preventing an extended ‘daisy-chain’ arrangement of the service connections.

Appendix E.3 Phase allocation

WPD have provided a database export file that gives the number of phases for each MPAN, and also contains a text field indicating the supply type. The supply type is typically recorded as LV single-phase or LV three-phase, but in some cases may be listed as an HV connection. Any MPANs for which the supply type includes ‘HV’ are excluded from the LV feeder loss assessment.

In some cases the number of phases is not included (a blank entry). If the number of phases is unknown, it is assumed that half-hourly meters are three-phase and that non-half-hourly meter are single-phase.

Phases for single-phase meters are allocated in turn for each connection junction beginning with L1 on the first service cable connection. The phase number is then incremented for subsequent connections to the same mains junction. The initial phase number is also incremented for each further junction to which service cables are connected. The phase allocations on the first mains connection are therefore 1, 2, 3, 1 etc. and the phase allocations on the next mains connection will be 2, 3, 1, 2 etc. The numbering for shared service cables also follows the sequence at the mains junction with the shared service cable connection.

Appendix E.4 LV cable impedance data

The LV impedance model does not include data for the cable admittances as this data is not included in the DEBUT cable data. However, cable admittances at low voltage have been considered previously and found to have a negligible impact on the currents.

The LV impedance model does not include data for the cable admittances as this data is not included in the DEBUT cable data. However, cable admittances at low voltage have been considered previously and found to have a negligible impact on the currents.

The DEBUT cable impedance data for normal operating conditions includes only the resistances of the phase and neutral conductors and a current rating. This gives a very simplified impedance matrix in which there are no inductances, and also no mutual impedances between the phases. Omitting this data gives an acceptable approximation for the purposes of loss calculations as the reactances have minimal impact. The phase impedance matrix has therefore been formed for each cable type from the phase resistance r_{P} and the neutral resistance r_{N} as:

$$\boldsymbol{z}_{\mathbf{phase}} = \begin{bmatrix} r_{\mathrm{P}} + r_{\mathrm{N}} & r_{\mathrm{N}} & r_{\mathrm{N}} \\ r_{\mathrm{N}} & r_{\mathrm{P}} + r_{\mathrm{N}} & r_{\mathrm{N}} \\ r_{\mathrm{N}} & r_{\mathrm{N}} & r_{\mathrm{P}} + r_{\mathrm{N}} \end{bmatrix}$$

This gives a corresponding sequence impedance matrix as:

$$\boldsymbol{z}_{\mathbf{sequence}} = \begin{bmatrix} r_{\mathrm{P}} + 3r_{\mathrm{N}} & 0 & 0 \\ 0 & r_{\mathrm{P}} & 0 \\ 0 & 0 & r_{\mathrm{P}} \end{bmatrix}$$

Therefore the zero sequence impedance is $r_{\mathrm{P}} + 3r_{\mathrm{N}}$ and the positive sequence impedance (for balanced demand) is r_{P}.

The DEBUT resistance data matches exactly with the DC conductor resistances specified in cable construction standards. A correction to the phase conductor resistances has therefore been applied, as described in Appendix D.2. No correction was applied to the neutral as it is unclear from the cable designations in DEBUT whether the neutral conductor is an additional core (as for a 4-core cable) or whether it is provided by concentric wire strands or a sheath. The AC corrections would differ for these two cases.

Appendix E.5 Connection data

There are three files that are used to provide the input data relating to the customer MPANs.

File#1
This file is part of the EA Technology Electric Nation data (as originally provided by WPD) and is an extract from the Electric Nation SQL database. The file provides a list of MPANs, the corresponding X and Y co-ordinates, the substation id and the LV feeder id. This data is used in the service cable assignment algorithm to locate point of connection and then determine which feeder should be selected for the connection.

This file also includes a field recording the energization status of the meter. De-energized meters are excluded.

Meters are also excluded if the LV feeder is recorded as 'NULL' or if there is no corresponding feeder number in the network.

File#2
This file has been provided directly by WPD and specifies the Elexon profile class and EAC for each MPAN.

If the Elexon profile class field is blank then the meter is omitted. Typically this is the case where half-hourly billing data is also available, or in some cases when the meter is no longer in use. However, there some cases where blank records for the profile class are probably errors and this will lead to the associated demand being omitted from the loss analysis.

If the EAC data is blank (but valid profile class data is present), then the default EAC associated with the Elexon profile is used.

Meters are excluded if they are missing from the WPD data file that defines connections of MPANs to substations and also their profile classes and EACs.

File#3
For each MPAN, this file specifies the connection type (HV or LV) and the number of phases. MPANs are excluded if the supply type references an HV connection.

Where the number of phases is unknown, it is assumed to be three for half-hourly meters and one for non-half-hourly meters.

Meters are excluded if they do not appear in this data file.

Appendix E.6 Basic input demand data

As with the HV assessment method, demand data for each half-hourly MPAN is constructed using the recorded meter data. The demand for non-half-hourly MPANs is derived from the Elexon profiles and scaled according to the customer Estimated Annual Consumption (EAC).

The process differs from the HV assessment method as there is no SCADA data for the substation that can be used to apply any further scaling to the non-half-hourly data. The initial treatment of non-half hourly demand input data is to scale the Elexon profiles such that the annual demand is consistent with the customer EAC.

Since there is no process here (as with the SCADA data in the HV loss assessment) to correct for missing demand, it is important that MPANs should not be excluded due to missing data records. The meters are therefore assigned as follows. If half-hourly data is available for an MPAN, then this is used to define the demand. If no half-hourly data is available, and the Elexon profile class is known, then the demand is generated using the corresponding Elexon profile. If the EAC is known then this is used to scale the profile. If the EAC is not available, then the Elexon profile is used without further scaling. This differs from the HV loss assessment where the MPAN would be excluded if the EAC was unknown.

Appendix E.7 Time Resolution of load model

It is recognised that losses calculated with half-hourly demand data will be systematically lower than loss calculations with a higher time resolution. The impact of this for LV feeders was investigated, through averaging the 1 minute resolution input data for the monitored feeders to periods of 2, 5, 10 and 30 minute periods, and then re-calculating losses using these averaged values. As expected, calculated losses were lower with longer time average periods as seen in Figure 160. This shows the resulting loss ratio from using lower time resolution (longer averaging periods) for the 11 monitored LV feeders. The loss ratios are based on the total losses for the LV feeder, including the transformer load-losses and no-load losses.

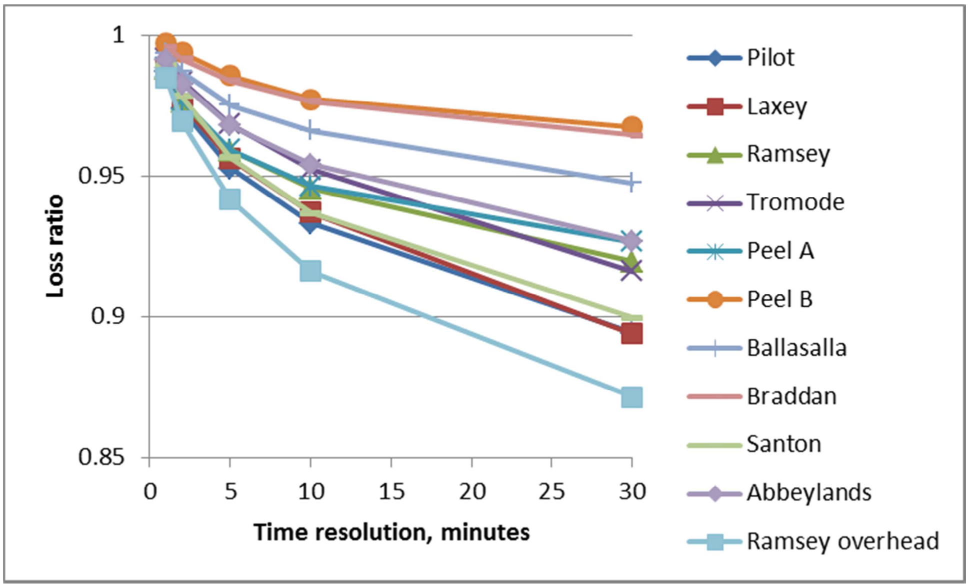

Figure 160 Impact of measurement time resolution for LV feeders

Because the LV input data was significantly less aggregated than the HV, the impact of modelling load at 30 minute (compared to 1 minute) resolution is material (using 30 minute time periods can cause a reduction of up to 13% in the assessment of losses). The LV loss assessment method therefore uses 1 minute time periods in the load model in order to describe the variation in loads that occur within half hour periods.

Appendix E.8 Diversified demand data: non-half hourly

Overview

The half-hourly demand data for non-half-hourly meters with the same profile class is fully correlated (the basic input demand data described in Appendix E.6). This demand data makes no allowance for individual customers having a demand that differs from the national average profile, or for variations in the demand within a half-hour period. The measured data from the LV trials has therefore been used to build a statistical model of deviations from the half-hourly profile that have been observed, together with the probabilities at which each deviation would occur.

A number of methods have been tested in order to provide this temporal diversity. One simple method would be to use the trials measurement data literally, with the measurements acting as a library of customer demand time series. The drawback with this method is that the trials data cannot be expected to cover all of the range of meter types and EACs seen across a WPD license area.

Another approach would be to use a demand modelling technique, such as the CREST demand model. The difficulty here is that the models do not cover commercial demands, and also that the configuration data is based at the level of individual appliances, such that it is not straightforward to create scenarios that are consistent with the known EAC data for the actual customers.

A third option would be to use a set of probability density functions for which parameters could be selected such that the diversified demand closely approximates the observed data. This approach would possibly work well if the only requirement were to model variations in the active power, but it is also necessary to include variations in the reactive power and in the unbalance of three-phase meters. These variations cannot be considered completely independently of the active power variations.

The selected method therefore uses a combination of these methods. The measurement data is used in the form of probability distributions (rather than by re-playing a time series). In order to generate the probability distributions from the measurement data, the measured samples of active and reactive power and the predicted active power from the scaled profiles are grouped into bands of width 100 W.

The process operates in two stages:

- Starting with the active power predicted by the scaled Elexon profile, a sample is taken from an active power probability distribution to find the diversified active power. A typical example distribution is shown in Figure 161
- A sample is then taken from a reactive power distribution. A typical example distribution is shown in Figure 162 where the reactive power is expressed as a phase angle relative to the active power. The actual probability distributions are created using the reactive power directly, rather than as an angle or ratio. This avoids unrealistic cases that could occur for active powers in the first 100 W band where a measured sample could have a phase angle near 90° but for an active power of near zero. A very high spike in current could be created if the same angle were applied to an active power nearer to 100 W.

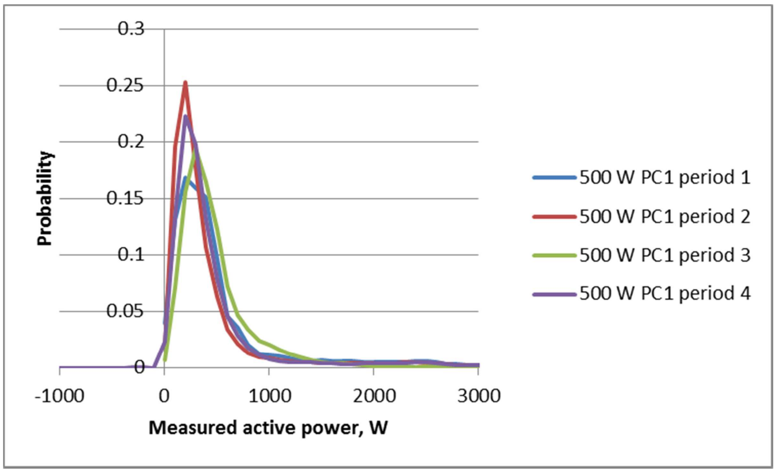

Figure 161 Probability distribution of measured 1-minute power for profile class 1, predicted demand power 500 W, and for periods 1 to 4

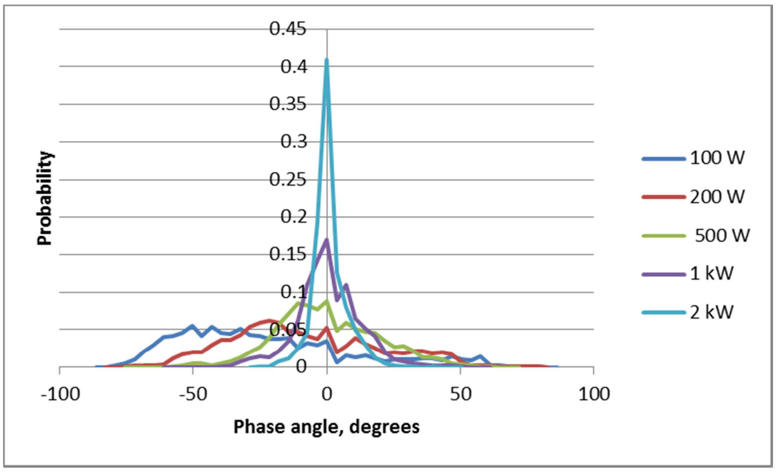

Figure 162 Probability distribution of measured 1-minute reactive power phase angle for profile class 1

Meters may occur in the loss assessment feeders where the levels of active power have not occurred for meters in the trials data. If the 100 W band did not appear in the trials data, but bands that are higher are available, then the probability distribution for the higher band is selected and the samples selected from the distribution are scaled down to maintain the desired EAC. If the required 100 W band is above all of the samples in the trials data then the power predicted by the scaled Elexon profile is used directly with no additional temporal diversity.

The probability distributions are derived from measured data from the Isle of Man LV feeder trials. There are very few customer connections on the trial feeders with embedded generation and few time samples for which there is a net export of power from the customer. The probability distributions therefore only include samples for which the active power is positive as there is insufficient data to give an accurate representation of the temporal diversity of generation.

The probability distributions were collated separately for meters in each profile class and for each of the Elexon time periods (1 to 4) for 'peak', 'winter', 'night' and 'other.

Meters in the Isle of Man do not have an allocated profile class and so a notional class was assigned for each meter, based on the following rules:

Domestic feeders

All meters classed as Elexon profile class 1 or profile class 2 according to whether a single or a dual tariff was applied.

The overhead feeders are included here as they also supply domestic customers.

Commercial feeders

Meters were classed as profile class 3 for an EAC of 40 kWh or less, and otherwise as profile classes 5 to 8 according to the Elexon definitions relating to load factor:

Load factor 0 to 20%	profile class 5
Load factor 20% to 30%	profile class 6
Load factor 30% to 40%	profile class 7
Load factor > 40%	profile class 8

As there were no profile class 4 meters in the trials data, and only one profile class 2 meter, the probability distributions for profile class 4 use those of profile class 3 meters, and the probability distributions for profile class 2 use those of profile class 1 meters. Although this may appear unrepresentative, it is still the case that an appropriate probability distribution is selected according to the level of active power predicted from the scaled profile. If a profile class 2 meter as a high predicted demand (e.g. after midnight when storage heaters are switched on), then the model will use probability distributions for profile class 1 for the same predicted power.

The process operates differently for single-phase and three-meters because the scaled Elexon profiles only provide the total demand, rather than the demand per phase.

Single-phase non-half-hourly meters

Temporal diversity is synthesized for single-phase meters as follows:

- The diversified active power is selected from a probability distribution of 1-minute active power samples that were observed in the trials data. A separate probability distribution is used for each profile class, and for four time periods (see below), and for each level of active power predicted by the profile data (Elexon profile scaled by EAC).
- The diversified reactive power is selected from a probability distribution of 1-minute reactive power samples that were observed in the trials data for the same 1-minute active power and profile class.

The trials data has measurements from many domestic meters but relatively few commercial meters. The trials include three-phase commercial meters in profile classes 5 to 8, but no single-phase meters in these profile classes. The probability distributions for single-phase meters with profile classes 5 to 8 are therefore based on the total three-phase active power of the three-phase commercial meters.

Three-phase non-half-hourly meters

The measurement data has shown that there can be considerable unbalance within three-phase meters and it cannot be assumed that one third of the demand occurs on each phase. In many cases the most unbalanced three-phase connections occur where a three-phase supply has been provisioned but one or more of the phases are effectively unused.

The highly unbalanced scenarios are more likely to occur for customers where the EAC is lower. This is shown in Figure 163 where the mean proportion of power on each phase is plotted for the three-phase meters in the trials data. The probability distribution also include four three-phase meters from the HV trial, using data from GridKey loggers at distribution substations and where there is monitoring on individual LV feeders that have only one commercial customer. The plot shows that very high levels of unbalance can occur, not only instantaneously but also as a persistent unbalance when the power per phase is averaged over a year. Customers with higher demand are less likely to have such high levels of unbalance of the mean power (although the instantaneous unbalance may still be high).

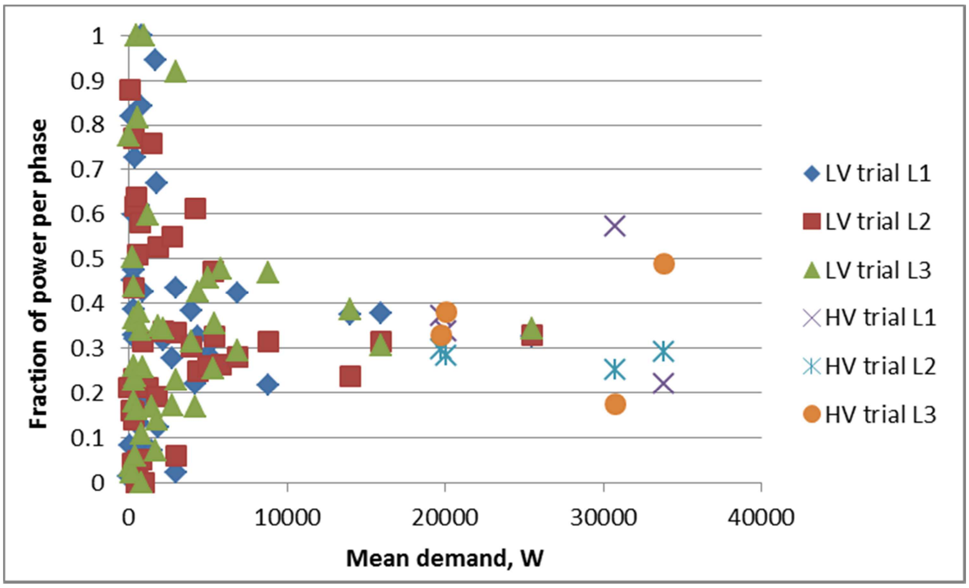

Figure 163 Mean unbalance of three-phase meters

As noted above, the unbalance and the time variation of the active power cannot be modelled as independent statistical processes. If the unbalance and the active power variation were modelled independently, then samples could occur where the active power is significantly higher than the expected mean, and where a high level of unbalance is also applied. This would create an unrealistically high peak current in one phase conductor, potentially causing the power-flow analysis to fail to converge, or otherwise to introduce a very high loss sample into the loss assessment.

A similar process therefore applies for three-phase meters as for single-phase meters, but with the unbalance being included in the active power distribution:

- The three-phase diversified active power is selected from a probability distribution of three-phase 1-minute active power samples that were observed in the trials data. As with the single-phase meters, a separate probability distribution is used for each profile class, for the four time periods, and for each level of active power predicted by the profile data, where the active power predicted by the profile data refers here to the total demand across all three phases.
- The sequence of three-phase active powers is randomised, such that the power observed in the measurement data on L1, L2 and L3 could occur on any combination of phases in the synthesized data.
- The diversified reactive power is applied independently for each phase using the same process as used for the single-phase meters.

Method for half-hourly meters

The temporal diversity for half-hourly meters is added using a similar method as for the non-half-hourly meters, except that the half-hourly mean demand is already known.

Half-hourly meters typically have higher demands than non-half-hourly meters and can therefore have a significant impact on the losses. If an unrealistically high current is included in the demand data, there is a risk that the power-flow analysis will fail to converge and the results for that feeder would then be excluded from the overall data. This could introduce a bias whereby feeders with high loads are more likely not to be included in the set of results.

The demand for three-phase half-hourly meters is therefore initially assumed to be balanced such that one third of the half-hourly power (active and reactive) from the billing data is allocated to each phase. This avoids very high currents being introduced on individual phases if a greater degree of unbalance was included than exists in reality. For single-phase meters, the power from the half-hourly billing data is used directly.

A temporal variation is then added to each phase based on a probability distribution. These probability distributions represent the variations in 1-minute active power samples that have occurred in the measurement data for a given half-hourly mean active power on the same phase.

Although the phases of three-phase meters are balanced on average, this process introduces short-term unbalance as the 1-minute active power samples are selected independently for each phase.

It is assumed that there is a constant power factor over the half-hourly period, and so the reactive power varies in proportion to the active power.

A final scaling is also applied to ensure that the mean active and reactive powers of the diversified demand data are equal to the mean power of the half-hourly billing data.

Sub-sampling

The measurement data is based on 1-minute averaged values, and so the synthesized data from the probability distributions also has this time resolution. The loss assessment operates on half-hourly data for a 1-year period, with 17, 520 half-hour periods. This could potentially be expanded to 525,600 samples at 1-minute resolution but this would have a significant impact on the computational time needed to perform the loss assessment on all of the feeders across a license area.

Modelling work with the measured data has shown that there is very little reduction in accuracy if the data is sub-sampled, provided that the selected samples adequately represent the diurnal and annual variations in demand. This is demonstrated in Figure 164 where the number of samples included in the power-flow analysis is progressively reduced. Samples are randomly selected from the 1-year time series. The impact on losses is shown in terms of a ratio of the loss calculated for the sub-sampled data to the loss calculated with the full 1-minute time series over a 1-year duration (ideally 525,600 samples, but reduced slightly due to instrumentation outages). The results show that the number of samples can be reduced to 1000 with an error of less than ±2%. For 10,000 samples, the error is less than ±1% of the loss power.

The power-flow analysis for the loss assessment method therefore uses only one sample per half-hour period, a sub-sampling of 1 in 30. The number of samples in the model therefore remains the same as with the half-hour profile data, but the samples can be considered to have 1-minute resolution.

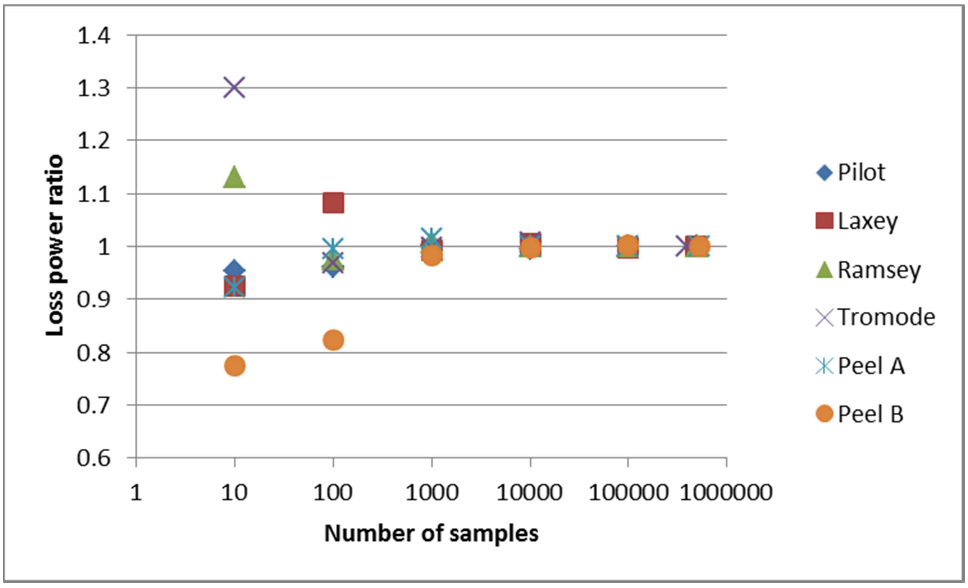

Figure 164 Ratio of loss for sub-sampled time series to loss for 1-minute time series

Embedded generation

As noted above, the measurement data from the Isle of Man trials has very few samples where there is a net export of power from the customer and so the probability distributions do not represent embedded generation. The Elexon profiles for non-half-hourly customers have positive values throughout and so only represent demand.

The demand for customers with embedded generation but a net positive EAC will follow the same profile as for a conventional demand-only customer. This generation is 'behind the meter' so the loss assessment software cannot distinguish these customers from similar customers with the same EAC but no generation. This will under-estimate the losses for these customer connections as the generation is modelled as offsetting demand throughout the day, rather than having a more likely profile in which there is reduced demand, or possibly a net export, corresponding with the variation in solar irradiance. A more accurate model of this scenario would require customers with embedded generation to be identified in the MPAN data.

Half-hourly customers may have active or reactive export power included in the billing data. This is combined with the import power to give a net complex demand power and temporal diversity is applied to the combined power. As for the non-half-hourly meters, no temporal diversity is applied when the combined active power is negative. (A future development of the software could maintain the imported and exported power separately and then apply temporal diversity to each as appropriate.)

Appendix E.9 Impact of unbalance on monitored feeders

LV Feeders

Unbalance between the demands on each phase can occur on a persistent basis where there are different mean demands on each phase, and also as a short-term unbalance as customers on each phase switch appliances on and off.

Losses are increased when the currents are unbalanced. This is demonstrated in Figure 165 where the variation of losses with demand is colour coded according to the degree of unbalance. Each point in this figure represents the loss in a 1-minute period for the LV trial pilot feeder. Unbalance is quantified as the ratio between the zero sequence and positive sequence currents, given by

$$U_{\mathrm{I}} = \frac{|I_{\mathrm{zero}}|}{|I_{\mathrm{positive}}|}$$

where

$$\begin{bmatrix} I_{\mathrm{zero}} \\ I_{\mathrm{positive}} \\ I_{\mathrm{negative}} \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix}^{-1} \cdot \begin{bmatrix} I_{\mathrm{L1}} \\ I_{\mathrm{L2}} \\ I_{\mathrm{L3}} \end{bmatrix}$$

For any given level of demand, Figure 165 shows that 1-minute periods with high losses tend to also have a high unbalance. However, although there are a number of highly visible points with a high unbalance ratio, it is also clear that the majority of points lie in a lower range. Although high losses and high unbalance occur, the demand is balanced for many of the sample periods.

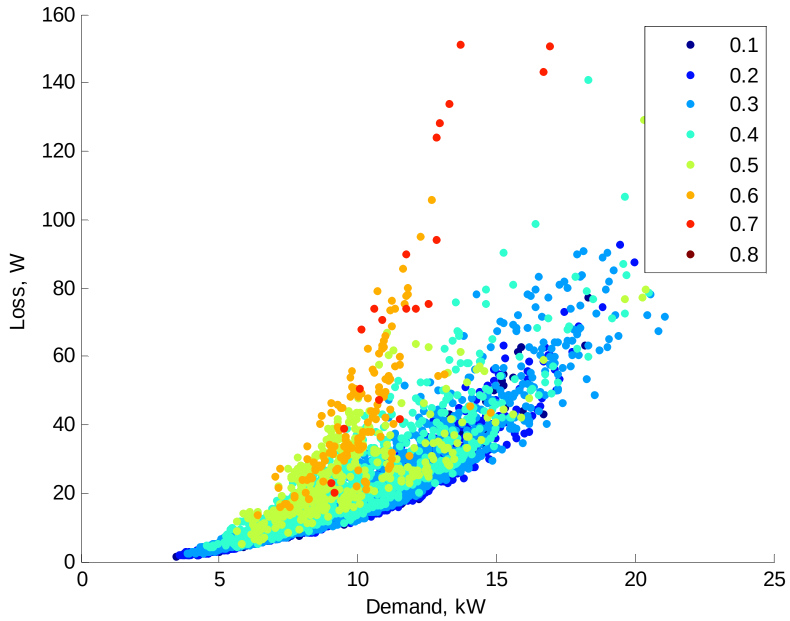

Figure 165 Loss vs. demand with colour indicating unbalance factor

The impact of unbalance has been assessed by repeating calculations of losses for the trials feeders with the demand balanced across the three-phases. Although this scenario could not be achieved in practice without a change to the single-phase wiring of individual LV customer connections, the results indicate the extent to which losses might be reduced in the hypothetical scenario in which a perfect balance could be achieved.

The comparison for the LV feeders uses the following approximations to model the losses for a balanced feeder:

- The balanced demand for a three-phase meter uses the average of all three phase demands on each phase
- The balanced demand for a single-phase meter uses one third of the demand on each phase. This implies a form of customer appliance wiring that does not exist, but model the best improvement in losses that could be achieved through balancing.

The service cables for single-phase customers are modelled as three-phase cables, with each phase having the same resistance as the line conductor of the existing single-phase cable. The service cables losses are therefore not directly comparable for the balanced model as the approximation implies a further two phase conductors which are not physically present. Some of the reduction in losses in service cables could therefore be attributed to this increased number of conductors in the balanced model, in addition to the benefits of balancing.

Losses for the eleven LV trials feeders with a balanced demand are shown in Table 15. The total losses (including metering, unaffected by the balancing) reduce by approximately 13% on average. A similar reduction applies in the mains cables, but individual feeders have reductions in losses of up to 40%. However, the greatest loss reductions due to balancing occur where the demand and losses are relatively low. The commercial feeders Peel A and Peel B have much greater losses with minimal unbalance. The loss reduction if these feeders were balanced is less than 5%.

These results show the importance of including unbalanced calculation methods in the LV loss assessment.

The impact of unbalance has also been tested for the LV feeders in the Milton Keynes trial, using results from the LV loss assessment methods. Using balanced demands in place of the predicted unbalanced demand data causes the estimated total losses to be reduced by 13%. There is a greater reduction of 22% for the losses in the mains cables.

Table 15: LV feeder losses calculated from measurement data and with balanced demand data

	Total loss power, W			Mains loss power, W		
Feeder	Unbalanced	Balanced	Difference	Unbalanced	Balanced	Difference
Pilot	31.4	22.6	-28.0%	8.8	5.2	-40.4%
Laxey	342.2	253.6	-25.9%	232.3	173.5	-25.3%
Ramsey	101.8	84.4	-17.0%	34.0	23.4	-31.2%
Tromode	748.8	542.2	-27.6%	620.8	462.4	-25.5%
Peel A	392.4	378.1	-3.6%	327.1	318.8	-2.5%
Peel B	2034.7	2005.7	-1.4%	1521.1	1500.3	-1.4%
Ballasalla	84.7	62.1	-26.8%	51.5	35.7	-30.6%
Braddan	246.6	205.8	-16.5%	182.0	153.6	-15.6%
Santon	39.4	29.2	-26.0%	15.0	9.3	-37.7%
Abbeylands	411.4	295.0	-28.3%	354.8	254.2	-28.4%
Ramsey overhead	144.2	106.4	-26.2%	85.1	61.6	-27.6%
Total	4577.8	3985.3	-12.9%	3432.6	2998.1	-12.7%

Appendix E.10 Power Flow Analysis

The LV loss assessment simulations use a forward/backward sweep power-flow analysis. This is more straightforward than for the HV loss assessment as there is no additional measurement data (analogous to the SCADA data used in the HV loss assessment) that can be taken into account.

The LV loss assessment calculates losses for a period of one year from 1st July 2016 to 1st July 2017 for which the half-hourly billing data is available. The loss assessment method has also been applied to the instrumented trials feeders in the Isle of Man, for comparison with results from measurements. The comparison for these feeders uses a different period, selected to match the availability of measurement data, from 2nd October 2017 to 2nd October 2018.

Appendix E.11 Output Data

The power-flow analysis provides output data describing the I^2R losses in each branch in the network. Mean losses are calculated over the one-year duration included in the loss assessment and summarised separately for feeder mains, service cables, and for overhead lines and underground cables.

The output data also provides a number of metrics to indicate the worst-case voltages ranges and the maximum currents. These metrics are used as indicators to determine whether the network and demand models are plausible and to exclude feeders from the set of results where the demand applied to the network is clearly inconsistent with network planning practices. Examples where the results differ significantly from the expected ranges typically indicate errors in the customer location data in the feeder topology, or in the feeder numbering (such that the incorrect set of customers is applied to the feeder cable).

To enable further analysis of the loss results, the software provides details of the lengths of mains and service cables forming the feeder. The length includes only sections of the feeder with downstream connected customers, so excluding any sections of mains cable that only serve to connect to link boxes. In practice these lengths are mostly relatively short on real networks, but can be longer in the DEBUT network models where sections of mains that are beyond open circuit junctions at link boxes are sometimes included.

The results also provide details of the number of customers connected, and list the number of half-hourly meters, non-half-hourly meters, together with the associated mean demands. The demand of non-half-hourly meters in each Elexon profile class is also listed, such that it is possible to classify feeders as having a domestic or commercial character according to the proportion of demand in each class.

A number of graphical outputs are also included, of which examples are presented below for feeder 4 at substation 941916, illustrated in Figure 166.

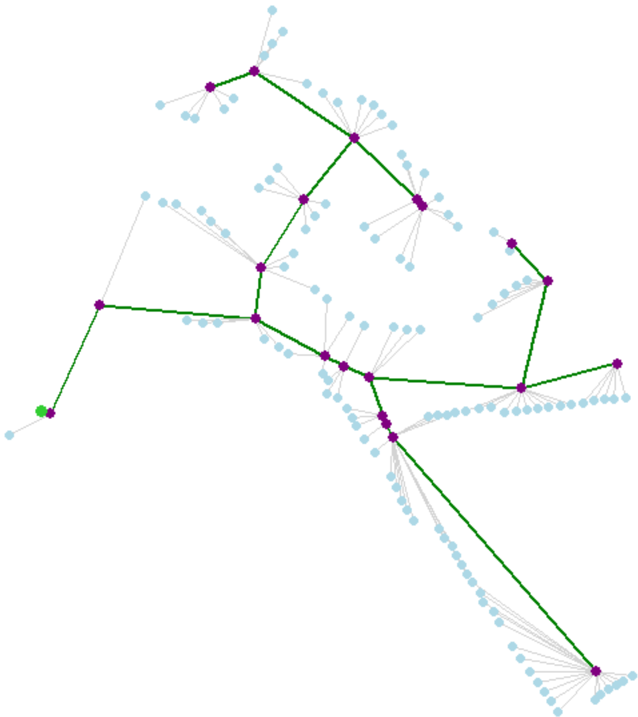

Figure 166 Substation 941916 feeder 4

The variation of active power at the substation is shown in Figure 166.

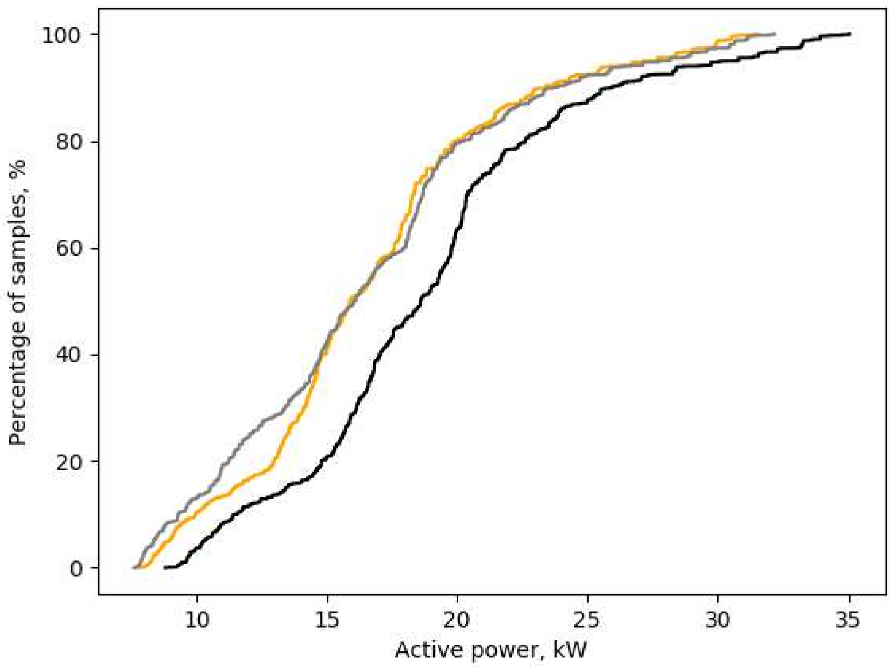

Figure 167 Example CDF of active power at distribution substation for 941916 feeder 4

Figure 168 shows the variation of losses with the distance from the substation. The multi-branched tree structure of the feeder network is represented here as a linear distance of any branch from the substation, calculated according to the sum of the upstream lengths, and losses are shown per metre of feeder cable. Losses in mains cables are shown in blue and losses in service cables in orange. The total loss in the mains cables or services is represented in this plot as the accumulated shaded area.

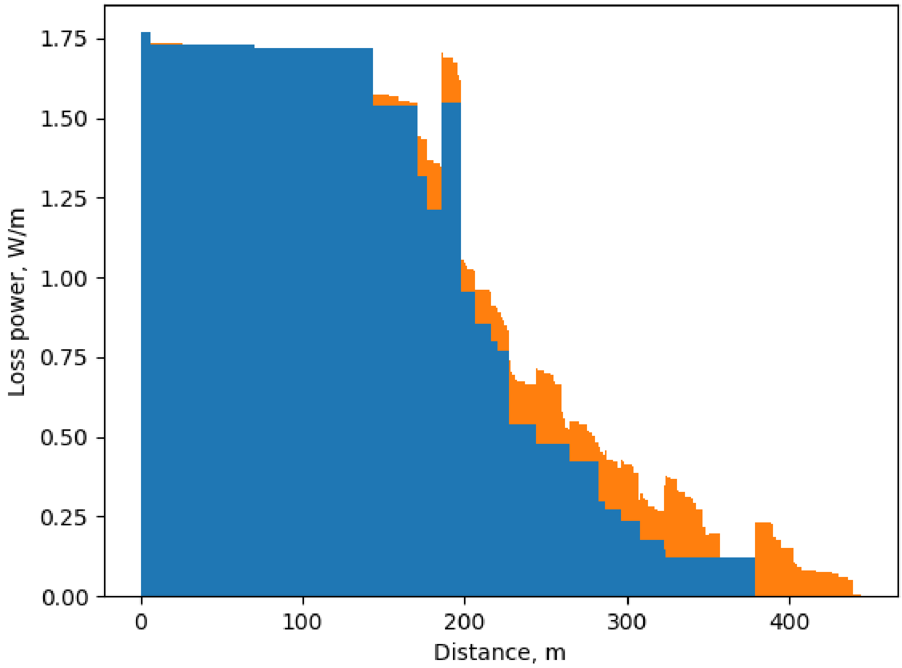

Figure 168 Example plot showing variation of losses with distance from substation for 941916 feeder 4

In this example, there is a fairly constant loss of 1.7 W/m for the first 140 m length, with slight variations due to the use of sections with different cable types and as there are two intermediate service junctions with low demands. There are junctions in the mains cables downstream of this 140 m distance and the losses in the cable then reduce significantly as the aggregated demand reduces. There are also a greater number of customer connections and so there are higher service cable losses.

The plot therefore illustrates the high proportion of total losses that occur in the cables near to the substation and the lower losses that occur towards the ends of the feeder. Although this is to be expected, as branches near to the substation have higher demand aggregation, branches near to the substation may also therefore have larger cable sizes, offsetting the impacts of the higher demand aggregation. Conversely, losses are lower in individual service cables that are towards at the downstream ends of the feeder, but there are also many more of these branches.

Appendix E.12 Validation against DEBUT

The loss analysis uses network data from the WPD Electric Nation project, supplied in the form of DEBUT files. Output data from DEBUT is also available for a DEBUT simulation and this can be compared with results from the loss assessment software, provided that the demand model is configured to be equivalent. This requires that the additional features in the loss assessment software, such as the inclusion of service cables and the use of customer EAC data, should be removed.

An exact comparison is not straightforward as the loss output from DEBUT provides the worst-case loss, allowing for the half-hourly profile period with the peak demand, and then also including a further margin to allow for the impact of individual customers having greater demand than the averaged profile. By definition, this worst-case loss therefore occurs very rarely. This is a very different metric to that used by the loss assessment method where the objective is to calculate the long term mean losses, and potentially ignoring extreme worst-case conditions if these have no significant contribution to the mean. The averaged profiles used by DEBUT are also different to the Elexon profiles and use standardised EACs rather than the actual customer EACs.

A further complication arises as DEBUT defines the demand in terms of a mean and standard deviation for each customer. Although the mean values can be added, as in a conventional power-flow calculation, the standard deviations must be included separately as they combine as a sum of variances, giving a root-mean-square summation of the standard deviations. This differs from the approach taken in the loss assessment method where individual samples are drawn from statistical distributions and the demand currents for each customer can be added directly to find the current in upstream branches.

The validation tests therefore required the loss assessment software to be reconfigured such that the network and demand data matched the DEBUT model as closely as possible. The use of actual customer EACs was deactivated, and the Elexon profiles were replaced by a single value taken from the DEBUT profiles for the half-hour period in which the worst-case loss occurred. A further profile scaling was required to allow for the numbers of meters with each DEBUT profile being slightly different from the numbers with corresponding Elexon profile classes in the loss assessment model.

This comparison ignores the additional losses due to the standard deviation of the demand that is included in the DEBUT model. The loss assessment method results for demands based only on the half-hourly profiles would therefore be expected to be slightly lower than those from DEBUT. Results were also calculated with statistical variation included in the loss assessment method. This variation allows for the variation on a 1-minute resolution and so losses from this model would be expected to be higher than those form DEBUT where the resolution is only half-hourly.

This comparison was tested for two substations:

941916, with three feeders

DEBUT worst-case loss	8.9 kW
Loss assessment without statistical variation	8.8 kW
Loss assessment with statistical variation	9.9 kW

942071, with four feeders

DEBUT worst-case loss	15.6 kW
Loss assessment without statistical variation	13.9 kW
Loss assessment with statistical variation	16.0 kW

These comparisons showed that two loss assessment method results were either side of the DEBUT result, as expected.

A more precise comparison of the two methods would require that exactly the same customer connections and phase allocations configured in both models, and that a version of the DEBUT result be calculated in which the standard deviations of the demand are set to zero. However, the comparison already demonstrates that the two methods give very similar losses when configured with similar networks and demand models.

Appendix E.13 Validation of assessment method using LV monitored feeders

Network approximations

The impact of using approximated service cable connections and lengths has been tested for four of the LV trial feeders. Results are shown in Figure 169 for three cases:

i) Using the fully detailed network data developed for the measurement analysis
ii) Where service cables connect by a straight-line route to the nearest service-cable joint (in most cases this is the actual connection joint)
iii) Where service cables connect by a straight-line route to the nearest mains joint (this is the approximation used in the LV loss assessment)

The results show that there is a slight increase in the calculated losses due to the service cable approximation, with a 14% increase in the mean losses over the four feeders. In the absence of detailed information to specify the service cables more accurately, it has been decided that this level of uncertainty is acceptable. A future development of the service cable algorithm could make use of more detailed exported data from the EMU database such that the mains cables routes would be more accurately known. Service cable joints could then be created within the length of the mains cables, rather than only at the junction nodes as assumed here.

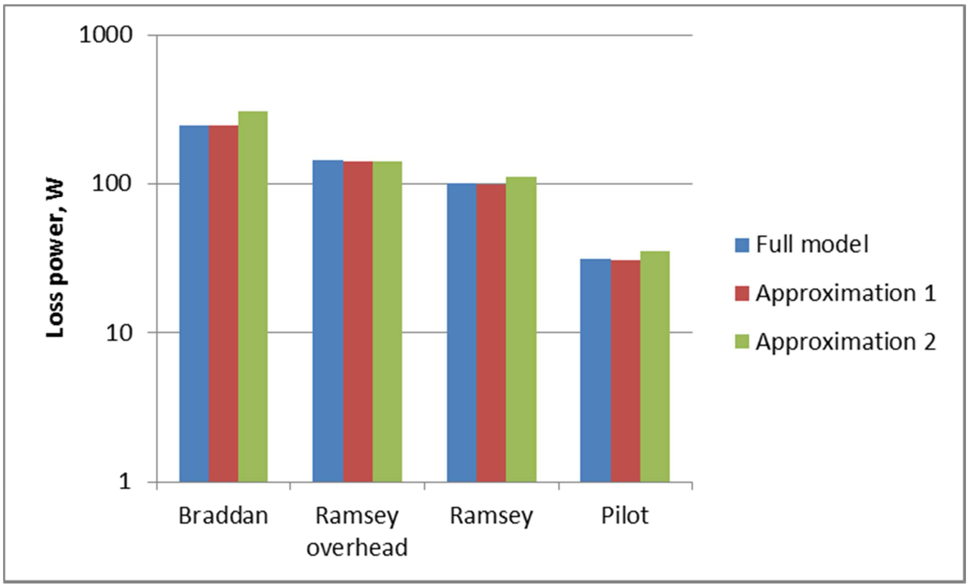

Figure 169 Impact of service cable approximations on LV trials feeders

Demand approximations

The demand model with diversification has been used applied to the LV trial feeders so that the mean losses can be compared with the losses calculated from measurement data.

In order for the comparison to assess only the impacts of the demand model, the measurement loss calculations are revised so as to exclude un-metered connections. These connections are monitored in the trials instrumentation but are not included in the loss assessment demand model. The measurement loss calculations also use the same estimated substation voltage of 245 V, rather than the actual substation voltage which would not be known from business-as-usual data.

The losses from the LV loss assessment method are compared against this modified measurement loss analysis (dented ‘reference’) in Figure 170. This shows very good agreement between the measurement loss analysis and the demand model with diversification. Over the set of eleven trials feeders, the total losses match to within 1% of the loss power.

This acts as a verification of the method, although it is to be expected that good results will be obtained when the demand model with probability distributions is applied to the same feeders from which the probability distributions were created.

The results with the demand model uses only the half-hourly data and omitting diversification match less well to the reference measurement losses. On average, the demand model with half-hourly data under-estimates the mean losses by 23%. However, the approximate rank order of losses is maintained, such that feeders with particularly high losses could still be identified.

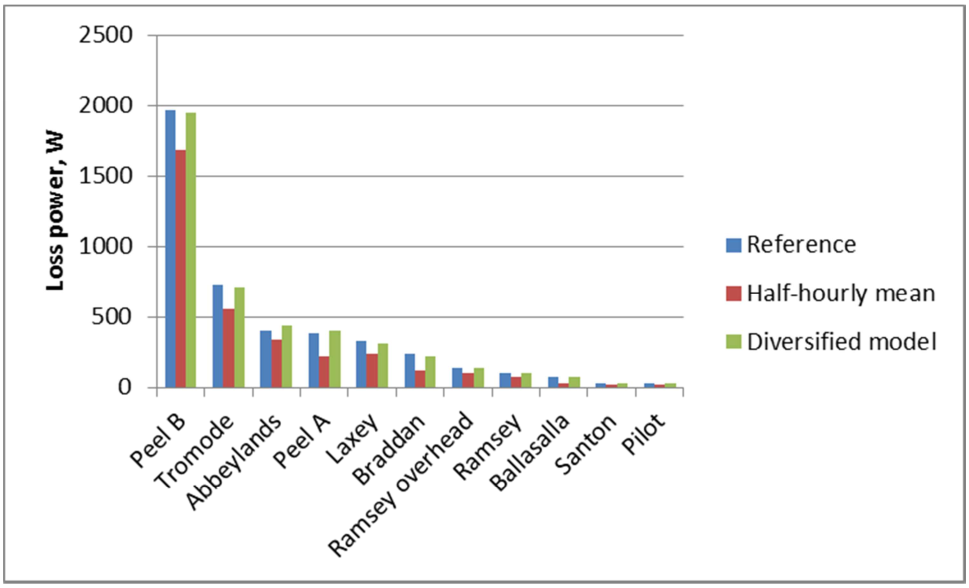

Figure 170 Mean loss power for LV trials feeders with demand model and measurement

Network and demand approximations

The end-to-end impact of these approximations in the loss assessment model is shown in Figure 171. This compares the loss calculations from the 1-minute measurement data with losses calculated incorporating the network approximations and using the time diversified demand model. Un-metered connections are also excluded from the loss assessment model, and an estimated substation voltage is used in place of measured data.

Over the set of eleven trials feeders, the losses predicted by the loss assessment method are 9% above the losses calculated from measurement data.

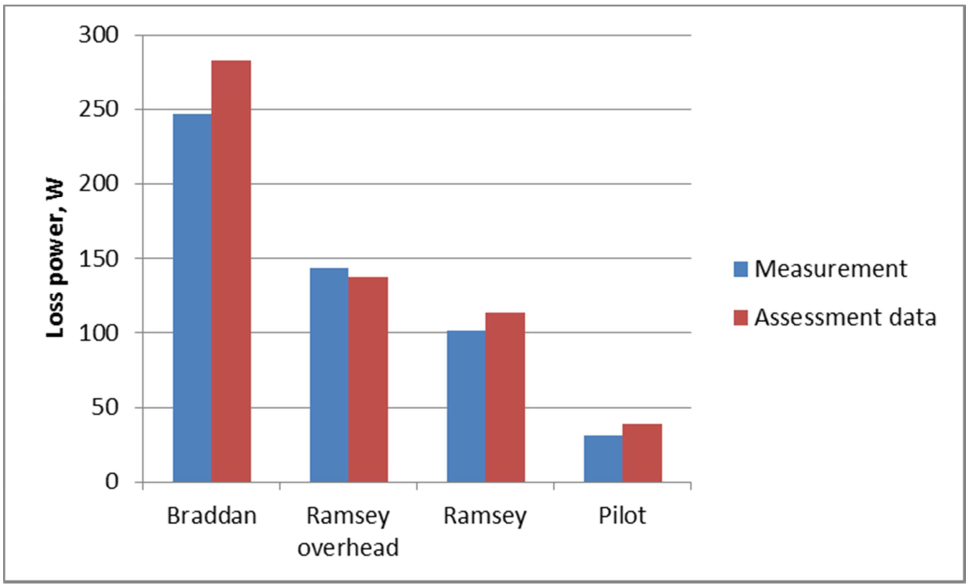

Figure 171 Mean loss power for LV trials feeders with demand and network approximations

Appendix E.14 Validation of LV demand model using HV monitored feeder data

Mean active demand

A key requirement for accurate assessment of losses is that the demand model should be accurate. The demand predicted for the LV feeders monitored as part of the Milton Keynes trial has therefore been compared to the measured demand data. An exact match cannot be expected as the measurement instrumentation for most feeders was not installed some months later than the start of the period used for the loss estimation. However, the mean loads are likely to be similar.

Figure 172 shows the mean demand over a 1-year period from the loss assessment method and from the measurements. It can be seen that there are many feeders for which the predicted demand is equal to the measurement, but there are significant differences for approximately one third of the feeders. The total demand of all of the feeders agrees to within 5%, a difference that could easily be due to the use of time periods. This suggests that the differences for individual feeders are due to load allocation errors, rather than load is systematically under- or over-estimated. Some of the differences may also be due to the feeder numbering used in the instrumentation being different to the feeder numbers assigned to customers in the CROWN database and used in the loss assessment.

These results demonstrate that the loss assessment method is highly dependent on the accuracy of the customer records. Errors in customer records can cause demand to be allocated incorrectly to the LV feeders, or possibly at the incorrect distance from the substation (although that would not be indicated in Figure 172). Errors in the customer location or feeder allocation could also cause the DEBUT feeder numbering to be incorrect.

Assuming that the differences seen in the Milton Keynes trial feeders are indicative of the demand model accuracy across the license area, then the loss assessment results should be considered more as a being representative of real LV feeders, rather than literally indicating the losses on each specific feeder. Approximately two thirds of the feeders may have a demand model that closely matches reality, and the remaining third will have realistic network topologies, but the connected loads may not be exactly as they are in practice.

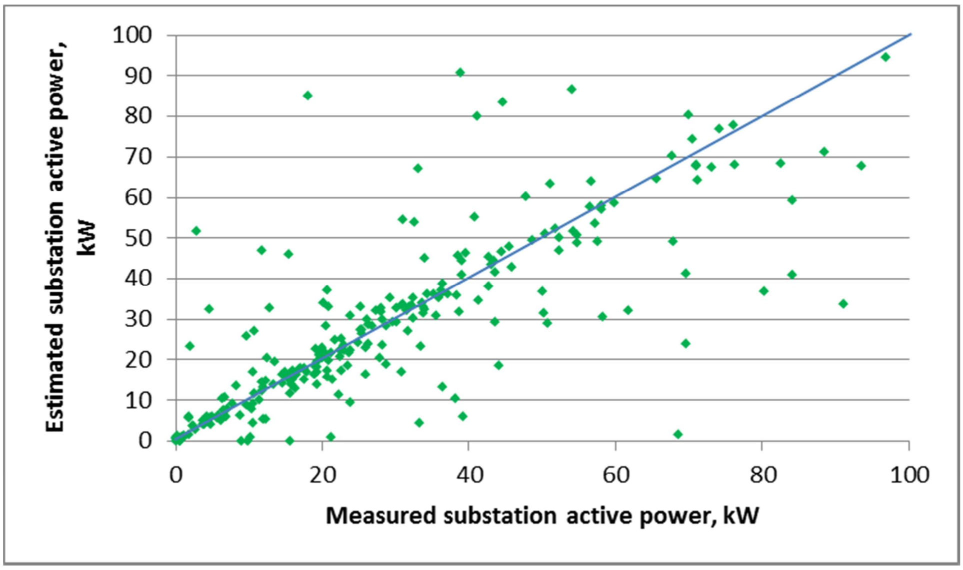

Figure 172 Mean demand from loss assessment and measurement for HV trials feeders

Reactive power

Distributions of reactive power for the demand model created by the loss assessment method at the substations in the Milton Keynes trial can be compared against distributions based on the measured data. In general, it has been found that the mean reactive power is positive, but with a level that implies a power factor close to unity. The variation in reactive power, as a proportion of the active power, reduces as the active power increases.

The mean and standard deviation of these distributions is compared in Figure 173 for all feeders and in Figure 174 for domestic feeders. The mean of the reactive power ratios agrees well with the means of the measured distributions although is higher for active powers of above 30 kW when all feeders are considered. This difference arises as the probability distributions used for the loss assessment are derived from commercial meters in the Isle of Man trial for which the reactive power is relatively high. However, these high levels of active power occur relatively rarely. Furthermore, a reactive power ratio of 20% for the loss assessment demands corresponds to a power factor of 0.98 and has an impact on losses of less than 4% when compared to the measured reactive power ratio of near zero. The variations in the reactive power ratio, indicated by the standard deviation, are similar.

It has therefore been concluded that the method used to add reactive power to the demand data provides an acceptable approximation to the measured data.

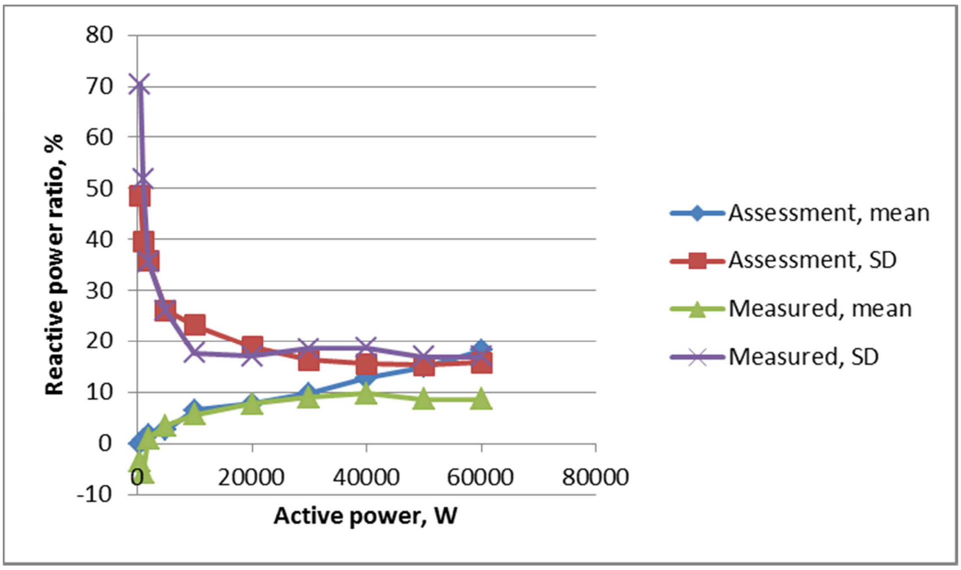

Figure 173 Mean and standard deviation of reactive power for all feeders at Milton Keynes trial distribution substations, from measured data and from loss assessment method

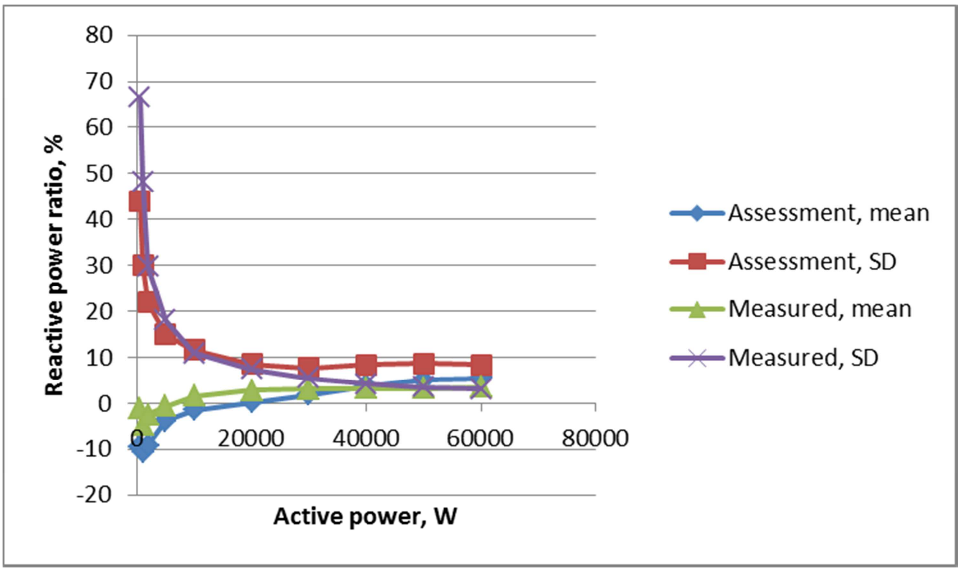

Figure 174 Mean and standard deviation of reactive power for domestic feeders at Milton Keynes trial distribution substations, from measured data and from loss assessment method

Appendix E.15 Potential causes of estimation error

Figure 175 shows the impact of applying current and voltage consistency tests as described in Appendix E.1. Points in red show feeders for which the peak current exceeds the cable rating, many with very high total loads. The blue points show feeders that have peak currents within the cable rating limits, but have node voltages below 217 V. The set of feeders with accepted results are shown in green and have both the load and losses within a narrower range.

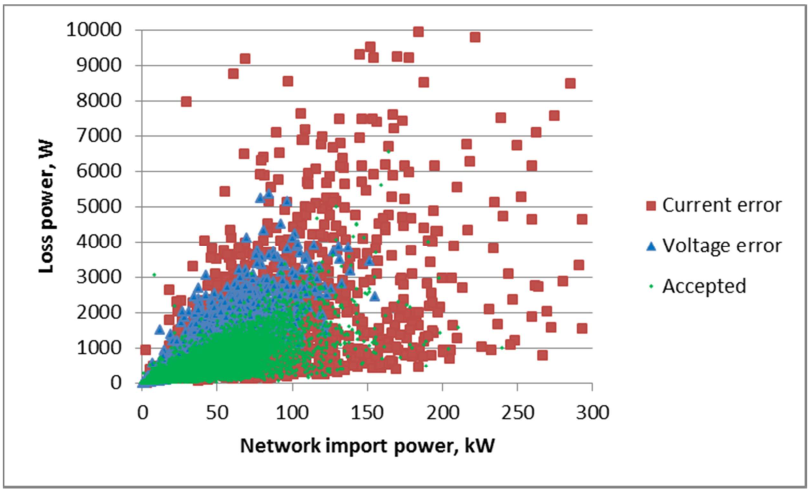

Figure 175 Availability of LV feeder results after consistency tests

The outlier feeders on Figure 175 include examples for which the losses or load are either unusually high or unusually low. When the network and demand models for the feeders with these outlier points were investigated, the loss estimates were mostly found to be incorrect. Key issues were:

Incorrect customer location details in the demand data.
If the DEBUT network model includes the customer on the correct feeder, the incorrect location can result in excessively long service cable lengths in the model, but can also cause the model to connect the customer service cable to an inappropriate part of the feeder main. The identified errors were mostly associated with single half-hourly metered customers. The demand for these customers has a high impact on the losses if the model connects them to a mains branch with high resistance, or where there is already a high demand from other customers.

Incorrect customer feeder number data
Some half-hourly customers were found with data records showing them being connected to the incorrect feeder.

Network model errors
A few of the incorrect results were associated with problems with the DEBUT file such that the network mains were not accurately modelled. This was found to cause

high losses where the feeder mains were modelled as being longer than in reality, but other examples were found with low losses where some of the mains length was omitted.

Approximated customer location data
Several cases were found where a number of customers were recorded as being co-located. In some instances this may be correct, such as where the customer meters are in a block of flats, but in other examples the records may omit the detail of individual customer locations. The algorithm used to create the DEBUT network model relies on associated customer locations with proximity to the cable routes and so the approximated locations then cause the recorded feeder numbers to be assigned to the incorrect cables. This can lead to incorrect loss estimates if the modelled demand is not appropriately matched to the length and resistance of the cables.

After checking a number of outlier points, a set of feeders with a mean load of around 75 kW was then considered. The loss estimates for these feeders generally appeared credible, although approximately half of those investigated were still subject to errors in either the demand model or the network model, for the same reasons as outlined above.

This assessment of the results suggests that the loss estimates are not sufficiently reliable to give a specific indication of individual feeders with unusually high losses. Although feeders with high losses are expected to have high losses estimates, there are too many false indications of high losses for those that are genuine to be identified.

However, unless remedial actions on individual feeders are anticipated, the inability to detect feeders with high losses is not necessarily a practical concern. The outlier points are rare examples of particularly high or low losses but results for most feeders are in a mid-range between these extremes. The loss estimation results may therefore act as a representative set of realistic networks, even if not exactly the same as the actual networks that are installed. The method can therefore be used to examine the impact of variations in design policy, or the aspects of the demand characteristics (unbalance, reactive power etc.) that cause losses to be increased.