A specialist energy consultancy

Enhanced Modelling of Complex Networks to Reduce Losses

Losses Discretionary Reward Tranche 1 WP4

SP Energy Networks

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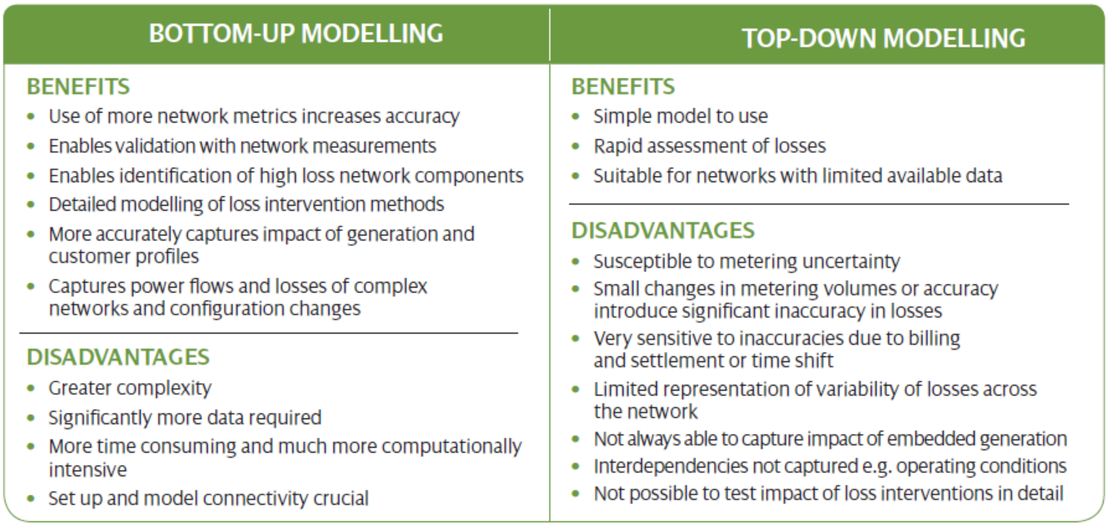
Executive Summary

Development of an Advanced Losses Modelling methodology and tool based on a 'bottom-up' approach has enabled significantly improved quantification of losses compared to existing practice.

Our losses modelling traditionally used a 'top-down' approach to quantify losses across voltage levels. This used metering data to calculated losses as Energy In minus Energy Out. This simplistic technique is prone to various sources of inaccuracy. It is also unable to test the impact of loss interventions in detail. With this historic approach the network cannot be accurately disaggregated into subsections and a portfolio of assets cannot be ranked based on the losses incurred on each asset. Where losses interventions needed to be studied in more detail, network analysis and modelling studies have historically been restricted to small scale models with a limited number of network operating conditions, typically reflecting times of peak demand or peak generation.

More advanced tools were required to help SPEN quantify losses. Losses Discretionary Reward Tranche 1, Initiative 4 investigated, designed and prototyped a more advanced 'bottom-up' modelling approach. A 'bottom-up' model automates modern power systems analysis tools to assess the network in a much more granular manner to assess losses in each individual asset. It applies half-hourly demands at all locations in the network where these are known. Where half-hourly demands are not available, the tool can either use defined profiles, or disaggregate the supply in-feeds. The advantage of a 'bottom-up' approach is that it gives much more detailed information on the losses characteristics of network, which facilitates the identification of high loss circuits and network components amongst other things. It enables increasingly complex networks to be designed and operated with tighter operating margins, leading to opportunities for improved loss management. A comparison of 'bottom-up' and 'top-down' modelling tools is summarised in the table below, indicating clear benefits of our enhanced modelling capability:



BOTTOM-UP MODELLING	TOP-DOWN MODELLING
BENEFITS • Use of more network metrics increases accuracy • Enables validation with network measurements • Enables identification of high loss network components • Detailed modelling of loss intervention methods • More accurately captures impact of generation and customer profiles • Captures power flows and losses of complex networks and configuration changes	**BENEFITS** • Simple model to use • Rapid assessment of losses • Suitable for networks with limited available data
DISADVANTAGES • Greater complexity • Significantly more data required • More time consuming and much more computationally intensive • Set up and model connectivity crucial	**DISADVANTAGES** • Susceptible to metering uncertainty • Small changes in metering volumes or accuracy introduce significant inaccuracy in losses • Very sensitive to inaccuracies due to billing and settlement or time shift • Limited representation of variability of losses across the network • Not always able to capture impact of embedded generation • Interdependencies not captured e.g. operating conditions • Not possible to test impact of loss interventions in detail

The bottom-up model has been successfully developed and has full detailed coverage of all 132kV and 33kV networks across SPM. In SPD a range of the GSPs have been selected and studied in detail to provide representative coverage. A range of both interconnected, and radial HV networks have also been studied. From these Tranche 1 studies, we now have losses information by network group and at an individual asset level. Our ability to consider our planned network throughout all operating periods in a year is expected to deliver a reduction in network losses through our ability to optimise how we operate our assets. This tool has been adopted for BAU use and will be used to consider losses when undertaking major investment/policy decisions during the remainder of RIIO-ED1 and forward into RIIO-ED2.

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1 Introduction

TNEI is supporting SPEN in delivering a number of their LDR Tranche 1 initiatives. This report summarises the activities and outcomes for Initiative 4 – Improved Modelling of Complex Networks (HV) to Reduce Losses.

1.1 Losses Obligations and Discretionary Reward Mechanism

Licence Condition 49 (Electricity Distribution Losses Management Obligation and Distribution Losses Strategy) imposes on DNOs a requirement to ensure that Distribution Losses from its Distribution System are as low as reasonably practicable. In addition to this obligation, in May 2016 Ofgem introduced a Losses Discretionary Reward (LDR) "to encourage and incentivise DNOs to undertake additional actions (over and above meeting their losses licence obligation) to better understand and manage electrical losses".

The LDR is awarded over three financial periods, or tranches. SPENs Tranche 1 submission was designed to meet Ofgems' expectations by driving innovation in our losses approach, improving our understanding of losses, increasing our engagement with stakeholders and developing our processes to manage losses.

Our program of work for Tranche 1 committed to conduct ten innovative initiatives to improve and share our understanding and management of losses. These initiatives cover a breadth of activities, including; examination of the application of smart meter data to reduce technical and non-technical losses, improving network modelling assessment tools, investigating voltage optimisation schemes and power factor assessments, reporting our revenue protection activities and improving distribution substation efficiency and metering.

This report details the outputs of initiative 4 "Enhanced Modelling of Complex Networks". This initiative is based on development of improved tools for considering losses in the planning timeframe. This will enhance our ability to make losses related investment decisions.

Following the award of LDR Tranche 1, Ofgem issued guidelines for Tranche 2 stating: "the focus will shift from an assessment of processes... to one of specific actions undertaken and concurrent improvements in understanding". Ofgem expect DNOs to be able to provide evidence of actions undertaken to improve their operations and to set out their vision for future in respect of managing losses.

This initiative report, and its peers, sets out the innovative activities undertaken by SPEN, over and above those mandated by Licence Condition 49, to better understand and manage electrical losses. The activities carried out to date will also form part of the supporting material for our Tranche 2 submission. SPENs Tranche 2 submission will be both forward and backward looking, to describe the actions already undertaken, and to present our ambitions for the future.

1.2 Background

Technical losses are a physical consequence of running electrical networks and can be complex, time-varying, stochastic and thus difficult to quantify. They are sensitive to many factors outside DNO control with the largest influence being customer behaviour and corresponding power flows.

Historically, power flows on distribution networks have been relatively predictable in their daily, seasonal and annual variation. However, network usage is changing due to a rapid growth in Distributed Generation, and customer behaviour is becoming more dynamic due to the adoption of Electric Vehicles, Heat Pumps, Energy Storage and increasing participation in Electricity Market services. This is leading to increased power flow complexity.

Simple tools for quantifying the losses associated with power flows are no longer appropriate in this evolving power system. Advanced tools are required that can accurately model complex power flows and resultant losses.

More work is needed to develop these tools and thus enable an accurate understanding of the value of loss reduction and optimisation interventions within a holistic network planning strategy.

1.3 Structure

This report is structured in the following way:

- Need for Improved Modelling Tools
- Literature Review of Losses
- Methodology and Tool Architecture
- Results
- Use Case
- Outcomes and Benefits

2 Need for Improved Modelling Tools

2.1 Changing Network Behaviour

2.1.1 Rapidly Increasing Generation Penetration

In SPM in 2015/2016, 216 distributed generation schemes were connected or accepted, totalling 2,791 MW installed capacity. In SPD the number of schemes was 258 totalling 3,704 MW of installed capacity. Figure 2-1 illustrates the trends in embedded generation connections from 2012.

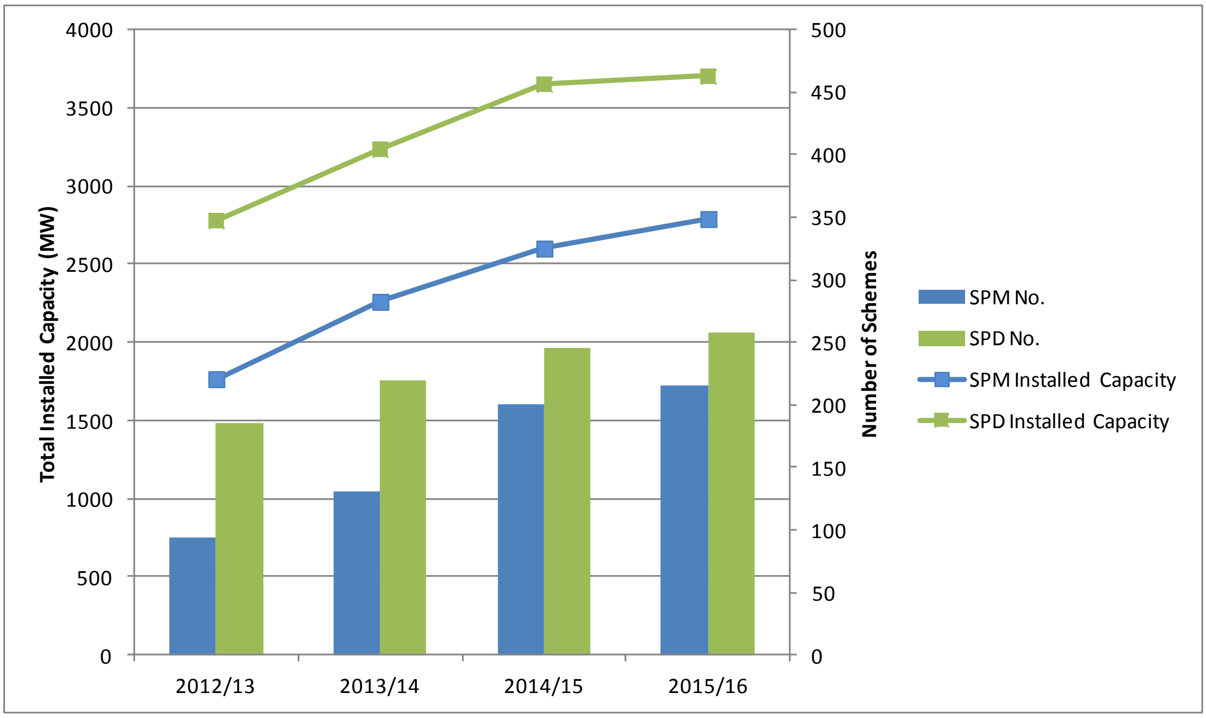

Figure 2-1: Embedded distribution schemes connected or accepted in SP Energy Networks

The impact of distributed generation on losses varies depending on the type of generation and network characteristics e.g. level of demand, demand profile behaviour and topology at the point of connection. For example, Solar PV will vary seasonally in a relatively predictable way, however; wind generation can be very intermittent.

Seasonal effects also influence the impact of embedded generation on losses experienced throughout the year.

The effect of different generation connection topologies on losses is explored below.

Radial connection: Where generation is connected directly to a GSP, the connection will incur losses throughout the seasonal cycle.

Connection to demand dominated distribution network: In a demand dominated network, distributed generation will generally reduce current, and therefore losses. The extent to which losses are reduced will depend on the generation characteristics e.g. capacity, intermittency and correlation with peak demand.

Connection to generation dominated distribution network: Connection of generation to areas of the network with low demand and high existing generation may increase losses if generation is significant enough to have the effect of generally increasing current.

2.1.2 Changes in customer behaviour and future LCT growth

Customer load patterns are also undergoing a period of change with general energy efficiency reductions overlaid with increases in the electrification of heat and transport. Various technologies such as sophisticated energy management systems, embedded generation, energy storage at a range of scales and transaction technologies such as blockchain mean that customers may be able to interact much more dynamically with the electricity network.

Increasing interfaces between multiple energy vectors mean that in future, home and commercial energy controls could provide a mechanism of increased interconnection between electricity and heating/cooling networks, utilising building level thermal storage. For the transport network, electric vehicles could be charged during times of high generation output, providing vehicle-to-grid services when required to support grid load management and stability, and hydrogen electrolysers could fill storage facilities for on-demand refuelling of various hydrogen vehicles.

Increasing sophistication and deployment of smart energy controls is enabling greater flexibility and control of these energy resources. This could provide a resource for losses optimisation. However, in the short-term, rapid electrification of heat and transport is likely to lead to higher loading and greater voltage drop, and thus increasing losses.

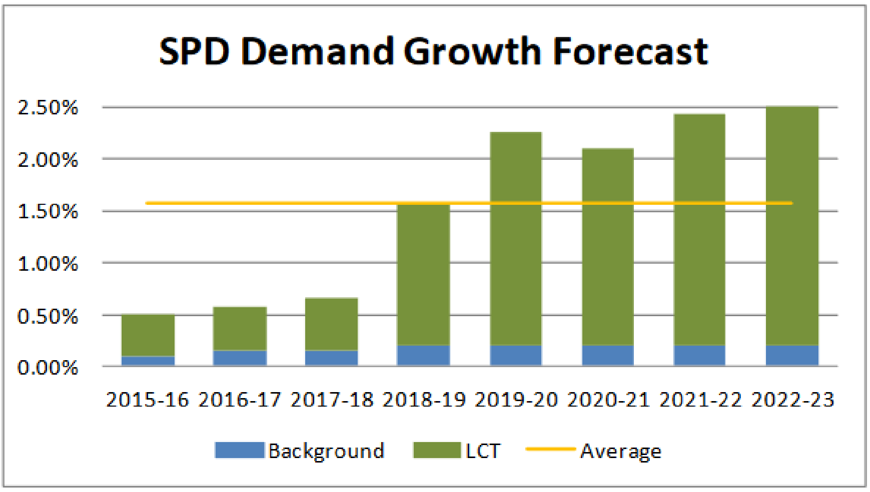

Figure 2-2: Demand growth forecast for SPD over the ED1 Period[1]

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[1] SP Energy Networks, SP Energy Networks 2015–2023 Business Plan Updated March 2014 Annex Load Related Investment Strategy, March 2014.

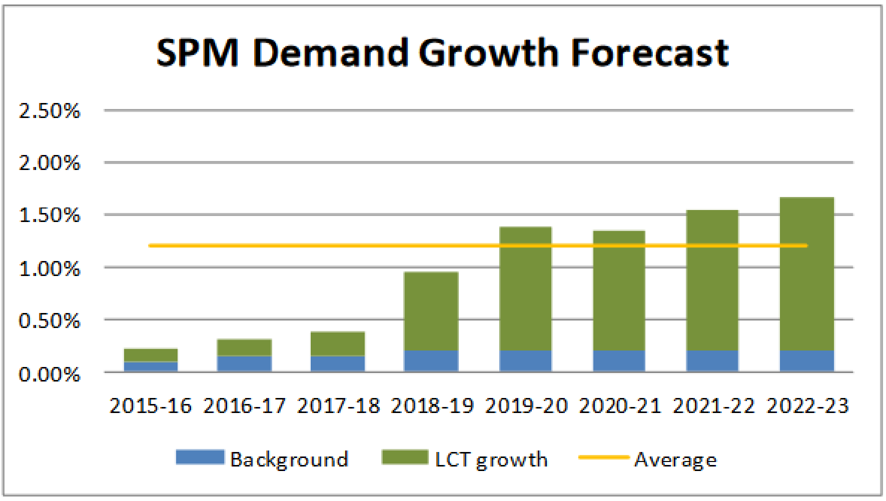

Figure 2-3: Demand growth forecast for SPM over the ED1 Period[2]

2.2 Interconnected Networks

SP Manweb's distribution network is fundamentally different from networks owned and operated by the other UK DNOs. The Manweb network has the legacy of being designed and operated as a 'meshed' network with interconnection at all voltage levels. Other DNOs generally design and build their network as radial systems with the exception of the London interconnected network. It should be noted that greater interconnection has been identified as a key "smart" solution for managing future load increases.

The 'meshed' network design philosophy gives the Manweb network some key benefits, including improved reliability and a higher level of asset utilisation. However, this design is more expensive to design, develop, operate and maintain.

In meshed networks, power flows are complex and in any one part, depend on the flows in other parts of the network. Geographically separated transformers supply a wide group of network customers, so reliability, loading and losses characteristics are inextricably linked. Correspondingly, assessment of losses is more complex and design decisions must consider implications for the whole meshed network group.

Losses are complex and sensitive to factors outside DNO control e.g. customer behaviour.

2.3 Asset Management

Network-wide visibility of the losses associated with each individual asset is ideally required to be able to enact effective asset management procedures. These plans, coupled with asset replacement programmes, will over the longer term replace those assets which incur the highest losses, and will aim to do so at the time which is most economically efficient.

2.4 Existing Losses Assessment Tools ("Top Down" Deterministic Approach)

In SP Energy Networks, a top-down approach has historically been used to quantify losses across voltage levels. This is based on **Losses = Energy In – Energy Out**. Total 'Energy In' can be determined

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[2] SP Energy Networks, SP Energy Networks 2015–2023 Business Plan Updated March 2014 Annex Load Related Investment Strategy, March 2014.

from metering at the transmission-distribution interface (and voltage level interfaces if available) and total ‘Energy Out’ can be estimated based on customer energy consumption records. It is generally assumed that non-technical losses mainly occur in the LV network so losses at higher voltage levels are primarily technical losses. The top down approach is described in more detail in Section 3.

This is a simplistic technique that is not able to accurately calculate losses in a meshed network or with network reconfigurations and is not fit-for-purpose with increasingly dynamic, stochastic loads. It specifically does not allow for identification of, and intervention in, losses hotspots within the distribution network. The impact of embedded generation on network losses is also not able to be quantified. Advantages and disadvantages of this approach are described further in the literature review section.

A weakness of the existing losses assessment approach is illustrated below. It can be seen in Figure 2-4 that transfer of load to an adjacent Grid Supply Point (GSP) in the Charlotte St Bulk Supply Point (BSP) network results in higher aggregated load from all the primary substations in the network than the total super grid transformer (SGT) flow (where the power flow in red exceeds power flow in blue). When calculating losses based on the described top-down deterministic approach, this will result in “negative” half-hourly losses for these periods which is not correct and could skew the total annual losses calculation.

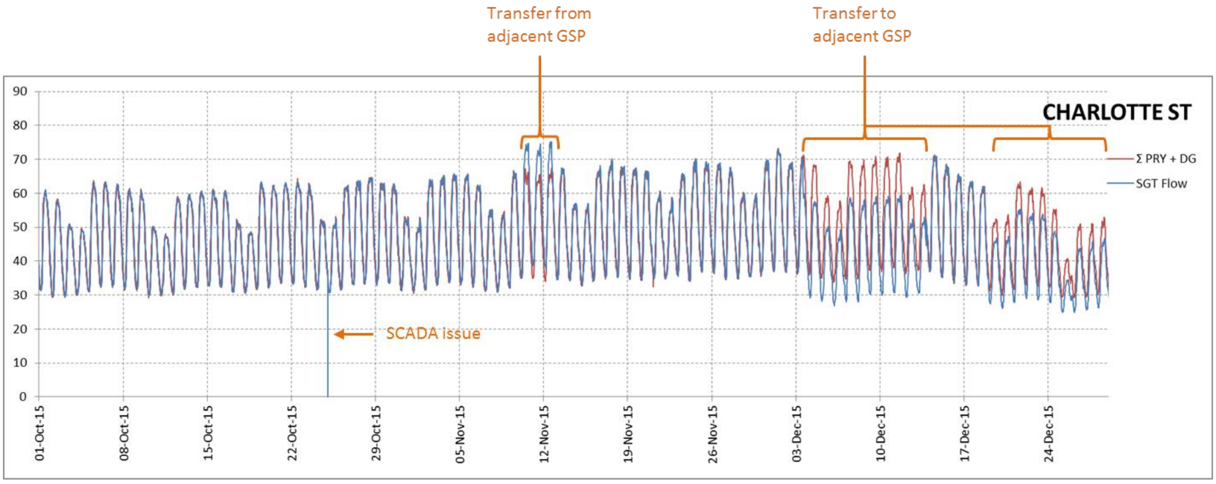


Figure 2-4 Application of top-down losses approach to network with load transfer

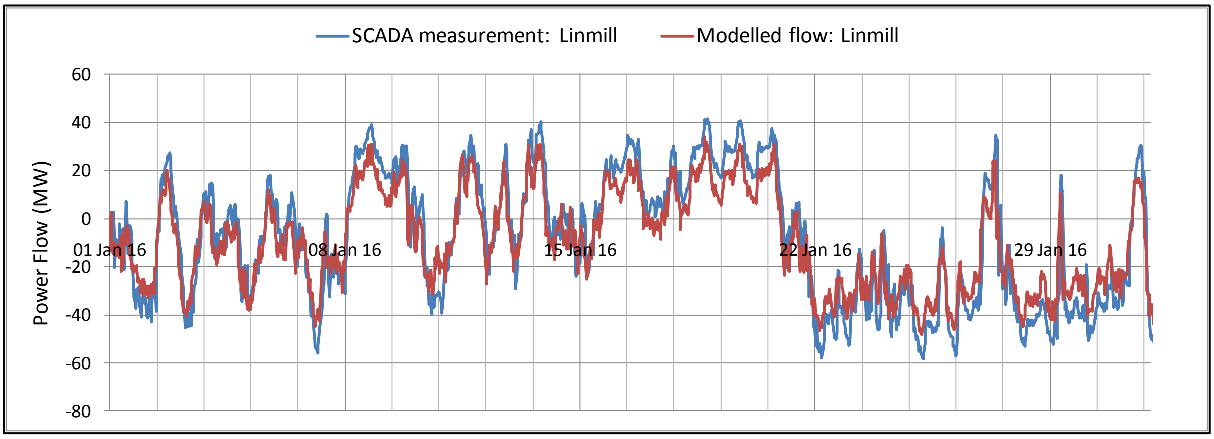


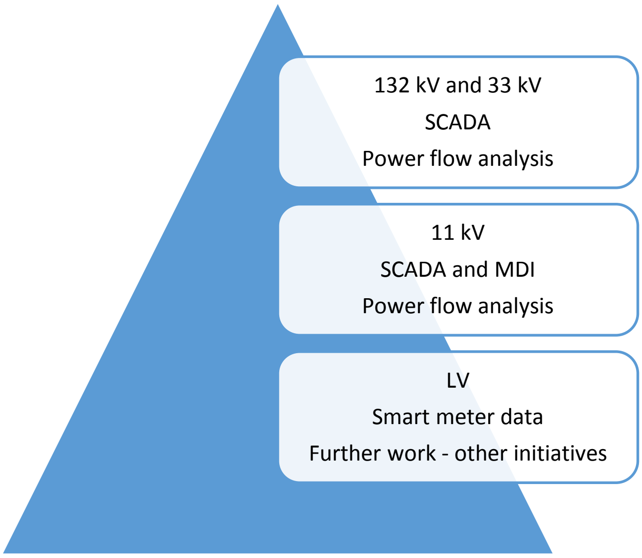
Figure 2-5 Power flow at Linmill substation

In Figure 2-5, embedded generation can be seen to have a significant impact on the Linmill 33 kV network in the SPD licence area. Some 33 kV feeders have reverse power flow for a material proportion of the year, resulting in high losses. A simple top-down approach would not be able to accurately characterise this.

Existing losses assessment tools are not fit for purpose with increasingly dynamic, stochastic loads, embedded generation and complex networks (meshed, reconfigured)

2.5 New Losses Assessment Tools ("Bottom Up" Stochastic)

A more advanced approach is required to accurately assess losses and to inform the business case of network interventions. A new approach can be encapsulated within a sophisticated losses modelling tool based on power system analysis of the network model which should address many of the shortcomings of the existing tools. This is a bottom up approach and is described in more detail in Section 3. The exact approach may vary across distribution voltage levels, to reflect the availability and sources of monitoring data, as described in the sections below.



2.5.1 132kV and 33kV

A "brute force" approach can be applied at 132kV and 33kV, in which the SCADA/metering records can be used to establish half hourly loadings across the network. Power flow modelling results can then be validated with import measured at the transmission interface.

2.5.2 HV (11 kV)

On the HV network, monitoring is historically more limited with maximum demand indicators on HV/LV substations read every 6 months. Half hourly loading can be established through making some assumptions for load profiles based, for example, on the load profile measured at the primary substation or Elexon customer profiles. Half hourly energy measurements for HV demand customers should be available; however, assumptions may need to be made for generation customers.

Power flows can then be validated against primary substation transformer and feeder monitoring. In a meshed network, validation can be based on power flows for multiple primary substations. Alternatively, total annual losses can be derived from calculation of losses at peak demand and a LLF (Load Loss Factor).

More detailed monitoring is being considered for rollout in highly stressed areas of the network during RIIO-ED1.

2.5.3 LV

The highest uncertainty of losses is in the LV network where there is little to no network monitoring, although this is slowly changing with the rollout of smart meters. LV networks account for the majority of network losses.

Further work must be undertaken in this area; however, this lies outside the scope of LDR Initiative 4. Losses estimation in LV networks is covered in more detail in LDR Initiatives 1 & 2 where SP Energy Networks intend to study smart meter data coupled with network data to identify areas of high losses.

A sophisticated losses modelling tool based on power system analysis should address many of the shortcomings of existing tools

3 Literature Review of Losses

To inform and guide the development of an advanced losses assessment tool, we have carried out a literature review. Figure 3-1 indicates the various elements covered.

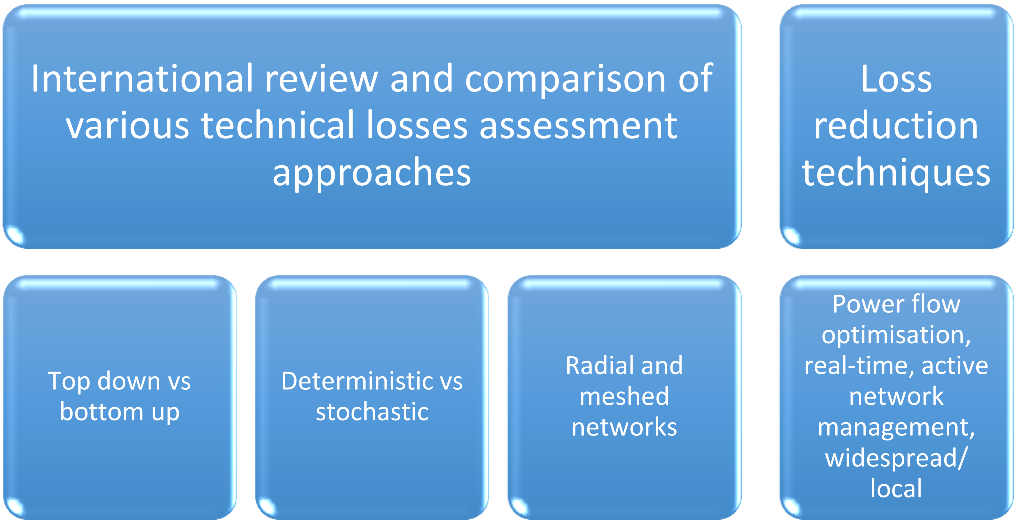


Figure 3-1 Literature review mapping

This literature review has focussed on technical losses rather than non-technical losses, as technical losses are the purpose of the modelling work described in this Initiative. Therefore, detailed consideration of non-technical losses is outside the scope of this literature review.

3.1 Introduction

Energy losses occur in the process of supplying electricity to customers due to technical and non-technical (commercial) losses. Non-technical losses arise due to meter errors, theft and inaccuracies in unmetered supplies. There are two main components of technical losses in a distribution network.

a) ***Load Losses:*** These losses depend on the quantity of electricity flowing through the network. At any given time, these losses are proportional to the square of the current flowing through network assets such as EHV, HV and LV circuits, 33/11kV primary transformers and 11/0.4kV distribution transformers. These losses are also known as **variable**, copper losses or I^2R losses and are described further in Appendix A.

b) ***No-load Losses:*** These losses are constant and do not depend on load. They arise from the iron losses of network transformers (magnetising losses) and cable dielectric losses. They are also known as **fixed** losses.

Work undertaken in 2014 estimated that electrical losses represent somewhere between 5.8% to 6.6%[3] of the total energy transmitted in the UK distribution system and that approximately three quarters of these losses occur in LV and HV networks, as shown in Table 3-1. These electricity losses are calculated to cost more than £1 billion a year and based on the generation mix, account for 1.5% of all greenhouse gas emissions in the UK[4].

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[3] Sohn Associates, Imperial College London, 2014, Management of electricity distribution network losses, http://www.westernpower.co.uk/docs /Innovation-and-Low-Carbon/Lossesstrategy/SOHN-Losses-Report.aspx

[4] "Electricity Distribution Price Control Review Final Proposals – Incentives and Obligation," Ofgem, London, UK, Doc. No. 145/09, 7th Dec. 2009.

Table 3-1 Distribution network losses[4]

Network Level	% Losses
LV circuits	1.7%
HV/LV transformers	1.5%
HV circuits	1.7%
EHV/HV transformers	0.3%
EHV circuits	0.6%
132kV/EHV transformers	0.4%
132kV circuits	0.5%
Total	**6.6%**

Circuit losses are primarily heat losses due to I^2R.

For transformers, load losses are comprised of I^2R losses in the windings (main source of losses) and eddy currents caused by leakage flux. These are a function of the amount of load the transformer is supplying. No-load losses occur primarily due to hysteresis and eddy current losses in the ferromagnetic core lamination. The age of the transformer influences the losses, whereas older assets perform less efficiently due to historic manufacturing processes and the grade of metals used in the ferromagnetic core.

3.1.1 Network conditions

A number of network conditions contribute to or indicate increased technical losses. The most prominent of these are described below:

- ***Phase imbalance:*** Phase imbalance results in higher currents in one or two phases of a feeder and thus increased heat losses.
- ***Voltage:*** Low voltage can be an indicator of high losses if there is a lot of constant power load (i.e. efficient lighting, computers, heat pumps/air conditioners etc) connected to a secondary substation.
- ***Power Factor:*** Reactive power flows also contribute to heat losses.
- ***High harmonic current:*** Harmonic injections from embedded generation in the network and non-linear customer loads increase network losses.
- ***Distributed Generation:*** Distributed generation is not always located close to load and production is mostly non-dispatchable so may not coincide with high demand (and may in fact coincide with lower levels of demand). Figure 3-2 below demonstrates that with a low share of embedded generation, losses generally drop because net load reduces, but once there are significant injections of generation, net load increases and grid losses increase correspondingly.

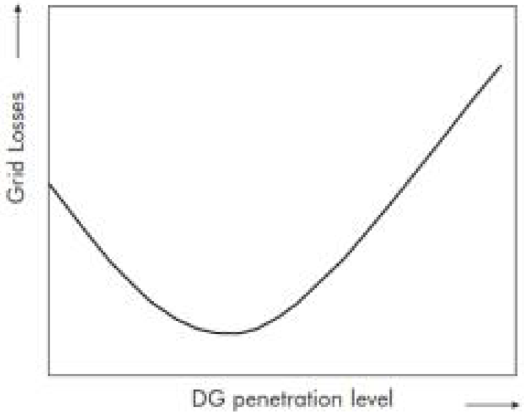

Figure 3-2 Relation between the degree of embedded generation penetration and grid losses[5]

3.2 Technical Losses Assessment Approaches

The various approaches for estimating technical losses in a distribution network can be broadly classified into the following two categories[6]:

[1] Top down

[2] Bottom up

These approaches can be applied with varying degrees of sophistication and accuracy depending on the availability and quality of network and customer data, and metering. Validation can be performed by comparing results obtained with different approaches.

It should be recognised that assessing distribution network losses can be challenging as losses are dependent on a number of factors including network configuration e.g. temporary configurations for load transfer, customer demand, embedded generation, voltage and ambient conditions. For meshed networks, this is more so due to complex power flow patterns. The consideration of these factors in each approach is explored below.

3.2.1 Top down approach

Predicting the overall energy losses based on historical SCADA data and customer billing/load type patterns is referred as the ‘top-down’ approach. At its most basic, it is the net difference in energy delivered from the higher voltage level (“Energy In”) and metered at LV customer connections (“Energy Out”) or measured at downstream nodes. This includes both technical and non-technical losses, although it is generally assumed that all non-technical losses are incurred at LV. Whilst this is a simple and rapid approach requiring limited data that is generally available from network metering and supplier records, there are a number of key challenges including:

- **Meter accuracy:** Losses calculations are highly dependent on the accuracy of the meters. For example, meters that are only +2.5%/-3.5% accurate (statutory limits for domestic energy metering) can introduce a significant level of error which is applied directly within the losses quantification, with total losses in the order of 5-6%. Also, if a metering node is

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[5] Active Distribution System Management- A key tool for the smooth integration of distributed generation (Euro Electric)

[6] Dortolina CA, Nadira R, “The Loss That is Unknown is No Loss At All: A Top-Down/Bottom-Up Approach for Estimating Distribution Losses”, IEEE Transactions on Power Systems, 2005, IEEE.

missing, this can skew the calculation. These errors are largely be avoided by using the I^2R method[7].

- **Disaggregation:** Using this approach, it is not possible to identify specific areas/voltage levels of network with unduly high losses and thus proactively target or manage network losses.
- **Meshed Networks:** It is not possible to determine the loss characteristics of a meshed network.

Top-down approaches tend to yield more rapid estimates that carry a relatively high degree of uncertainty and lack detail.

3.2.2 Bottom up approach

In its purest form, the bottom up approach involves a complete and detailed network model and analysis is performed using specialised software. Thus, bottom up analysis requires significantly more input data, such as network data, SCADA power measurements, customer load types/profiles and analysis than the top down approach. This is often described as the I^2R approach as it calculates the network current directly to determine load losses with no-load losses calculated separately and then aggregated.

Technical losses can be computed with relative accuracy, particularly at 33kV and 132kV. Meter accuracy for loading is still an issue although this is indirect. At lower voltages, due to the significant volumes of data associated with modelling HV and LV networks, it is often more prudent to apply a Classification and Interpolation tool (described below) to calculate distribution network wide losses based on modelling of a subset of representative networks. Also, at lower voltages there is generally greater uncertainty in circuit electrical parameters, transformer data, network configuration and customer load profiles e.g. only peak demand is measured at HV/LV substations. Figure 3-3 illustrates the energy flow from the grid supply point to downstream networks. Typically, hundreds of kilometres of feeders and transformers are connected to each grid supply point. It also demonstrates considerations for application of the bottom up approach to a typical distribution network.

In the absence of detailed demand data for lower voltage networks, average losses can be estimated by multiplying the losses at peak demand by a loss load factor. Load Loss Factor (LLF) is the ratio of the average load loss to the peak load loss and can be calculated using the following formula:

$$LLF = ((1-\alpha)\,LF^2) * (\alpha * LF) \qquad (1)$$

Where LF is the load factor calculated from the ratio of peak load to average load and α is an empirical factor based on the average demand profile.

This **deterministic** approach works best on feeders that do not have significant varying seasonal profiles and the impact of embedded generation on the average demand profile should be carefully considered to determine whether this the LLF is appropriate/accurate. Alternatively, the half hourly load profile of the primary substation can be used, although diversity will not be well represented. Generally, a **stochastic** approach based on half hourly data for example is preferable for fully

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[7] URQUHART, A., THOMSON, M. And HARRAP, C., 2017. Accurate determination of distribution network losses. IN: Proceedings of 2017 24th International Conference and Exhibition on Electricity Distribution (CIRED 2017), Glasgow, Great Britain, 12-15 June 2017, paper no. 1076.

capturing the influence of embedded generation and more widely, the behaviour of more dynamic, flexible networks.

A stochastic approach is best for fully capturing the influence of embedded generation and more widely, dynamic, flexible networks.

Because of the complexities associated with LV diversity and unbalanced networks, the LV Network losses incurred between the HV/LV transformer and the customer meter are considered to be outside the scope of this initiative and report. Two separate LDR initiatives are focusing on the losses in LV networks using smart meter data (LDR T1, Initiatives 1 &2).

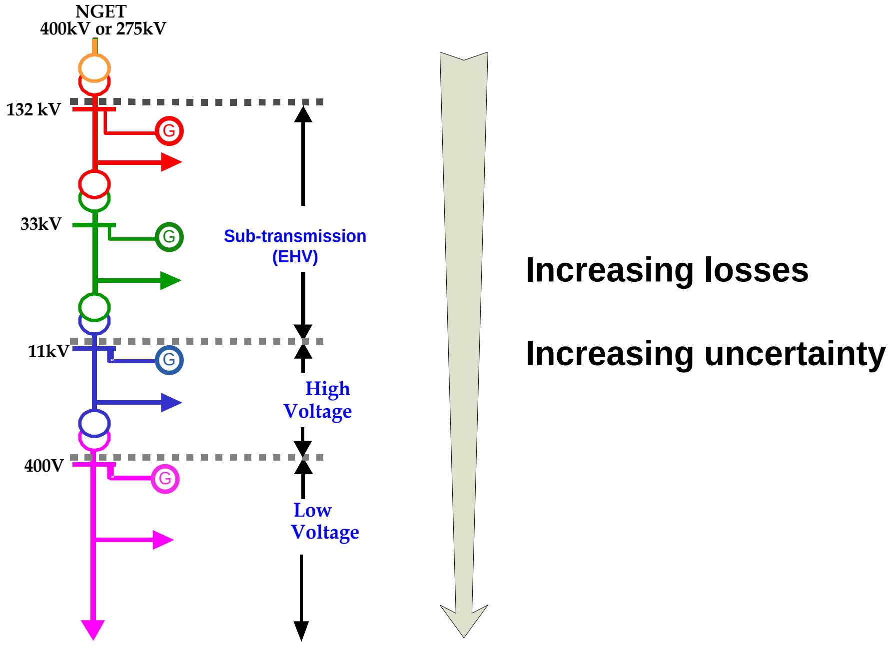

Figure 3-3: Considerations for application of the Bottom up approach

Table 3-2 summarises pragmatic application of the bottom up approach across different voltage levels depending on available levels of network and metering data. Power flow studies are carried out on an accurate impedance model of the network to determine the load losses under a range of network conditions e.g. half hourly loading over a year. This could be carried out in a network model that preserves connectivity (power system model) or a non-connective model (reference – DNV). A non-connective model would not be able to accurately represent the power flows in a **meshed** network although a **radial** network may be appropriately modelled. No-load losses can then be added to determine total losses. Results can then be used to identify areas of unduly high network losses and modelling of losses interventions to understand where these would provide benefits to customers.

Table 3-2 Bottom up modelling approach across voltage levels

Network Element	Bottom up losses assessment approach
132kV circuits	Power flow studies based on substation and customer* half hourly load profiles
132kV/33kV substation	
33kV circuits	
33kV/11kV substation	
11kV circuits	Power flow studies based on substation and customer* half hourly load profiles or LLF for representative networks
11kV/LV circuits	
LV circuits	

*this includes generation and demand customers

At LV, any remaining losses (based on comparison with metering) may be allocated to commercial losses. Losses on the LV network are challenging to determine with precision because of significant diversity in load and configuration. Ultimately, the accuracy of the losses model is proportionate to the accuracy of the underlying input data.

The bottom up approach should provide a more accurate quantification of losses, identification of loss hotspots and enables modelling of interventions.

3.2.3 Classification and Interpolation

A classification and interpolation tool[7] can be applied with the top down or bottom up approaches to allow losses to be calculated in more detail for specific network voltage levels. This can provide some level of disaggregation and identification of hotspots on a network "type" basis for the top down approach.

Figure 3-4 below depicts the steps involved in the classification and interpolation method.

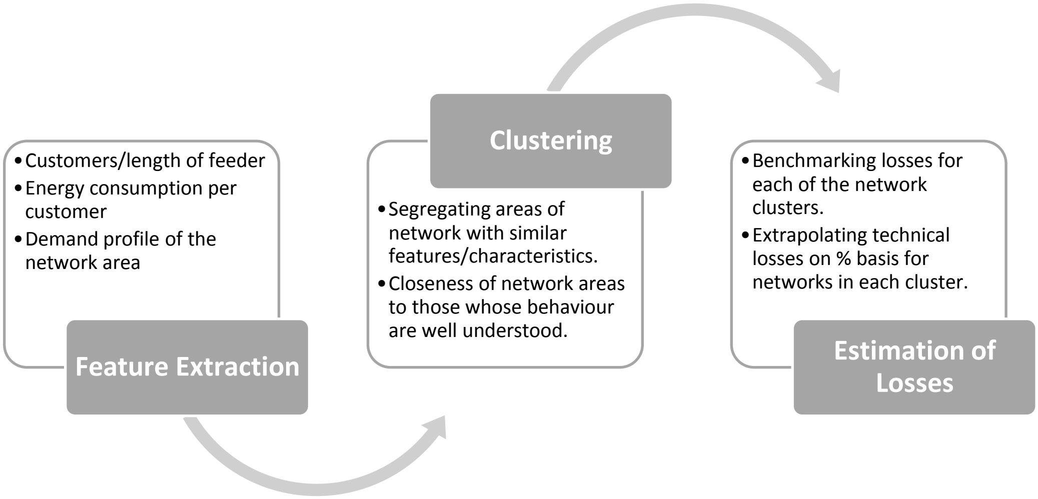

Figure 3-4: Steps involved in Classification and Interpolation approach

Step 1 - Feature extraction: The feature extraction step involves defining the variables that sufficiently describe the characteristics and performance of the distribution system and thus likely technical losses, such as kWh per customer, numbers of customers per feeder, length of feeder and number of feeders per substation.

Step 2 - Clustering: Distribution network areas with similar characteristics are identified and grouped e.g. urban, suburban, industrial parks, rural etc. The closeness of distribution network areas compared to network areas whose characteristics and performance are known with high certainty can be determined. Closeness is generally measured in terms of the feature variables.

Step 3 - Estimation of Losses: Losses are estimated for those network areas whose behaviour is known with high certainty e.g. based on metering or modelling. It is assumed that the cluster of distribution network areas with similar (close) characteristics will have comparable technical losses (on a percentage basis).

The classification and interpolation tool enables identification of networks that may generally suffer from high losses, although not specifically whether these are unduly high. Network clustering is a broad grouping approach that captures general patterns of losses but certainly does not reflect the full variability of network behaviour.

As such, outcomes from quantifying losses in this way require further investigation and verification before they can be used to model specific interventions and justify investments to improve system performance.

3.2.4 Summary

Table 3-3 provides a comparison of the loss assessment approaches described above.

Table 3-3 Comparison of loss assessment approaches

	Pros	Cons
Top-down	• Simple model and limited network data required • Rapid assessment of losses • Suitable for networks with limited available data	• Susceptible to metering uncertainty • Limited representation of variability of losses across the network (not possible to apportion losses to different parts of the network within metering boundaries) • Not able to accurately capture impact of embedded generation • Not able to accurately measure losses for meshed networks or capture operational topology changes • Interdependencies not captured e.g. operational topology changes • Not possible to test impact of loss interventions in detail
Bottom-up	• Power system model of network impedance and time-varying loading so more accurate • Enables validation with network measurements • Enables identification of lossy areas of the network and detailed modelling of loss intervention methods • More accurately captures impact of embedded generation and customer load profiles • Captures power flows and thus losses of complex (meshed) networks and operational topology changes	• Greater complexity • Significantly more data required, risk of poor data quality • More time consuming • May not be able to capture operational topology changes or voltage varations, depending on how modelling is set up and model connectivity
Classification and Interpolation	• Can be used for both the top down and bottom up method • Losses for representative modelled and/or metered networks can be extrapolated to networks that are not modelled and/or with little to no metering	• Network features and clustering analysis may not be representative of all networks (variations in demand loading, embedded generation, network topologies etc)

3.3 Loss Reduction and Optimisation Techniques

A conventional way to reduce losses is by adding more copper to the network. This is usually by reconductoring with higher cross sectional area or to use copper instead of aluminium for the conductor, and to replace old transformers with energy efficient ones. As DNOs move towards deployment of “smart” or “no-network” solutions, this can lead to more highly utilised networks in some cases, giving rise to higher losses. However, some smart solutions can provide benefits both in terms of losses as well as capacity.

Another conventional approach to reduce losses is to increase network voltages however there are significant investment implications for this.

As it stands, there is limited to no cost-benefit case to deploy these techniques purely to address losses[8]. However, reduction in losses can and should be considered as part of a holistic solution when networks are constrained and require reinforcement. This is reflected to an extent in the Ofgem RIIO-ED1 cost benefit analysis template (reference). Some existing and emerging innovative solutions are presented below that provide capacity improvements and loss reductions. Costs and benefits are not presented here, these are outside the focus of this report and can be quite specific to network characteristics.

3.3.1 Phase/Load Balancing

Phase balancing of load in a distribution network can significantly reduce losses and provide additional capacity headroom. For example, reducing phase imbalance from 25% to below 10% can reduce distribution line losses by up to 10% to 15%[9]. Balancing load between phases reduces average losses in the phase conductors by lowering current in one or more conductors towards the average. Whilst the current in one or more conductors may also proportionally increase towards the average, overall, losses will be lower because they are proportional to the square of the current. A balanced system will also reduce neutral return current to zero, eliminating the neutral losses in the return path.

Most phase imbalance occurs on the LV network and practically, it is often costly and complex to balance. Link box reconfiguration may provide some limited benefits but customer loads are stochastic, and re-jointing customer connections to another phase on an underground cable requires excavation. This is an area of continued interest for DNOs, particularly on automated, real-time innovations.

In addition to phase balancing, load balancing between feeders can reduce losses in distribution systems. Appropriate feeder balancing is achieved when the losses on each feeder are generally equal. Feeder balancing can be performed by transferring load between feeders permanently or in real-time depending on network connectivity. However, the time dependent nature of loads means that this may be complex and benefits may vary.

3.3.2 Load Management

Reduction of peak loads through active or passive load control has typically been applied as a way to ease generation constraints, particularly in countries with a generation deficit. However, it is also emerging as an effective way to reduce losses. For improvement of capacity and loss reduction, the area and customers affected may be small but sufficient to ensure diversity between loads. Demand

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[8] Acosta J, Higgins C, Hughes M, Manolopoulos T, “Innovative Approaches to Identification and Reduction of Distribution Network Losses”, 24th International Conference on Electricity Distribution (CIRED), Glasgow, 12-15 June 2017.

[9] Northwest Energy Efficiency Alliance (NEEA), “Distribution Efficiency Study,” 2007. http://tdworld.com/overhead_distribution/distribution-system-efficiency-20100201/

Response (DR) or Demand Management (DM) techniques could be applied via an aggregator or energy supplier to reduce loading, smoothing the load profile and reducing distribution losses in real-time especially during peak demand periods.

3.3.3 Network Automatic Reconfiguration

The reconfiguration of distribution network can be characterised as an optimisation problem. In normal operation, the reconfiguration of distribution network can often reduce losses, balance loads and improve quality indicators. The increasing use of remote controlled equipment in distribution networks is leading to the development of more efficient techniques for automatic reconfiguration of network; these could be integrated into a future smart grid toolbox[10]. Automatic reconfiguration in real time can be used to unload a heavily loaded line. However, it is currently constrained by the design practice of tapering the lines further from the substations on radial circuits. It would also require the widespread addition of controllable sectionalisers, equipment that separates distribution feeder into sections to isolate a fault, and corresponding monitoring equipment.

Automatic reconfiguration algorithms consider improving network performance by establishing one or more objectives (e.g. reduce losses, increase capacity, improve reliability etc). These objectives then determine which configuration produces the best result, without violating constraints on the proper and safe operation of the network. This configuration is defined, then, as the optimal solution for the system. When more than one objective is set, multi-criteria decision making techniques can be used for setting the preference for one objective over another. This can be a local or more widespread optimization.

3.3.4 Embedded DC Systems

A Medium Voltage Direct Current (MVDC) link is being deployed as part of the ANGLE-DC Network Innovation Competition project. It will convert an existing double 33kV Alternating Current (AC) circuit to Direct Current (DC) operation and will be the first MVDC link in Europe and one of the first tests to convert circuits from AC to DC operation[11].

The Anglesey network is symptomatic of a network under stress due to high levels of renewable generation connections and load growth. The MVDC link resolves a wide range of system issues (for example low voltage and thermal overloads), which would otherwise need to be addressed individually by a complex and costly conventional reinforcement scheme.

The MVDC link should radically improve network voltages and this will reduce losses in circuits and transformers throughout Anglesey. In developing the link, losses were considered throughout the entire network under a range of operational scenarios rather than just considering losses in the assets themselves.

3.3.5 Conservation Voltage Reduction (CVR)

Conservation Voltage Reduction uses voltage control technology to lower voltage levels and improve efficiency. Two main benefits are reduction in energy consumption and reduction in the amount of peak load[12]. CVR can be implemented through various means such as tap change of primary or HV/LV transformers, capacitors or STATCOMs located along feeders. The magnitude of voltage reduction is such that the end-user should not notice any change in quality of supply. The Low

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[10] Intelligent system for automatic reconfiguration of distribution network in real-time – D.Bernardon, L.Pfitscher, L.Canha, M.Ramos, M.Sperandio, V.Garcia- CIRED Workshop- Rome 2014.

[11] https://www.spenergynetworks.co.uk/pages/angle_dc.aspx

[12] “Evaluation of Conservation Voltage Reduction (CVR) on a National Level”- Pacific Northwest National Laboratory, US Depertment of Energy PNNL-19596

Carbon Network Fund project Smart Street run by Electricity North West found that the use of CVR has the potential to reduce the energy consumption on the network by up to 12%[13].

The reduction in demand load and energy is highly dependent on the types of loads connected. CVR is effective on constant impedance or constant current loads where a reduction in voltage leads to a reduction in power. In addition, losses will be reduced for constant impedance loads due to reduced current. However, CVR on voltage dependent (constant power) loads will lead to increased losses and thus higher load. Also, for constant impedance resistive loads such as space heaters, reduced voltage may reduce the current; however, the same amount of energy is required so there are no energy efficiency savings for the consumer.

3.3.6 Volt-VAR Optimization (VVO)

Voltage/VAR control is essential to the DNOs' ability to deliver power within appropriate voltage limits so that consumers' equipment is not impacted, and to deliver power at an optimal power factor to minimise losses. Voltage control is influenced by a variety of factors throughout the distribution network including: substation bus voltages, length of feeders, conductor sizing, type, size, and location of different loads, and the type, size, and location of distributed energy resources among others.

A number of technologies have been employed by utility companies to monitor and adjust voltage and/or VAR levels on their electrical networks. These include capacitor banks, voltage regulators, power transformers with on-load tap changers (OLTC) and STATCOMs. However the deployment of STATCOMs is restricted by high costs.

VVO is an advanced application that runs periodically or in response to operator demand, at the control centre for the distribution network or in substation automation systems[14]. Combined with two-way communication infrastructure and remote control capability for capacitor banks and voltage regulating transformers, VVO makes it possible to optimise the energy delivery efficiency on distribution networks using real-time information.

VVO attempts to minimise voltage variations and as a consequence may reduces losses and demand. VVO is designed to work in various system design and operating conditions. For example, a distribution system could be meshed, supplied from multiple sources with unbalanced phases and/or unbalanced loadings.

3.3.7 Active Network Management (ANM)

The Active Network Management Good Practice Guide[15]defines active network management as "using flexible network customers autonomously and in real-time to increase the utilisation of network assets without breaching operational limits, thereby reducing the need for reinforcement, speeding up connections and reducing costs". ANM can be used with both generation and demand customers. Historically, innovation projects in the UK have been mainly focussed on managing generation that is connecting to constrained areas of the network. However, the Smart Energy

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[13] Electricity North West Limited, "Smart Street, HV and LV Voltage and Configuration, Optimisation Study", February 2017.
https://www.enwl.co.uk/globalassets/innovation/smart-street/smart-street-key-docs/hv-and-lv-voltage-and-configuration-optimisation-study.pdf

[14] National Electrical Manufacturers Association (NEMA), Volt/VAR Optimization Improves Grid Efficiency, Accessed October 2017. https://www.nema.org/Policy/Energy/Smartgrid/Documents/VoltVAR-Optimazation-Improves%20Grid-Efficiency.pdf

[15] Baringa & TNEI Services Limited for Energy Network Association, Active Network Management Good Practice Guide, August 2015.
http://www.energynetworks.org/assets/files/news/publications/1500205_ENA_ANM_report_AW_online.pdf

Islands programme[16] in Cornwall is looking to optimise the use of electric vehicles for local energy balancing and customer energy, integrated on an island wide platform.

Voltage and thermal violations refer to the undesirable excursion from normal operating range e.g. current exceeding the maximum rated limit safe for a given conductor type, or voltage exceeding or falling short of a limit needed for normal operation for end users.

The main principle is that the generator and demand customers are only curtailed under defined infrequent network loading (generation output/network demand) and/or network configuration conditions. ANM may evolve in the future to provide control and optimisation of voltage constraints, reactive power, fault level, losses and more complex network constraints.

3.3.8 Summary

Table 3-4 provides a broad comparison of various loss reduction techniques. Please note that these are based on US eletricity networks however findings should be broadly comparable to the UK.

Table 3-4 Comparison of various loss reduction techniques[17]

Loss Reduction Technique	Advantage	Disadvantage/Uncertainties	Loss Reductions
Phase/Load Balancing	- redistributes loads to address variation in phase balance, demand loads, location, and technology, optimises power flow	- may require interruption of customer services/other inconvenience to customer as grid connections are redistributed - may require additional infrastructure for sufficient connectivity - may require audits to determine e.g. where demand is concentrated, when demand is increasing /decreasing, etc. - may not be feasible for areas with high demand and/or little tolerance for interruption of power - loading including phase imbalance can vary in a stochastic and complex way	~5-20%
Load Management	- can increase capacity and reduce losses by reducing (local) power supply requirements during peak times - Load management could also include distributed generation, energy storage	- Requires customer enrolment/consent for participation - Requires consideration of impact of load shifting - advanced monitoring and control technologies necessary to implement	~8-20%

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[16] Cornwall and Isle of Scilly Growth, Smart Energy Islands, 2017. http://www.cornwallislesofscillygrowthprogramme.org.uk/growth-story/smart-energy-islands/

[17] Opportunities for Energy Efficiency Improvements in the U.S. Electricity Transmission and Distribution System –Oak Ridge National Lab 2015

Loss Reduction Technique	Advantage	Disadvantage/Uncertainties	Loss Reductions
Conservation Voltage Reduction	- can reduce energy consumption and peak load - effective in reducing the losses where constant impedance loads dominate	- benefits highly influenced by load type e.g. increases the overall losses where constant power loads dominate	up to 2.2%
Volt/VAr Optimization (VVO)	- can reduce distribution circuit losses and can reduce the losses associated with reactive power delivery - a high degree of control (near real time) - Use of advanced technologies such as STATCOMs provided dynamic support to the system	- complexity in implementation and controls - reactive power could be more efficiently compensated locally instead of substation level centralized Volt/VAr regulators - Cost is dependent on type of technology.	~2-5%
Active Network Management	- can effectively increase capacity in real time by limiting total demand or generation to a constraint - not focussed on loss reduction to date	- advanced monitoring and control technologies necessary to implement	similar to load management
Automatic Network Reconfiguration	- effective for dense and highly interconnected networks - can reduce losses through power flow optimisation	- advanced monitoring and control technologies necessary to implement reconfiguration - Complex technique with moderately high cost	~5-20%

3.4 Data Requirements

Deployment of advanced monitoring and control technologies is generally required to implement many of the solutions above. The exact requirements should be assessed on a site by site basis but with consideration at enterprise level of proportion of centralised and decentralised monitoring and control, SCADA and network management systems.

In the transition to DSO, it is envisaged that significantly greater amounts of data on network behaviour and performance and customer behaviour will be needed in order to specify, procure and deploy system services. Advanced state estimation techniques may also be more widely used in areas with limited monitoring, where cost-benefit is more attractive and accuracy is acceptable.

3.5 Costs and Benefits

Decisions about whether to implement strategies to reduce losses in the distribution network should be made based on an understanding of the associated costs and benefits. Costs includes capital cost of equipment, wayleaves, design, installation and commissioning as well as operational costs such as inspection and maintenance, system services costs. The cost of developing and implementing new software and/or communication and control equipment should also be included.

Benefits of loss reduction strategies include direct cost savings to customers from reducing electricity generated that is lost (e.g. less power production is required to meet same demand) and indirect or long-term savings from reducing the need for new generation and distribution infrastructure. Direct cost savings depend on the amount of losses reduced and the avoided cost of producing that electricity; calculating this can be challenging because the value of reducing losses are associated with the cost of production at the time of the reduction. There may also be material carbon benefits depending on the generation mix.

Reducing losses through power flow optimisation i.e. peak smoothing, will incrementally and over time, reduce the need to expand the capacity of the distribution system.

4 Methodology and Tool Architecture

This section describes the methodology and tool architecture of an Advanced Losses Modelling Tool to model variable losses on the 132 kV, 33 kV and 11 kV networks. Fixed losses are also calculated separately, to fully characterise the network losses. Figure 4-1 illustrates the contributors of technical losses and the impact of distributed generators across the different voltage levels of the network that the tool aims to represent.

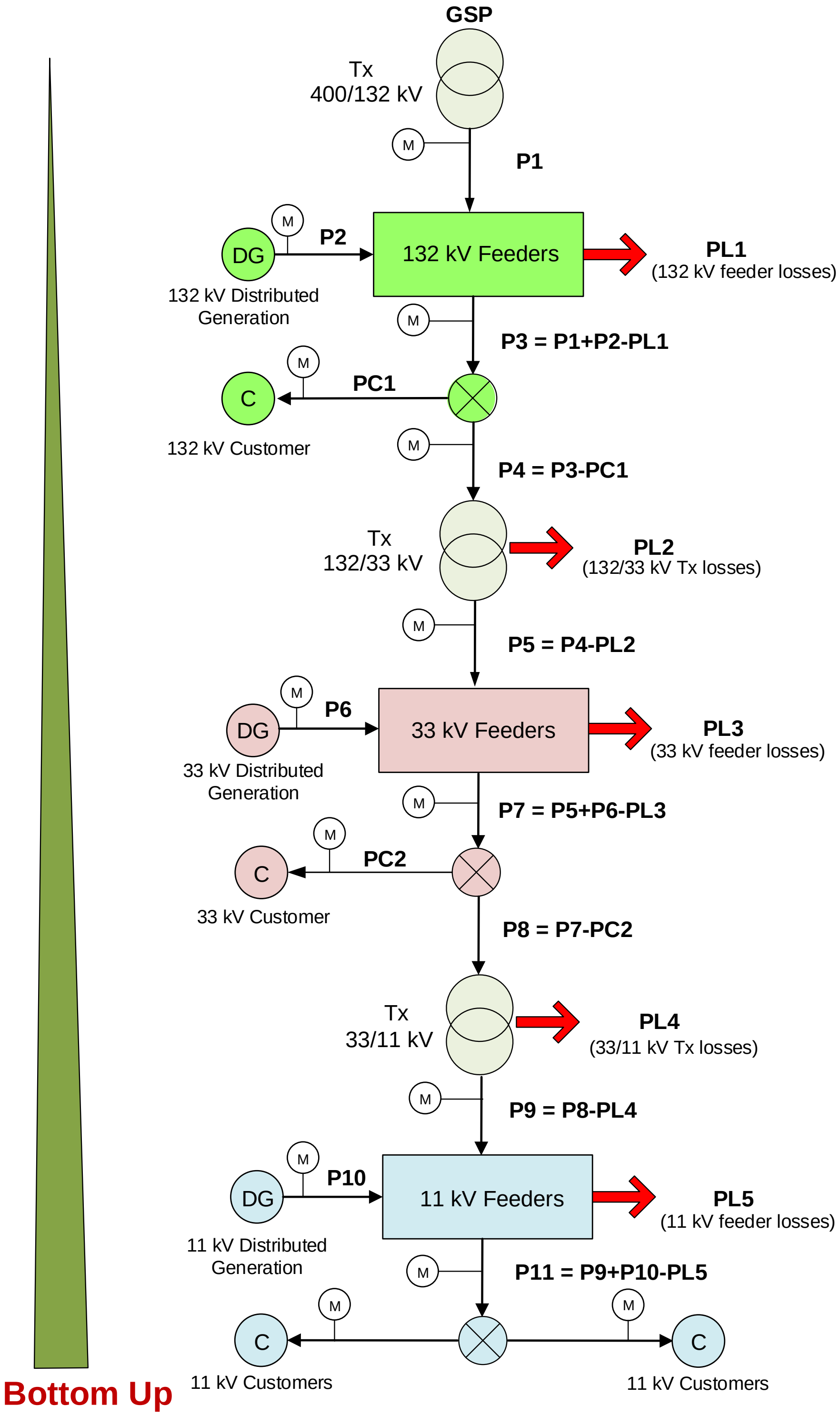


Figure 4-1 Adopted method for variable technical loss calculation

The Advanced Losses Modelling Tool adopts a 'Bottom-up' approach as described in Section 3. A power system model is used that represents full connectivity and impedance of the network to estimate the technical losses. The tool uses a load-flow engine to evaluate system losses on as close to a continuous basis as possible over the period of one year. The input data used for these studies is derived from regularly updated network models together with half-hourly measurement data from SCADA. Computation times for a years' worth of data are rapid.

Losses are calculated separately for 132 kV /33 kV and 11 kV network models. This is in order to keep the modelling and computation time to a manageable size and to reflect that currently, network modelling for primary groups at 11 kV is generally carried out ad-hoc.

The Advanced Losses Modelling Tool adopts a 'Bottom-up' approach with a power system model that represents full connectivity and impedance.

4.1 132 kV and 33 kV

The steps followed to calculate the variable losses on the 132 kV and 33 kV networks using the Advanced Losses Modelling Tool can be summarised as:

Network Model	Develop the network model in a power system analysis software supporting load flow engine (IPSA+ used in this case)
Define Substation Loads	Use the power flow measurements (from SCADA) at the 33/11 kV substations to define the net power exiting the 33 kV network ("brute force" method")
Customer Loads	Include metering data from large customers and/or generators connected at the 132 kV and 33 kV to define these network loads
Load Flow	Perform load flow to calculate the losses in the circuits and the transformers
Validation	Use the power flow measurements (from SCADA) at the 400/132 kV substations to validate the net injection to 132 kV network and thus the loss calculations

The above approach is taken for the 132kV and 33kV networks in SP Manweb (SPM) and the 33kV networks in SP Distribution (SPD) to calculate the following load losses:

- 132kV circuit losses (SPM only)
- 132/33kV transformer copper losses (SPM only)
- 33kV circuit losses

- 33/11kV transformer copper losses

For SPM, this model has **FULL** coverage of the 132kV and 33kV networks. For SPD, to date, we have analysed 5 of the total 89 GSPs in the model. The characteristics of these 5 networks has been reviewed and assessed in relation to the wider network characteristics of SPD to demonstrate that they are representative. Further analysis with a full set of SCADA data would be required to extend losses modelling to the entire SPD network. However, for the purposes of this study, 5 GSP networks demonstrate the capability of the tool and SPD specific results.

4.2 11 kV

The loss modelling for 11 kV networks in the Advanced Losses Modelling Tool is not as straightforward as the 132 kV and 33 kV networks owing to reduced network visibility. The secondary substations (11/0.4 kV) are not generally equipped with a SCADA measurement facility and the only available data are the annual peak demand for the ground mounted substation transformers. Therefore, a slightly different approach has been adopted to represent the variation of load profile throughout the year. This may change in future as more sophisticated monitoring is rolled out across the network and as smart meter data becomes available.

The base values of the loads are influenced by the type of transformer supplying it. For ground-mounted (GM) transformers, the maximum demand indicator (MDI) is used while for pole-mounted (PM) transformers there are no MDI measurements and hence the nominal rating of the transformer is used. At primary network load peak, all loads connected to GM transformers are considered to be 80% of the MDI reading in the applicable year while loads connected to PM transformers are considered to be 20% of the nominal rating; this is a standard SP Energy Networks planning assumption.

To generate the load profile, a scaling factor (f) is calculated at every half-hourly interval based on (1), where P_i^{SCADA} denotes the measurement on the secondary of the i^{th} primary transformer in a substation group and P_{Li}^{base} denotes the base demand of the i^{th} load in the same substation group.

$$f = \frac{\sum_i P_i^{\mathrm{SCADA}}}{\sum_i P_{\mathrm{Li}}^{\mathrm{base}}} \tag{1}$$

The above equation provides a fixed scaling factor for all the loads connected to a specific primary substation group and hence a load profile is obtained over a period (which can be a day or a year) based on the infeed measurements. The advantage of this method is that the power flow measurements of the primary transformers can be used to model the downstream load profiles. However, there are certain limitations of this method such as:

- it does not capture the actual diversity of variation of HV/LV substation load profile within a primary group;
- it may not be suitable for highly-meshed networks having soft-open points, where there are multiple primary substations;
- it does not capture the effects of embedded generation and the spatial distribution of loads in the downstream network.

The steps followed to calculate the variable losses can be summarised as:

Network Model	Develop the network model in a power system analysis software supporting load flow engine (IPSA+ in this case)
Define Load Profile	Use the power flow measurements (from SCADA) at the 33/11 kV substations to set up the net injection to 11 kV network and define load profile
Determine Net Load	Subtract the metering data of distributed generators and customer demand loads at 11kV from the load profile data to obtain the net load on the 11 kV network.
Distribute Net Load	Distribute the net load among secondary substations as a percentage of their peak demand (GM)/transformer rating (PM)
Load Flow	Perform load flow to calculate the losses in the circuits and the transformers
Validation	Compare modelled power flow to power flow measurements to ensure reasonable match

The above modelling approach is used to calculate the following load losses on the 11kV networks in SPM and SPD:

- 11kV circuit losses
- 11/0.4kV transformer copper losses

4.3 Modelling Limitations

The following are modelling assumptions and/or limitations of the Advanced Losses Modelling Tool that should be considered:

- The model only considers variable losses. Fixed losses associated with transformers (and series reactors) are considered separately.
- The network running arrangement is assumed to be static i.e. the effect of temporary network reconfiguration is not considered. This could be incorporated in future with detailed data on configuration changes.
- The resistance of assets remains constant i.e. the effect of increased operating temperature increasing the resistance of conductors has not been considered.
- Busbar voltage remains constant, set to accepted SP Energy Networks operation policy. Some voltage variation could be modelled in future.

- Constant transformer impedance is assumed i.e. the change in transformer winding impedance due to tap operation has not been considered.
- Cable and line parameters, including inaccuracy in line length, may be significant sources of error in technical loss calculations.
- There may be uncertainty in MDI measurements.

Sources of uncertainty in technical losses modelling are explored further in Appendix B. Any future refinements to the tool would be considered carefully to ensure that they were likely to provide material benefits as compared to the cost of implementation and given any associated uncertainty.

4.4 Validation

A significant validation process was undertaken to compare the power flows of the modelled network in IPSA+ with that of the measured flows available from SCADA. This validation is undertaken to ensure that the modelled network is as close to reality as possible such that:

- All customer behaviour is accounted for i.e. all the network parameters and customers are included correctly;
- SCADA data is being used correctly (for example that the correct polarity is used when using Amps, or where the direction of MW/MVAr flows is unclear);
- Any significant anomalies can be identified and necessary steps taken to rectify them

The data for validation is significant in size. To put it in perspective, the data for SPM is available from approximately 1000 locations with 17,568 half-hourly measurements for MW and MVAr values thus leading to **35.1 million data points.** This makes the validation process relatively laborious. Future work should consider semi-automated tools to assist these tasks. Please note that this validation exercise is NOT used in any way to calculate the network losses.

We have focussed on a visual check of the validation results for all 12 months and a more detailed validation for January which is generally the month when peak demand or higher demand is recorded.

Model validation can be laborious, an automated approach should be considered for future.

5 Results

Results are shown below for the application of the Advanced Losses Modelling Tool to 132 kV, 33 kV and 11 kV networks. This provides learning on how the tool can be applied and validated in future to support identification of loss hotspots, modelling of interventions, minimisation of losses, and key modelling considerations.

5.1 SPM 132kV and 33kV Network

The SPM 132kV network has 15 GSP groups. The SPM 33kV network has 35 substation groups each of which belongs to one of the 15 GSP groups. The SPM network is highly meshed and is modelled in its entirety in IPSA.

Validation shows very close agreement of the modelled flows to the measurement values. "10963-04-Validation for Improved Loss Modelling of Complex Networks D01" presents validation results for the Advanced Losses Modelling Tool including a number of SPM 132 kV substations. Modelled flows closely match in the majority of the cases.

The infeed into each group and the variable losses in the 132kV circuit are calculated from the modelled flows. The fixed losses are considered separately based on data available for any assets connected to the circuit such as voltage regulators and shunt reactors. Figure 5-1 presents the circuit losses for each GSP group as a percentage of its group infeed. Apart from one group (Carrington), the incurred losses for all the others are around 0.5% of their respective infeeds. We have investigated this and found that the impedance per circuit km, circuit length and level of loading is consistent with other feeders. It may require more detailed investigation outside the scope of this study.

The fixed losses components in the 132kV circuits are due to 132kV series reactors. Two are located in the Carrington substation to balance the flows between Fiddlers Ferry and Carrington SGTs. The Kirkby 132kV series reactor limits the through-flows from Penwortham SGTs via Southport.

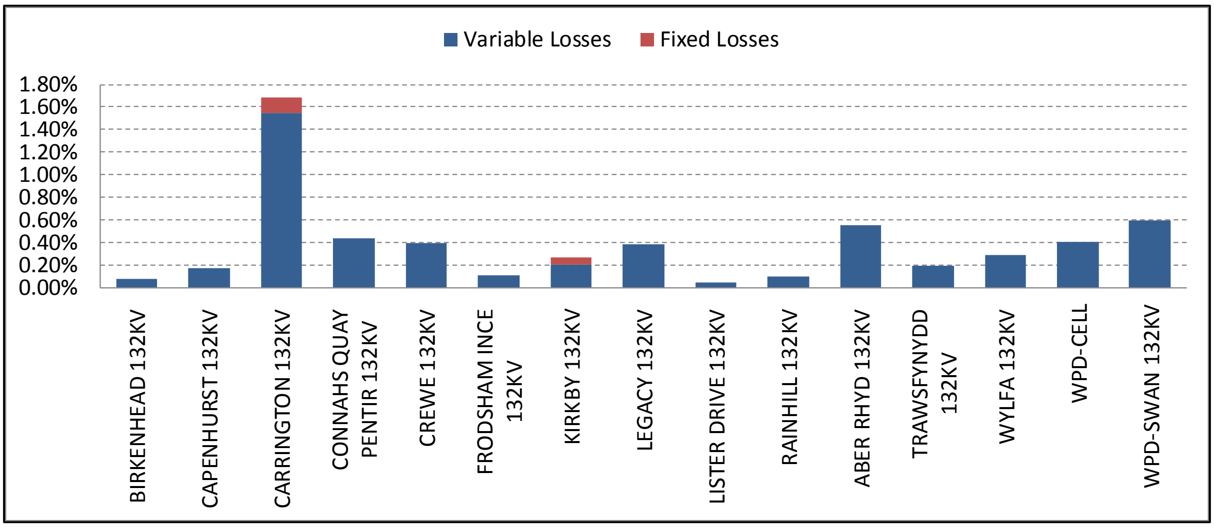


Figure 5-1 132kV circuit losses

Figure 5-2 presents the 33 kV circuit losses for the 35 groups as a percentage of their group infeeds. Fixed losses are present in 8 out of the 56 groups; however, they are insignificant compared to the variable losses. There are four substation groups having losses higher than 1%, these groups have higher comparative impedance compared to other groups. The overall loss of the 33kV circuit is found to be around 0.46% compared to 0.37% for the 132kV network. Higher circuit losses at 33 kV may be generally attributed to the higher current flow in the network due to the lower voltage level but there are other influencing factors such as circuit lengths, conductor size, number of circuits etc.

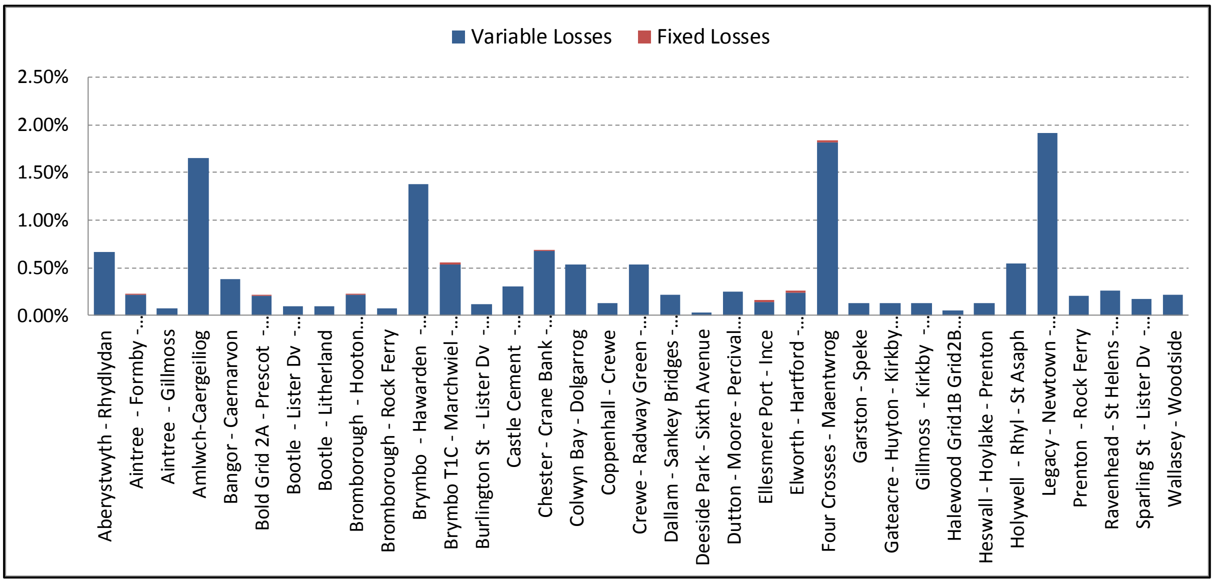


Figure 5-2 33kV circuit losses

The 132/33kV transformer variable losses are calculated from the power flow results obtained from IPSA while the fixed losses are calculated separately using asset data. Unlike the circuit losses, transformer losses are dominated by fixed losses (in the iron core). Out of the total losses in all 132/33kV transformers, 64% accounts for fixed losses and the rest is variable losses.

Figure 5-3 presents the transformer losses for all the 35 substation groups and they are found to all be close to 0.4%[4] as expected. It can be seen that for some transformers such as Aberystwyth-Rhydlydan and Halewood Grid1B, the fixed losses are higher compared to other transformers with a similar rating of 60 MVA. Based on a review of transformer age, there appears to be a correlation. Older transformers generally tend to have higher core losses compared to newly commissioned ones.

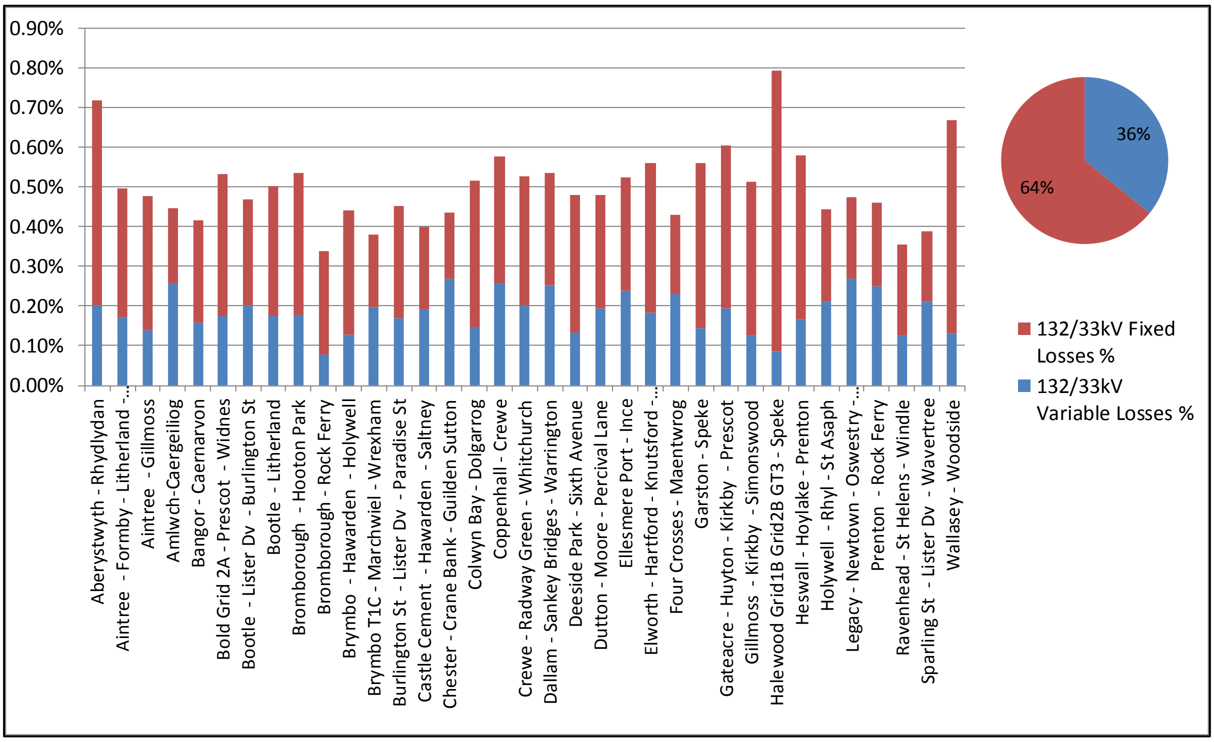


Figure 5-3 132/33 kV transformer losses

5.2 SPD 33kV Network

The SPD network has 87 Bulk Supply Points (BSPs) (132/33kV) in total. We have selected 5 representative BSPs to analyse in detail; their characteristics are provided below. These BSPs represent a mix of different load types (highly urban, urban, rural etc.) supplied by the 33kV network. The characteristics of these 5 BSPs are listed in Table 5-1 for reference. The analysis presented in the following sections provides an insight into the impact of load types and embedded generation on the losses in the circuit.

Table 5-1 Types of substations considered in SPD network

BSP	Type	Comments
Charlotte Street	Highly-urban	In Glasgow metropolitan area
Dalmarnock	Highly-urban/urban	In Glasgow metropolitan area
Ayr	Urban	Ayr is a large town on the west coast of Ayrshire
Livingston	Urban/semi-urban	Largest town in West Lothian
Linmill	Rural	Isolated

Generally, modelled flows show very close agreement to the measurement values. For example, Ayr substation supplies primarily an urban load on the west coast of Scotland and does not have any embedded generation, it compares well. In Linmill and Livingstone there is significant embedded generation connected so flows are more stochastic and less well matched. Validation results for the representative SPD substations are provided in an accompanying report “10963-04-Validation Annex for Improved Loss Modelling of Complex Networks R0”.

Figure 5-4 presents the losses for the 5 representative BSPs as a percentage of their respective infeeds. The overall circuit loss of the 5 BSPs is around 0.77% and is shown by the red dotted line in the figure. Linmill substation is found to suffer from high losses, likely to be due to the connection of significant embedded generation, leading to reverse power flow over longer distances. Linmill supplies a rural load with 8 embedded generation sites, the generation being a mixture of wind and solar parks along with two sites having pump storage stations. At certain times of each day, the substation experiences reverse power flow due to excess of generation and low demand.

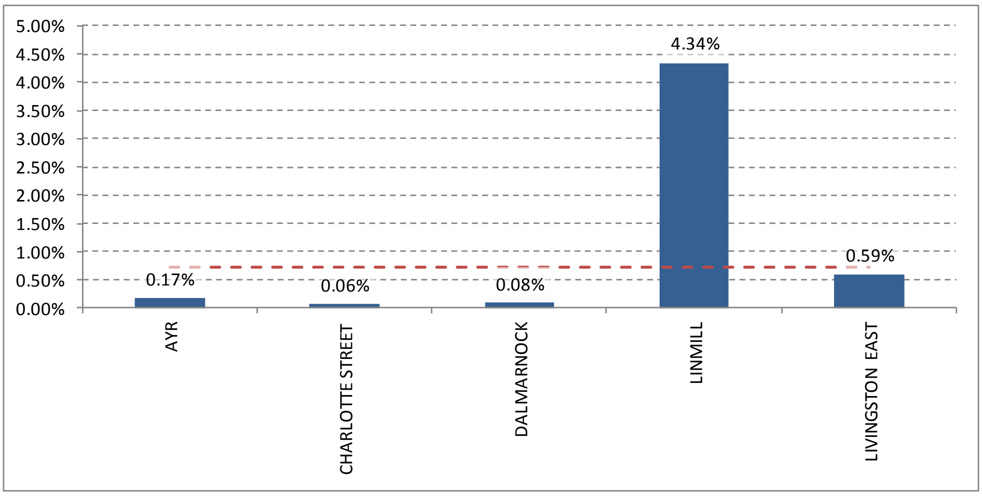


Figure 5-4 33kV circuit losses for the SPD network

The 132/33kV transformer losses are presented in Figure 5-5 for the 5 BSPs. Linmill substation is found to have higher losses, although the difference is not as high as circuit losses due to some netting off of demand. The transformer fixed losses are found to be higher than the variable losses, accounting for around 70% of the total losses in the 5 substations. Transformer losses for these 5 GSPs appear to be lower than SPM, this could be due to lower ratings, loading as well as other factors.

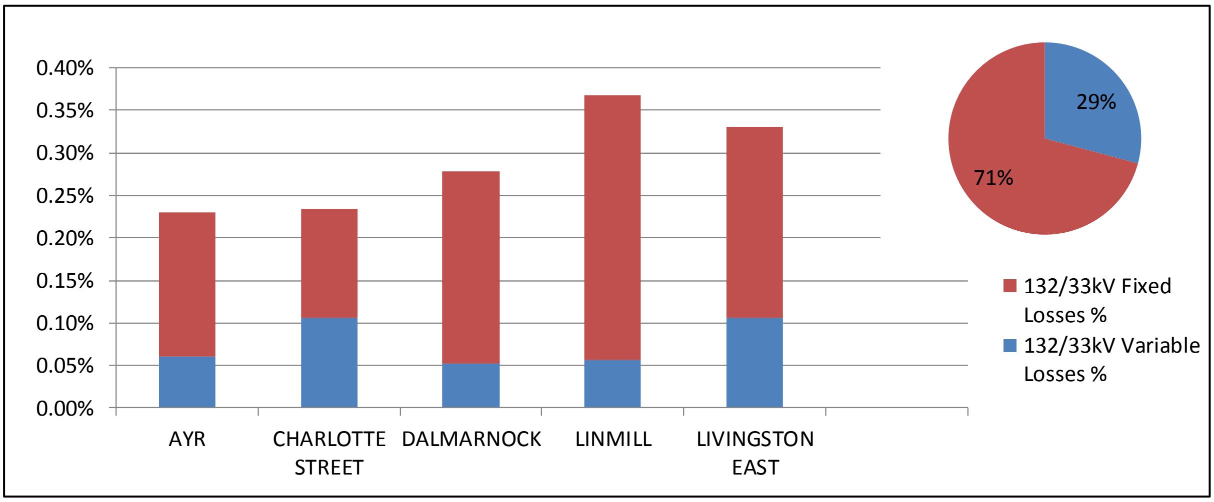


Figure 5-5 132/33 kV transformer losses for SPD substations

5.2.1 Effect of Embedded Generation on Network Losses

In a demand dominated meshed network group, the circuits directly out of the BSP substation are most heavily loaded and therefore might be expected to experience the highest losses. Losses then reduce to their lowest values around the null points in the group where the lowest current is flowing. However, the connection of embedded generation is changing this. Furthermore, as networks are reconfigured to accommodate additional demand/generation, these reconfigurations affect the flows throughout the group which in turn alter the losses.

Although the generation is located amongst the demand, generation has been found to significantly increase the overall losses in some cases. Rather than being relatively predictable, the power flows and hence the losses become more stochastic in nature. Figure 5-6 and Figure 5-7 present a sensitivity analysis of the losses in the network with respect to embedded generation. The losses calculated with generation connected to the network are found to be higher than that of the scenario without any embedded generation.

The increase in losses in the Amlwch-Caergeiliog substation group is experienced throughout the year with the situation becoming more severe during typically high demand periods such as the winter months of November to January. There is substantial wind generation connected circa 70 MW and output is higher over winter months, potentially during low demand periods overnight]. The location and connection configuration of generation are also important factors, it is likely not evenly distributed across the network and impact on losses may vary depending on proximity to demand loads and complex power flow paths on meshed networks.

Livingston is a generation dominated 33 kV network in SPD with 60+ MW of wind generation and 60 MW of peak demand in 2015/16. It can be seen in Figure 5-7 that with wind generation, losses are significantly higher. This does have some seasonality, it can be seen that from May to October, wind generation contributes less losses. Whilst in general at these levels, generation can often net off demand and losses are reduced, the location and connection configuration of the generation are also key factors in the actual impact on power flow and losses.

In this case, generation is connected in to one radial feeder in a direct path to the substation busbar. Demand on this feeder is low, it is not near a load centre. Thus, both losses from demand (import) and losses from generation (export) are incurred in this network. This would not be detected using a top down approach based on net load at the BSP. More detailed consideration of network wide losses reduction may have suggested a different connection configuration.

Thus, the connection of new generation may increase losses particularly in areas of low demand and high existing embedded generation. This is explored further in the Use Cases.

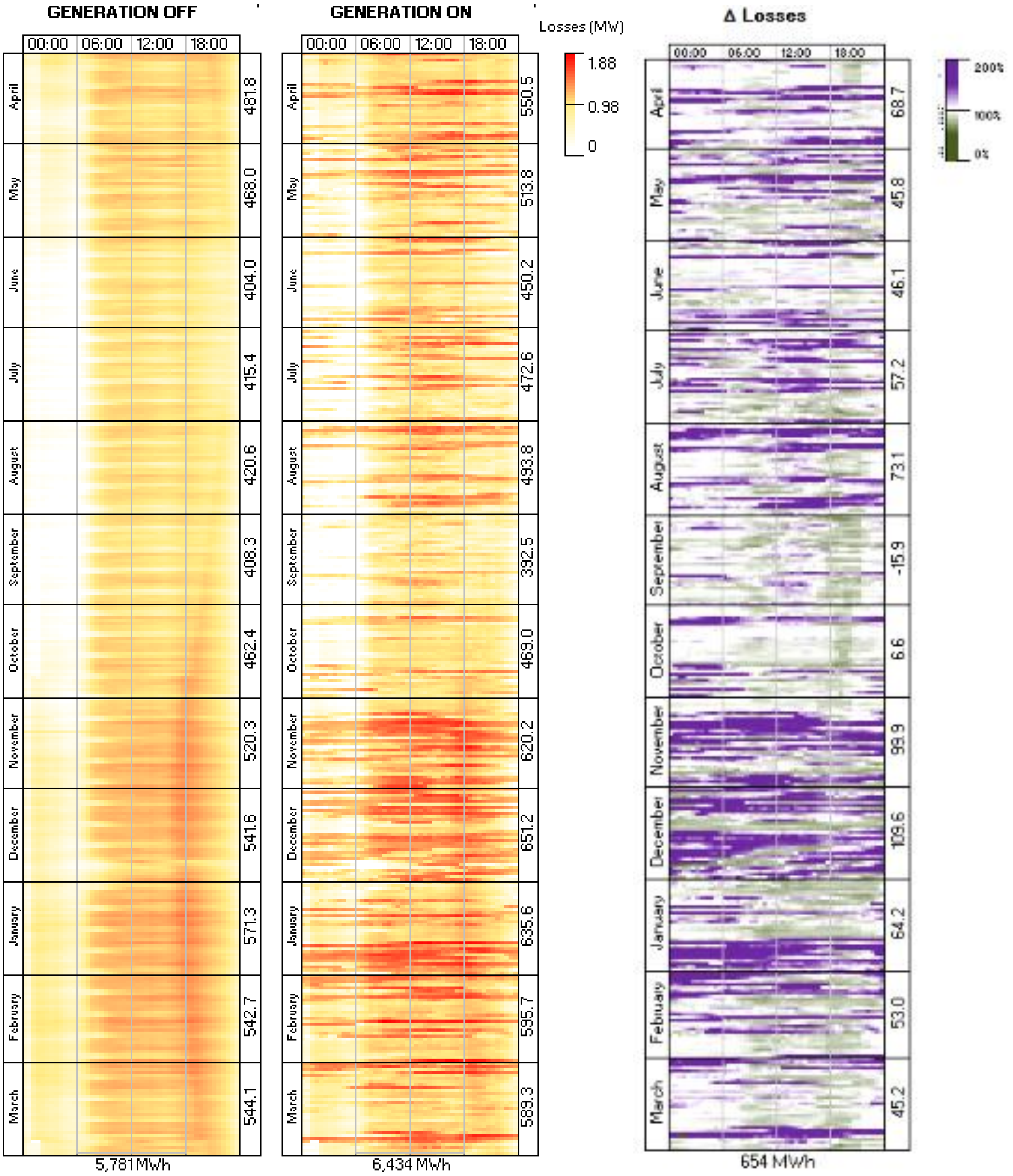


Figure 5-6 Modelled losses showing the effect of embedded generation in the Amlwch-Caergeiliog substation group

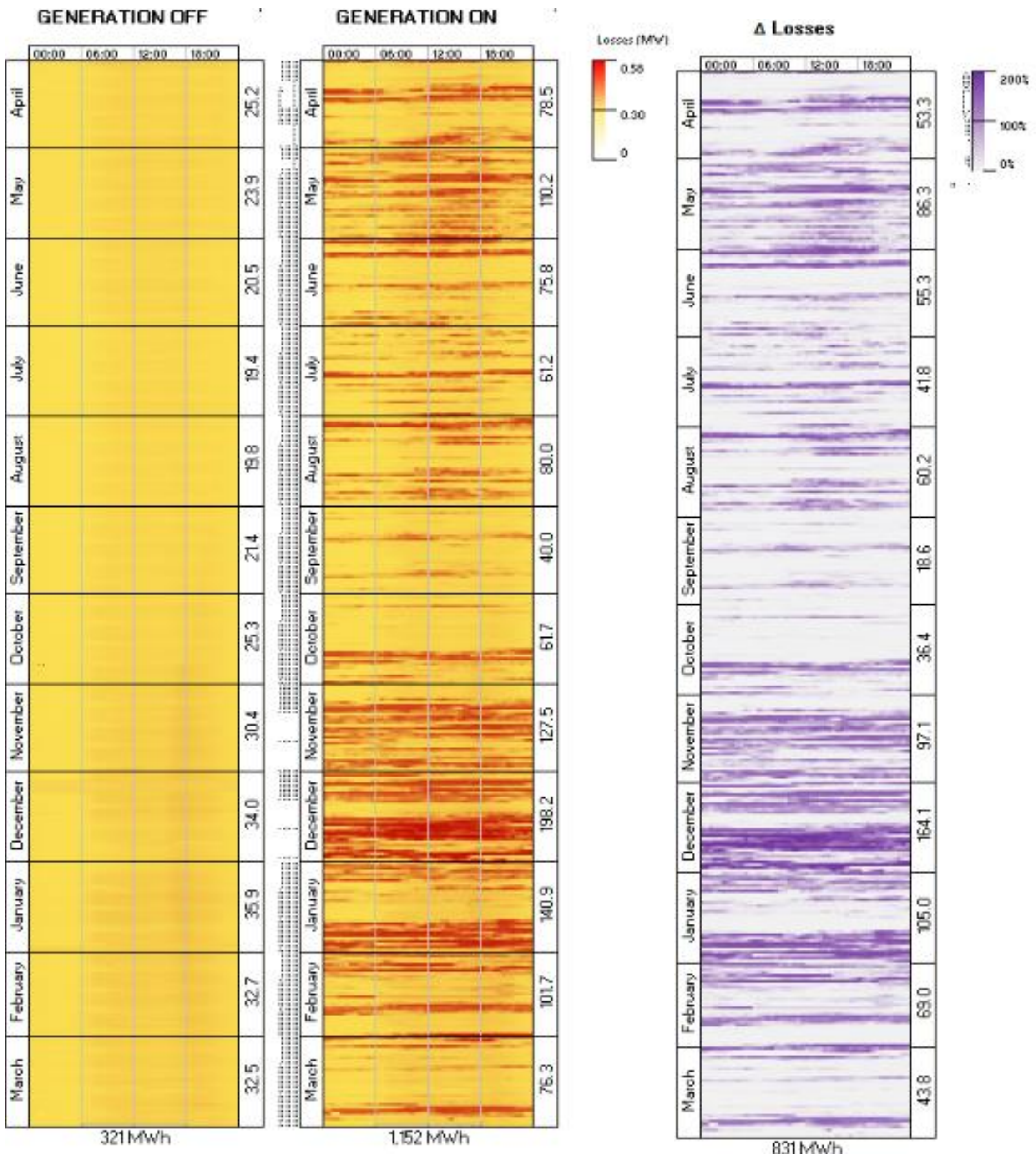


Figure 5-7 Modelled losses showing the effect of embedded generation in the 33kV network under Livingston substation

Embedded generation can increase network losses, location and connection configuration of generation are key factors.

5.3 HV Networks

5.3.1 Northwich

The Northwich network has been modelled to analyse the performance of the Advanced Losses Modelling Tool for application to an HV meshed network. Four substations out of a total of nine in the group (Table 5-2) are interconnected and are considered in detail.

There is no embedded generation in the Northwich network. The maximum load for HV Group 1 is around 20.3 MW for the year 2015/16. Maximum loads for the individual substations are listed in Table 5-2.

Table 5-2 List of 33/11kV substations in SPM-Northwich

No.	Substations	Maximum Load (2015/16) (MW)	Substation Groups
1	Castle Beeston Street – Outer	5.01	HV Group 1
2	Hartford – Outer	5.54	
3	Northwich Town - Outer	4.62	
4	Winnington	5.12	

For validation, an iterative method is adopted wherein the HV/LV loads in HV Group 1 are scaled accordingly with an objective of minimizing the error between measured and modelled power flow of each HV infeed substation. Whilst there are some differences between the measured and the modelled flows for HV Group 1, they are minor. Validation results are presented in a separate report. This illustrates a robust validation process for a meshed network at 11 kV.

Castle Outer BB, Winnington, Hartford Outer and Northwich Town are meshed to form an infeed group “HV Group 1”. Losses results using the Advanced Losses Modelling Tool are considered for this group below. Fixed losses data for the transformers have been derived from the 132/33kV transformers in proportion to their MVA ratings as an approximation.

Table 5-3 Losses results for Northwich meshed network

Parameter		Loss as % of infeed
Circuit losses (11 kV)		0.35%
Transformer losses (33/11 kV)	Fixed	0.53%
	Variable	0.47%

5.4 Ruabon

Ruabon is a small village located in the borough of Wrexham, Wales, with a population of approximately 2500. The Ruabon 33/11 kV network consists of one 7.5MVA 33/11 kV primary transformer which supplies the 11 kV distribution network. The 11 kV circuits from this primary substation are operated radially but with the facility to be interconnected to neighbouring networks supplied from Llangollen, Johnstown, Monsanto and Maelor Creamery following a system outage.

The Ruabon network has been selected for analysis as there are a number of secondary substations that were monitored as part of the LCNF Tier 2 Flexible Networks project. This allows us to explore and to an extent, further verify the performance of the modelling approach.

Ruabon network has 146 11/0.4 kV substations out of which measurements are available for 25 of them. To model the demand throughout the year at the remaining substations, a scaling factor based method has been adopted similar to Northwich to obtain a representative disaggregation of primary load to secondary substations based on demand at time of peak. Known meter data for large HV connected individual customers, embedded generation and any monitored secondary substations can also be considered within this approach.

Where MDI values are available, 80% of the maximum demand indicator (MDI) values are used as the base peak demand value. For pole mounted substations, MDI values are generally not available. In such cases, 20% of the rated MVA of the transformers are considered as the base peak demand.

11kV feeder section losses as a percentage of the overall circuit losses are presented in Figure 5-8. Certain feeder sections have higher losses compared to others due to factors such as loading, length and type of the cable. Total circuit losses are 0.44% of total infeed.

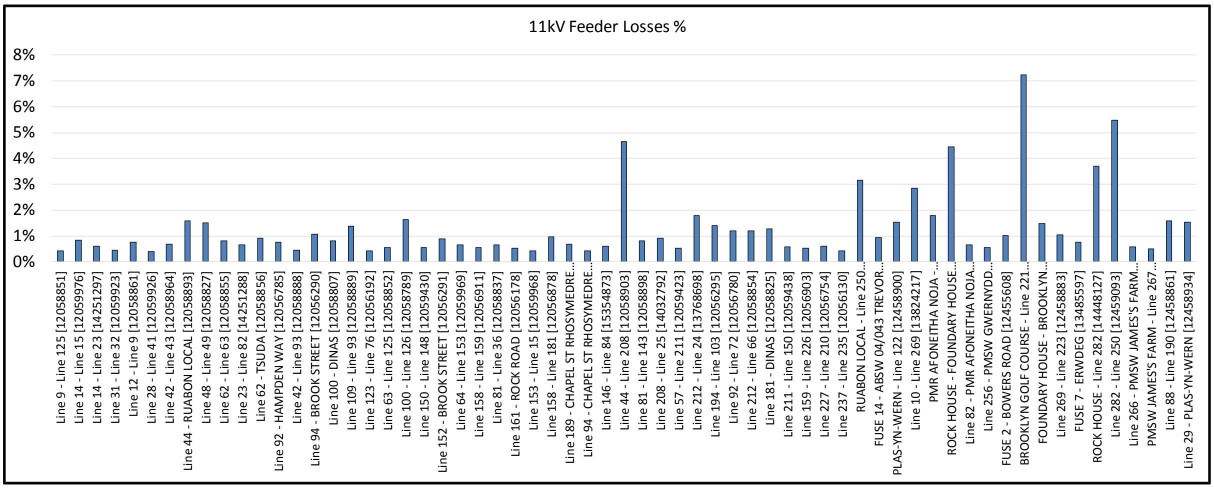


Figure 5-8 11kV feeder losses in the Ruabon Network

Secondary substation (11/0.433kV) transformer losses are presented in Figure 5-9 as a percentage of their respective power flows. The variable losses are calculated based on the load flow results obtained from IPSA+ while the fixed losses are taken from asset data available from SP on impedance. As expected, the results show that the losses in all the transformers are less than 1% except one (AFONEITHA ROAD - name not visible in the figure).

The reason for higher losses in this substation transformer can be explained with the help of Figure 5-10 and this illustrates how the Advanced Losses Modelling Tool can support investigation of losses issues. The figure shows the percentage loading of transformers at two different locations for the month of January. It clearly shows that AFONEITHA ROAD substation has high loading compared to other substations such as BODYLLTYN resulting in higher variables losses. The overall variable losses in all the secondary substations is found to be around 57%, slightly more than the fixed losses.

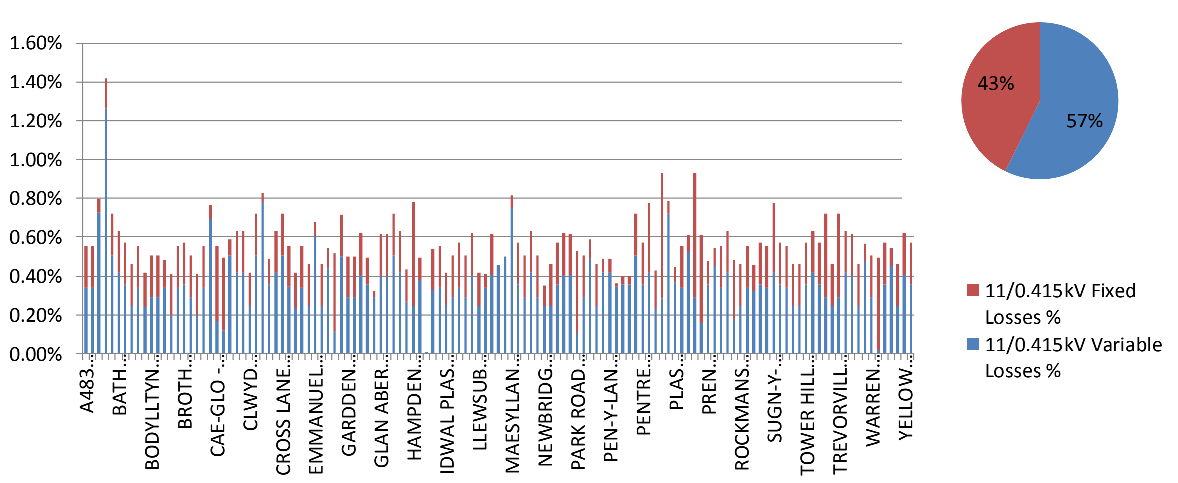


Figure 5-9 Transformer losses in the Ruabon network

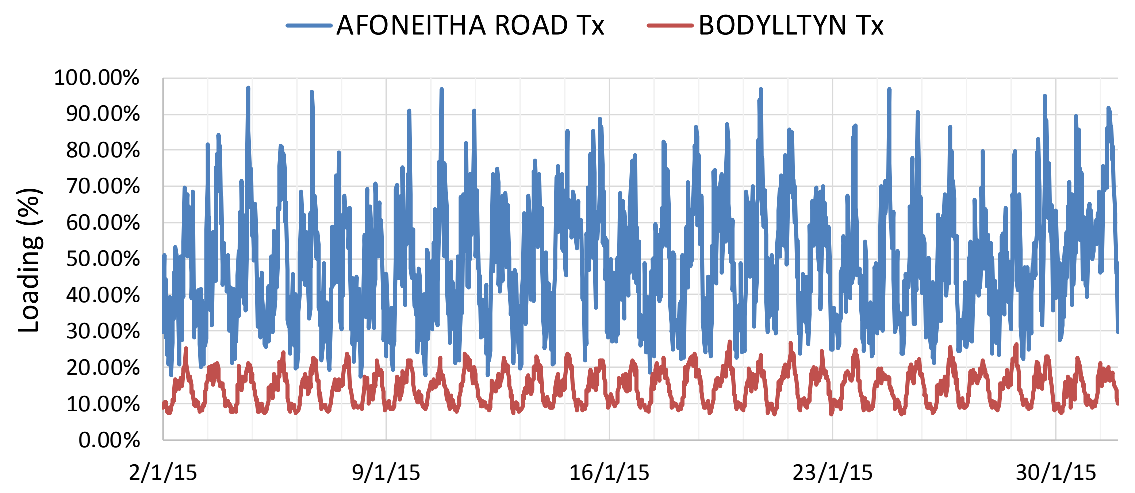


Figure 5-10 Transformer loading for the month of January for two different locations in Ruabon Network

5.5 Kilsyth

Kilsyth is a small town in North Lanarkshire roughly halfway between Stirling and Glasgow in Scotland. It is supplied by a single primary substation having two parallel 33/11 kV transformers. The 11kV network has a radial configuration with 165 secondary substations (11/0.433 kV) supplying the low voltage network. Out of the total number of secondary substations, 62 of them are of Ground Mounted (GM) type while the rest (103) are Pole Mounted (PM).

SCADA measurements are available at the Kilsyth primary substation and MDI records are available at the ground mounted substations. To model the demand at all the secondary substations, a peak demand scaling approach has been adopted similar to the one used for Ruabon. The IPSA model of the Kilsyth distribution network has four secondary substation transformers modelled in detail. The losses in these transformers are presented in the following section along with the 11 kV circuits losses. Results have been validated and it was found that the modelled flow corresponds closely to measurements.

Based on the load flow results obtained from the IPSA model, variable losses are calculated for each 11 kV feeder section. Figure 5-11 presents the feeder section losses as a percentage of the primary substation annual infeed energy, the overall circuit loss is 1.24%. The individual feeder section losses are well below 0.2%. Some feeders have higher losses than the others due to longer circuit section lengths, high loading and the type of the cable for example.

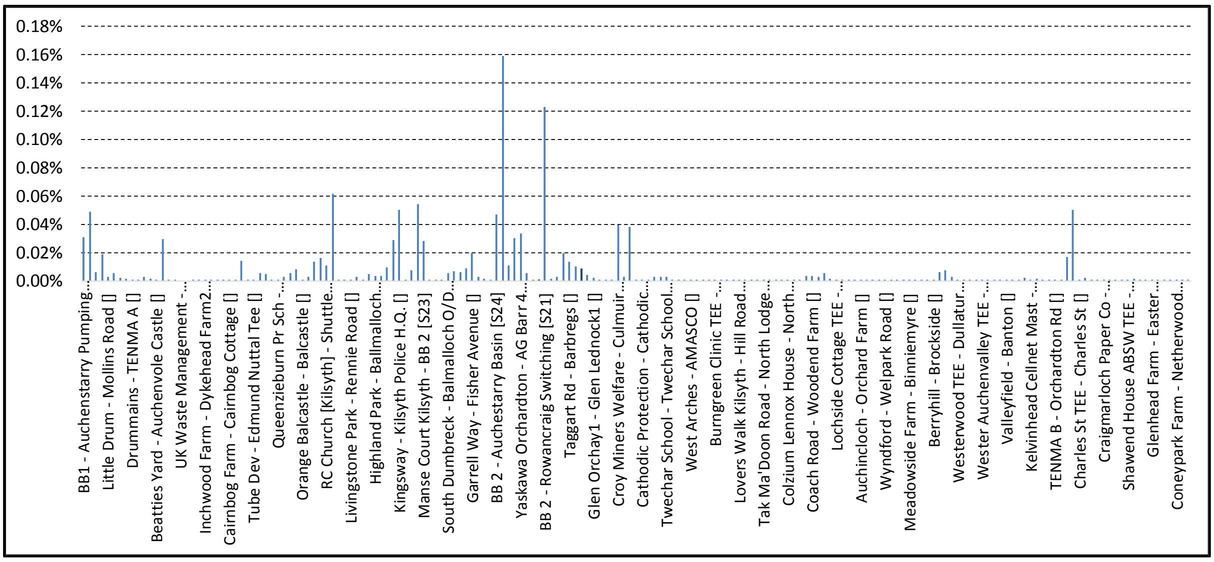


Figure 5-11 Circuit losses for the 11 kV Kilsyth network

The Kilsyth network has two primary transformers and 165 secondary transformers. Figure 5-12 presents the variable and fixed losses of the four secondary transformers which are modelled. The total losses in these transformers are less than 1% and the variable losses dominate with 76% share. Smaller transformers have higher X/R ratio and smaller iron cores thus resulting in higher variable losses and lower fixed losses. This is evident from the losses calculation of the 132/33 kV transformers in SPM network. The fixed losses are calculated based on the asset data available from SP which relates to the year of manufacture of the transformers. For cases where transformer ratings do not match with the database, the iron losses have been scaled based on the ratio of their respective MVA ratings.

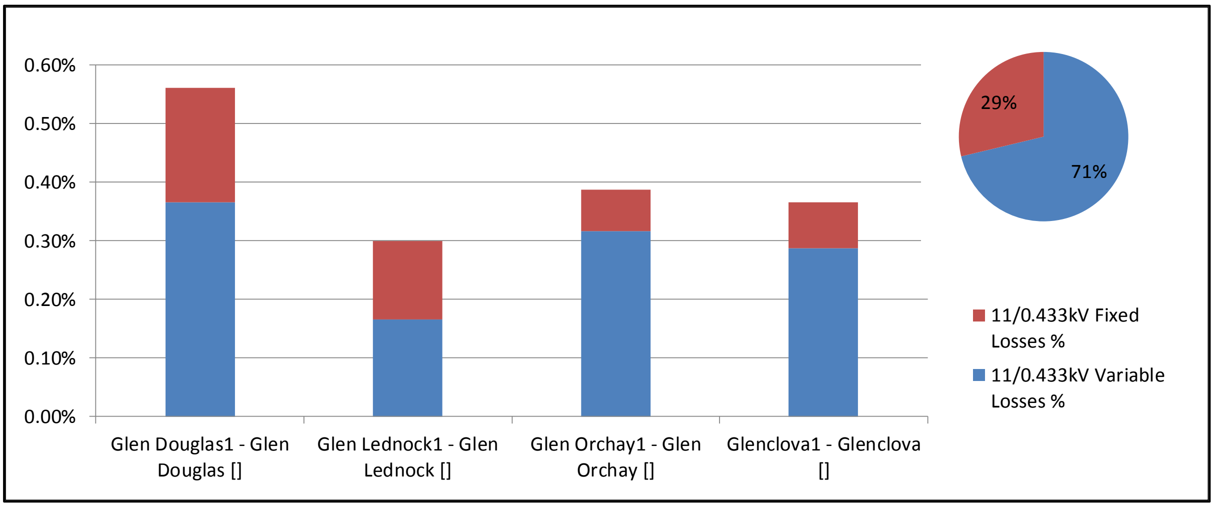


Figure 5-12 Secondary transformer losses for Kilsyth

The losses incurred by the two primary transformers are calculated separately and presented in Figure 5-12. These transformers are connected in parallel and hence have identical rating and losses figures. As expected, the variable losses are higher than the fixed losses and the total loss incurred is less than 1% of the infeed flow.

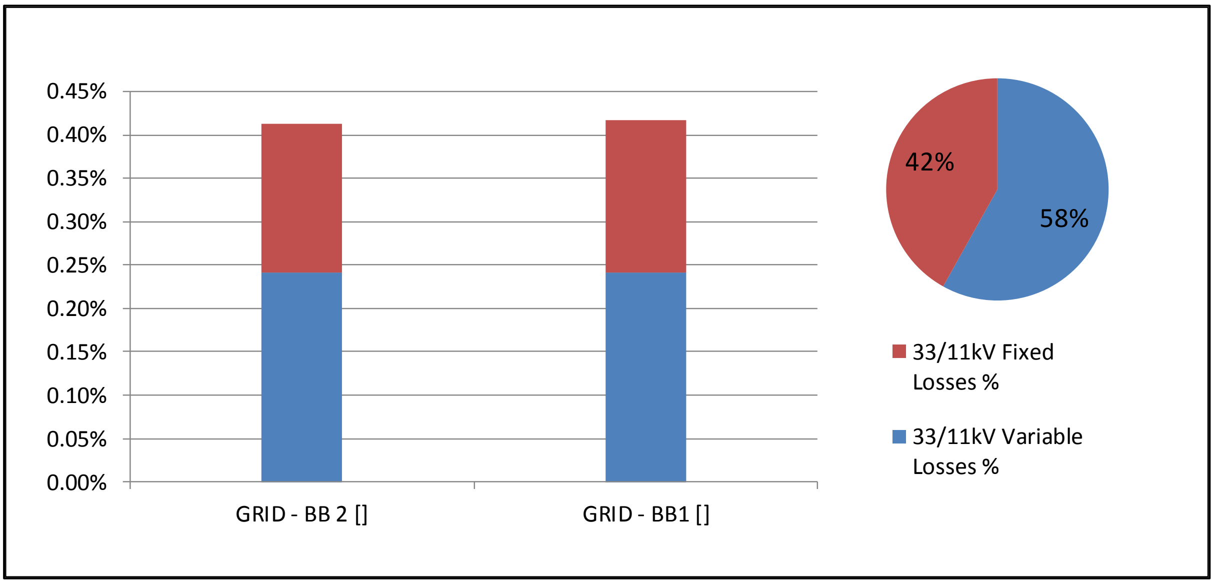


Figure 5-13 Primary transformer losses

6 Use Cases

For maximum benefit, losses should be considered as part of the holistic network planning process. For example, during network connection and reinforcement studies, losses could be quantified for various design options. This can then be assessed within a cost-benefit analysis with value for losses being reflected in the total financial costs. This will better ensure that losses are more fully considered and minimised across the network.

A number of use cases are presented below across network business functions where the Advanced Losses Modelling Tool could support improvement of the efficiency of network design and contribute to losses minimisation.

6.1.1 Major Reinforcement

Major reinforcement is triggered by significant increase in load (demand or generation) across the network leading to thermal or voltage constraints. Particularly at EHV level, major reinforcements are carried out infrequently and more detailed consideration of losses could lead to improved option selection.

Losses are valued in the Ofgem RIIO-ED1 cost-benefit analysis template used by DNOs in reinforcement optioneering, considering total lifetime costs. This requires a reasonable quantification of losses within the existing network as well as quantification of likely losses for various reinforcement options – conventional and "smart". Losses modelling can be carried out rapidly using the Advanced Loss Modelling Tool, this should be appropriate for the level of investment.

A specific example is ANGLE-DC, where the MVDC link resolves a wide range of system issues (low voltage, thermal overloads), which would otherwise need to be addressed individually by a complex and costly conventional reinforcement scheme. It also considers losses optimisation.

Losses should be modelled and optimised during optioneering for major reinforcement schemes.

6.1.2 Load based

In addressing underlying load growth on lower voltage networks due to uptake of low carbon technology, losses should be considered in the deployment of both smart and conventional solutions. For example, the deployment of voltage regulators or STATCOM may provide improved voltage control but when added to a circuit, introduce thermal losses also. Some no-network solutions such as dynamic thermal ratings may increase load utilization of a network, leading to higher losses. This may favour some smart/conventional solutions over others depending on other attributes.

Losses could be modelled using the Advanced Losses Modelling Tool, on a feeder or network basis for representative networks.

Smart solutions may result in increased losses due to higher network utilisation and/or asset impedance.

6.1.3 Customer based

The exploration of losses with and without generation in the Livingstone 33 kV network provides a good example of how losses can be exacerbated with embedded generation. In this case, all generation sites are connected to the 33 kV busbar along a single feeder with low demand. This results in little to no netting off of demand and in some cases reverse power flow along the feeder, thus contributing to increased network losses.

For some connections, it may be very clear how the customer should be connected to the network most economically. However, for other connections where there are a range of feasible options, losses should be one of the considerations for recommending the final design. Losses could be assessed for a range of generic connection options that can then provide guidance with requiring further modeling.

A threshold approach based on connecting capacity and network characteristics (indicating potential losses at high level) may be appropriate for indicating when a customer connection should be assessed with the Advanced Losses Modelling Tool. This should be reflected in Connections Policy.

Also, potentially a DNO could provide signals to generation to connect in areas of higher demand to provide some netting of demand, reducing losses and potentially increasing capacity headroom. This could be as a system service in a DSO market model.

Providing appropriate market signals for generation (and demand) connections may enable loss reductions and capacity headroom increase.

6.1.4 Asset Management

In order to enact effective asset management strategy, an improved understanding of the losses associated with assets across the network is required. The value of different asset replacement strategies can then be quantified and compared. For example, an asset replacement programme that identifies and over the longer term replaces those assets which incur the highest losses due to age, design etc., will aim to do so at the time which is most economically efficient. For example, during RIIO-ED1, a number of old high loss distribution transformers are to be replaced with low loss transformers due to an EU Directive.This may also be during related reinforcement processes.

The lossiness of different design approaches such as cable conductor sizes and transformer sizes should also be assessed from a combined network planning and asset management perspective and reflected in design policy.

A holistic network planning and asset management strategy can support losses reduction through improved design and replacement programmes.

6.1.5 Operations

From an operational perspective, as the distribution network moves towards a more dynamic and automated network, there may be increased opportunities to manage and reduce losses.

STATCOMs may be deployed to provide voltage control due to increases in embedded generation for example. The Advanced Losses Modelling Tool could enable detailed assessment and recommendation of operational set points for every half hour of the year to meet a range of criteria including losses optimization. This could be on a range of timescales – planning to real-time however real time set points should have much less uncertainty.

Automatic reconfiguration of local networks in real time could consider loss reduction as a key objective within a multi-criteria optimisation model. This would require loss calculation in real time to determine appropriate configurations and in a planning timescale to determine appropriate normally open points and location of sectionalising equipment.

This could also be applied within an embedded MVDC scheme where the voltage set point s can be adjusted to support loss minimisation.

Detailed modelling of losses will underpin real time loss optimisation.

6.1.6 Policy/Process

Whilst power system models exist for 132 kV and 33 kV networks and are readily available for losses analysis, these are often only developed for 11 kV networks on exception and/or in reduced level of detail. They may not be maintained on a regular basis. Due to the significant volumes of 11 kV network, this is a pragmatic approach, focussing only on networks where there is reasonable value to be extracted in detailed modeling.

In order to select appropriate 11 kV networks to model, a threshold approach can be developed and used based on network impedance, demand and generation forecasts, capacity headroom and a high level assessment of losses. Losses can then be modelled and interventions analysed to provide input to cost benefit analysis. This should be reflected in network planning policy.

7 Outcomes and Future Benefits

7.1 Outcomes

The development of an Advanced Losses Modelling methodology and tool based on a bottom up approach has enabled significantly improved quantification of losses compared to existing practice. This includes identification of losses hotspots and modelling of losses interventions in planning timeframes and in real-time.

The bottom-up model has been demonstrated and validated on all 132kV and 33kV networks in SPM. In SPD a range of the GSPs have been selected and studied in detail to provide representative coverage. A range of both interconnected, and radial HV networks have also been studied.

The modelling tool is able to accurately capture stochastic, complex power flows including embedded generation. There are also some learning outcomes in how this tool can be applied in future. Whilst there are some modelling limitations, this provides a strong basis for losses analysis. The modelling tool is appropriate for represent the changing, dynamic power flows with increasing low carbon technology.

Our ability to consider our planned network throughout all operating periods in a year is expected to deliver a reduction in network losses through our ability to optimise how we operate our assets. This will include changes to network configuration and the target set points on power flow controllers and voltage control devices.

7.2 Future Benefits

There are a number of benefits that the Advanced Losses Modelling can provide:

- **Holistic Assessment:** Enable holistic losses assessments with TSO regarding overall losses including parallel paths with transmission network. Assessment of losses can inform alignment of planning and asset management strategies.
- **Major Reinforcement Scheme Optioneering:** Optimise losses during optioneering for major reinforcement schemes.
- **Load Growth:** Selection of appropriate solutions to manage load growth whilst considering losses impact.
- **Customer Connections:** Provide appropriate locational market signals for generation (and demand) connections to reduce losses and increase capacity headroom. Consideration of losses in connection design.
- **Real Time Loss Optimisation:** Modelling losses to underpin real time loss optimisation.

Appendix A – Factors Affecting Load Losses

Network Topology

Major network reinforcements, reconfigurations or changes to the running arrangement will alter the impedance of the supply path to customers and therefore alter the losses.

Customer consumption

Variable losses are due to I^2R and therefore scale non-linearly with consumption. Variations in underlying customer consumption and customer load distribution significantly affect losses.

Embedded generation

Embedded generation may net off demand to reduce losses or in large enough quantities, may result in reverse power flow and increased losses.

Changes in Voltage or Reactive Power

Changes to the voltage at any point along the power flow path will impact the current flowing and therefore the losses. Changes to the reactive power will have an impact on the apparent current flowing through the network assets and therefore the losses.

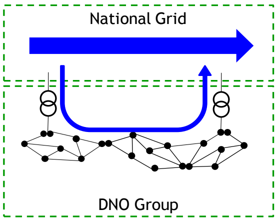
Re-distribution of Power Flows

In interconnected areas of network, changes to the proportions of power being supplied through each of the supply transformers will alter the current flowing through each of the assets in the mesh. This can alter the overall losses, particularly if the impedances of the circuits between the supply transformers is large. This effect is interactive with changes in consumption across the network group.

Parallel Power Flows

Some areas of DNO network operate in parallel to the National Grid network. As such some current will flow through the DNO network due to bulk power flows across the NG network. These can be sensitive to:

- new generation or changes to existing generation connected to upstream network, or indeed to generation dispatch.
- proportions of power flows through infeed transformers



Appendix B - Uncertainty in Technical Losses Estimation

There are a number of sources of uncertainty in the estimation of technical losses

Transformers

Transformers have both fixed and variable losses when considered against the level of current flowing through them. Fixed losses do however vary with the energising voltage which typically ranges by 10%. There is a crude assumption that fixed losses from all network assets are about 30% of total technical system losses[18].

Transformer fixed losses vary not only by energising flux level (proportional to voltage) but also by the grade of steel and the number of turns in service (tap changer position – normal movement range is a few taps). To simplify calculations, when calculating loss adjustment factors for charging losses to customers, it is the practice to assume a fixed tap changer position on transformers.

Referring to the steel grade as the most significant factor, transformer fixed losses differ dramatically with the hysteresis curve. The magnetic softness of steels was a technology improvement over time. A significant improvement occurred about early 1950’s with the introduction of cold rolled grain orientated steels and continuous improvements occurred as the core was shrunk in size and weight, as steels became capable of higher flux densities. Recent improvements towards amorphous steels are leading to low loss and very low loss cores. Tier 1 eco transformers have about 25% of the fixed losses compared to pre-1961 transformers (for 132/33kV transformers and 33/11kV transformers). For HV/LV units, the figure is about 35% compared with pre-1955 units. It should also be noted that over time, steel becomes magnetically harder resulting in higher hysteresis losses.

If all transformers from grid supply down account for 75% of fixed technical losses[2], then generalisation of their parameters is likely to lead to uncertainties in total technical loss estimation. Assuming then that transformer fixed losses are about 23% of all technical losses, this equates to about 1.4% of all energy entering the system (based on total technical losses of approximately 6%). A 10% uncertainty resulting from transformer parameters would therefore account for +/-0.14%.

Errors may also result from inaccurate parameterisation of the winding resistance and reactance of transformers. Uncertainties due to variation in tap changer position may be significant and could, when taken with other uncertainties, result in +/- 0.28% of energy entering the system.

Lines and Cables

Inaccurate cable and line parameters, including inaccuracy in line length, may be significant sources of error in technical loss calculation. Manufacturing tolerances may also give rise to significant error when based on generic parameters.

Load Distribution

A further source of error is modelling of the distribution of load across the network. Modelling network types and loading regimes generically to estimate technical losses provides an

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[18] UK Power Networks, Business Plan (2015-2023) Annex 7: Losses Strategy, March 2014, https://library.ukpowernetworks.co.uk/library/en/RIIO/Main_Business_Plan_Documents_and_Annexes/UKPN_Losses_Strategy.pdf

approximation to the diversity of actual networks although monitoring data can support analysis validation. However, many assumptions are made and this is a significant source of uncertainty.

Even assuming best practice modelling, it is likely that load distribution modelling would still result in technical losses uncertainty of > +/-5%to +/-10% based on our experience. This would result in an uncertainty in total losses of > +/-0.3%to +/-0.6% of the energy entering the system (assuming technical losses of 6% of energy entering the system).

Load Profiles

Variable technical losses for all assets (~70% of total technical losses depending on type of network[14]) are proportional to the square of the current and are much higher at periods of high load. To model total technical losses requires profiling of both half hourly metered large Users (HH) and non-half hourly metered smaller Users (NHH).

For large Users, the availability of half hourly data enables more accurate characterisation of load profiles. For smaller Users, this is somewhat more challenging due to lack of data and there are various reasons why the assumed profiles may be inaccurate. Customer archetypes may not be representative, customer demand patterns change, environmental factors cause shifts from year to year and customer demographics change. The original profile may continue to be applied to a User located at a particular metering point although the User has changed. It is not possible to accurately estimate the uncertainty associated with this but it is likely to be at least as great as +/- 0.2% of energy entering the system.

Other Factors

Whilst there are other factors affecting technical losses e.g. phase balance (particularly affecting the LV network), voltage variation and operational regimes e.g. network topology and location of normally open point which could change seasonally or under maintenance or fault conditions for example, these are likely to have a secondary effect on the uncertainty in losses estimation.

Conclusions on Uncertainty in Technical Losses Estimation

Reviewing the above potential sources of uncertainty indicates that technical loss estimation may have an uncertainty of > +/-0.5% to 1% or more of energy entering the system.