Project NETWORK EQUILIBRIUM

Detailed Design of the Enhanced Voltage Assessment Method

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GLOSSARY

AVC	Automatic Voltage Controller
BEAMA	British Electrotechnical and Allied Manufacturers' Association
BS / BSI	British Standards / British Standards Institution
BSP	Bulk Supply Point
C++	A general purpose programming language
CENELEC	European Committee for Electrotechnical Standardisation
CVR	Conservation Voltage Reduction
DC	Direct Current
DINIS	Geographic based power system modelling tool
DNO	Distribution Network Operator
EN	European Norm
ER	Engineering Recommendation
ESQCR	Electricity Safety, Quality and Continuity Regulations
EU	European Union
EVA	Enhanced Voltage Assessment
FPL	Flexible Power Link
GOR	Global Object Reference
GSP	Grid Supply Point
HV	High Voltage
IEC	International Electrotechnical Commission
IPSA	IPSA power analysis software
LCNF	Low Carbon Networks Fund
LV	Low Voltage
LVNT	LV Network Templates
MPAN	Meter Point Administration Number
MSC	Mechanically switched capacitor bank
MV	Medium Voltage
MVDC	Medium Voltage Direct Current
NOABL	Numerical Objective Analysis Boundary Layer (wind speed map)
NOP	Normally Open Point
PCC	Point of Common Coupling
PV	Photovoltaic (solar generation)
R	Programming language for statistical computing
RMS	Root Mean Square
RVC	Rapid Voltage Change
SLD	Single line diagram
SVO	System Voltage Optimisation
VLA	Voltage Limits Assessment
VSC	Voltage Source Convertor
WPD	Western Power Distribution

Executive Summary

In this Successful Delivery Reward Criterion (SDRC) report we present the detailed design of the Enhanced Voltage Assessment (EVA) Method: Voltage Limits Assessment and Advanced Planning Tool.

Distribution networks expect increasing penetration of low carbon generation and demand technologies in the short and medium term. Generation from low carbon technologies (solar photovoltaic and wind) is both variable and unpredictable. Increased penetration of heat pumps and electric vehicles will increase electricity demand and, in the case of electric vehicles, perhaps increase variability of electricity demand.

With the addition of these technologies to the network, system voltage and power flows will become unpredictably variable. Integrating significant levels of distributed generation has caused voltage management and thermal issues within electricity distribution networks. These problems are worsened during outage conditions.

The aim of Voltage Limits Assessment work package is to explore the rational for voltage limits currently applied in the UK and the possibility of amending the limits. The aim of the Advanced Planning Tool work package is the development of a forecasting and network modelling tool that will assist in load and generation planning.

Chapters 1 through 3 pertain to the Voltage Limits Assessment work and describe:

- The findings from the stakeholder engagement activity; input from Distribution Network Operators, regulatory authorities, manufacturer associations, consultants and technical specialists;
- The limiting factors for amending the statutory voltage limits; that is, the limits imposed by physical assets in the network; and
- The scope for amending the statutory voltage limits.

In Chapter 4 the design and implementation of an Advanced Planning Tool is described.

Voltage limits referring to steady-state operation of networks were examined separately from step change limits, which are related to flicker and other infrequent voltage change events. The limits enforced in the UK were compared against the corresponding limits for the EU and private/industrial networks. Through identification of the differences, it was possible to subsequently examine whether they are due to any inherent differences in the networks, if they result in different requirements for equipment connected to the distribution system, and then assess if there is scope for the potential amendment of voltage limits applicable in the UK.

Statutory voltage limits in the UK are defined in the Electricity Safety, Quality and Continuity Regulations (ESQCR) and are set as ±6% of nominal voltage for 11kV and 33kV networks. These limits have effectively remained in force since 1934. Steady-state EU limits are defined in European Norm (EN) 50160 "*Voltage characteristics of electricity*

supplied by public distribution systems". A summary of the steady-state voltage limits in the UK and the EU is provided in Table 1 below.

Table 1: Steady State voltage limits for 11kV and 33kV networks in the UK and EU

UK – ESQCR 2002 (statutory)	EU – EN 50160:2010
±6% of declared voltage (no time requirement defined)	±10% of U_C (declared supply voltage) 99% of 10-minute mean values over a week **PLUS** ±15% of U_C 100% of time

Step change voltage limits in the UK are specified in the Distribution Planning and Connection Code and in Engineering Recommendation P28 (ER P28). Step change voltage limits in the EU are recommended in EN 50160 including Rapid Voltage Changes (RVCs), flicker and supply voltage dips/swells. A summary of voltage change limits in the UK and EU is provided in Table 2: Voltage Change Limits for 11kV and 33kV networks in the UK and Table 3 Voltage Change Limits for 11kV and 33kV Networks in the EU

Table 2: Voltage Change Limits for 11kV and 33kV networks in the UK

UK – Distribution Code			UK – ER P28	
Maximum Number of Occurrences (n)	**Limits**		**Maximum Number of Occurrences (n)**	**Limits**
n > 1 per 10 minutes	<3% (also see P28 flicker limit)		n > 1 per 10 minutes	<3% (see P28 flicker limit)
n >1 per year and not >1 per 10 minutes	3%		n>1 per several months and not >1 per 10 minutes	3%
n ≤ 1 per year	10%		n≤1 per several months	DNO discretion

Table 3 Voltage Change Limits for 11kV and 33kV Networks in the EU

EU – EN 50160:2010			IEC TR 61000-3-7:2008	
Maximum Number of Occurrences (n)	**Limits**		**Maximum Number of Occurrences (n)**	**Limits**
(Informative only)	$\Delta V/U_C$ at supply terminals		(Indicative planning levels)	$\Delta V/V_N$ at PCC
Unspecified	≤4%		2 < n ≤ 10 per hour	3%
Some times per day	≤6%		n ≤ 2 per hour & n > 4 per day	4%
			n ≤ 4 per day	5-6%

The potential benefits resulting from an amendment of 11kV and 33kV voltage limits were acknowledged and welcomed by most respondents to the stakeholder questionnaire. Technical considerations were also identified, mainly involving voltage regulation issues, equipment voltage withstand capabilities and lifetime, protection coordination and the impact of wider 11kV and 33kV limits on HV and LV networks. The workshop concluded that barriers, such as network equipment withstand characteristics, maintaining LV voltages within limits, changes to fault levels, impact on customers and customer reaction, require further exploration.

Most of the equipment suitable for installation on systems of a nominal voltage of 11kV has a highest voltage for continuous operation (U_m) of 12kV, which is approximately 9%

above the nominal system voltage. Similarly, equipment suitable for 33kV nominal system voltages has a U_m of 36kV, which is again approximately 9% higher than the nominal. With respect to power frequency withstand voltages, for the test duration of 1 minute, 12kV rated equipment can typically withstand 28kV while 36kV rated equipment can withstand 70kV.

The study of the WPD South West licence area network showed that if an amendment to the existing statutory steady-state voltage limits was implemented, the fully exploited widened steady-state voltage limits would cause some of the 33kV and 11kV nodes to go outside the existing ±6% limits.

Based on the results of the modelling study and the review of equipment limitations, it was concluded that the vast majority of equipment connected at 11kV and 33kV would not require replacement, provided that the new range of voltage variation would not be greater than ±10% applied in a probabilistic manner so that operation in the extreme ends of that range would only be allowed for short periods of time.

Current planning tools have been designed for passive network operation. Using these tools, it is challenging to model complex network conditions accurately and integrate innovative technologies. The creation of an Advanced Planning Tool (APT) that will enable better network control, network planning and outage planning on distribution networks with increasing penetration of variable generation and demands.

The aims and objectives of an Advanced Planning Tool are outlined and then specified in terms of the functional and non-functional requirements. The Tool consists of:

- A model of the trial area network at 11kV and above;
- Forecast tools that enable the prediction of electricity demand and generation from wind and solar sources, given a 48-hour weather forecast.

The implementation of the Tool is described in four sections:

- The creation of an IPSA network model of the trial area is described, that is, the conversion from Western Power Distribution PSS/E network models and DINIS network models;
- The statistical analysis of historic electricity demand data to determine the relationship between demand and weather and time factors; the creation of an generalised model that can be used to forecast electricity demand;
- The development of a model that can be used to predict the power output for each operational wind farm in the trial area based on forecast wind speed and direction provided by the Met Office; and
- The development of a model that can be used to calculate solar photovoltaic generation based on forecast solar irradiance data, again provided by the Met Office.

This initial aspect of the Voltage Limits Assessment work has provided a thorough understanding to inform the next step, which is to consider the opportunities and barriers to amending limits.

The design stage of the Advanced Planning Tool has demonstrated the forecasting of demand and generation, based on models built from the analysis of historical data. The APT will be implemented within WPD business processes through 2016.

1 Key findings from the statutory voltage limit workshop and questionnaire

1.1 Background

Statutory voltage limits in the UK are defined in the Electricity Safety, Quality and Continuity Regulations (ESQCR) and are set as ±6% of nominal voltage for 11kV and 33kV networks. These limits have effectively remained in force since 1934, while anecdotal evidence of their rationale refers back to the 19th century and the allowances of 10% voltage drop made at the time.

Steady-state EU limits are defined in European Norm (EN) 50160 "*Voltage characteristics of electricity supplied by public distribution systems*". According to this standard, the voltage limits for medium voltage (MV) levels are ±10%, while a probabilistic approach is adopted for testing compliance (i.e. at least 99% of the measured 10-minute mean values of supply voltage over a week need to be within these specified limits). The rationale behind the voltage limits in EN 50160 appears to be based on establishing harmonisation across the EU and the ability of existing systems to operate without significant change.

A summary of the steady-state voltage limits in the UK and the EU is provided in Table 1 below.

Table 4: Steady State voltage limits for 11kV and 33kV networks in the UK and EU

UK – ESQCR 2002 (statutory)	EU – EN 50160:2010
±6% of declared voltage (no time requirement defined)	±10% of U_C (declared supply voltage) 99% of 10-minute mean values over a week **PLUS** ±15% of U_C 100% of time

Step change voltage limits in the UK are specified in the Distribution Planning and Connection Code and in Engineering Recommendation P28 (ER P28). A general classification into planned events (frequent or infrequent) and unplanned events or outages is used. Planned voltage fluctuations are defined in ER P28, with a maximum limit of ±3% applying to these voltage step changes. The Distribution Code stipulates the same limit for the above cases, but also allows for design to a voltage step change of ±10% for unplanned events. The rationale for the first type of limits stems from the introduction of severity values for flicker, limits of which were validated by field measurements of customers' reactions and laboratory tests. Unplanned events are examined on a more case-specific basis and due to their unpredictability and rarity wider limits up to ±10% are accepted.

Step change voltage limits in the EU are recommended in EN 50160 including Rapid Voltage Changes (RVCs), flicker and supply voltage dips/swells. For an event to be characterised as an RVC, the voltage at the supply terminals during the change should not cross the dip or swell thresholds, i.e. 90% or 110% of the reference voltage respectively. Should it cross any of these thresholds, the event is characterised as a voltage dip or swell. Voltage dips, swells and RVCs do not have explicit compliance limits, but only indicative values. For RVCs at MV, these are indicated as 4% and 6% of the reference supply voltage, depending on the frequency of the events and other circumstances. The rationale for step change limits in EN 50160 and other International Electrotechnical Commission (IEC) standards is not necessarily based on considerations of equipment immunity, but it could be driven by the desire to avoid over- and under-voltage protection operation or the need to control visibility and annoyance issues experienced by consumers.

A summary of voltage change limits in the UK and EU is provided in Table 2: Voltage Change Limits for 11kV and 33kV networks in the UK and Table 3 Voltage Change Limits for 11kV and 33kV Networks in the EU

Table 5: Voltage Change Limits for 11kV and 33kV networks in the UK

UK – Distribution Code			UK – ER P28	
Maximum Number of Occurrences (n)	**Limits**		**Maximum Number of Occurrences (n)**	**Limits**
n > 1 per 10 minutes	<3% (also see P28 flicker limit)		n > 1 per 10 minutes	<3% (see P28 flicker limit)
n >1 per year and not >1 per 10 minutes	3%		n>1 per several months and not >1 per 10 minutes	3%
n ≤ 1 per year	10%		n≤1 per several months	DNO discretion

Table 6 Voltage Change Limits for 11kV and 33kV Networks in the EU

EU – EN 50160:2010			IEC TR 61000-3-7:2008	
Maximum Number of Occurrences (n)	**Limits**		**Maximum Number of Occurrences (n)**	**Limits**
(Informative only)	$\Delta V/U_C$ at supply terminals		(Indicative planning levels)	$\Delta V/V_N$ at PCC
Unspecified	≤4%		2 < n ≤ 10 per hour	3%
Some times per day	≤6%		n ≤ 2 per hour & n > 4 per day	4%
			n ≤ 4 per day	5-6%

1.2 Introduction

Stakeholder engagement and input is one of the key aspects of the Network Equilibrium project. On that basis and in the context of the work relevant to the Voltage Limits Assessment work package, VLA questionnaires were issued to the main industry stakeholders across the UK and Europe, as identified by the Network Equilibrium project team.

The aim of the questionnaire was to:

- Seek information regarding how voltage limits are currently implemented in distribution networks of the UK and EU,
- Identify constraints they impose to the relevant stakeholders operating or connecting to the networks, and
- Explore amendments to existing statutory voltage limits and step change limits in Engineering Recommendations where applicable, highlighting both limitations and opportunities for change.

The results from the questionnaire were compiled and are presented concisely in this chapter, which allows the explored issues to be viewed from the different perspectives of Distribution Network Operators (DNO), regulatory authorities, manufacturer associations, consultants and other technical specialists with long experience in the industry.

1.3 VLA Questionnaire

In order to achieve better functionality of the questionnaires and more workable responses from the various stakeholders, two different versions were prepared and issued. The first was addressed to DNOs, IDNOs and TSOs operating the networks and included questions relevant to Regulation and Policy managers and Network Strategy/Planning staff, as well as an introductory and a technical section. The second version of the questionnaire was addressed to other key stakeholders within the industry including manufacturing bodies, electricity producers, trade bodies, regulatory authorities and other technical experts such as consultants and academics.

The first questionnaire was issued to 33 DNO, TSO and IDNO contacts, while the second was addressed to 71 industry contacts. The two versions of the questionnaire can be seen in Appendices A1 and A2. The following section provides an overview of the responses received, summarising the key points and highlighting the most salient arguments made by the respondents.

A wide range of responses to the questionnaire was received. Importantly, the responses covered various types of recipients.

Specifically responses were received from the following companies:

• ABB	• Ormazabal
• Beama	• Oesterreichs Energie
• Chiltern Power	• Power System Partners Ltd
• National Grid	• Ricardo AEA
• ENA	• Langley Engineering

1.4 Summary of Responses

1.4.1 General

It was generally agreed by most respondents that relaxation of voltage limits could have positive effects on the connection of higher levels of embedded generation, under the premise that this could be achieved without adverse impact on network users. It was recognised in various responses that the required network reinforcements and timescales for network connections could be reduced as a result of the implementation of wider limits.

One of the key areas identified in the responses was the need to operate networks with voltage control approaches flexible enough to perform different corrective actions at different times within the daily load curve, in order to maintain operation in an efficient manner at all times. It was argued that a higher flexibility of the limits would potentially increase the need for implementation of these types of measures. One recommendation was to consider active voltage control approaches enabling the voltage profiles and/or the voltage control direction to be flexibly set dependent on network conditions, and that development of such control philosophies should form an implicit part of any review.

Another respondent noted that operating at more extended upper or lower voltages will require wider system voltage co-ordination to be checked through, as current standard tap ranges across voltage levels were based on the expectations of system design at the time. This was also mentioned in another response, where it was noted that while historically the most critical voltage limit has been the lower limit (based on considerations of low lighting output, increased excitation current of motors, poor performance or non-performance of computers and other electronics etc.) and the voltage control in MV networks started as a voltage drop problem, the nature of today's networks (with increased embedded generation and extensive use of cables), has actually biased the problem more towards the issues of voltages higher than nominal.

From a DNO perspective, a potential implication of voltage regulation and tap changers was highlighted, as there could be a risk of running out of taps and losing regulation at certain parts of the networks, thus requiring changes to existing transformers. This also ties in with the interpretation of statutory limits by DNOs (such as the adoption of a 10-minute average approach, as per EN 50160 recommended practice) against the interpretation manufacturers may have when specifying equipment ratings.

A response noted that a potential widening of statutory limits may need to be accompanied by a corresponding review of G59 settings, in order to avoid the risk of more tripping events.

A manufacturer of distribution system transformers confirmed that, from a voltage regulation point of view, no technical issues would emerge from an amendment of voltage limits and the manufacturers would require the target voltage and range for the (secondary) 11kV and 33kV systems, in order to ensure that the tapping ranges offered support these. Some amendments to local specifications related to tapping ranges might need to be considered, but not to the fundamental IEC or British Standards (BS standards).

The issue of engagement and information to the directly connected customers at network voltages of 11kV and 33kV from the early stages of a potential amendment was also pointed out.

1.4.2 Increased upper voltage limit (>+6%)

The consensus among responses was that upper regulation limits are understood to reflect the specification and capabilities of plant installed at 11kV and 33kV voltage levels, particularly equipment life. Upper limits reflect withstand and insulation level and the withstand capabilities of plant to related areas of power quality and transient, overvoltage and voltage stability when operating at such levels. Potential impacts on various types of equipment and functionalities were also identified, including power and instrumentation transformers, overhead lines and cables, circuit breakers and overvoltage protection settings. Therefore, an asset strategy was proposed to address the above issues.

It was pointed out by one of the respondents that increasing voltages during periods of low demand could lead to some significant changes in reactive power absorption and generation within distribution networks, which has the potential to lead to network investments in voltage control.

Another point was that harmonic emission levels could also be increased at times of low system strength, and that negative phase sequence distortion could increase.

Higher voltages would equally cause higher fault levels, which may require marginal sites to be further sectionalised, diluting any benefit to reductions in network losses during peak flows that might otherwise be derived.

On the other hand, permitting higher voltages may have benefits related to active power loss minimisation.

Furthermore, at a higher voltage extreme, the system might start to encroach on its over-voltage headroom for voltage travelling waves (switching, lightning etc.).

1.4.3 Decreased lower voltage limit (<-6%)

It was generally acknowledged that lower limits relate to user protections in relation to historically rotating plant limits, which more recently have been complimented by steady state plant withstand limits for power electronic devices subject to voltage depressions, and to the ability for system and plant to dynamically recover from disturbances, which cause steady state voltage depressions within the normal voltage regulation limits post fault.

The identified benefits of decreasing the allowable voltage were related to the reduction of capacity limitations supporting higher demands, the reduction of network losses and the potential improvement of asset life.

Some of the potential drawbacks associated with lowering the -6% limit were identified as: running voltages low may have a knock-on impact on greater voltage collapse risk and on limiting the emergency response of the distribution system in reducing demand, something which via Grid Code OC6 provisions could be called upon at any time (i.e. by reducing distribution network voltages). Voltage instability/collapse was also raised by another respondent, who highlighted the importance of checking the rigidness of the network at these extremes as voltage instability limits can be remarkably sudden in their onset; this will vary from network to network and is sensitive to how remote the sources of variable reactive power are.

Another point was that it will be important to check that system loading can be accommodated within ratings, checking current (Amps) and not nominal MW or MVA.

The potential under-performance of critical loads, such as MV motors was also covered by the responses.

1.4.4 Step Change limits

With regard to the amendment of voltage step change limits, the issues of system losses and equipment life were pointed out. Attention was brought to implications for sensitive equipment and mal-operation of protective equipment with settings addressing lower step change limits.

Some commercial implications were identified in relation to this issue, involving liability and potential compensations by the DNOs to customers due to equipment damage.

Furthermore, it was noted by one of the respondents that a widened voltage regulation range and larger voltage step change would be, if not applied with care and against a dynamic and flexible operational strategy, in danger of aggravating the challenge of obtaining sufficient reactive power reserves in appropriate forms and locations in the future.

Reference was made to the proposed GC076 modification of voltage dips within the Grid Code, which includes various areas of technical impact and alignment with other standards (for example ER P28) that are currently under consideration.

A response from the manufacturing sector did not identify any technical barriers against the implementation of wider step change limits.

1.4.5 Impact on higher voltages

It was noted that current and historical practice in voltage control at 11kV and 33kV is to design tap change control between voltages in such a way that the lower voltages' regulation is dependent upon the voltage set at higher voltages and the reactive power reserves present at higher voltages can sustain that profile. However, this approach has been based on a historical power flow predominantly from higher voltages downwards, upon which power stations and other sources of dynamic reactive power reserves have been connected supporting those lower voltages where large inert demand supplies have been based. This has led to particular care surrounding the operation and planning of voltage targets at transmission voltages, which support these profiles. As such, any adoption of higher or lower regulation levels of voltage in 11kV and 33kV needs to be accompanied by impact assessment of the regulation of voltage profiles at higher levels.

Furthermore, present management of voltage targets at transmission voltages, including voltage step and dips, is based on the understanding that below present under-voltage settings, there are issues of user supply interruptions relating to rotating plant stability, fault ride through and customer under voltage protections. Operating at lower voltages within the distribution system leads to a greater pre fault and post fault transfer from higher voltages to lower voltages of supporting reactive power resources to maintain such levels, thus leading the overall transmission system towards greater vulnerability against voltage dips and towards increased exposure to voltage collapse conditions, which would require careful dynamic consideration.

It was also noted that due to increased penetration of intermittent embedded generation, such as solar PV, the present voltage control paradigm might be challenged and voltage control strategies will need to be reversed in order to appropriately exploit the dynamic reactive power reserves currently implemented at lower voltages and support the transmission system demand.

1.4.6 Impact on lower voltages

It was observed in a response that if the low voltage limits remain the same, then widening the 11kV range could cause/increase voltage excursions outside the LV statutory limits and drive LV reinforcement.

On the same basis, a response mentioned that HV customers already have transformation equipment, which ensures that their voltage sensitive LV electrical equipment (lighting, variable speed drives etc.) operates satisfactorily without damage. If the HV supply voltage changes this may have an effect on the HV customers’ LV equipment depending on the flexibility of the customers’ existing transformation equipment.

1.5 Conclusions

The overall perception of the project scope by the industry, as recorded in the questionnaire responses, was positive with most respondents noting that they find the proposals put forward interesting and in alignment with the recent evolution of distribution networks.

Some key observations were made on the basis of voltage control and the increased requirement to enhance that aspect as a result of the more complex operation of today’s networks, extended further by a potential widening of voltage limits. A need for wider system voltage coordination was identified.

Technical considerations regarding the implementation of higher upper limits involved voltage withstand characteristics of distribution equipment, with focus on insulation levels and lifetime. Reactive power levels during periods of low demand, harmonic emissions and potentially higher fault levels were additional issues identified. Benefits regarding minimisation of ohmic losses in networks, due to operation in higher voltages, could counterbalance the above barriers.

Technical considerations regarding the implementation of decreased lower limits involved potentially increased risks of voltage collapse, implications regarding OC6 provisions and under-performance of sensitive loads such as motors. Protection coordination was seen as a key factor, while the identified benefits were related to the reduction of capacity limitations supporting higher demands, reduction of network losses due to decreased demand and potential improvement of asset life.

Step change limit amendments were associated with the (mal-) operation of sensitive and protective equipment, possibly resulting in commercial implications for the DNOs. Reference was also made to the proposed GC076 modification proposal on voltage dips within the Grid Code, which includes various areas of technical impact and alignment with other standards such as ER P28 (which is also under review).

Impacts on other voltages, lower and higher than 11kV and 33kV, were identified in the form of more challenging voltage regulation for HV networks (augmented by reverse power flows in modern MV networks of high embedded generation levels) and LV reinforcement requirements associated with the operation of sensitive equipment, such as lighting.

2 The limiting factors for Amending 11kV and 33kV statutory voltage limits

2.1 EQUIPMENT LIMITATIONS

2.1.1 Manufacturing Standards

The review of manufacturing standards was focussed on the voltage withstand characteristics and allowable voltage variations for a wide range of distribution equipment suitable for connection at 11kV and 33kV, including switchgear, generators and motors, transformers and tap changers, other distribution system plant such as overhead equipment, lines and cables, network measurement and metering equipment. An overview of insulation coordination standards is also presented in order to demonstrate the range of standardised rated withstand voltages implemented across the industry.

The two types of rated voltages that are of particular interest for the purpose of this report and the VLA task are reported in the next paragraphs and are defined as:

- The highest voltage for equipment Um, or rated voltage Ur, for most equipment types
- The standard rated short duration power frequency withstand voltage, or Ud, for most equipment types

The highest voltage for equipment, Um, is defined as the highest value of phase to phase voltage Root Mean Square (RMS) for which the equipment is designed in respect of its insulation as well as other characteristics, which relate to this voltage in the relevant equipment standards. This voltage can be applied continuously to the equipment, under normal service conditions.

The standard short duration power frequency voltage is defined as a sinusoidal voltage with frequency between 48Hz and 62Hz, and duration of 60sec. The symbolism of the power frequency withstand voltage for equipment, used in the industry, is Ud

British Standard BS EN 60071 1:2006+A1:2010 “Insulation co-ordination Part 1: Definitions, principles and rules” is the UK implementation of EN 60071 1:2006+A1:2010. It is identical to IEC 60071 1:2006, incorporating amendment 1 of 2010.

Part 1 of this standard applies to three-phase AC systems having a highest voltage for equipment above 1 kV. It specifies the procedure for the selection of the rated withstand voltages for the phase-to-earth, phase-to-phase and longitudinal insulation of the equipment and the installations of these systems. It also gives the lists of the standard withstand voltages from which the rated withstand voltages should be selected.

The standard states that the selected withstand voltages should be associated with the "highest voltage for equipment" (Um). Under normal service conditions, specified by the relevant apparatus committee, this voltage can be applied continuously to the

2.1.2 Insulation co ordination

British Standard BS EN 60071 1:2006+A1:2010 "Insulation co-ordination Part 1: Definitions, principles and rules" is the UK implementation of EN 60071 1:2006+A1:2010. It is identical to IEC 60071 1:2006, incorporating amendment 1 of 2010.

Part 1 of this standard applies to three-phase AC systems having a highest voltage for equipment above 1 kV. It specifies the procedure for the selection of the rated withstand voltages for the phase-to-earth, phase-to-phase and longitudinal insulation of the equipment and the installations of these systems. It also gives the lists of the standard withstand voltages from which the rated withstand voltages should be selected.

The standard states that the selected withstand voltages should be associated with the "highest voltage for equipment" (Um). Under normal service conditions, specified by the relevant apparatus committee, this voltage can be applied continuously to the equipment. The association with the Um voltage is for insulation coordination purposes only and does not relate to human safety of equipment during operation.

The values of standardised Um are listed in Table 2 of the standard (see Figure 1). 12kV RMS rated voltage is specified for systems with nominal voltage of 11kV and 36kV RMS rated voltage for systems of 33kV nominal.

The standard short duration power frequency voltage is defined as a sinusoidal voltage with frequency between 48Hz and 62Hz, and duration of 60sec.

The values of standardised rated short duration power frequency withstand voltages are defined in clause 5.6 and in Table 2 of the standard (see Figure 1). 28kV RMS withstand voltage is specified for equipment rated at 12kV and 70kV RMS withstand voltage for equipment rated at 36kV.

Previous versions of this standard were:

- BS EN 60071 1:1996, which was based on EN 60071 1:1995 and IEC 71 1:1993;
- BS 5622: Part 1:1979 which was identical to IEC publication 71 1 "Insulation coordination", Part 1:1976 "Terms, definitions, principles and rules"

Both these versions specified the same values of rated short duration power frequency withstand voltage, for highest equipment voltages of 12kV and 36kV.

Highest voltage for equipment (U_m) kV (r.m.s. value)	Standard rated short-duration power-frequency withstand voltage kV (r.m.s. value)	Standard rated lightning impulse withstand voltage kV (peak value)
3,6	10	20
		40
7,2	20	40
		60
12	28	60
		75
		95
17,5 [a]	38	75
		95
24	50	95
		125
		145
36	70	145
		170
52 [a]	95	250
72,5	140	325
100 [b]	(150)	(380)
	185	450
123	(185)	(450)
	230	550
145	(185)	(450)
	230	550
	275	650
170 [a]	(230)	(550)
	275	650
	325	750
245	(275)	(650)
	(325)	(750)
	360	850
	395	950
	460	1050
NOTE If values in brackets are considered insufficient to prove that the required phase-to-phase withstand voltages are met, additional phase-to-phase withstand voltage tests are needed.		
[a] These U_m are non preferred values in IEC 60038 and thus no most frequently combinations standardized in apparatus standards are given.		

Figure 1: Standard Insulation levels in BS EN 60071-1:2006+A1:2010

2.1.3 Switchgear Plant

Industry standards pertaining to switchgear plant were reviewed with respect to the aspect of over voltage, which creates stresses to the insulation.

BS EN 62271 1:2008+A1:2011 "High-voltage switchgear & controlgear – Part 1: Common specifications" applies to AC switchgear and controlgear designed for indoor and outdoor installation and for operation at service frequencies up to and including 60Hz on systems having voltages above 1,000V. This standard applies to all HV switchgear and controlgear except as otherwise specified in the relevant IEC standards for the particular type of switchgear and controlgear.

It is the UK implementation of EN 62271 1:2008+A1:2011 and is identical to IEC 62271 1:2007, incorporating amendment 1 of 2011.

Clause 4.1 stipulates the definition of the rated voltage (Ur), which, as mentioned previously, is defined as the voltage which is equal to the maximum system voltage for which the equipment is designed. It indicates the maximum value of the "highest system voltage" of networks for which the equipment may be used. Reference is also made to Clause 9 of IEC 60038.

Standard values of rated voltages within Series I are:

3,6 kV – 7,2 kV – 12 kV – 17,5 kV – 24 kV – 36 kV – 52 kV – 72,5 kV – 100 kV – 123 kV – 145 kV – 170 kV – 245 kV.

So, typically for equipment operating on 11kV and 33kV networks, rated voltages of 12kV and 36kV are selected. This represents a rating for equipment which is higher by approximately 9% than the nominal system voltage.

Clause 4.2 is concerned with the selection of rated insulation levels, i.e. the rated withstand voltage values for lightning impulse voltage (Up), switching impulse voltage (Us) (when applicable), and power frequency voltage (Ud). An extract from Table 1a of the standard, where the above values are presented, is given in Figure 2 below with focus on the power frequency voltage levels.

As can be seen, for the rated voltages of 12kV and 36kV, short duration power frequency withstand voltages of 28kV and 70kV are stipulated respectively as "common values". These refer to application of voltage over a period of 1 minute. The common values refer to voltages which are phase to earth, between phases and across the open switching device. The withstand voltage values "across the isolating distance" are valid only for the switching devices, where the clearance between open contacts is designed to meet the functional requirements specified for disconnectors.

Rated voltage U_r kV (r.m.s. value)	Rated short-duration power-frequency withstand voltage U_d kV (r.m.s. value)	
	Common value	Across the isolating distance
(1)	(2)	(3)
3,6	10	12
7,2	20	23
12	28	32
17,5	38	45
24	50	60
36	70	80
52	95	110
72,5	140	160
100	150	175
	185	210
123	185	210
	230	265
145	230	265
	275	315
170	275	315
	325	375
245	360	415
	395	460
	460	530

Figure 2: Rated insulation levels for rated voltage range I, series I in BS EN 62271-1 Rotating Electrical Machines

This standard supersedes BS EN 62271-1:2008 and the previously applicable BS EN 60694:1997 "*Common Specifications for High-Voltage Switchgear and Controlgear*

Standards"[1]. The latter defines the same voltage ranges, but does not make explicit reference to IEC 60038. The same applies also for BS 6581:1985[2].

2.1.4 Rotating Electrical Machines

British Standard BS EN 60034-1:2010 stipulates requirements for the rating and performance of rotating electrical machines, including generators and motors[3]. With respect to rated voltages and for ratings higher than 1kV, AC machines are classified into various bands of preferred ratings in this standard, ranging between 1kV and 15kV.

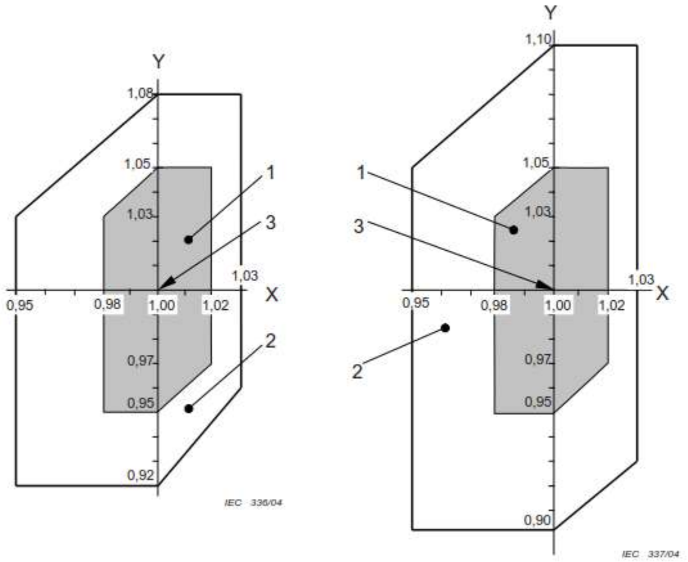
Electrical operating conditions are detailed in Clause 7 of the standard and the form and symmetry of supply voltages and currents are defined for AC motors, AC generators, synchronous machines and Direct Current (DC) motors supplied from static power converters.

Section 7.3 of the standard is concerned with voltage variations during operation of both AC and DC machines. For AC machines rated for use on a power supply of fixed frequency supplied from an AC generator (whether locally or via a supply network), combinations of voltage variation and frequency variation are classified as being either zone A or zone B, in accordance with Figure 3 below, which is extracted from the standard. The plot on the left applies to generators and synchronous condensers, while the one on the right applies to motors.

[1] British Standards Institution, *BS EN 60694:1997 IEC 60694:1996 – Common specifications for high-voltage switchgear and controlgear standards* (BSI, 2002)

[2] British Standards Institution, *BS 6581:1985+AMD 6463:1990 IEC 694:1980 – Common requirements for high-voltage switchgear and controlgear standards* (BSI, 1990)

[3] British Standards Institution, *BS EN 60034-1:2010 – Rotating electrical machines Part 1: Rating and performance* (BSI, 2010)



Key

X axis frequency p.u.

Y axis voltage p.u.

1 zone A

2 zone B (outside zone A)

3 rating point

Figure 11 – Voltage and frequency limits for generators

Figure 12 – Voltage and frequency limits for motors

Figure 3: Voltage and frequency limits for generators and motors in BS EN 60037-1

A machine needs to be capable of performing its primary function, as specified in Table 7 below, continuously within zone A, but need not comply fully with its performance at rated voltage and frequency (rating points in Figure 1Figure 3), and may exhibit some deviations. Temperature rises may be higher than at rated voltage and frequency.

It is also noted in the standard that, in practical applications and operating conditions, a machine will sometimes be required to operate outside the perimeter of zone A. Such excursions should be limited in value, duration and frequency of occurrence. Corrective measures should be taken where practical and within a reasonable time, such as a reduction in power output. Such action may avoid a reduction in machine life due to temperature effects.

Table 7 Primary Functions of machines in BS EN 60034-1

Item	Machine type	Primary function
• 1	• AC generator, excluding item 5	• Rated apparent power (kVA), at rated power factor where this is separately controllable
• 2	• AC motor, excluding items 3 and 5	• Rated torque (Nm)
• 3	• Synchronous motor, excluding item 5	• Rated torque (Nm), the excitation maintaining either rated field current or rated power factor, where this is separately controllable

Item	Machine type	Primary function
• 4	• Synchronous condenser, excluding item 5	• Rated apparent power (kVA) within the zone applicable to a generator, unless otherwise agreed
• 5	• Turbine-type machine, with rated output ≥10 MVA	• See IEC 60034-3

A machine shall be capable of performing its primary function within zone B, but may exhibit greater deviations from its performance at rated voltage and frequency than in zone A. Temperature rises may be higher than at rated voltage and frequency and most likely will be higher than those in zone A. Extended operation at the perimeter of zone B is not recommended.

Therefore, it can be observed that for generators operating at nominal frequency, the voltage variations for operation within zone A are between 0.95pu and 1.05pu. This range is extended to 0.92pu – 1.08pu (i.e. a voltage tolerance of ±8%) for operation within zone B, but it is not recommended to operate a generator at the extreme limits of this voltage range. The lower voltage limit is more onerous for operation at higher frequencies, while the same applies for the higher voltage limit at low-frequency operation.

The operating range for motors is exactly the same as for generators when it comes to operation within zone A, but the allowable voltage tolerance for zone B operation is wider (0.90pu – 1.10pu, i.e. a ±10% tolerance).

The standard does not make reference to any operation of generators and motors outside of the limits of zone B, therefore these limits could be interpreted as absolute in terms of system voltage variations.

It is anticipated that the connection to the 11kV or 33kV network for the majority of rotating machines would be through a transformer or static converter, as for instance is the case for wind farm generators or motors operating at lower voltages, so the above limits would not apply to system voltage variations in those cases.

The 2010 version of BS EN 60034 was derived by European Committee for Electrotechnical Standardisation (CENELEC) from IEC 60034 1:2010 and supersedes BS EN 60034 1:2004, which was withdrawn in 2013. The same requirements regarding voltage and frequency variations, as detailed above, were also stipulated in that standard, as well as in the 1995 and 1998 versions.

2.1.4.1 Specific requirements for synchronous generators

BS EN 60034 3:2008 stipulates specific requirements for synchronous generators driven by steam turbines or combustion gas turbines. Section 4.6 of the standard details the ranges of voltage and frequency for continuous operation. It is recommended that generators should be capable of continuous rated output at the rated power factor over the ranges of ±5% in voltage and ±2% in frequency, as defined by the shaded area of Figure 4 below.

As the operating point moves away from the rated values of voltage and frequency, the temperature rise may progressively increase. Generators will also carry output at rated power factor within the ranges of ±5% in voltage and +3% / -5% in frequency, as defined by the outer boundary of Figure 4, but temperature rises will be further increased. Therefore, to minimise the reduction of the generator's lifetime, it is recommended that operation outside the shaded area is limited in extent, duration and frequency of occurrence. The output should be reduced or other corrective measures should be taken as soon as practicable.

If operation over a still wider range of voltage or frequency or deviations from rated frequency and voltage is required, this should be the subject of an agreement.

It is considered that overvoltage together with low frequency, or low voltage with over frequency, are unlikely operating conditions. The former is the condition most likely to increase the temperature rise of the field winding. Figure 4 shows operation in these quadrants, restricted to conditions that will cause the generator and its transformer to be over- or under fluxed by no more than 5%.

IEC publications 60034 15 of 1995 and 1990 (and their respective EN and BS versions) specified the impulse voltage withstand levels of rotating AC machines with form wound stator coils . Values of rated power frequency withstand voltage, in accordance with IEC 34 1, were associated with respective values of rated voltage, UN. This definition was abandoned in the later IEC and BS EN publications of 2009, although the definition of a power frequency voltage withstand test remained the same.

The power frequency voltage test can be used to test the impulse withstand level of the main insulation. It requires a voltage of (2UN + 1kV) to be applied for 1 minute between the coil terminals and earth; following that, the applied voltage should be increased at a rate of 1kV/sec up to 2 x (2UN + 1kV), and then immediately reduced at a rate of at least 1kV/sec to zero. The corresponding impulse withstand level of the main insulation and the overhang corona protection is then considered as compliant with the requirements of the standard. For a rotating machine rated at 11kV, the testing requirement for a power frequency voltage test is 23kV.

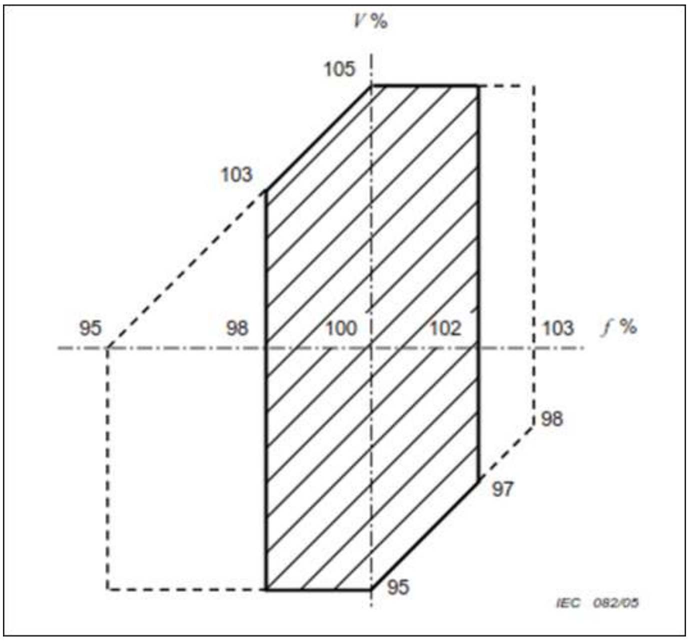


Figure 4: Operation over ranges of voltage and frequency is BSEN 60043-3

2.1.5 Transformers

The suite of British standards that relates to power transformers is BS EN 60076 with part 1, whose last revision was issued in 2011, giving general information about three-phase and single-phase power transformers with the exception of some small and special ones.

Part 3, last issued in 2013, details the standard test voltages for power transformers according to the phase-to-phase highest voltage for equipment applicable to a transformer winding (U_m). The U_m values are the same as those in BS EN 60071-1:2006+A1:2010.

The U_m is selected as the value equal to or nearest above the value of the rated voltage of the windings. For example, for a 33/11kV transformer the U_m values of the two windings would be 36kV and 12kV respectively.

BS EN 60076-3:2013 does not explicitly define U_m in terms of duration of application or operating conditions, but it might be fair to assume that it follows the definition in BS EN 60071-1. U_m values for 33kV and 11kV transformers did not change from the BS EN 60076-3:2001 version or from its predecessor BS 171-3:1987.

BS EN 60076-3:2013 also specifies that U_m is the voltage upon which the dielectric insulation tests are based. U_m along with the rated insulation level characterise the transformer dielectrically.

For transformers with $U_m \leq 72.5$kV, the Applied Voltage (AV) test is one of the routine tests that verifies the alternating voltage withstand capability of line and neutral considered as the counterpart of the power frequency test specified in the latest BS EN 60071 1.

Typical AV test voltages for 11kV and 33kV windings are 28kV (or 34kV) and 70kV respectively.

The same values are given in the 2001 version of the standard, only the test was then called “separate source AC withstand voltage test”. In BS 171 3:1987, the test was named differently (“separate source power frequency voltage withstand test”), but the test voltages (“rated short duration (60sec) power frequency withstand voltages”) were the same

2.1.6 Tap Changers

Standard BS EN 60214 1:2014 specifies the requirements for on load and off circuit tap changers. Um is defined as the highest phase to phase voltage in a three phase system for which the tap changer is designed with respect to its insulation. As with power transformers, the duration of the application of such a voltage and the operating conditions under which this might occur are not explicitly defined.

The Um values of tap changers are the same as the ones in the power transformers standard, i.e. 12kV for 11kV nominal and 36kV for 33kV nominal. The same values, based on European practice, are specified in BS EN 60214 1:2003.

Their predecessors, BS EN 60214:1998 and BS 4571:1994, were only concerned with on load tap changers with a Um of 24kV or higher. Before 1994, the relevant standard BS 4571:1978 on load tap changers did not define or use the term Um.

Test voltages in BS EN 60214 1:2014 are based on the transformer standard BS EN 60076 3:2013 and are the highest given test voltages per Um. Therefore, the AV test voltage is 34kV for 11kV tap changers and 70kV for 33kV tap changers for duration of 60sec. These values apply to both on load and off circuit tap changers.

As with the transformers standards in the previous section, the AV test was named differently in the preceding standard BS EN 60214 1:2003 (“rated separate source AC withstand voltage”). Based on European practice, the 33kV value was the same, i.e. 70kV, but the 11kV value was lower, i.e. 28kV. It is likely that this discrepancy occurred due to the fact that the 34kV value in the 2014 version was introduced to reflect common practice in other parts of the world and was not in line with the insulation coordination standard IEC 60076 1:2011.

In BS EN 60214:1998 and BS 471:1994 the “rated short duration power frequency withstand voltage” (60sec) was 70kV for 33kV on load tap changers, while in BS 4571:1978 the “power frequency test voltage” (60sec) was 70kV, presumably for 33kV nominal voltages.

2.1.7 Overhead Equipment

This section is split into overhead lines (OHL) and surge arresters, with a separate review undertaken for each.

2.1.7.1 Overhead Lines (OHL)

Standard BS EN 50341-1:2012 specifies the general requirements for transmission and distribution OHL of 1kV AC or higher. For GB and Northern Ireland, it is supplemented by BS EN 50341 2 9:2015, which details the pertinent National Normative Aspects (NNA).

BS EN 50341-1:2012 uses the term "highest voltage for equipment" (Um) for the insulation levels of insulators and other equipment connected to OHL. In juxtaposition with IEC 60038:2009 it can be derived that for nominal system voltages (Un) of 11kV and 33kV, the Um values are 12kV and 36kV respectively.

BS EN 50432 1:2005 preceded BS EN 50341-1:2012 and specified the general requirements for OHLs exceeding 1kV up to and including 45kV AC. However, it did not refer to Um values, but only to highest system voltages (Us). With regard to Us then, 12kV and 36kV were the anticipated voltages.

Overhead line insulators are tested for their power frequency withstand voltage levels under wet conditions. Different standards apply to the different insulator types and materials, for example BS EN 60383 1:1998 for ceramic and glass insulator units and BS EN 61109:2008 for composite suspension and tension insulators.

2.1.7.2 Surge Arresters

BS EN 60099 4:2014 details the requirements and testing conditions for metal oxide, gapless surge arresters that are applied to systems with a Us above 1kV. Other parts of BS EN 60099 cover other types of surge arresters. BS EN 60099 5:2013 provides information and guidance on the selection and applications of surge arresters.

Surge arresters' characteristic voltages are defined in a relatively unique manner and are not to be directly compared with similar definitions of other types of equipment.

Their rated voltage (Ur) is one of the fundamental parameters and it is the maximum voltage that the surge arrester can withstand for 10sec. Ur is the reference parameter for establishing the power frequency versus time characteristic of the arrester. This characteristic illustrates the withstand capability of the arrester against temporary over voltages (TOV) sustained for a specified length of time that ranges between 0.1sec and 3,600sec. For an application of 10sec, Ur is the minimum TOV capability of the arrester. Since the TOV characteristic depends on the initial temperature of the resistor elements prior to the application of the TOV, manufacturers give TOV curves with and without prior duty, i.e. with and without prior absorption of energy or transfer of charge.

Standard rated voltage ranges are tabulated in BS EN 60099 4:2014 and range from 3kV to 30kV, with a 1kV step, and 30kV to 54kV, with a 3kV step.

The continuous operating voltage (Uc) is defined as the voltage that can be continuously applied between the surge arrester terminals. Typical values are not provided.

The above voltages are associated with the surge arrester's internal parts and are used during operating duty tests that determine the capability to recover after the injection of thermal energy or thermal charge.

Insulation withstand tests are separate and determine the withstand capability of the external insulation of the arrester housing. The required withstand voltages of the insulating housing are based on the protective levels Upl (lightning impulse protection level) and Ups (switching impulse protective level) with suitable safety factors applied as per the apparatus standard. Withstand values given in the BS EN 60071 1:2006+A1:2010 standard should not be used for surge arresters.

Housings of distribution class arresters shall withstand a power frequency voltage with a peak value equal to the lightning impulse protection level multiplied by 0.88 for a duration of 1 minute.

2.1.8 Cables

IEC 60183 gives guidance on the selection of AC high voltage cables and cable systems with extruded insulation, to be used on three phase alternating systems, operating at voltages exceeding 1kV (in this standard the term "high voltage" is used to cover any cables above 1kV).

Guidance is given on the selection of the conductor size, insulation level and constructional requirements of the cables to be used. In addition, information necessary to enable the appropriate selection to be made is summarised.

The voltages pertaining to the cable and its accessories are defined as follows:

- U0 = the rated RMS power frequency voltage between each conductor and screen or sheath for which cables and accessories are designed
- U = the rated RMS power frequency voltage between any two conductors for which cables and accessories are designed
- Um = the maximum RMS power frequency voltage between any two conductors for which cables and accessories are designed. It is the highest voltage that can be sustained under normal operating conditions at any time and point in a system. It excludes temporary voltage variations due to fault conditions and the sudden disconnection of large loads.

Based on the above, cables are designated by U0/U (Um), in order to provide guidance on compatibility with switchgear and transformers.

With regard to voltages pertaining to the system on which cables and accessories are to be used, the following definitions are made:

- "Nominal voltage of a system" is defined as the RMS phase to phase voltage by which the system is designated and to which certain operating characteristics of the system are related.

- "Highest voltage of a three phase system" is defined as the highest RMS phase to phase voltage which occurs under normal operating conditions at any time and point in a system. It excludes voltage transients (such as those due to system switching) and temporary voltage variation due to abnormal system conditions (such as those due to fault conditions or sudden disconnection of large loads).

Based on the above, it can be deduced that the critical value of voltage for the selection and applicability of a particular cable type for operation within a specified system (under normal operating conditions) is Um. Clause 4.3 stipulates that this voltage should be chosen to be equal to or greater than the highest voltage of the three phase system, as defined above.

Figure 5 below shows the relationship between U0/U and (Um). It can be seen that the Um voltage levels for equipment below 100kV are identical to the ones stipulated in BS EN 60071 (Figure 1).

Rated voltage of cables and accessories (U_0/U kV)	Highest voltage for equipment (U_m kV)
1.8/3 and 3/3; 1.9/3.3 and 3.3/3.3	3.6
3.6/6 and 6/6; 3.8/6.6 and 6.6/6.6	7.2
6/10 and 8.7/10; 6.35/11 and 8.7/11	12
8.7/15	17.5
12/20; 12.7/22	24
18/30; 19/33	36
26/45; 27/47	52
38/66; 40/69	72.5
63.5/110; 66/115	123
76/132; 80/138	145
87/150; 93/161	170
127/220; 133/230	245
159/275; 166/287	300
190/330; 200/345	362
220/380; 230/400	420
290/500	525
405/700; 430/750	765

Figure 5: Relationship between U0 /U and (Um) in IEC 60183 for cables

IEC 60502 Part 1 defines standards for power cables with extruded insulation and their accessories for rated voltages from 1kV (Um = 1.2kV) up to 30kV (Um = 36kV). Part 2 specifically relates to cables with rated voltages from 6kV (Um = 7.2kV) up to 30kV (Um = 36kV).

Table 1 of that standard associates the recommended rated voltages of cables (U0) with the highest system voltages (Um) as per Figure 5 above for three categories of systems operated with different fault clearance times. For the most common categories A and B, a rated voltage U0 equal to 6kV is recommended for a highest system voltage (Um) of 12kV and a U0 of 18kV is recommended for a Um of 36kV.

2.1.9 Network Measuring Equipment

The IEC 61869 series of standards specifies the requirements for the operation of various types of instrument transformers, including Current Transformers (CTs), Voltage Transformers (VTs), Capacitor Voltage Transformers (CVTs) and combined transformers. Electronic VTs and CTs are specified in IEC 60044 Parts 7 and 8 respectively.

According to BS EN 61869 1:2009, the rated primary insulation level for instrument transformers shall be based on the “highest voltage for equipment” (Um) value, which under normal environmental conditions should be at least equal to the “highest system voltage” (Us). For instrument transformers rated at Um = 12kV, the rated power frequency withstand voltage is 28kV, while for those rated at Um = 36kV, the rated power frequency withstand voltage is 70kV. The duration of the test for the power frequency withstand voltage of the primary terminals is 1 minute and it is considered a routine test.

The rated power frequency withstand voltage for the secondary terminals and between sections of interconnected terminals, if any, shall be 3kV and the test shall be carried out for 1 minute.

Standard BS EN 60044 7:2000 “Electronic Voltage Transformers” specifies the same values as above.

BS EN 60044 8:2002 on “Electronic Current Transformers” points to IEC 60044 1, which has now been superseded by IEC 61869 (or the BS EN 61869 1:2009 mentioned above).

2.1.10 Control and Metering Equipment

BS EN 62052 Part 11 specifies the general requirements, tests and test conditions for AC electricity metering equipment. The standard is identical to IEC 62052 11:2003.

Standard reference voltages for meters range between 120V and 480V for direct connection and between 57.7V and 230V for connections through voltage transformers.

Clause 7.1 defines the electrical requirements regarding the influence of supply voltage. A specified operating range of 0.9Un – 1.1Un is stated (where Un is the reference voltage), which is defined as the range of voltage which forms a part of the rated operating conditions.

The extended operating voltage range is set as 0.8Un – 1.15Un and describes extreme conditions which an operating meter can withstand without damage and without degradation of its metrological characteristics when it is subsequently operated under its rated operating conditions. For this range, relaxed accuracy requirements may be specified, as follows:

Voltage dips and short interruptions shall not produce a change in the register of more than x units and the test output shall not produce a signal equivalent of more than x units. The value x is derived from the following formula:

x = 10–6 m · Un · Imax where:

- m is the number of measuring elements
- Un is the reference voltage in volts
- Imax is the maximum current in amperes

When the voltage is restored, the meter shall not have suffered degradation of its metrological characteristics.

The BS EN 62053 series, based on the corresponding IEC standards, define particular requirements for electricity metering equipment in AC, for active / reactive energy and various classes. These standards stipulate the limits of variation in percentage error of various classes of meters and for different influence quantities.

For a voltage variation of ±10%, the allowable limits of percentage error for meters of active energy range between 0.1% and 1.5%, depending on class and selected value of current. It should be noted, however, that for voltage ranges from 20% to 10% and from +10% to +15%, the limits of variation in percentage errors are tripled compared to the values above.

BS EN 60255 1:2010 defines common requirements for measuring relays and protection equipment. Clause 5.2 stipulates requirements for voltage ratings: the rated value of input energising voltage for the primary relay shall be declared by the manufacturer, while for the secondary relays the rated AC values shall be in line with IEC 60044 2 and IEC 60044 5. In terms of the auxiliary energising voltage, the preferred operating range is set within the range of 80% - 110% of the rated voltage.

2.2 Equipment Specifications

2.2.1 Introduction

A large number of equipment specifications and operational manuals were provided by WPD and reviewed with respect to their voltage withstand characteristics. The specifications covered a range of age profiles and, in various cases, made references to historical manufacturing British Standards, which have now been superseded. Nevertheless, these cases are also reported here in order to provide an indication of voltage withstand characteristics of older equipment, which may still be connected to the WPD network.

Particular focus was given on the rated voltage for equipment (or the highest continuous voltage that the equipment can withstand) and the short duration power frequency voltage, i.e. the RMS voltage which the equipment can withstand for 1 minute or longer. Due to the fact that different definitions/measures of withstand characteristics may be provided for the different equipment types in their respective specifications, the above definitions are revisited for each type of equipment below.

The following sections provide an overview of the voltage withstand characteristics for each type of equipment examined.

2.2.2 Switchgear Plant

Specifications and operating manuals from 24 different manufacturers, who have supplied equipment to WPD, were reviewed, with the majority of equipment being suitable for operation on 11kV systems or lower.

The main voltage withstand characteristics for grouped types of equipment in 11kV and 33kV networks are summarised in the tables below (Table 8 and Table 9). A number of manufacturers denote a service/working voltage rather than a rated voltage, e.g. 11kV rather than 12kV, which has been noted in the tables. Furthermore, where power frequency withstand voltage values are not stated (particularly in specifications of older equipment), some test values are proposed within the operating manuals and are noted below. These refer to the application of phase to phase and phase to earth power frequency AC voltages, with the additional note that subsequent tests following initial installation are inadvisable since they may over stress the insulation.

Table 8

Equipment Type	System Voltage (kV)	Rated Voltage (kV)	Duration	Power Frequency Withstand Voltage (kV)	Duration (sec)
Switchgear (generic)	11	12	Cont.	23-24 (test) 28	60
Switch fuse/unit	11	-	Cont.	24 (test)	60
Air insulated switchgear	11	-	Cont.	24 (test)	60
Metal-clad switchgear	11	11 (service) 12	Cont.	24 (test) 28	60
Oil-break switchgear	11	11 (working) 12	Cont.	24 (test) 28	60 (test) 60
Vacuum switchgear	11	12 11 (service)	Cont.	28 24 (test)	60 60 (test)
SF6 Switchgear	11	12	Cont.	22.4 (test) 24 (test) 28	60 (test) 60 (test) 60
Disconnector / Earth switch	11	12	Cont.	28 32	60

In the event that the HV withstand tests are impracticable to perform at full voltage, alternative tests are proposed with lower RMS voltages, with reference to BS 116 and BS 5227. For instance, a proportional value of voltage equal to 60% of the full voltage can be applied for a period of 10 minutes. This corresponds to approximately 14.4kV for equipment rated at 12kV, which is 30.9% higher than the nominal voltage of the system (11kV).

BS 5227:1984 also specified a 1-minute 50Hz power frequency test with an applied voltage equal to 80% of the full value, i.e. 22.4kV for equipment rated at 12kV, which some specifications are referencing.

Table 9

Equipment Type	System Voltage (kV)	Rated Voltage (kV)	Duration	Power Frequency Withstand Voltage (kV)	Duration (sec)
Oil-break switchgear	33	33 (working)	Cont.	70	60 (test)
SF6 Switchgear	33	36	Cont.	70	60
SF6 Disconnector / Earth switch	33	36	Cont.	80	60

2.2.3 On load Tap Changers

The specifications of 5 on load tap changers, some of which date from 1965, were examined. The standards, around which the tap changers had been designed and tested, were not always mentioned, especially for older equipment. One standard that was mentioned was BS 4571:1978.

The rated voltage of the tap changers, possibly for continuous application, ranges between 36kV (9.09% above the nominal 33kV) and 44kV. The latter does not relate directly to any of the IEC 60038:2009 recommended nominal voltages.

The power frequency withstand voltage for the 36kV tap changers is 70kV, while that for 44kV tap changers is 95kV. In most cases it was either specified or possible to determine that the duration of the power frequency test was 1 minute.

2.2.4 Overhead Equipment

This section is split into disconnectors and reclosers and surge arresters, with a separate review undertaken for each

2.2.4.1 Disconnectors and Reclosers

Specifications for various overhead disconnectors and reclosers, some relatively modern, were examined. Although some of the specifications referred to an IEC standard, the majority referred to ANSI standards, therefore the rated voltages (Ur) and the insulation withstand type tests are defined slightly differently.

For the purposes of this report, IEC rated voltages are 12kV, for nominal (Un) 11kV systems, and 36kV, for nominal 33kV systems and the 1 minute power frequency withstand voltages are 50kV and 70kV respectively. The standards that were mentioned were BS EN 60265 1:1998, IEC 60694, IEC 60256 and IEC 56. All of these standards fall at present under the IEC 62271 suite.

In terms of ANSI specified equipment, the rated voltages that can be related to the UK 11kV and 33kV systems are 15.5kV and 38kV respectively. ANSI requires a 1 minute dry power frequency test and a 10sec wet one. For equipment rated at 15.5kV the 1 minute dry power frequency withstand voltage is 50kV, while for equipment rated at 38kV the withstand voltage is 70kV or 80kV. The 10sec wet power frequency withstand voltages is 45kV or 50kV for the 15.5kV equipment, while for the 38kV rated equipment it is either 60kV or 80kV.

Table 10summarises the above.

Table 10: Voltage withstand characteristics of overhead disconnectors and reclosers

Equipment Type	System Voltage (kV)	Rated Voltage (kV)	Duration	Power Frequency Withstand Voltage (kV)	Duration (sec)
OH Disconnector / Recloser	11	12	Cont.	/ 50	10 / 60
		15.5	Cont.	45 or 50 / 50	10 / 60
	33	36	Cont.	/ 70	10 / 60
		38	Cont.	60 or 80 / 70 or 80	10 / 60

2.2.4.2 Surge Arresters

The selection of surge arresters depends very much on the type of earthing of the systems, thus the voltage of the system the device was intended to be installed could not be readily determined from the specifications provided by WPD. As a first step, in order to choose the continuous voltage (Uc) and subsequently the rated voltage (Ur) of the arrester, the highest voltage of the system (Us) is taken into consideration instead of Un.

Specifications of metal oxide surge arresters of one company (Tridelta) were available. Selected models are presented in Table 11 below.

Table 11: Tridelta metal oxide surge arrester voltage specifications

Equipment Type	Continuous Voltage (kV)	Rated Voltage (kV)	Duration (sec)	Power Frequency Withstand Voltage (kV)	Duration (sec)
Surge arrester (metal oxide)	9.6	12	10	55	60
	28.8	36	10	90	60
	9.6	12	10	39	60
	28.8	36	10	84	60

2.2.5 Conclusions

From the range of equipment specifications examined, it can be observed that switchgear specifications follow the general guidelines of the insulation coordination standard 60071 and the high voltage switchgear manufacturing standards (the 62271 series or previous British Standards).

A rated voltage of 12kV and 36kV is typically specified (or system/working voltages of 11kV and 33kV respectively), which is 9% higher than the nominal system voltages of 11kV and 33kV networks, while the short duration (1 minute) power frequency withstand voltage for 11kV networks lies typically within the range of 24kV to 28kV, for factory and site tested equipment. In terms of the 36kV rated equipment examined, the power frequency withstand voltage ranged between 68kV and 80kV.

Notice should also be given to the lower values of power frequency voltage for site testing purposes, implemented for longer periods than the standard 1 minute duration (i.e. 2-15 minutes as per BS 5227). This indicates that these types of equipment can withstand voltages significantly higher than the rated values (in the order of 20% higher) for periods of 5 - 10 minutes.

The selection of on load tap changer specifications was limited. All of the tap changers were rated at either 36kV or 44kV with power frequency withstand voltages of 70kV and 95kV respectively.

Most of the overhead disconnectors and reclosers were specified according to an ANSI standard. Those that were designed around an IEC/British Standards Institution (BSI standard) have a rated voltage of either 12kV or 36kV and power frequency (1 minute) withstand voltage of 50kV or 70kV respectively.

Surge arresters are a unique case of overhead equipment and do not follow the usual definitions or selection processes of insulation coordination.

2.3 Voltage Unbalance

2.3.1 Engineering Recommendation P29

ER P29 is concerned with distribution systems operating at 132kV and below. The scope of the recommendation is to assess proposed new loads that might cause voltage unbalance under normal operating conditions and not to generally specify network limits.

Three phase rotating machines and three phase rectifiers and inverters are highlighted as the potentially most sensitive equipment. As far as rotating machines are concerned, the prime effect is rotor and stator heating, with synchronous machines being the most sensitive, and an unbalance of more than 2% can be tolerated for short periods. With regard to rectifiers and inverters, they inject additional harmonics when supplied by an unbalanced voltage.

Maintaining low levels of voltage unbalance should help to avoid increased losses.

ER P29 recommends that unbalance at the Point of Common Coupling (PCC) caused by a new load should not exceed 2% for any 1 minute period. For no more than 5 minutes every half an hour, the caused unbalance may not exceed 1.3%, for systems with a nominal voltage below 33kV, and 1% for other systems up to 132kV.

Existing unbalance levels should be taken into consideration and in case the resulting combined unbalance appears to be excessive, tighter limits might be implemented following detailed assessments.

2.3.2 BS EN 50160:2010

Voltage unbalance in BS EN 50160:2010 is considered in relation to three phase systems and negative phase sequence at the supply terminals.

Under normal operating conditions and during one week, 95% of the 10 minute averages of the negative phase sequence component should be within 0% and 2% of the positive phase sequence component, for LV ($U_n \leq 1kV$), MV ($1kV < U_n \leq 36kV$) and HV ($36kV < U_n \leq 150kV$) systems. For the HV systems, the limits are indicative.

2.3.3 Potential Issues with Monitoring and Unbalance

It is the common practice of some network operators to monitor voltages only on two phases and use the third signal channel to monitor current. This leads to only one phase pair being utilised in the majority of Automatic Voltage Controller (AVC) and metering schemes.

Regulating system voltages based on only two of the phases might lead to the third phase breaching the statutory limits, even if voltage supply is compliant in terms of voltage unbalance, because the unmonitored voltage may be worst case.

For example, based on the BS EN 50160 voltage unbalance limit of 2% and assuming that two phase to phase voltages are sitting on the statutory limit of 6% above the nominal

33kV, i.e. U1,2 = U2,3 = 1.06pu, the third one, U3,1, can be as high as 1.0919pu, thus exceeding the statutory limit for this nominal voltage level.

Unbalance= (negative sequence RMS) / (positive sequence RMS) □ (≈) max 〖deviation from mean value of voltages〗 /(mean value of voltages)=(1.0919-((1.06+1.06+1.0919)/3))/(((1.06+1.06+1.0919)/3))≈2%

Therefore, it should not be readily assumed that a narrow limit for voltage unbalance will always mean that with one phase to phase supply voltage being monitored, the other two will be within statutory limits. Monitoring of all three phase to phase voltages would provide complete transparency on supply voltage levels and unbalance.

2.3.4 BS EN 60034-26:2006 ‘Effects of unbalanced voltages on the performance of three- phase induction motors’

This standard informs that an unbalanced voltage supply at the terminals of an induction motor will cause even more unbalanced currents to flow in its stator windings (approximately 6 to 10 times the voltage unbalance).

The unbalanced voltage supply introduces negative sequence voltage, which in turn causes the flow of high currents in the windings. Consequently, the temperature rise due to losses under unbalanced supply will be greater than in the case of balanced supply under otherwise the same operating conditions.

Under severe voltage unbalance, the torques associated with the operation of the motor decrease significantly and might not be adequate for the intended application. The speed of the motor at full load is also lower due to higher slip associated with additional rotor losses.

The permissible power of the motor is reduced to less than the rated power if unbalance persists for a long period. Operation of the motor above 5% voltage unbalance is not recommended.

2.3.5 Conclusions

Voltage unbalances, which can be a consequence of single phase loads at the LV, larger single phase loads at higher voltages, dissimilar impedances between the phases particularly with overhead lines or some fault conditions, can cause overheating to three phase electrical machines or the injection of increased levels of harmonics by rectifiers or inverters.

ER P29 specifies a 2% limit for any 1 minute period for proposed new loads that might give rise to voltage unbalance at the PCC. Also, where a balance is used and for no more than 5 minutes every half an hour, the caused unbalance at the PCC may exceed 1.3% for 33kV systems and 1% for higher systems up to 132kV.

BS EN 50160:2010 recommends that voltage unbalance at supply terminals should stay within 0% and 2% for 95% of the 10 minute averages over one week.

Due care should be given to the monitoring of supply voltages by the network operators so that compliance with voltage unbalance recommendations does not mislead to a voltage supply outside the statutory limits.

2.4 LV Impact

Although the scope of the VLA analytical study does not cover potential recommendations on LV steady state voltage limits, it was considered important that impact on the LV systems of any suggested changes at the 11kV or 33kV networks be investigated, since changes at higher voltage systems would probably have some effect downstream with the present common approach with no active LV regulation.

2.4.1 LV Network Templates Data

WPD's LV Network Templates (LVNT) was a Low Carbon Networks Fund (LCNF) Tier 2 project that mainly looked to accurately identify different cluster types of load and voltage profiles, referred to as "templates", at a particular substation negating the need for extensive LV monitoring or reliance on historic assumptions. On a secondary level, LVNT attempted to estimate the degree of legroom at LV and the viability of adapting UK legislation to the EU proposed LV steady state limits of 230V ± 10%.

For the above reason, monitoring of the LV system was carried out both at distribution substations and the end of LV feeders, normally at the supply terminals of various domestic properties (feeder end voltages).

2.4.2 Assessment of Measurements

For the purposes of this report, monitored points at the end of LV feeders were examined. These points were associated with domestic consumers and captured single phase voltage measurements at or electrically very close to the supply terminals for a period of at least one year (10 minute averages).

For 17 monitored supplies in 2013, the analysis revealed that vast majority of the measurements lay above the nominal 230V and all of them within the UK statutory limits (Figure 6). The most common recorded voltages were between 5% and 8% of the nominal 230V. A similar graph was obtained for 2014.

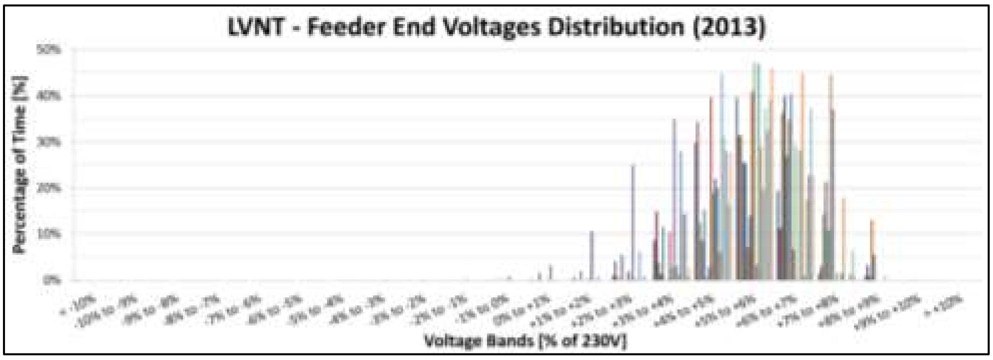


Figure 6: Distribution of monitored feeder end voltages of the LVNT project at 17 different points (y axis is the percentage of the year 2013)

A weighted voltage reduction was then applied to every 10 minute average measurement, i.e. the previously lower voltage instances (denoting greater demand) were reduced proportionally more than the previously higher ones (denoting light loading), while no load instances were not reduced at all; therefore the demand shapes that had been previously recorded were preserved in this exercise. It was assumed that there is no distributed generation connected on the feeders associated with the above 17 monitored locations. Therefore, the higher feeder end voltages (e.g. around 249V) were regarded as times of very low or miniscule demand.

This voltage reduction exercise could be considered to mimic potential future load growth at these 17 points of interest.

For each location, voltages were decreased to the point that they would only exceed the 6% statutory limit for approximately 0.5% of the year. In other words, voltages were reduced to the extent that they touched on the lower statutory limit without essentially breaching it. Between the 17 locations, the highest permitted voltage reduction was 16.8% of the nominal 230V, while the lowest was 7.2% of nominal. The distribution of the reduced voltages at the same locations is shown in Figure 7.

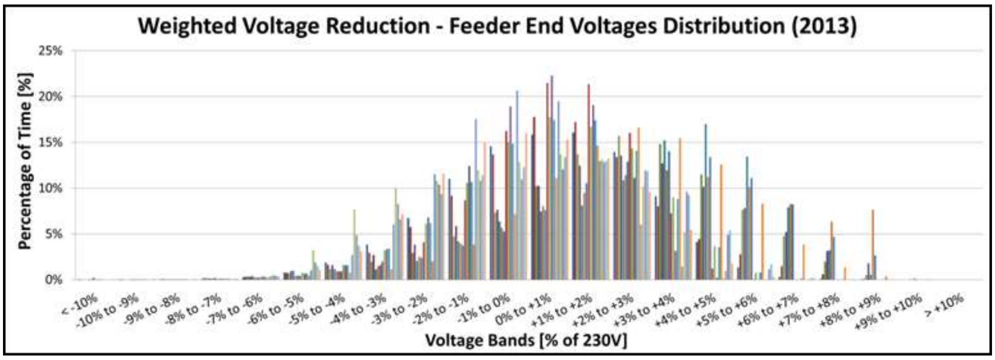


Figure 7: Distribution of feeder end voltages following a weighted voltage reduction of each 10 minute average measurement (y axis is the percentage of the year 2013)

The distribution of the resulting voltages is more centred on the nominal LV voltage (230V). Of particular interest are the voltages in the 6% to 5% band. Between the 17 feeder ends, only ~1% of the year on average would the reduced voltages lie within this band (ranging between 3.24% and 0.43% of the year). This indicates that only a small proportion of the time would the LV feeder end voltages be impacted by a potential lowering of the 11kV statutory limit.

Similar results were obtained for 2014 measurements for 10 feeder end locations. The permitted voltage reductions ranged between 6.7% and 13.8% of nominal. Between the 10 feeder ends, on average for 0.77% of the year the reduced voltages would lie in the 5% to 6% band (ranging between 1.04% and 0.48% of the year).

2.4.3 WPD Voltage complaints

Several system logs of voltage related incidents, primarily on the LV networks, were examined for the purposes of this report and although these logs are not very detailed, some interesting remarks can be made.

Firstly, the vast majority of records related to high LV voltages rather than low ones. This was expected as typically distribution transformers operate near the upper statutory LV limit, i.e. operate at higher tapping.

Secondly, customer complaints associated with high volts at their premises revolved primarily around light bulbs failing prematurely, but also around appliances tripping out or crackling. The recorded high voltages were not significantly higher than permitted and were close to the statutory limits (most measurements lay between 254V and 257V). Therefore, it could be deduced that with regard to domestic electric equipment, the margin above statutory limits before equipment starts to malfunction is small; this seems to be particularly true for lamps.

Voltage complaints are only concerned with steady state supply voltage variations under normal operating conditions and thus exclude concerns around flicker, voltage dips, interruptions and abnormal system conditions. A voltage complaint is created when a customer informs WPD of a perceived supply voltage problem, so complaints are customer driven.

2.4.4 Conclusions

Examined feeder end voltages, monitored during the LVNT project, lie primarily near the upper statutory limit for the majority of the time. A preliminary exercise was carried out based on these monitored data, which showed that a potential reduction of the HV statutory limit would only drive LV feeder end voltages outside the LV statutory limit for a small amount of time, even at the extreme conditions of increased loading and without any additional voltage regulation. However, further detailed system studies should be undertaken to inform any future decisions.

Voltage complaints received by WPD were also mainly concerned with high voltages at consumer premises (measured 254V – 257V). The most common evidence of high voltages was light bulbs failing, thus indicating that they could be a constraint to a potential increase of supply voltage limits.

3 Where statutory limits for 11kV and 33kV networks could be amended

Investigations of the impact of a potential amendment to the current statutory steady state limits (ESQCR 2002) and the voltage step change limits were carried out.

In particular, a system study was undertaken to understand the potential extent of network (33kV and 11kV) that would be operating outside the current statutory limits, if the limits were to be changed in the future. Also, a preliminary exercise was undertaken that considered data collected during WPD’s Low Voltage Network Templates (LVNT) project and that examined the length of time that LV feeder end voltages might lie outside LV statutory limits, if the limits at 11kV or 33kV were amended.

Lastly, other aspects of impact were considered through literature review.

3.1 System Study – Impact on Locations

The study considered the 33kV and 11kV networks below the Bridgwater and Street BSPs in WPD’s South West licence area. The models consisted of an equivalent infeed from 132kV, the 33kV network below the two BSPs, the 33/11kV primary transformers and the downstream 11kV networks.

3.1.1 Method

In order to understand the effects of widened steady state voltage limits on the 33kV and 11kV network, two demand and generation cases were examined:

- A low voltage case, with loads at their maximum demand values, and all generation offline
- A high voltage case, with loads at assumed minimum demand values, and all generation online and at full output

The main assumptions included:

- Thermal limits of network components were not considered
- Scaling of load and generation was applied uniformly across the model
- The assumed minimum demand was 36.5% of maximum load

- For the loads, both real and reactive power demand were scaled equally
- For the generators, only the real power output was scaled

3.1.2 33kV Results

33kV nodes corresponded to transformer or substation connections points.

Figure 8 shows a cumulative frequency plot of 33kV node voltages when the system loading (low voltage case) or generation (high voltage case) within the upstream model is increased until the worst case voltages hit the widened steady state voltage limits. Both the high and low voltage cases are shown.

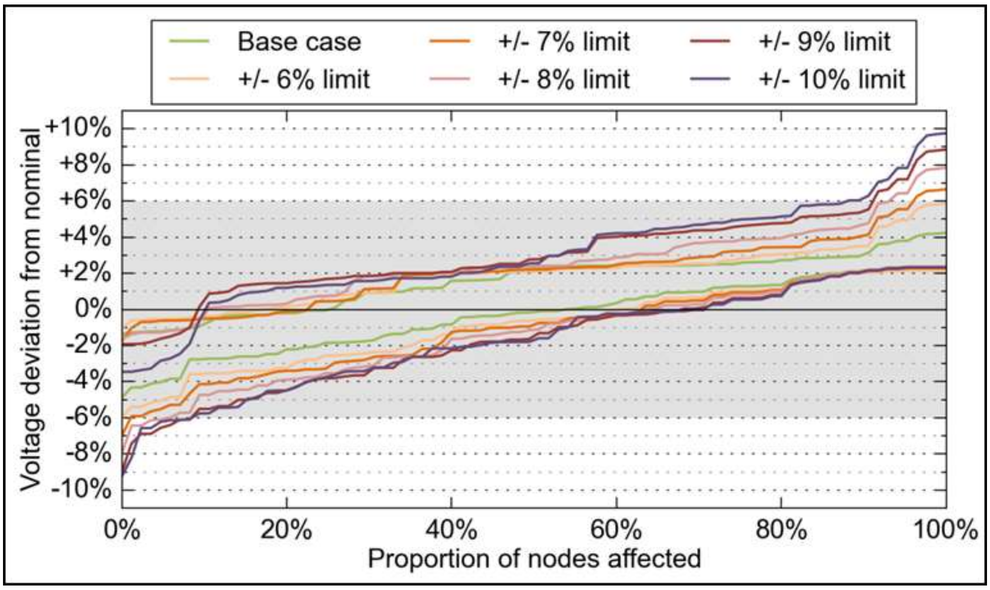


Figure 8: Cumulative frequency plots of steady state voltages for the high and low voltage cases when widened voltage limits are applied at 33kV (results from upstream model)

Figure 9 shows the proportion of 33kV nodes that would fall outside the current statutory steady state voltage limits if widened voltage limits were applied. No 33kV node was found to experience both over- and under-voltages.

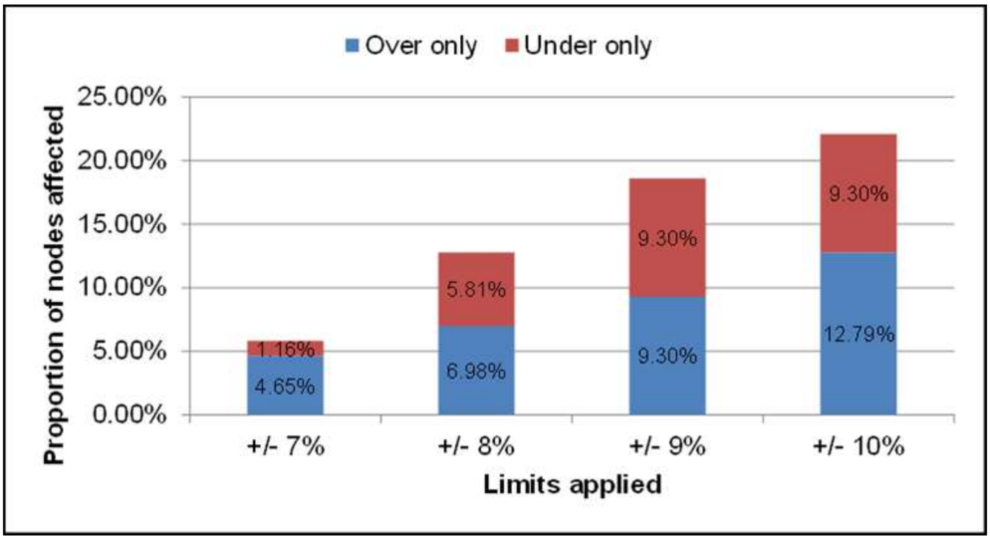


Figure 9: Proportion of 33kV nodes outside the current statutory limits

The fully exploited ±7% widened limits led 5.81% of the total nodes to go above the existing +6% upper statutory limit (4.65%) or below the 6% lower statutory limit (1.16%).

The effect on 132/33kV and 33/11kV transformer tap operation was assessed. With network operating at the 10% limit, no transformers hit the limits of their tap changers. At the +10% limit a single 33/11kV primary transformer (Burnham) hit the limit of its tap operation and could not control voltage to within the AVC bandwidth.

3.1.3 11kV Results

11kV nodes corresponded to points where 11kV/LV transformers were connected.

Figure 10 is a cumulative frequency plot of 11kV node voltages. It is clear to see that the maximum voltages are only affected for the feeders containing generation (the nodes on the top right).

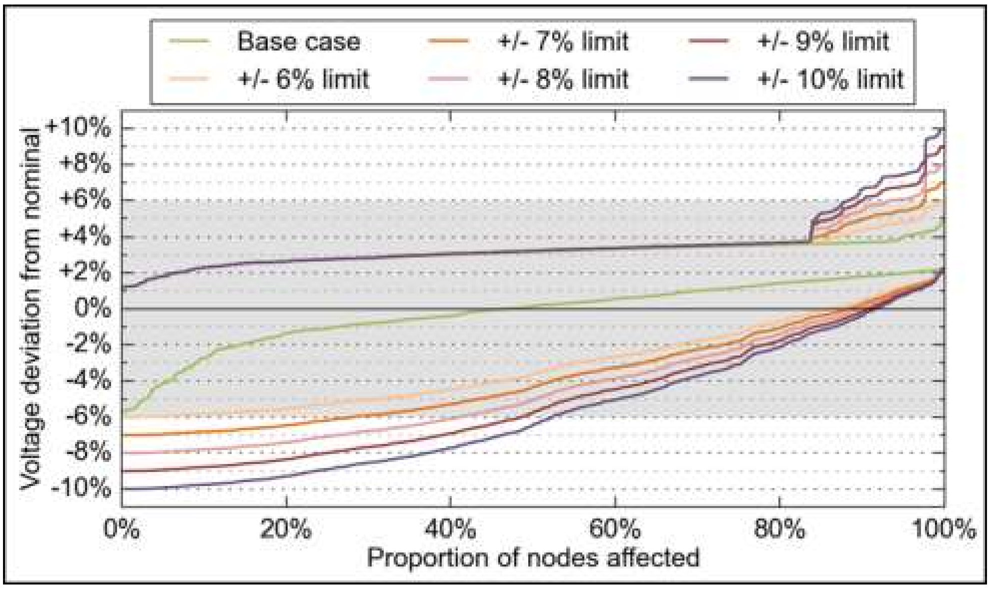


Figure 10: Cumulative frequency plots of steady state voltages for the high and low voltage cases when widened voltage limits applied at 11kV (results from the downstream models)

Figure 11 shows the proportion of 11kV nodes that would fall outside the current statutory steady-state voltage limits if widened voltage limits were applied and then fully exploited within each feeder.

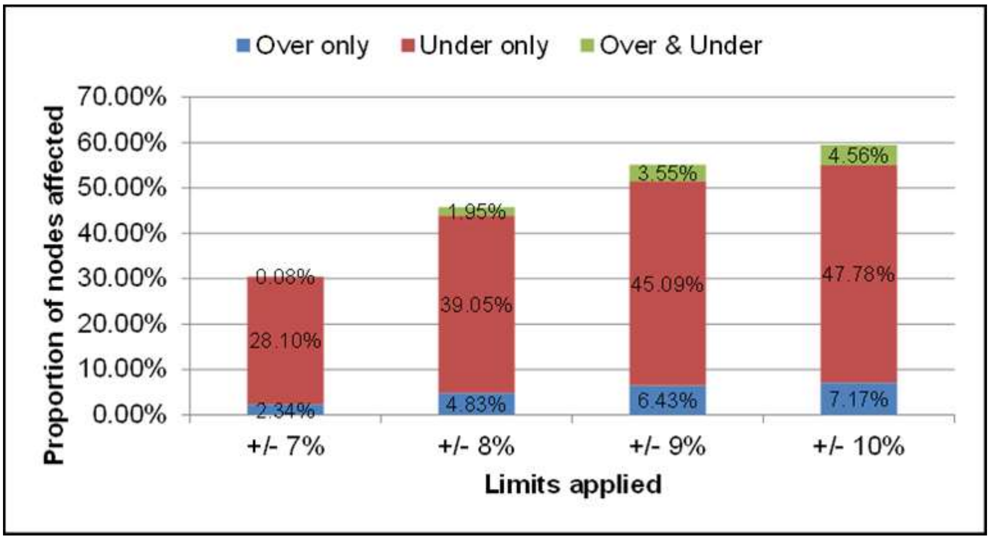


Figure 11: Proportion of 11kV nodes outside the current statutory limits

For example, with limits widened to ±7% and after achieving their full exploitation on each 11kV feeder, 30.51% of the total studied 11kV nodes went outside the existing limits (28.10% went above the +6% limit, 2.34% went below the 6% limit, while another 0.08% exceeded both ±6% limits).

3.1.4 Effect on Voltage Step Change

Fundamentally, voltage step change is determined by the currents flowing through the network before a contingency event, and the difference in impedance that a contingency will cause.

The results of the steady state voltage limits study have shown that significant increases in load and generation would be required to exploit the widened steady state limits. Therefore, network reinforcement would be required in order to provide enough thermal capacity to allow for additional load and generation. This would lower impedances and thus decrease voltage step changes. Therefore, it is difficult to assess where applying widened steady state limits would result in voltage steps greater than the existing limits and whether increased voltage step change limits would be required.

If the exploitation of widened steady state voltage limits in particular areas were to lead to voltage step change outside the current limits, this could be mitigated through the use of solutions such as an SVC to reduce the reactive power flow through the transformers and associated voltage step change.

3.2 Low Voltage Network Templates – Impact on Time

LVNT was a LCN Fund Tier 2 project that mainly looked to accurately identify different cluster types of load and voltage profiles, referred to as “templates”, at a particular substation negating the need for extensive LV monitoring or reliance on historic assumptions.

For the purposes of VLA, monitored points at the end of LV feeders were examined. These points were associated with domestic consumers and captured single phase voltage measurements at or electrically very close to the supply terminals for a period of at least one year (10 minute averages).

A weighted voltage reduction was applied to every 10 minute average measurement that preserved the monitored demand shapes and that could be considered to mimic potential future load growth at examined points. For 2013 and for 17 feeder ends, voltages were decreased to the point that they would touch on the lower statutory limit (99.5% of the time above 6%). The distribution of reduced voltages is shown in Figure 12.

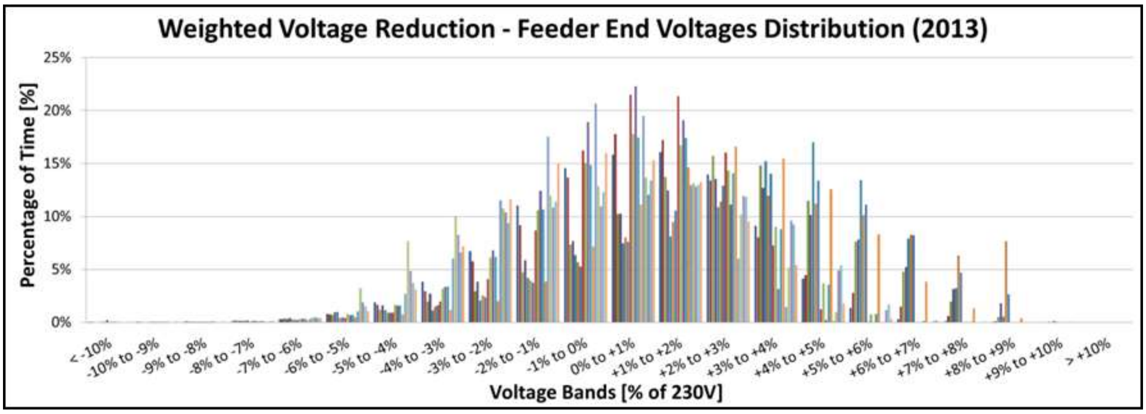


Figure 12: Distribution of feeder end voltages following a weighted voltage reduction

Between the 17 feeder ends, only ~1% of the year on average would the reduced voltages lie within the “ 5% to 6%” band (ranging between 3.24% and 0.43% of the year).

Similar results were obtained for 2014 measurements for 10 feeder end locations. On average, for 0.77% of the year the reduced voltages would lie in the “ 5% to 6%” band (ranging between 1.04% and 0.48% of the year).

This indicates that only a small proportion of the time would the LV feeder end voltages be impacted by a potential lowering of the 11kV statutory limit.

3.3 Other Considerations to Changing Limits

3.3.1 G59 Protection Settings

The scope for a potential amendment of step change limits ought to be examined in association with steady state limits and their present and proposed values. A voltage step change may occur with an initial voltage level which is not the nominal system voltage and, in extreme cases, may be the upper or lower statutory limit of the steady state voltage.

As per the Distribution Code section 4.2.3.3, voltage step changes of ±10% are acceptable for design purposes in the cases of unplanned outages, such as faults and for energisation of sites with multiple transformers, on the condition that these do not become more frequent than once per year .

On that basis, a 10% step when operating at 0.94pu results in a voltage equal to 0.9 x 0.94pu = 0.846pu, i.e. a voltage 15.4% lower than nominal. A +10% step when operating at 1.06pu would give 1.1 x 1.06pu = 1.166pu, which is 16.6% higher than nominal voltage.

The above are of particular importance to generation protection requirements. ER G59 sets the following under voltage and over voltage protection settings for generating plant connected at HV (clause 10.5):

- Under voltage Stage 1 protection should have a setting of 13% and a time delay of 2.5sec
- Over voltage Stage 2 protection at HV should have a setting of +13% with a time delay of 0.5sec

So, based on these settings, G59 protection would operate if the under voltage of 15.4% was sustained for 2.5sec and if the over voltage of 16.6% was sustained for 0.5sec.

This would imply that, if the statutory limits were widened, there would be need to review these G59 settings, so a smaller under voltage or over voltage limit may be needed to avoid G59 protection operation. Moreover, this would create scope for review of permitted step change limits, with consideration of a potential reduction.

3.3.2 LV Impact – Lighting

The limits for voltage step change in ER P28 (3%) were based on laboratory tests and field experience regarding the visual annoyance of consumers to excessive flicker (Pst, short term flicker severity). ER P28 was issued at a time when tungsten filament lamps were in widespread use, hence the design of the IEC flickermeter (IEC 61000 4 15:2010), which is still used for flicker assessment, was based on a 60W tungsten filament lamp as this was regarded to be the most sensitive lighting source at the time.

It has been demonstrated by the CIGRE C4.108 working group that a selection of typical modern lamps are less sensitive to sinusoidal voltage fluctuations than a 60W tungsten filament lamp.

However, a study by the University of the Basque Country demonstrated that modern lamps are not always less sensitive to flicker. For certain ranges of modulation frequencies, modern lamps are more sensitive to either sinusoidal or rectangular voltage fluctuations. Under real, more complex fluctuations, a more unpredictable behaviour was observed, which does not always correlate with behaviour under simpler fluctuations, thus further complicating the analysis.

Frank Deter (Miele) in a presentation recommends the preservation of the IEC 61000 3 3 flicker curve and the CIGRE working group cautioned the readers of its report about the limited selection of modern lamps and also about the limited number of tests carried out, therefore recommending additional, wider testing before generalising conclusions.

So, despite the evolution of lighting technology, the existing flicker curve based on the 60W incandescent lamp is still relevant, in combination with the principle that any new lamp should not be more sensitive to flicker than this reference lamp. Careful consideration and extensive research are necessary prior to any possible amendment of the IEC 61000 3 3 flicker curve, the IEC flickermeter or even the ER P28 step voltage change limits.

3.3.3 Voltage Unbalance

Voltage unbalances, which can be a consequence of single phase loads at the LV, larger single phase loads at higher voltages, dissimilar impedances between the phases particularly with overhead lines or some fault conditions, can cause overheating to three phase electrical machines or the injection of increased levels of harmonics by rectifiers or inverters.

ER P29 specifies a 2% limit for any 1 minute period for proposed new loads that might give rise to voltage unbalance at the PCC. Also, where a balance is used and for no more than 5 minutes every half an hour, the caused unbalance at the PCC may exceed 1.3% for 33kV systems and 1% for higher systems up to 132kV.

BS EN 50160:2010 recommends that voltage unbalance at supply terminals should stay within 0% and 2% for 95% of the 10 minute averages over one week.

Regulating system voltages based on only two of the phases might lead to the third phase breaching the statutory limits, even if voltage supply is compliant in terms of voltage unbalance, because the unmonitored voltage may be worst case. Due care should be given to the monitoring of supply voltages by the network operators so that compliance with voltage unbalance recommendations does not mislead to a voltage supply outside the statutory limits.

3.4 Assessment of Commercial Impact of Changing Limits

3.4.1 Demand and Energy Consumption

A potential widening of voltage limits would mean that slightly lower voltages would be allowed at the consumers' terminals, which could potentially be associated with lower voltage set-points on primary transformers or the allowance for larger voltage drops along 11kV feeders. This would have a decreasing effect on peak demand and energy consumption, similarly with UK and global applications of Conservation Voltage Reduction (CVR). Indicatively and by conservative estimates, an average reduction in steady state voltage in the region of 1-2% could be expected to create a demand reduction of at least 1%, which would also drive the energy consumption down.

Higher voltages would be experienced only on generation feeders, which would have an effect on a limited number of nodes across the network, therefore would not be expected to increase energy consumption significantly.

3.4.2 Equipment replacement

A direct commercial impact from the modification of voltage limits might arise from the need to replace equipment. Equipment may need to be replaced if the modified voltage limits were outside of their identified capability to withstand higher voltages, or operate within extended ranges of voltage (either higher or lower).

Based on the review of equipment standards and specifications it is anticipated that any proposed new voltage limits would be within equipment capabilities, provided that the new range of voltage variation would not be greater than ±10% and that operation in the extreme ends of that range would only be allowed for short periods of time, in the order of minutes.

Therefore, it is not envisaged that significant replacements of equipment would need to take place in 11kV and 33kV networks.

3.4.3 HV Voltage regulation

With regard to the voltage regulating operation of primary transformers within the examined area, as shown by the modelling study, even at the extreme ends of applied voltage of ±10% only one transformer out of the 15 primary substations hit the limit of its tap operation. Considering the fact that the modelling scenario examined represented an extremely onerous condition whereby generation output was increased by a scaling factor in the order of 400%, it is estimated that no issues would be expected to arise with regulating voltages on the HV network, due to the widened voltage limits.

3.4.4 LV Voltage Regulation

It can be deduced that the maximum variation of the HV voltage that typical distribution transformers can manage whilst LV system voltages remain within statutory limits is as follows:

- Maximum LV limit = +10%
- Minimum LV limit = -6%
- Maximum LV voltage variation defined by LV limits = 10 - (-6%) = 16%

This variation can be broken down into various parts including the voltage drop along the LV circuit and the distribution transformer. Typical assumptions correspond to a combined maximum voltage drop across the LV network of -8%. This leaves 8% (16 - 8%) for the voltage variation on the HV side of the distribution transformers.

The granularity of the taps available on the existing fixed tapped distribution 11kV/LV transformers should be taken into consideration. The tap steps are 2.5% so there is the possibility that a tap may not be entirely appropriate for the apparent system voltages. The maximum bandwidth that the tap step might be out from the most optimum setting is 1.25%, so this leaves approximately 6.75% (i.e. 8% - 1.25%) for the voltage variation of the HV system.

The appropriate tap position of the 11kV/LV transformer depends upon how the average 11kV nodal voltage sits against the +10% / -6% LV limits, along with the inherent voltage gain of the distribution transformer (typically 11kV/433V). If this average varies throughout the year, then the fixed tap position may be changed seasonally.

So, there is need for alternative ways for regulating voltage if the daily voltage at a particular 11kV node varies by more than 6.75%. The alternative may be an on load tap changer (OLTC), a voltage regulator or, ultimately, the replacement of the entire distribution transformer.

The worst case HV voltage variation occurs at the remotest nodes and comprises variation due to the granularity of control at the upstream transformer and variation due to power flow through the 11kV circuit.

On an HV feeder with no generation, the minimum voltage is -6% and maximum voltage is approximately +0.75% (or +0.0075pu) higher than the AVC setting of the primary transformer, which represents half of its bandwidth. If the AVC set point is set at 1.03pu (as was the case for the transformers examined in the modelling study), the total voltage variation of 6.75% (or 0.0675pu) results in a minimum voltage of the HV feeder of 0.97pu (or 3%) (i.e. 1.03pu + 0.0075pu – 0.0675pu = 0.97pu), which allows the system to maintain LV voltages.

Assuming that no generation is present on the HV feeders (i.e. assuming the low voltage scenarios of the modelling study only), we can see in Figure 8 that for the existing voltage limits of ±6% and loading on feeders scaled up in order to fully exploit the 6%, 57% of the nodes along the feeder will reach 0.97pu or lower, thus requiring voltage regulation that could not be provided by existing LV voltage control mechanisms.

Under the same premise, if the voltage limits were allowed to be ±7%, then using the same graph it can be noted that 65% of the nodes would have voltages equal to or lower than 0.97pu, assuming no generation on these feeders and thus maximum voltage drop from the upstream primary transformer to the distribution transformer. So, by extending the voltage limits to ±7%, approximately 8% (65% - 57%) of the nodes (i.e. distribution transformers) would require additional voltage regulation mechanisms. For the scenario of ±10% limits, approximately 18% of the nodes would require additional voltage regulation or replacement.

If generation was connected to these circuits, then there would be an associated voltage rise and the permitted voltage drop before additional LV voltage regulation was required would be less than the 6.75% mentioned above. If the maximum voltage rise along the feeder due to reverse power flow was 1%, then the allowable voltage drop would be 5.75%.

Due to the unpredictable nature of DG connections, with regard to location and export capacity, a full assessment of these types of scenarios cannot be undertaken. It should be noted though that the connection of large volumes/capacities of DG would typically be accompanied by reinforcement of the 11kV network, so the requirement for additional voltage regulation would be relatively alleviated.

Overall, the percentage of distribution transformers requiring reinforcement or replacement will depend upon the following:

- The numbers of HV feeders on which the demand is increased to realise the benefits of the widened voltage limits

- The numbers of HV feeders on which generation is installed and the variation in voltage between maximum demand and maximum export is greater than 6.75%

3.5 Recommendations

With regard to a potential modification of the steady state voltage limits, as a provisional recommendation, subject to further investigation and consultation, it would be advisable to adopt a probabilistic approach (similar to the requirements relating to weekly measurements and the differentiation per voltage ranges existing in EN 50160). More restrictive overall limits than the ones stated in EN 50160 would need to be applied, in order to ensure satisfactory conditions of operation for the most sensitive equipment on the 11kV network.

A maximum limit of ±10% should be considered for the 33kV network (treated as absolute, i.e. relating to 100% of voltage measurements over a specific period). As a consequence of some equipment specifications only requiring a withstand of 9% above nominal voltage for continuous operation, it is recommended that operation above +9% and below +10% is restricted by an appropriate percentile of measurements within a defined period, for example in the order of 99% over the measured period as applied in EN 50160.

As far as voltage limits at 11kV are concerned, a tighter range than at 33kV would need to be considered due to issues pertaining to voltage regulation and equipment sensitivity. A point for consideration, which was raised during the VLA workshop, was that, due to the manner in which LV voltage is regulated via the 11kV network and the tap ratio/settings of the distribution transformers, it would be difficult to realise a higher upper statutory limit at 11kV without concurrent change of the LV upper statutory limit. Some selective adjustments on tap settings of distribution transformers could resolve this issue in problematic areas. A decreased lower 11kV limit would be easier to accommodate after the LV harmonisation to the EU has been implemented (230V +/-10%). However, it is recognised that any proposed amended limits could not be realised in all parts of the 11kV networks, as is currently the case with the existing ±6% limits.

A modification of steady state voltage limits at 33kV would not be expected to create problems on the downstream network, due to the larger flexibility of the regulation of voltages across the primary transformers, i.e. wider tapping range and automatic voltage control. A review of AVC target voltages would be required on an individual basis, accounting for the maximum amounts of generation and demand along the associated 11kV feeders.

Voltage unbalance needs to be monitored closely by measuring voltage in all 3 phases, which is something that some DNOs have already begun implementing, in order to avoid excursions of the steady state voltage beyond the proposed limits in any unmonitored phases.

An amendment to steady state limits would need to be accompanied by a review of the protection coordination recommendations and the G59/G83 under voltage and over voltage protection settings in particular. The ER P28 WG is currently reviewing the voltage step change limits from various perspectives, which include the G59/G83 settings, and is expected to issue recommendations by the end of 2016. Caution should be given to the fact that widening the steady state voltage limits would require a similar increase/decrease of those settings or re-consideration of the effect of the voltage step change limits.

With regard to voltage step change limits, reference should be given to the draft paper written by Simon Scarbro (WPD) proposing planning limits for RVCs, which has also been a point of discussion for the ER P28 WG. In that, the 3% limit for infrequent planned events is proposed to be maintained; the maximum 10% limit is also to be maintained for infrequent unplanned events, such as faults or energisation of multiple transformers (as per DPC 4.2.3.3 of the Distribution Code) and a probabilistic approach is proposed for events with frequency that sits between that of the aforementioned phenomena. Values of maximum voltage change and residual voltage change (as included in the latest version of the Grid Code) are proposed to be adopted and implemented in the setting of voltage step change limits, while different limits would be applied for different event durations to ensure coordination with protection settings implemented at 11kV and 33kV networks and avoid unnecessary tripping operations. The recommendations extended in the paper are not to be treated as final at this stage; the final report of the ER P28 WG in 2016 will need to be reviewed and considered within the overall scope of an assessment of voltage limits, both steady state and step change.

It is recognised that pertinent research is being conducted in areas related to the VLA analytical study and it is anticipated that additional work will be undertaken as part of the formal consultation process, associated with exploring future change, between stakeholders and various working groups concerned with voltage limits. These areas could include the localised examination of distribution networks, particularly the ones experiencing issues of extreme voltages, and further consultation with equipment manufacturers and their representative bodies, such as British Electrotechnical and Allied Manufacturers' Association (BEAMA). Other focus areas could be the consultation with customers connected to the network, liaison with distribution network regulators in the UK and the EU, further system modelling to examine potential impacts in other parts of the UK network and more extensive dissemination of learning between DNOs with regard to particular cases of application of wider voltage levels (potentially through the inauguration of a working group looking specifically at the assessment of voltage limits in 11kV and 33kV networks). Coordination with other working groups such as the ER P28 WG and the LV harmonisation group would be advisable, as well as with other corresponding European bodies.

4 Specification and guide to implementation of an EVA power system analysis tool

4.1 Introduction

4.1.1 Background

Distribution networks expect increasing penetration of low carbon generation and demand technologies in the short and medium term. Generation from low carbon technologies (solar photovoltaic and wind) is both variable and unpredictable. Increased penetration of heat pumps and electric vehicles will increase electricity demand and, in the case of electric vehicles, perhaps increase variability of electricity demand.

With the addition of these technologies to the network, system voltage and power flows will become unpredictably variable. Integrating significant levels of distributed generation has caused voltage management and thermal issues within electricity distribution networks[4]. These problems are worsened during outage conditions.

Current practice has network planning of customer connections assume the most onerous conditions during normal operation and electricity network outages. Once customers are connected, passive operation is assumed. These planning practices can lead to underutilisation of the present network capacity. Outage planning requires complex studies to assess the continued connection of distributed generation during outage conditions. During abnormal and unexpected constrained operation (for example, following faults) existing distributed generation customers are usually switched off until normal operation is resumed.

Current planning tools have been designed for passive network operation. Using these tools, it is challenging to model complex network conditions accurately and integrate innovative technologies.

Therefore, one aspect of the Network Equilibrium Project is the creation of an Advanced Planning Tool (APT) that will enable better network control, network planning and outage planning on distribution networks with increasing penetration of variable generation and demands.

[4] Evidence for this can be found in the IET's Power Networks Joint Vision report "Electricity Networks – Handling a shock to the system" and in a recent external study for WPD (focusing on the South West network).

4.1.2 Report structure

The report is structured as follows:

- In Section 4.2 the aims, objectives and scope of the Advanced Planning Tool are described;
- In Section 4.3 the functional and non-functional requirements specification of the Advanced Planning Tool are described;
- In Section 4.4 the implementation of the Advanced Planning Tool is described; and
- Section **Error! Reference source not found.** is the conclusion; this includes a description of learning from the project to date.

4.2 Aim and objectives of the APT

The aim of the Advanced Planning Tool is to deliver nodal analysis software and input data to enable the calculation of historical and forecast of power flows and voltage profiles across the 11kV, 33kV, 132kV and 400kV networks in the trial area.

This aim will be achieved through the delivery of the following objectives:

- Creation of a nodal model of the network within the study area in IPSA Power software;
- Creation of seasonal, time and weather driven profiles of expected generation from wind generators, solar photovoltaic generators and synchronous generators;
- Development of a generalised model of the drivers of electricity demand:
  - Analysis of historic demand data to establish patterns on long-term, seasonal, weekly and daily timescales;
  - Assessment of the correlation between of temperature and solar irradiance to demand;
- Creation of a forecasting tool that generates electricity generation and demand profiles based on two day ahead weather forecast data supplied by the Met Office;
- Development of a desktop based user interface for specifying power system simulations and viewing results;
- Creation of IPSA plug-in component models of novel technologies, including[5]:
  - System voltage optimisation technique;
  - Flexible power link devices;
  - Alternative generator operation schemes; and
  - STATCOM devices.
- Validation of the advanced planning tool against PSS/E and complete user acceptance tests;

[5] The development of the plug-ins, validation of the tool, user documentation, and support and maintenance will be described in SDRC-4.

- Provision of user documentation for tools created, training packs and training courses; and
- Provision of technical support until 14th June 2019.

4.3 Specification of the APT

In Section 4.3 the specification of the APT is described such that the aim and objectives are met. The overview in Section 4.3.1 outlines the requirements associated with each objective in more detail. Sections 4.3.2 and 4.3.3 outline the functional and non-functional requirements specification of the APT, respectively.

4.3.1 Overview

4.3.1.1 Creation of a nodal model of the network within the study area in IPSA Power software

A nodal model of the study area, shown in **Error! Reference source not found.**, is required to enable steady state load flow and voltage analysis to be undertaken by the Advanced Planning Tool, using network data provided by WPD from its PSS/e and DINIS packages. The nodal model shall include:

- 400kV and 132kV network modelled for the entire WPD southwest region in order to capture any effects due to the interconnections outside the trial area at these voltage levels;
- 33kV network modelled for a total of 13 Bulk Supply Points (BSPs) and all connected Primary networks for these:
    - Bowhays Cross BSP;
    - Bridgwater BSP;
    - Exeter City BSP;
    - Exeter Main BSP;
    - Radstock Main BSP;
    - Sowton BSP;
    - Street BSP;
    - Taunton Local BSP;
    - Tiverton Junction BSP;
    - Woodcote BSP;
    - Paignton BSP;
    - Totnes BSP; and
    - Yeovil BSP.
- The approximately 130 Primary Substations associated with all these BSPs[6] and a reduced[7] model of all feeders off each Primary Substation busbar; and
- For remaining BSPs, aggregated demand and generation at 132kV busbars.

[6] Except the last three BSPs listed above; only 33kV was modelled for Paignton BSP, Totnes BSP and Yeovil BSP

[7] The reasons for, and methods for modelling, a reduced 11kV network are described throughout this document.

Additionally:

- To ensure the APT can be used for the analysis of apparatus such as Flexible Power Links, the 33kV and 11kV feeders which can interconnect with other BSPs or Primaries shall include pairs of nodes at the (potential) interfaces.
- The network model should be expandable such that it can incorporate additional BSPs and their associated lower voltage networks; users should be able to update the model including changes to network connectivity, and connected generation and demand.

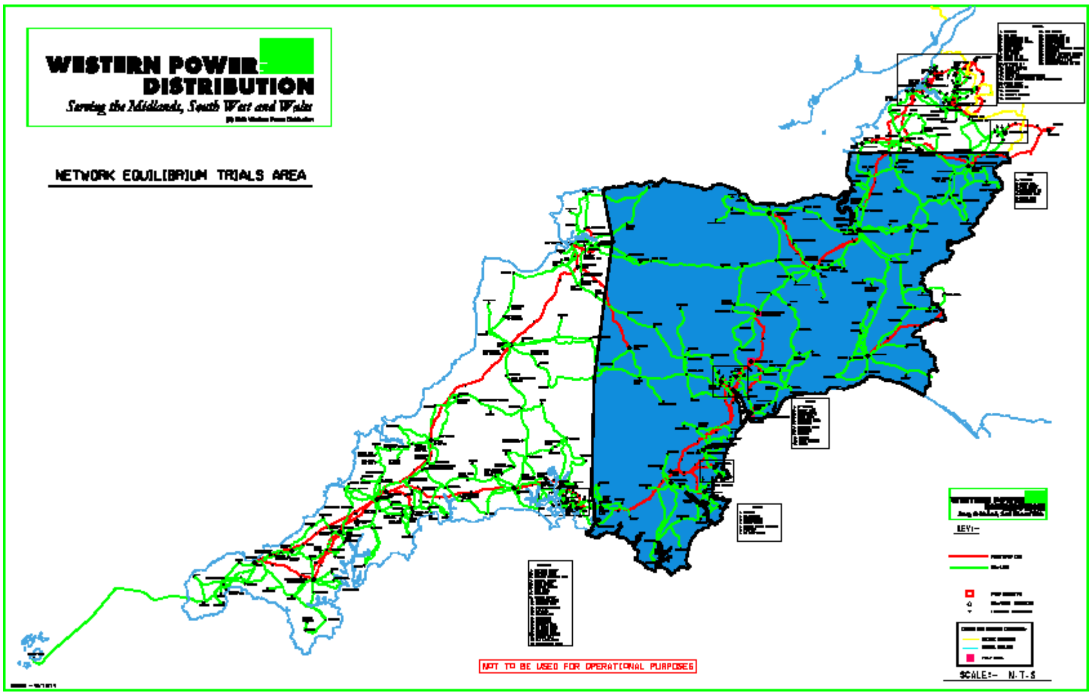


Figure 13 Network Equilibrium Project trial area

4.3.1.2 Creation of seasonal, time and weather driven profiles of expected generation from wind generators, solar photovoltaic generators and synchronous generators[8]

Generation output models are required to enable the tool to use weather data (forecast or historic) to predict output from generation. This should be:

- For all generators connected at 11kV and above, within the modelled BSPs; and
- By season, time of day and weather drivers.

[8] The output from synchronous generators is affected by the weather. However, the dependence on weather is small with synchronous generation compared to solar and wind power sources. The focus was therefore on the weather dependence modelling of solar and wind power.

Where generation output data is available for individual connections, this can be used as the basis for model building; however, there is also the requirement for a method of estimating generation output data. Weather data is also required to build the model and should be provided by a third party e.g. the Met Office. Statistical validation of the resulting models is required.

Example profiles of generation in typical seasonal and weather conditions are required and should be stored in a time series database (TSDS).

4.3.1.3 Development of a generalised model of the drivers of electricity demand: Analysis of historic demand data to establish patterns on long-term, seasonal, weekly and diurnal timescales; assessment of the correlation between weather and demand

A statistical demand model is required to enable the tool to use weather data, time of year, weekday/weekend and time of day (forecast or historic) to predict half-hourly electricity demand.

Demand profiles are required for individual feeders or groups of feeders on the reduced 11kV network nodes. Further demand profiles are required to reflect loadings at the 33kV busbars on BSPs that are modelled at 33kV only. The resultant profiles shall be stored in the TSDS.

Western Power Distribution (WPD) historic demand data is to be used as the basis for analysis. As with generation, third party weather data is being used.

Statistical models are evaluated both in terms of fit to the historical data and the ability to forecast accurately.

4.3.1.4 Creation of a forecasting tool that generates electricity generation and demand profiles based on two day ahead weather forecast data supplied by the Met Office

The TSDS will be provided with a tool that can create, write, or extract forecast demand and generation profiles. The User should be able to select a season / weekday / weekend (demand) and either manually input forecast weather conditions, including wind speed and ambient temperature, or have these automatically inputted from third party data sources, to create forecast demand and generation profiles for each demand and generator profile within the study area for two days ahead or some future User-selected date.

4.3.1.5 Development of a desktop based user interface for specifying power system simulations and viewing results

A User Interface for the Advanced Planning Tool is required and must be user friendly and designed for both technical and non-technical DNO staff to conduct analysis. The tool should allow network analysis to be conducted for configurable periods of time, including selectable days, weeks, months, distinct seasons and one year. The Advanced Planning tool must be enable the User to select historic demand and generation profiles to undertake balanced power flow studies, to identify locations and times of voltage and thermal stress on the studied network under normal and abnormal running arrangements (up to n-2). The tool should also identify and display the error bands associated with the analysis.

This will provide a benchmark to measure the impact of use of the historic profile modelling versus the existing Business as Usual (BAU) approach, and to enable benefit comparison with the use of System Voltage Optimisation (SVO) and Flexible Power Links (FPL).

The TSDS should be capable of storing the circuit power flows and voltage outputs for each busbar in the study area, against each uniquely referenced run. The Advanced Planning Tool should be able to display the data from the user interface in the following ways:

- Against the Single Line Diagram with Power flows (maximum, minimum and average values) against the associated assets (Circuits, Transformers and generators);
- Against the Single Line Diagram with Voltages (maximum, minimum and average values) against the associated with nodes;
- Graphically displaying voltage profiles for the selected BSP (all circuits), Primary substation (all circuits), individual 33kV circuits, or individual 11kV circuits plotted against time;
- Graphically displaying voltage profiles for the selected BSP (all circuits), Primary substation (all circuits), individual 33kV circuits, or individual 11kV circuits plotted as cumulative duration curves;
- Graphically displaying selected power flows and asset limits for the selected circuits or transformers plotted against time;
- Graphically displaying selected power flows and asset limits for the selected circuits or transformers plotted as cumulative duration curves (as an example, standard load duration curves).

The tool must be suitable for planning and operational analysis of the network, on this basis, the Tool should be capable of outputting results for a 24 hour analysis period within 60 seconds.

4.3.2 Functional requirements specification

To deliver these overall requirements the functional requirements specification detailed in Appendix A must be met. In Appendix A the requirements of software implementation, databases, server-side software, user interface and workflows are described. An overview of the system architecture is shown in Figure 14.

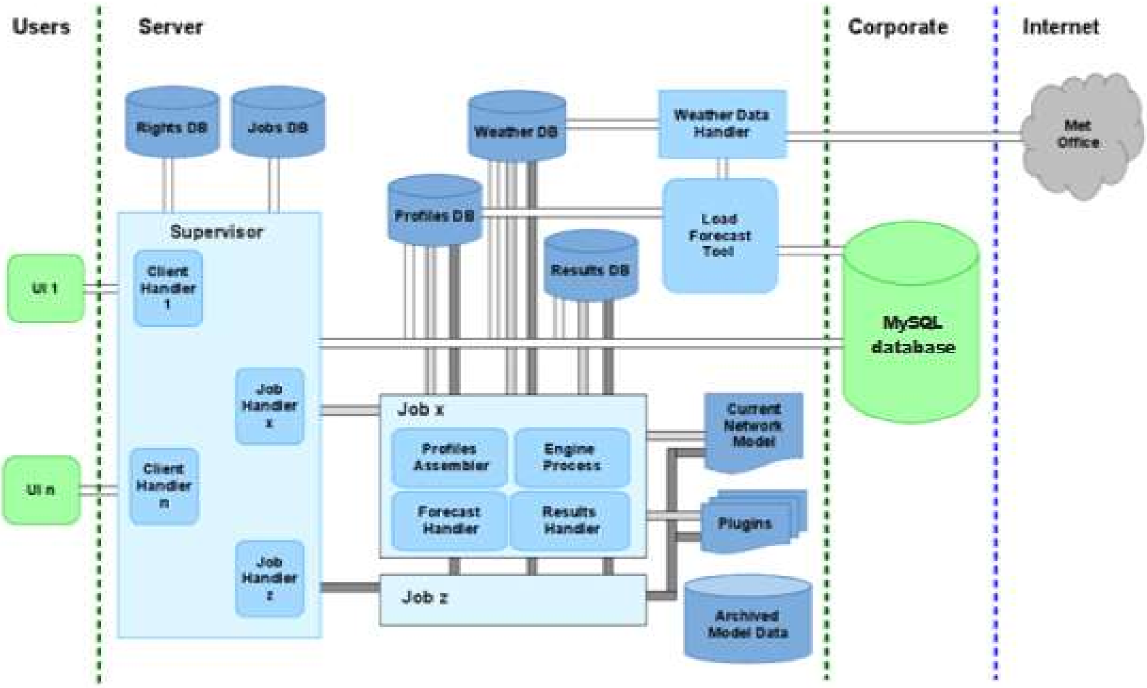


Figure 15 APT system architecture

The Equilibrium server software will support multiple concurrent users. It is estimated that there will be 10-20 in the trial phase of the Network Equilibrium Project. Roll-out of the APT to business as usual would result in approximately 500 users (not necessarily concurrent).

There will be four general types of user:

4.3.2.1 Control Engineer

WPDs control room is permanently manned, control engineers are responsible for all planned network switching through PowerON and system restoration after faults.

Proactive Use:

- Whilst checking/reviewing switching schedules approximately 8 weeks in advance of any operation to understand the network impact and predicted power flows and voltage profiles across the network. Their focus will be on the expected and/or credible worst case conditions.
- Reviewing planned switching operations 1 – 24 hours in advance of any operation to understand the predicted power flows and voltage profiles across the network. Their focus will be on the expected and/or credible worst case conditions.

Reactive Use:

- In the event of faults (especially at night and weekends) a simple assessment to assess the immediate and longer term restoration options to keep the network within capacity. Their focus will be analysis of thermal limits.

4.3.2.2 Outage Planner

During normal business hours, WPDs has a small team of planners who model the impacts of all individual planned work on the overall 132kV and 33kV networks. This team reports on the potential impacts and risks of a depleted network and the potential restoration plans.

Proactive Use:

- Understand the impact of outages;
- A 132kV customer will be informed of planned outages 1 year in advance,
- A 33kV customer will be informed of planned outages 8 weeks in advance,
- Understand if multiple outages can be taken at the same time, the impact of adjacent networks and return to service plans;
- Understand after a fault if an outage can still be taken or if a network must be returned to normal operation / alternative switching operations are required;
- Understand the credibility of any restoration plans for credible n-1 and n-2 conditions to assess impact and customer minutes lost or capacity shortfall; and
- Identify if generation customers will need to be constrained down or switched off in the event of an outage. Modelling network power flows whilst generation is capped at a certain output limit.

Reactive Use:

- In the event of faults, provide an assessment of the immediate and longer term restoration options to keep the network within capacity, with a focus on thermal limits.

4.3.2.3 Primary System Design Engineer

During normal business hours, WPDs has a team of planners who model the impacts of all new demand and generation connections to the 132kV and 33kV networks and 11kV connections that will trigger primary system network reinforcement.

Proactive Use:

- Identify the point of connection for new demand and generation connections to provide the minimum cost scheme;
- Assess demand and generation connections for the next 25 years based on normal and credible abnormal network running arrangements;
- Identify assets that are or will over time approaching their design limits or statutory limits, 1 – 10 year planning;
- Assess reinforcement schemes to identify how the network can be most cost effectively reinforced or operated to maintain equipment within limits and statutory limits;
- Strategic network planning such as resilience tree cutting, moving of normal open points, strategic switching points, installation of new assets for sectionalising; and
- Modelling and configuration of smart solutions such as Statcoms, SVO and FPL.

4.3.2.4 Future Networks Team

Proactive Use:

- Modelling and configuration of smart solutions such as Statcoms, SVO and FPL; and
- Strategic network assessment.

Administration of the tool will be the responsibility of the Future Networks Team. Future Networks and Primary System Design Engineers will have the ability to update the underlying network models in the APT tool, to ensure it reflects reality. Other users will have read only access to the master network model, but will be able to temporarily modify the model to complete their studies.

4.3.3 Non-functional requirements specification

The non-functional requirements are outlined in Appendix B.

4.3.3.1 IT hardware requirements

The APT is not due to be installed and operating on WPD systems until the end of February 2016. The requirements outlined here are therefore based on the test server installed at TNEI offices, and are subject to change. Note that Dell hardware was used by TNEI.

The hardware requirements are outlined in Table 12.

Table 12 IT hardware requirements

Hardware specification
PowerEdge T430 Server
PowerEdge T430 Motherboard
2 x Intel Xeon E5-2660v3 2.6GHz, 25M Cache, 9.60 GT/s QPI
4 x 8GB RDIMM, 2133MT/s, dual rank, x8 data width
2 x 2TB 7.2k rpm SATA 6Gbps

4.4 Implementation of the APT

4.4.1 Network model implementation

There are three main tasks involved in producing the IPSA network model required for the Equilibrium software:

- 33kV network and above—PSS/E to IPSA conversion
    - Data conversion
    - Validation checks
    - Reduction of network outside the trial area
- 11kV network—DINIS to IPSA conversion
    - Data conversion

- Validation checks
- Reduction of 11kV feeders
- Merge with PSS/E derived model

WPD provided a PSS/E model of the South West network which included all network items from the 11kV primary busbars up to and including the 400kV NGET system. The process in was undertaken to convert it from a PSS/E network model to an IPSA model. This is detailed in Appendix C and summarised in Figure 16.

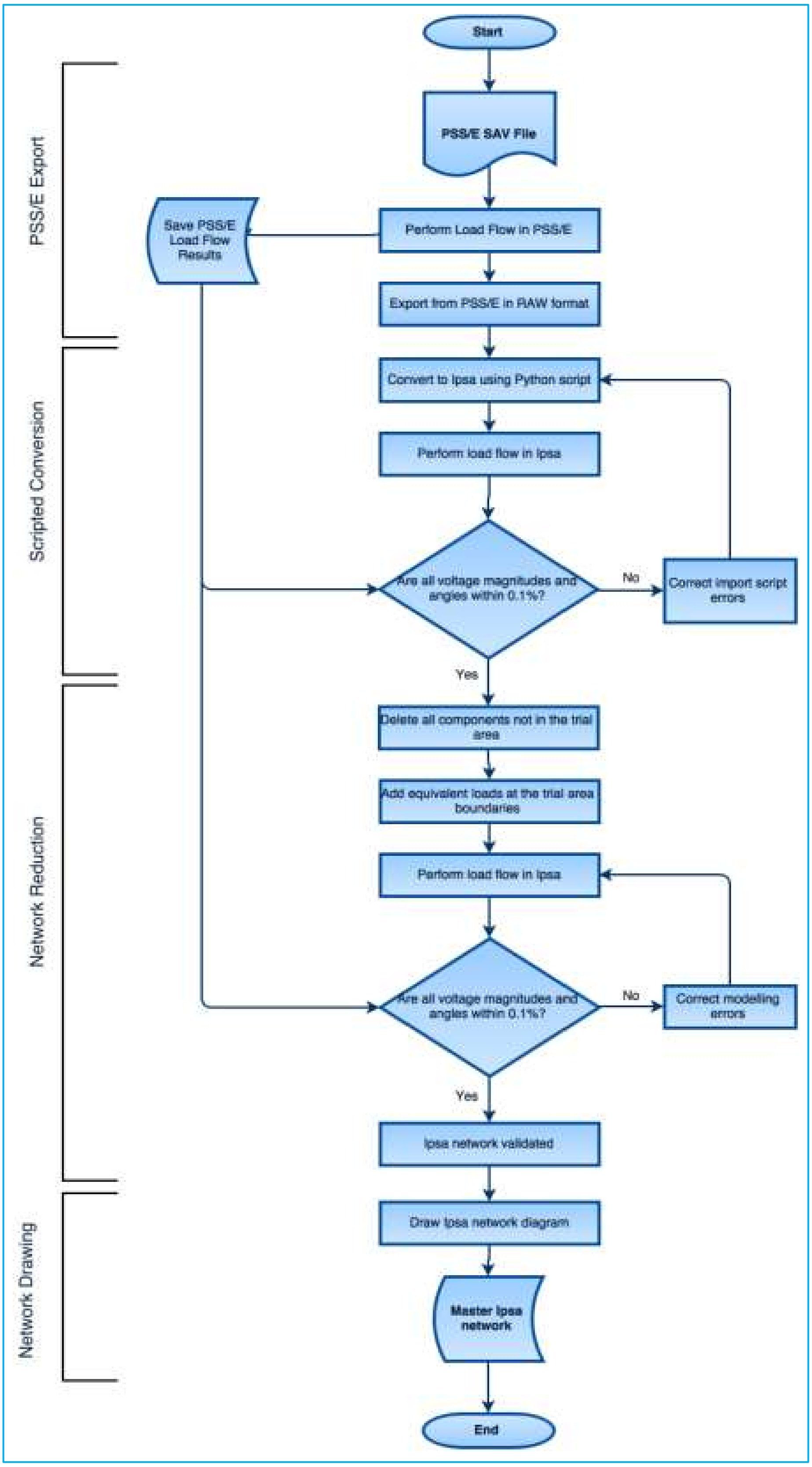


Figure 16 - PSS/E to IPSA Conversion

WPD provided a DINIS model of the South West network which included all the 11kV busbars, junctions, cables and overhead lines. Due to the large number of busbars in the DINIS networks, typically ~600 per 11kV primary substation, the project required that these networks were reduced down in order to reduce the overall analysis times.

The network reduction was originally intended to reduce each 11kV feeder to approximately four busbars. Following discussions with the end users and examination of the network a number of additional constraints were added to the network reduction:

- Normally open points on the feeders were to be maintained:
  - Network planners would require the NOPs in order to investigate system operation under abnormal conditions;
  - Some feeders may have enough NOPs such that more than 4 busbars would be required to represent the overall feeder.
- Keep the busbar with the lowest voltage:
  - One of the principal aims of the Equilibrium project is to investigate how new technologies, such as SVO, can be used to manage the network voltages. It is therefore important that the reduced feeders represent the full range of voltages present on the original feeder.

The network import was further complicated by the following additional factors:

- The DINIS network data did not contain any loads:
  - Whilst sufficient data was provided to allow load flow analysis, the absence of load data would have resulted in a flat voltage profile along each feeder;
  - Customer numbers were available as well as secondary transformer ratings (11kV to 415V transformers).
- No generators were modelled in the DINIS network:
  - Generation data was provided in the form of a spreadsheet with generator ratings and feeder locations.

Three options for network reduction were explored (all three are detailed in appendix C). It was decided that the voltage drop based reduction be used because the resulting reduced network most closely maintained the characteristics of the full model.

4.4.2 Demand model implementation

In this section, the development of the generalised model of the drivers of electricity demand is described.

4.4.2.1 Identifying patterns in demands

The initial data exploration involved graphically identifying patterns in demand vs temperature. The patterns in demand at different temporal resolution including (i) long term changes in underlying levels; (ii) seasonal patterns; (iii) shorter-term patterns, including weekly and within-day patterns, were investigated. These plots were then used as a tool to decide what features should be included in the formal statistical model.

Historical data from the Met Office, both forecast and observational data, was obtained for the same time period as historic demand data between 31/12/2013 and 29/04/2015 at 10 locations, spread across the Trial Area. The data is either measured at the location, or interpolated from nearby measurements. The ten locations are listed in

Weather Station	Latitude Longitude	Location Name
North Wyke/Folly Bridge SS	Existing Met Office location	North Wyke
Exeter Airport	Existing Met Office location	Exeter Airport
Liscombe	Existing Met Office location	Liscombe
Dunkeswell	Existing Met Office location	Dunkeswell
Prevailing 1	51° 8'11.50"N	Woolavington
	2°54'46.76"W	51.1676,-2.9329
Prevailing 2	51°16'45.48"N	Chilcompton
	2°32'49.85"W	51.2681,-2.5012
Bodmin Airfield/Cardinham	Existing Met Office location	Cardinham
Salcombe	50°11'48.90"N	Salcombe
	3°40'42.21"W	50.237,-3.7686
Chivenor	Existing Met Office location	51.0886, -4.1474
Teignmouth	Existing Met Office location	50.5445, -3.4936

For every day in the study period 16 days of data were provided: the previous day's observed data and forecasted data for the next 15 days. For both the observed and forecasted data, hourly values of temperature were provided. In addition, uncertainty measures in the form of 5th and 95th quantiles were provided for all quantities, when available[9].

The data was sense checked and then patterns analysed, initially using a series of figures created at different temporal resolutions. The locations of each feeder were given in the form of bounding rectangles. The centroid of each bounding rectangle was used as a representative location for that feeder. After merging with the demand data by allocating the nearest Met Office measurements to each demand point, correlations between demand, temperature and other factors were investigated.

From this exploration, it was determined that traditional linear modeling does not adequately capture the complex relationship between demand and the included

[9] 31% of the data contains at least some uncertainty information. There is no uncertainty information provided before 01/09/2013, however almost all days from this point forward have at least some uncertainty attached.

explanatory variables. Hence, Generalised Additive Models (GAMs) that allow for non-linear patterns were used.

Generalised Additive Models provide a flexible, formal statistical framework for modeling complex relationships between predictors and outcome variables. The aim of the statistical modeling is to produce a function *g(time, temperature)* such that:

$$demand = g(time, temperature) + [residual]$$

where the *[residual]* denotes the small, un-modeled term. If the patterns of demand are sufficiently well captured by the predictors *time* and *temperature*, then the *[residual]* term will not have any further patterns in it.

While GAMs allow for almost unlimited flexibility, they perform best when the function *g(time, temperature)* is decomposed into simpler components. To wit, a good modeling strategy is to write:

$$g(\text{time, temperature}) = f_1(\text{time}) + f_2(\text{temperature})$$

It is possible to add a further interaction term $f_3(time, temperature)$ that models how the effect of time changes with temperature, but for this problem that was found to be unnecessary. Finally, in order to properly take into account the multiscale temporal effects, that is, the way in which there are different demand patterns at different temporal scales, the further decomposition was made:

$$f_1(time) = h_1(year) + h_2(day\ of\ year) + h_3(day\ of\ week) + h_4(time\ of\ day).$$

A diagram that represents the full model is given in Figure 17.

Figure 17 A representation of the GAM model. The "short time" effects are the effect of "time of day" and "day of week". The "long time" effects are the effects of year, and day of year (which include a seasonal trend).

4.4.2.2 Forecasting future demands using Met Office weather forecasts

The final stage of the modeling was to construct a 48 hour forecast based on new temperature data received daily from the MET office. The forecast 'window' defines the time period from which data is used to populate the models and estimate the parameters. Estimates of demand for a user-specified time period will be produced together with associated measures of uncertainty (error bars). These will take the form of intervals within which we are confident the true value lies (confidence intervals), the most commonly reported of these being 95% intervals.

Initial investigation revealed that the relationship between demand and temperature varied from feeder to feeder. At some feeders, the empirical relationship appears to be consistent with a linear trend, whereas at other sites the apparent trend is non-linear, or even non-existent. The non-linear trends can be thought of as modeling “saturation”-type events, where the demand decreases as temperature increases until it reaches a certain “threshold” value, at which point the demand remains essentially constant. These three types of demand vs temperature profiles are demonstrated in Figure 18, Figure 19 and Figure 20. In Figure 18, the linear effect of Temperature on Demand at Tiverton Moorhayes feeder X18 is clearly present. By contrast, Figure 19 suggests that there is no significant effect of Temperature on Demand at Staplegrove Feeder X908. Finally, a non-linear effect of Temperature is demonstrated in Figure 20, where the Demand at Wellington Town feeder X884 shows a clear non-linear trend.

The GAM framework allows the production of demand forecasts that take into account the underlying non-linearity of the relationship between demand, temperature, and time. The produced forecasts will have uncertainty bounds that increase as the forecast period increases.

Adjusted R^2 values for each feeder were calculated to test the effectiveness of the modelling procedure. For some feeders, all three non-linear effects (temperature, short-time and long-time) were found to have significant descriptive power. In other feeders, the descriptive power was less evident.

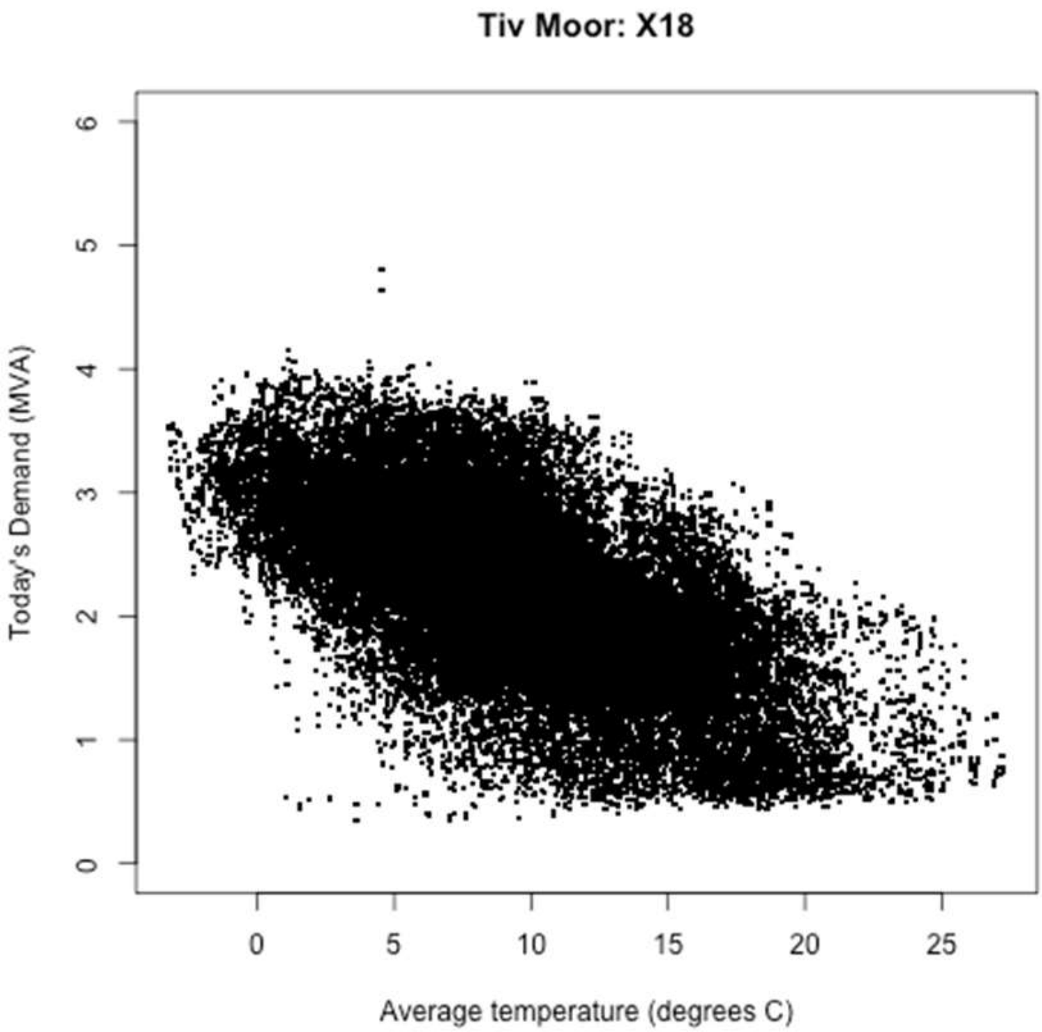


Figure 18 Scatter plot of demand against average temperature at Tiverton Moorhayes feeder

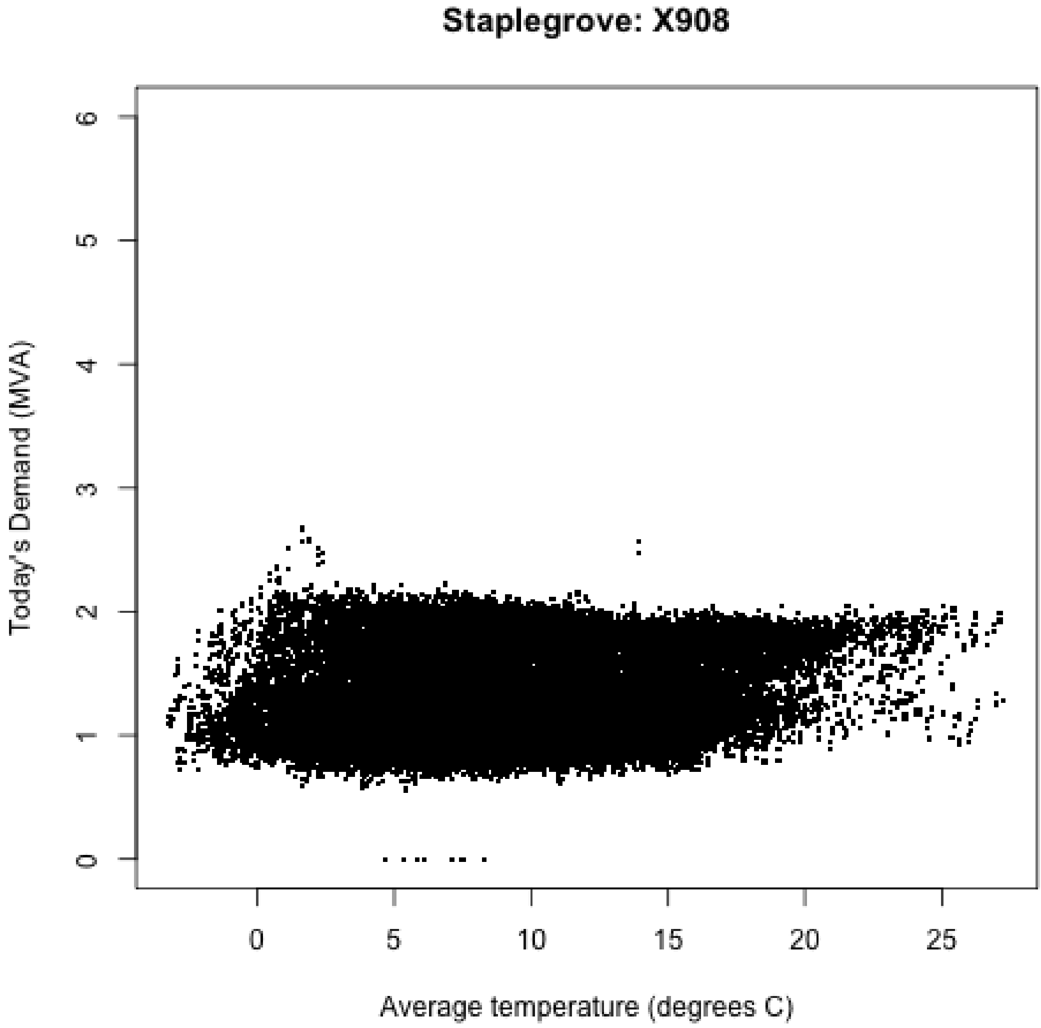


Figure 19 Scatter plot of demand against average temperature at Staplegrove feeder

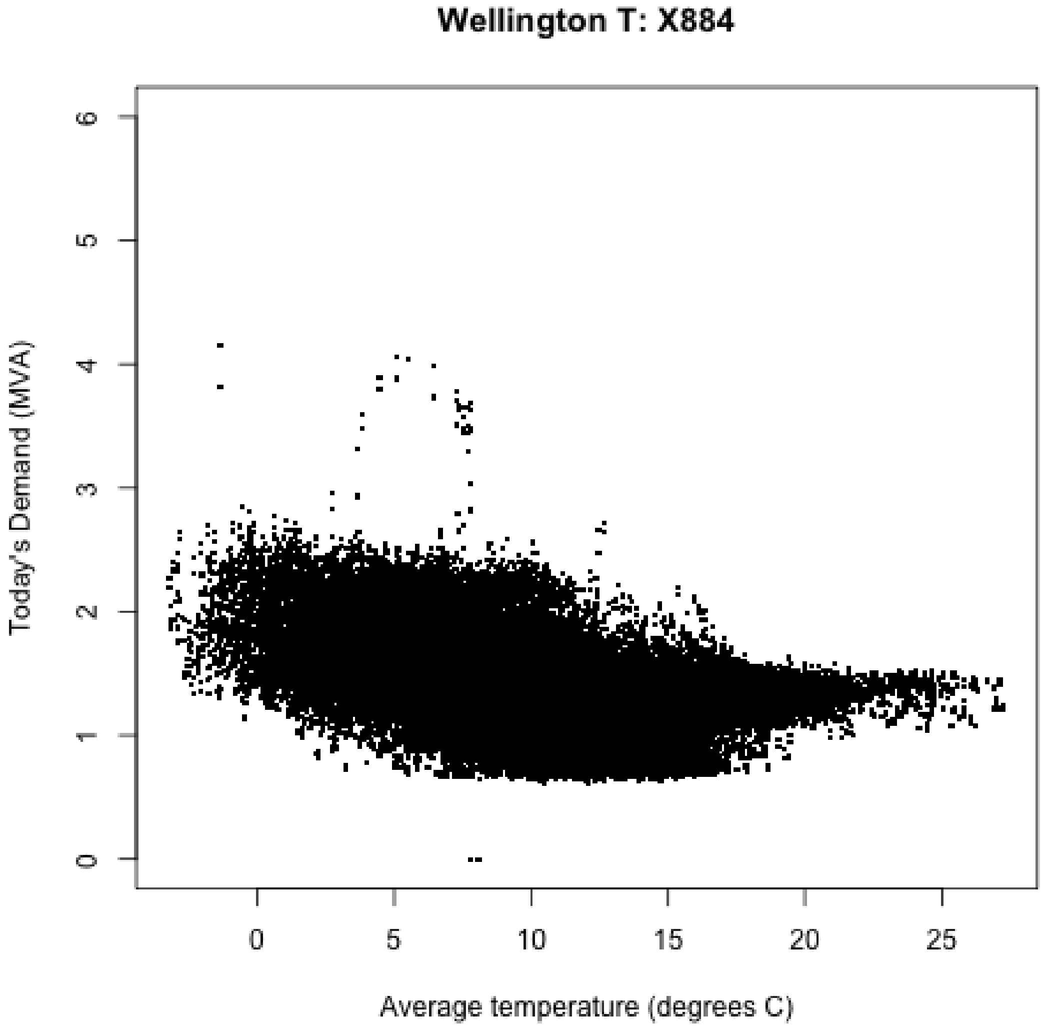


Figure 20 Scatter plot of demand against average temperature at Welington Town feeder

4.4.3 Wind generation model implementation

A model was developed[10] that can be used to predict the power output for each operational wind farm in the Trial Area based on forecast wind speed and direction provided by the Met Office at the ten forecast locations across the area.

Historical metered generation data was available for the larger wind farm sites within the Trial Area. This data was used in combination with historical weather forecasts to generate a matrix of power generation as a function of wind speed and direction for each

[10] Project Prime Contractor TNEI subcontracted this task to Prevailing Wind Farm Analysis Ltd.

wind farm. For smaller wind projects of less than 500 kW, which make up a small fraction of the total regional generation, the generation matrices were derived using modelling only. Metered data are only available for a subset of this size of wind generation site, and this data was used to help tune the methodology and estimate the error.

An example of the resulting power generation matrix (the determination of which is described in this section) is shown in Table 13.

Table 13 Example wind generation power matrix

	Wind direction											
Wind speed (m/s)	0	30	60	90	120	150	180	210	240	270	300	330
0	0	20	28	1358	6	0	0	865	2168	1534	0	12
1	1010	0	1350	2694	1124	0	705	2448	4056	3460	1221	0
2	2809	650	3222	4279	2751	1194	2315	4378	6579	6039	3187	1159
3	5113	3035	5687	6292	4772	3066	4291	6954	9873	9523	5809	3198
4	8262	6451	9032	8789	7465	5517	6952	10282	14037	14043	9421	5965
5	12381	11507	13378	11819	10920	8866	10424	14462	19195	19755	14173	9820
6	17619	18540	18879	15441	15243	13243	14821	19609	25379	26678	20246	14938
7	24085	27727	25597	19718	20545	18807	20269	25738	32310	34393	27632	21521
8	31519	38136	33180	24649	26796	25628	26754	32566	39475	42210	35804	29467
9	39304	48344	40965	30087	33677	33338	33922	39599	46468	49719	43976	38070
10	46897	57162	48494	35790	40681	41243	41208	46462	53003	56327	51709	46517
11	53903	62332	55275	41477	47486	48873	48263	52885	58412	61011	58154	54266
12	59437	63805	60351	47019	53778	55687	54687	58239	61887	63198	62107	60133
13	62554	64016	62936	52254	58894	60664	59706	61752	63423	63863	63608	63011
14	63698	64028	63800	56834	62086	63080	62554	63356	63891	64007	63955	63851
15	63967	64028	63991	60345	63478	63839	63663	63872	64010	64028	64028	64011
16	64028	64028	64028	62461	63900	64002	63950	64002	64028	64027	64028	64028
17	64028	64028	64027	63481	64011	64028	64026	64028	64027	64028	64028	64027
18	64027	64028	64028	63862	64028	64027	64028	64028	64028	64028	64028	64028
19	64028	64028	64028	63984	64027	64028	64027	64027	64028	64028	64028	64028
20	64028	64028	64028	64028	64028	64028	64028	64028	64028	64028	64028	64028
21	64028	64028	64028	64028	64028	64028	64028	64028	64028	64028	64028	64028
22	64028	0	64028	64207	64028	64028	64028	64028	64028	64028	64028	64028
23	64028	0	64028	64028	64028	64028	64028	64028	64028	64028	64028	64028
24	64028	0	64028	64028	64028	64028	64028	64028	64028	64028	0	64028
25	0	0	0	64028	64028	64028	64028	64028	0	0	0	0
26	0	0	0	64028	64028	0	64028	0	0	0	0	0
27	0	0	0	64028	0	0	64028	0	0	0	0	0
28	0	0	0	64028	0	0	0	0	0	0	0	0
29	0	0	0	64028	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0	0	0	0	0	0

4.4.3.1 Data used in the analysis

Details of all the wind generation sites within the trial area were provided. Locations indicated as postcodes then translated to grid references. Therefore the locations used in the analysis may not exactly match the actual project locations.

Met Office weather data for ten weather forecast locations across the were provided, as described in Section 4.4.2.

Historical half-hourly metered output data were was provided for larger wind generation sites. For the clusters of small wind projects, where metered generation data is generally not available, the modelling required an estimate of the relative wind speeds across the study area. The Numerical Objective Analysis Boundary Layer (NOABL) wind speed database[11] was used for this purpose, from which data was extracted at 10 m height at a resolution of 1 km.

4.4.3.2 Modelling method

A different modelling method was used depending on what data was available for a given wind turbine site:

1. Where historical generation data was available and projects are greater than, or equal to, 500 kW, a power generation matrix was calculated for each individual site by correlating its historical generation and forecast data;
2. For sites less than 500 kW, the generation matrix was calculated by modelling the wind resource between the nearest forecast location and wind generation site. Given the small size of these sites, generation matrices were derived for clusters of between 6 and 27 sites. Generation data was available for 9 generation sites; this data was used to tune the modelling methodology in order to improve prediction accuracy.

The split of methods by generation sites is summarised in Table 14.

Table 14 Summary of modelling method by wind generation site

Method	No. of sites	No. of power generation matrices	Total rated capacity (MW)
1	6	6	84.95
2	119	8	1.91

4.4.3.3 Method 1

The six sites in the study area with rated capacity of 500 kW or more make up more than 97 % of the operational wind power capacity. Site details are summarised in Table 15. Power generation matrices for these sites were calculated for each individual wind farm using historical forecast and metered generation data and are referenced to wind speed and direction at the forecast location. Galsworthy, East Youlstone and Otterham sites had metering data for on 7 months, 3 months and 3 months, respectively. The resulting power matrices for these sites were therefore less accurate.

[11] Wind speed map providing estimated annual mean wind speed across the UK at 1km resolution

Table 15 Summary of six "Method 1" sites

Wind farm	No. of turbines	Turbine type	Rated capacity (MW)	Forecast reference site
Fullabrook Down	22	Vestas V90 3MW	66.00	Cardinham
Galsworthy	4	Enercon E70	9.20	Chivenor
Forestmoor	3	NEG-Micon NM60	2.70	Chivenor
East Youlstone	2	Vestas V80 2.0MW	4.00	Chivenor
Higher Darracott	3	Gamesa G58 850kW	2.55	Chivenor
Otterham	1	EWT DWT54-500	0.50	Cardinham

Generation data was processed as:

- The half-hourly metered generation data was summed to an hourly time base for correlation with the hourly forecast data;
- Periods of turbine downtime were identified by examining the concurrent wind speed at the nearest forecast location for periods when there was no power output. Where the wind speed was above a certain threshold for the periods where the turbine produced no power, the associated data period was excluded from derivation of the generation matrices on the basis these periods represent turbine faults;
- Periods of curtailment were identified by plotting power curves for the wind farms using the wind speeds at the forecast locations. While there is large scatter in such power curves, curtailment was evident at three of the wind farms - East Youlstone, Forestmoor and Higher Darracott.

Studying the frequency of occurrence of curtailment and downtime across different times of day and sectors, the constraints did not appear specific to any particular time of day. Additionally, sectors in which constraints typically occurred contained non-constrained generation data. Therefore the observed curtailment was likely temporary and therefore not representative of the long-term operation. As a consequence, curtailed generation data from these wind farms was excluded from derivation of the generation matrices.

This approach results in a higher power curve than the wind farm will generate on average over time. However the power curve will be more representative of the highest output for given forecast wind conditions. The likelihood of an under prediction in a generation forecast, and hence overloading the network, will be reduced hence the approach is considered appropriate here.

The power generation matrix was derived for each of the six wind farms as follows:

- The filtered hourly generation data was correlated to the historic forecast data to establish the relationship between wind speed and generation at each wind farm. The relationship was defined using data for each 1 m/s and 30 degree direction sector defined by the forecast data;

- Data was filtered to include only wind speed bins with more than a set number of hourly data points. The filter threshold was adjusted individually for each of the 6 projects, depending on the scatter of the resultant power curves. Depending on the available data, this filter was set from a minimum of 5 samples for sites with little data available up to 40 for sites with more than 2 years of valid data;
- Based on the filtered data, a power curve was derived for each of 12 direction sectors referenced to the corresponding forecast location;
- Theoretical wind farm power curves, based on the sales power curves for the turbine types installed at each site, were then derived and fitted to the binned power curves derived from the generation data to provide a realistic generation matrix in each sector;
- Where sufficient data was not available in a given wind direction sector, the power curve was interpolated from the power curves derived in the neighbouring wind direction sectors. This reduces the accuracy of analysis to some extent. However, additional data can be used in the future to enhance the coverage in sectors with little data and therefore improve the accuracy of the resultant generation matrices;
- Generation data sets used to derive the matrices do not include wind speeds high enough to derive the cut out wind speed in each sector. Assumptions have been made to estimate when the wind farm shuts down due to excessive wind speed.

4.4.3.4 Method 2

The majority of the remaining sites comprised a single turbine. The sites were divided into eight clusters per forecast location, with between six and 27 sites per cluster. Generation matrices were derived for each cluster referenced to wind speed at the forecast location. The generation matrices were referenced to wind speed only and hence are applicable to all wind directions at the forecast locations.

The power generation matrix was derived for each cluster as follows:

- For each individual wind generator location an approximate power curve was derived using the rated power and a typical wind speed / power relationship for a small scale wind turbine;
- The ratio of mean wind speed between each site and the corresponding forecast location was calculated using the NOABL wind speed database. The absolute wind speeds of the NOABL database have large uncertainty. However it was the relative wind speeds between the forecast locations and each wind site that were of importance;
- The derived power curves at each wind project and the wind speed ratio from forecast location to the project were used to calculate the power curve referenced to the forecast location;
- The individual generation matrices were combined for each cluster to give the generation matrix for the cluster referenced to the wind speeds at the associated forecast location;

- Half-hour metered generation data was supplied for nine of the sites in which method two was applied. This data was used to tune the wind speed relationship between reference stations and sites.

The wind speed relationship between the reference station and the site derived from the NOABL wind speed map does not capture differences in the turbine hub height. Therefore the model was tuned by applying an adjustment to the relationship of wind speeds at the reference station and wind farm.

The adjustment was derived, based on the 9 sites with valid generation data. The adjustment was tuned so that the overall error between the actual generation (based on the supplied generation data), and the calculated generation (based on the wind reference data and the derived generation matrices) is minimised. The adjustment was applied consistently throughout all the wind farms and clusters and was based on a sample of sites rather than a single site, hence reducing the risk of introducing an individual bias due to the exposure a particular site.

4.4.4 Solar photovoltaic generation model implementation

A model was developed that can be used to predict the power output for solar photovoltaic (PV) generation based on forecast solar irradiance.

Solar generation has a linear relationship with solar irradiance which simplifies the modelling of EHV and HV solar connections. The available data on the installed capacity and the actual generation output were used to correlate solar irradiance with generated power output. This correlation could then be utilised for generators where no half-hourly metered data is available.

Initially (to ensure the analysis was comprehensive), separate output models were created based on high generation output days (summer), low generation output days (winter) and mid-output days (spring / autumn).

Only PV generators that were connected at the time of analysis and were assigned a Meter Point Administration Number (MPAN) were considered as part of the analysis. There were 274 solar generators with an MPAN and available metered data connected within the trial area (and 19,785 solar generators with MPANs but with installed size less than 30kW).

The solar generation modelling is divided into four steps:

- Select solar irradiance days per site;
- Process and Select particular PV installations/generators from the 274 generators with data;
- Match power outputs with solar irradiance inputs using the rated power and the location of the sites;
- Calculate Capacity Factors and aggregate per voltage level and installed capacity.

These steps are described in further detail below.

4.4.4.1 Solar irradiance days

Four days of solar irradiance data were chosen from the Met Office dataset (dates between 19/06/2013 and 30/04/2015). Per season, a day with high solar irradiance was chosen. Days with high measured solar irradiance have low cloud cover. Cloud cover introduces uncertainty to the analysis, since the cloud cover above the solar site may not match that above the Met Office monitoring site. The days with the highest solar irradiance in a given season were selected as:

- Spring - 30/03/2014;
- Summer – 17/06/2014;
- Autumn – 24/09/2014;
- Winter – 05/01/2015.

4.4.4.2 Solar PV site selection

It was assumed that the relationship between solar irradiance and power output is consistent between PV installations of similar size; the rated power output of a PV installation is reached at 1000 W/m^2 irradiance[12] . Therefore, a sample of PV sites were analysed to establish this relationship.

That said, to ensure any variation between unit types was captured the analysis was carried out on samples of sites grouped by criteria:

- Voltage level (33 kV or 11 kV);
- Installed size:
  - Greater than 5 MW
  - 1 MW – 5 MW
  - Less than 1 MW
- Location: solar irradiance does vary by latitude; generators at disparate locations across the trial area were therefore chosen.

Generators connected at 33 kV were divided into two groups: Greater than 5 MW and 1 – 5 MW. For generators sized 5 MW and above, seven were selected based on being the largest installations per BSP and are shown in Table 16.

Table 16 Selected generators above 5MW connected at 33kV

PV site	Installed size (MW)	Corresponding weather station
Watchfield Lawn	8.14	Prevailing 1
Burrowton Fm PV	10.9	Exeter Airport
Derriton Fields	9.52	North Wyke/Folly Bridge SS
Mendip Solar PV Farm	6.36	Prevailing 2
Culmhead	7.17	Dunkeswell
Marley Thatch Farm PV	8.50	Salcombe
Stonebarrow	9.54	Exeter Airport

[12] British Standard (EN/IEC) 60904-3:2008 “Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data”

For generators between 1 MW - 5 MW, eight were selected and are shown in

Table 17 Selected generators at or below 5MW connected at 33kV

PV site	Installed Size (MW)	Corresponding weather station
Cobbs Cross	5000	Prevailing 1
Liverton Farm	3910	Teignmouth
Foxcombe	5000	North Wyke/Folly Bridge SS
Whitchurch PV Farm	5000	Prevailing 2
Grange Farm	5000	Liscombe
Ayshford Court PV	4550	Dunkeswell
Bidwell Dartington	5000	Teignmouth
Newlands Farm	4920	Exeter airport

Generators connected at 11 kV were divided into two groups: 1 – 5 MW and <1 MW. The eight selected generators between 1 and 5MW capacity are shown in Table 18.

Table 18 Selected generators 1MW-5MW connected at 11kV

Generator MPAN	Installed size (kW)	Corresponding weather station
2200042013307	5015	Prevailing 1
2200042241194	1000	Prevailing 1
2200042215041	1100	North Wyke / Folly Bridge SS
2200042128211	1380	Salcombe
2200042302252	1500	Prevailing 2
2200042198798	5000	Exeter Airport
2200042340903	2500	Prevailing 1
2200042465203	2800	Dunkeswell

For generators below 1 MW, seven PV installations were selected and are listed in Table 19.

Table 19 Selected generators below 1MW connected at 11kV

Generator MPAN	Installed size (kW)	Corresponding weather station
2200042116703	39.79	Liscombe
2200042361727	135	Prevailing 1
2200042326341	40	Exeter Airport
2200042285466	165	Teignmouth
2200042063664	50	Prevailing 2
2200042256650	68	Dunkeswell
2200042407309	225	Dunkeswell

4.4.4.3 Solar models

The power output for each selected PV site and the historic forecast solar irradiance was used to calculate a de-rating factor that could be used as in equation to calculate PV power output.

$$P_{out}\ (kW) = P_{rated}\ (kW) * G\left(\frac{W}{m^2}\right) * \frac{f}{1000}$$

Where P_{out} is the PV power output, P_{rated} is the rated capacity of the PV generator, G is the solar irradiance received at the generator and f is the de-rating factor.

As expected, the calculated de-rating factor varied slightly depending on the angle of the sun (i.e. by time of day and seasonally) and with cloud cover. Therefore, the mean value through the day was used in each seasonal representative day.

The resulting de-rating factors are shown in Table 20.

Table 20 Calculated de-rating factors

		De-rating factor					
Voltage	Range	Spring and Summer	Spring, Summer, Autumn	Spring	Summer	Autumn	Winter
33 kV	5 MW - 10 MW	0.5382	0.5907	0.5302	0.5461	0.6956	1.84
33 kV	Below 5 MW	0.6386	0.5796	0.6976	0.5797	0.4616	1.13
11 kV	1 MW - 5 MW	0.6533	0.6382	0.6981	0.6084	0.6081	1.29
11 kV	Below 1 MW	0.281	0.2503	0.331	0.231	0.1888	0.24

Note that the de-rating factors for 11kV installations below 1MW are significantly different from those at higher capacity installations. This is because the position of small installations is not often optimised to generate the most power (they are often simply installed on the roof of a house). The difference in winter de-rating factors is explained by the angle of incidence of solar irradiance in winter time. The measured (and therefore forecast) values of solar irradiance at these angles is proportionally less than the power generated at the angle of incidence; a larger de-rating factor results.

5 Conclusion

The detailed design of the Enhanced Voltage Assessment (EVA) Method was presented. In the Voltage Limits Assessment work package the rational for the statutory voltage limits on 11kV and 33kV networks was explored with relevant stakeholders, the limiting factors were identified and the possibility of amending the limits was discussed. In the Advanced Planning Tool work package the specification of the tool and a guide to its implementation were described.

The conclusions drawn from the previous sections of the report are summarised below.

- A VLA questionnaire was issued to industry stakeholders to obtain information and wider perspective on the VLA work. The responses indicated a positive perception of the proposed scope by industry members. Technical considerations were also identified, mainly involving voltage regulation issues, equipment voltage withstand capabilities and lifetime, protection coordination and the impact of wider 11kV and 33kV limits on HV and LV networks.
- The VLA workshop (held in IET Birmingham in October 2015) identified voltage limits as being a significant constraint to DG connections, also recognising that other constraints, such as thermal and power quality issues, may then become the limiting factor. The workshop concluded that barriers, such as network equipment withstand characteristics, maintaining LV voltages within limits, changes to fault levels, impact on customers and customer reaction, require further exploration.

- The overall conclusion of the literature review of manufacturing standards and equipment specifications is that the majority of the equipment is characterised by its highest voltage for continuous operation (U_m) and by the power frequency withstand voltage, which typically is applied and tested for 1 minute during the pertinent insulation withstand test. The main series of standards for the purposes of insulation withstand levels is the IEC 60071 series titled "*Insulation Co-ordination*".
- Most of the equipment suitable for installation on systems of a nominal voltage of 11kV have a U_m of 12kV, which is approximately 9% above the nominal system voltage. Similarly, equipment suitable for 33kV nominal system voltages has a U_m of 36kV, which is again approximately 9% higher than the nominal.
- As far as power frequency withstand voltages are concerned, for the test duration of 1 minute, 12kV rated equipment can typically withstand 28kV while 36kV rated equipment can withstand 70kV. Notice is also given to certain testing requirements from BS standards and equipment specifications, pertaining to applying lower test voltages, but over longer periods.
- The study of the WPD South West licence area network showed that if an amendment to the existing statutory steady-state voltage limits was implemented, the fully exploited widened steady-state voltage limits would cause some of the 33kV and 11kV nodes to go outside the existing ±6% limits.
- For example, with limits widened to ±7% and fully exploited, 30.51% of the total studied 11kV nodes went outside the existing limits. At 33kV and considering again full exploitation, 5.81% of the total nodes went either above the existing +6% upper statutory limit or below the existing -6% lower statutory limit.
- However, load and generation would need to increase significantly if the widened voltage limits were to be fully exploited, particularly at 11kV. It would be expected that thermal limits would constrain the ability to fully exploit widened voltage limits.
- Within the modelled area of the network, no primary transformers would require replacement or upgrade of their voltage regulating capabilities in order to cope with the wider limits, while a maximum of 18% of distribution transformers might require OLTC or other types of voltage regulation for the extreme scenario of ±10% statutory voltage limits.
- Based on the results of the modelling study and the review of equipment limitations, it was concluded that the vast majority of equipment connected at 11kV and 33kV would not require replacement, provided that the new range of voltage variation would not be greater than ±10% applied in a probabilistic manner so that operation in the extreme ends of that range would only be allowed for short periods of time.
- An IPSA model was created for the entire 400kV/275kv, 132kV and 33kV network within the trial area; the 11kV network within the trial area was modelled in a reduced form to ensure that power flow analysis studies could be completed in the order of minutes.
- A generalised model of demand was created for each feeder within the trial area, based on analysis of historical electricity demand and historical weather data.

- Models of wind and photovoltaic electricity generation were created based on historic generation data, installed capacity of generation plant, and historic weather forecast data.

The benefits and drawbacks of amending voltage limits and use of the APT will be presented in Successful Delivery Reward Criteria report four.

A white paper has been produced to stimulate industry discussion of the topic and can be found here:

http://www.westernpowerinnovation.co.uk/Document-library/2016/Voltage-Limits-Assessment-Discussion-Paper.aspx

6 Appendices

A Functional requirements specification

A.1 Software Implementation

Each user will access the APT software through a client application, running on the user's computer. The user's computer will be running Microsoft Windows version 7 or later.

The client application will be used to specify the parameters of the study that the user wishes to perform on the Equilibrium software, and to view the results of such studies.

Each client application will communicate with the APT server. The APT analysis software runs on this server, together with the files and databases required to perform the studies, and the results of those studies.

A.2 External software and communication

Demand forecast profiles created by the Load Forecast Tool and the generation profiles selected by the Forecast Handler will be copied daily to the TSDS. The results of the daily APT studies on the 48 hour forecast data will be copied daily to the TSDS.

The Met Office will provide a weather forecast for the pre-defined locations for the next 48 hours at the same time every day. The weather forecast data will be placed by the Met Office in an agreed directory on a computer which allows external access to the Internet. The Met Office will use a pre-defined IP address and login to transfer the data to this directory using secure FTP.

The Weather Data Handler will check the directory for updated weather forecast data and when new data has been received it will convert it as necessary and place it in the Weather database.

A.3 Software languages

The APT software will be written in the C++, Python and SQL programming languages. The analysis code will use C++ wherever possible to increase speed performance.

The Load Forecast Tool will be developed in the R programming language. Once the Tool is complete this may be converted to C++ to improve the speed of operation.

A.4 Databases

A database system will be installed on the APT server. There will be several databases on the server, each assigned to a specific role. The databases on the APT server will be accessible using SQL.

The user rights database will contain the log-in details of each user allowed to access the Equilibrium server, such as their user name and password. Each user will be allocated a user profile. Administrators will be able to add, remove and modify user accounts and profiles.

The jobs database will store the input parameters used to define a study run on the Equilibrium server. These parameters will have been created by a user using the Client application.

The weather database will store processed weather forecast data received daily from the Met Office. The processed data is the output from the Weather Data Handler, which takes the raw information from the Met Office and converts it into a form suitable for entry into the weather database.

The stored forecasts will be used by the Load Forecast Tool and the Forecast Handler to create and select generation and demand profiles for the predicted weather conditions. The forecast profiles database will store the demand profiles created each day by the Load Forecast Tool, and the generation profiles created each day by the Forecast Handler. As profiles are created daily for the next 48 hours, some of the forecast profiles will be overwritten when the next set of weather forecasts come in. The forecast profiles will be indexed by date, time and a unique identifier for each demand or generator.

The generation forecast database will store the wind and PV generation profiles created from studying historical weather and generation data. The generation forecast profiles database will only be updated when new generation comes online. The generation forecast profiles will be indexed by weather data (such as wind speed, direction and temperature) and generation unique identifier. The Forecast Handler will use this database, and the weather forecast, to daily select generation profiles to be placed in the Forecast profiles database.

The stored profiles database will be used for long-term storage of demand and generation profiles. “Typical” profiles will be stored in this database, such as monthly profiles, as well as profiles deemed by users to be worth keeping, such as unusual or extreme weather conditions, for example.

The results database will store the results of system studies performed by the Equilibrium software. The results of the daily predicted 48 hour operation of the network model will be stored each day. The results of each study performed by a user will also be written to the Results database.

A.5 Server-side software

The Supervisor process will run continuously on the APT server. The Supervisor will start and stop other APT server software as appropriate. Some processes will be automatic and run at predetermined times or in response to user selection.

The Weather Data Handler will place weather forecast data received from the Met Office into the Weather database, performing any conversions necessary on the data in the process.

The Load Forecast Tool will read weather forecast data from the Weather database and create demand profiles for the forecast. The created profiles will be placed in the Forecast Profiles database.

The Forecast Handler will read weather forecast data from the Weather database and use the Generation forecast database to select generation profiles to be placed in the Forecast profiles database.

The Client Handler process will deal with communication between an APT Client application running on a user's PC and the Supervisor process running on the APT server.

The Job Handler will read study parameters from the Job database and perform the necessary calculations. If the calculations are successful then results will be placed in the Results database.

The Profiles Assembler will fetch the profiles required for a particular study from the Forecast Profiles database and / or the Stored Profiles database, as specified by the study parameters.

The Calculation Engine will be created from the core load flow calculation routines of the IPSA power system analysis package. IPSA's load flow calculations were written to be accessible as a callable library of functions for embedding in other applications.

The calculation routines will be modified and extended as necessary to meet the demands of the APT server.

The Results Handler will place the results of a study in the Results database. It will also read results from that database and pass them to the Client Handler as needed.

The Administrator Interface will be a web-based tool for users with Administrator rights to perform maintenance and update tasks on the APT server software.

A.6 User interface

Users will access the APT server through a client application installed on their PC. In order to connect to the APT server the user will have to enter their login details. The user interface presented to them will be determined by the rights that an Administrator has assigned to them. The Client user interface will be designed to allow the user to set the parameters for a study, to run that study, and then to review the results.

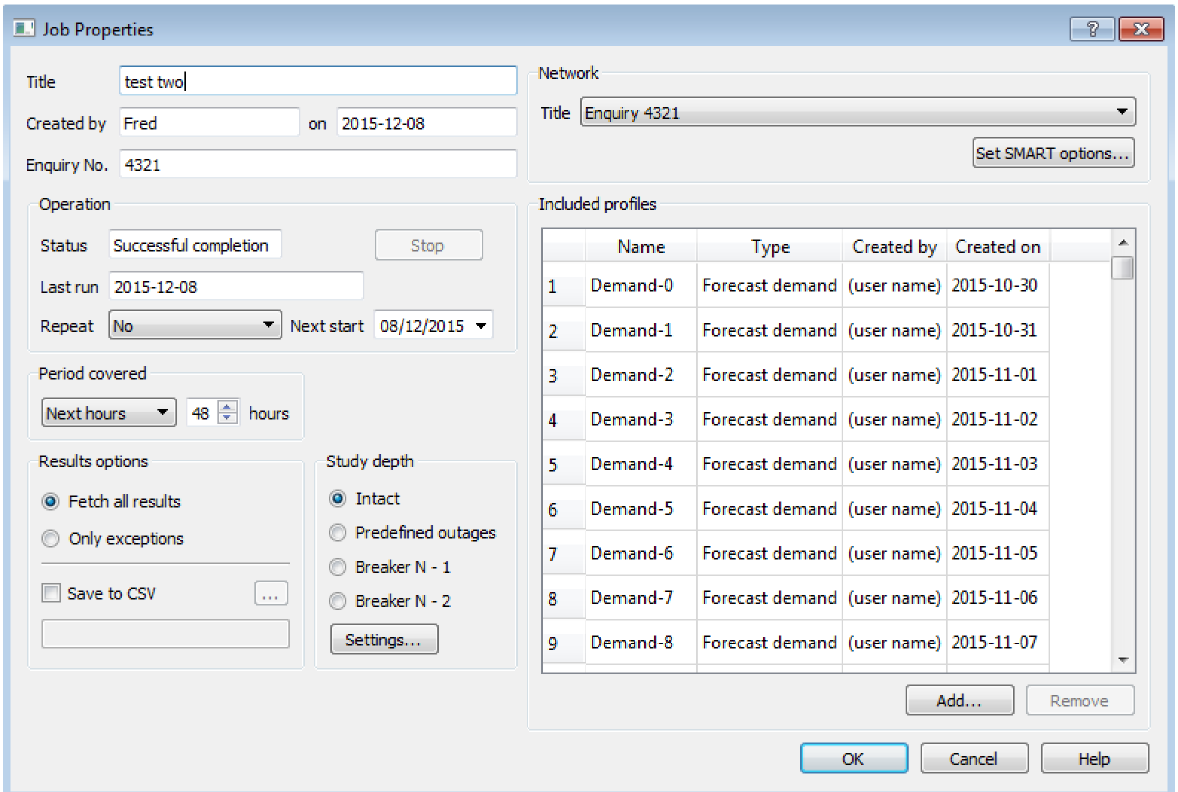
The Client user interface will have a Messages area that will be used to report messages, warnings and errors to the user. Significant messages (such as errors) will bring up a dialog prompting the user to make a choice as to whether to continue or not.

The title bar of the Client confirms which Job is open. Depending upon the current status of the Job, some of the menu options may be disabled.

The Jobs menu allows you to create, edit and run tasks on the APT server:

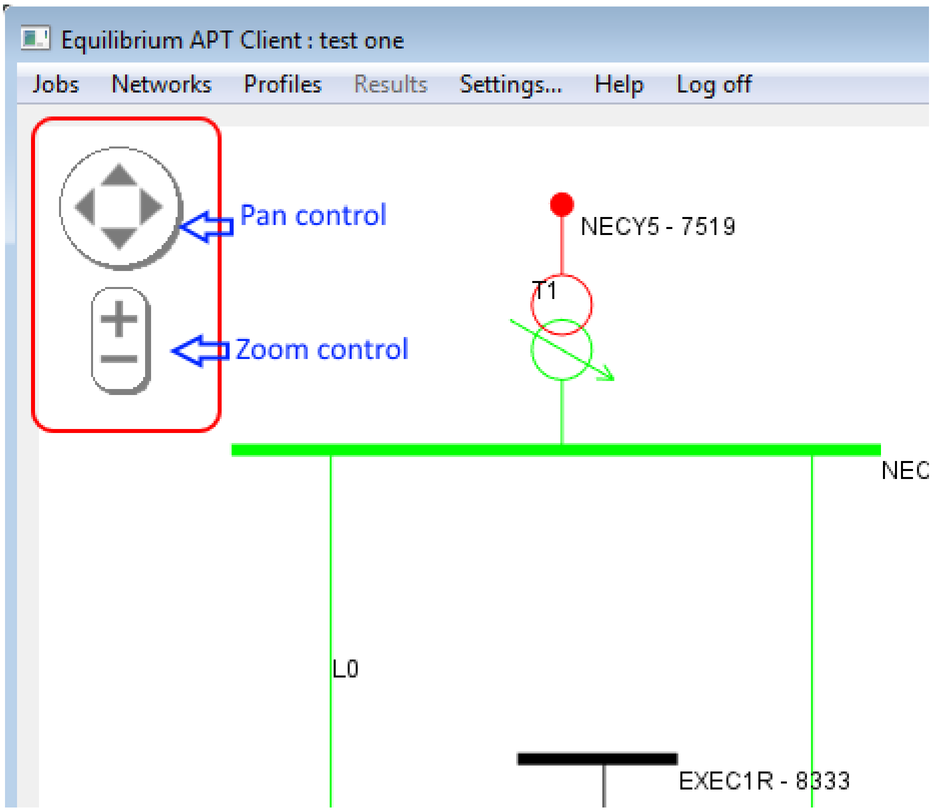
- As there is a requirement to be able to repeat studies, once a Job has been run successfully it cannot be edited (or deleted);
- Jobs can be copied from previous Jobs, or created from scratch;
- With permission to do so, the user can stop Jobs that are running on the Server.

When a job is selected, the Job properties dialog will be displayed. From here, parameters can be set or viewed.



Once a Job has been opened, a network diagram will be displayed in the Client, for example:

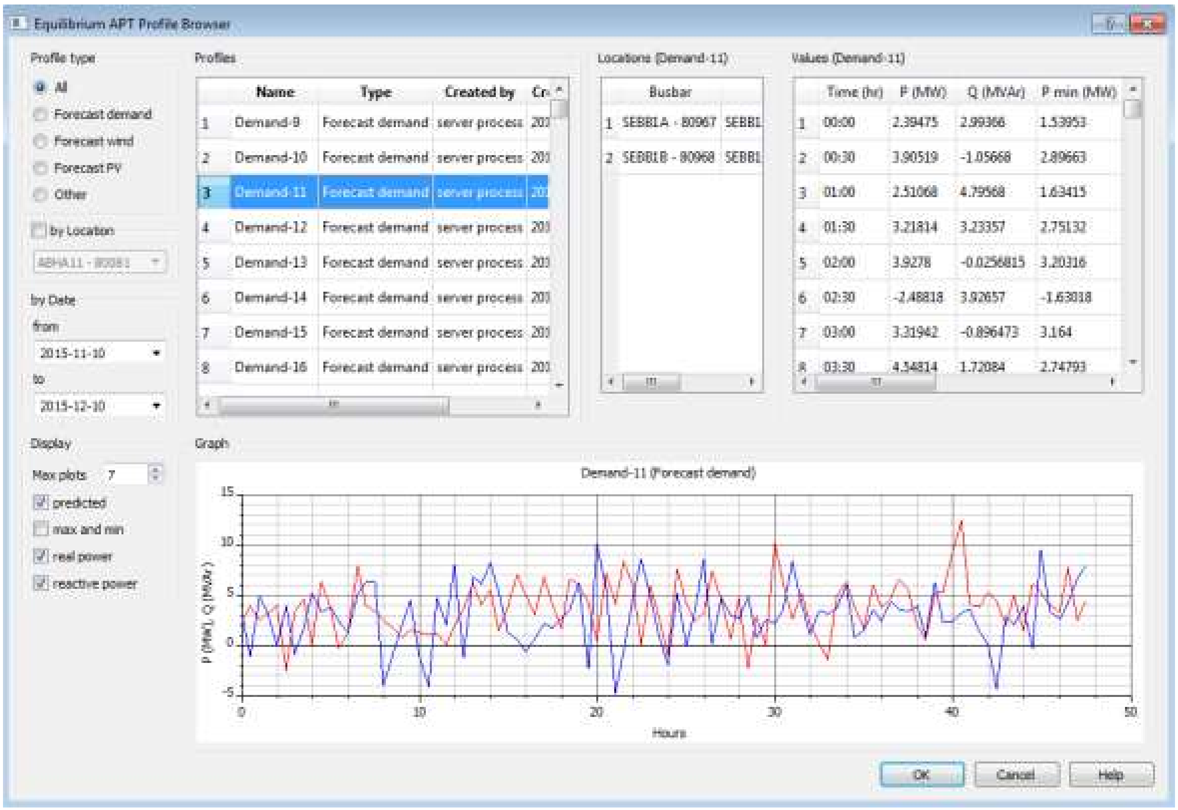

Equilibrium APT Client : no job
Jobs
Networks
Profiles
Results
Settings...
Help
Log off
TOTN1T - 8022
TOTN1S - 8021
TOTN1R - 8028
TOTN1Q - 8029
EXEC1Q - 8331
EXMO3 - 8325
EXMO1R - 8322
EXET1R - 8313
EXET1Q - 8312
EXET14 - 83014
ABHA1J - 8011
ABHA1K - 8012
EXET1 - 8311
TORQ1R - 8032
TORQ1Q - 8031
PAIG1Q - 8369
NEWA1J - 8351
NEWA1K - 8352
SOWT1R - 8370
EXGN1
Messages



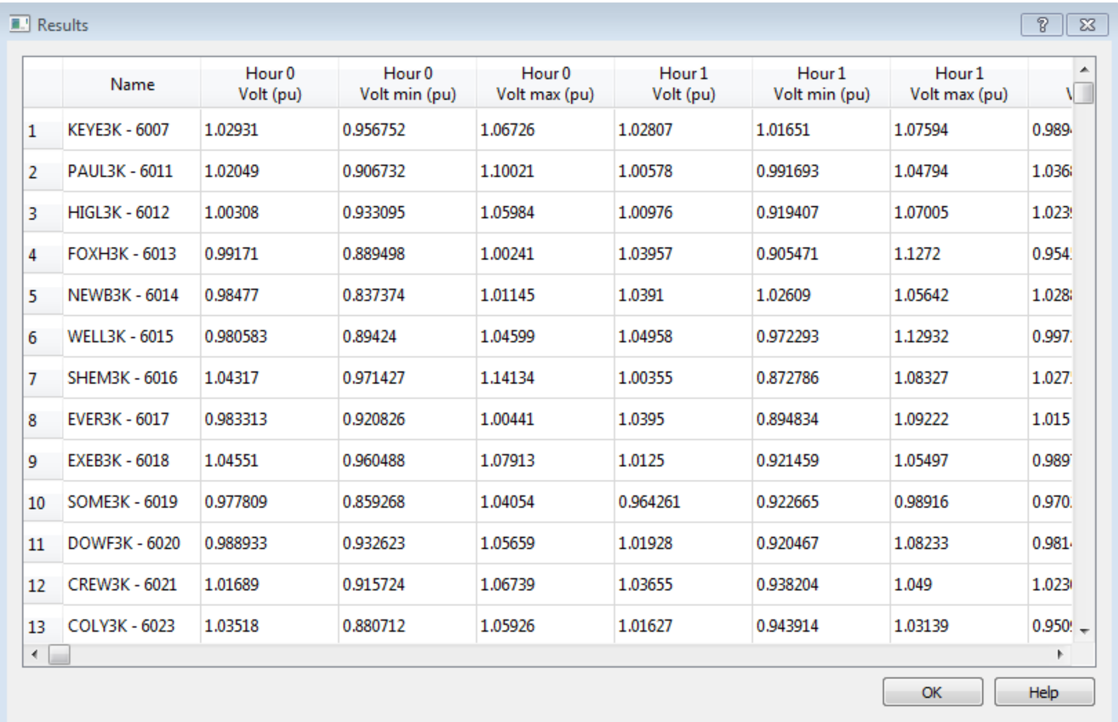
Simple switching of network components can be performed directly from the Network diagram. More complicated operations, such as adding new demand or generation, will require using IPSA to make changes to the network.

The Profiles menu allows the viewing, editing, copying and creation of load and generation profiles on the APT server. The profiles browser allows the users to view all the profiles stored on the APT server; filters allow the user to refine choice of profile based on e.g. location, date range or profile type.

An example of a profile is shown (note that the forecast demand data in this example is random):

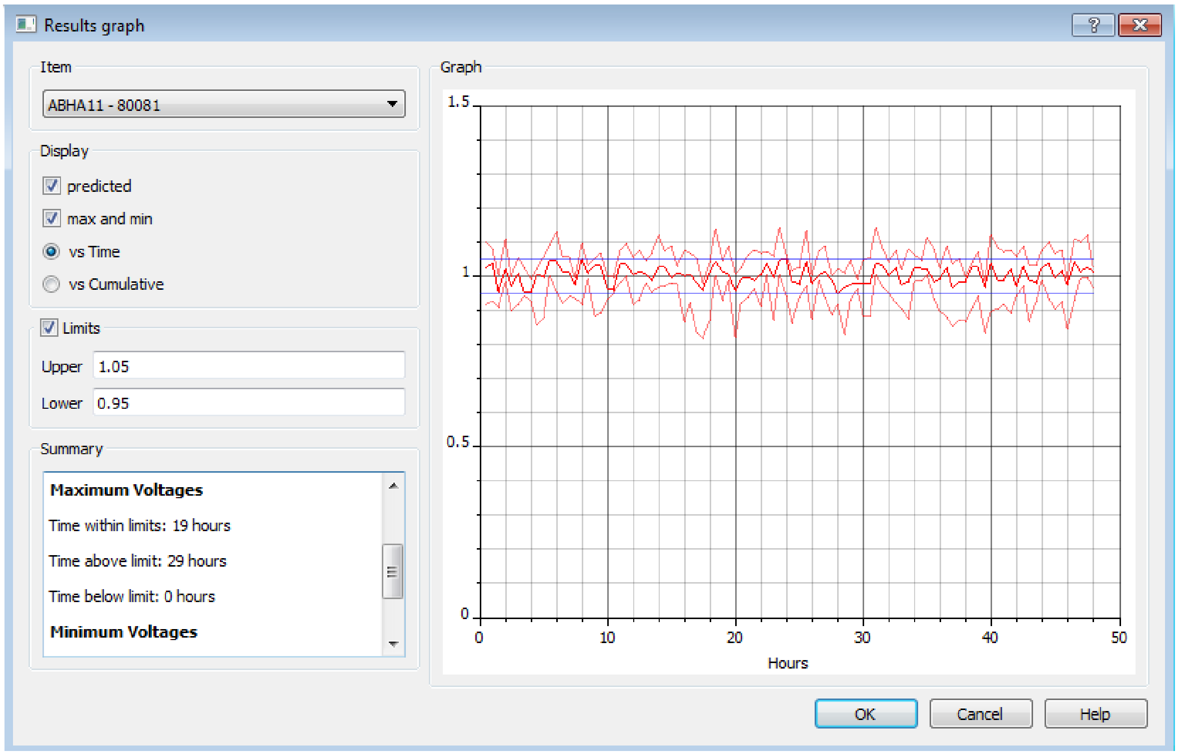


Once a job is complete, the results of the power flow analysis can be viewed in tabular or graph format. Results can be viewed time-series or cumulative. For example:


Results

	Name	Hour 0 Volt (pu)	Hour 0 Volt min (pu)	Hour 0 Volt max (pu)	Hour 1 Volt (pu)	Hour 1 Volt min (pu)	Hour 1 Volt max (pu)	V
1	KEYE3K - 6007	1.02931	0.956752	1.06726	1.02807	1.01651	1.07594	0.989
2	PAUL3K - 6011	1.02049	0.906732	1.10021	1.00578	0.991693	1.04794	1.036
3	HIGL3K - 6012	1.00308	0.933095	1.05984	1.00976	0.919407	1.07005	1.023
4	FOXH3K - 6013	0.99171	0.889498	1.00241	1.03957	0.905471	1.1272	0.954
5	NEWB3K - 6014	0.98477	0.837374	1.01145	1.0391	1.02609	1.05642	1.028
6	WELL3K - 6015	0.980583	0.89424	1.04599	1.04958	0.972293	1.12932	0.997
7	SHEM3K - 6016	1.04317	0.971427	1.14134	1.00355	0.872786	1.08327	1.027
8	EVER3K - 6017	0.983313	0.920826	1.00441	1.0395	0.894834	1.09222	1.015
9	EXEB3K - 6018	1.04551	0.960488	1.07913	1.0125	0.921459	1.05497	0.989
10	SOME3K - 6019	0.977809	0.859268	1.04054	0.964261	0.922665	0.98916	0.970
11	DOWF3K - 6020	0.988933	0.932623	1.05659	1.01928	0.920467	1.08233	0.981
12	CREW3K - 6021	1.01689	0.915724	1.06739	1.03655	0.938204	1.049	1.023
13	COLY3K - 6023	1.03518	0.880712	1.05926	1.01627	0.943914	1.03139	0.950

OK Help



B Non-functional requirements specification

Security:

- No data stored on the APT servers will be confidential to individual customers of WPD.
- The network model, demand and generation profiles stored on the server will only be accessible to users of the APT software who can connect to the APT server.

Performance:

- Power system studies on all BSPs using the 48 hour forecast data will be performed daily. The studies will be timed to complete before the start of WPDs working day, so that the results of the studies will be available when engineers arrive at work.
- Users will also be able to perform their own studies on the APT server. Testing will be performed to determine how long each general type of study takes on the actual WPD network model (e.g. on an intact system, on pre-defined outage scenarios, etc.).
- There will be points at which the number of studies being run by multiple users will begin to impact performance, depending on the type of studies and number of users. These points will be identified in testing and used to determine the hardware specification of the Deployment servers.

- Preliminary and conservative tests on non-server hardware indicate that a 24 hour forecast on the complete intact network model should take less than one minute, while an n-1 contingency on an individual BSP for a 24 hour forecast should also be complete in less than one minute.

Reliability:

- When an error occurs it will be logged, and an appropriate message will be displayed. The software will revert to a stable state as needed.
- During beta-testing, users will be able to report bugs and other concerns.
- Users with Administrator rights will be able to access error log files and user bug reports in order to investigate and resolve the underlying issues.
- All user input forms within the software will have appropriate validation.
- Two Equilibrium servers will be deployed to provide redundancy in case of hardware failure.

Support:

- Two user guides will be provided; one for users with basic rights and one for users with advanced or administrator rights. The two guides will reflect the two different user interfaces that users with different rights will see. The guides will be provided in electronic format.
- The Equilibrium client software will be provided with help files accessible from the client software itself.

Maintenance:

- After final delivery of the APT server and client software, maintenance and updates will be provided by TNEI on a cost basis.
- No custom mechanism will be implemented for creating archived or backup copies of the Equilibrium server databases or network files. Standard Linux backup procedures may be used.
- Updating software or databases on the APT servers will require access to the servers. It is anticipated that this access will remain with WPD's own IR department. Server updates will therefore be provided to nominated people in the IR department, with instructions as to how the updates should be installed.

C Network model methodology

C.1 PSS/E to IPSA

WPD provided a PSS/E model of the South West network which included all network items from the 11kV primary busbars up to and including the 400kV NGET system. The process in Figure 16 was undertaken to convert it from a PSS/E network model to an IPSA model. This is detailed in the following sections.

The original PSS/E network was provided in the form of a PSS/E save case file (SAV format). This was opened in PSS/E in the normal manner and one steady state load flow analysis was successfully performed. The results for the busbar voltage magnitudes and phase angles were then saved in an Excel spreadsheet to provide the basis for the validation of the IPSA network results. The screen shot in Figure 21 shows the load flow setting parameters used for the studies.

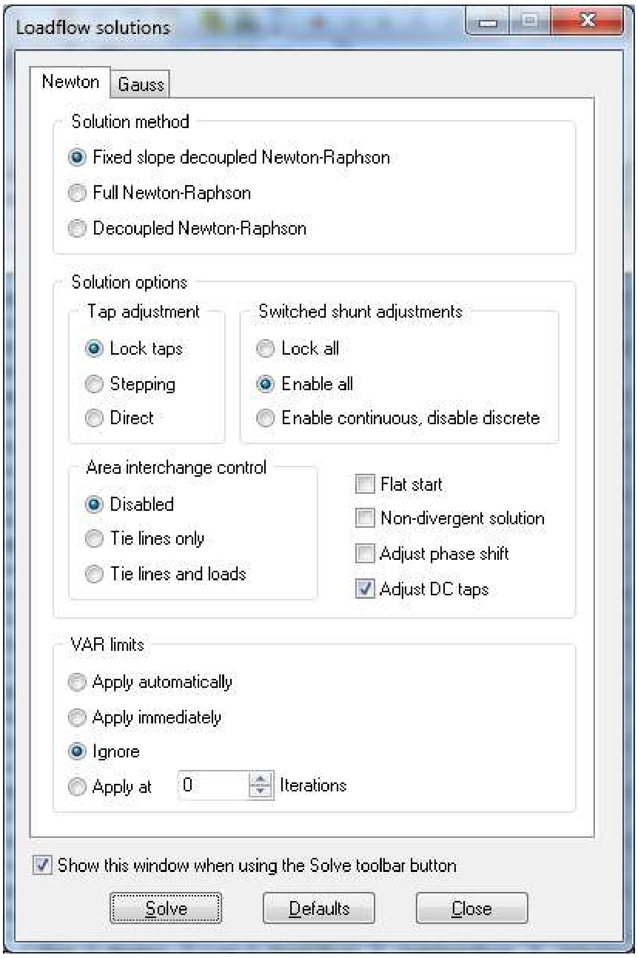


Figure 21 - PSS/E Load Flow Settings

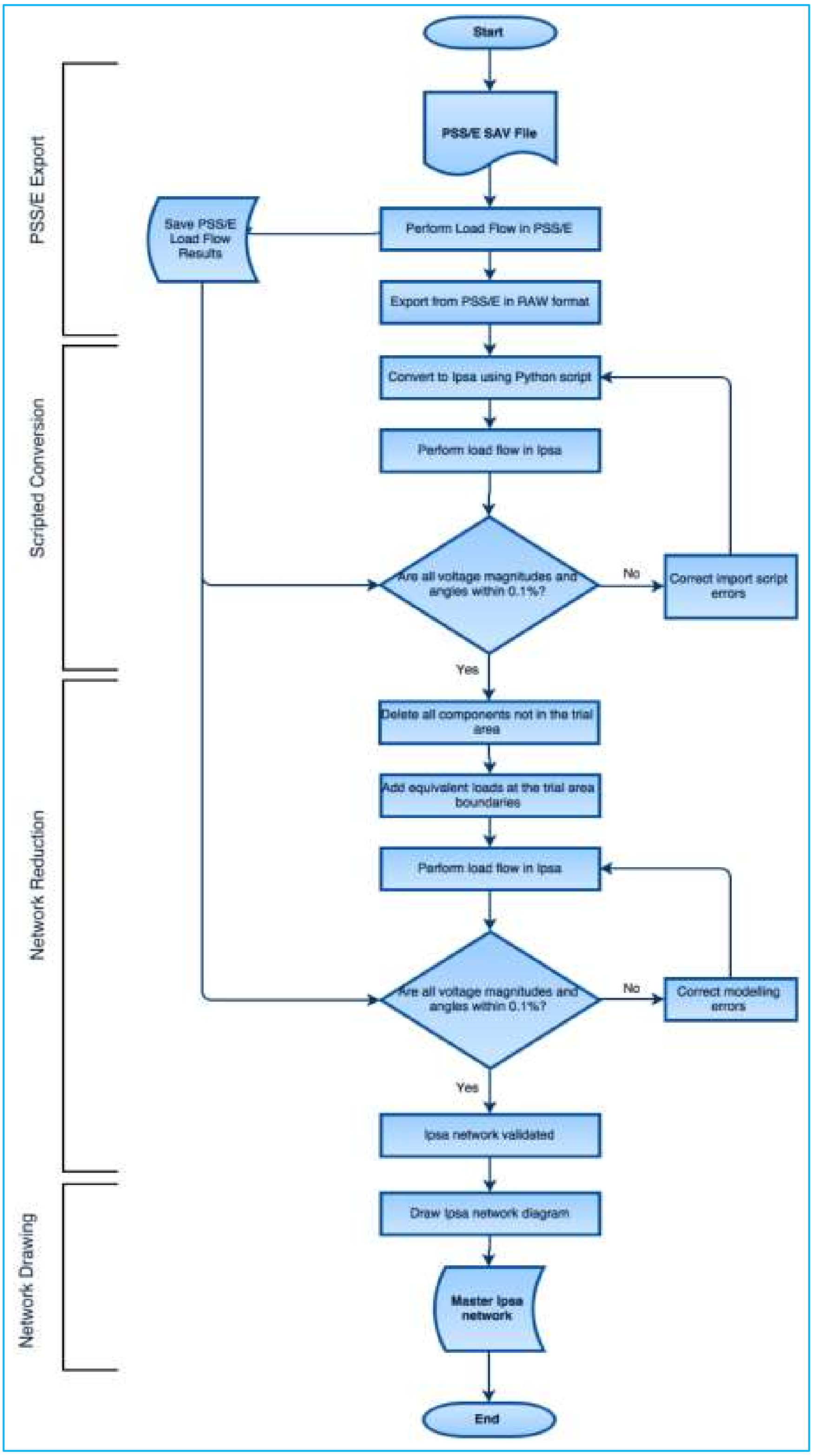


Figure 22 - PSS/E to IPSA Conversion

Other power flow results, for example branch flows, were not saved as these are in fact calculated from the busbar voltages and angles. If the voltages and angles are equal in different models then the individual branch and transformer flows must also be equal.

Any differences in transformer tap position, generator output powers, switched capacitor position etc must affect the busbar voltages and angles in order to change the network power flows in order that the power flow results themselves are affected.

The PSS/E network was then saved in a human readable text format (RAW format) as an input to the next stage.

C.1.1 Scripted Conversion

IPSA has a PSS/E to IPSA conversion utility that is provided in the form of a Python script. This script reads the PSS/E RAW file and creates an IPSA network based on the RAW file contents. It is supplied as part of the normal IPSA installation.

The IPSA network created includes all impedance data as well as generator power limits, transformer tap changer limits and position, switched capacitor limits and position and loading data. Sequence data, used for fault level studies, was not imported. The RAW file does not contain any diagram data, so diagrams in IPSA must be drawn manually.

An important inclusion was the conversion of the PSS/E zones and areas to groups in IPSA. This provided a mechanism for deleting components from the network that were not required.

The script was run for the generated RAW file which performed the full conversion and saved the resulting network in IPSA format.

Validation studies have been undertaken to demonstrate that the IPSA load flow results provide an accurate match compared to the PSS/E results. The validation studies were performed under the same conditions as the initial PSS/E load flow studies, such as locked transformer tap changers.

The load flow results for the busbar voltages and phase angles were then copied to an Excel spreadsheet and compared to the PSS/E results already obtained.

Initially, some significant differences were identified between the two result sets. Data checks on the IPSA network identified a small number of conversion errors which were then rectified.

Further iterations of the conversion and load flow analysis identified two inconsistencies between the PSS/E and IPSA load flow results. These are described below together with the resolutions.

C.1.2 Network Validation

Following the resolution of each issue the maximum mismatches between the PSS/E and IPSA models was obtained. A tolerance of 0.1% was used in order to determine if the IPSA results were sufficiently accurate. Figure 23 illustrates the spread of the voltage errors when compared to the original PSS/E model.

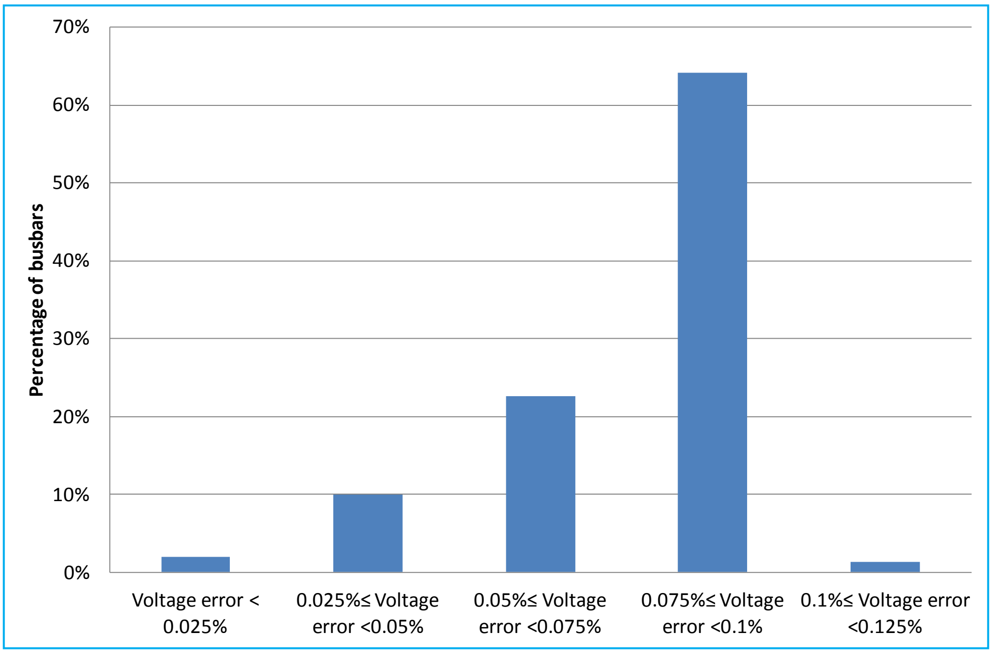


Figure 23 – Validation Results after PSS/E to IPSA Conversion

In total, there are 2252 busbars. For 2223 busbars, the voltage magnitude mismatches are within 0.1%. For the remaining 29 busbars, the voltage magnitude mismatches are slightly over 0.1%, with the maximum mismatch of 0.12%.

C.1.3 Trial area network

Up to this stage the PSS/E and IPSA networks have represented the full WPD South West network area. Next, all components from the IPSA network that are not required for the trial area network were deleted:

- All 11kV components outside the main trial area
- All 33kV components outside both the main trial area and the two adjacent 33kV only areas

This process was achieved by utilising the groups feature in IPSA. The zones in the original PSS/E network had been imported into IPSA as groups, each typically representing a BSP or GSP. The groups that were not required were further filtered by voltage level and the remaining components deleted from the IPSA network. For example the PSS/E zone 290 for Fraddon 33kV is not included in the trial area. This group does not include any 132kV components and therefore all of its components were deleted from the IPSA network.

In order to maintain the same network voltages and power flows loads were added to the IPSA network to represent the deleted components, for example loads were placed at the 132kV Fraddon busbars to mimic the power flows through the 132/233kV transformers. This process was undertaken using a Python script. This process was also repeated on the 33kV circuits that crossed the trial area boundary. The details of the original and trial area network models are summarized in Table 21.

Table 21 Full network area versus trial network area

Component Type	Full IPSA Model	Trial Area Model
Busbars	2252	934
Branches	1952	835
Transformers	890	835
Loads	351	228
Generators	981	305
MSCs	31	22

On completion of the network removal further load flow studies were undertaken, as described in Section C.1.2, to confirm that the accuracy of the model was not comprised. The final error magnitude and distribution is shown in Figure 24.

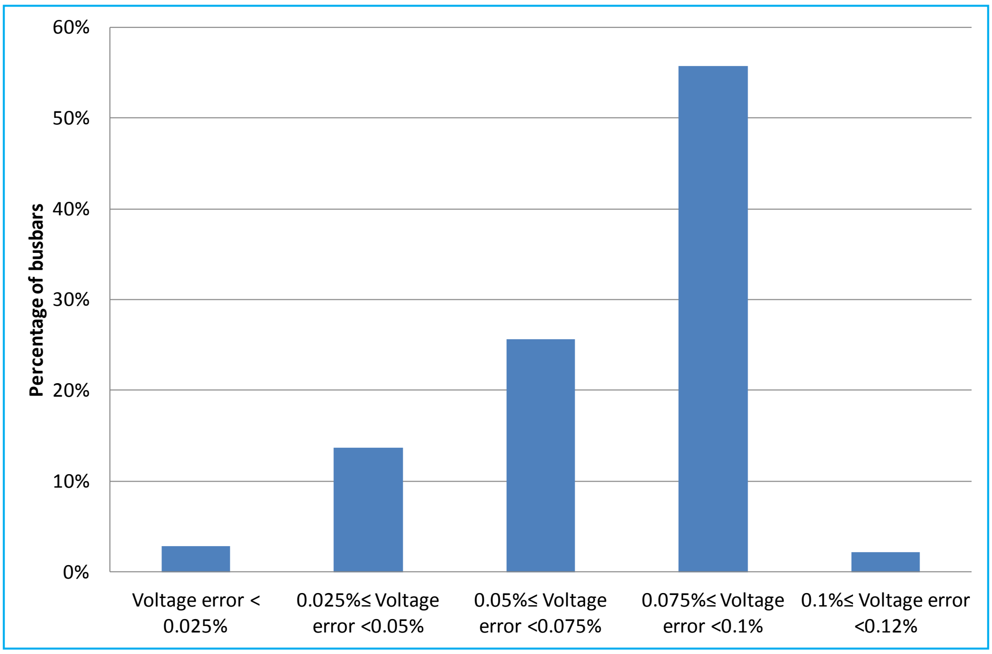


Figure 24 – Validation Results after Network Reduction

After reduction, there are 934 busbars in total. For 914 busbars, the voltage magnitude mismatches are within 0.1%. For the remaining 20 busbars, the voltage magnitude mismatches are slightly over 0.1%, with the maximum mismatch of 0.115%.

C.1.4 Network Drawing

The last stage of the PSS/E to IPSA conversion involved the creation of the IPSA network diagram. This represented all the components in the network laid out in a similar arrangement to the existing PSS/E diagrams.

The resulting IPSA network file represented the converted and validated PSS/E network for the trial area.

C.2 DINIS to IPSA

Additional work, described in this section, was required to add in the detail of the 11kV feeders in the trial area.

WPD provided a DINIS model of the South West network which included all the 11kV busbars, junctions, cables and overhead lines. Due to the large number of busbars in the DINIS networks, typically approximately 600 per 11kV primary substation, the project required that these networks were reduced down in order to reduce the overall analysis times.

The network reduction was originally intended to reduce each 11kV feeder to approximately four busbars. Following discussions with the end users and examination of the network a number of additional constraints were added to the network reduction:

- Normally open points (NOP) on the feeders were to be maintained:
    - Network planners would require the NOPs in order to investigate system operation under abnormal conditions;
    - Some feeders may have enough NOPs such that more that 4 busbars would be required to represent the overall feeder;
- Keep the busbar with the lowest voltage:
    - One of the principal aims of the Equilibrium project is to investigate how new technologies, such as System Voltage Optimisation, can be used to manage the network voltages. It is therefore important that the reduced feeders represent the full range of voltages present on the original feeder.

The network import was further complicated by the following additional factors:

- The DINIS network data did not contain any loads
    - Whilst sufficient data was provided to allow load flow analysis, the absence of load data would have resulted in a flat voltage profile along each feeder;
    - Customer numbers were available as well as secondary transformer ratings (11kV to 415V transformers);
    - No generators were modelled in the DINIS network; generation data was provided in the form of a spreadsheet with generator ratings and feeder locations.

C.2.1 DINIS Conversion

IPSA also has a DINIS to IPSA conversion utility that is provided in the form of a Python script. This script reads two DINIS files and creates an IPSA network based on the file contents. One file contains the network data, including geographic coordinates, the other is a data base of cable and overhead line types to impedances.

The IPSA network created includes all impedance data as well as the connectivity. Where provided the transformer parameters, load and generation data is also imported. The DINIS file contains sufficient information to allow a geographic representation of the network to be created in IPSA.

In order to use this process for Equilibrium a number of changes to the standard conversion script were required:

- DINIS networks normally use global object references (GOR) to uniquely identify individual components. The WPD network did not contain GOR references and therefore the script was adjusted to use the grid references to identify components;
- For the purpose of performing load flow studies the substation demands were estimated to be 30% of the transformer nameplate rating;
- Split network by primary substation:
    - Due to the large file size additional code was required to identify all components in a single primary substation;
    - This permitted the networks to be saved and reduced on a primary by primary basis;
    - This was achieved by use of a graph module which identified all connected components when the NOP branches were omitted from the network;
- Adjust busbar names:
    - The names of the DINIS primary substation busbars were changed to reflect those in the PSS/E network, for example, the primary busbar for Millfield was named MILL5 – 7492;
    - This allowed IPSA to successfully merge each primary DINIS network with the overall IPSA network;
    - All other DINIS busbars retained the original DINIS site name where given;
    - Any DINIS busbar without a site name was given a default name based on the primary busbar name and a unique number. For

example busbars in the Millfield primary were named MILL5_xxx where xxx started at 1.

Following the DINIS to IPSA conversion a load flow was performed to ensure that the network would be suitable for further analysis. The resulting IPSA network file was then saved for merging into the main IPSA network.

The final stage of the DINIS conversion added additional data into the IPSA model in order to retain important data which may be used by network planners. This data comprised:

- Original grid references for the site;
- Primary busbar name;
- 6 digit Primary reference number;
- Feeder/circuit breaker number;
- 6 digit site reference number;
- Enquiry number.

C.2.2 Network Reduction Methods

Two methodologies were identified for the reduction of the feeders, these being most appropriate to radial networks:

- Remove or reduce branches based on order of increasing impedance magnitude
  - This method would work with no loading data or load flow results
  - It could also be performed with loading data
- Remove or reduce branches based on order of increasing voltage drop along the branch
  - This method would require a set of representative load flow results

The network reduction code was added to the DINIS conversion script such that the full converted network could then be reduced by any of the available techniques.

Each of these techniques is described below together with results from the reduction of the Millfield primary substation.

C.2.3 Overall Reduction Methodology

All the reduction techniques applied the following common operations to the full network:

- Combine two series branches into a single branch:
    - Removes the intermediate busbar;
    - Load at the intermediate busbar must be moved to one of the new branch ends;
    - If load flow results are available the new load value is selected to give the same voltage drop along the branch;
    - If no load flow results are available no load adjustment can be made;
    - All branch impedances are combined into a single multi-section branch.
- Remove a spur branch completely:
    - A busbar with only one branch connected to it can be removed completely;
    - Any load at the busbar must be moved to the opposite end of the single branch, taking losses into account;
    - Can only be applied at circuit or feeder ends.

C.2.4 Combination of Two Branches

Two branches can be combined together at any busbar which has only two branches connected to it. If a busbar has more than two branches connected to it, for example at a tee point, then any additional branches must be removed first in order to leave two series connected branches.

Figure 25 illustrates the reduction of two branches into a single branch.

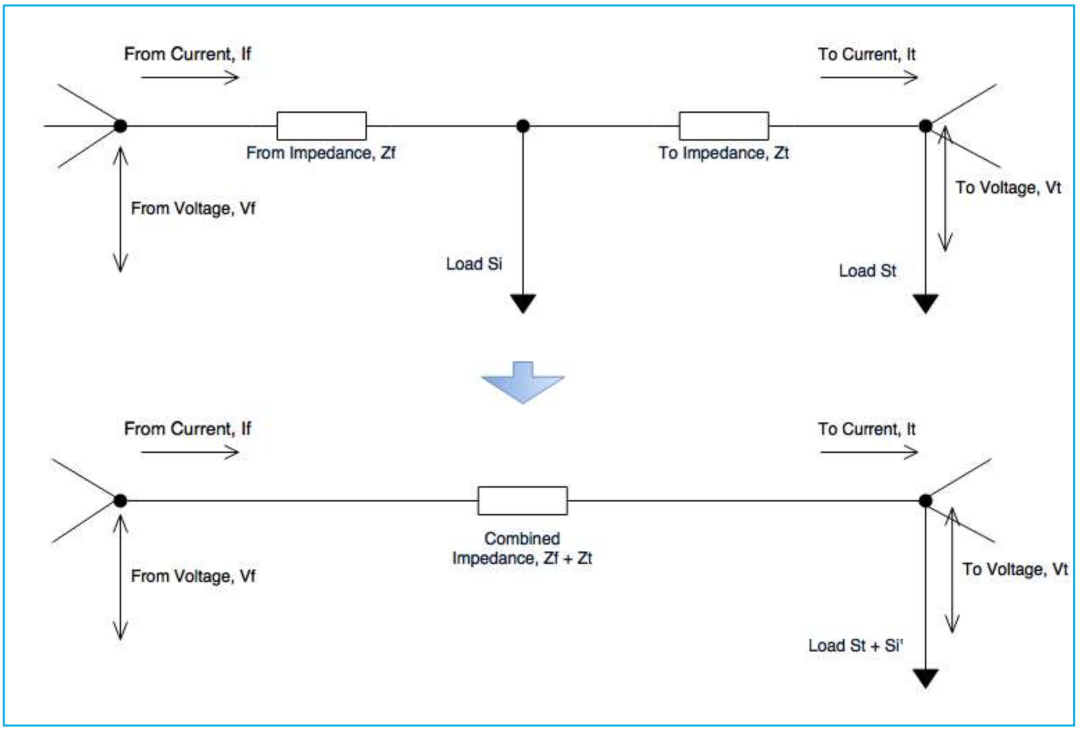


Figure 25 - Combination of Two Branches

If a load flow analysis has been performed then the voltages and currents at each end of the two branches are available. This information is used to ensure that the combined voltage drop across both branches is kept constant. The following steps are performed:

Calculate total branch impedance using a two port model to determine $Z_f + Z_t$:

$$Z_{1+2} = \begin{bmatrix} a_1 & b_1 \\ c_1 & d_1 \end{bmatrix} . \begin{bmatrix} a_2 & b_2 \\ c_2 & d_2 \end{bmatrix}$$

Where:

$$a_n = 1 + \frac{Z_n + B_n}{2}$$

$$b_n = Z_n$$

$$c_n = B_n . \left(1 + \frac{Z_n . B_n}{4}\right)$$

$$d_n = 1 + \frac{Z_n + B_n}{2}$$

Z_n = Complex branch impedance for branch n

B_n = Complex branch susceptance for branch n

Calculate the new 'to' current I_t required to give the same voltage drop ($V_f - V_t$) across the combined branch. This current represents the current flow in any loads connected at the 'to' busbar plus the flow in any other branches connected to the 'to' busbar.

$$\begin{bmatrix} V_{from} \\ I_{from} \end{bmatrix} = \begin{bmatrix} a & b \\ c & d \end{bmatrix} . \begin{bmatrix} V_{to} \\ I_{to} \end{bmatrix}$$

$$I_{to} = \frac{V_{from} - a.V_{to}}{b}$$

Calculate new 'to' end load (St + Si') to give the same current flow, taking into account any current flow leaving the 'to' busbar down other connected branches.

$$S_{to} = V_{to}.(I_{to} - I_{other})^*$$

Connect the new load (St + Si') into the network

Replace the original from and to branches with a single multi-section branch which includes all sections of both original branches. Note that this does not use the two port model but simply creates a combined multi-section branch

If load flow results are not available then a simple reduction of the branch impedances is undertaken.

C.2.5 Remove a spur branch completely

A single branch can be combined together removed from the network if it forms the end of a feeder, i.e. it is the only branch connected to a particular busbar.

Figure 26 illustrates the removal of one branch from the network.

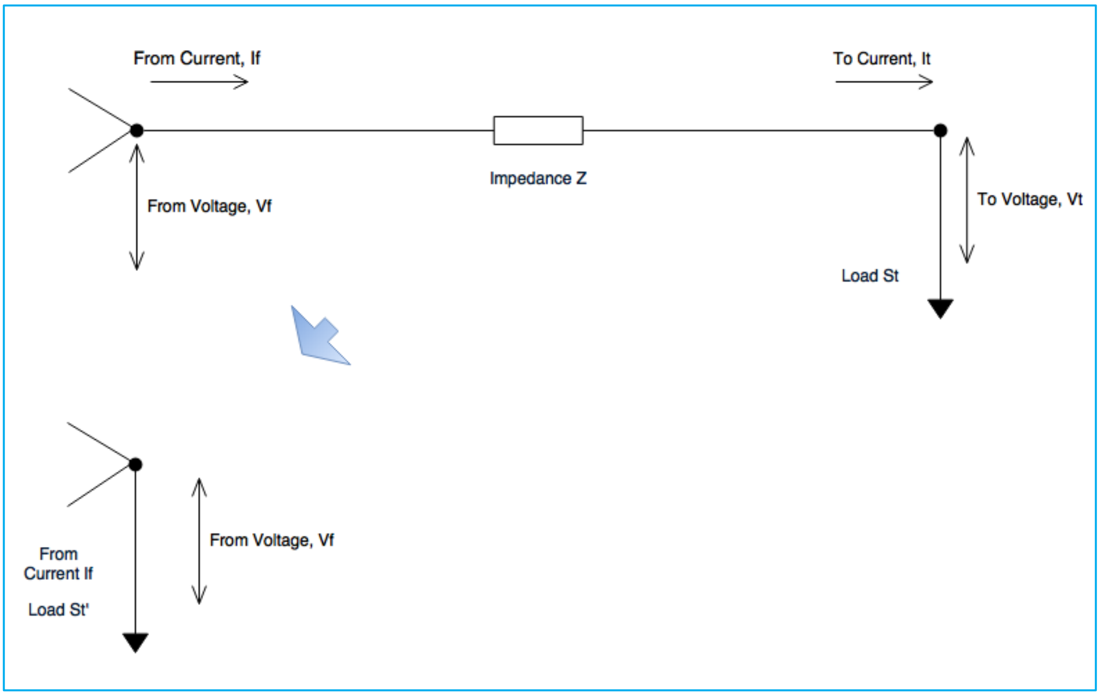


Figure 26 – Removal of One Branch

If a load flow analysis has been performed then the voltages and currents at each end of the branch is available. This information is used to ensure that any load at the 'to' end of the branch is moved correctly to the 'from' end. This process must take account of the branch losses to ensure that the voltages and currents at the 'from' end of the branch are unchanged. This simply requires the 'from' end load to be calculated from the 'from' end voltage and current.

If the load flow results are not available then the branch is simply removed from the network.

C.2.6 Reduction Method

The complete reduction method uses both the above techniques to iteratively remove branches and busbars from the network. This process is performed on a feeder by feeder basis for a complete primary, then for each primary in the network.

The order in which the branches are removed is determined to the magnitude of the branch voltage drop or the branch impedance magnitude.

In order to determine which method provided sufficiently accurate results the Millfield primary substation was chosen to provide a sample network for comparison of the different results. All the reduction methods were applied to the Millfield network and the voltage profiles obtained for the resulting networks.

The original converted Millfield network includes approximately 530 busbars, 540 branches and 230 assumed loads at identified transformer HV nodes. These are divided between eight feeders, two of which are dedicated PV generation connections. No generation was included in the DINIS network however it is known that at least two PV sites have dedicated feeders connected to the Millfield busbars. Note that some of the 540 branches represented the NOP connections to adjacent primaries.

Transformer nameplate ratings were available and therefore static loads at a power factor of 0.95 lagging and equal to 30% of the rating were added to the model. This allows results to be obtained from load flow calculations allowing the voltage drop reduction technique to be applied.

Table 22 provides further details on the breakdown of the Millfield network. This excludes the PV only feeders which comprised single cables.

Table 22 Millfield network summary

Demand Feeders	Number of Branches	Number of Loads	Feeder Load (MVA)
Feeder 0924	61	27	2.20MVA
Feeder 0925	34	19	2.59MVA
Feeder 0926	174	70	1.68MVA
Feeder 0927	60	26	1.67MVA
Feeder 0928	61	28	2.67MVA
Feeder 0929	139	63	4.15MVA

Table 23 provides the network make up following application of the three reduction methods including the percentage reduction in the number of components compared to the base case.

Table 23 Comparison of reduction methods

	No Load Impedance based reduction		Loaded Network Impedance based reduction		Loaded Network Voltage drop based reduction	
Demand Feeders	Branches	Loads	Branches	Loads	Branches	Loads
Feeder 0924	16 -74%	0	17 -72%	12 -56%	13 -79%	44 -59%
Feeder 0925	8 -76%	0	9 -74%	5 -74%	9 -74%	6 -68%
Feeder 0926	17 -90%	0	15 -91%	11 -84%	11 -94%	7 -90%
Feeder 0927	3 -95%	0	10 -83%	8 -69%	7 -88%	4 -85%
Feeder 0928	11 -82%	0	13 -79%	8 -71%	11 -82%	6 -79%
Feeder 0929	12 -91%	0	11 -92%	8 -87%	13 -91%	10 -84%

Load flow studies were undertaken on the base case network and the reduced networks in order to identify any differences in the reduction methods. Table 24 provides a comparison of the different reduction techniques with the base case. The voltage at the primary Millfield busbar was 100% in all cases. The change in the feeder demands has also been included.

Table 24 Comparison of reduction methods

	Base Network		Loaded Network Impedance based reduction		Loaded Network Voltage drop based reduction	
	Min Feeder Voltages % (% errors in brackets)	Feeder Demands (MVA)	Min Feeder Voltages % (% errors in brackets)	Feeder Demands (MVA)	Min Feeder Voltages % (% errors in brackets)	Feeder Demands (MVA)
Feeder 0924	98.9%	2.20MVA	97.8% (-1.1%)	1.75MVA (-0.45MVA)	98.6% (-0.3%)	2.24MVA (+0.04MVA)
Feeder 0925	98.7%	2.59MVA	98.5% (-0.2%)	2.44MVA (-0.15MVA)	98.4% (-0.3%)	2.80MVA (+0.21MVA)
Feeder 0926	96.6%	1.68MVA	95.6% (-1.0%)	1.38MVA (-0.3MVA)	95.3% (-1.3%)	1.63MVA (-0.05MVA)
Feeder 0927	98.0%	1.67MVA	97.7% (-0.3%)	0.98MVA (-0.69MVA)	98.0% (0.0%)	0.95MVA (-0.72MVA)
Feeder 0928	98.8%	2.67MVA	98.4% (-0.4%)	2.18MVA (-0.49MVA)	98.0% (-0.8%)	2. 70MVA (+0.03MVA)
Feeder 0929	93.5%	4.15MVA	92.9% (-0.6%)	2.93MVA (-2.22MVA)	92.8% (-0.7%)	3.13MVA (-1.02MVA)
Average % Error			-0.6%		-0.6%	
Total MVA Demand		14.96MVA		11.66MVA -12.1%		13.45MVA -10.1%

It was decided that the voltage drop based reduction method be used, since this method best maintained similarity to the base network.

C.3 Master Model Creation

The activities undertaken in Sections C.1 and C.2 resulted in a single converted PSS/E model plus one 11kV model for each primary substation. These models were then combined and drawn in order to create a single master network model suitable for the power system analysis studies.

The following activities were undertaken to combine the models.

C.3.1 Prepare 11kV Models

The DINIS conversion process resulted in one 11kV network model per primary substation, a total of 82 separate files. A Python script was written to merge these separate networks into the PSS/S derived network.

The script addressed the following issues:

- Merge NOP circuits:
  - Most networks included normally open (NOP) circuits which connected between different primary substations. Each NOP circuit was therefore present in two separate networks;
  - The merge scripts identified these NOP circuits and ensured that the final network model included only one instance of each unique NOP branch.
- Identical busbar names:
  - Some of the DINIS busbars had similar or identical busbar names. The only method of identifying uniqueness was to use the busbar grid references;
  - The merge script identified busbars by grid reference and ensured that unique names were created for these busbars.
- Additional primary loads:
  - The DINIS reduction process resulted in a lower total load at each primary substation. This was due to the combination of higher combined branch impedance and lower load in order to give the same voltage drop;
  - Additional loads were placed at each primary substation in order to ensure that the same total feeder demand was applied at the primary substation;
  - This in turn ensured that the total load at 33kV and above was also maintained.
- Additional extended data was also added to each 11kV busbar; this data included:
  - Primary substation name;
  - Primary substation reference number;

  - Site reference number;
  - Grid reference;
  - Feeder name;
  - Load scaling factor .
- NOP branches at the edge of the trial area, connecting to nodes outside the trial area were deleted from the 11kV models.
- Add generation:
  - The original DINIS networks did not contain any details of the location of connected generation;
  - A Python script was executed to add a generator at each busbar where generation existed;
  - The list of generator MPANs was used to identify the approximate location of this generation and to total up the generation at each DINIS busbar;
  - The final generator added at each IPSA busbar represented the total generation found in the MPAN file for that DINIS location.

Completion of the above operations resulted in a single combined IPSA model of the trial area plus the relevant adjacent circuits. Checks were undertaken to ensure that the load flow calculations could be undertaken successfully.

Careful control of the transformer tap changers was required initially in order to achieve a solved power flow. Initially all the target voltages were set to unity and all tap changers locked at a tap position of 0%. A series of load flows was then undertaken to restore the original tap changer settings. This process started with the 400kV transformers and continued in stages for each voltage level down to 11kV. At each stage the original target voltages were reapplied and the tap changers unlocked.

This process identified some suspect transformer data which resulted in high levels of circulating reactive power. Minor differences in the target voltages, bandwidths and tap step across transformers at the same substation resulted in one transformer moving to an extreme tap position in order to attempt to control the substation voltage. This was a particular issue at sites with 3 grid transformers.

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