Customer-Led Network Revolution

Review of the Distribution Network Planning and Design Standards for the Future Low Carbon Electricity System

DOCUMENT NUMBER

CLNR-L186

AUTHORS

Manuel Castro, Duncan Yellen, Daniel Hollingworth and Ronnie Mukherjee, EA Technology

Christian Barteczko-Hibbert, Robin Wardle, Chris Dent, Durham University

Rupert Way, Newcastle University

Customer-Led Network Revolution

Contents

Reviewed by	Alan Creighton, Michael Walbank and Dave Miller, Northern Powergrid
	Chris Dent, Durham University
Approved by	Mark Nicholson, Northern Powergrid

Date	**Issue**	**Status**
31/10/14	1.0	Published

Executive summary

The Customer-Led Network Revolution (CLNR) project is the UK's largest smart grid, research and innovation project. The CLNR project is led by Northern Powergrid in partnership with British Gas, Durham University, Newcastle University and EA Technology.

More than 11,000 domestic, industrial and commercial customers are taking part in the project, which involves the trialling of innovative smart grid solutions on the Northern Powergrid electricity network and the trialling of novel commercial arrangements to encourage customer flexibility.

The project will support distribution network operators like Northern Powergrid finding cost-effective ways to manage the introduction of low carbon technologies like solar PV, heat pumps and electric vehicles and to ensure customers continue to receive a safe, secure and affordable electricity supply now, and in a low-carbon future. The project is testing flexibility in the way customers generate and use electricity and help network operators finding ways to reduce customers' energy costs and carbon footprint in the years to come.

The CLNR project have set up a number of test cells to enhance the understanding of existing and future customer generation/demand profiles and the potential flexibility of different customer types. This report uses the wealth of information collected from these real-world customer field trials to explore the challenges posed by the integration of new distributed generation and demand technologies to the current planning and design standards. The UK electricity distribution systems were considerably expanded in 1950s and 1960s to meet the increasing customer requirements. The networks were developed in accordance with network planning and design standards that have stood the test of time and are still relevant today. Nevertheless, the integration of these new technologies in the network, with fundamentally different technical and operational characteristics to those of the incumbent technologies, will prompt the need to establish how they should be treated in the planning and design of distribution networks and to establish whether modifications to the standards should be made.

In this context, this report reviews:

- ACE Report No. 49[1] for the design of low voltage radial distribution networks, demands and voltage by understanding future basic demand profile of regular domestic customers and those with heat pumps, electric vehicles and solar photo-voltaic cells using smart meter data.
- Engineering Technical Report (ETR) 130[2] for assessing the capability of a distribution network containing distributed generation to meet demand, in order to comply with the security requirements of ER P2/6[3], by exploring the information collected from test cells related to profiling distributed generation.
- Engineering Recommendation (ER) G59/3-1 for the connection of generating plant to the distribution systems of electricity distribution licence holders by exploring the information collected from test cells related to profiling distributed generation

[1] ENA, 1981. "Report on Statistical Method for Calculating Demands and Voltage Regulations on LV Radial Distributions Systems", Energy Networks Association, 1981.
[2] ENA, 2006. "Engineering Technical Report 130, Application Guide for Assessing the Capacity of Networks Containing Distributed Generation", Energy Networks Association, Engineering Directorate, July 2006.
[3] ENA, 2006. "Engineering Recommendation P2/6, Security of Supply", Energy Networks Association, Engineering Directorate, July 2006.

The key recommendations to consider during a future fundamental review and update of ACE 49 Report can be summarised as follows:

- **R1**. To review and update the load curves of ACE 49 Report to represent the characteristics and behaviour of present electricity customers in accordance with the work developed and findings of the CLNR project.

The demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyle and behaviour. In this context, customers' use of electricity in a dissimilar manner to that of the ACE 49 Report. The new load shape and lower annual electricity consumption of domestic customers lead to lower utilisation of the network assets during peak load conditions and to a consequent decrease of network reinforcement requirements. This work provides and recommends a generic set of load curves representative of domestic customers together with the demand factors 'p' and 'q' and associated values of 'P' and 'Q'. These load curves can be directly applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems.

- **R2**. To review and update the types of customers of ACE 49 Report to represent present customers in accordance with the work developed and findings of the CLNR project.

The ACE 49 Report has broadly defined domestic customer types according to their electricity tariff (e.g. unrestricted, restricted), type of heating (e.g. water, space), electrical appliances (e.g. electric cooking), electricity consumption (i.e. low, medium, high), etc. Nonetheless, the demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyle and behaviour. This work recommends to review and update the types of domestic customers of ACE 49 Report in accordance with the socio-demographic segmentation used in the CLNR project as these attributes were observed to shape the way customers use electricity.

- **R3**. To consider additional load curves and generation curves in the ACE 49 Report to represent low carbon technologies.

The increasing presence of LCTs (e.g. heat pumps, electric vehicles, solar photovoltaic) in the electricity distribution network with fundamentally different technical and operational characteristics will drive a dissimilar impact to that of the incumbent technologies. Since ACE 49 Report does not consider LCTs, this work provides and recommends a generic set of load and generation curves representative of the operating regime of LCTs. This set of curves together with the demand and generation factors 'p' and 'q' and associated values of 'P' and 'Q' can be directly applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems. It is noted that these load and generation curves should be considered in addition to the load curve of a customer as they do not represent the overall load of a customer.

- **R4**. To consider the effects of seasonality in the ACE 49 Report.

Network planners have traditionally considered conditions of peak demand (i.e. central winter period – November to March) to evaluate the sufficiency of distribution network capacity. The significant presence of LCTs (e.g. distributed solar photovoltaic and wind power) in the LV networks are likely to cause voltage regulation problems during coincidence of low daytime demand and high distributed low carbon generation. This work has demonstrated that the coincidence of high solar photovoltaic with low demand during the summer period may cause voltage headroom constraints in the network depending on the penetration level of distributed solar photovoltaic generation and network characteristics and topology. These voltage headroom constraints are driven by the surplus power of solar photovoltaic DG being injected in the network at times of low demand. In this sense, the inclusion of a network study for the summer period should be considered during a future review of the ACE 49 Report to ensure the robustness of the network design against voltage rise.

The key recommendations to consider during a future fundamental review and update of ETR 130 can be summarised as follows:

- **R1**. To review and update the current F-factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project.

The security of supply standard for the planning and design of distribution networks suggests that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". In this respect, it is recommend to review and update the current F-factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project. This supports DNOs to better recognise the contribution that DG makes to the system security and therefore to comply with the security requirement ER P2/6.

- **R2**. Review of the ETR 130 methodology for assessing the contribution of DG to network security.

The consideration within the CLNR project of the modelling structure underlying ETR 130 reveals a number of concerns about how the planning methodology contained therein relates to the real system situations under study. In general, if a simplified approach (such as the F-factors used at present) is to be used in assessing the contribution of DG and other new technologies in practical planning, then such a simplified approach should have a sound basis in a particular risk calculation relevant to the real network situations under study. This might either be based in a probabilistic calculation with a particular target risk level, or in a probabilistic cost-benefit analysis between investment cost and future reliability cost. More generally, there is no natural way of extending a deterministic standard such as the present ETR 130 and P2/6 to include distributed resources. The only natural basis for considering such new components of the system is to develop a fully probabilistic risk-based planning approach, which can integrate consideration of all relevant technologies. There are clear advantages of using a simplified approach such as the present F-factors for practical purpose (including resource expended on any individual study, and applicability by a wide range of planning engineers who are not experienced in probability techniques), but in order to have confidence that such an approach will deliver good results it should have a sound basis in a fully detailed calculation.

The key recommendations to consider during a future fundamental review and update of G59/3-1 can be summarised as follows:

- **R1**. To treat electrical energy storage facilities as distributed generation for the purpose of protection systems and settings.

This report contributes to the Successful Delivery Reward Criteria[4] (SDRC) set out for the CLNR project by providing evidence on: (i) "proposals for changes to standard load profiles for network planning" in ACE Report 49; (ii) "proposals for changes to standard generation profiles for network planning" in ETR 130; and (iii) "generic GB distribution policy guidance on generator interface protection to secure contribution to system security" in ER G59/3-1.

[4] Ofgem, 2010. "Low Carbon Network Fund Project Direction Customer Led Network Revolution", Office of Gas and Electricity Markets, December 2010.

1. Introduction

1.1 Context

The integration of renewable energy resources into the electricity system and the electrification of heating and transport are central to the UK government plans to reduce carbon emissions by 80% by 2050. The move towards a low carbon electricity system poses new challenges to the design and operation of electricity distribution networks to support the widespread adoption of distributed generation (DG) or new electricity intensive low carbon technologies (LCTs). The CLNR project has been exploring smarter alternatives for building networks including the integration of distributed energy resources combined with smarter management and control of electricity demand that would allow for more of the existing network capacity to be used whilst at the same time ensuring that the network licence holders meet their obligations and customers' expectations of improved quality and security supply. These smarter solutions have contributed to the concept of smart grids which facilitate new technologies and commercial products to enable a much wider penetration of distributed generation from renewable or low carbon sources, a major increase in electricity consumption from the electrification of heat and transport and an increase of the utilisation of the existing network assets.

The UK electricity distribution systems were considerably expanded in 1950s and 1960s to meet the increasing customer requirements. The networks were developed in accordance with network planning and design standards that have stood the test of time and are still relevant today. Nonetheless, the network integration of these new distributed generation and demand technologies, with fundamentally different technical and operational characteristics to those of the incumbent technologies, will prompt the need to establish how they should be treated in the planning and design of distribution networks and to establish whether modifications to the standards should be made.

In this context, this report explores the challenges posed by the integration of new distributed generation and demand technologies to the current planning and design standards, specifically: (i) ACE Report No. 49[5] for the design of low voltage radial distribution networks, demands and voltage; (ii) Engineering Technical Report (ETR) 130[6] for assessing the capability of a distribution network containing DG to meet demand in order to comply with the security requirements of ER P2/6[7]; and (iii) Engineering Recommendation (ER) G59/3-1[8] for the connection of generating plant to the distribution systems of electricity distribution licence holders. The report uses the Learning Outcomes (LOs) of the CLNR project including as its real-world customer field trials to identify and recommend appropriate modifications to these standards for a future review process of these electricity distribution network standards.

This report contributes to the Successful Delivery Reward Criteria[9] (SDRC) set out for the CLNR project by providing evidence on: (i) "proposals for changes to standard load profiles for network planning" in ACE Report 49; (ii) "proposals for changes to standard generation profiles for network planning" in the ETR 130;

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

[6] ENA, 2006. "Engineering Technical Report 130, Application Guide for Assessing the Capacity of Networks Containing Distributed Generation", Energy Networks Association, Engineering Directorate, July 2006.

[7] ENA, 2006. "Engineering Recommendation P2/6, Security of Supply", Energy Networks Association, Engineering Directorate, July 2006.

[8] ENA, 2014. "Recommendations for the Connection of Generating Plant to the Distribution Systems of Licensed Distribution Network Operators", Issue 3, Amendment 1, Energy Networks Association, Engineering Directorate, August 2014.

[9] Ofgem, 2010. "Low Carbon Network Fund Project Direction Customer Led Network Revolution", Office of Gas and Electricity Markets, December 2010.

and (iii) "generic GB distribution policy guidance on generator interface protection to secure contribution to system security" in the ER G59/3-1.

1.2 Questions, aims and objectives

The UK's transition towards a low carbon electricity system of the future prompts the need to establish how new distributed generation and demand technologies should be treated in the planning and design of distribution networks and to identify which appropriate modifications to the standards should be made. The CLNR project has contributed to this objective through the development of real-world field customer trials and through the LO on customer's current, emerging and possible future load and generation technologies. In this respect, this work can be divided into three main questions and areas of analysis:

- **Q1**. Review of ACE 49 standard: (i) Are the load curves and associated annual electricity consumption levels of the current ACE 49 Report representative of the behaviour and electricity use of the present customer types? (ii) How to consider the load and generation curves of LCTs in the current ACE 49 Report?
- **Q2**. Review of ETR 130 standard: (i) Are the current set of F-factors fit for purpose on the basis of the new field trial data? (ii) What is the contribution of LCTs based DG to distribution network security?
- **Q3**. Review of ER G59 standard: Is the current G59/3-1 standard fit to facilitate the connection of low carbon generating plant technologies whilst maintaining the safety and quality of supply of the distribution system.

1.3 Scope of the work

The report uses the LOs of the CLNR project as well as its real-world customer field trials to identify and recommend which appropriate modifications to the standards should be made during a future review process of the electricity distribution network standards under consideration.

In particular, this report contributes to the SDRC set out for the CLNR project by providing evidence on: (i) "proposals for changes to standard load profiles for network planning" in the ACE Report 49; (ii) "proposals for changes to standard generation profiles for network planning" in the ETR 130; and (iii) "generic GB distribution policy guidance on generator interface protection to secure contribution to system security" in the ER G59/3-1.

1.4 Approach to work

The overall approach looked to address the requirements of the SDRC of the CLNR project relating to the review of planning and design standards of electricity distribution networks is illustrated in Figure 1.

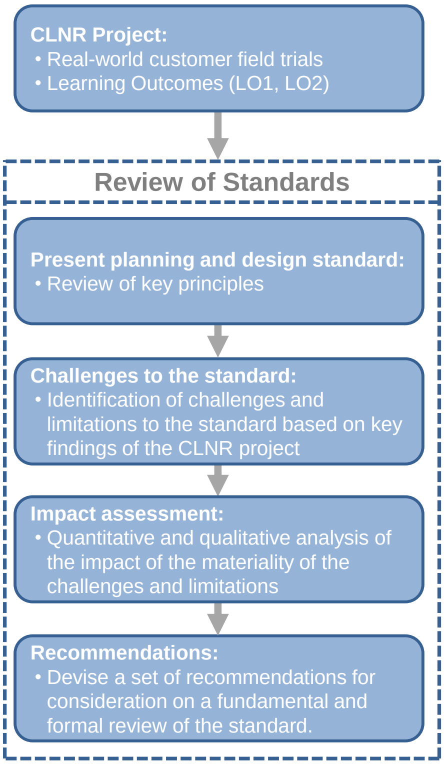


Figure 1: Overview of the approach to work

For each distribution network planning and design standard under consideration, the review process is developed as follows:

- Brief introduction of the fundamental principles of the standard that are important for the development of the overall review;
- To identify and understand the challenges and limitations of the standard within a future low carbon electricity system;
- To quantify and assess the impact of the low carbon challenges in the current standard based on the LO and customer trial data of the CLNR project.
- To devise a set of recommendations to be considered by the Energy Networks Association (ENA) and the DNOs during a future review process of the electricity distribution network standards under consideration.

1.5 Structure of the report

The report uses the LOs and the real-world customer field trials of the CLNR project to identify and recommend appropriate modifications for the review of ACE 49, ETR1 30 and G59/3-1 for the future low carbon electricity system. The report is structured as follows:

- Section 2 devises a set of recommendations to be considered for a future review and update of ACE Report 49 standard.
- Section 3 provides a set of recommendations to be considered for a future review and update of ETR 130 standard.
- Section 4 investigates the appropriateness of ER G59/3-1 standard identifying its appropriateness for a future review and update.
- Section 5 summarises the key findings of this work.

2. Review of ACE 49 standard

This section reviews the principles of the ACE Report 49 for the design of low voltage (LV) radial distribution networks, demands and voltage. The section combines the key concepts underpinning this distribution network planning and design standard with the LOs of the CLNR project that support the design philosophy of LV electricity distribution networks, to achieve techno-economic efficiency and value for money for consumers.

The section first introduces the key principles of ACE Report 49 standard. It then lays out some potential limitations within a future low carbon electricity system. Subsequently, the section uses the LOs of the CLNR project to quantify the impact of the low carbon challenges in the current planning and design standard. Finally, the section establishes a set of recommendations that could be adopted into ACE 49 and therefore drive the planning and design of future low voltage electricity distribution networks.

2.1 Principles of the ACE 49 standard

The ACE Report 49 outlines a statistical method for the design of low voltage networks, in particular for the design of demands and for voltage regulation, taking account of diversity and unbalance between customers. This subsection introduces the principles of the ACE Report 49 that relate to the method for estimating demands in LV distribution networks.

2.1.1 Estimation of demand

The statistical method for the estimation of demand is based on studies performed over a number of years in the 1970s which concluded that:

- The mean demand caused by a group of customers in any half hour during the central winter period, November to March, is approximately proportional to the annual unit consumption of those customers; and
- The demands for any half-hour of weekdays during the central winter period have a statistical distribution that can be regarded as normal.

The statistical method uses these two observations to define the design demand as the mean demand plus a number of standard deviations from that mean value. These are derived for different times of the day and thus the basic expression used for the design demand over any half-hour during the central winter period for a group of customers is given by Equation (1).

$$D = G + Z \cdot \sigma \qquad (1)$$

'*D*' is the design demand, '*G*' is the mean demand over the half-hour being considered, '*σ*' is the standard deviation of the distribution of demands over the half-hour being considered and '*Z*' is the chosen number of standard deviations added to the mean for design purposes.

The mean demand and the standard deviation components of Equation (1) can be represented by Equation (2) and Equation (3) respectively.

$$G = N \cdot C \cdot \Psi \qquad (2)$$

'*N*' is the number of customers, '*C*' is average annual unit consumption and '*Ψ*' is the demand estimation coefficient (i.e. constant of proportionality) for that half-hour.

$$\sigma = N \cdot C \cdot \Psi \cdot \sqrt{\sigma_1^2 + \sigma_2^2 + \frac{\sigma_3^2}{N}} \tag{3}$$

'σ_3^2' is the relative variance due to the differences between individual customers within a group, 'σ_2^2' is the relative variance due to the temperature sensitivity of demand and 'σ_1^2' is the relative variance due to residual causes.

Approximating the central winter demand for any half-hour to a normal distribution and considering the mean demand '*G*' as the design demand, it would be concluded that there is a 50% probability that the demand could exceed the design demand. Moreover, selecting a number of standard deviations '*Z*' equal to 1 leads to a 15.9% probability of exceeding the design demand. Under two standard deviations, the probability of exceeding the design demand falls to 2.3%. Hence, it is possible to design a more, or less, robust network circuit (i.e. LV cable or overhead line) depending on the number of standard deviations of the mean demand included to produce the design demand.

The ACE Report 49 considers that the acceptable level of risk probability of meeting demand within the design voltage regulation is 90% (i.e. the 90th percentile of the standard normal distribution). This probability is obtained by adding to the mean demand 1.28 standard deviations. Thus, the design demand for a group of customers can be expressed by Equation (4).

$$D = G + 1.28 \cdot \sigma \tag{4}$$

Since the values of '*C*', '*Ψ*', 'σ_1', 'σ_2' and 'σ_3' can be determined for a given type of customers then Equation (4) can be simplified. In this respect, the design demand per customer, for a group of size '*N*' customers can be written as in Equation (5).

$$\overline{D} = P + \frac{Q}{\sqrt{N}} \tag{5}$$

'$\overline{D}$' is the design demand per customer over the half-hour being considered, '*P*' is the mean demand per customer over the half-hour being considered and '*Q*' is the chosen number of standard deviations (based on the 90th percentile of the standard normal distribution) times the standard deviation of the customer demand distribution over the half-hour being considered. The values of '*P*' and '*Q*' have been calculated for various types of customer and are tabulated in the Appendix of the ACE Report 49.

The design demand per customer in Equation (5) can be expanded to define the design demand for group of '*N*' customers in the half-hour being considered over the central winter period as in Equation (6).

$$D = \overline{D} \cdot N = N \cdot P + Q \cdot \sqrt{N} \tag{6}$$

The values of '*P*' and '*Q*' are dependent upon the annual unit consumption '*C*' of the customers. In order to have values that are independent of a particular customers' unit consumption, the values of '*P*' and '*Q*' can be rewritten as in Equation (7) and Equation (8) respectively.

$$P = p \cdot C \tag{7}$$

$$Q = q \cdot C \tag{8}$$

The factor '*p*' is called the mean demand factor whilst the factor '*q*' is termed as the enhancement demand factor. These factors are provided in the Appendix of the ACE Report 49 for various types of customers together with the associated '*P*' and '*Q*' values.

The mean demand factor '*p*' is defined in Equation (9) as follows:

$$p(\mathit{Mean\ demand\ factor}) = \frac{P(\mathit{Average\ demand\ per\ half\text{-}hour})}{C(\mathit{Annual\ unit\ consumption\ in\ kWh})} \cdot 10^3 \tag{9}$$

The enhancement demand factor '*q*' is defined in Equation (10) as follows:

$$q(\mathit{Enhancement\ demand\ factor}) = \frac{Q(\mathit{Enhancement\ demand\ per\ half\text{-}hour})}{C(\mathit{Annual\ unit\ consumption\ in\ kWh})} \cdot 10^3 \tag{10}$$

In many cases the load on a substation or on an LV circuit results from a combination of types of customers. Thus, for more than one type of customer (i.e. customers with differing values of '*P*' and '*Q*'), the demand can be estimated by adding '*P*' terms arithmetically and by taking the square root of the sum of the squares of the '*Q*' terms in the demand estimate. Details of the approach for combination of groups of customers can be found in the ACE Report 49.

2.1.2 Estimation of voltage

The ACE Report 49 extends the statistical method for the estimation of demand to quantify the voltage drop in the LV networks considering the effects of load diversity and unbalanced load in the conductor phases. The full details of the method for the determination of voltage drops are presented in ACE Report 49 and in the user guide of the DEBUT[10] computer program.

Since the review of the ACE Report 49 within the CLNR project focusses on the estimation of demand, the fundamental concepts and principles related to voltage regulation are not introduced in this report but rather only referenced.

2.1.3 Challenges to the ACE 49 standard

The UK's commitments towards the decarbonisation of the energy sector have led DNOs to start exploring smarter means of accommodating distributed energy resources combined with smarter management and control of electricity demand. These smarter solutions have contributed to the rise of the concept of smart grids which facilitate new technologies and commercial products to enable a much wider penetration of distributed generation from renewable or low carbon sources and a major increase in electricity consumption from the electrification of heat and transport. As a consequence, it is important to understand the impact that this technological shift may have in the design and operation of distribution networks. The CLNR project has contributed to this objective through the development of real-world field customer trials[11] and through the LO on customer's current, emerging and possible future load and generation technologies.

The current planning and design standards (e.g. ACE Report 49) related to the electricity distribution system are broadly fit for the purpose to which they were designed, in that they are widely acknowledged to have

[10] EA Technology, 2001. "DEBUT User Guide", EA Technology Report, March 2001.
[11] CLNR-L071, 2014. "CLNR Customer Trials – A Guide to the Load and Generation Profile Datasets", Report L071 of the Customer Led-Network Revolution project, August 2014.

delivered a reasonable level of security of supply at an appropriate level of capital cost. However, at the time ACE 49 Report was developed, the integration of distributed generation and electricity demand technologies (e.g. electric vehicles, heat pumps, etc.) were not considered feasible and therefore were not considered as part of the criterion during the statistical analysis. With the move towards a low carbon electricity system prompts the need to establish how the new distributed generation and demand technologies should be treated in the planning and design of distribution networks and to identify which appropriate modifications to the standard should be made. In this context, based on the LO of the CLNR project, the challenges associated with the current ACE 49 planning and design standard are presented as follows:

- **C1**. Applicability of the load curves of the ACE 49 Report to represent present customer types.

The appendix D of the ACE 49 Report specifies various load curves (i.e. values of '*P*' and '*Q*' and associated '*p*' and '*q*') and respective annual electricity consumption levels for different customer types. The customer load curves have been derived from field measurements performed in the 1970s from which little knowledge of the survey process and statistical estimation methods used currently exists. The political, economic, social and technological developments observed since, raise concerns of the applicability of the current load curves of the standard to represent the electricity consumption of present customers.

- **C2**. Applicability of the customer types of the ACE 49 Report to represent present customers.

The ACE 49 Report has broadly defined domestic customer types according to their electricity tariff (e.g. unrestricted, restricted), type of heating (e.g. water, space), electrical appliances (e.g. electric cooking), electricity consumption (i.e. low, medium, high), etc. Nonetheless, the demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyle and behaviour. In this context, there is a need to consider the applicability of the customer types of the ACE 49 Report to represent the characteristics and behaviour of present customers. To this end, the CLNR project has segmented customers based on a variety of factors that are critical in shaping their energy use. For the domestic customers, some of these factors include: home energy rating, ages of household members, household income, housing tenure, rurality, etc.

- **C3**. Consideration of load curves and generation curves for LCTs in the ACE 49 Report.

The UK energy sector provides a safe, reliable and secure energy network and this role will be to ensure that it is safe, reliable and secure in sustainable, decarbonised and affordable future. The increasing presence of LCTs (e.g. heat pumps, electric vehicles, solar photovoltaic) in the electricity distribution network with fundamentally different technical and operational characteristics will drive a dissimilar impact to that of the incumbent technologies. Since ACE 49 Report does not consider LCTs, there is a need to establish a generic set of load curves and generation curves representative of the operating regime of LCTs that can be used within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems within a low carbon future (in the case of solar generation which is the most significant for of DG connected to LV networks, this means low *daytime* demand, not minimum demand which occurs at night).

- **C4**. Consideration of seasonality effects in the ACE 49 Report.

The Appendix D of the ACE 49 Report specifies various load curves for different customer types. The demand caused by a group of customers in any half-hour during the central winter period, November to March. Network planners have traditionally considered conditions of peak demand (i.e. winter season for the UK case) to evaluate the sufficiency of distribution network capacity. The significant presence of LCTs for DG (e.g. solar photovoltaic and wind) in the LV networks is likely to cause voltage regulation problems during coincidence of low demand and high DG power output. Thus, there might be a need consider conditions of low load demand (e.g. summer) and high DG in the planning and design of distribution networks for a low carbon future.

- **C5**. The acceptable level of risk probability of the out-turn demand exceeding the design demand.

The ACE Report 49 defines the acceptable level of risk probability of meeting demand within the design specifications as the percentile of the normal distribution curve of the central winter demand for a group of customers. The standard considers the 90th percentile of the Standard Normal Distribution to define the design demand and consequently the circuit capacity requirement. The materiality of the impact of the acceptable level of risk on the planning and design of distribution networks needs to be comprehensively understood in order to achieve a techno-economic efficient network plan. A low level of risk may lead to overinvestment in networks assets whilst a high level of risk may contribute to underinvestment and consequently to network constraint problems.

- **C6**. The basis of the statistical approach of ACE49 standard.

There are a several issues associated with the statistical modelling assumptions underpinning ACE49 which should be resolved in order to give the maximum degree of confidence in a planning approach for integrating LCTs. Most fundamentally, while ACE49 specifies design requirements in terms of a given percentile of a probability distribution, it does not specify clearly the definition of the variable of whose distribution this percentile is taken. There are also questions over the assumption of statistical independence between customers on a single feeder where LCTs are significant (i.e. supply or demand from some technologies such as solar PV may be highly correlated between properties). This report has concentrated on providing new datasets for use within the existing standards; however as penetrations of LCTs become very high the issues raised in C6 should be addressed.

2.2 Impact assessment for the review of ACE 49 standard

This subsection investigates the materiality of the impact of the challenges to the ACE49 planning and design standard. In particular, the impact assessment uses datasets collected from the CLNR customer field trials and key findings of the CLNR LOs to modify the current standard to mitigate the challenges imposed by potential changes in the way customers use electricity and the integration of LCTs. For each of the challenges presented in subsection 2.1.3, the assessment then establishes a comparison of the performance of modified ACE 49 standard against that of the current standard.

2.2.1 Load curves

This analysis investigates the applicability of the load curves of the ACE 49 Report to represent the way that the characteristics and behaviour of present customers affects the shape of their energy use. The customer load curves of the ACE 49 Report were derived from field measurements performed in the 1970s. The political, economic, social and technological developments observed since, raise concerns of the applicability of the current load curves to represent the electricity consumption behaviour of present customers.

The Appendix D of the ACE 49 Report specifies various load curves and respective annual electricity consumption levels for different customer types. The load curves are described by a set of 48 half-hourly factors (i.e. values of ‘P’ and ‘Q’ and associated ‘p’ and ‘q’) for weekdays and 4 half-hourly factors for Sunday lunch time during the central winter period, November to March. This selection of half hours within the standard was found to include the significant times of maximum demand for all types of customers.

The analysis establishes a comparison between the load curves representative of domestic customers in the ACE 49 Report and the load curves of domestic customers observed in the 'Test Cell 1a' (TC1a) of the CLNR customer field trials. The TC1a dataset represents the basic profiling of regular domestic smart meter customers and covers a two year period, from May 2011 to May 2013 (for the purposes of this report, the TC1a trials will be referred as smart meter trials). The comparison of the load curves is performed for the peak load day in the central winter period. Figure 2 identifies the peak load day per domestic customer in the central winter period over the two years of analysis. The peak load on each day in the period of analysis is defined as the maximum of the mean load of the customers considered in the smart meter trials.

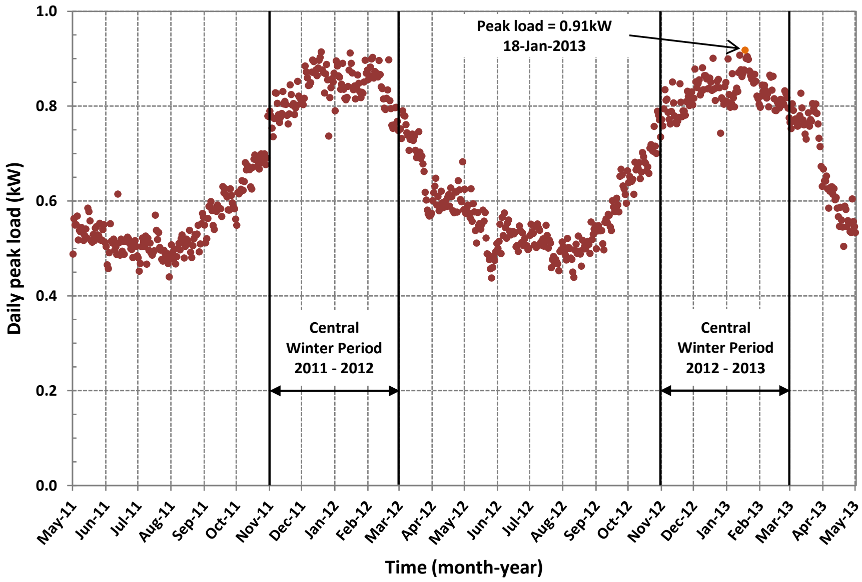
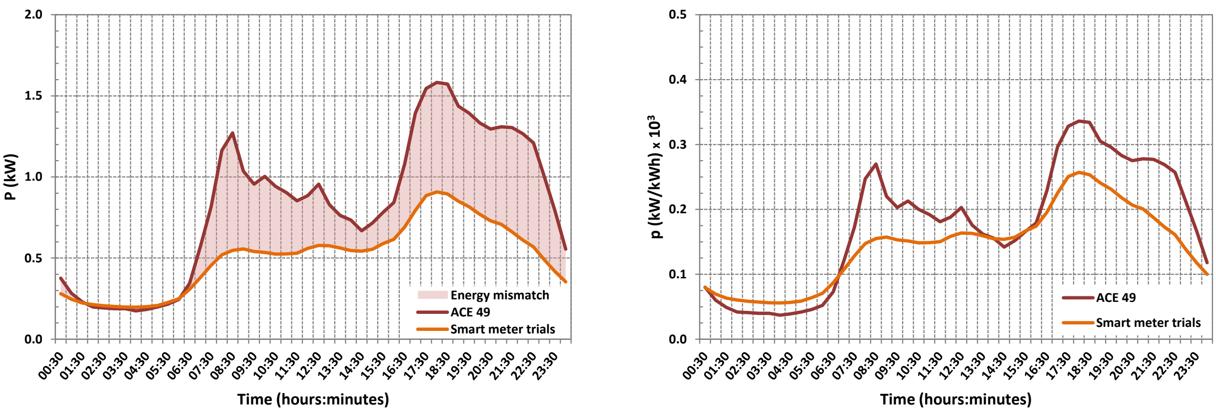


Figure 2: Daily peak load over the period 2011 – 2013

It can be seen in Figure 2 that the daily peak load over the period of analysis has occurred on Friday 18 January 2013 with a magnitude equal to 0.91kW. The comparison of the load curves is performed for this peak load day in the central winter period and their respective mean demand '*P*' and mean demand factors '*p*' are presented in Figure 3.



(a) Mean demand '*P*'

(b) Mean demand factor '*p*'

Figure 3: Mean demand '*P*' and mean demand factor '*p*'

Figure 3a shows the mean demand '*P*' for the ACE 49 load curve of a domestic consumer with UnRestricted tariff and Medium Consumption (i.e. URMC) and for the smart meter trials load curve of a domestic consumer. It can be observed in Figure 3a that the smart meter trials load curve has a high positive correlation (i.e. r = +0.96) with the ACE 49 load curve indicating that both load curves move together in the same direction. These lower energy requirements may potentially be a result of significant energy efficiency gains over the years, mainly due to technological improvements in the electric devices of houses, a move from coal supplemented by electric heating to gas central heating and enhancements in the thermal performance of the buildings.

It can be seen in Figure 3a that the maximum mean demand '*P*' for the day under study occurs simultaneously in both curves at 18:00 hours. The ACE 49 Report indicates that the sample average annual electricity consumption for URMC groups is 4,709kWh whilst the annual consumption for the smart meter trials group was observed to be 3,532kWh. Based on these annual electricity consumption levels, the maximum mean demand '*P*' decreases from 1.58kW in the ACE 49 curve to 0.91kW in the smart meter trials curve. The observed 42% reduction in the maximum mean demand, as a result of the update of the current URMC load curve, is likely to drive lower network capacity requirements and consequently lower expenditure requirements for the development of the electricity distribution networks to accommodate additional LCTs.

Figure 3b shows the mean demand factor '*p*' for the ACE 49 load curve of URMC domestic customers and for the smart meter trials load curve of the domestic customers considered in the CLNR trials. It is observed that the mean demand factor '*p*' decreases from 0.336(kW/kWh)x10^3 in the ACE 49 curve to 0.257(kW/kWh)x10^3 in the smart meter trials curve. The mean demand factor '*p*' of the smart meter trials load curve can be directly used in the current ACE 49 framework for the estimation of the design demand in LV radial distribution systems.

The full details of the smart meter trials load curves are presented in Appendix A together with the demand factors '*p*' and '*q*' and associated values of '*P*' and '*Q*'.

The analysis has explored the impact of these load curves in the operation and development of electricity distribution networks. The network analysis has been performed on the "Maltby" electricity distribution network of the Northern Powergrid (NPG) licence area. Figure 4 displays the schematic representation of the "Maltby" distribution network used in the analysis.

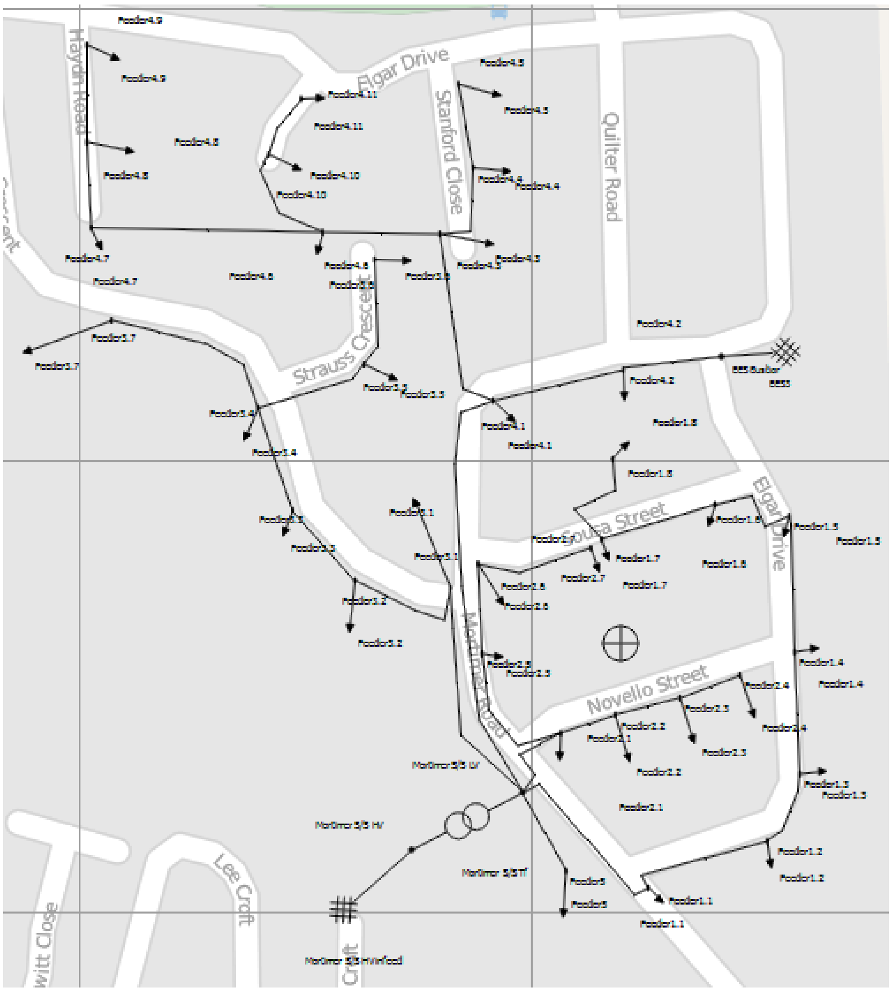


Figure 4: Schematic representation of "Maltby" electricity distribution network

"Maltby" electricity distribution network is supplied through Mortimer Road substation serving 256 domestic customers. This substation is constituted of an 11/0.4kV, 500kVA transformer and main outgoing circuits.

The concept of "headroom" has been used to ensure that the distribution network impacts of the load curves defined by the ACE 49 Report and by the smart meter trials of the CLNR project both for domestic customers are captured in a consistent manner. Headroom refers to the difference between the load experienced on a network, and the rating (i.e. cable laid direct in ground) of that network. If the rating exceeds the load, then there is a positive amount of headroom and reinforcement is not required. However, once load exceeds the rating then the headroom figure becomes negative and reinforcement to release additional headroom must be undertaken. The advantage to using headroom in this way is that it allows numerous parameters to be discussed on a common base. For the purpose of this analysis, headroom is evaluated for two different parameters: thermal and voltage. Based on the concept of headroom, the effect of customers' load on these parameters can be captured simultaneously. For instance, if a particular customer load contributes to a reduction in both thermal and voltage headroom, this can be easily identified.

In the specific case of voltage, the concept of legroom has also been introduced. As the voltage in the network has to maintained within the statutory limits (i.e. lower and upper limits) specified in the

Distribution CodeESQCR[12], legroom refers to the difference between the voltage experienced on a network, and the statutory lower voltage limit of that network.

The network analysis has been performed with the DEBUT software package as referenced in the ACE 49 Report. DEBUT[13] is a software tool that uses the statistical demand data from the ACE 49 Report to design radial, tapered, LV networks. The network analysis has been further complemented with the "Network Planning and Design Decision Support[14]" (NPADDS) software tool developed as part of the CLNR project. NPADDS is a network planning and design decision support tool for the integration of LCTs and solutions in distribution networks.

Table 1 details the minimum levels of headroom and legroom available across the circuits of the five feeders that form the "Maltby" electricity distribution network for different customer types. These levels of headroom and legroom are attained for the most overload network circuits for a specific half hour of the peak load day in the central winter period.

Table 1: Circuit headroom and legroom for the "Maltby" electricity distribution network

Customer type	Annual electricity consumption (kWh)	Thermal headroom (%)		Voltage legroom (%)	Voltage headroom (%)
		Feeders	Transformers		
URMC	4,709	24%	15%	0%	n.a.
URMC	3,532	43%	36%	28%	n.a.
Smart meter	3,532	54%	51%	38%	n.a.

It can be seen in Table 1 that URMC domestic customers with an annual electricity consumption of 4,709kWh as specified by the ACE 49 Report reach low levels of headroom. The thermal headroom of the transformer at Mortimer Road substation has only 15% headroom available whilst the voltage legroom in some of the networks circuits is practically 0%. These network circuits are characterised by a voltage drop close to the voltage statutory limits for this network.

Reducing the annual electricity consumption of URMC customers from 4,709kWh to a level identical to that of the domestic customers of the smart meter trials, i.e. 3,532kWh, results in a relatively significant release of headroom. It is observed in Table 1 that the voltage legroom increases by 28%.

Table 1 also shows that modifying the shape of the load curve and the annual electricity consumption of URMC domestic customers of the ACE 49 Report to represent the practices and activities of present domestic customers as in the smart meter trials, leads to a significant release of thermal headroom and voltage legroom. For instance, for "Maltby" electricity distribution the thermal headroom of feeders increases from 24% in the URMC to 54% in smart meter trials whilst the thermal headroom of transformers increases from 15% in the URMC to 51% in smart meter trials. Similarly, the voltage legroom increases by 38% overall.

The practices and activities of the present domestic customers shape the use of electricity in a dissimilar manner to that of the ACE 49 Report. The new load shape and lower annual electricity consumption of domestic customers lead to lower utilisation of the network assets during peak load conditions and may have implications on the requirement for network investment.

[12] Statutory Instruments, 2002, No. 2665, "The Electricity Safety Quality and Continuity Regulations".
[13] EA Technology, 2001. "DEBUT User Guide", EA Technology Report, March 2001.
[14] D. Hollingworth et al., 2013. "A Network Planning and Design Decision Support Tool for Integration of Low Carbon Technologies and Solutions", Paper 0229, 22nd International Conference on Electricity Distribution, CIRED, Stockholm, 10-13 June 2013.

2.2.2 Load curves per type of customer

The ACE 49 Report has broadly defined domestic customer types according to their electricity tariff (e.g. unrestricted, restricted), type of heating (e.g. water, space), electrical appliances (e.g. electric cooking), electricity consumption (i.e. low, medium, high), etc. Nonetheless, the demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyle and behaviour. In this context, there is a need to consider the applicability of the customer types of the ACE 49 Report to represent the characteristics and behaviour of present customers. To this objective, the CLNR project has segmented domestic customers according to socio-demographic attributes that shape their energy use. Whilst any other cut of the datasets would have been possible, for instance by Mosaic[15] group, the CLNR project was interested in exploring the social and anthropological drivers underpinning domestic energy use. Thus, the domestic customer groups[16] considered in the project are presented in Table 2.

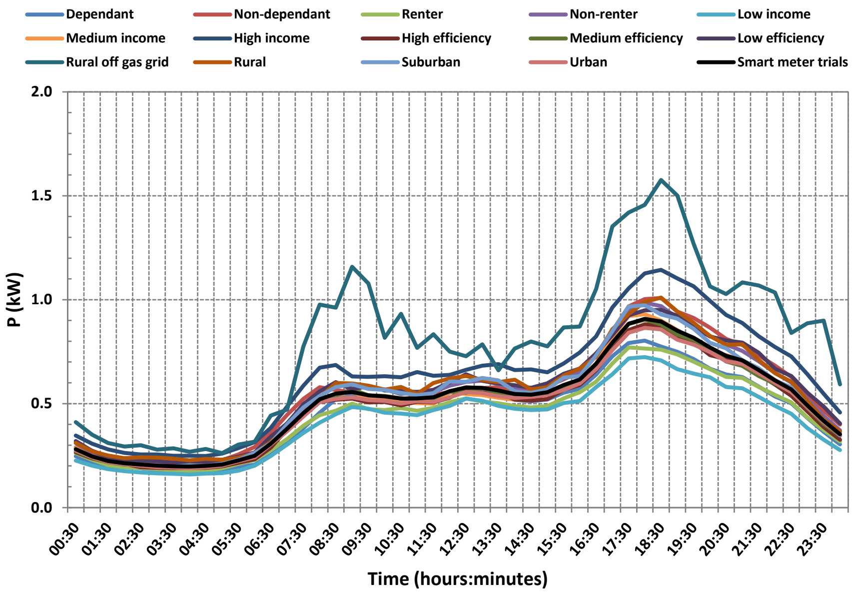
Table 2: Domestic customer group types

Customer attribute	Customer type label
Ages of the household members	Dependant: household includes at least one child aged < 5 and/or adult aged ≥ 65years
	Non-dependant: all members ≥ 5 and/ < 65 years
Household income	Low income: ≤ £14,999yr
	Medium income: £15,000yr – £29,999yr
	High income: > £29,999yr
House tenure	Renter
	Non-renter
Thermal performance of the building	Low thermal efficiency
	Medium thermal efficiency
	High thermal efficiency
Rurality	Rural
	Rural off gas grid
	Suburban
	Urban

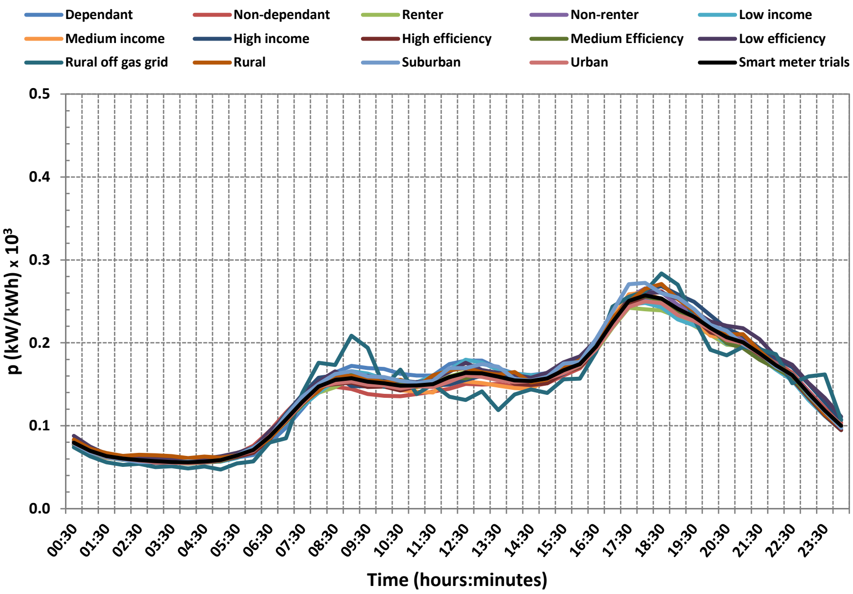
The CLNR project has used the data collected from the customer field trials to produce a generalised set of load curves for different types of domestic customers that can be applied within the current ACE 49 framework for the estimation of the design demand in LV radial distribution systems. Figure 5 presents an overview of the load curves of the different domestic customer types considered in the smart meter trials of the CLNR project.

[15] Experian, 2009. "Mosaic United Kingdom, the Consumer Classification of the United Kingdom", Experian, 2009. http://www.experian.co.uk/assets/business-strategies/brochures/Mosaic_UK_2009_brochure.pdf

[16] CLNR-RE002, 2011. "Protocol for Population of Domestic Test Cells", Report RE002 of the Customer Led-Network Revolution project, September 2011.



(a) Mean demand '*P*'



(b) Mean demand factor '*p*'

Figure 5: Mean demand '*P*' and mean demand factor '*p*' for different type of customers in the smart meter trials

It can be seen in Figure 5a that "rural off gas grid" and "high income" customers have higher electricity consumption than all the other types of domestic customers considered in the analysis. Domestic customers whose properties are off the gas grid generally use electricity for heating and cooking increasing the overall electricity consumption levels. Domestic customers with higher income appear to have daily routines that involve activities/practices with higher electricity consumption requirements. In contrast, domestic customers of "low income" and "renter" are observed to achieve the lowest electricity consumption levels of the sample under analysis.

Figure 5a shows that the household income is a significant driver for the levels of electricity consumed by domestic customers. Thus, disregarding the load curve of "rural off gas grid" customers, it is observed that domestic customers of "high income" and those of "low income" form the upper and lower bounds of the electricity consumption levels away from the overall average behaviour given by the load curve for the smart meter trials.

Figure 5b presents the load curves of the different domestic customer types of smart meter trials normalised by their respective annual energy consumption (i.e. mean demand factor '*p*'). It can be seen that almost all of the difference between demand curves for different customer types in the sample is explained by differences in annual energy demand.

It can be concluded that based on the variety of factors considered in the CLNR project to segment and characterise the electricity use by domestic customers, the load curves driven by household income, rurality (i.e. rural off gas grid only) and average of smart meter trial customers have relatively different electricity consumption levels and therefore could potentially be considered in the current ACE 49. These load curves can be directly applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems. The generalised set of load curves is presented in Appendix A together with the demand factors '*p*' and '*q*' and associated values of '*P*' and '*Q*'.

To further explore the impact of these load curves in the operation and development of electricity distribution networks, a network analysis has been performed for the "high income" and "low income" domestic customers of the smart meter trials. These customers have been selected to provide higher and lower bounds for the network impacts. The network analysis has been performed on the "Maltby" electricity distribution network of the Northern Powergrid (NPG) licence area.

Table 3 details the minimum levels of headroom and legroom available across the circuits of the five feeders that form the "Maltby" electricity distribution network for different customer types. These levels of headroom and legroom are presented for the most overloaded network circuit in a particular half hour of the peak load day during the central winter period.

Table 3: Circuit headroom and legroom for the "Maltby" electricity distribution network

Customer type	Annual electricity consumption (kWh)	Thermal headroom (%)		Voltage legroom (%)	Voltage headroom (%)
		Feeders	Transformers		
Low income	2,918	63%	61%	49%	n.a.
Smart meter	3,532	54%	51%	38%	n.a.
High income	4,265	43%	38%	21%	n.a.

It can be observed in Table 3 that the thermal headroom and voltage legroom decrease as the peak load and electricity consumption increase from "low income" to "high income" domestic customers. It can also be seen in Table 3 that the change in peak load and electricity consumption has a greater impact in voltage legroom than thermal headroom. For instance, the voltage legroom diminishes by 28% whilst the thermal headroom of feeders and transformers reduces by 20% and 23% respectively.

Domestic customers characterised by different peak load and electricity consumption will drive dissimilar levels of available headroom in the network assets. For "Maltby" electricity distribution network the network headroom is estimated to drop on average by 24% (i.e. across the three different types of headroom) as the peak load and electricity consumption range from the lowest to the highest levels observed in smart meter trials for domestic customers. This relatively significant impact on design demand and voltage regulation will have implications on network investment requirements. Thus, these new load curves ought to be considered during a future review of the ACE 49 Report to represent the characteristics and behaviour of present customers.

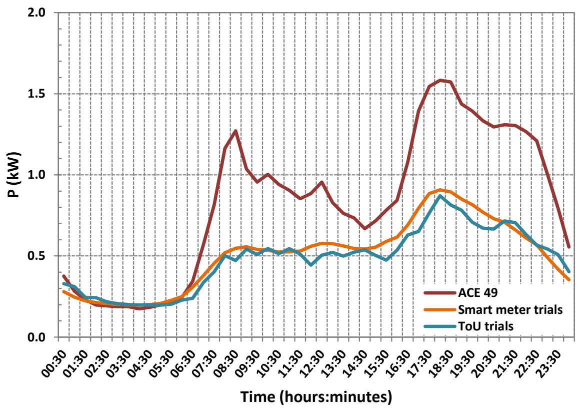
The CLNR project has also set up test cells to trial novel commercial arrangements to encourage customer flexibility such as domestic time of use tariffs. In this context, the analysis establishes a comparison between the load curves representative of domestic customers in the ACE 49 Report, domestic smart meter customers (i.e. TC1a) and the load curves of domestic customers observed in the 'Test Cell 9a' (i.e.

TC9a) CLNR customer field trials. The TC9a dataset represents pure Time of Use (ToU) tariff for domestic customers and covers a full year period, from January 2013 to December 2013 (for the purposes of this report, the TC9a trials will be referred as ToU trials). The overall ToU tariff used in the CLNR customer trials is composed by three different bands (i.e. peak, off-peak and day) for every weekday. The datasets were then used to determine the proportion of demand in each tariff band. The structure of the CLNR 3-rate ToU tariff is detailed in Table 4.

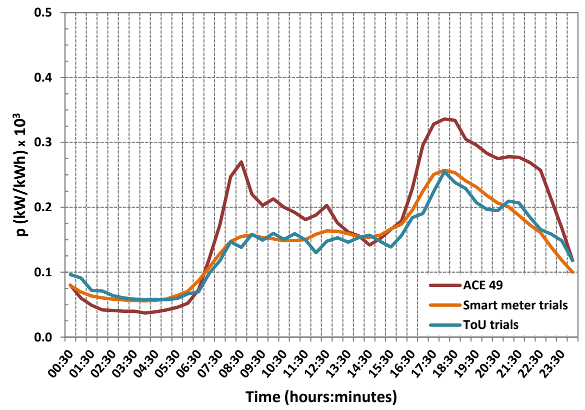
Table 4: Time of Use tariff time bands

Tariff band		Time
Weekday	Peak	16:00 – 20:00 (Monday – Friday)
	Day	07:00 – 16:00 (Monday – Friday)
	Off-peak	Monday: 00:00 – 07:00 Tuesday – Thursday: 20:00 – 07:00 Friday: 20:00 – 00:00
Weekend		All-day

The comparison of the ACE 49, smart meter trials and ToU trials load curves of domestic customers is performed for the peak load day in the central winter period and their respective mean demand ‘P’ and mean demand factors ‘p’ are presented in Figure 6.



(a) Mean demand ‘*P*’



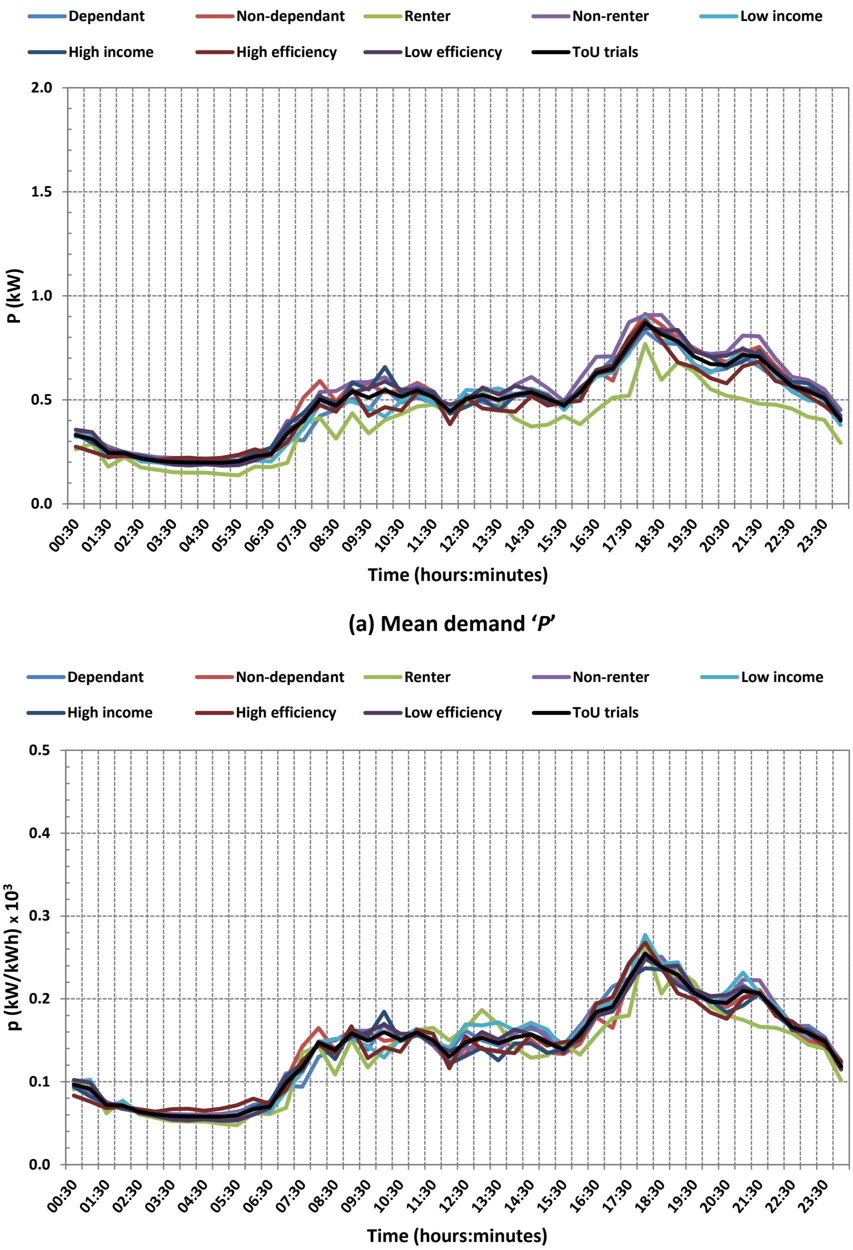
(b) Mean demand factor ‘*p*’

Figure 6: Mean demand ‘*P*’ and mean demand factor ‘*p*’

Figure 6a shows the mean demand ‘*P*’ for the ACE 49 load curve of a domestic consumer with UnRestricted tariff and Medium Consumption (i.e. URMC), the smart meter trials load curve of a domestic consumer and the ToU trials load curve of a domestic consumer. It can be seen in Figure 6a that the maximum mean demand ‘*P*’ for the day under study occurs simultaneously in the three curves at 18:00 hours. The ACE 49 Report indicates that the sample average annual electricity consumption for URMC groups is 4,709kWh whilst the annual consumption for the smart meter trials group was observed to be 3,532kWh and for the ToU trials group was found to be 3,417kWh. Based on these annual electricity consumption levels, the maximum mean demand ‘*P*’ decreases from 1.58kW in the ACE 49 curve to 0.91kW in the smart meter trials curve and to 0.87kW in the ToU trials curve. This reduction in the maximum mean demand, as a result of the update of the current URMC load curve, is likely to drive lower network capacity requirements and consequently lower expenditure requirements for the development of the electricity distribution networks to accommodate additional LCTs.

It is observed in Figure 6b that the mean demand factor ‘*p*’ decreases from 0.336(kW/kWh)x10^3 in the ACE 49 curve to 0.257(kW/kWh)x10^3 in the smart meter trials curve and to 0.26(kW/kWh)x10^3 in the ToU trials curve. The mean demand factor '*p*' of the ToU trials load curve can be directly used in the current ACE 49 framework for the estimation of the design demand in LV radial distribution systems.

The CLNR project has used the data collected from the ToU customer field trials to produce a generalised set of load curves for different types of domestic customers that can be applied within the current ACE 49 framework for the estimation of the design demand in LV radial distribution systems. Figure 7 presents an overview of the load curves of the different domestic customer types considered in the ToU trials of the CLNR project.



(a) Mean demand '*P*'

(b) Mean demand factor '*p*'

Figure 7: Mean demand '*P*' and mean demand factor '*p*' for different type of customers in the ToU trials

The full details of the ToU trials load curves are presented in Appendix B together with the demand factors '*p*' and '*q*' and associated values of '*P*' and '*Q*.a

2.2.3 Load curves and generation curves for LCTs

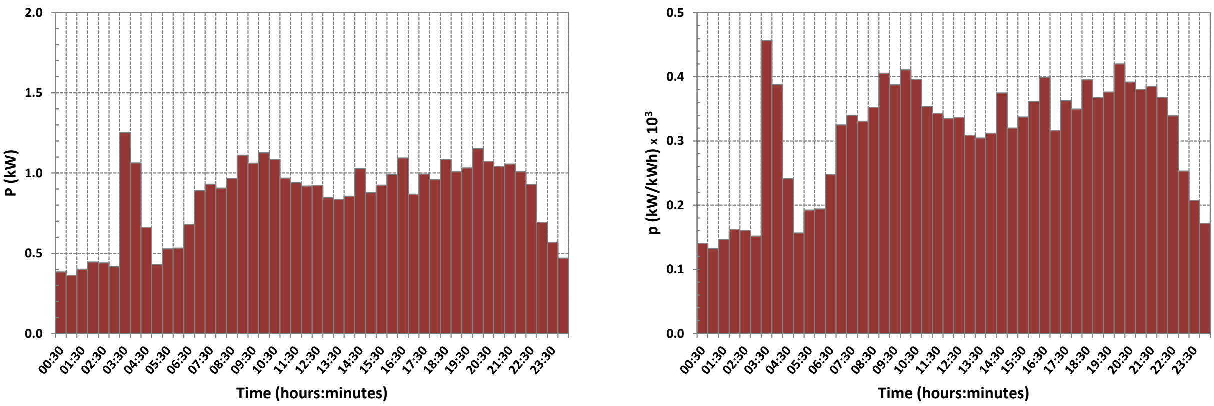
UK's path towards a sustainable and low-carbon energy system will inevitably require a major shift in the structure of electricity generation and demand technologies. In this context, the increasing presence of LCTs in the LV networks for DG and for the electrification of the heat and transport sectors, will inevitably bring new challenges to DNOs when designing and planning electricity distribution networks. Since ACE 49 Report does not consider LCTs, there is a need to establish a generic set of load curves and generation curves representative of the operating regime of LCTs that can be used within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems within a low carbon future.

The CLNR project has trialled various LCTs (e.g. heat pumps, electric vehicles, solar photovoltaic, etc.) in order to build a better understanding of the challenges that their integration poses to DNOs and to devise mitigation strategies to ensure their cost efficient and secure integration in distribution networks. In this respect, this subsection details the load curves and generation curves of LCTs and their respective demand factors '*p*' and '*q*' and values of '*P*' and '*Q*'. These load and generation curves can be directly applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems.

Figure 8 and Figure 9 introduce the mean demand '*P*' and mean demand factors '*p*' for heat pumps and electric vehicles respectively, for peak load day in the central winter period. Figure 10 details the mean generation '*P*' and mean generation factors '*p*' for solar photovoltaic installations in the distribution LV networks over the central winter period.

Heat pumps

The dataset representative of the operating regime of the heat pumps has been extracted from the test cell TC3 (i.e. "enhanced profiling of Heat Pumps") of the CLNR field trials. Figure 8 shows the mean demand '*P*' and mean demand factors '*p*' for heat pumps in the peak load day during the central winter period.



(a) Mean demand '*P*' **(b) Mean demand factor '*p*'**

Figure 8: Mean demand '*P*' and mean demand factor '*p*' for heat pumps

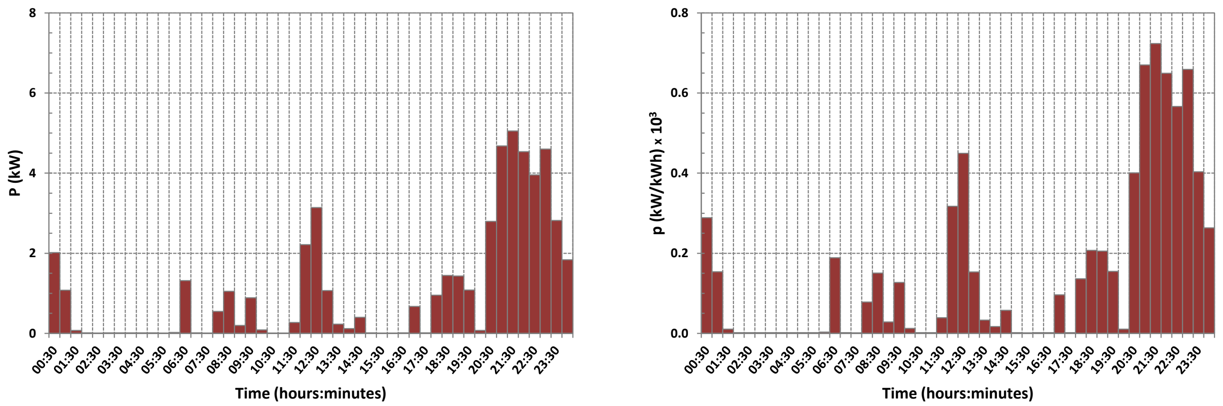
Note: This figure is provided for guidance, however the datasets used to create this figure have limited statistical robustness and one should take care when using these mean generation factors for heat pumps.

It can be seen in Figure 8a that the peak power consumption is reached at 03:30 hours and is equal to 1.25kW. This early morning power peak is a consequence of the default hot water setting observed in the trials. . The daily energy consumption of heat pumps for the peak load day during the central winter period is estimated to be 20kWh. Figure 8b shows the mean demand factors '*p*' that can be used in the application of the ACE 49 framework for the estimation of the design demand and voltage regulation.

It is important to note that the datasets collected from the real-world field trials of the CLNR project to describe the operating regime of electric heat pumps are limited in size, space (i.e. geographic location of the trials) and time (i.e. observation period of the trials). As a result, the statistical significance of the sample may be limited.

Electric vehicles

The dataset representative of the charging regime of electric vehicles has been extracted from the test cell TC6 (i.e. "enhanced profiling of Electric Vehicles") of the CLNR customer field trials. Figure 9 displays the mean demand '*P*' and mean demand factors '*p*' for electric vehicles in the peak load day during the central winter period.



(a) Mean demand '*P*' **(b) Mean demand factor '*p*'**

Figure 9: Mean demand '*P*' and mean demand factor '*p*' for electric vehicles

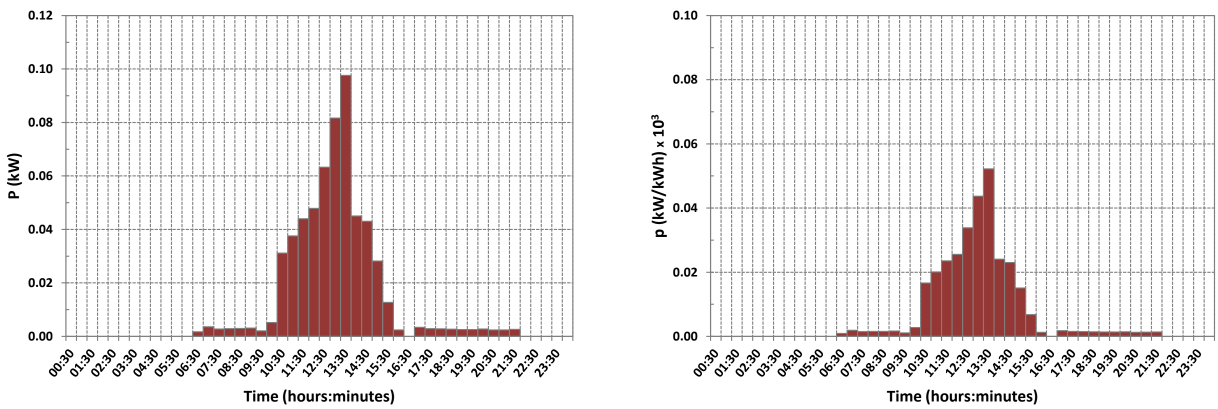
Note: This figure is provided for guidance, however the datasets used to create this figure have limited statistical robustness and one should take care when using these mean generation factors for electric vehicles.

It can be observed in Figure 9a that the power peak consumption attributed to the domestic charging of electric vehicles mostly occurs overnight reaching a magnitude of around 5kW at 21:30 hours. The daily energy consumption of the charging of electric vehicles for the peak load day during the central winter period is estimated to be 25kWh. Figure 9b displays the mean demand factors '*p*' that can be used in the application of the ACE 49 framework for the estimation of the design demand and voltage regulation.

Solar photovoltaic

The dataset representative of the operating behaviour of solar photovoltaic installations has been extracted from the test cells TC5 (i.e. "enhanced profiling of solar PV customers") and $TC20_{IHD}$ (i.e. "within-premises balancing for solar PV customers with IHD") of the CLNR customer field trials.

Figure 10 depicts the mean generation '*P*' and mean generation factors '*p*' for solar photovoltaic installations in the distribution LV networks over the central winter period.



(a) Mean generation '*P*'

(b) Mean generation factor '*p*'

Figure 10: Mean generation '*P*' and mean generation factor '*p*' for solar photovoltaic

Note: This figure is provided for guidance, however the datasets used to create this figure have limited statistical robustness and one should take care when using these mean generation factors for solar photovoltaic.

It is seen in Figure 10 that the power output of domestic solar photovoltaic installations in the peak load day over the central winter period is very low. Thus, the ability of solar photovoltaic installations contributing to supply domestic load during central winter period is very limited. Under these conditions, providing generation factors '*p*' and '*q*' and associated values of '*P*' and '*Q*' to be used in the application of the ACE 49 framework is deemed unnecessary.

The generalised set of load curves representative of the operating regime of the LCTs, considered the CLNR project, is presented in Appendix C together with the demand and generation factors '*p*' and '*q*' and associated values of '*P*' and '*Q*'.

The application of the ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems requires the network planner to specify the type of customers connected to the network feeder. The Appendix D of the ACE 49 Report will then associate a load curve (i.e. a set of demand factors '*p*' and '*q*') to a customer type to characterise the shape of its electricity consumption. For a domestic customer with LCTs present in the household (e.g. heat pumps), the planner should add the aforementioned load curve of the specific LCT (e.g. heat pumps) to the load curve of the ACE 49 Report for the customer type under consideration. The combination of these load curves describes the half-hourly daily load of a domestic customer with LCTs present in the household. In the case of distributed generation based LCT (e.g. solar photovoltaic), the planner should subtract the generation curve of the specific LCT by the load curve of the customer type under consideration (i.e. as defined in this report of the CLNR project or as defined in the ACE 49 Report if fit for purpose).

2.2.4 Load curves for the summer season

The Appendix D of the ACE 49 Report specifies various load curves for different types of customer during the central winter period. The design standard specifies that the selected 48 half hours for weekdays have been found to include the significant times of maximum demand for all types of customers. This becomes particularly important when estimating the design demand to be served by an LV radial distribution network as network planners have traditionally considered conditions of peak demand (i.e. winter season for the UK case) to drive the design of electricity distribution capacity. These conditions have generally resulted in conservative levels of network capacity ensuring the adequacy of the network to serve load under all other system conditions (e.g. summer season).

Moving towards a low carbon energy system of the future, the increasing and significant presence of LCTs (e.g. solar photovoltaic and wind) in the LV networks are likely to cause voltage regulation problems during coincidence of low daytime demand and high LV solar photovoltaic or coincidence of low night-time demand and high LV wind. Thus, designing the electricity distribution system to accommodate conditions of peak demand may not be sufficient as network voltage limits may be breached during such conditions. Thus, there might be a need consider conditions of low load demand (e.g. summer season) and high DG (e.g. solar photovoltaic during summer season) in the planning and design of distribution networks for a low carbon future.

This subsection explores the impact of coincidence of high LV solar photovoltaic with low demand both during the summer period on the design demand and voltage regulation. The analysis is then performed for the minimum load day during the summer[17] period (i.e. May to August). Figure 11 identifies the minimum load day for domestic customer over three consecutive summer periods. The minimum load on each day in the period of analysis is defined as the minimum of the mean load of the customers considered in the smart meter trials.

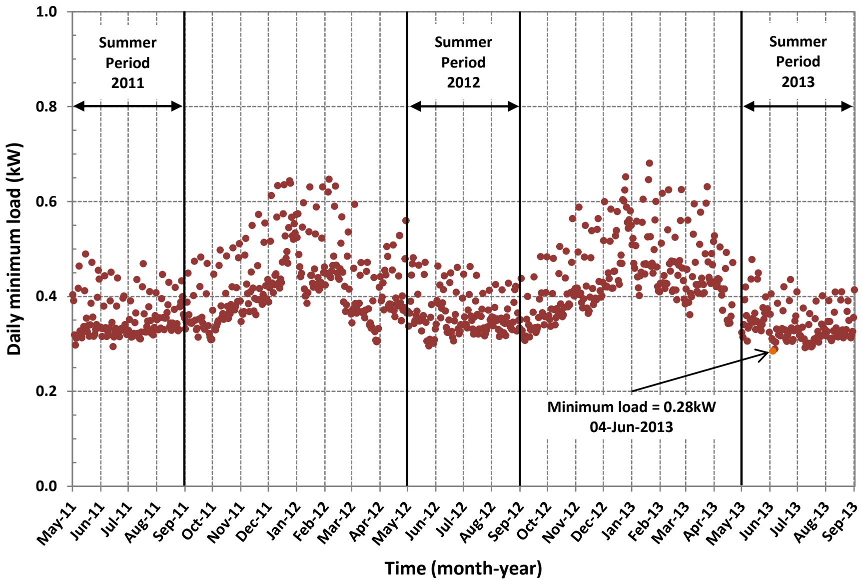
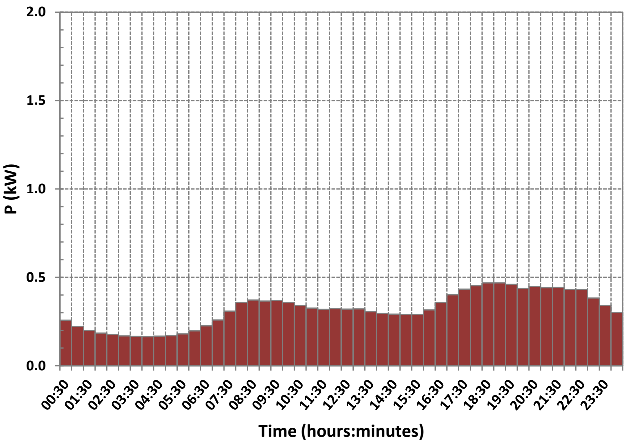


Figure 11: Daily minimum load over the period 2011 – 2013

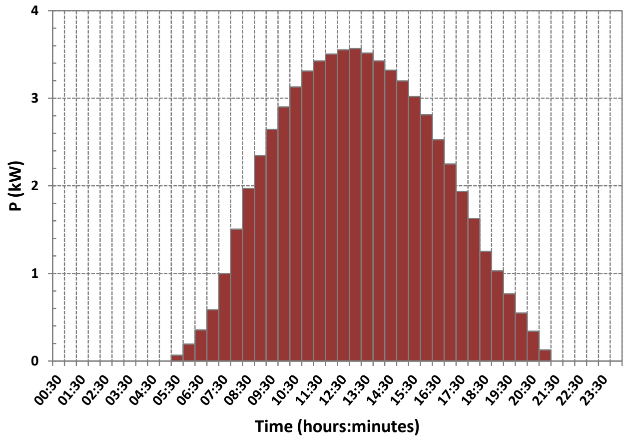
Figure 11 shows that the daily minimum load over the period of analysis has occurred on Tuesday 4 June 2013 with a magnitude equal to 0.28kW.

For this minimum load day during the summer period, the analysis uses the datasets collected from the test cells TC5 (i.e. "enhanced profiling of solar PV customers") and $TC20_{IHD}$ (i.e. "within-premises balancing for solar PV customers with IHD") of the CLNR customer field trials to characterise the electricity production behaviour of domestic customers that have solar photovoltaic installations. Figure 12 shows the average household load, solar photovoltaic generation and net load (i.e. load minus generation) for domestic customers with solar photovoltaic installation.

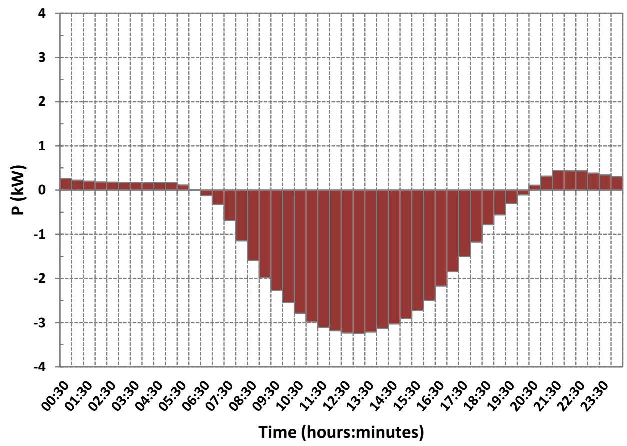
[17] ELEXON, 2013. "Load Profiles and their Use in Electricity Settlement", ELEXON Guidance Document, November 2013.
http://www.elexon.co.uk/wp-content/uploads/2013/11/load_profiles_v2.0_cgi.pdf



(a) Household load



(b) Household solar photovoltaic generation



(c) Household net load

Figure 12: Household load and generation and net load characteristics for the summer period

Figure 12c depicts the household net load for the minimum load day during the summer period. Positive net load values suggest that the household load is greater than the solar photovoltaic power generated by the household installation. Negative net load values indicate that the solar photovoltaic power generated over and above load with the surplus being directly exported to the distribution network. It can be seen that the maximum solar photovoltaic power exported to the network is 3.25kW at 13:00 hours.

The analysis has then explored the impact of coincidence of high LV solar photovoltaic with low demand in the operation and development of electricity distribution networks. The network analysis has been performed on the "Maltby" electricity distribution network of the Northern Powergrid (NPG) licence area. The analysis is performed for the minimum load day during the summer period for domestic customers characterised by an annual energy consumption of 3,532kWh as in the smart meter trials. Table 5 details the minimum levels of headroom and legroom available across the circuits of the five feeders that form the "Maltby" electricity distribution network and for different penetration levels of solar photovoltaic installations. These levels of headroom and legroom are attained for the most overload network circuits for a specific half hour of the minimum load day in the summer period. The penetration level of solar photovoltaic is defined as the number of customers that have solar photovoltaic installations over the total number of customers present in the network. Based on the CLNR customer field trials, the installed capacity of a domestic solar photovoltaic installed was considered to be equal to 3.68kW.

Table 5: Impact of domestic solar photovoltaic on circuit headroom and legroom for the "Maltby" electricity distribution network in the minimum load day during the summer period

Penetration level (%)	Thermal headroom (%)		Voltage legroom (%)	Voltage headroom (%)
	Feeders	Transformers		
0%	63%	73%	59%	n.a.
10%	66%	76%	61%	27%
20%	66%	77%	55%	23%
30%	67%	77%	64%	22%
40%	55%	75%	64%	-3%
50%	37%	64%	64%	-5%
60%	29%	54%	64%	-2%
70%	25%	44%	64%	-12%
80%	7%	34%	64%	-21%
90%	-6%	24%	64%	-41%
100%	-16%	14%	64%	-28%

Table 5 shows that the increasing presence of domestic solar photovoltaic installations in the "Maltby" electricity distribution network has a relatively significant impact on thermal and voltage headroom and legroom of network assets. It can be seen in Table 5 that the voltage headroom corresponds to the first type of headroom to be breached as the network voltage rises over and above the statutory limits. For instance, the "Maltby" network is capable of accommodating a maximum penetration level of solar photovoltaic of around 30% without observing voltage rise issues. It is noted in Table 5 that the overall decrease in voltage headroom as the penetration level of solar photovoltaic rises presents a lumpy behaviour that is driven by the phase to which the solar installation is being deployed. Figure 13 details the level of voltage headroom across the three different phases for every per cent level of solar photovoltaic present in the network.

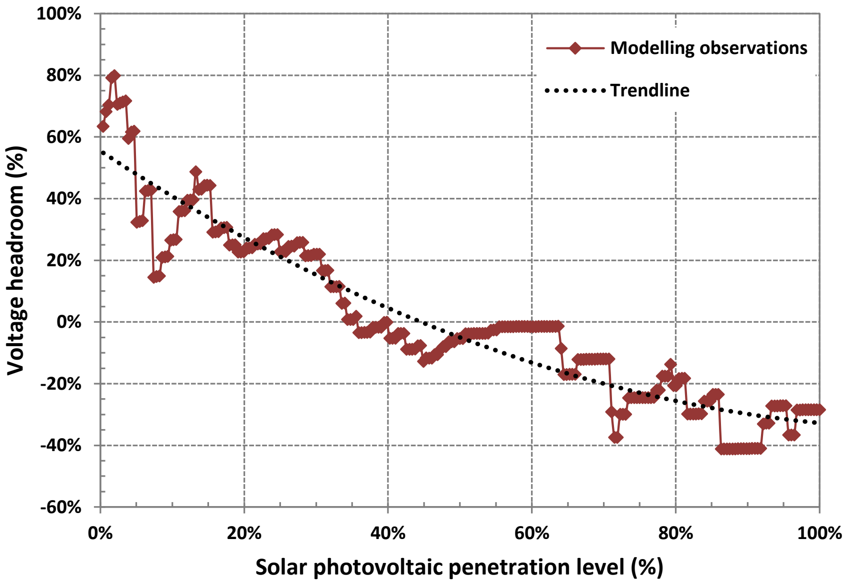


Figure 13: Voltage headroom

The "trendline" curve in Figure 13 indicates that in the long-run there is an overall reduction on voltage headroom (or increase in voltage rise) as the penetration level of solar photovoltaic in the network increases. Nonetheless, the "modelling observations" curve shows that in the short-run the voltage headroom slightly oscillates as new solar photovoltaic customers are connected in the network. In DEBUT computer program, customers are connected at different phases and therefore subjected to slightly different phase voltages leading to the oscillation observed in Figure 13 that reflects the maximum voltage of the three phases.

It can be also seen in Table 5 that the coincidence of high solar photovoltaic with low demand both during the summer period has little effect on the voltage legroom as the increase of power in the network from solar photovoltaic distributed generators will not cause significant drops in voltage.

It is observed in Table 5 that at high penetration levels of solar photovoltaic (e.g. 80% to 90%), the thermal headroom of feeders also becomes negative indicating that some network circuits are overloaded. Thus, the network is not capable of accommodating more solar photovoltaic installations without reinforcing network circuits.

The coincidence of high solar photovoltaic with low demand during the summer period may cause voltage headroom constraints in the network depending the penetration level of distributed solar photovoltaic generation and network characteristics and topology. These voltage headroom constraints are driven by the surplus power of solar photovoltaic DG being injected in the network at times of low demand. The inclusion of a network study for the summer period should be considered during a future review of ACE 49 Report to ensure the robustness of the network design against voltage rise.

2.2.5 Risk of out-turn demand exceeding the design demand

The ACE Report 49 defines the acceptable level of risk probability of meeting demand within the design voltage regulation as the percentile of the normal distribution curve of the central winter demand for a group of customers. The standard considers the 90th percentile of the Standard Normal Distribution to define the design demand and consequently the circuit capacity requirement.

A network analysis is performed to evaluate the materiality of the impact of the acceptable level of risk on the planning and design of distribution networks. Thus, the design demand is evaluated computed for the smart meter trials load curve of domestic customers under different levels of risk. Figure 14 shows the design demand for the three levels of risk considered in the analysis. The design demand has been determined from Equation (4) considering the 85th, 90th and 95th percentiles of the standard normal distribution respectively. These probabilities are obtained by adding to the mean demand 1.04, 1.28 and 1.64 standard deviations.

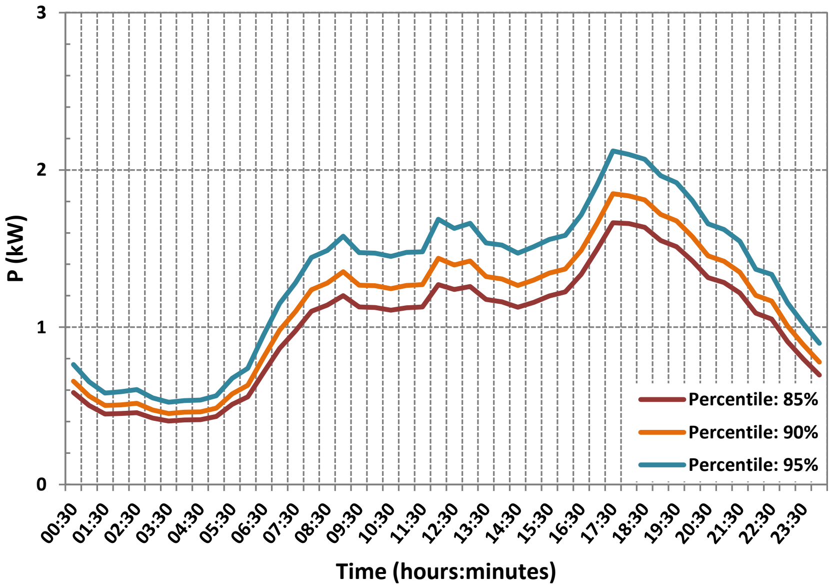


Figure 14: Design demand for the smart meter trials of domestic consumers

It can be seen in Figure 14 that increasing the level of risk at peak load time from the 85th to the 90th percentiles increases the number of standard deviations of the mean demand included to produce the design demand and leads to a 21% increase of the peak design load at 18:00 hours.

The network analysis has been performed on the "Maltby" electricity distribution network of the Northern Powergrid (NPG) licence area. Table 6 details the minimum levels of headroom available across the circuits of the five feeders that form the "Maltby" electricity distribution network for different levels of risk. These levels of headroom are presented for the most overloaded network circuit in a particular half hour of the peak load day during the central winter period.

Table 6: Impact of the level of risk for design demand on circuit headroom for the "Maltby" electricity distribution network

Percentile (%)	Thermal headroom (%)		Voltage legroom (%)	Voltage headroom (%)
	Feeders	Transformers		
85%	56%	51%	43%	n.a.
90%	54%	51%	38%	n.a.
95%	52%	50%	32%	n.a.

Table 6 illustrates that accepting a level of risk 5% higher than that of the ACE 49 Report the network planner benefits from a 2% higher feeder headroom and a 5% higher voltage legroom. In contrast, from a risk averse perspective characterised by a 5% lower level of risk compared to that of ACE 49 Report, the planner observes a reduction in feeder headroom of 2% and a reduction of 6% in voltage legroom.

In the ACE Report 49 the acceptable level of risk probability of meeting demand within the design voltage regulation impacts the circuit capacity required to serve customers' load. Thus, it is possible to design a more, or less, robust LV network depending on the level of risk taken to produce the design demand.

2.3 Recommendations for the review of ACE 49 standard

Based on the LOs and real-world customer field trials of the CLNR project, the key recommendations to consider during a future review and update of ACE 49 Report can be summarised as follows:

- **R1**. To review and update the load curves of ACE 49 Report to represent the characteristics and behaviour of present electricity customers in accordance with the work developed and findings of the CLNR project.

The demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyle and behaviour. In this context, customers' use of electricity in a dissimilar manner to that of the ACE 49 Report. The new load shape and lower annual electricity consumption of domestic customers lead to lower utilisation of the network assets during peak load conditions and to a consequent decrease of network reinforcement requirements. This work provides and recommends a generic set of load curves representative of domestic customers together with the demand factors '*p*' and '*q*' and associated values of '*P*' and '*Q*'. These load curves can be directly applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems.

- **R2**. To review and update the types of customers of ACE 49 Report to represent present customers in accordance with the work developed and findings of the CLNR project.

The ACE 49 Report has broadly defined domestic customer types according to their electricity tariff (e.g. unrestricted, restricted), type of heating (e.g. water, space), electrical appliances (e.g. electric cooking), electricity consumption (i.e. low, medium, high), etc. Nonetheless, the demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyle and behaviour. This work recommends to review and update the types of domestic customers of ACE 49 Report in accordance with the socio-demographic segmentation used in the CLNR project as these attributes were observed to shape the way customers use electricity.

- **R3**. To consider additional load curves and generation curves in the ACE 49 Report to represent low carbon technologies.

The increasing presence of LCTs (e.g. heat pumps, electric vehicles, solar photovoltaic) in the electricity distribution network with fundamentally different technical and operational characteristics will drive a dissimilar impact to that of the incumbent technologies. Since ACE 49 Report does not consider LCTs, this work provides and recommends a generic set of load and generation curves representative of the operating regime of LCTs. This set of curves together with the demand and generation factors '*p*' and '*q*' and associated values of '*P*' and '*Q*' can be directly applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems. It is noted that these load and generation curves should be considered in addition to the load curve of a customer as they do not represent the overall load of a customer.

- **R4**. To consider the effects of seasonality in the ACE 49 Report.

Network planners have traditionally considered conditions of peak demand (i.e. central winter period – November to March) to evaluate the sufficiency of distribution network capacity. The significant presence of LCTs (e.g. distributed solar photovoltaic and wind) in the LV networks are likely to cause voltage regulation problems during coincidence of low daytime demand and high distributed low carbon generation. This work has demonstrated that the coincidence of high solar photovoltaic with low demand during the summer period may cause voltage headroom constraints in the network depending on the penetration level of distributed solar photovoltaic generation and network characteristics and topology. These voltage headroom constraints are driven by the surplus power of solar photovoltaic DG being injected in the network at times of low demand. In this sense, the inclusion of a network study for the summer period should be considered during a future review of the ACE 49 Report to ensure the robustness of the network design against voltage rise.

3. Review of ETR 130 standard

This section reviews some of the principles of the ETR 130 for assessing the capability of a network containing DG to meet demand in order to comply with the security requirements of ER P2/6. The section combines the key concepts underpinning this distribution network planning and design standard with the LOs one and two of the CLNR project to support DNOs improving the design of electricity distribution networks, ensuring techno-economic efficiency and value for money for consumers.

The section first introduces the key principles of ETR 130. It then lays out some potential limitations within a future low carbon electricity system. Subsequently, the section uses the LOs of the CLNR project to quantify the impact of the low carbon challenges in the current planning and design standard. Finally, the section establishes a set of recommendations to be considered by DNOs in the planning and design of future electricity distribution networks.

3.1 Principles of the ETR 130 standard

ETR 130 supports Engineering Recommendation (ER) P2/6[18] by providing guidance on assessing the capability of a network containing DG to meet demand. In particular, ETR 130 specifies the network security contribution that should be credited to different forms of DG. This subsection introduces the key principles of ETR 130 that relate to the method for estimating the contribution of DG to network security.

The distribution network security standard ER P2/6 consists primarily of two tables and an approach to determine the capability of a network to meet demand.

- “Table 1” (as in ER P2/6) sets out the normal levels of security required for distribution networks classified in ranges of Group Demand. Namely, it specifies the maximum reconnection times following pre-specified events leading to an interruption. This time is dependent on the group demand affected by the interruption, reducing as the group demand increases.
- “Table 2” (including “Tables 2.n” as in ER P2/6) sets out the contribution to system security expected from different types of DG connected within a demand group.
- The capability of a system to meet the group demand after first and second circuit outages should be assessed as: (i) the appropriate cyclic rating of the remaining distribution circuits which normally supply the group demand, following outage of the most critical circuit (or circuits); plus (ii) the transfer capacity which can be made available from alternative sources; plus (iii) the contribution of the DG to network capacity as specified in “Table 2”, for demand groups containing DG.

[18] ENA, 2006. “Engineering Recommendation P2/6, Security of Supply”, Energy Networks Association, Engineering Directorate, July 2006.

Following a network circuit outage, the standard specifies the approach for assessing the expected contribution that the remaining network circuits and DG can make to security of supply as depicted in Figure 15.

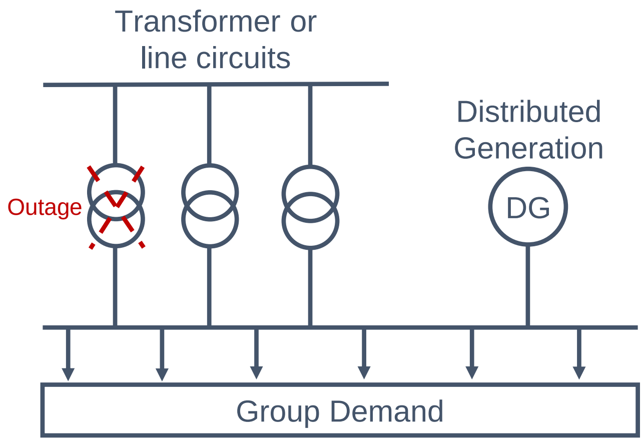


Figure 15: Example of a distribution system structure

The basic principle, adopted by the distribution network security standard, for assessing the contribution of DG to security of supply[19][20] is to determine the capacity of a perfect circuit that, when substituted by DG, gives the same level of reliability. The standard compares DG with the effective capacity of a perfect circuit and uses Expected Energy Not Supplied (EENS) as the reliability criterion. This principle is illustrated in Figure 16

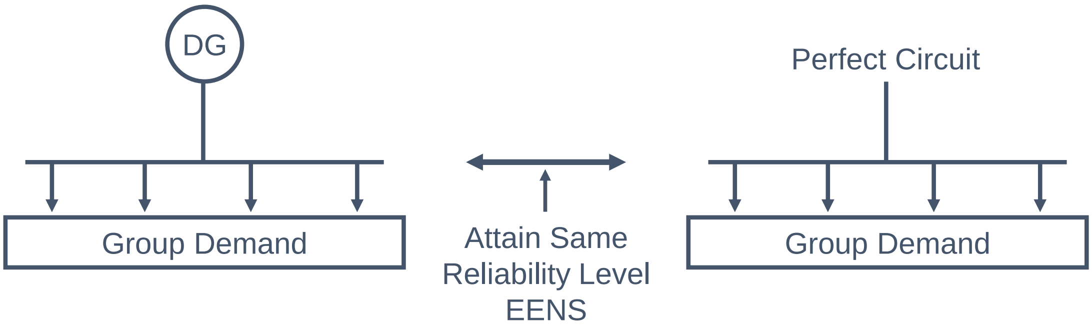


Figure 16: Comparison of DG with a circuit capacity

Assuming the perfect circuit is fully reliable, the comparison between DG and circuit capacity is performed by adjusting the circuit capacity until the same level of EENS is attained. Under this condition, the capacity of the perfect circuit will be lower than the peak demand. Figure 17 displays under the load duration curve, the magnitude of capacity of the perfect circuit and therefore the DG capability that attains the same level of EENS for the period of analysis.

[19] ENA, 2006. "Engineering Technical Report 130, Application Guide for Assessing the Capacity of Networks Containing Distributed Generation", Energy Networks Association, Engineering Directorate, July 2006.
[20] N. Allan, G. Strbac, P Djapic and K. Jarret, 2002. "Security Contribution from Distributed Generation (Extension part II)", ETSU/FES Project, K/EL00287 Extension, Final Report, University of Manchester Institute of Science and Technology, 11 December 2002.

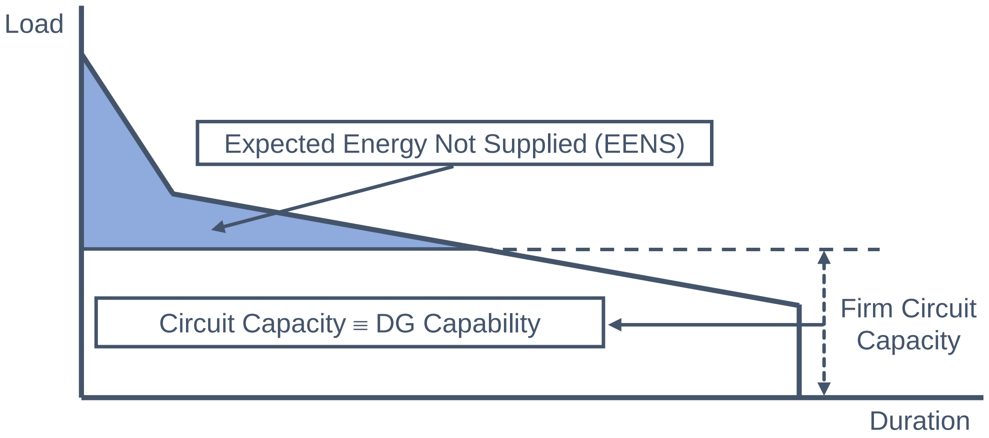


Figure 17: Evaluation of firm circuit capacity for a specific level of EENS

The capability of DG to meet demand is equivalent to the quantified perfect circuit capacity. It can be translated into an F-factor (in percentage) through the ratio between the capability of DG and the rated capacity of DG.

The approach followed by the ETR 130 to calculate the F-factors can be summarised as follows:

- Defined the capacity outage and probability table[21] (COPT) for the DG plant;
- Define the load duration curve (LDC) at a primary substation over the winter period;
- Rescale the LDC so that the peak demand equals to the installed capacity of the DG plant;
- Superimposed the COPT on to the rescaled LDC and calculate the EENS;
- Calculate the capacity of a perfectly reliable circuit that would give the same EENS if it supplied the demand in the absence of the generation; and
- Calculate the F-factor for DG as then the ratio of the perfectly reliable circuit capacity over the installed capacity of the DG plant.

The distribution network security standard ER P2/6 supplies generic F-factors for a number of technologies, based on historic data available at the time the standard was developed. In cases where the available data was sparse, it is noted that there is low statistical confidence in these generic F-factors as specified in the ETR 130. For cases where more detailed consideration of a particular DG unit is required, or where a technology is not included in "Table 2", ER P2/6 notes that reference should be made to the guidance in ETR 130, including the possible use for assessing F factors of the computer package described in ETR 131[22].

For non-intermittent generation, the F-factors for units of a given technology depend on the number of generation units in an installation (as for an ensemble of units having similar properties, the distribution of available capacity exhibits less variability from its mean if the number of units is larger), the size of the units and their individual long-term availability. For intermittent generation, the F-factors for a technology depends only on the total installed capacity and the availability statistics for that technology. Furthermore, the F-factor is reduced if the contribution of the DG is required to persist for a substantial period of time.

[21] R. Billinton, R Allan, 1996. "Reliability Evaluation of Power Systems", Second Edition, Plenun Press, New York, 1996.
[22] ENA, 2006. "Engineering Technical Report 131, Analysis Package for Assessing Generation Security Capability – Users' Guide", Energy Networks Association, Engineering Directorate, July 2006.

ETR 130 also provides general guidance on the likely technical and contractual considerations that a DNO might need to consider when looking to include the contribution for a DG plant(s) to satisfy the requirements of ER P2/6. The range of technical and contractual considerations include common mode failures, the de-minimis criterion under which only DG above a certain size is included in an assessment under P2/6, and how commercial considerations may influence the predictability of output profiles.

3.2 Challenges to the ETR 130 standard

The decarbonisation of the energy sector is leading to a shift of the distributed generation and electricity demand technologies that is likely to have major implications for distribution networks as it will drive a dissimilar impact on network design and operation to that of the traditional practices. The CLNR project has contributed to the understanding of the decarbonisation impact through the development of real-world customer field trials[23] and through the LO on customer's current, emerging and possible future load and generation technologies.

The move towards a low carbon economy prompts the need to establish how the new distributed generation and demand technologies should be treated in the planning and design of distribution networks and to identify whether appropriate modifications to the standard should be made. In particular, the security of supply standard for the planning and design of distribution networks suggests that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". Based on the LO of the CLNR project, this subsection highlights some of the challenges associated with the current ETR 130 planning and design standard.

- **C1**. Review of current and development of new F-factors representing the contribution of different distributed generation technologies to distribution network security.

"Table 2" and "Tables 2.n" of the ER P2/6 specify the network security contribution that could be credited to a specific type of non-intermittent and intermittent DG. This type of assessment requires accurate information regarding the number, ratings and operating regimes of the distributed generators within a demand group. The new information collected from the CLNR customer field trials on the operating regime of current DG will support the review of the current and the development of new F-factors enabling DNOs to better recognise the contribution that current of distributed generation makes to the system security of the electricity distribution network and therefore maintain the techno-economic efficiency of the distribution network investment.

- **C2**. Methodological challenges:
    - **C2a**. Combination of security contributions from different units.

Within the ETR 130 approach, the total capacity contribution (i.e. MW) from a demand group's DG is found by simple addition of the contributions from each DG technology contained within the demand group. For the standard to be internally consistent, this same capacity contribution would have to be found by calculating an F-factor for the whole collection of DG in one step approach. However, examination of the F-factor definition shows that this is not in general the case.

-
    - **C2b**. System structure for the underlying calculations of the F-factor.

[23] CLNR-L071, 2014. "CLNR Customer Trials – A Guide to the Load and Generation Profile Datasets", Report L071 of the Customer Led-Network Revolution project, August 2014.

There are various assumptions in the F-factor calculation approach which are substantially at variance with the reality of real distribution systems and the way the standard is applied. At one level, the rescaling of peak demand to the installed DG capacity breaks the link to the real system. More fundamentally, however, the F-factors do not transparently represent the contribution of the DG in any particular risk calculation which is relevant to the real system under study; the F-factor essentially compares the risk level of an islanded demand group supplied only by the DG with that in a system without the DG but with a perfectly reliable incoming circuit, but this capacity contribution is then used with respect to the N-1 or N-2 state of the real system. These uncontrolled assumptions expose the system to unknown, and potentially substantial, risks when the security contribution from DG compared to that provided from network assets is significant[24].

- **C2c**. Extension of the deterministic standards.

Capacity values are usually assigned to DG resource as a deterministic MW equivalent to the security from network assets which gives the same risk level, or by quantifying the additional demand which the resource can support while maintaining the same risk level. This presupposes that there is an "original" risk level, however without the DG the P2/6-ETR 130 standard essentially says that under defined circumstances all demand must be met always, i.e. no finite baseline risk level is defined. This is an example of a more general challenge with deterministic standards, namely that there is often no natural way in which to extend them to a more complex world in which an increased number of resources or demands must be taken into account.

3.3 Impact assessment for the review of ETR 130 standard

The security of supply standard for the planning and design of distribution networks states that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". The impact assessment uses the datasets collected from customer field trials of the CLNR project to review current and develop new F-factors representing the contribution of different distributed generation technologies to distribution network security.

3.3.1 Impact assessment approach

TC8 (i.e. "Basic profiling of distributed generation") of the CLNR customer field trials has provided half-hourly average power output metered data for a range of DG sites within the Yorkshire and Northeast electricity distribution networks. The collected data is representative of a variety of different technology types and DG configurations covering a two year period from March 2009 to May 2011. The impact assessment applies the current methodological approach of ETR 130 to quantify new sets of F-factors for the DG technology types monitored in TC8 and establishes a comparison with the original ETR 130 F-factors. In particular, the assessment uses the computerised model of the methodology introduced in ETR 131. The key findings of the impact assessment were then be used to devise recommendations to consider during a future review and update of the ETR 130.

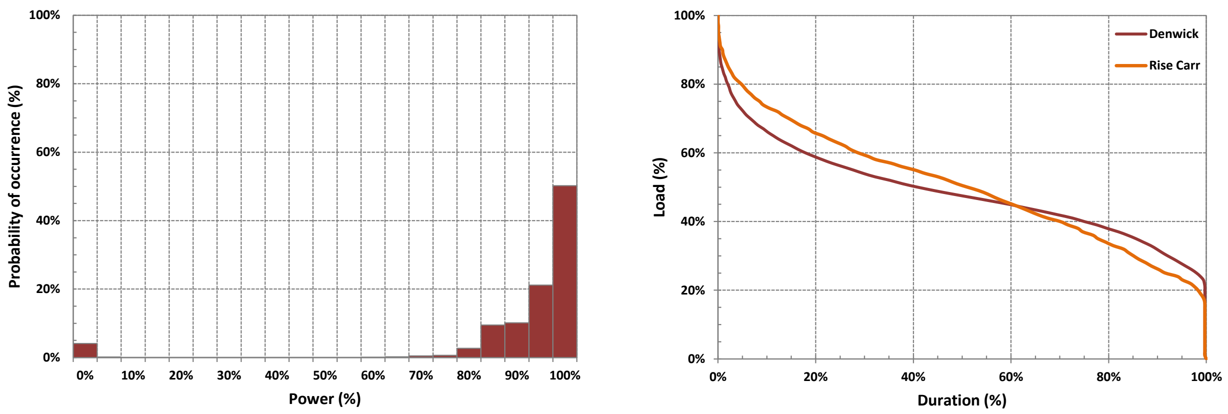
In order to ensure the applicability of the ETR 130 method and respective calculation of F-factors, the data compilation and validation process gathered information of the DG sites with known nameplate rating and

[24] For a detailed technical description of the relevant risk modelling and capacity value calculation issues refer to: C. Dent, et al., 2014. "Defining and Evaluating the Capacity Value of Distributed Generation", Submitted to IEEE Transactions on Power Systems, 2014.

technology type only. In this respect, the breakdown of the admissible datasets by technology type is as follows:

- Landfill Gas: 25 sites;
- Combine Heat and Power (CHP): 10 sites;
- Gas: 7 sites;
- Biomass: 2 sites;
- Wind: 16 sites; and
- Small hydro: 2 sites.

The data collected from the CLNR customer field trials is used within the ETR 130 F-factor methodology to characterise the operational behaviour of DG sites of a particular technology. The performance of each DG site is then statistically assessed through its probability distribution that is constructed from the half hour time series of the active power output of the monitored DG site. Group demand is represented by the annual half hour time series of electricity demand of a particular substation and subsequently converted into a load duration curve (LDC). NPG has provided for this impact assessment two distinct LDCs (i.e. Denwick and Rise Carr) to represent load demands across a wide range of electricity distribution networks in the UK. In order to preserve consistency with the studies performed to develop "Table 2" of ETR 130, the LDC for the winter period is considered. The probability distribution of DG performance and the LDC of the network load of a substation are then superimposed to quantify the EENS and the capability of DG to meet that group demand (i.e. F-factor). Figure 18 provides an illustration of the DG and load characteristics used for the assessment of the F-factors. Specifically, Figure 18a depicts the probability distribution of the operational performance of a single monitored Landfill Gas site and Figure 18b illustrates the annual LDCs.



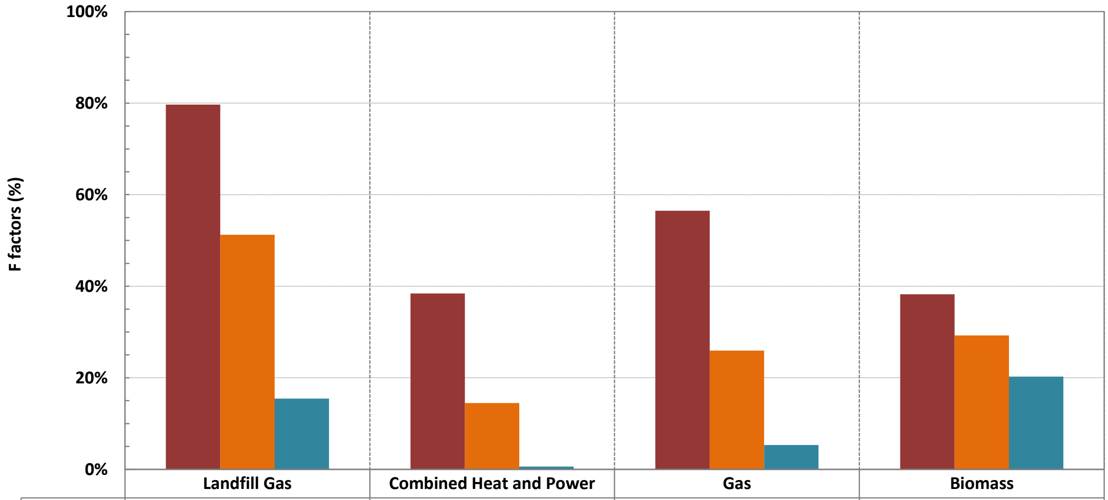
(a) Probability distribution of the operational performance of a monitored Landfill Gas site

(b) Load duration curve

Figure 18: Distributed generation and load characteristics

The calculation process of F-factors, for each technology specific DG site, combined each of the two monitored years of active power output of DG with each of the two LDCs resulting in a total number of four distinct combinations between DG and LDC. These four configurations cover a good range of design situations. The computation of F-factors has been performed with the software package developed for assessing the security capability of DG described in ETR 131.

Figure 19 presents the range of F-factors quantified for the non-intermittent DG technologies considered in the customer field trials of the CLNR project.



	Landfill Gas	Combined Heat and Power	Gas	Biomass
Maximum	80%	38%	56%	38%
Average	51%	14%	26%	29%
Minimum	15%	1%	5%	20%

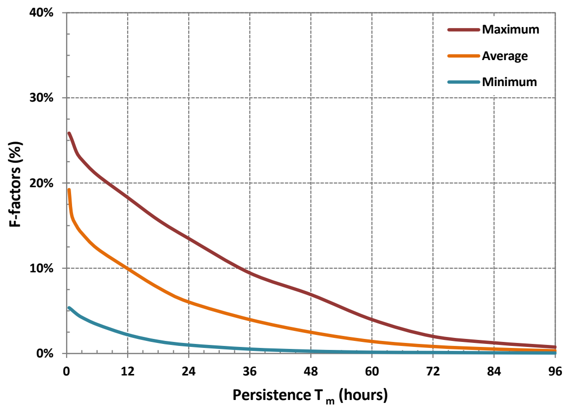
Figure 19: F-factors for non-intermittent DG technologies

It can be seen in Figure 19 that the capacity contribution of DG to system security can vary significantly across different technology types of plant and also for different plants of the same type. For instance, the average F-factor varies from 14% for CHP to 51% for Landfill Gas plants. Furthermore, under the same technology type, the F-factor for Landfill Gas sites ranges from a minimum of 15% to a maximum of 80%.

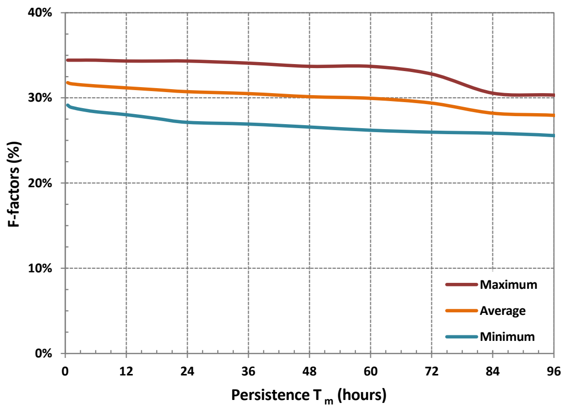
The contribution of DG to system security is driven by various factors related to both generation and load. On the generation side factors such as the availability of the generating units that constitute the DG plant, the number of units, the size of the units and their operating regime can have a significant impact on the F-factors. On the load side, drivers such as the magnitude and duration of the peak load can affect the contribution of DG plants to system security.

In Figure 19, the variability observed in the capacity contribution of DG was found to be mainly driven by the operating regime of the DG plants under consideration and consequently their availability. It is noted that the overall availability of the technology specific DG site is implicitly considered in the time series of the operational performance of the DG plants observed in the trials. Broadly, the overall availability includes attributes related to: (i) technical availability which reflects whether the facility is in a working state; (ii) energy availability which reflects whether energy is available to drive the generating units; and (iii) commercial availability which reflects whether it is commercially available. For example, a Gas plant generally has high technical availability, typically above 90%, together with good fuel availability. However, when operated as a merchant DG plant with its main objective being to meet energy contracts, or provide energy balancing services, the availability of its full output is under control of the 'Generator' and will be varied for purely commercial reasons. Based on the data available from the CLNR customer field trials, it is extremely difficult to attempt disaggregating the overall availability of the DG site into the three aforementioned availability types.

Figure 20 presents the range of F-factors quantified for the intermittent DG technologies considered in the customer field trials of the CLNR project. The F-factors for intermittent generation are related directly to the persistence time T_m, i.e. the period of time for which generation will need to operate continuously at or above a certain output level in order to support the demand and hence to provide system security. This period of time is related to the duration of the system conditions for which such generation may be able to avoid or reduce customer disconnections. Broadly, intermittent generation sources persist in generating at a particular output level for significantly shorter periods of time.



(a) Wind farm



(b) Small hydro

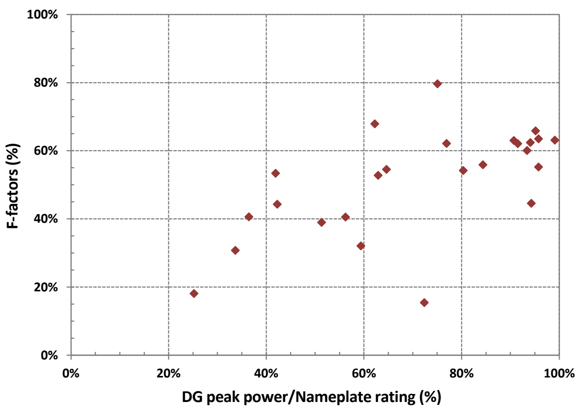
Figure 20: F-factors for intermittent DG technologies

It can be observed in Figure 20 that increasing the level of required persistence reduces the contribution of intermittent generation to security. For example, it is seen in Figure 20a that the average contribution of the wind farm to network security decreases from about 20% for T_m = ½ hr to 6% for T_m = 24 hr.

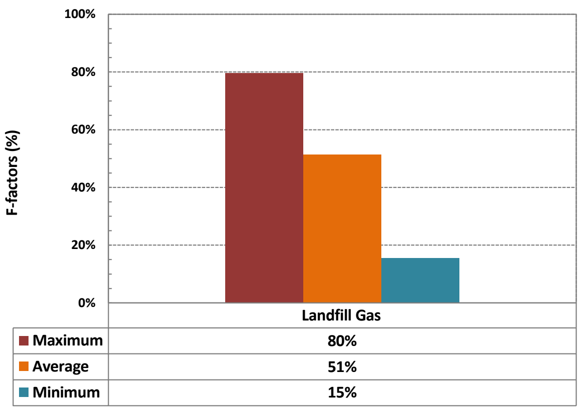
The following subsections present the technology specific contribution of DG to distribution network security for the sites monitored in the CLNR project.

3.3.2 Landfill Gas

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F-factors for 25 DG Landfill Gas sites. The nameplate rating of these sites rages from 0.3MW to 8MW. The set of F-factors quantified for the 25 monitored DG Landfill Gas sites are presented in Figure 21.



(a) Distribution of F-factors



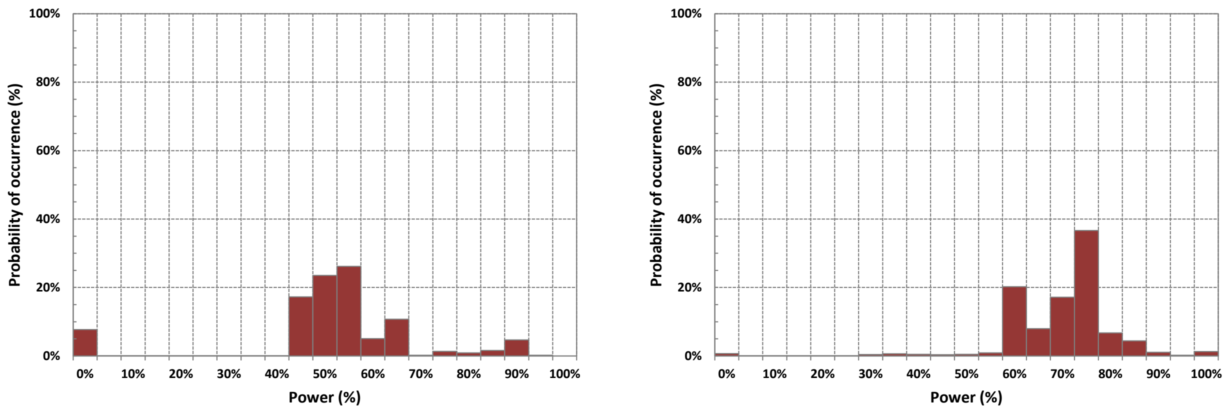
(b) Statistics of F-factors

Figure 21: F-factors for Landfill Gas sites

It can be inferred from Figure 21b that the mean F-factor over the four configurations of DG and LDC is 51%. A Landfill Gas site with a nameplate rating of 1MW could usually be expected to support a maximum demand of 0.5MW. The sample standard deviation is found to be relatively wide and is estimated to be 17%. This reflects the significant variation of the contribution of different Landfill Gas sites to system security as demonstrated in Figure 21a. It should be mentioned that the mean F-factor over the four configurations between DG and LDC has been presented as the impact of these different configurations on the F-factor was found to be marginal.

It is seen in Figure 21a that distributed generators operating with a peak power output near to their nameplate rating (i.e. 100%) are characterised by contribution to network security ranging from 60% to 65%. It is noted that the F-factor provided by ETR 130 for a Landfill Gas site constituted of one generating unit is 63% based on technical availability only. Nevertheless, the operating regime (i.e. including technical, fuel and commercial availabilities) of a generator is clearly seen to have an important effect on the contribution of the site to system security. Hence, for a generator operating with a peak power output of only 40% of the nameplate rating, the F-factor is observed to be closer to 40%.

In this context, Figure 21b shows that from the 25 DG Landfill Gas sites considered in the analysis, the F-factor varies significantly from a minimum of 15% to a maximum of 80%. Figure 22a and Figure 22b detail the operational performance of the Landfill Gas sites that result in the minimum and maximum levels of the contribution to network security, respectively.



(a) Probability distribution of Landfill Gas site with 15% contribution to network security

(b) Probability distribution of Landfill Gas site with 80% contribution to network security

Figure 22: Operational performance of Landfill Gas sites

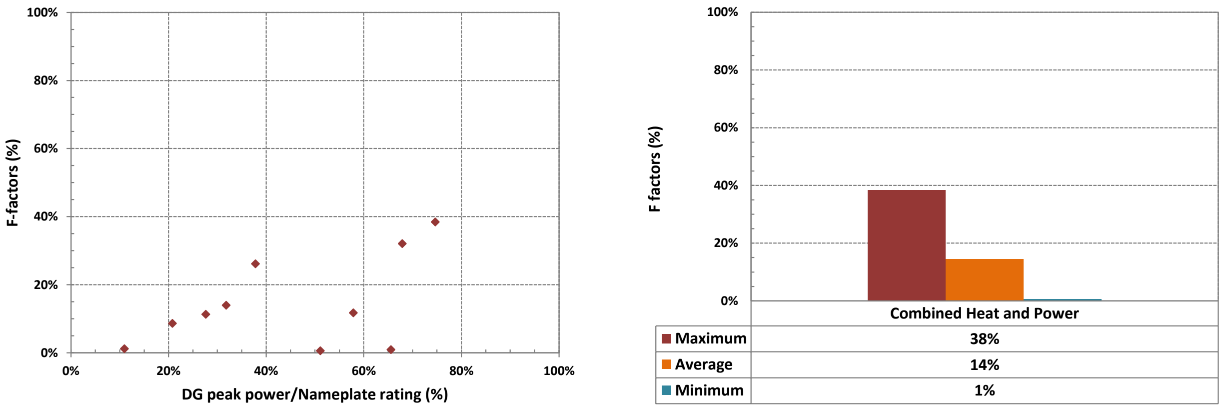
The Landfill Gas site in Figure 22a is characterised by a nameplate rating of 0.34MW and an annual average load factor of 50%. It can be seen in Figure 22a that there is approximately 8% chance of this site being out of service. Moreover, it is observed that power output levels between 45% and 55% of the nameplate rating of this site have the highest likelihood of occurrence that is estimated to be around 67% overall. This means that for most of the time that this Landfill Gas is in operation, its power output is in the region of 50% of its nameplate rating. As a consequence, the operation performance of this DG site results in a limited contribution to network security.

The Landfill Gas site in Figure 22b is characterised by a nameplate rating of 2.5MW and an annual average load factor of 70%. It is observed that the likelihood of power outputs between 0% and 55% is practically negligible whilst the most likely power output level is estimated to be around 75% of the nameplate rating of this site. In this respect, the operation performance of this DG site results in a significant contribution to network security. The 2.5MW nameplate rating site could usually be expected to support a maximum demand of 2MW.

The CLNR project provides the half hour time series of the active power output of the monitored DG Landfill Gas sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

3.3.3 Combined Heat and Power

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F-factors for 10 DG CHP sites. The nameplate rating of these sites rages from 0.1MW to 39MW. The set of F-factors quantified for the 10 monitored DG CHP sites are presented in Figure 23.



(a) Distribution of F-factors **(b) Statistics of F-factors**

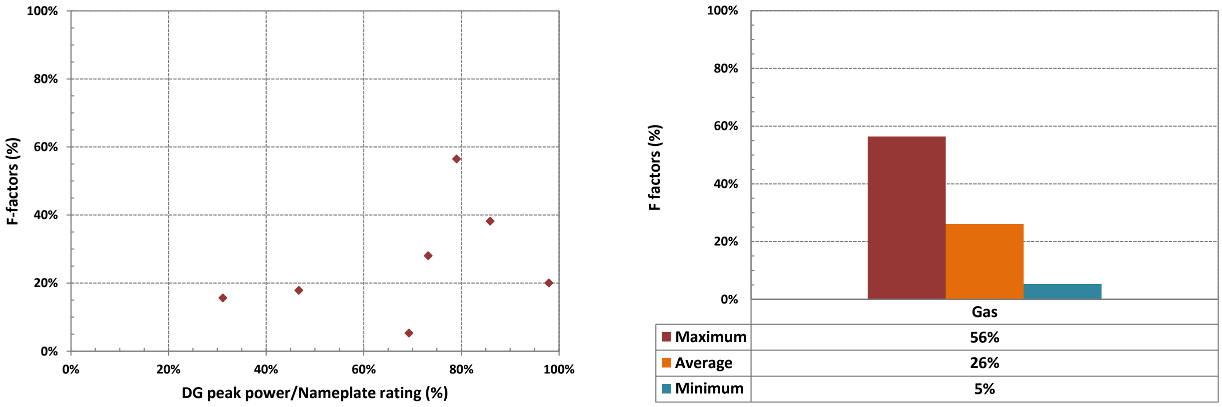
Figure 23: F-factors for Combined Heat and Power sites

It can be derived from Figure 23a that the mean F-factor over the four configurations of DG and group demand is 14%. A CHP site with a nameplate rating of 1MW, could usually be expected to support a maximum demand of 0.14MW. The sample standard deviation is found to be relatively wide and is estimated to be 13%. Figure 23b shows that from the 10 DG CHP sites considered in the analysis, the F-factor varies significantly from a minimum of 1% to a maximum of 38%.

The CLNR project provides the half hour time series of the active power output of the monitored DG CHP sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

3.3.4 Gas

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F-factors for 7 DG Gas sites. The nameplate rating of these sites rages from 2MW to 12MW.The set of F-factors quantified for the 7 monitored DG Gas sites are presented in Figure 24.



(a) Distribution of F-factors

(b) Statistics of F-factors

Figure 24: F-factors for Gas sites

It can be estimated from Figure 24a that the mean F-factor over the four configurations of DG and group demand is 26%. A Gas site with a nameplate rating of 1MW, could usually be expected to support a maximum demand of 0.26MW. The sample standard deviation is found to be relatively wide and is estimated to be 16%. Figure 24Figure 24b shows that from the 7 DG Gas sites considered in the analysis, the F-factor varies significantly from a minimum of 5% to a maximum of 56%.

The CLNR project provides the half hour time series of the active power output of the monitored DG Gas sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

3.3.5 Biomass

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F-factors for only 2 DG Biomass sites. The nameplate rating of these sites rages from 1MW to 3MW.The set of F-factors quantified for these 2 monitored sites are presented in Figure 25.

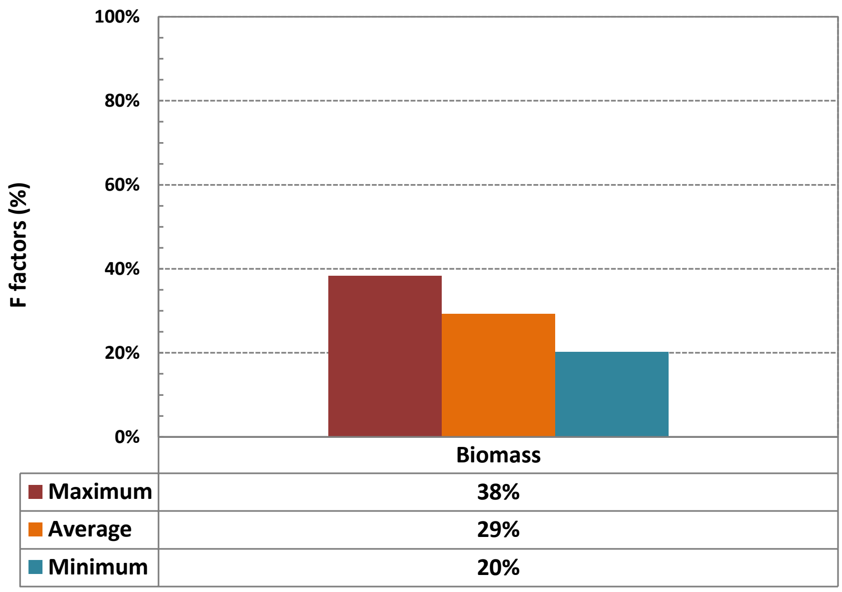


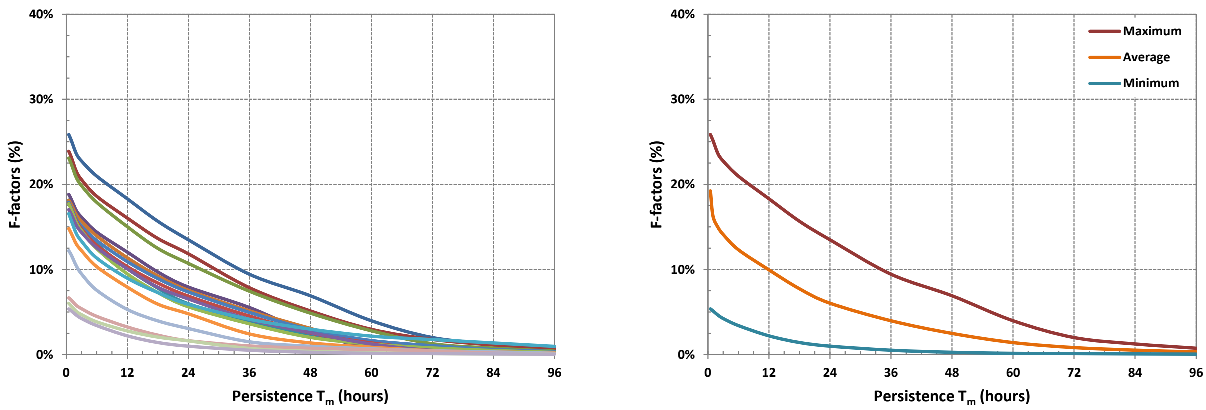
Figure 25: F-factors for Biomass sites

It can be observed in Figure 25 the F-factor for the DG Biomass sites varies from a minimum of 20% to a maximum of 38%. It is stressed that the datasets used to create this Figure 25 have limited statistical robustness due to data scarcity.

The CLNR project provides the half hour time series of the active power output of the monitored DG Biomass sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

3.3.6 Wind

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F-factors for 16 DG Wind sites. The nameplate rating of these sites rages from 0.02MW to 30MW. The time series representing the operational performance of the DG Wind sites is constituted of thirty minutes time intervals. Since wind output may vary considerably during each half hour, the variation in associated levels of generation would need to be absorbed by the remaining network circuits. For a short period of time, the generation output could drop significantly and hence the remaining circuits may become overloaded. ETR 131 recommends using a five minutes sample rate to take account of the effect of these short term fluctuations of the wind resource. ETR 131 then provides a table of 'Correction Factors' for wind farm contribution, for typical values of T_m (ETR 131, Figure 18). This table has been used in this work to scale the wind farm data by the appropriate data resolution 'correction factors'. The F-factors quantified for the 16 monitored DG Wind sites are presented in Figure 26 for different persistence values of T_m.

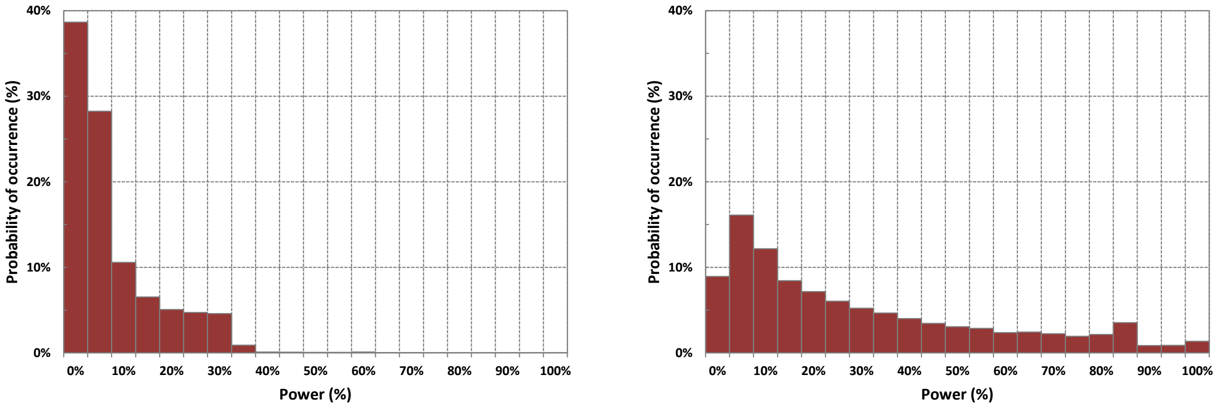


(a) Distribution of F-factors **(b) Statistics of F-factors**

Figure 26: F-factors for Wind sites

It can be seen in Figure 26a that the capacity contribution of DG Wind to system security can vary significantly across different sites due to the variable nature of the wind resource. For instance, for T_m = ½ hr the F-factors range from 5% to 26%. It is also seen that increasing the level of required persistence reduces the contribution of the DG Wind sites to security, as expected.

Figure 27a and Figure 27b detail the operational performance of the monitored wind sites that result in the minimum and maximum levels (i.e. from Figure 26b) of contribution to network security, respectively. The Wind site in Figure 27a is characterised by a nameplate rating of 1.8MW and an annual average load factor of 6% whilst Figure 27b represents a wind site of 9.3MW of nameplate rating and 28% annual average load factor.



(a) Probability distribution of a Wind site for the minimum observed contribution to network security

(b) Probability distribution of a Wind site for the maximum observed contribution to network security

Figure 27: Operational performance of Wind sites

It can be seen in Figure 27a that the likelihood of no or very low wind power output is relatively high. Furthermore, the maximum power output observed in this Wind site is as low as 35% of the nameplate rating. Thus, it is expected that the ability of this DG site to contribute to network security is very low as previously demonstrated. In contrast, Figure 27b represents a wind site characterised by higher availability of the wind resource over a wide range of power outputs levels. In this sense, the operation performance of the latter DG site results in a relatively higher contribution to network security.

Table 7 establishes a comparison of the average F-factors across the 16 monitored DG Wind sites (i.e. average curve in Figure 26b against the original F-factors of wind farms specified in the ETR 130.

Table 7: Comparison of the F-factors of wind farms from ETR 130 against the CLNR monitored sites

Cases	T_m						
	0.5	2	3	18	24	120	360
ETR130: F-factors for wind farm	28%	25%	24%	14%	11%	0%	0%
CLNR Trials: Average F-factors for wind farm	19%	15%	14%	8%	6%	0%	0%

Table 7 shows that the F-factors for wind farm can vary significantly depending on the characteristics of the wind resource. For example, for T_m = ½ hr the contribution to network security of the wind farms considered in the ETR 130 studies is 28% whilst the contribution to network security based on the monitored sites of the CLNR project is estimated to be 19%.

Based on the real-world customer field trials of the CLNR project it observed that the capacity contribution of DG Wind to system security can vary significantly across different plants of the same type and that F-factors for DG Wind were found to be significantly lower than those specified in ETR 130.

The CLNR project provides the half hour time series of the active power output of the monitored DG Wind sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

Customer-Led Network Revolution

3.3.7 Small Hydro

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F-factors for only 2 DG Hydro sites. The nameplate rating of these sites rages from 0.1MW to 5MW. The set of F-factors quantified for these 2 monitored sites are presented in Figure 28 for different persistence values of T_m.

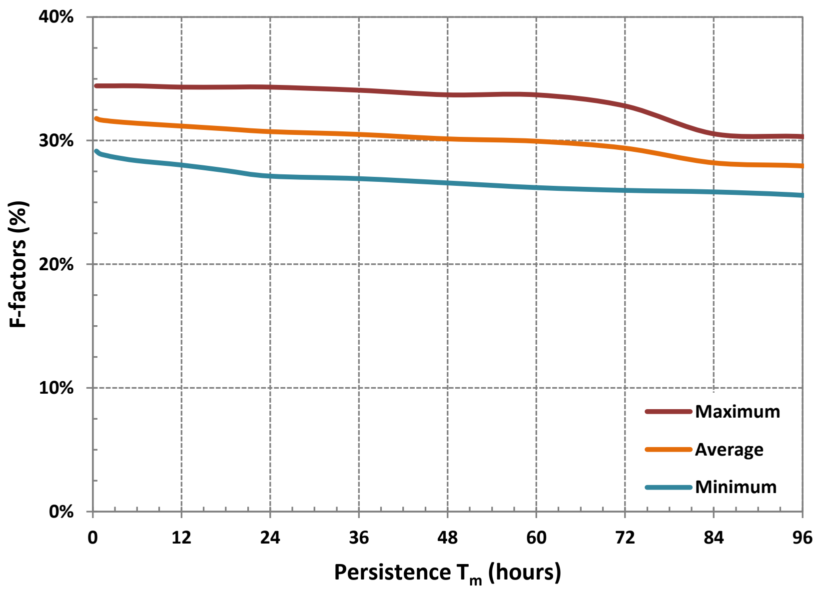


Figure 28: F-factors for Hydro sites

It can be observed in Figure 28 Figure 28 that for T_m = ½ hr the F-factor for the DG Wind sites varies from a minimum of 29% to a maximum of 34%. It is stressed that the datasets used to create this Figure 28 have limited statistical robustness due to data scarcity.

Table 8 compares the average F-factors across the 2 monitored DG hydro sites i.e. average curve in Figure 28 against the original F-factors of wind farms specified in the ETR 130.

Table 8: Comparison of the F-factors of small hydro from ETR 130 against the CLNR monitored sites

Cases	T_m						
	0.5	2	3	18	24	120	360
ETR 130: F-factors for small hydro	37%	36%	36%	34%	34%	25%	13%
CLNR Trials: Average F-factors for small hydro	32%	32%	32%	31%	31%	27%	21%

Table 8 shows that the F-factors for small hydro based on the monitored sites of the CLNR project are found to be relatively close to those of ETR 130. Nevertheless, it should be noted that different operating regimes of DG can lead to very different contributions to network security.

The CLNR project provides the half hour time series of the active power output of the monitored DG Wind sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

3.4 Recommendations for the review of ETR 130 standard

Based on the LOs and real-world field trials of the CLNR project, the key recommendations to consider during a future review and update of ETR 130 can be summarised as follows:

- **R1**. To consider the data collected from the customer field trials of the CLNR project in the review and update of the F-factors to represent the contribution of different DG technologies to distribution network security. To review and update the current F-factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project.

The security of supply standard for the planning and design of distribution networks suggests that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". In this respect, it is recommend to review and update the current F-factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project. This supports DNOs to better recognise the contribution that DG makes to the system security and therefore to comply with the security requirement ER P2/6.

- **R2**. Review of the ETR 130 methodology for assessing the contribution of DG to network security

As discussed in Section 3.2 ("Challenges to the ETR 130 Standard"), challenge C2 (Methodological challenges), the consideration within the CLNR project of the modelling structure underlying ETR 130 reveals a number of concerns about how the planning methodology contained therein relates to the real system situations under study. In general, if a simplified approach (such as the F-factors used at present) is to be used in assessing the contribution of DG and other new technologies in practical planning, then such a simplified approach should have a sound basis in a particular risk calculation relevant to the real network situations under study. This might either be based in a probabilistic calculation with a particular target risk level, or in a probabilistic cost-benefit analysis between investment cost and future reliability cost.

More generally, as discussed in the "Methodological challenges", there is no natural way of extending a deterministic standard such as the present ETR 130 and P2/6 to include distributed resources. The only natural basis for considering such new components of the system is to develop a fully probabilistic risk-based planning approach, which can integrate consideration of all relevant technologies. There are clear advantages of using a simplified approach such as the present F-factors for practical purpose (including resource expended on any individual study, and applicability by a wide range of planning engineers who are not experienced in probability techniques), but in order to have confidence that such an approach will deliver good results it should have a sound basis in a fully detailed calculation.

4. Review of the ER G59 standard

ER G59 provides recommendations for the connection of generating plant to the distribution systems of electricity distribution licence holders. It is referenced in Annex 1 of the Distribution Code and is incorporated within the Distribution Code[25].

ER G59/1 version came into effect in 1995. It was supplemented by the ETR 113[26], which provides further guidance for the protection of generating plant that operates in parallel with a distribution network. A further document, ER G75/1[27], was also available to provide additional guidance for the connection of generators that have a capacity greater than 5MW or are connected at a voltage greater than 20kV.

All of these documents were reviewed by a Working Group established by the Distribution Code Review Panel (DCRP) in June 2006. As a result of the review process, the regulator for gas and electricity markets[28] (Ofgem) issued the replacement of the ERs G59/1, G75/1 and ETR 113 with ER G59/2 in July 2010.

In 2011, an amendment to the ER G59/2 revising the current limits for DC injection led to the issue of the ER G59/2-1. In March 2011, the network licensees found that the Type Testing[29] had not been as effective as intended and therefore a review of the ER G59/2-1 was initiated to improve the Type Testing provisions. The scope of the review of ER G59/2-1 was then further extended to include the impacts of the ER G83/2[30] introduced in December 2012. Consequently, the revised document was issued by the ENA in August 2013 as the ER G59/3. In August 2014, the ENA issued an amendment to the ER G59/3 revising the settings of protection equipment for the Rate of Change of Frequency (RoCoF) resulting the ER G59/3-1 version.

Currently, the ER G59/3-1 provides guidance on the connection of Generating Plant to the Distribution Systems of licensed DNOs. It is intended to address all aspects of the connection process from standards of functionality to site commissioning, such that Customers, Manufacturers and Generators are aware of the requirements that will be made by the local DNO before the generation Plant will be accepted for connection to the Distribution System.

Based on the LOs and real-world field trials of the CLNR project, the key recommendations to consider during a future review and update of ER G59/3-1 can be summarised as follows:

- **R1**. To treat electrical energy storage facilities as distributed generation for the purpose of protection systems and settings.

---

[25] Distribution Code, 2014. “The Distribution Code and the Guide to the Distribution Code of Licensed Distribution Network Operators of Great Britain: Issue 24”, 21 August 2014.

[26] ENA, 1995. “Engineering Technical Report 113, Notes of Guidance for the Connection of Private Generating Plant up to 5MW for Operation in Parallel with Public Electricity Suppliers’ Distribution Systems”, Energy Networks Association, Engineering Directorate, 1995.

[27] ENA, 2002. “Engineering Recommendation G75 Issue 1, Recommendations for the Connection of Embedded Generating Plant to Public Distribution Systems Above 20kV or with Outputs over 5MW”, Energy Networks Association, Engineering Directorate, 2002.

[28] Office of Gas and Electricity Markets (Ofgem). https://www.ofgem.gov.uk/

[29] Type Testing is testing to determine whether a product or system meets a specified standard that has been developed for efficiency and/or interoperability. In the context of this ER, Type Testing avoids the need for bespoke commissioning tests by the DNO.

[30] ENA, 2012. “Engineering Recommendation G83 Issue 2, Recommendations for the Connection of Type Tested Small-scale Embedded Generators (Up to 16A per Phase) in Parallel with Low-Voltage Distribution Systems”, Energy Networks Association, Engineering Directorate, 2012.

5. Conclusions

The CLNR project have set up a number of test cells to enhance the understanding of existing and future customer generation/demand profiles and the potential flexibility of different customer types. This report uses the wealth of information collected from these real-world customer field trials to explore the challenges posed by the integration of new distributed generation and demand technologies to the current planning and design standards. The UK electricity distribution systems were considerably expanded in 1950s and 1960s to meet the increasing customer requirements. The networks were developed in accordance with network planning and design standards that have stood the test of time and are still relevant today. Nevertheless, the integration of these new technologies in the network, with fundamentally different technical and operational characteristics to those of the incumbent technologies, will prompt the need to establish how they should be treated in the planning and design of distribution networks and to establish whether modifications to the standards should be made.

In this context, this report reviews:

- ACE Report No. 49 for the design of low voltage radial distribution networks, demands and voltage by understanding future basic demand profile of regular domestic customers and those with heat pumps, electric vehicles and solar photo-voltaic cells using smart meter data.
- Engineering Technical Report (ETR) 130 for assessing the capability of a distribution network containing distributed generation to meet demand, in order to comply with the security requirements of ER P2/6, by exploring the information collected from test cells related to profiling distributed generation.
- Engineering Recommendation (ER) G59/3-1 for the connection of generating plant to the distribution systems of electricity distribution licence holders by exploring the information collected from test cells related to profiling distributed generation.

The key recommendations to consider during a future fundamental review and update of ACE 49 Report can be summarised as follows:

- **R1**. To review and update the load curves of ACE 49 Report to represent the characteristics and behaviour of present electricity customers in accordance with the work developed and findings of the CLNR project.

The demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyle and behaviour. In this context, customers' use of electricity in a dissimilar manner to that of the ACE 49 Report. The new load shape and lower annual electricity consumption of domestic customers lead to lower utilisation of the network assets during peak load conditions and to a consequent decrease of network reinforcement requirements. This work provides and recommends a generic set of load curves representative of domestic customers together with the demand factors 'p' and 'q' and associated values of 'P' and 'Q'. These load curves can be directly applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems.

- **R2**. To review and update the types of customers of ACE 49 Report to represent present customers in accordance with the work developed and findings of the CLNR project.

The ACE 49 Report has broadly defined domestic customer types according to their electricity tariff (e.g. unrestricted, restricted), type of heating (e.g. water, space), electrical appliances (e.g. electric cooking), electricity consumption (i.e. low, medium, high), etc. Nonetheless, the demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyle and behaviour. This work recommends to review and update the types of domestic customers of ACE 49 Report in accordance with the socio-demographic segmentation used in the CLNR project as these attributes were observed to shape the way customers use electricity.

- **R3**. To consider additional load curves and generation curves in the ACE 49 Report to represent low carbon technologies.

The increasing presence of LCTs (e.g. heat pumps, electric vehicles, solar photovoltaic) in the electricity distribution network with fundamentally different technical and operational characteristics will drive a dissimilar impact to that of the incumbent technologies. Since ACE 49 Report does not consider LCTs, this work provides and recommends a generic set of load and generation curves representative of the operating regime of LCTs. This set of curves together with the demand and generation factors 'p' and 'q' and associated values of 'P' and 'Q' can be directly applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems. It is noted that these load and generation curves should be considered in addition to the load curve of a customer as they do not represent the overall load of a customer.

- **R4**. To consider the effects of seasonality in the ACE 49 Report.

Network planners have traditionally considered conditions of peak demand (i.e. central winter period – November to March) to evaluate the sufficiency of distribution network capacity. The significant presence of LCTs (e.g. distributed solar photovoltaic and wind power) in the LV networks are likely to cause voltage regulation problems during coincidence of low daytime demand and high distributed low carbon generation. This work has demonstrated that the coincidence of high solar photovoltaic with low demand during the summer period may cause voltage headroom constraints in the network depending on the penetration level of distributed solar photovoltaic generation and network characteristics and topology. These voltage headroom constraints are driven by the surplus power of solar photovoltaic DG being injected in the network at times of low demand. In this sense, the inclusion of a network study for the summer period should be considered during a future review of the ACE 49 Report to ensure the robustness of the network design against voltage rise.
The key recommendations to consider during a future fundamental review and update of ETR 130 can be summarised as follows:

- **R1**. To review and update the current F-factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project.

The security of supply standard for the planning and design of distribution networks suggests that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". In this respect, it is recommend to review and update the current F-factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project. This supports DNOs to better recognise the contribution that DG makes to the system security and therefore to comply with the security requirement ER P2/6.

- **R2**. Review of the ETR 130 methodology for assessing the contribution of DG to network security.

The consideration within the CLNR project of the modelling structure underlying ETR 130 reveals a number of concerns about how the planning methodology contained therein relates to the real system situations under study. In general, if a simplified approach (such as the F-factors used at present) is to be used in assessing the contribution of DG and other new technologies in practical planning, then such a simplified approach should have a sound basis in a particular risk calculation relevant to the real network situations under study. This might either be based in a probabilistic calculation with a particular target risk level, or in a probabilistic cost-benefit analysis between investment cost and future reliability cost. More generally, there is no natural way of extending a deterministic standard such as the present ETR 130 and P2/6 to include distributed resources. The only natural basis for considering such new components of the system is to develop a fully probabilistic risk-based planning approach, which can integrate consideration of all relevant technologies. There are clear advantages of using a simplified approach such as the present F-factors for practical purpose (including resource expended on any individual study, and applicability by a wide range of planning engineers who are not experienced in probability techniques), but in order to have confidence that such an approach will deliver good results it should have a sound basis in a fully detailed calculation.

Based on the LOs and real-world field trials of the CLNR project, the key recommendations to consider during a future review and update of ER G59/3-1 can be summarised as follows:

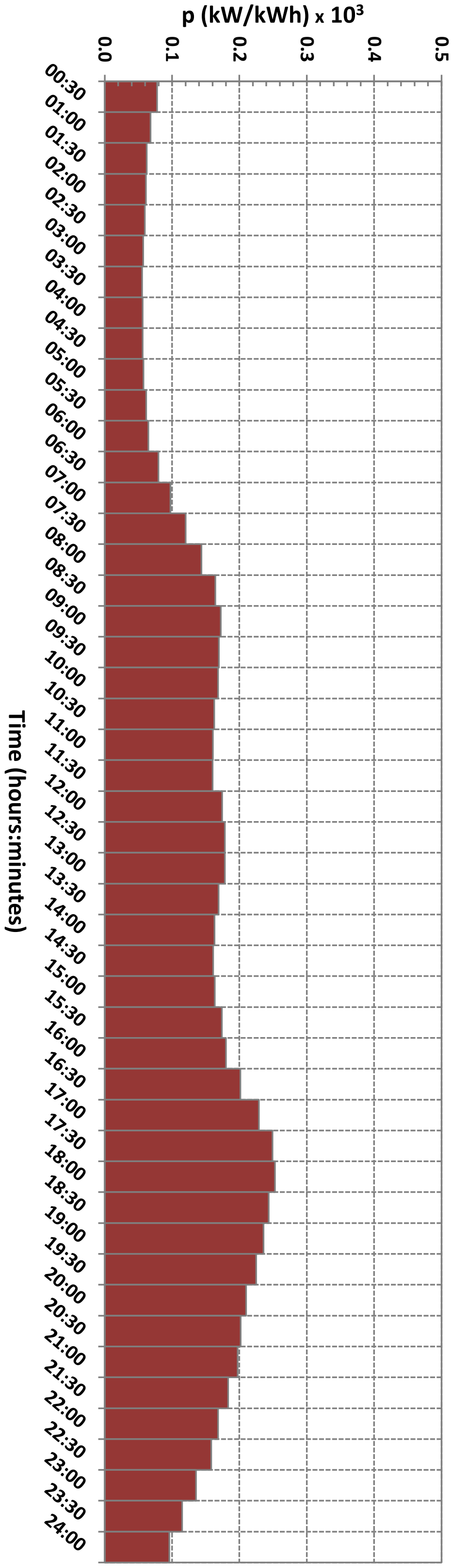
- **R1**. To treat electrical energy storage facilities as distributed generation for the purpose of protection systems and settings.

Appendix A

The CLNR project has used real-word data collected from the smart meter domestic customer field trials to produce a generalised set of load curves for different types of domestic customers that can be applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems. The load curves are presented in this Appendix together with the demand factors ‘p’ and ‘q’ and associated values of ‘P’ and ‘Q’ for the central winter period.

Dependant consumer group (household includes at least one child aged < 5 and/or an adult aged ≥ 65years)

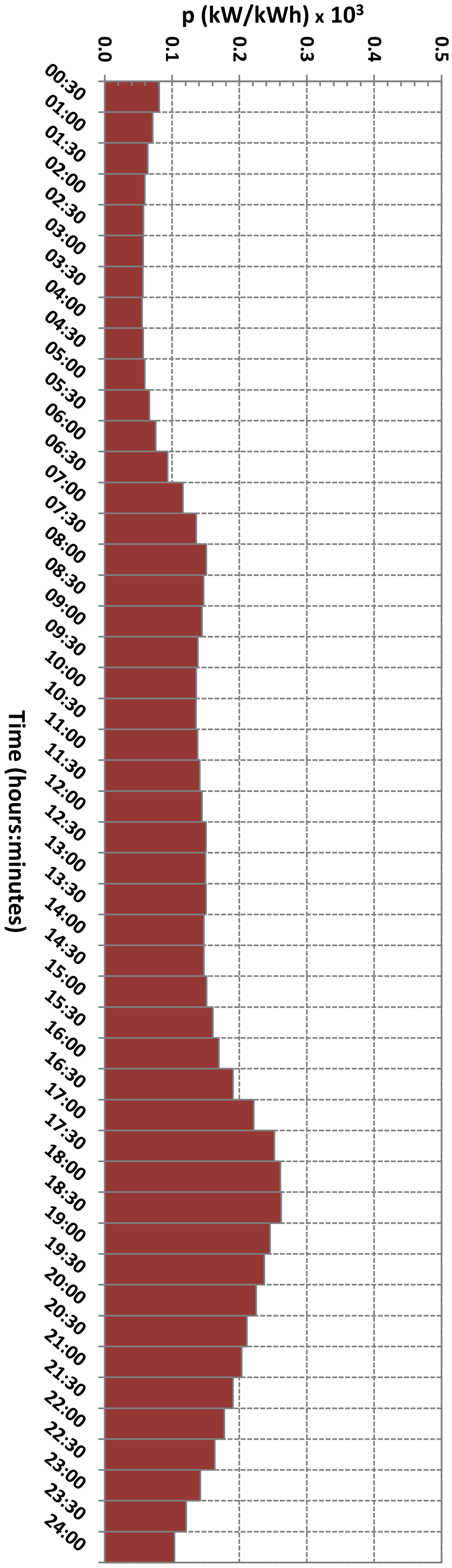
Time	p	q	P	Q
00:30	0.078	0.100	0.25	0.32
01:00	0.068	0.089	0.22	0.28
01:30	0.063	0.078	0.20	0.25
02:00	0.061	0.095	0.19	0.30
02:30	0.059	0.103	0.19	0.33
03:00	0.057	0.075	0.18	0.24
03:30	0.056	0.064	0.18	0.20
04:00	0.057	0.073	0.18	0.23
04:30	0.056	0.071	0.18	0.23
05:00	0.058	0.075	0.18	0.24
05:30	0.062	0.095	0.20	0.30
06:00	0.065	0.091	0.21	0.29
06:30	0.080	0.125	0.25	0.40
07:00	0.098	0.156	0.31	0.49
07:30	0.120	0.184	0.38	0.59
08:00	0.144	0.196	0.46	0.62
08:30	0.164	0.223	0.52	0.71
09:00	0.172	0.238	0.55	0.75
09:30	0.169	0.217	0.54	0.69
10:00	0.168	0.213	0.54	0.68
10:30	0.163	0.210	0.52	0.67
11:00	0.160	0.209	0.51	0.66
11:30	0.160	0.211	0.51	0.67
12:00	0.174	0.277	0.55	0.88
12:30	0.178	0.239	0.57	0.76
13:00	0.178	0.251	0.57	0.80
13:30	0.169	0.220	0.54	0.70
14:00	0.163	0.228	0.52	0.73
14:30	0.161	0.210	0.51	0.67
15:00	0.163	0.209	0.52	0.66
15:30	0.174	0.203	0.55	0.65
16:00	0.180	0.214	0.57	0.68
16:30	0.201	0.224	0.64	0.71
17:00	0.229	0.240	0.73	0.76
17:30	0.249	0.258	0.79	0.82
18:00	0.253	0.256	0.80	0.81
18:30	0.244	0.238	0.77	0.76
19:00	0.236	0.248	0.75	0.79
19:30	0.225	0.237	0.71	0.75
20:00	0.210	0.218	0.67	0.69
20:30	0.202	0.200	0.64	0.64
21:00	0.198	0.211	0.63	0.67
21:30	0.183	0.190	0.58	0.60
22:00	0.168	0.152	0.53	0.48
22:30	0.158	0.170	0.50	0.54
23:00	0.136	0.143	0.43	0.46
23:30	0.115	0.135	0.36	0.43
24:00	0.096	0.111	0.30	0.35



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,177kWh.

Non-dependant consumer group (all household members ≥ 5 and/ < 65 years)

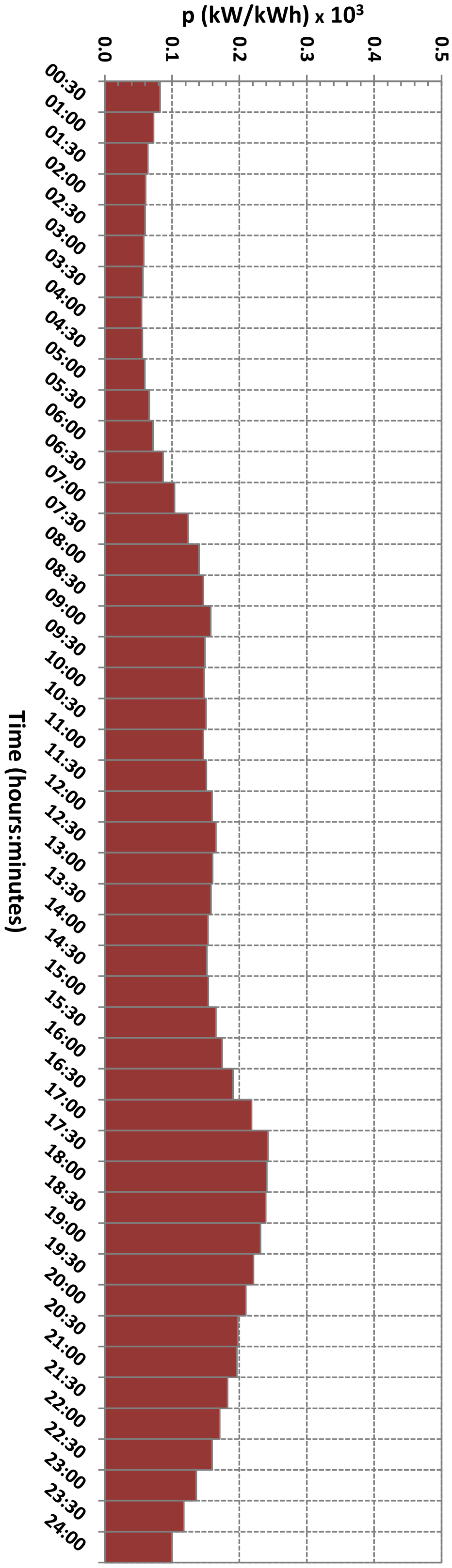
Time	p	q	P	Q
00:30	0.081	0.111	0.31	0.43
01:00	0.071	0.091	0.27	0.35
01:30	0.064	0.080	0.25	0.31
02:00	0.060	0.071	0.23	0.27
02:30	0.058	0.072	0.22	0.28
03:00	0.057	0.078	0.22	0.30
03:30	0.057	0.078	0.22	0.30
04:00	0.055	0.075	0.21	0.29
04:30	0.057	0.077	0.22	0.30
05:00	0.059	0.082	0.23	0.31
05:30	0.066	0.102	0.26	0.39
06:00	0.076	0.121	0.29	0.46
06:30	0.094	0.155	0.36	0.60
07:00	0.116	0.182	0.45	0.70
07:30	0.136	0.180	0.52	0.69
08:00	0.151	0.209	0.58	0.80
08:30	0.147	0.192	0.57	0.74
09:00	0.144	0.212	0.55	0.82
09:30	0.138	0.194	0.53	0.74
10:00	0.136	0.198	0.52	0.76
10:30	0.136	0.197	0.52	0.76
11:00	0.138	0.209	0.53	0.80
11:30	0.141	0.207	0.54	0.80
12:00	0.145	0.219	0.56	0.84
12:30	0.150	0.223	0.58	0.86
13:00	0.150	0.226	0.57	0.87
13:30	0.150	0.209	0.58	0.80
14:00	0.147	0.202	0.57	0.78
14:30	0.147	0.199	0.57	0.76
15:00	0.151	0.212	0.58	0.81
15:30	0.161	0.222	0.62	0.85
16:00	0.169	0.213	0.65	0.82
16:30	0.190	0.226	0.73	0.87
17:00	0.221	0.249	0.85	0.96
17:30	0.252	0.284	0.97	1.09
18:00	0.261	0.268	1.00	1.03
18:30	0.262	0.275	1.01	1.06
19:00	0.245	0.242	0.94	0.93
19:30	0.237	0.247	0.91	0.95
20:00	0.225	0.236	0.86	0.91
20:30	0.211	0.208	0.81	0.80
21:00	0.203	0.192	0.78	0.74
21:30	0.191	0.199	0.73	0.77
22:00	0.177	0.179	0.68	0.69
22:30	0.164	0.168	0.63	0.65
23:00	0.142	0.148	0.55	0.57
23:30	0.121	0.131	0.47	0.50
24:00	0.104	0.127	0.40	0.49



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,844kWh.

Renter consumer group (house tenure)

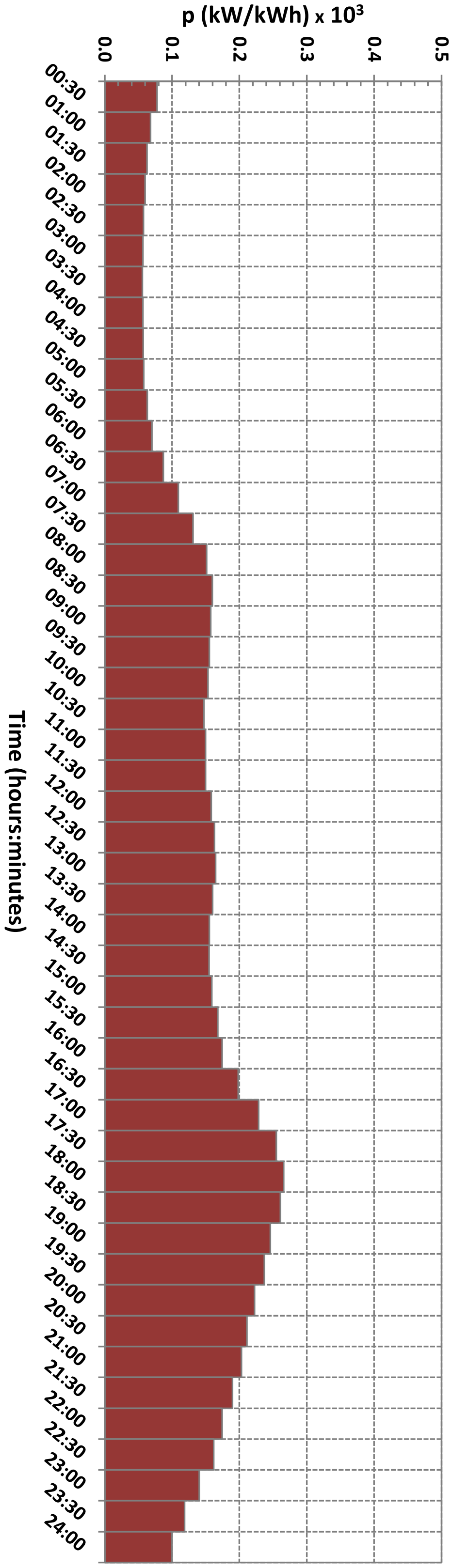
Time	p	q	P	Q
00:30	0.082	0.115	0.26	0.37
01:00	0.072	0.096	0.23	0.30
01:30	0.064	0.082	0.20	0.26
02:00	0.061	0.079	0.19	0.25
02:30	0.060	0.106	0.19	0.34
03:00	0.058	0.086	0.18	0.27
03:30	0.057	0.073	0.18	0.23
04:00	0.055	0.070	0.17	0.22
04:30	0.056	0.073	0.18	0.23
05:00	0.060	0.086	0.19	0.27
05:30	0.066	0.102	0.21	0.32
06:00	0.072	0.113	0.23	0.36
06:30	0.087	0.155	0.28	0.49
07:00	0.104	0.170	0.33	0.54
07:30	0.124	0.182	0.39	0.58
08:00	0.140	0.211	0.44	0.67
08:30	0.146	0.197	0.47	0.63
09:00	0.157	0.245	0.50	0.78
09:30	0.149	0.199	0.47	0.63
10:00	0.148	0.207	0.47	0.66
10:30	0.151	0.224	0.48	0.71
11:00	0.146	0.211	0.47	0.67
11:30	0.151	0.211	0.48	0.67
12:00	0.159	0.228	0.51	0.72
12:30	0.165	0.238	0.52	0.76
13:00	0.160	0.229	0.51	0.73
13:30	0.158	0.220	0.50	0.70
14:00	0.153	0.230	0.49	0.73
14:30	0.152	0.203	0.48	0.64
15:00	0.154	0.201	0.49	0.64
15:30	0.165	0.208	0.52	0.66
16:00	0.174	0.217	0.55	0.69
16:30	0.190	0.223	0.61	0.71
17:00	0.218	0.242	0.69	0.77
17:30	0.242	0.288	0.77	0.92
18:00	0.241	0.250	0.76	0.79
18:30	0.239	0.257	0.76	0.82
19:00	0.231	0.251	0.74	0.80
19:30	0.221	0.221	0.70	0.70
20:00	0.209	0.201	0.67	0.64
20:30	0.198	0.179	0.63	0.57
21:00	0.196	0.195	0.62	0.62
21:30	0.182	0.181	0.58	0.58
22:00	0.171	0.163	0.54	0.52
22:30	0.159	0.179	0.51	0.57
23:00	0.136	0.147	0.43	0.47
23:30	0.117	0.131	0.37	0.42
24:00	0.100	0.120	0.32	0.38



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,179kWh.

Non-renter consumer group (house tenure)

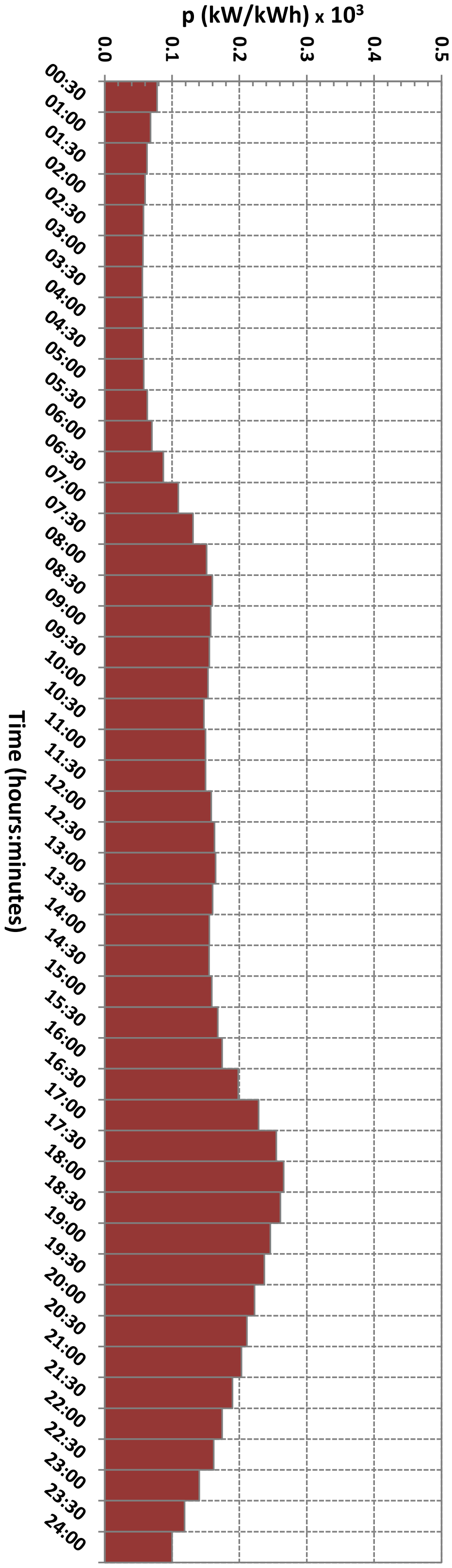
Time	p	q	P	Q
00:30	0.078	0.101	0.29	0.38
01:00	0.068	0.087	0.25	0.32
01:30	0.063	0.077	0.23	0.29
02:00	0.060	0.085	0.22	0.32
02:30	0.058	0.076	0.21	0.28
03:00	0.057	0.071	0.21	0.27
03:30	0.056	0.071	0.21	0.26
04:00	0.057	0.076	0.21	0.28
04:30	0.057	0.075	0.21	0.28
05:00	0.058	0.074	0.22	0.28
05:30	0.063	0.097	0.23	0.36
06:00	0.070	0.105	0.26	0.39
06:30	0.087	0.135	0.32	0.50
07:00	0.109	0.170	0.41	0.63
07:30	0.131	0.183	0.49	0.68
08:00	0.151	0.199	0.56	0.74
08:30	0.160	0.212	0.59	0.79
09:00	0.157	0.214	0.58	0.80
09:30	0.155	0.209	0.58	0.78
10:00	0.153	0.206	0.57	0.76
10:30	0.147	0.193	0.55	0.72
11:00	0.150	0.209	0.56	0.77
11:30	0.150	0.208	0.56	0.77
12:00	0.158	0.258	0.59	0.96
12:30	0.163	0.228	0.60	0.85
13:00	0.165	0.244	0.61	0.91
13:30	0.160	0.212	0.59	0.79
14:00	0.155	0.207	0.58	0.77
14:30	0.155	0.205	0.58	0.76
15:00	0.159	0.216	0.59	0.80
15:30	0.168	0.216	0.62	0.80
16:00	0.174	0.211	0.65	0.78
16:30	0.198	0.227	0.74	0.84
17:00	0.228	0.246	0.85	0.91
17:30	0.255	0.264	0.95	0.98
18:00	0.266	0.268	0.99	0.99
18:30	0.261	0.259	0.97	0.96
19:00	0.246	0.242	0.91	0.90
19:30	0.237	0.253	0.88	0.94
20:00	0.222	0.241	0.83	0.89
20:30	0.211	0.217	0.78	0.80
21:00	0.203	0.204	0.75	0.76
21:30	0.190	0.202	0.70	0.75
22:00	0.174	0.169	0.65	0.63
22:30	0.162	0.163	0.60	0.61
23:00	0.140	0.145	0.52	0.54
23:30	0.119	0.134	0.44	0.50
24:00	0.100	0.120	0.37	0.45



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,712kWh.

Low income consumer group (household income ≤ £14,999yr)

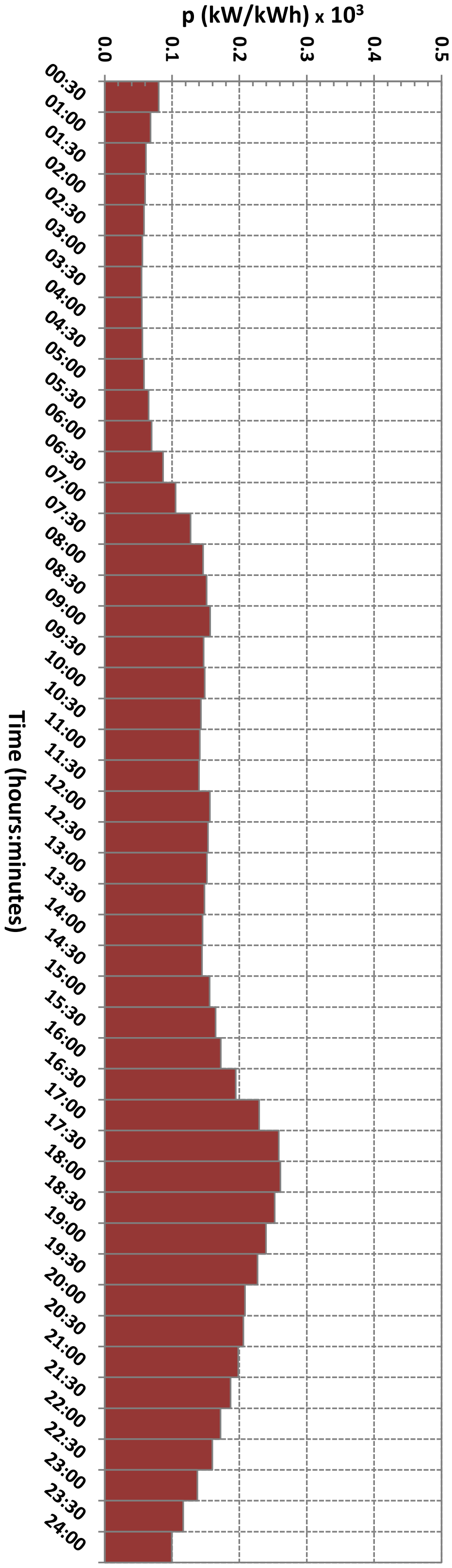
Time	p	q	P	Q
00:30	0.078	0.100	0.23	0.29
01:00	0.069	0.089	0.20	0.26
01:30	0.063	0.082	0.18	0.24
02:00	0.060	0.080	0.17	0.23
02:30	0.058	0.070	0.17	0.21
03:00	0.056	0.072	0.16	0.21
03:30	0.056	0.071	0.16	0.21
04:00	0.055	0.070	0.16	0.20
04:30	0.056	0.073	0.16	0.21
05:00	0.057	0.073	0.17	0.21
05:30	0.061	0.094	0.18	0.27
06:00	0.069	0.106	0.20	0.31
06:30	0.085	0.149	0.25	0.44
07:00	0.104	0.179	0.30	0.52
07:30	0.123	0.191	0.36	0.56
08:00	0.140	0.208	0.41	0.61
08:30	0.154	0.223	0.45	0.65
09:00	0.166	0.261	0.48	0.76
09:30	0.163	0.234	0.48	0.68
10:00	0.156	0.223	0.46	0.65
10:30	0.155	0.228	0.45	0.66
11:00	0.152	0.229	0.44	0.67
11:30	0.161	0.240	0.47	0.70
12:00	0.168	0.254	0.49	0.74
12:30	0.180	0.255	0.52	0.75
13:00	0.176	0.270	0.51	0.79
13:30	0.167	0.231	0.49	0.67
14:00	0.163	0.246	0.48	0.72
14:30	0.161	0.219	0.47	0.64
15:00	0.162	0.213	0.47	0.62
15:30	0.172	0.222	0.50	0.65
16:00	0.175	0.207	0.51	0.60
16:30	0.198	0.232	0.58	0.68
17:00	0.220	0.238	0.64	0.69
17:30	0.246	0.262	0.72	0.77
18:00	0.248	0.261	0.72	0.76
18:30	0.243	0.254	0.71	0.74
19:00	0.228	0.235	0.67	0.69
19:30	0.221	0.250	0.64	0.73
20:00	0.215	0.247	0.63	0.72
20:30	0.199	0.198	0.58	0.58
21:00	0.197	0.216	0.57	0.63
21:30	0.183	0.184	0.53	0.54
22:00	0.168	0.169	0.49	0.49
22:30	0.155	0.165	0.45	0.48
23:00	0.131	0.143	0.38	0.42
23:30	0.112	0.126	0.33	0.37
24:00	0.095	0.116	0.28	0.34



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 2,918kWh.

Medium income consumer group (household income £15,000yr – £29,999yr)

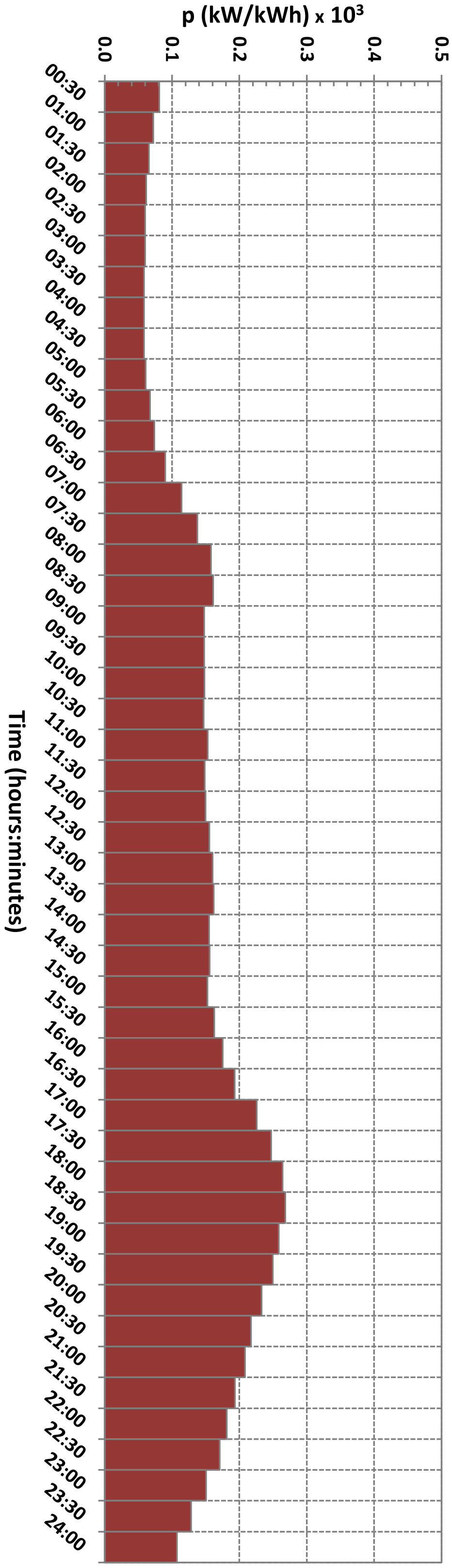
Time	p	q	P	Q
00:30	0.080	0.109	0.29	0.39
01:00	0.068	0.081	0.24	0.29
01:30	0.061	0.073	0.22	0.26
02:00	0.060	0.093	0.21	0.33
02:30	0.058	0.102	0.21	0.36
03:00	0.056	0.074	0.20	0.27
03:30	0.055	0.071	0.20	0.25
04:00	0.055	0.078	0.20	0.28
04:30	0.056	0.071	0.20	0.25
05:00	0.059	0.078	0.21	0.28
05:30	0.065	0.103	0.23	0.37
06:00	0.070	0.107	0.25	0.38
06:30	0.087	0.142	0.31	0.51
07:00	0.105	0.161	0.38	0.57
07:30	0.127	0.174	0.45	0.62
08:00	0.146	0.193	0.52	0.69
08:30	0.151	0.199	0.54	0.71
09:00	0.157	0.217	0.56	0.77
09:30	0.147	0.182	0.52	0.65
10:00	0.148	0.200	0.53	0.71
10:30	0.143	0.185	0.51	0.66
11:00	0.141	0.183	0.50	0.65
11:30	0.140	0.180	0.50	0.64
12:00	0.156	0.277	0.56	0.99
12:30	0.153	0.221	0.55	0.79
13:00	0.152	0.216	0.54	0.77
13:30	0.148	0.187	0.53	0.67
14:00	0.145	0.186	0.52	0.66
14:30	0.144	0.184	0.51	0.66
15:00	0.156	0.213	0.55	0.76
15:30	0.165	0.204	0.59	0.73
16:00	0.172	0.208	0.61	0.74
16:30	0.195	0.225	0.69	0.80
17:00	0.229	0.263	0.82	0.94
17:30	0.258	0.295	0.92	1.05
18:00	0.261	0.272	0.93	0.97
18:30	0.252	0.259	0.90	0.92
19:00	0.239	0.239	0.85	0.85
19:30	0.227	0.222	0.81	0.79
20:00	0.208	0.195	0.74	0.70
20:30	0.206	0.207	0.73	0.74
21:00	0.198	0.187	0.71	0.67
21:30	0.187	0.212	0.67	0.76
22:00	0.172	0.153	0.61	0.55
22:30	0.160	0.156	0.57	0.56
23:00	0.138	0.136	0.49	0.49
23:30	0.116	0.125	0.41	0.45
24:00	0.099	0.123	0.35	0.44



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,565kWh.

High income consumer group (household income > £29,999yr)

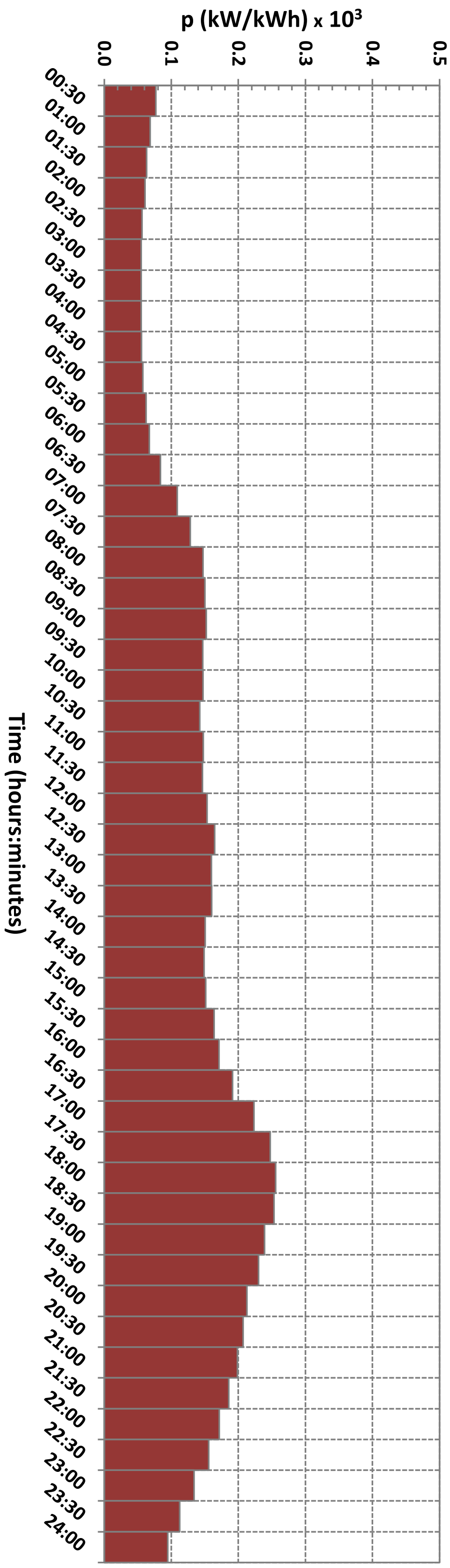
Time	p	q	P	Q
00:30	0.081	0.110	0.35	0.47
01:00	0.072	0.099	0.31	0.42
01:30	0.066	0.081	0.28	0.34
02:00	0.062	0.073	0.26	0.31
02:30	0.060	0.089	0.25	0.38
03:00	0.060	0.085	0.26	0.36
03:30	0.058	0.073	0.25	0.31
04:00	0.058	0.075	0.25	0.32
04:30	0.058	0.079	0.25	0.34
05:00	0.061	0.086	0.26	0.37
05:30	0.067	0.100	0.29	0.43
06:00	0.074	0.111	0.31	0.47
06:30	0.090	0.133	0.38	0.57
07:00	0.114	0.169	0.49	0.72
07:30	0.137	0.180	0.59	0.77
08:00	0.158	0.208	0.67	0.89
08:30	0.161	0.196	0.69	0.83
09:00	0.148	0.180	0.63	0.77
09:30	0.147	0.192	0.63	0.82
10:00	0.148	0.191	0.63	0.81
10:30	0.147	0.192	0.63	0.82
11:00	0.153	0.213	0.65	0.91
11:30	0.148	0.198	0.63	0.85
12:00	0.150	0.201	0.64	0.86
12:30	0.155	0.209	0.66	0.89
13:00	0.160	0.220	0.68	0.94
13:30	0.162	0.222	0.69	0.95
14:00	0.155	0.204	0.66	0.87
14:30	0.156	0.206	0.66	0.88
15:00	0.153	0.206	0.65	0.88
15:30	0.162	0.213	0.69	0.91
16:00	0.175	0.226	0.75	0.97
16:30	0.193	0.217	0.82	0.93
17:00	0.226	0.232	0.96	0.99
17:30	0.247	0.257	1.05	1.10
18:00	0.264	0.252	1.13	1.08
18:30	0.268	0.262	1.14	1.12
19:00	0.258	0.262	1.10	1.12
19:30	0.250	0.256	1.06	1.09
20:00	0.233	0.237	0.99	1.01
20:30	0.217	0.209	0.93	0.89
21:00	0.208	0.197	0.89	0.84
21:30	0.193	0.187	0.82	0.80
22:00	0.181	0.178	0.77	0.76
22:30	0.171	0.187	0.73	0.80
23:00	0.150	0.159	0.64	0.68
23:30	0.128	0.148	0.55	0.63
24:00	0.107	0.122	0.46	0.52



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 4,265kWh.

High thermal efficiency consumer group (thermal performance of the building)

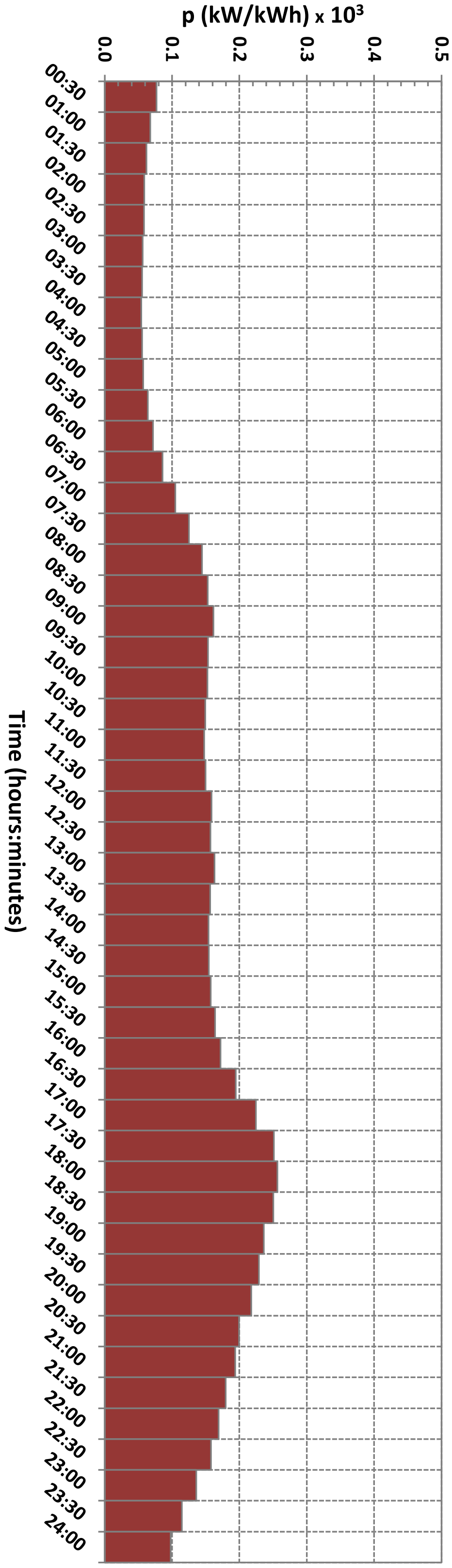
Time	p	q	P	Q
00:30	0.077	0.100	0.27	0.35
01:00	0.069	0.085	0.24	0.29
01:30	0.063	0.083	0.22	0.29
02:00	0.061	0.081	0.21	0.28
02:30	0.056	0.067	0.19	0.23
03:00	0.055	0.066	0.19	0.23
03:30	0.055	0.064	0.19	0.22
04:00	0.055	0.065	0.19	0.22
04:30	0.055	0.066	0.19	0.23
05:00	0.057	0.074	0.20	0.25
05:30	0.062	0.089	0.22	0.31
06:00	0.067	0.097	0.23	0.33
06:30	0.084	0.121	0.29	0.42
07:00	0.109	0.181	0.38	0.62
07:30	0.128	0.188	0.44	0.65
08:00	0.147	0.194	0.51	0.67
08:30	0.150	0.193	0.52	0.67
09:00	0.152	0.212	0.52	0.73
09:30	0.147	0.197	0.51	0.68
10:00	0.147	0.211	0.51	0.73
10:30	0.142	0.194	0.49	0.67
11:00	0.148	0.220	0.51	0.76
11:30	0.147	0.209	0.51	0.72
12:00	0.153	0.226	0.53	0.78
12:30	0.165	0.232	0.57	0.80
13:00	0.160	0.210	0.55	0.72
13:30	0.160	0.209	0.55	0.72
14:00	0.151	0.190	0.52	0.65
14:30	0.149	0.192	0.51	0.66
15:00	0.151	0.189	0.52	0.65
15:30	0.164	0.210	0.57	0.72
16:00	0.171	0.211	0.59	0.73
16:30	0.191	0.227	0.66	0.78
17:00	0.223	0.246	0.77	0.85
17:30	0.247	0.261	0.85	0.90
18:00	0.255	0.261	0.88	0.90
18:30	0.253	0.258	0.87	0.89
19:00	0.239	0.233	0.82	0.80
19:30	0.230	0.231	0.79	0.80
20:00	0.213	0.217	0.73	0.75
20:30	0.207	0.202	0.71	0.70
21:00	0.198	0.204	0.68	0.70
21:30	0.186	0.186	0.64	0.64
22:00	0.172	0.161	0.59	0.56
22:30	0.156	0.149	0.54	0.52
23:00	0.134	0.137	0.46	0.47
23:30	0.112	0.119	0.39	0.41
24:00	0.095	0.109	0.33	0.38



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,449kWh.

Medium thermal efficiency consumer group (thermal performance of the building)

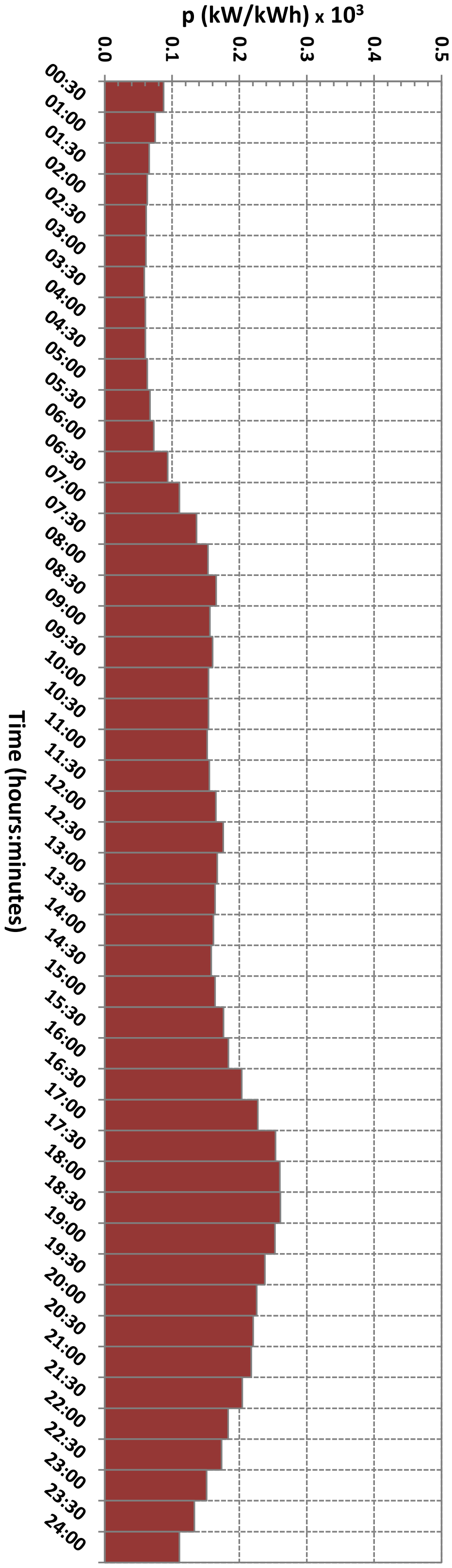
Time	p	q	P	Q
00:30	0.077	0.096	0.27	0.34
01:00	0.068	0.081	0.24	0.28
01:30	0.062	0.074	0.22	0.26
02:00	0.059	0.086	0.21	0.30
02:30	0.058	0.103	0.21	0.36
03:00	0.056	0.075	0.20	0.26
03:30	0.056	0.066	0.20	0.23
04:00	0.054	0.065	0.19	0.23
04:30	0.056	0.072	0.20	0.25
05:00	0.057	0.072	0.20	0.25
05:30	0.064	0.103	0.22	0.36
06:00	0.072	0.114	0.25	0.40
06:30	0.086	0.145	0.30	0.51
07:00	0.105	0.166	0.37	0.59
07:30	0.125	0.173	0.44	0.61
08:00	0.144	0.203	0.51	0.72
08:30	0.153	0.202	0.54	0.71
09:00	0.161	0.238	0.57	0.84
09:30	0.153	0.203	0.54	0.71
10:00	0.152	0.202	0.54	0.71
10:30	0.149	0.204	0.53	0.72
11:00	0.148	0.206	0.52	0.73
11:30	0.150	0.206	0.53	0.73
12:00	0.159	0.234	0.56	0.82
12:30	0.157	0.219	0.55	0.77
13:00	0.163	0.259	0.57	0.91
13:30	0.157	0.212	0.55	0.75
14:00	0.154	0.228	0.54	0.80
14:30	0.155	0.207	0.54	0.73
15:00	0.157	0.217	0.55	0.76
15:30	0.164	0.211	0.58	0.74
16:00	0.172	0.207	0.61	0.73
16:30	0.194	0.219	0.68	0.77
17:00	0.225	0.248	0.79	0.87
17:30	0.251	0.276	0.88	0.97
18:00	0.257	0.260	0.90	0.91
18:30	0.250	0.249	0.88	0.88
19:00	0.236	0.246	0.83	0.87
19:30	0.229	0.249	0.81	0.88
20:00	0.218	0.231	0.77	0.81
20:30	0.199	0.191	0.70	0.67
21:00	0.194	0.184	0.68	0.65
21:30	0.180	0.168	0.63	0.59
22:00	0.169	0.160	0.60	0.56
22:30	0.158	0.166	0.56	0.59
23:00	0.136	0.137	0.48	0.48
23:30	0.114	0.120	0.40	0.42
24:00	0.098	0.113	0.34	0.40



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,521kWh.

Low thermal efficiency consumer group (thermal performance of the building)

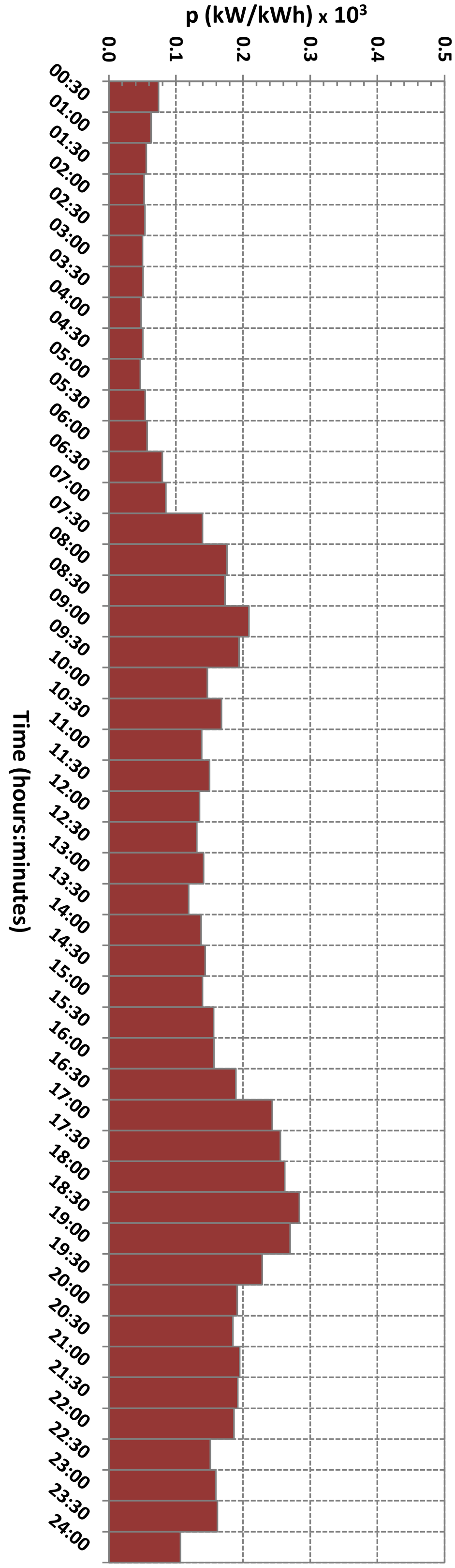
Time	p	q	P	Q
00:30	0.088	0.130	0.32	0.47
01:00	0.075	0.110	0.27	0.40
01:30	0.066	0.082	0.24	0.30
02:00	0.063	0.079	0.23	0.29
02:30	0.061	0.077	0.22	0.28
03:00	0.061	0.092	0.22	0.33
03:30	0.059	0.090	0.21	0.33
04:00	0.060	0.098	0.22	0.36
04:30	0.060	0.086	0.22	0.32
05:00	0.063	0.096	0.23	0.35
05:30	0.067	0.101	0.25	0.37
06:00	0.073	0.108	0.27	0.39
06:30	0.094	0.159	0.34	0.58
07:00	0.111	0.164	0.40	0.60
07:30	0.136	0.193	0.50	0.71
08:00	0.153	0.214	0.56	0.78
08:30	0.165	0.233	0.60	0.85
09:00	0.156	0.213	0.57	0.78
09:30	0.160	0.221	0.58	0.81
10:00	0.154	0.209	0.56	0.76
10:30	0.154	0.216	0.56	0.79
11:00	0.152	0.202	0.56	0.74
11:30	0.155	0.215	0.57	0.78
12:00	0.165	0.299	0.60	1.09
12:30	0.176	0.255	0.64	0.93
13:00	0.167	0.230	0.61	0.84
13:30	0.164	0.228	0.60	0.83
14:00	0.161	0.217	0.59	0.79
14:30	0.158	0.214	0.58	0.78
15:00	0.164	0.223	0.60	0.81
15:30	0.176	0.222	0.64	0.81
16:00	0.183	0.227	0.67	0.83
16:30	0.203	0.237	0.74	0.86
17:00	0.227	0.238	0.83	0.87
17:30	0.253	0.279	0.92	1.02
18:00	0.260	0.270	0.95	0.98
18:30	0.261	0.277	0.95	1.01
19:00	0.253	0.258	0.92	0.94
19:30	0.238	0.245	0.87	0.90
20:00	0.226	0.234	0.82	0.85
20:30	0.220	0.232	0.80	0.85
21:00	0.218	0.227	0.79	0.83
21:30	0.204	0.248	0.75	0.90
22:00	0.183	0.186	0.67	0.68
22:30	0.174	0.195	0.63	0.71
23:00	0.151	0.172	0.55	0.63
23:30	0.133	0.167	0.49	0.61
24:00	0.111	0.143	0.40	0.52



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,647kWh.

Rural off gas grid consumer group (rurality)

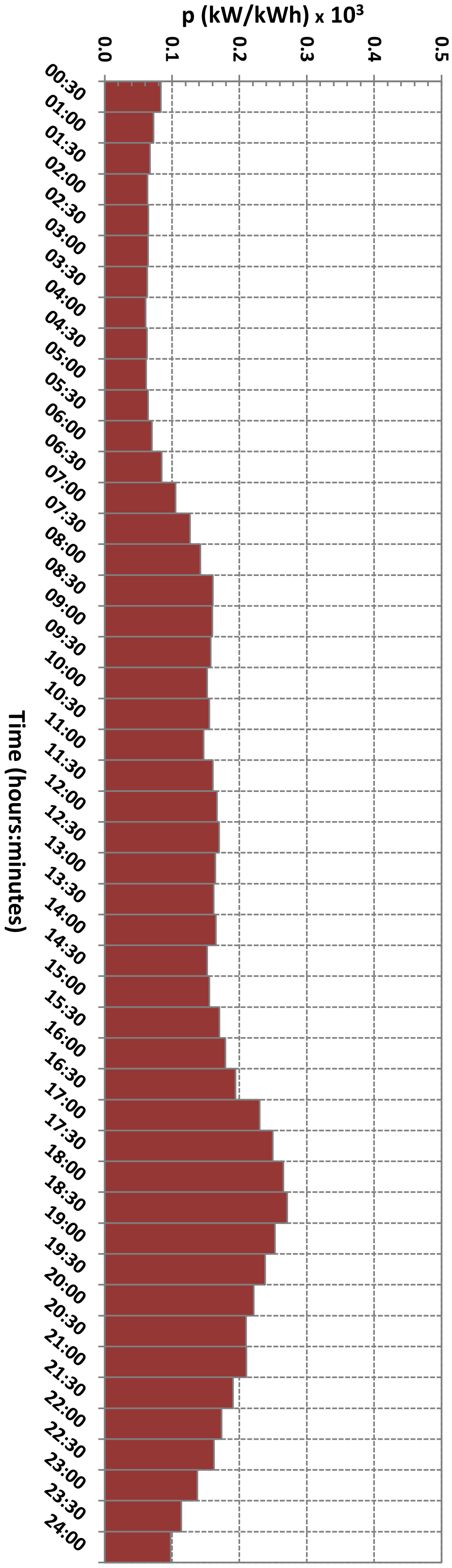
Time	p	q	P	Q
00:30	0.074	0.087	0.41	0.48
01:00	0.063	0.054	0.35	0.30
01:30	0.056	0.039	0.31	0.22
02:00	0.053	0.042	0.29	0.23
02:30	0.054	0.046	0.30	0.26
03:00	0.050	0.044	0.28	0.24
03:30	0.051	0.042	0.28	0.23
04:00	0.048	0.047	0.27	0.26
04:30	0.051	0.045	0.28	0.25
05:00	0.047	0.041	0.26	0.23
05:30	0.054	0.047	0.30	0.26
06:00	0.057	0.044	0.32	0.24
06:30	0.080	0.076	0.44	0.42
07:00	0.085	0.070	0.47	0.39
07:30	0.140	0.128	0.78	0.71
08:00	0.176	0.170	0.98	0.95
08:30	0.173	0.154	0.96	0.85
09:00	0.209	0.323	1.16	1.80
09:30	0.194	0.237	1.08	1.32
10:00	0.147	0.124	0.82	0.69
10:30	0.168	0.182	0.93	1.01
11:00	0.138	0.120	0.77	0.67
11:30	0.150	0.164	0.83	0.91
12:00	0.135	0.109	0.75	0.61
12:30	0.131	0.129	0.73	0.72
13:00	0.141	0.143	0.79	0.79
13:30	0.119	0.092	0.66	0.51
14:00	0.138	0.132	0.76	0.73
14:30	0.144	0.173	0.80	0.96
15:00	0.140	0.151	0.78	0.84
15:30	0.156	0.173	0.87	0.96
16:00	0.157	0.151	0.87	0.84
16:30	0.189	0.274	1.05	1.52
17:00	0.243	0.205	1.35	1.14
17:30	0.256	0.251	1.42	1.39
18:00	0.262	0.216	1.46	1.20
18:30	0.284	0.277	1.58	1.54
19:00	0.270	0.208	1.50	1.15
19:30	0.228	0.186	1.27	1.03
20:00	0.192	0.135	1.06	0.75
20:30	0.185	0.127	1.03	0.71
21:00	0.195	0.191	1.08	1.06
21:30	0.192	0.186	1.07	1.03
22:00	0.186	0.162	1.03	0.90
22:30	0.151	0.109	0.84	0.60
23:00	0.160	0.144	0.89	0.80
23:30	0.162	0.165	0.90	0.92
24:00	0.107	0.086	0.59	0.48



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 5,554kWh.

Rural consumer group (rurality)

Time	p	q	P	Q
00:30	0.083	0.114	0.31	0.43
01:00	0.072	0.096	0.27	0.36
01:30	0.067	0.089	0.25	0.33
02:00	0.064	0.083	0.24	0.31
02:30	0.065	0.122	0.24	0.45
03:00	0.064	0.126	0.24	0.47
03:30	0.063	0.110	0.24	0.41
04:00	0.061	0.107	0.23	0.40
04:30	0.063	0.105	0.23	0.39
05:00	0.062	0.097	0.23	0.36
05:30	0.064	0.091	0.24	0.34
06:00	0.070	0.108	0.26	0.40
06:30	0.085	0.127	0.32	0.47
07:00	0.105	0.152	0.39	0.57
07:30	0.127	0.185	0.47	0.69
08:00	0.142	0.178	0.53	0.66
08:30	0.161	0.221	0.60	0.82
09:00	0.160	0.206	0.60	0.77
09:30	0.157	0.205	0.59	0.76
10:00	0.152	0.203	0.57	0.76
10:30	0.155	0.212	0.58	0.79
11:00	0.147	0.192	0.55	0.72
11:30	0.161	0.221	0.60	0.82
12:00	0.167	0.249	0.62	0.93
12:30	0.170	0.233	0.63	0.87
13:00	0.164	0.218	0.61	0.81
13:30	0.162	0.205	0.60	0.77
14:00	0.165	0.243	0.61	0.91
14:30	0.152	0.207	0.57	0.77
15:00	0.155	0.203	0.58	0.76
15:30	0.170	0.212	0.64	0.79
16:00	0.179	0.203	0.67	0.76
16:30	0.194	0.228	0.72	0.85
17:00	0.230	0.249	0.86	0.93
17:30	0.250	0.257	0.93	0.96
18:00	0.265	0.268	0.99	1.00
18:30	0.271	0.279	1.01	1.04
19:00	0.253	0.259	0.94	0.97
19:30	0.238	0.255	0.89	0.95
20:00	0.221	0.242	0.83	0.90
20:30	0.210	0.256	0.78	0.95
21:00	0.210	0.247	0.78	0.92
21:30	0.190	0.218	0.71	0.81
22:00	0.173	0.179	0.65	0.67
22:30	0.162	0.190	0.60	0.71
23:00	0.138	0.156	0.51	0.58
23:30	0.114	0.130	0.42	0.49
24:00	0.098	0.120	0.37	0.45

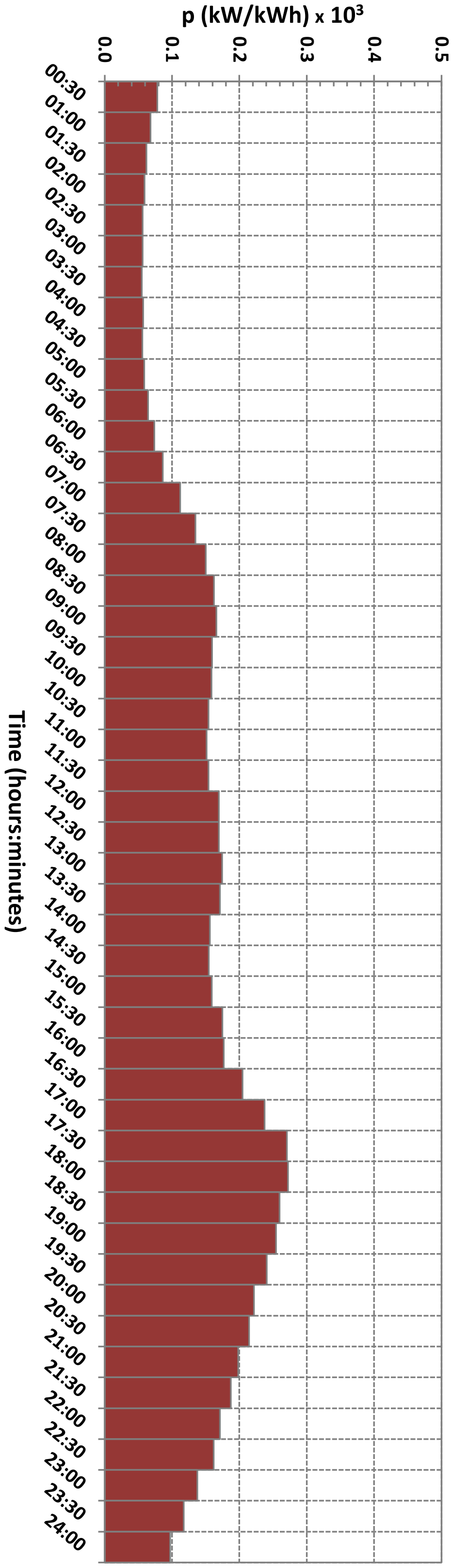


'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,729kWh.

Customer-Led Network Revolution

Suburban consumer group (rurality)

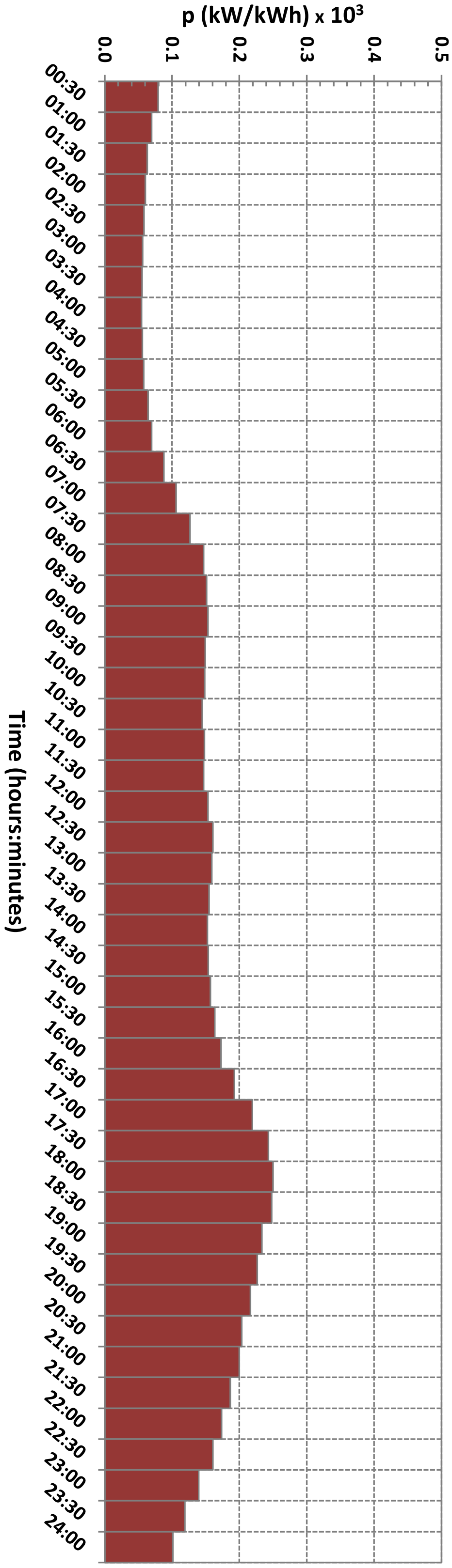
Time	p	q	P	Q
00:30	0.078	0.113	0.28	0.40
01:00	0.068	0.088	0.24	0.32
01:30	0.062	0.078	0.22	0.28
02:00	0.059	0.067	0.21	0.24
02:30	0.056	0.066	0.20	0.24
03:00	0.056	0.069	0.20	0.25
03:30	0.055	0.071	0.20	0.25
04:00	0.057	0.082	0.20	0.29
04:30	0.056	0.071	0.20	0.25
05:00	0.059	0.079	0.21	0.28
05:30	0.064	0.092	0.23	0.33
06:00	0.074	0.119	0.26	0.43
06:30	0.086	0.133	0.31	0.48
07:00	0.112	0.168	0.40	0.60
07:30	0.135	0.185	0.48	0.66
08:00	0.150	0.203	0.54	0.73
08:30	0.162	0.210	0.58	0.75
09:00	0.166	0.241	0.59	0.86
09:30	0.160	0.220	0.57	0.79
10:00	0.159	0.213	0.57	0.76
10:30	0.154	0.203	0.55	0.73
11:00	0.151	0.203	0.54	0.73
11:30	0.154	0.201	0.55	0.72
12:00	0.170	0.305	0.61	1.09
12:30	0.169	0.245	0.61	0.87
13:00	0.174	0.248	0.62	0.89
13:30	0.171	0.239	0.61	0.85
14:00	0.156	0.205	0.56	0.73
14:30	0.154	0.199	0.55	0.71
15:00	0.159	0.214	0.57	0.76
15:30	0.175	0.232	0.63	0.83
16:00	0.177	0.209	0.63	0.75
16:30	0.205	0.239	0.73	0.85
17:00	0.237	0.255	0.85	0.91
17:30	0.271	0.292	0.97	1.04
18:00	0.272	0.275	0.97	0.98
18:30	0.260	0.251	0.93	0.90
19:00	0.254	0.272	0.91	0.97
19:30	0.241	0.263	0.86	0.94
20:00	0.222	0.233	0.79	0.83
20:30	0.214	0.214	0.77	0.77
21:00	0.198	0.185	0.71	0.66
21:30	0.187	0.178	0.67	0.64
22:00	0.171	0.163	0.61	0.58
22:30	0.162	0.151	0.58	0.54
23:00	0.138	0.142	0.49	0.51
23:30	0.117	0.132	0.42	0.47
24:00	0.097	0.121	0.35	0.43



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,574kWh.

Urban consumer group (rurality)

Time	p	q	P	Q
00:30	0.079	0.102	0.27	0.35
01:00	0.070	0.089	0.24	0.31
01:30	0.063	0.077	0.22	0.27
02:00	0.060	0.088	0.21	0.31
02:30	0.058	0.087	0.20	0.30
03:00	0.056	0.067	0.19	0.23
03:30	0.055	0.063	0.19	0.22
04:00	0.055	0.063	0.19	0.22
04:30	0.056	0.069	0.19	0.24
05:00	0.058	0.075	0.20	0.26
05:30	0.064	0.103	0.22	0.36
06:00	0.070	0.104	0.24	0.36
06:30	0.088	0.148	0.30	0.51
07:00	0.106	0.175	0.37	0.60
07:30	0.127	0.181	0.44	0.63
08:00	0.147	0.208	0.51	0.72
08:30	0.151	0.204	0.52	0.71
09:00	0.153	0.221	0.53	0.76
09:30	0.149	0.200	0.52	0.69
10:00	0.148	0.205	0.51	0.71
10:30	0.145	0.203	0.50	0.70
11:00	0.148	0.215	0.51	0.75
11:30	0.147	0.210	0.51	0.73
12:00	0.153	0.224	0.53	0.78
12:30	0.161	0.227	0.56	0.78
13:00	0.159	0.240	0.55	0.83
13:30	0.155	0.207	0.54	0.72
14:00	0.152	0.214	0.53	0.74
14:30	0.154	0.206	0.53	0.71
15:00	0.157	0.211	0.54	0.73
15:30	0.163	0.207	0.57	0.72
16:00	0.173	0.217	0.60	0.75
16:30	0.192	0.219	0.67	0.76
17:00	0.219	0.241	0.76	0.83
17:30	0.243	0.267	0.84	0.92
18:00	0.250	0.256	0.86	0.89
18:30	0.248	0.257	0.86	0.89
19:00	0.233	0.232	0.81	0.80
19:30	0.227	0.233	0.78	0.80
20:00	0.216	0.224	0.75	0.77
20:30	0.203	0.190	0.70	0.66
21:00	0.200	0.198	0.69	0.68
21:30	0.187	0.196	0.65	0.68
22:00	0.174	0.166	0.60	0.57
22:30	0.161	0.172	0.56	0.59
23:00	0.140	0.146	0.48	0.50
23:30	0.119	0.133	0.41	0.46
24:00	0.101	0.120	0.35	0.41



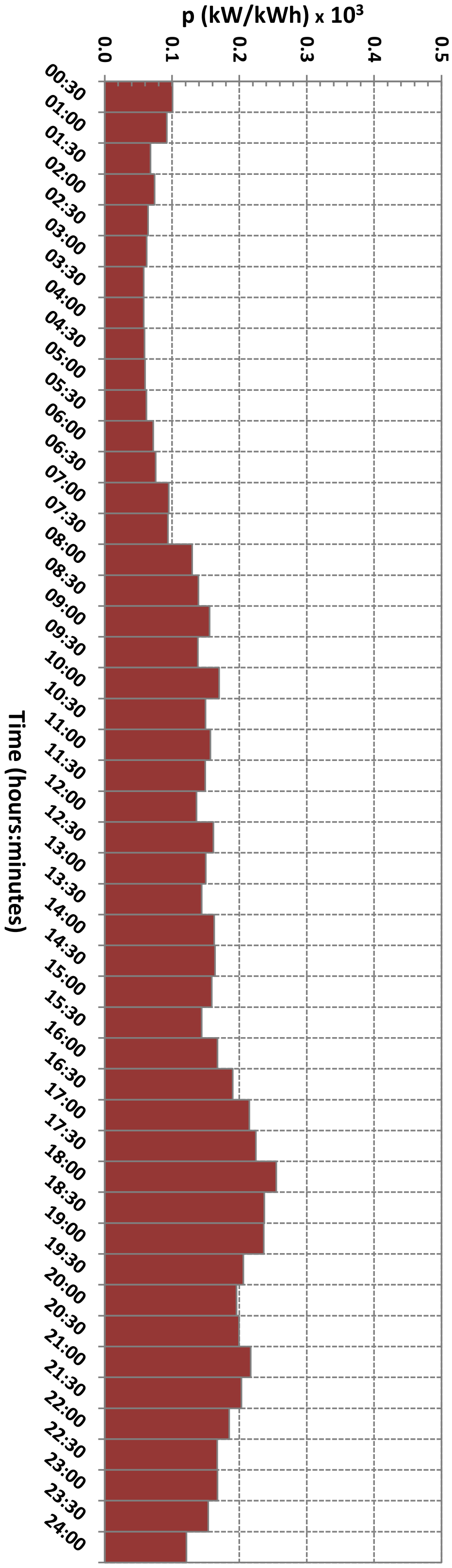
'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,459kWh.

Appendix B

The CLNR project has used real-word data collected from the ToU domestic customer field trials to produce a generalised set of load curves for different types of domestic customers that can be applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems. The load curves are presented in this Appendix together with the demand factors ‘*p*’ and ‘*q*’ and associated values of ‘*P*’ and ‘*Q*’ for the central winter period.

Dependant consumer group (household includes at least one child aged < 5 and/or an adult aged ≥ 65years)

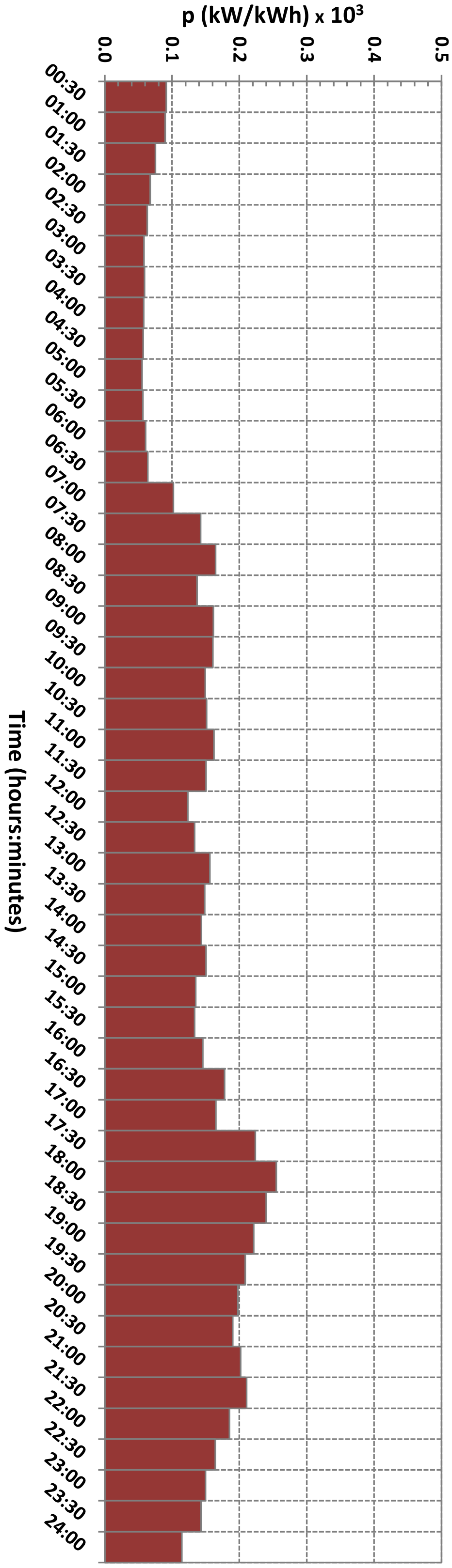
Time	p	q	P	Q
00:30	0.101	0.129	0.33	0.42
01:00	0.092	0.254	0.30	0.83
01:30	0.068	0.070	0.22	0.23
02:00	0.074	0.143	0.24	0.46
02:30	0.065	0.083	0.21	0.27
03:00	0.062	0.072	0.20	0.23
03:30	0.058	0.072	0.19	0.23
04:00	0.058	0.071	0.19	0.23
04:30	0.059	0.073	0.19	0.24
05:00	0.060	0.081	0.19	0.26
05:30	0.062	0.094	0.20	0.31
06:00	0.072	0.105	0.23	0.34
06:30	0.076	0.117	0.25	0.38
07:00	0.095	0.167	0.31	0.54
07:30	0.094	0.127	0.31	0.41
08:00	0.130	0.194	0.42	0.63
08:30	0.139	0.181	0.45	0.59
09:00	0.156	0.158	0.51	0.51
09:30	0.138	0.135	0.45	0.44
10:00	0.170	0.249	0.55	0.81
10:30	0.150	0.177	0.49	0.58
11:00	0.157	0.219	0.51	0.71
11:30	0.149	0.153	0.49	0.50
12:00	0.136	0.140	0.44	0.46
12:30	0.161	0.209	0.53	0.68
13:00	0.150	0.149	0.49	0.49
13:30	0.144	0.159	0.47	0.52
14:00	0.163	0.207	0.53	0.67
14:30	0.164	0.226	0.53	0.74
15:00	0.159	0.175	0.52	0.57
15:30	0.144	0.122	0.47	0.40
16:00	0.167	0.163	0.54	0.53
16:30	0.190	0.207	0.62	0.67
17:00	0.215	0.228	0.70	0.74
17:30	0.224	0.219	0.73	0.71
18:00	0.255	0.231	0.83	0.75
18:30	0.237	0.223	0.77	0.73
19:00	0.236	0.377	0.77	1.23
19:30	0.206	0.205	0.67	0.67
20:00	0.196	0.160	0.64	0.52
20:30	0.200	0.168	0.65	0.55
21:00	0.217	0.198	0.71	0.65
21:30	0.203	0.164	0.66	0.53
22:00	0.185	0.138	0.60	0.45
22:30	0.167	0.132	0.54	0.43
23:00	0.168	0.154	0.55	0.50
23:30	0.154	0.151	0.50	0.49
24:00	0.122	0.120	0.40	0.39



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,253kWh.

Non-dependant consumer group (all household members ≥ 5 and/ < 65 years)

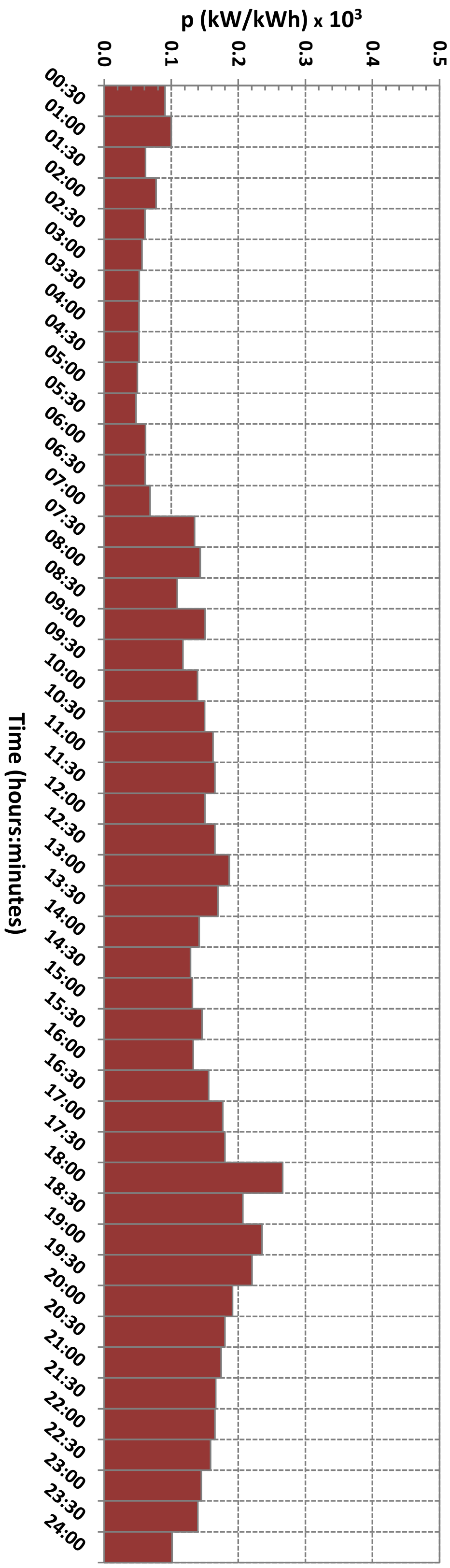
Time	p	q	P	Q
00:30	0.092	0.125	0.33	0.45
01:00	0.090	0.192	0.32	0.69
01:30	0.075	0.103	0.27	0.37
02:00	0.068	0.076	0.24	0.27
02:30	0.063	0.073	0.23	0.26
03:00	0.058	0.060	0.21	0.22
03:30	0.059	0.054	0.21	0.19
04:00	0.058	0.059	0.21	0.21
04:30	0.057	0.054	0.20	0.19
05:00	0.055	0.054	0.20	0.19
05:30	0.057	0.053	0.20	0.19
06:00	0.061	0.066	0.22	0.24
06:30	0.064	0.070	0.23	0.25
07:00	0.102	0.226	0.37	0.81
07:30	0.143	0.228	0.51	0.82
08:00	0.165	0.211	0.59	0.76
08:30	0.137	0.151	0.49	0.54
09:00	0.161	0.233	0.58	0.84
09:30	0.161	0.297	0.58	1.06
10:00	0.149	0.281	0.54	1.01
10:30	0.151	0.243	0.54	0.87
11:00	0.162	0.262	0.58	0.94
11:30	0.150	0.227	0.54	0.81
12:00	0.123	0.150	0.44	0.54
12:30	0.133	0.165	0.48	0.59
13:00	0.156	0.240	0.56	0.86
13:30	0.148	0.230	0.53	0.82
14:00	0.144	0.188	0.51	0.67
14:30	0.150	0.200	0.54	0.72
15:00	0.135	0.152	0.48	0.55
15:30	0.133	0.184	0.48	0.66
16:00	0.146	0.153	0.52	0.55
16:30	0.178	0.215	0.64	0.77
17:00	0.165	0.149	0.59	0.53
17:30	0.224	0.267	0.80	0.96
18:00	0.255	0.289	0.91	1.03
18:30	0.240	0.245	0.86	0.88
19:00	0.221	0.183	0.79	0.66
19:30	0.209	0.169	0.75	0.61
20:00	0.198	0.195	0.71	0.70
20:30	0.190	0.168	0.68	0.60
21:00	0.202	0.176	0.72	0.63
21:30	0.211	0.215	0.75	0.77
22:00	0.185	0.157	0.66	0.56
22:30	0.164	0.135	0.59	0.48
23:00	0.150	0.110	0.54	0.39
23:30	0.143	0.178	0.51	0.64
24:00	0.114	0.109	0.41	0.39



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,585kWh.

Renter consumer group (house tenure)

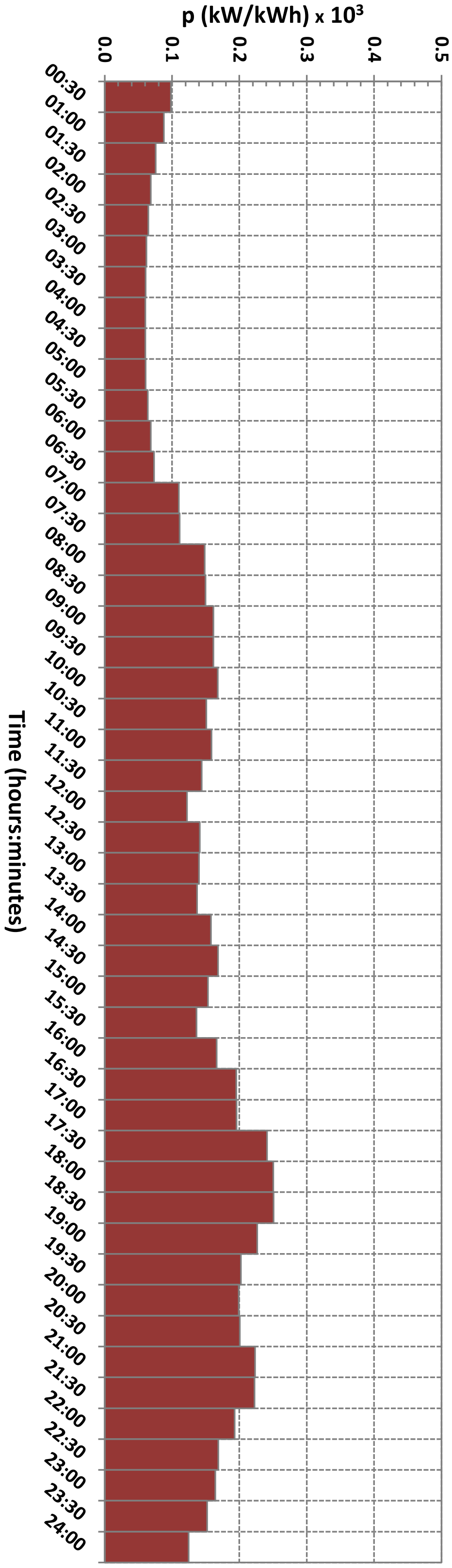
Time	p	q	P	Q
00:30	0.091	0.102	0.26	0.29
01:00	0.100	0.333	0.29	0.96
01:30	0.062	0.050	0.18	0.15
02:00	0.077	0.177	0.22	0.51
02:30	0.061	0.067	0.18	0.19
03:00	0.056	0.048	0.16	0.14
03:30	0.052	0.042	0.15	0.12
04:00	0.052	0.041	0.15	0.12
04:30	0.052	0.046	0.15	0.13
05:00	0.049	0.041	0.14	0.12
05:30	0.048	0.042	0.14	0.12
06:00	0.062	0.077	0.18	0.22
06:30	0.061	0.071	0.18	0.21
07:00	0.068	0.089	0.20	0.26
07:30	0.135	0.264	0.39	0.76
08:00	0.143	0.247	0.41	0.71
08:30	0.109	0.123	0.31	0.35
09:00	0.151	0.243	0.43	0.70
09:30	0.117	0.122	0.34	0.35
10:00	0.139	0.271	0.40	0.78
10:30	0.150	0.181	0.43	0.52
11:00	0.162	0.250	0.47	0.72
11:30	0.165	0.184	0.48	0.53
12:00	0.150	0.177	0.43	0.51
12:30	0.165	0.192	0.48	0.55
13:00	0.187	0.209	0.54	0.60
13:30	0.169	0.229	0.49	0.66
14:00	0.141	0.170	0.41	0.49
14:30	0.129	0.130	0.37	0.37
15:00	0.132	0.143	0.38	0.41
15:30	0.146	0.204	0.42	0.59
16:00	0.133	0.134	0.38	0.39
16:30	0.156	0.168	0.45	0.48
17:00	0.177	0.197	0.51	0.57
17:30	0.180	0.146	0.52	0.42
18:00	0.266	0.254	0.77	0.73
18:30	0.207	0.198	0.60	0.57
19:00	0.235	0.450	0.68	1.30
19:30	0.220	0.261	0.64	0.75
20:00	0.191	0.177	0.55	0.51
20:30	0.180	0.132	0.52	0.38
21:00	0.174	0.126	0.50	0.36
21:30	0.166	0.102	0.48	0.30
22:00	0.165	0.114	0.48	0.33
22:30	0.158	0.129	0.46	0.37
23:00	0.145	0.125	0.42	0.36
23:30	0.140	0.211	0.40	0.61
24:00	0.101	0.092	0.29	0.27



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 2,887kWh.

Non-renter consumer group (house tenure)

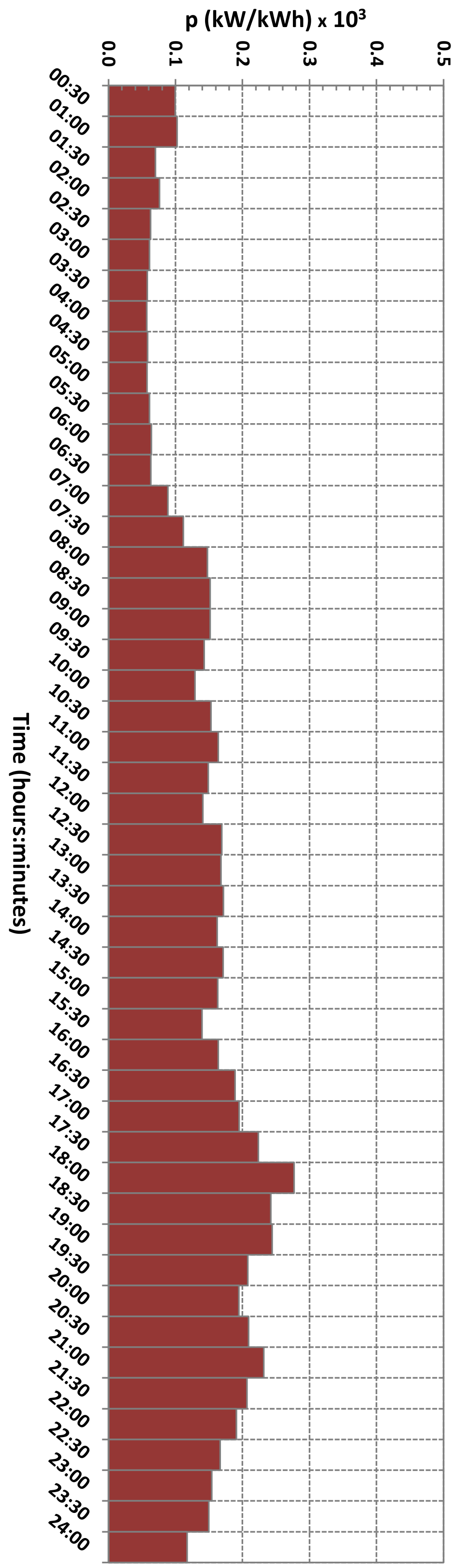
Time	p	q	P	Q
00:30	0.098	0.125	0.36	0.45
01:00	0.088	0.192	0.32	0.70
01:30	0.076	0.103	0.27	0.37
02:00	0.068	0.076	0.25	0.27
02:30	0.065	0.073	0.24	0.27
03:00	0.062	0.060	0.22	0.22
03:30	0.061	0.054	0.22	0.19
04:00	0.060	0.059	0.22	0.21
04:30	0.060	0.054	0.22	0.20
05:00	0.061	0.054	0.22	0.19
05:30	0.064	0.053	0.23	0.19
06:00	0.069	0.066	0.25	0.24
06:30	0.073	0.070	0.27	0.25
07:00	0.110	0.226	0.40	0.82
07:30	0.111	0.228	0.40	0.83
08:00	0.148	0.211	0.54	0.77
08:30	0.150	0.151	0.54	0.55
09:00	0.161	0.233	0.58	0.84
09:30	0.161	0.297	0.58	1.08
10:00	0.168	0.281	0.61	1.02
10:30	0.151	0.243	0.55	0.88
11:00	0.158	0.262	0.57	0.95
11:30	0.144	0.227	0.52	0.82
12:00	0.122	0.150	0.44	0.54
12:30	0.141	0.165	0.51	0.60
13:00	0.140	0.240	0.51	0.87
13:30	0.137	0.230	0.50	0.83
14:00	0.158	0.188	0.57	0.68
14:30	0.168	0.200	0.61	0.72
15:00	0.153	0.152	0.56	0.55
15:30	0.136	0.184	0.49	0.66
16:00	0.166	0.153	0.60	0.55
16:30	0.195	0.215	0.71	0.78
17:00	0.196	0.149	0.71	0.54
17:30	0.241	0.267	0.87	0.97
18:00	0.250	0.289	0.91	1.05
18:30	0.251	0.245	0.91	0.89
19:00	0.227	0.183	0.82	0.66
19:30	0.202	0.169	0.73	0.61
20:00	0.199	0.195	0.72	0.71
20:30	0.201	0.168	0.73	0.61
21:00	0.223	0.176	0.81	0.64
21:30	0.222	0.215	0.81	0.78
22:00	0.193	0.157	0.70	0.57
22:30	0.169	0.135	0.61	0.49
23:00	0.164	0.110	0.59	0.40
23:30	0.152	0.178	0.55	0.64
24:00	0.125	0.109	0.45	0.39



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,621kWh.

Low income consumer group (household income ≤ £19,999yr)

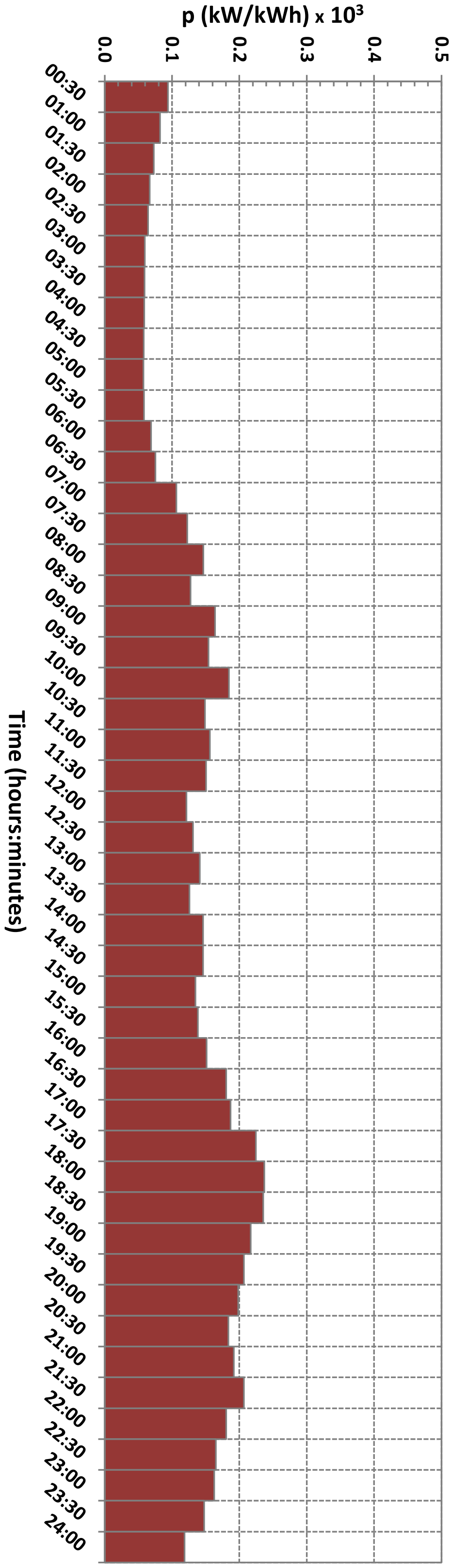
Time	p	q	P	Q
00:30	0.100	0.135	0.32	0.44
01:00	0.102	0.292	0.33	0.95
01:30	0.070	0.077	0.23	0.25
02:00	0.076	0.154	0.25	0.50
02:30	0.063	0.080	0.20	0.26
03:00	0.061	0.069	0.20	0.22
03:30	0.058	0.060	0.19	0.19
04:00	0.057	0.064	0.18	0.21
04:30	0.058	0.063	0.19	0.20
05:00	0.058	0.070	0.19	0.23
05:30	0.061	0.087	0.20	0.28
06:00	0.064	0.082	0.21	0.26
06:30	0.063	0.080	0.20	0.26
07:00	0.089	0.146	0.29	0.47
07:30	0.112	0.164	0.36	0.53
08:00	0.148	0.226	0.48	0.73
08:30	0.152	0.200	0.49	0.65
09:00	0.152	0.164	0.49	0.53
09:30	0.143	0.167	0.46	0.54
10:00	0.129	0.167	0.42	0.54
10:30	0.153	0.186	0.49	0.60
11:00	0.164	0.248	0.53	0.80
11:30	0.149	0.174	0.48	0.56
12:00	0.141	0.144	0.46	0.47
12:30	0.169	0.198	0.55	0.64
13:00	0.168	0.184	0.54	0.60
13:30	0.172	0.209	0.56	0.68
14:00	0.162	0.181	0.52	0.58
14:30	0.171	0.236	0.55	0.77
15:00	0.163	0.179	0.53	0.58
15:30	0.140	0.134	0.45	0.43
16:00	0.164	0.156	0.53	0.50
16:30	0.189	0.220	0.61	0.71
17:00	0.195	0.191	0.63	0.62
17:30	0.224	0.268	0.72	0.87
18:00	0.277	0.305	0.90	0.99
18:30	0.242	0.227	0.78	0.74
19:00	0.244	0.373	0.79	1.21
19:30	0.208	0.158	0.67	0.51
20:00	0.195	0.171	0.63	0.55
20:30	0.209	0.168	0.68	0.54
21:00	0.232	0.219	0.75	0.71
21:30	0.207	0.200	0.67	0.65
22:00	0.191	0.162	0.62	0.52
22:30	0.167	0.138	0.54	0.45
23:00	0.154	0.123	0.50	0.40
23:30	0.150	0.147	0.48	0.48
24:00	0.117	0.111	0.38	0.36



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,236kWh.

High income consumer group (household income ≥ £20,000yr)

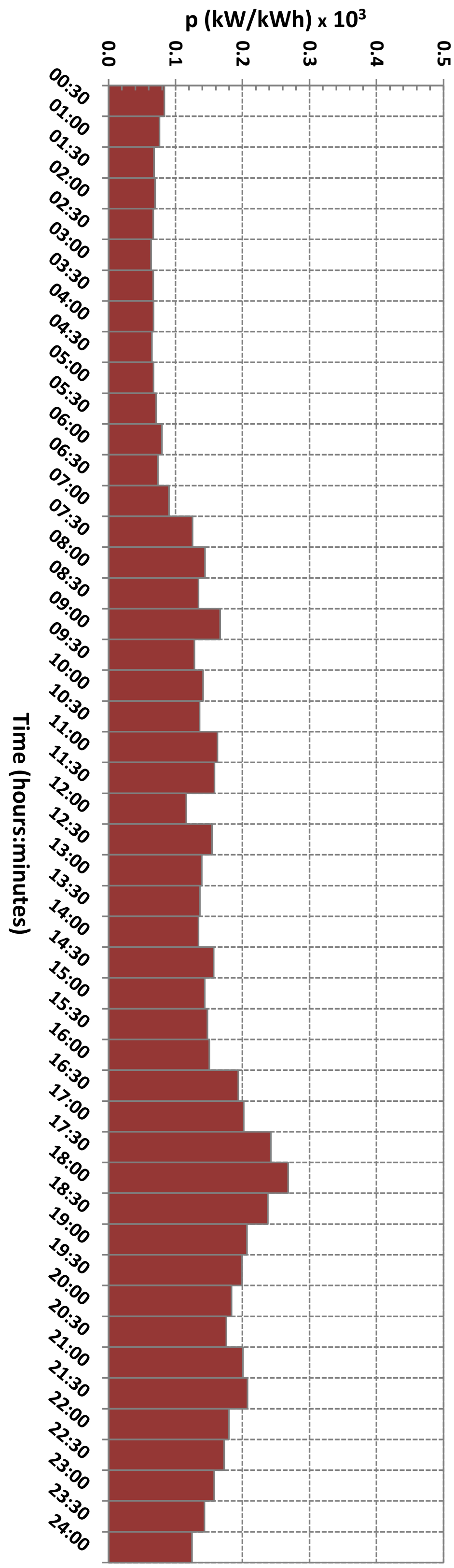
Time	p	q	P	Q
00:30	0.094	0.121	0.31	0.40
01:00	0.082	0.153	0.27	0.50
01:30	0.073	0.096	0.24	0.32
02:00	0.067	0.069	0.22	0.23
02:30	0.065	0.077	0.21	0.25
03:00	0.060	0.064	0.20	0.21
03:30	0.059	0.066	0.19	0.22
04:00	0.059	0.067	0.19	0.22
04:30	0.058	0.066	0.19	0.22
05:00	0.058	0.069	0.19	0.23
05:30	0.058	0.068	0.19	0.22
06:00	0.069	0.094	0.23	0.31
06:30	0.075	0.109	0.25	0.36
07:00	0.106	0.231	0.35	0.76
07:30	0.123	0.202	0.40	0.66
08:00	0.146	0.185	0.48	0.61
08:30	0.127	0.133	0.42	0.44
09:00	0.164	0.221	0.54	0.73
09:30	0.154	0.268	0.51	0.88
10:00	0.184	0.319	0.61	1.05
10:30	0.149	0.230	0.49	0.76
11:00	0.156	0.236	0.51	0.78
11:30	0.151	0.207	0.50	0.68
12:00	0.121	0.146	0.40	0.48
12:30	0.131	0.180	0.43	0.59
13:00	0.141	0.209	0.46	0.69
13:30	0.126	0.183	0.41	0.60
14:00	0.146	0.211	0.48	0.69
14:30	0.146	0.193	0.48	0.64
15:00	0.135	0.152	0.44	0.50
15:30	0.138	0.170	0.46	0.56
16:00	0.151	0.161	0.50	0.53
16:30	0.180	0.204	0.59	0.67
17:00	0.187	0.201	0.61	0.66
17:30	0.224	0.223	0.74	0.73
18:00	0.237	0.216	0.78	0.71
18:30	0.235	0.239	0.77	0.79
19:00	0.217	0.221	0.71	0.73
19:30	0.207	0.210	0.68	0.69
20:00	0.198	0.183	0.65	0.60
20:30	0.184	0.168	0.60	0.55
21:00	0.192	0.155	0.63	0.51
21:30	0.207	0.183	0.68	0.60
22:00	0.180	0.136	0.59	0.45
22:30	0.165	0.130	0.54	0.43
23:00	0.162	0.144	0.53	0.47
23:30	0.148	0.177	0.49	0.58
24:00	0.119	0.118	0.39	0.39



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,564kWh.

High thermal efficiency consumer group (thermal performance of the building)

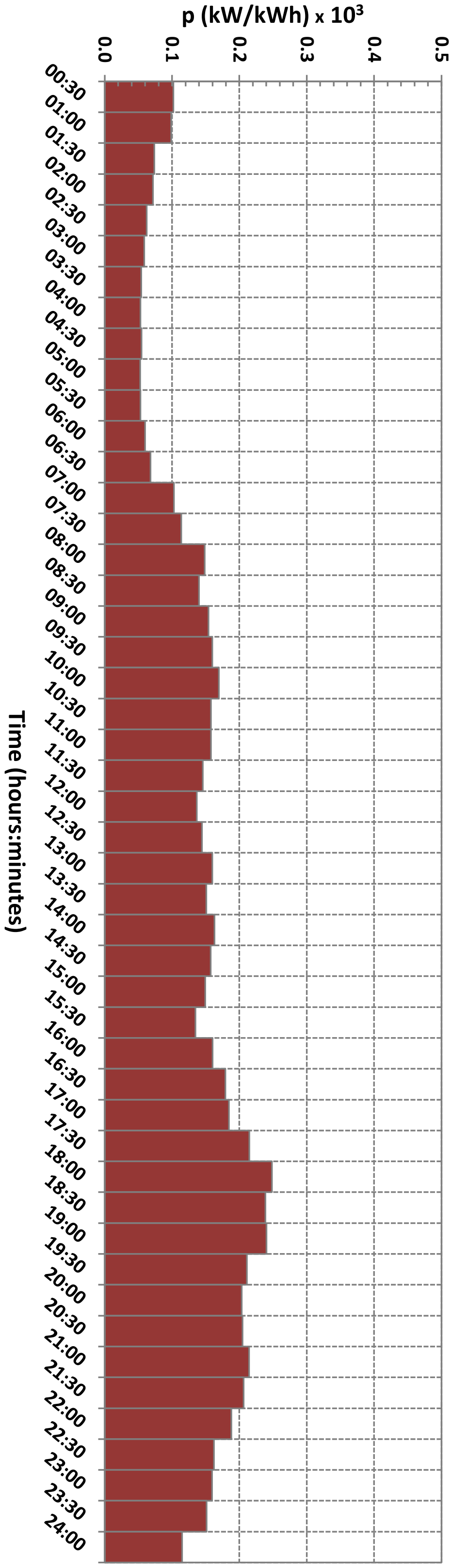
Time	p	q	P	Q
00:30	0.083	0.092	0.29	0.32
01:00	0.076	0.073	0.26	0.26
01:30	0.068	0.069	0.24	0.24
02:00	0.070	0.080	0.24	0.28
02:30	0.067	0.081	0.23	0.28
03:00	0.064	0.073	0.22	0.25
03:30	0.067	0.077	0.23	0.27
04:00	0.067	0.085	0.23	0.30
04:30	0.065	0.078	0.23	0.27
05:00	0.067	0.087	0.23	0.30
05:30	0.071	0.102	0.25	0.36
06:00	0.080	0.111	0.28	0.39
06:30	0.074	0.091	0.26	0.32
07:00	0.090	0.107	0.31	0.37
07:30	0.125	0.211	0.44	0.73
08:00	0.144	0.171	0.50	0.60
08:30	0.134	0.145	0.47	0.51
09:00	0.167	0.171	0.58	0.59
09:30	0.128	0.134	0.45	0.47
10:00	0.141	0.228	0.49	0.79
10:30	0.136	0.160	0.47	0.56
11:00	0.163	0.239	0.57	0.83
11:30	0.158	0.184	0.55	0.64
12:00	0.116	0.125	0.40	0.44
12:30	0.155	0.219	0.54	0.76
13:00	0.139	0.134	0.48	0.47
13:30	0.136	0.116	0.47	0.41
14:00	0.134	0.146	0.47	0.51
14:30	0.157	0.193	0.55	0.67
15:00	0.143	0.146	0.50	0.51
15:30	0.148	0.184	0.51	0.64
16:00	0.150	0.131	0.52	0.46
16:30	0.194	0.241	0.67	0.84
17:00	0.202	0.204	0.70	0.71
17:30	0.242	0.289	0.84	1.00
18:00	0.268	0.302	0.93	1.05
18:30	0.238	0.253	0.83	0.88
19:00	0.207	0.165	0.72	0.57
19:30	0.199	0.217	0.69	0.75
20:00	0.184	0.142	0.64	0.49
20:30	0.176	0.106	0.61	0.37
21:00	0.200	0.167	0.70	0.58
21:30	0.208	0.213	0.72	0.74
22:00	0.179	0.126	0.62	0.44
22:30	0.173	0.137	0.60	0.48
23:00	0.158	0.134	0.55	0.47
23:30	0.143	0.151	0.50	0.53
24:00	0.124	0.128	0.43	0.44



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,292kWh.

Low thermal efficiency consumer group (thermal performance of the building)

Time	p	q	P	Q
00:30	0.102	0.139	0.00	0.00
01:00	0.099	0.272	0.00	0.00
01:30	0.074	0.096	0.00	0.00
02:00	0.072	0.129	0.00	0.00
02:30	0.062	0.077	0.00	0.00
03:00	0.059	0.063	0.00	0.00
03:30	0.054	0.055	0.00	0.00
04:00	0.053	0.052	0.00	0.00
04:30	0.055	0.056	0.00	0.00
05:00	0.053	0.057	0.00	0.00
05:30	0.053	0.058	0.00	0.00
06:00	0.060	0.073	0.00	0.00
06:30	0.068	0.100	0.00	0.00
07:00	0.103	0.231	0.00	0.00
07:30	0.114	0.172	0.00	0.00
08:00	0.148	0.219	0.00	0.00
08:30	0.140	0.176	0.00	0.00
09:00	0.154	0.210	0.00	0.00
09:30	0.160	0.264	0.00	0.00
10:00	0.169	0.281	0.00	0.00
10:30	0.158	0.233	0.00	0.00
11:00	0.158	0.243	0.00	0.00
11:30	0.146	0.197	0.00	0.00
12:00	0.137	0.154	0.00	0.00
12:30	0.144	0.173	0.00	0.00
13:00	0.160	0.224	0.00	0.00
13:30	0.151	0.227	0.00	0.00
14:00	0.163	0.219	0.00	0.00
14:30	0.157	0.224	0.00	0.00
15:00	0.149	0.174	0.00	0.00
15:30	0.135	0.138	0.00	0.00
16:00	0.160	0.171	0.00	0.00
16:30	0.179	0.194	0.00	0.00
17:00	0.185	0.192	0.00	0.00
17:30	0.215	0.217	0.00	0.00
18:00	0.248	0.236	0.00	0.00
18:30	0.239	0.224	0.00	0.00
19:00	0.240	0.347	0.00	0.00
19:30	0.211	0.172	0.00	0.00
20:00	0.203	0.193	0.00	0.00
20:30	0.205	0.191	0.00	0.00
21:00	0.214	0.197	0.00	0.00
21:30	0.206	0.179	0.00	0.00
22:00	0.188	0.158	0.00	0.00
22:30	0.162	0.131	0.00	0.00
23:00	0.159	0.135	0.00	0.00
23:30	0.151	0.171	0.00	0.00
24:00	0.115	0.108	0.00	0.00



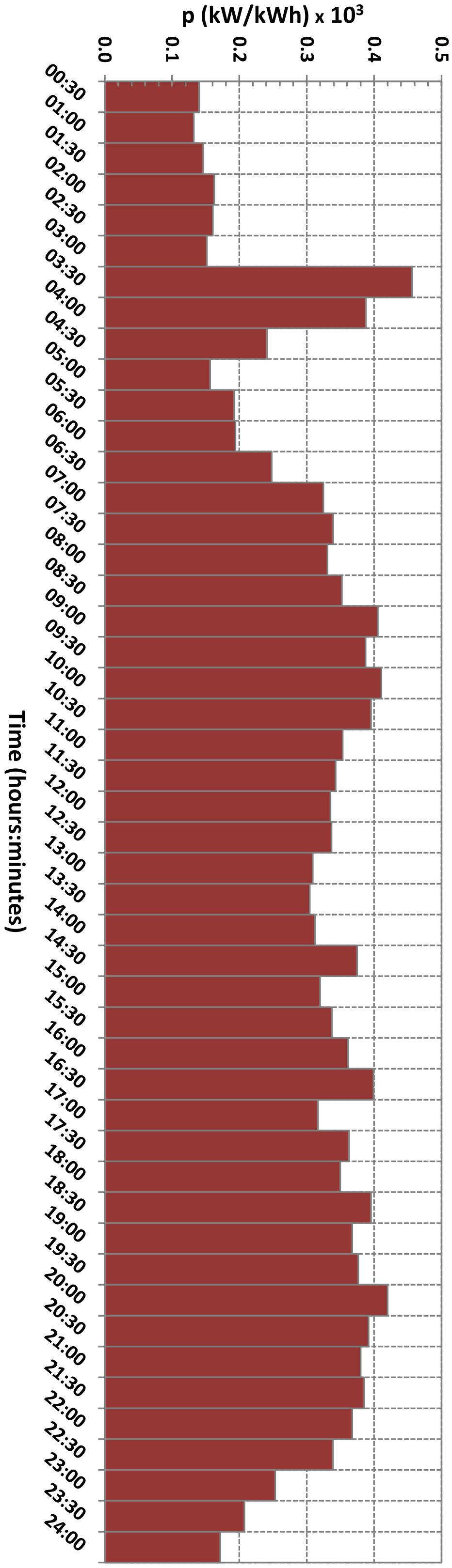
'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 3,478kWh.

Appendix C

The CLNR project has used real word data collected from the field trials to produce a generalised set of load curves for different low carbon technologies that can be applied within the current ACE 49 framework for the estimation of the design demand and voltage regulation in LV radial distribution systems. The load curves are presented in this Appendix together with the demand factors '*p*' and '*q*' and associated values of '*P*' and '*Q*' for the central winter period.

Heat pumps

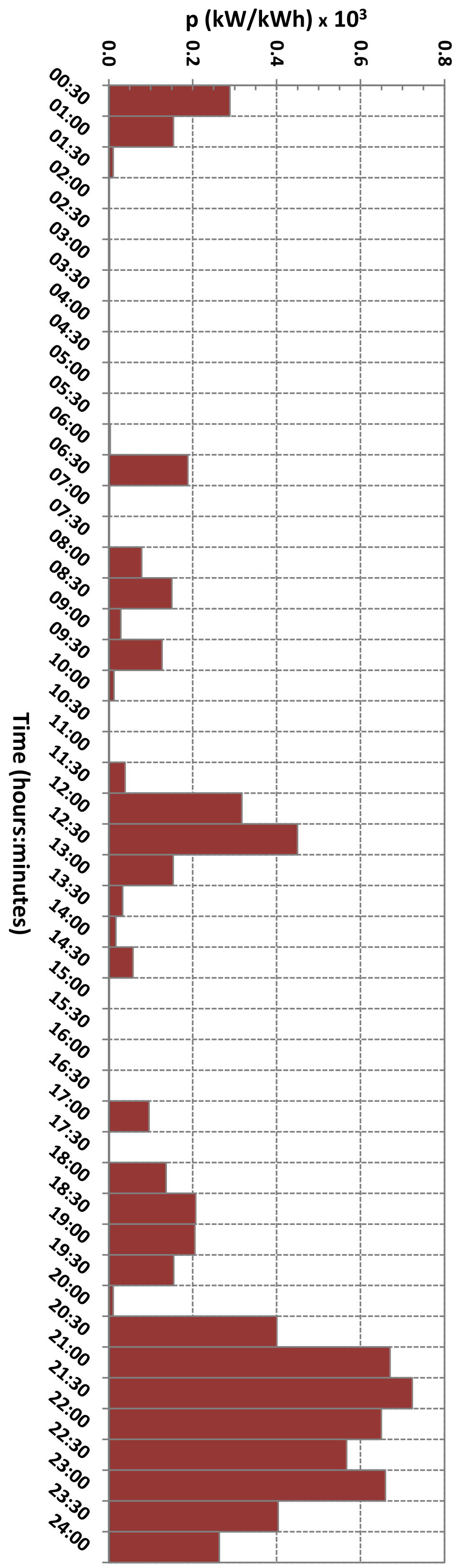
Time	p	q	P	Q
00:30	0.140	0.251	0.38	0.69
01:00	0.132	0.220	0.36	0.60
01:30	0.146	0.247	0.40	0.68
02:00	0.162	0.267	0.45	0.73
02:30	0.161	0.261	0.44	0.72
03:00	0.152	0.233	0.42	0.64
03:30	0.457	0.482	1.25	1.32
04:00	0.388	0.623	1.06	1.71
04:30	0.241	0.357	0.66	0.98
05:00	0.157	0.321	0.43	0.88
05:30	0.192	0.549	0.53	1.51
06:00	0.194	0.321	0.53	0.88
06:30	0.248	0.311	0.68	0.85
07:00	0.325	0.368	0.89	1.01
07:30	0.339	0.377	0.93	1.03
08:00	0.331	0.309	0.91	0.85
08:30	0.352	0.311	0.97	0.85
09:00	0.406	0.543	1.11	1.49
09:30	0.387	0.303	1.06	0.83
10:00	0.411	0.376	1.13	1.03
10:30	0.395	0.337	1.08	0.92
11:00	0.353	0.346	0.97	0.95
11:30	0.343	0.301	0.94	0.83
12:00	0.335	0.294	0.92	0.81
12:30	0.337	0.269	0.92	0.74
13:00	0.309	0.295	0.85	0.81
13:30	0.305	0.281	0.83	0.77
14:00	0.312	0.298	0.86	0.82
14:30	0.375	0.429	1.03	1.18
15:00	0.320	0.292	0.88	0.80
15:30	0.337	0.279	0.92	0.76
16:00	0.361	0.327	0.99	0.90
16:30	0.399	0.676	1.09	1.85
17:00	0.317	0.306	0.87	0.84
17:30	0.363	0.326	0.99	0.89
18:00	0.350	0.292	0.96	0.80
18:30	0.395	0.372	1.08	1.02
19:00	0.368	0.454	1.01	1.24
19:30	0.376	0.325	1.03	0.89
20:00	0.420	0.392	1.15	1.07
20:30	0.392	0.397	1.07	1.09
21:00	0.380	0.417	1.04	1.14
21:30	0.385	0.444	1.06	1.22
22:00	0.368	0.415	1.01	1.14
22:30	0.339	0.385	0.93	1.06
23:00	0.253	0.388	0.69	1.06
23:30	0.208	0.365	0.57	1.00
24:00	0.172	0.317	0.47	0.87



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 2,741kWh.

Electric vehicles

Time	p	q	P	Q
00:30	0.289	0.610	2.01	4.26
01:00	0.154	0.338	1.08	2.36
01:30	0.011	0.020	0.07	0.14
02:00	0.002	0.001	0.01	0.00
02:30	0.002	0.000	0.01	0.00
03:00	0.002	0.000	0.01	0.00
03:30	0.002	0.001	0.01	0.00
04:00	0.002	0.000	0.01	0.00
04:30	0.002	0.000	0.01	0.00
05:00	0.002	0.000	0.01	0.00
05:30	0.002	0.000	0.01	0.00
06:00	0.003	0.003	0.02	0.02
06:30	0.189	0.414	1.32	2.89
07:00	0.002	0.000	0.01	0.00
07:30	0.001	0.001	0.01	0.00
08:00	0.079	0.123	0.55	0.86
08:30	0.150	0.287	1.05	2.00
09:00	0.029	0.069	0.20	0.48
09:30	0.127	0.304	0.89	2.13
10:00	0.012	0.024	0.09	0.17
10:30	0.002	0.000	0.01	0.00
11:00	0.002	0.000	0.01	0.00
11:30	0.039	0.083	0.27	0.58
12:00	0.317	0.554	2.22	3.87
12:30	0.450	0.589	3.14	4.12
13:00	0.153	0.272	1.07	1.90
13:30	0.033	0.070	0.23	0.49
14:00	0.017	0.034	0.12	0.24
14:30	0.058	0.124	0.40	0.87
15:00	0.002	0.000	0.01	0.00
15:30	0.001	0.000	0.01	0.00
16:00	0.002	0.000	0.01	0.00
16:30	0.002	0.000	0.01	0.00
17:00	0.096	0.210	0.67	1.46
17:30	0.002	0.000	0.01	0.00
18:00	0.137	0.299	0.95	2.09
18:30	0.207	0.455	1.45	3.18
19:00	0.205	0.451	1.43	3.15
19:30	0.155	0.339	1.08	2.37
20:00	0.011	0.021	0.08	0.14
20:30	0.401	0.512	2.80	3.58
21:00	0.670	0.527	4.68	3.68
21:30	0.723	0.350	5.05	2.44
22:00	0.650	0.578	4.54	4.04
22:30	0.566	0.582	3.96	4.07
23:00	0.659	0.446	4.60	3.12
23:30	0.404	0.537	2.82	3.75
24:00	0.263	0.580	1.84	4.05



'*P*' and '*Q*' values were obtained from '*p*' and '*q*' respectively using a sample average annual consumption of 6,983kWh.