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Final Report: Review of Distribution Network Design and Performance Criteria

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with

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Objectives of the study

This report was commissioned by Ofgem, the regulator for gas and electricity markets in Britain. Distribution companies have a licence obligation to plan and develop their systems in accordance with a standard agreed by Ofgem. The standard currently in force is Engineering Recommendation (ER) P2/6.

ER P2/6 is a development of ER P2/5 which was originally introduced in 1978. It has provided clear guidance to Distribution Network Operators, in the majority of design situations, as to the network capacity required. However, the development of ER P2/6 raised questions regarding the methodology and the data supporting ER P2/6.

Ofgem' Interruption Incentive Scheme (IIS) has also impacted distribution network design. The IIS sets output performance targets for network operators and there is evidence that these targets are now of equivalent importance to ER P2/6 in some situations. In addition, the prospect of continued growth in the deployment of distributed generation and the gradual introduction of active networks may require new approaches to network design.

This report examines the case for a review of the current distribution network arrangements in Britain. For further information regarding the background to this study, please contact Gareth Evans at Ofgem, 9 Millbank, London, SW1P 3GE.

Executive Summary

The purpose of this study was to review distribution network design and performance criteria, specifically focussing on the adequacies and limitations of the current distribution network planning standard ER P2/6. This review also considered the influence on network design of the Interruption Incentive Scheme and the linkages to output performance measures. In addition to reviewing the current standard and incentive arrangements, this study outlines options to ensure these arrangements remain aligned with future customer requirements.

The electricity distribution networks of Britain have delivered secure and reliable supplies to customers. This performance is directly related to the network planning, design and operating practices of the DNOs. The distribution network performance indices for Britain compare favourably with the networks from other developed countries. Consequently, it can be inferred that ER P2/5, ER P2/6 and regulatory incentive arrangements have been effective in delivering secure and reliable networks to date. The key issue going forward is how this framework needs to evolve to remain fit-for-purpose in the future.

Given that the key function of electricity networks is to securely and efficiently transport energy from generation to demand, the location of generation relative to demand is the dominant factor driving the design and operation of electricity networks. Furthermore, the generation technologies employed, together with the pattern of demand, will impact network operation and development. Should significant penetrations of distributed generation materialise and/or new demand side capabilities emerge, a radical review of the current network design philosophy will be required. However, the development options proposed in this report build on the current framework and are evolutionary in nature.

Requirements for a network planning standard

Since introduction, the Interruption Incentive Scheme (IIS) has become an influential driver of HV/LV network design and the requirements of ER P2/6 have effectively been superseded for Classes of Supply A, B and C. For these Classes, DNOs typically plan their networks beyond the minimum planning requirement, and the IIS has reinforced this approach. Although the IIS has adequately addressed frequent low-impact supply interruptions originating on LV/HV networks, it may not adequately protect customers with respect to low probability / high-impact events for the larger Classes of Supply, should the planning standard requirements be removed.

The contribution of EHV networks to long-run output measure performance is low, hence the IIS is insufficient to drive EHV design and investment alone. The high reliability of the established network design is driven by the redundancy provisions and network automation requirements of ER P2/6. The absence of a planning standard would require DNOs to balance the risks associated with possible IIS related penalties with the capital gains associated with the postponement of investment. This could lead to reductions in the reliability of EHV networks, particularly in the short-run. An over-reliance on incentive arrangements as a driver for network planning is that customers could be exposed to a higher risks (and costs) of supply interruptions, although this risk would be largely invisible to both the regulator and customers.

In order for robust incentive-based arrangements to be developed, potentially superseding requirements for a planning standard, it will be necessary to more accurately understand customer outage costs for a range of customers and the failure distributions of network components and systems. This information is not yet readily available to either DNOs or the regulator, thus undermining the feasibility of adopting purely incentive based arrangements in the short-term. Similar constraints apply to the adoption of probabilistic approaches to network planning.

Consequently, it would appear sensible to retain the both a planning standard and an output performance incentive framework to deliver appropriate levels of security at EHV and a high quality of service to customers connected at HV/LV.

It should be recognised that ER P2/5 supported a variety of network designs in terms of voltage levels and interconnection capability. These design strategies have implications for network performance, costs and losses. Divergent approaches have evolved between different DNOs and there is no evidence to suggest designs will converge in future.

Supply interruption frequency to individual customers

A significant omission from ER P2/6 is the absence of planning guidance regarding supply interruption frequency for individual customers, although the standard does address the durations of different interruptions. Individual customer (rather than average) interruption frequency guidance was evaluated in ACE Report 51, although was not included in ER P2/5. A useful development of the current planning framework (from a customer perspective), would be to specify maximum expected interruption frequencies. Ideally, it would be helpful for the planning standard to contain such guidance as in ACE Report 51. However, the licence compliance implications of such inclusion may present a barrier, and thus favour alternative approaches, e.g. inclusion in future Guaranteed Standards or incentive arrangements. Before incorporation within the planning framework, it will be essential to determine appropriate interruption frequencies through further modelling and analysis.

The IIS and Guaranteed Standards of Performance provide some customer protection for interruption frequency although the Customer Interruption (CI) and Customer Minutes Lost (CML) output measures are not ideal as these are average system indices rather than individual load point indices and therefore reflect the impact of system behaviour on the “average” customer – a customer who in reality does not exist.

Analysis demonstrates that there can be significant variations in performance experienced by individual customers which CIs / CMLs do not convey. This can be considered a weakness in the *application* of CIs and CMLs when discussing performance actually received by customers (rather that the weakness of the indices per se).

Critical network loadings

ER P2/6 contains assumptions regarding the critical network loading conditions on which security evaluations are based. The critical network loading condition adopted in ER P2/6 is assumed to occur during an Average Cold Spell. Changes in network usage have resulted in this assumption becoming invalid for particular network areas, e.g. during summer-time in urban areas due to the growth of air conditioning loads.

There is an argument that the planning standard should not specify when the peak loading condition may arise. Investigations in the Dutch market have confirmed that it is the DNOs responsibility to determine the critical loading scenarios impacting their networks and then to plan accordingly. A useful development of the current planning standard would be to make DNOs responsible for assessing the critical network loading conditions relevant to their networks. In reality, such an amendment would serve to reflect current DNO practice and remove a potentially inaccurate assumption regarding the timing of peak loadings.

A further implication of summer load growth is increased asset utilisation with reduced differences between the summer and winter peak loading conditions. The issue of increased summer loading is further complicated by the reduced equipment ratings of network components due to the higher ambient temperatures. DNOs have historically been able to rely upon reduced network demand during the summer months for outage scheduling to maintain network security as implicitly recognised in ER P2/6. Increases in summer loading utilises capacity headroom on the circuits retained in service during outages, potentially reducing network security to customers (particularly under Second Circuit Outage conditions) and complicating outage management.

Group Demands and Transfer Capacity

The consistent application of ER P2/6 requires DNOs to segregate their networks into different Classes of Supply which are related to Group Demands which may also be supported using Transfer Capacity. Neither of these terms are defined in ER P2/6 and interpretation is therefore a matter for the DNO. In order to improve transparency and to clarify the compliance requirements for network operators (including transmission) and the regulator, it would be helpful for representatives of all the relevant stakeholders to establish agreed definitions/principles for Group Demand boundaries and associated Transfer Capacities for inclusion in any revised planning standard.

Transmission / Distribution network interface considerations

A further issue regarding the availability of transfer capacity applies at the interface of the transmission system with distribution networks, where the Transmission System Operator (TSO) may require the use of EHV transfer capacity on distribution networks. Some DNOs have indicated concern that the provision of EHV transfer capacity to the TSO can sometimes reduce security to downstream customers and also increase DNO risk exposures. Whilst not strictly a distribution planning issue, requirements for DNOs to provide transfer capacity could benefit from clarification to ensure that risks apparent to each network operator (and the corresponding customer groups) are clearly understood and that co-ordinated approaches to risk mitigation can be adopted.

Analysis has demonstrated that Grid Supply Point arrangements, as specified by Transmission Owner (TO), can impact the expected IIS performance of a DNO. In an era of asset replacement, it can be attractive for the TO to rationalise transformer arrangements at a Grid Supply Points (e.g. reducing transformer numbers from 3 to 2). Reliability calculations reveal that such developments can increase CI/CML exposures for DNOs. Again, to clarify requirements at the transmission interface, it would be helpful to establish co-ordination procedures between DNOs (ER P2/6 driven) and the TO (GB SQSS driven).

Minimum planning requirements and lifecycle costing

The IIS drives distribution network design for the smallest Demand Groups and DNOs typically design beyond the minimum planning requirement, whereas low (initial) capital cost network designs aligned with the minimum planning standard, may not be optimised from lifecycle cost or network security perspectives. In a liberalised electricity market, 3rd parties may be responsible for network design without any ongoing network management responsibilities and therefore low capital cost solutions can be attractive, although the outcome from a customer perspective may be sub-optimal in the long-run.

With respect to energy losses on distribution networks, recent work indicates that it can be economically efficient to install some network components (e.g. cables) rated at 5-10 times the demand requirement when evaluated over 20 year time horizon, especially for LV and HV circuits. These findings suggest that least initial cost asset replacement strategies may not be optimal, particularly in the context of UK efforts to meet CO_2 reduction targets. ER P2/6 only addresses the ability of networks to meet peak demand requirements and does not consider lifecycle costs.

A further benefit of robust, low-loss electricity network infrastructure is flexibility regarding the sustainable development of the UK electricity system. Such networks are readily able to accommodate the uncertainties associated future generation portfolios in terms of type, size, location and performance. In order to ensure optimised network designs are implemented, it will be increasingly important to consider lifecycle costing when reinforcing and extending networks.

Construction outages

In the current era of asset renewal, it is important to consider network security during extended construction outage periods. However, ER P2/6 was developed to specifically address short duration 'maintenance' outages. Analysis has revealed that construction outages for the larger Demand Groups (D and E) can impose significantly increased risk exposures for both DNOs and customers. As ER P2/6 does not explicitly address construction outages, there is a requirement to understand and quantify the increased risks of interruptions that are driven by different outage management practices. It is important to quantify the cost of alternative strategies for mitigating risks so that appropriate decisions can be made in relation to contingency arrangements.

In order to make informed decisions as to how to manage and implement construction outages, DNOs need to undertake comprehensive risk assessments beforehand. Depending on the level of confidence in their evaluations and each DNO's attitude towards risk, mitigation strategies may vary between companies and over time. DNOs with insufficient confidence regarding input data assumptions, combined with a risk adverse position, may prefer to install temporary network infrastructure to reduce exposures. Conversely, DNOs with a higher confidence in their ability to manage failures post-event, combined with a less risk adverse attitude, may prefer to rely on post-fault management capabilities.

The development of mitigation techniques to avoid losses of supply to large numbers of customers for extended periods could require DNOs to increase holdings of strategic spares, make more frequent use of temporary overhead line structures and becoming more reliant on off-line build approaches. The possibility of second circuit outages taking days (possibly weeks) to rectify for the larger demand groups is regarded as credible, especially when reliant upon heavily loaded ageing assets. It is interesting to note that the Dutch Grid Code specifically acknowledges the risks associated with extended outages on EHV networks, requiring DNOs to maintain n-1 security during outages beyond 6 hours in duration. The impact of this requirement is the extensive use of temporary structures during extended outages with associated cost implications for the DNO and regulator.

Another valid mitigation technique to minimise CMLs and customer interruption exposures during extended outages relates to the availability of transfer capacity. Where increased transfer capacity can be provided at low cost, it can be possible to avoid/minimise the staged restoration of supplies to customers under Second Circuit Outage (SCO) conditions.

Given the issues of increased summer demand and construction outage management, it would be appropriate to review whether the staged restoration process for Second Circuit Outages as specified by ER P2/6 should be removed or amended. ER P2/6 could also be amended to differentiate between maintenance and construction outages and to provide guidance on risk mitigation.

Common mode faults

ER P2/6 does not specify how the required levels of redundancy should be delivered, nor does it prevent reserve circuits being exposed to common mode faults, which can significantly degrade IIS performance. Common mode network failures can arise where there is a risk of multiple faults occurring following a single event, e.g. a cable fire or the actions of 3rd parties. Typical network components exposed to common mode failure risks include overhead and underground circuits along identical routes, e.g. shared overhead line towers, cable tunnels and cable trenches.

The IIS may encourage more attention to common mode failure risk in future. However, it is likely that numerous existing assets are exposed to common mode failures which significantly reduces the value of the redundancy provided. This appears particularly relevant for some large demand groups and it is recommended that this issue be examined in greater detail.

Consistency and correlations between the planning and incentive frameworks

The underlying methodology underpinning ER P2/6 is based on the concept of Expected Energy Not Supplied (EENS). High-level analysis has confirmed a significant correlation between energy not supplied and customers not supplied and it therefore follows there is a similar correlation between EENS and CMLs. This finding cannot be generalised to be valid for all possible customer mixes although it can be expected that many situations will exist where there is a significant correlation between the percentage energy not supplied and percentage of customers not supplied. Additional analysis regarding the network security contributions from distributed generation, again based on EENS and CMLs criteria, demonstrated consistency between these two indices.

For interruption frequency, expected CIs can be estimated from probabilistic analysis of network states where available capacity is less than customer demand. Supply restoration and repair times can be demonstrated to significantly impact CMLs whilst not affecting CIs. Correlations between CIs and CMLs are weaker.

Overall, the IIS framework can be considered to be broadly consistent with ER P2/6 when quality of supply incentives for large numbers of customers are compared to planning requirements for different Classes of Supply, especially with respect to average interruption durations.

CML implications for network design

IIS related investments have predominantly focussed on HV network automation and remote control. After exhausting such HV automation opportunities, it will be logical to address LV network performance improvements although such investments may be more costly due to requirement to reconfigure (and potentially duplicate) primary assets. The extent to which DNOs will pursue such strategies in future will depend on the level of targets and incentives rates. As opportunities for ‘quick-wins’ diminish, the setting of appropriate cost-reflective targets will become increasingly challenging for the economic regulator. The ability to concurrently improve both CI and CML performance has influenced DNO investment priorities and has resulted in the widespread deployment of secondary assets on HV networks, i.e. quality of supply performance improvement has not required significant investment in primary assets (yet).

Substation redundancy

Analysis has revealed that substation redundancy requirements are significantly impacted by equipment repair times. High-level examples demonstrate that extended repair times can result in high CML exposures. Reductions in asset repair/replacement times can be demonstrated to reduce CML exposures accordingly. Transformer replacement times are linked to the size / voltage of the transformer and therefore asset replacement times significantly impact redundancy requirements. Analysis confirms redundancy requirements to be greatest for the larger Demand Groups which is consistent with ER P2/6.

Maintenance outages

IIS exposures associated with short maintenance outages vary considerably, depending on the level of network redundancy available. Analysis demonstrates that maintenance outages incur considerable IIS penalties where no redundant circuits are available to maintain supplies. Consequently, LV networks must be designed to be virtually maintenance-free. Conversely, where two or more transformers are installed per substation (n-1 etc), maintenance outages do not adversely impact IIS performance, i.e. maintenance outages can be scheduled at low-risk where network redundancy is available.

LV networks

For LV networks, improvements in CML performance can be achieved using sectionalising techniques followed by the installation of reserve cables. Analysis reveals the cost-effectiveness of sectionalising LV circuits. The economics of installing reserve LV cables appear to be marginal under the current IIS arrangements. However, for circuits with large numbers of customers, the installation of reserve cables may be viable. Should incentive rates increase in future, this may stimulate the network designs with higher levels of redundancy at LV, particularly those with large number of customers or systems supplying high value loads. It should be noted that such arrangements would be well beyond the minimum ER P2/6 requirement.

Redundancy in HV/LV substation design

ER P2/6 requires no substation redundancy (n-0) for Class of Supply A. IIS exposure evaluations have confirmed that adopting a (n-1) network design in HV/LV substations instead of the typical (n-0) arrangement does not justify adding an additional substation transformer. Consequently, the current practice of no redundant assets at the HV/LV interface represents an appropriate network design under the current IIS framework.

Similar analysis demonstrates the validity and effectiveness of the actions taken by DNOs with respect to increased automation and remote control on 11 kV feeders which has resulted in significant reductions in CMLs and CIs since the incentive arrangements were introduced.

Distributed generation

Security contributions from distributed generation

The rate of deployment of new distributed generation has remained relatively low since the implementation of ER P2/6 and no examples of distributed generation being used to secure Demand Groups have been identified. The lack of an established framework by which DNOs can reward generators for the provision of security contributions has been identified as a barrier and the current regulatory arrangements do not incentivise DNOs to make payments to generators. However, examples of DNOs procuring short-term network security contributions from distributed generation were identified in the Dutch electricity market with generators being rewarded accordingly.

Generation connection criteria

ER P2/6 is silent regarding the network redundancy requirements for generator connections. As the ratings of distributed generators tend to be significantly smaller than transmission connected units, the ability of individual generators to secure demand is more limited. In the event that multiple distributed generators were being used to secure demand collectively, the contribution of individual generators would be less significant than in a transmission context. Consequently, it is less important that connection criteria for distributed generation be formally defined in the planning standard. The current approach whereby generator connection requirements are agreed through bilateral negotiation between the DNO and the generator appears reasonable.

Energy exports and transfers across distribution networks

ER P2/6 does not address the security of power transfers originating from generation. DNOs are not currently required to provide a particular level of security to generator customers. Should offshore transmission networks emerge, distribution networks may be required to transfer energy between transmission operators. In such circumstances, the applicability of the offshore Security and Quality of Supply Standard could be undermined in the absence of requirements to securely transport the power flows from such generation across distribution networks. As the current arrangements may not provide sufficient certainty for the developments in offshore wind, it will be important to understand these requirements and to quantify the appropriate levels of network security to transport the output from generators. In the event that a generation development constraint emerges, a possible development path would be to review the existing industry codes, practices and governance procedures followed by development of an SQSS for onshore distribution networks and a corresponding industry code.

Recommendations

Prioritised recommendations regarding the development of the distribution network planning framework are summarised below in descending order of importance:

Planning framework: It is recommended that a distribution network planning standard for use by British DNOs is retained. A planning, design and operational framework comprising an evolutionary development of ER P2/6 complemented by regulatory incentive arrangements can deliver appropriate levels of network security at EHV and a high quality of service to customers connected at HV/LV. Further work needs to be undertaken to determine whether an incentive based approaches could remove the requirement for a planning standard in future. Current shortfalls in input data quality mean that adoption of incentive based approaches would be premature.

Critical network loadings: It is recommended that distribution planning standard should make DNOs responsible for the determination and assessment of the critical network loading conditions and corresponding equipment ratings relevant to their networks (summer or winter) and that references to Average Cold Spell Criteria be removed.

Construction outage risk and Second Circuit Outage provisions: In order to expose and minimise the escalating network security risk to customers associated with extended construction outages, it is recommended that further work be undertaken to quantify these risks (and implied costs) against the current planning requirements. Following further analysis, it may be appropriate to consider removal of the staged restoration criteria for Second Circuit Outages. In the interim, consideration should be given to explicitly acknowledging the increased network security risk associated with extended construction outages. Ideally, future versions of the planning standard should differentiate between maintenance and construction outages and provide guidance regarding risk mitigation.

Energy exports and transfers across distribution networks: In future, it may be important quantify distribution network security required to transport the output from offshore generation connected via distribution networks. A possible development path to accommodate such a scenario would be to ensure that the industry codes and governance procedures for both transmission (on and offshore) and distribution are developed on a consistent basis.

Design practices at the Transmission/ Distribution interface: Design practices on the transmission system can impact distribution network performance. It is recommended that co-ordination procedures are established between the Transmission Owners and DNOs to ensure substation designs consider the network performance implications for customers.

Operational co-ordination between DNOs and the TSO: It is recommended that requirements for DNOs to provide transfer capacity to the TSO are clarified in order that the risks apparent to the respective network operators (and the corresponding customer groups) are clearly understood and that co-ordinated approaches to risk mitigation can be adopted.

Frequency of Supply Interruptions to customers: It is recommended that the distribution planning framework (planning standard, Guaranteed Standards or incentive arrangements) be developed to specify maximum expected interruption frequencies for individual customers. The determination of appropriate provisions will require further modelling and analysis.

Lifecycle costing: In order to ensure network performance and costs are optimised in the long-run, it is recommended that DNOs increasingly adopt lifecycle costing practices when reinforcing and extending their networks.

Group Demand and Transfer Capacity definitions: In order to improve transparency and to clarify the compliance requirements for network operators (including transmission) and the regulator, it is recommended that agreed interpretations of Group Demand boundaries and associated Transfer Capacities are established between the relevant stakeholders.

Common Mode Failures: It is recommended that the risks associated with common mode failures be investigated further. Should these risks be confirmed to be material, it is recommended that ER P2/6 be amended to include guidance regarding the minimisation of Common Mode Failure risks.

Distributed Generation Connection Criteria: It is recommended that connection requirements for distributed generation continue to be agreed on a bilateral basis between generators and DNOs. It is not essential for the distribution planning standard to contain prescriptive guidance with respect to generator connection criteria.

1. Introduction

1.1 Background

British distribution companies have a licence obligation to plan and develop their systems in accordance with a national standard. The standard currently in force is Engineering Recommendation (ER) P2/6. This report examines the strengths and limitations of the current arrangements.

ER P2/6 was introduced in 2006 and is a development of its predecessor, ER P2/5. ER P2/5 was originally introduced in 1978. It has provided clear guidance to Distribution Network Operators, in the majority of design situations, as to the network capacity required. However, the development of ER P2/6 identified questions about the methodology and the supporting data.

A further development impacting ER P2/6 was Ofgem's Information and Incentives Project (IIP). The IIP set output performance targets for networks and there is evidence that these targets are now of at least equivalent importance to ER P2/6 in some situations. The prospect of continued growth in distributed generation and the gradual introduction of active networks may also require new approaches to system design.

1.2 Scope of the assignment

The purpose of this study was to review distribution network design and performance criteria, specifically focussing on the adequacies and limitations of the current distribution network planning standard ER P2/6. This review also considered the influence on network design of the IIP and the linkages to output performance measures. In addition to reviewing the current standard and incentive arrangements, this study outlines options to establish alternative network planning arrangements over the next 10 – 20 years.

The objectives of this review are stated below:

1. Establish whether there is a case, from a customer's point of view, to review ER P2/6; and if such a case can be made.

2. Identify the most appropriate options for a new standard taking account of:

   - existing output performance measures and the options for linking input and output measures in the future; and

   - the likely evolution of distribution networks to accommodate more generation connected at all voltages, demand side management and more active networks.

3. Propose a development route for any new standard.

1.3 Key work areas

For clarity, the key work areas to be addressed by this study were as follows:

1. Summarise in detail the methodology adopted by ER P2/6 (as described in ACE Report 51) and the key system data assumptions (e.g. reliability, outage restoration times, demand profiles etc.).

2. Provide a detailed commentary on the methodology and data focusing on:

   - their appropriateness to today's distribution systems;

   - the quantitative impact of any weaknesses identified; and

   - issues that may become material as distribution systems develop over the next 10-20 years.

3. Draw together and comment on the strength of the case for and scope of a review of ER P2/6.

4. Propose options for a new planning standard (this could range from updating ER P2/6 to a completely new methodology and standard).

5. Propose a development path for a new planning standard.

1.4 Report structure

The structure of this report is provided below:

- Section 2 provides an overview of the distribution network planning, design and performance framework applicable in Great Britain (GB);

- Section 3 provides detailed analysis of the background, application, strengths and limitations of the current distribution planning standard;

- Section 4 addresses the key features and implications of the regulatory incentive arrangements and output measures by which quality of services is assessed;

- Section 5 considers potential future planning standards and design developments for distribution networks in GB;

- Section 6 captures and summarises the key conclusions arising from this study; and

- Section 7 makes recommendations regarding future developments to potentially improve the network planning and design requirements applicable in GB.

2. Distribution network design and performance

2.1 Overview of regulatory framework and incentives

Distribution Network Operators (DNOs) are required to plan and develop their distribution systems to a standard not less than set out in Engineering Recommendation (ER) P2/6. This requirement is specified in each Electricity Distribution licence held by the ex-Public Electricity Supplier distribution companies. The requirement for distribution companies to plan and develop their networks to a standard not less than set out in ER P2/6 is also contained in the Distribution Code for Great Britain.

In addition to ER P2/6, Ofgem implemented the Information and Incentives Project (IIP) in April 2002 to financially incentivise DNOs to improve the overall quality of service delivered to customers. Since implementation, this initiative has influenced network design practices at High Voltages (HV), particularly 11 kV, in terms of network automation and remote control. The IIP was reinforced from April 2005 when the targets associated with the Interruption Incentive Scheme (IIS) became more onerous.

Another regulatory initiative impacting DNO network design and performance are the Guaranteed Standards of Performance. Guaranteed Standards set service levels that must be met on an individual customer basis. Where a DNO fails to provide the prescribed level of service, the customer affected is entitled to receive financial compensation subject to certain exemptions[1]. Guaranteed Standards cover 12 aspects of service quality although only Guaranteed Standards GS2, GS11 and GS12 are relevant to network design and operation, each addressing different aspects of supply restoration under different weather conditions. A significant feature of Guaranteed Standard compensation payments to customers is that the total amount payable by the DNO is uncapped.

2.2 Network planning standards and Engineering Recommendations

Network security is a high priority in the electricity supply industry and effort is made at both the planning and operational stages to ensure that security is as high as possible commensurate with cost. Because of the need to balance cost against the benefit, different distribution systems inherently possess different levels of security: the security generally improves with increasing voltage level, and with increasing levels of underground cables compared with overhead lines. Therefore transmission is generally more secure than distribution, and urban systems more secure than rural ones. In order to ensure that all customers have a minimum level of security, guidelines and standards exist.

[1] GS2 and GS12 entitle customers to compensation where individual supply interruptions are not restored in 18 hours, currently £50 for domestic, £100 for non-domestic and £25 for each subsequent 12 hours off supply. GS2A addresses multiple interruptions and entitles customers experiencing more than 4 interruptions per annum (>3 hours duration) to compensation, currently £50 for all customer groups. Such DNO liabilities only become payable where individual customers make a claim.

Prior to privatisation of the electricity supply industry, the Electricity Council was responsible for setting and maintaining a range of common technical and economic requirements, one of which was to determine and set appropriate levels of security. In order to create "consistency" between all distribution companies existing at that time, the Electricity Council formulated ER P2/5 in 1978.

ER P2/6 was implemented in July 2006, superseding ER P2/5. Whilst ER P2/6 is more comprehensive in the way it accommodates network security contributions from different forms of distributed generation, the underlying methodology and application requirements are fundamentally the same as ER P2/5.

2.3 Interruption Incentive Scheme

The Interruption Incentive Scheme sets DNO specific annual targets for the average number of Customer Interruptions (CI) per 100 customers and the number of Customer Minutes Lost (CML). Consequently, the IIS provides network performance output measures for interruption frequency and duration. The IIS was reinforced during the last distribution price control review such that symmetrical rewards and penalties were applied to a proportion of DNO revenues (±3%) from April 2005. The maximum annual DNO revenue adjustment attributable to CI and CML performance is ±1.2% and ±1.8% respectively.

In the context of the IIS, Customer Interruptions are defined as the number of customers affected by interruptions per 100 customers per year and significantly, only include interruptions lasting 3 minutes or longer. Where several outages occur affecting the same customer as part of the same fault, these only count as one interruption unless the second or subsequent power cuts occurred more than 3 hours after all customers in the first power cut were restored, or after 18 hours in the case of temporary restoration.

Customer Minutes Lost are defined as the annual number of minutes that customers are without power, averaged per customer relative to the total number of customers connected to each DNO network.

A feature of the IIS is that CI/CML targets for each DNO become more challenging in subsequent years of the price control and the corresponding incentive rates also increase as illustrated in Table 1 to Table 4. In addition, dependent upon whether interruptions are planned, unplanned or can be attributed to the transmission network, different weighting factors apply to the output measures as shown in Table 5.

Table 1 – DNO CI targets for the period 2005 – 2010

	Actuals				Target				
	2001/02	2002/03	2003/04		2005/06	2006/07	2007/08	2008/09	2009/10
CN - Midlands	120.1	99.8	113.1		109.4	107.8	106.2	104.6	103.0
CN - East Midlands	77.0	74.7	83.4		77.9	77.5	77.1	76.7	76.3
United Utilities	55.5	65.7	50.3		57.2	57.1	57.1	57.1	57.1
CE - NEDL	82.2	76.5	64.9		74.5	74.5	74.5	74.5	74.5
CE - YEDL	77.4	62.8	66.0		68.7	68.6	68.5	68.5	68.4
WPD - South West	100.7	81.8	71.0		84.5	84.5	84.5	84.5	84.5
WPD - South Wales	112.7	96.0	94.7		99.7	98.2	96.8	95.3	93.9
EDF - LPN	38.0	35.8	34.7		36.2	36.2	36.2	36.2	36.2
EDF - SPN	93.0	88.4	96.1		90.5	88.5	86.5	84.5	82.5
EDF - EPN	101.0	84.7	89.6		90.3	88.8	87.2	85.7	84.2
SP Distribution	59.0	63.4	60.2		60.9	60.8	60.8	60.8	60.8
SP Manweb	46.1	41.0	49.2		46.7	46.7	46.7	46.7	46.7
SSE - Hydro	115.4	90.0	84.1		96.2	95.8	95.5	95.2	94.9
SSE - Southern	98.3	91.5	86.1		91.0	90.1	89.2	88.3	87.4
Average	83.1	75.0	75.3		77.1	76.5	75.8	75.1	74.5

Source: Ofgem

Table 2 – DNO CI incentive rates for the period 2005 – 2010

Incentive rates for the number of customers interrupted per 100 customers (£m/CI – 02/03 prices)						
DNO	2005/6	2006/7	2007/8	2008/9	2009/10	2004/5 IIP incentive rate
CN - Midlands	0.10	0.11	0.11	0.11	0.11	0.06
CN - East Midlands	0.15	0.15	0.15	0.15	0.16	0.09
United Utilities	0.18	0.18	0.18	0.19	0.19	0.13
CE – NEDL	0.10	0.10	0.10	0.10	0.10	0.06
CE – YEDL	0.13	0.14	0.14	0.14	0.14	0.08
WPD - South West	0.10	0.10	0.10	0.10	0.11	0.07
WPD - South Wales	0.07	0.07	0.07	0.08	0.08	0.03
EDF – LPN	0.29	0.30	0.30	0.31	0.31	0.24
EDF – SPN	0.09	0.09	0.09	0.10	0.10	0.05
EDF – EPN	0.15	0.15	0.16	0.16	0.17	0.10
SP Distribution	0.23	0.23	0.23	0.23	0.23	0.13
SP Manweb	0.18	0.18	0.18	0.18	0.18	0.11
SSE - Hydro	0.08	0.08	0.08	0.09	0.09	0.04
SSE - Southern	0.18	0.18	0.18	0.19	0.19	0.11
Average	0.15	0.15	0.15	0.15	0.15	0.10

Source: Ofgem

Table 3 – DNO CML targets for the period 2005 – 2010

	Actuals				Target				
	2001/02	2002/03	2003/04		2005/06	2006/07	2007/08	2008/09	2009/10
CN - Midlands	116.9	100.9	100.3		102.3	98.5	94.7	91.0	87.2
CN - East Midlands	87.0	78.5	84.8		80.1	76.7	73.4	70.0	66.7
United Utilities	61.7	65.6	57.4		59.8	58.1	56.4	54.7	53.0
CE - NEDL	83.9	67.7	65.8		71.4	70.4	69.4	68.4	67.4
CE - YEDL	72.6	66.2	71.8		68.5	66.8	65.1	63.4	61.7
WPD - South West	78.6	57.9	50.2		62.2	62.2	62.2	62.2	62.2
WPD - South Wales	83.3	69.5	63.8		72.2	72.2	72.2	72.2	72.2
EDF - LPN	40.8	41.7	38.2		40.2	40.1	40.1	40.1	40.0
EDF - SPN	93.3	77.4	86.7		81.4	77.0	72.6	68.2	63.8
EDF - EPN	77.5	74.6	73.4		73.7	72.2	70.6	69.1	67.6
SP Distribution	61.8	70.3	73.4		64.9	61.2	57.6	54.0	50.4
SP Manweb	50.2	49.9	61.0		51.8	49.9	48.0	46.1	44.2
SSE - Hydro	135.6	79.6	75.6		95.9	94.9	93.9	93.0	92.0
SSE - Southern	95.8	78.8	76.2		82.0	80.5	78.9	77.4	75.8
Average	79.7	70.8	71.1		71.8	69.8	67.8	65.8	63.8

Source: Ofgem

Table 4 – DNO CML incentive rates for the period 2005 – 2010

Incentive rate for the number of customer minutes lost per customer (£m/CML)						
DNO	2005/6	2006/7	2007/8	2008/9	2009/10	2004/5 IIP incentive rate
CN - Midlands	0.14	0.15	0.15	0.16	0.17	0.10
CN - East Midlands	0.18	0.19	0.20	0.21	0.23	0.17
United Utilities	0.22	0.23	0.23	0.24	0.25	0.16
CE – NEDL	0.13	0.13	0.14	0.14	0.14	0.08
CE – YEDL	0.17	0.18	0.18	0.19	0.20	0.16
WPD - South West	0.17	0.17	0.17	0.18	0.18	0.13
WPD - South Wales	0.12	0.12	0.12	0.12	0.13	0.05
EDF – LPN	0.33	0.33	0.34	0.35	0.35	0.25
EDF – SPN	0.12	0.13	0.14	0.15	0.16	0.09
EDF – EPN	0.23	0.24	0.25	0.25	0.26	0.17
SP Distribution	0.27	0.28	0.30	0.33	0.35	0.14
SP Manweb	0.20	0.21	0.22	0.23	0.24	0.12
SSE – Hydro	0.10	0.11	0.11	0.11	0.11	0.04
SSE - Southern	0.24	0.25	0.26	0.27	0.28	0.15
Average	0.19	0.19	0.20	0.21	0.22	0.13

Source: Ofgem

Table 5 – Current CI and CML weighting factors

Source of CI/CML	Weighting
Unplanned CI & CML arising on the distribution network	100% for CI and CML
Pre-arranged CI & CML arising on the distribution network	50% for CI and CML
CI & CML arising from distributed generators	100% weighting for CI and CML
CI & CML arising from transmission and other connected networks	0% weighting for CI 10% weighting for CML

Source: Ofgem

These targets and incentive rates effectively enable DNOs to determine the priorities and extent of quality of service related network investments to be pursued during the price control period.

2.4 Incentives for reduction of electrical losses

The current regulatory arrangements, implemented in April 2005, provide an incentive for DNOs to reduce electrical losses on their networks. The loss reduction incentive is based on the difference between the estimated volume of electricity entering and exiting each network and the losses target is fixed for the five years of the price control. In 2004/2005 prices, the losses incentive rate was set at £48/MWh for the duration of the current price control period and DNOs are allowed to keep the benefit of reductions in losses for five years through the application of a rolling retention mechanism.

Traditionally, some network operators pursued lifecycle costing techniques with respect to asset ratings and losses. Post privatisation, there has been increased focus on low capital cost solutions to the extent that losses on British distribution networks remain higher than in other Western European countries.

Another factor impacting the overall magnitude of electricity distribution losses are the economics of loss optimisation. Historically, comparatively high equipment and raw material prices resulted in lifecycle cost solutions which favoured relatively high loss network designs. More recently, relative rises in energy costs have seen this situation change to the extent that lower loss designs are now optimal from a lifecycle cost perspective. Network asset ratings particularly influenced by lifecycle costing include transformers and Low Voltage (LV) cables.

2.5 Incentives to connect distributed generation

In April 2005 Ofgem introduced an incentive scheme for DNOs in relation to the connection of distributed generation in which DNO costs incurred when providing network access to distributed generators are partially (80%) passed-through and potential shortfalls are compensated through the application of a supplementary £/kW revenue incentive of £1.50/kW for all DNOs (except for the North of Scotland). This arrangement was devised to incentivise DNOs to actively facilitate the connection of all forms of distributed generation. From a DNO's perspective, increasing the capacity of distributed generation connected to a DNO network also increases the DNO's corresponding revenue allowance.

This incentive arrangement is based upon a ‘shallowish’ connection charging methodology whereby generators pay the full cost of sole-use connection assets and a proportion of any network reinforcement costs up to the next voltage boundary on the network. The remaining costs of deep network reinforcement are then recovered from generators according to the incentive arrangement described above. In order to provide some financial certainty to both generators and the relevant DNO, the assumed asset life for both connection and shared assets has been aligned with the duration of the incentive arrangement and set at 15 years.

A potentially attractive feature of this incentive arrangement for DNOs relates to the connection of large capacities of distributed generation where capacity headroom already exists. In such situations, the costs of connection and network reinforcement can often be relatively low, whereas the incremental revenue generated via the £/kW incentive can be significant. Since the introduction of this incentive arrangement, the deployment rate of distributed generation has been modest.

3. Distribution network planning in Great Britain

3.1 Origins of GB network planning standards

Prior to 1978, networks were designed according to the Security Standard known as Engineering Recommendation P2/4. This was an interim recommendation issued in 1968 by the-then Chief Engineers' Conference of the Electricity Council. During the 1970s, reliability evaluation techniques and reliability data improved sufficiently to allow P2/4 to be updated by taking into account the probabilistic nature of system failures in a more formal way. The Electricity Council developed the new standard using reliability evaluation techniques current at that time and computer programs such as REFOS (a CEGB development) and RELNET[2] (a UMIST development) which became Engineering Recommendation P2/5.

At the same time as these developments, discussions were underway as to the benefit of embedded generation. However the embedded generation at that time was different to that being installed today. Then, the generation embedded in the distribution system largely originated from the pre-nationalised industry, constructed by the large number of small-scale electricity companies that existed in local conurbations. The question being asked at that time was "Should this generation be declared obsolete or did it still add value to the system?". A version of RELNET[3] was developed by UMIST in order to assess these benefits and ER P2/5 was enhanced to provide a procedure by which their contribution could be measured.

It should be stressed that ER P2/5 was developed before the privatisation and the restructuring of the British electricity supply industry. It therefore reflects the industry structure of the 1970s rather than the liberalised market of today. Even so, ER P2/5 was incorporated into the statutes dealing with the privatisation of the British electricity industry.

Although ER P2/5 is a stand-alone document, the basis of ER P2/5 and the values quoted in it, have a stronger and more reasoned background as detailed in the application report ACE Report 51[4], with reliability cost assessments provided in ACE Report 67[5]. The following sections are based on P2/5 and these related documents.

3.2 Relationship between P2/5 and ACE Report 51

ER P2/5 was a stand-alone document which specified requirements for network planners but contained little background information or explanations. Part of this background is contained in ACE

2 MF De Oliveira. "Reliability Evaluation of Electrical Systems". PhD Thesis, UMIST, 1976

3 EN Dialynas. "Reliability Evaluation of Electrical Power Supply Systems". PhD Thesis, UMIST, 1979

4 ACE Report 51 (1979). "Report on The Application of Engineering Recommendation P2/5, Security of Supply". The Electricity Council.

5 ACE Report No.67 (1979). "Report on Reliability Investment in Radial H.V. Distribution Systems with Overhead Lines". The Electricity Council.

Report 51. This application report includes a brief description of the background philosophy of P2/5, but is mainly concerned with the assessment of the effect of generation and application of this assessment, with a description of reliability evaluation techniques of systems (these being essentially the same models and techniques described in other texts[6 7]), with the assessment of cost implications using the concept of “implied cost per kWh saved”, and with inclusion of some plant reliability data.

The most useful part of this report is the discussion relating to generation contribution. Whilst not explicit or completely transparent, sufficient information is included to enable the methodology to be reproduced. Essentially, this methodology determines the capacity of a ‘perfect’ circuit which, when substituted for the distributed generation, gives the same level of “reliability” (not explicitly defined but, from the text[8] of ACE Report 51, can be assumed to be the expected energy not supplied, EENS). From a large number of reliability studies, the authors of Report 51 found an average value of 67% of declared net generation capability. This capacity was then taken as the effective contribution of the generating equipment for use in ER P2/5 security assessments.

3.3 Principles of Engineering Recommendation P2/5

The general aims of the security standard as perceived in the 1970s are described in ACE Report 51 as “providing sufficient plant and other resources to provide and maintain an economic level of reliability of supply to the consumer”. It proposed that “the main factors affording a gauge of reliability of supply are frequency of interruption, duration of interruption and value of the service not provided”.

It is interesting to note that these factors were astutely defined some 30 years ago, are still recognised as being of prime importance, are still being actively proposed, but are still not fully developed into present-day security standards. However, before discussing these factors more fully, it is necessary to summarise the main principles and limits of P2/5.

P2/5 consists primarily of two tables and an approach for determining the capability of the network remaining after specified first and second order outage conditions:-

- Table 1 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

6 R.Billinton, and R.N.Allan. “Reliability Evaluation of Engineering Systems – Concepts and Techniques”. Plenum Publishing, New York, Second Edition, 1992

7 R.Billinton, and R.N.Allan. “Reliability Evaluation of Power Systems”. Plenum Publishing, New York, Second Edition, 1996

8 ACE Report 51 states ‘The most useful indicator of the loss of supply to consumers, when evaluating reliability of supply investment, is considered to be expected energy not supplied when required, measured as “kWh lost”……….If a planned system reinforcement affects the network, it is convenient to term the predicted change in energy not supplied “kWh saved”.’.

- Table 2 in ER P2/5 specified the network security contribution that could be credited to any embedded generation. The contribution is generally specified as 67% of the declared net capability of the generating units.

The approach used for determining the capability of the network is defined in the following way:

> "*The capacity of a network to meet a Group Demand after first and second circuit outages should be assessed as:*
>
> *a) The appropriate cyclic rating of the remaining transmission or distribution circuits which normally supply the Group Demand, following outage of the most critical circuit (or circuits)*
>
> *b) Plus the transfer capacity which can be made available from alternative sources*
>
> *c) Plus, for demand groups containing generation, the effective contribution of the generation to network capacity as specified in Table 2"*

This capability is then used in deciding whether the Group Demand could be satisfied in accordance with the values quoted in Table 1. It should be noted that ER P2/5 and ER P2/6 address network security required to supply peak demand. Neither standard addresses the security requirements of embedded generation.

In addition, P2/5 (and P2/6) addresses situations arising post-fault or post-interruption, i.e. the restoration process. It does not consider the reliability aspect prior to the fault and interruption. This is a significant point which is discussed in the following section.

3.4 Methodology adopted for ACE Report 51

ER P2/6 and its predecessor require the same level of network redundancy as prescribed by Table 1 of both ER P2/6 and ER P2/5. ACE Report 51 provided the methodology underpinning the requirements of this Table 1 and the key factors considered in the analysis of the reliability of supply to consumers were:

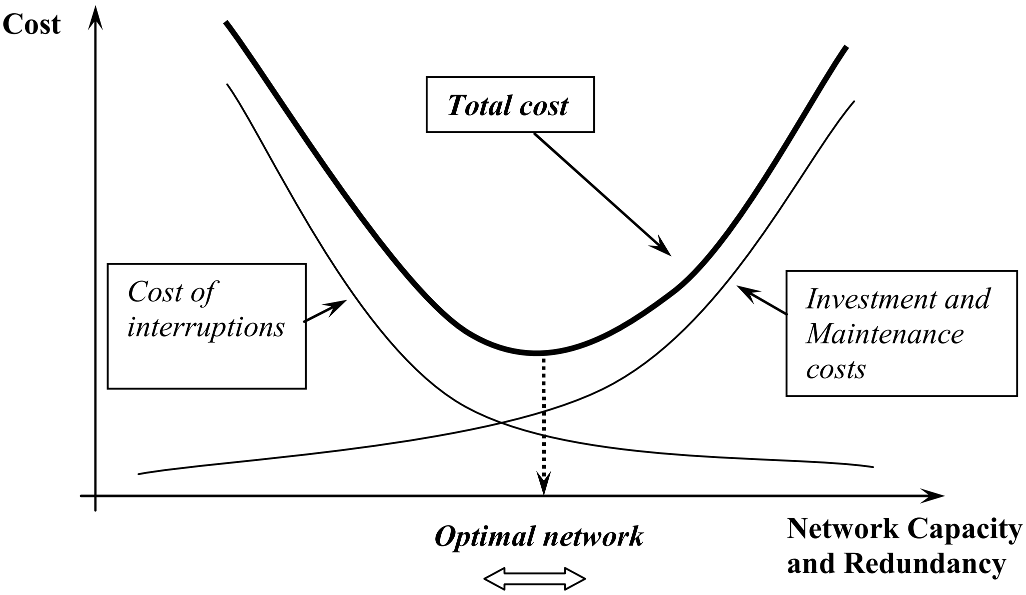
- Frequency of interruption;
- Duration of interruption; and
- Value of service not provided.

To assess the frequency and duration of interruptions appropriate data was required on plant fault rates and outage durations, maintenance outage duration and operational procedures. In addition to the method of calculation, the accuracy of these assessments was dependent upon assumptions made regarding future trends, which introduced the inherent problem of basing predictive analyses on historic data. Nevertheless, given the focus of the analysis on the evaluation of the overall benefits experienced by groups of consumers affected by investments (rather than individual customers), long-term statistical averages were used.

In deriving ER P2/6 it was recognised that the values placed on loss of supply by customers vary widely across different classes of consumers and are also affected by the time of the day. Consequently, the single value for loss of supply does not adequately reflect actual variations. By simulating the operation of the system, cost-benefit analyses were conducted involving the identification of the incremental reliability investment components of schemes, and estimating the change in reliability performance (experienced by consumers) as a result of such investment. ACE Report 51 recommended that alternative network reinforcement proposals should be assessed by comparing the capital cost of the infrastructure with frequency and duration of consumer interruption and the cost per kWh saved. This cost-benefit approach is described in ECR/M966[9].

A cost-benefit analysis approach was used to determine the optimum economic and technical design of the distribution network. Figure 1 shows the concept of cost-benefit approach that underpins the ER P2/6. This approach balances the cost of outages (which is impacted by stochastic behaviour of the system) against investment and maintenance costs. Generally, cost of outages reduces with increasing redundancy, given that this reduces the number of interruptions. However, investment costs obviously increase with the provision of increased redundancy and the improvement of the reliability performance of the network. The optimal compromise in relation to network capacity / redundancy is where the incremental cost of investment and maintenance is equal to benefit of reducing cost of outages.

Figure 1 – Concept of cost-benefit analysis



9 W. Cartwright and B. A. Coxson, Reliability Engineering and Cost-Benefit Techniques for Use in Power System Planning and Design, Electricity Council research Centre Memorandum ECR/M966

It should be recognised that the cost-benefit concept is fundamentally probabilistic and that ER P2/6 provides the opportunity for such analysis to be conducted for any specific network reinforcement and development scenarios. The benefits and practicalities of implementing comprehensive probabilistic analyses are explored further in Section 5.3.

It is interesting that ACE Report 51 also sets out levels of predicted interruption frequency to consumers above which further consideration of the network design of the system was required. This is summarised in Table 6 below that indicates the relative contributions to unreliability at each voltage level in the chain of supply to consumers and it could provide a trigger for reinforcement.

Table 6 - Levels of predicted interruption frequency in each class of supply which call for examination of predicted overall frequency of interruption experienced by consumers

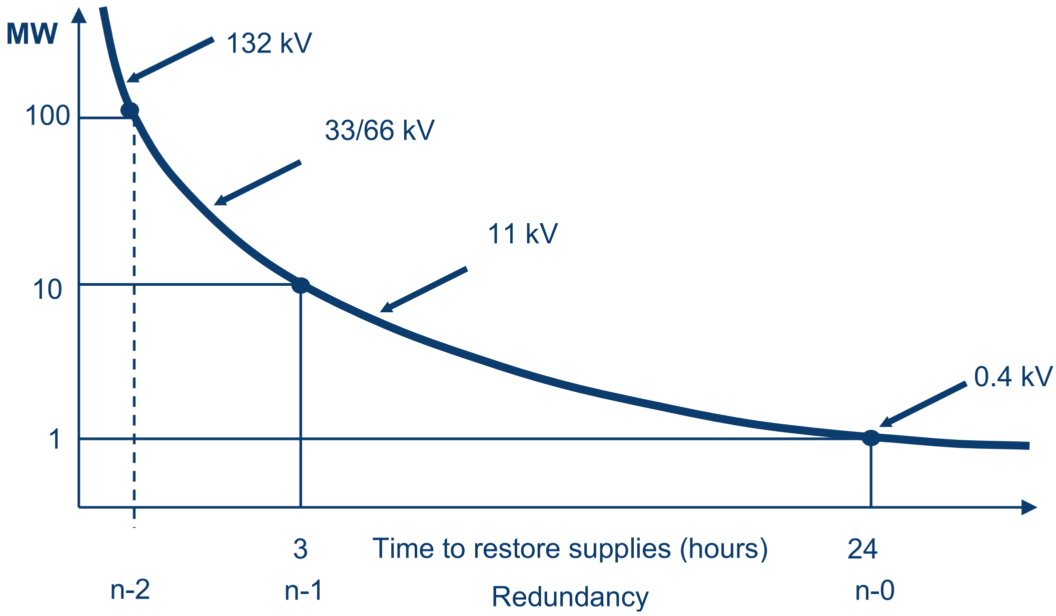
Class of Supply	Range of Group Demand (MW)	Predicted Long-Run-Average Maximum Frequency of Supply Interruptions per Year due to Outages within the Class
A	Up to 1	5
B	Over 1 to 12	3
C	Over 12 to 60	2
D	Over 60 to 300	0.5
E	Over 300 to 1500	0.2
F	Over 1500	0.1
Overall maximum for any consumer		8

3.5 Requirements of ER P2/6 –Table 1

Primary assets (transformers, switchgear, overhead lines and cables) employed on distribution networks have been specified to accommodate a set of pre-specified operating conditions, ensuring the technical parameters of supply (e.g. voltage and power flows) are maintained within statutory tolerances, without the requirement for proactive network monitoring and reconfiguration. This is a key feature of the overall philosophy of network operation/investment and is implicitly reflected in ER P2/6.

ER P2/6 broadly defines the network design philosophy and requirements to comply with the security standard are a key network cost driver. The level of security in distribution networks is defined in terms of the time taken to restore power supplies following a predefined set of outages. Consistent with this concept, security levels on distribution systems are graded according to the total amount of peak power that can be lost. A simplified illustration of this network design philosophy is presented in Figure 2. For instance small demand groups, less than 1MW peak, are provided with the lowest level of security, and have no redundancy (N-0 security). This means that any fault will cause an interruption and the supply will be restored only after the fault is repaired. It is expected that this could take up to 24 hours.

Figure 2 – ER P2/6 restoration time philosophy relative to peak network demand



Where:

- n-0 = no redundancy in security (must wait for repair of network);
- n-1 = one level of network redundancy; and
- n-2 = two levels of network redundancy.

For demand groups between 1MW and 100 MW, although a single fault may lead to an interruption, the bulk of the lost load should be restored within 3 hours. This requires presence of redundancy, as 3 hours is usually insufficient to implement repairs, but it does allow network reconfiguration activities. Such networks designs are often described as providing n-1 security. For demand groups larger than 100MW, the networks should be able to provide supply continuity to customers following a single circuit outage (with no loss of supply) but also provide significant redundancy to enable supply restoration following a fault on another circuit superimposed on the existing outage, i.e. n-2 security.

In light of this general philosophy, Table 1 of ER P2/6 specifies the minimum demand that must be met after specified circuit outages, according to the magnitude of the 'Group Demand' or 'Class of Supply'. Table 1 of ER P2/6 is reproduced in Table 7 below. A key feature of ER P2/6 Table 1 for the larger demand groups is the validity of a staged approach to restoration under second circuit outage conditions. For Demand Groups D & E under second circuit outage conditions, it is acceptable to initially restore 33% and 66% of the impacted demand. This has considerable implications for output measure performance and is evaluated further in Section 4.

Table 7 – Requirements of ER P2/6 Table 1

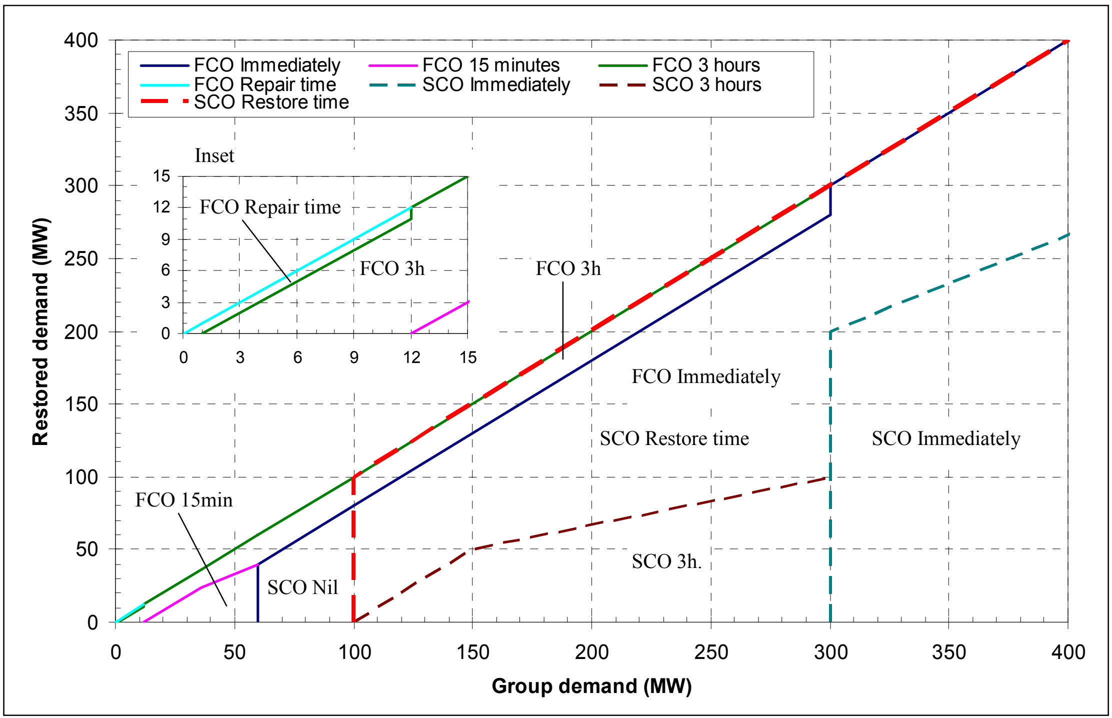
		Minimum Demand to be met after	
Class of Supply	**Range of Group Demand**	**First Circuit Outage**	**Second Circuit Outage**
A	Up to 1 MW	In repair time (Group Demand)	NIL
B	Over 1 MW to 12 MW	(a) Within 3 hours (Group Demand minus 1 MW) (b) In repair time (Group Demand)	NIL
C	Over 12 MW to 60 MW	(a) Within 15 minutes (Smaller of Group Demand minus 12 MW and 2/3 Group Demand) (b) Within 3 hours (Group Demand)	NIL
D	Over 60 to 300 MW	(a) Immediately (Group Demand minus up to 20 MW (Automatically disconnected)) (b) Within 3 hours (Group Demand)	(c) Within 3 hours (For Group Demands greater than 100 MW, smaller of Group Demand minus 100 MW and 1/3 Group Demand) (d) Within time to restore arranged outage (Group Demand)
E	Over 300 to 1500 MW	(a) Immediately (Group Demand)	(b) Immediately (All customers at 2/3 Group Demand) (c) Within time to restore arranged outage (Group Demand)
F	Over 1500 MW	GB SQSS	

Figure 3 provides a graphical representation of Table 1 of ER P2/6. The X-axis represents a Group Demand from 0 to 400 MW. The Y-axis represents the restored Group Demand following various outages. Solid lines represent the minimum of Group Demand that should be restored following First Circuit Outage (FCO). Dashed lines represent the minimum of Group Demand that should be restored following Second Circuit Outage (SCO). Line colours represent minimum time in which Group Demand should be restored. For convenience, Group Demand A and B are shown in the inset.

The interesting part of the diagram is associated with large Demand Groups. Consider a Group Demand of 200 MW. Under FCO conditions, a minimum of 180 MW should be restored immediately (solid blue line) and the remaining part of the Group Demand within 3 hours (solid green line). Following the SCO condition (fault superimposed on a planned outage situation) a minimum of 67 MW should be restored within 3 hours (dashed brown line) and remaining interrupted load of 133 MW should be restored within the time required to restore the arranged outage (dashed red line).

One of the important issues for consideration is the treatment of construction outages for large Demand Groups (above 100MW) in the event of SCO conditions arising. In this context, the diagram in Figure 3 shows that, in accordance with ER P2/6, there will be a significant amount of load, measured potentially in hundreds of Megawatts, (133 MW in the above example) that would be interrupted and only expected to be restored after the arranged outage is completed (all the load above the dashed brown line and below the dashed red line). Clearly the impact of this staged approach to restoration depends on the duration of planned outages. In an era of major network asset refurbishment and replacement, such outages could be for extended periods and the implications for customers are evaluated further in Section 5 of this report.

Figure 3 – Graphical illustration of ER P2/6 Table 1 requirements



3.6 Requirements of ER P2/6 – Table 2

Although several amendments to various sections of P2/5 have been made in P2/6 in order to ensure these sections were more appropriate to modern networks, the significant change has been the development of the approach used to update Table 2. In its place are a series of tables that allow the "effective contribution" to be related to the type of generating plant, the number of units and their availability. In addition, an accompanying computer program allows changes to be made to the assumed data so that the "effective contribution" can be made even more realistic for the system being assessed.

It must be noted however that the underpinning approach used in the development of P2/6 was that used in P2/5, i.e. EENS was the reliability measure used in the assessments. Consequently, only one of the weaknesses associated with P2/5 was addressed in the development of P2/6, all others remain.

Following the implementation of ER P2/6, planning standard compliance assessments have become more involved where security contributions from distributed generation must to be considered. By identifying network locations where compliance is marginal, the analysis of distributed generation can be restricted to these instances, i.e. initial assessments are usually based solely on network infrastructure capability. In order to accurately determine the security contributions from distributed generation, it is important for the DNO to accurately estimate the gross network demand, excluding reductions from distributed generators. This assessment requires accurate information regarding the number, ratings and operating regimes of the distributed generators within a Demand Group. One DNO commented that compliance reassessment according to ER P2/6 can be more onerous than P2/5 due to the requirement to offset the gross Group Demand with only a proportion of the distributed generation available.

The methodology used to update Table 2 determines the capacity of a perfect circuit which, when substituted for the distributed generation, gives the same level of expected energy not supplied (EENS). This capacity is the effective contribution of the generation system. This approach is identical in concept with that used in developing the present P2/5, a conclusion confirmed by the results given in the Report, which reproduce the 67% value specified in Table 2 of P2/5.

The methodology however permits a more extensive set of plant and system attributes to be considered and reflects modern types of generating units and operational modes including conventional, CHP and renewable energy units. Specifically the methodology permits the following attributes to be assessed:

- **Unit attributes**: number of units, capacity of units, technology of units.
- **System attributes**: peak load, load profile, multiple generation sites, remote location of generation sites, units not available for 24hr in a day.
- **Availability attributes**: technical availability which relates to whether the plant is in a working state, i.e. it must not have failed: energy availability which relates to whether energy is available to drive the units: commercial availability which relates to whether it is commercially available.
- **Materiality attributes**: the methodology is applicable to all generation sites irrespective of number of units and their capacity, whereas P2/5 has special considerations for one and two units particularly if these have relatively large capacities.

For intermittent generation, such as wind and hydro, the average winter output profile and the minimum persistence time T_m is used. Persistence time is the period of time for which intermittent generation will need to operate continuously at or above a certain output level in order to support the demand and provide system security. The minimum persistence time is dependent on the system state and conditions (such as switching, repair, and maintenance processes). As Table 2 of ER P2/6 indicate, the longer the time period over which a certain level of output is expected the lower the capacity contribution of the intermittent generator. For example, if the time over which the support is required is 30 minutes, 28% of the installed capacity can be “relied upon” while this value reduces to 11% for the time period of 24 hours.

3.7 Strengths of ER P2/6

The underlying network planning philosophy defined in ER P2/5 and P2/6 and reinforced through electricity distribution licences provides a robust national framework to ensure some consistency with respect to the minimum network planning requirements in Britain. This minimum requirement serves to protect customer interests with respect to security of supplies and network reliability, whilst also enabling DNOs to plan networks beyond the minimum requirement where necessary. Whilst the existence of a national standard is not a pre-requisite for secure networks, such requirements do minimise regional variations in supply security. It should be noted that in many other European countries, no national distribution network planning standards exist and DNOs develop their networks according to internal company-specific standards and guidelines.

As the British distribution network planning framework evolved over a period of more than 50 years, the requirements of ER P2/5 (latterly ER P2/6) had to be aligned with the distribution infrastructure already employed. As much of the fundamental network architecture had already been established by the 1970s (voltage levels, network redundancy, key equipment ratings etc.), the requirements of ER P2/5 had to be broad enough to accommodate a variety of network configurations and avoid deeming wide areas of network non-compliant. The adoption of a minimum standard approach thus ensured a wide range of configurations could be accommodated and avoided requirements for retrospective reinforcement. Similarly, by stipulating restoration criteria for different group demand sizes, both ER P2/5 and P2/6 avoid defining network design detail and thus provide scope for DNOs to adopt a variety of approaches, i.e. the standard is non-prescriptive in terms of detailed network design.

The specification of minimum planning requirements for different Group Demands has enabled network operators to increase the level of security provided to customers where requested or deemed economically beneficial. Historic deviations beyond this minimum standard are commonplace amongst almost all of the British DNOs, especially with respect to the smaller demand groups. For example, for Classes of Supply B and C, it is not unusual for DNOs to have the ability to restore all (rather than a proportion of) demand within the initial timescales contained within the standard, i.e. 3 hours and 15 minutes respectively). Investigations have also confirmed that most distribution networks are closely aligned with the minimum prescribed standard for the larger demand groups where requirements are more onerous, especially with respect to second circuit outage scenarios.

A particular strength of ER P2/6, cited by all British DNOs, is the clear and concise nature in which requirements are defined within Table 1 of the standard. The adoption of concise deterministic rules simplifies network planning assessments and subsequent compliance evaluations for network operators. A valid concern expressed by some DNOs relates to any future requirements to undertake more technically demanding and time consuming compliance assessments which could result in resource constraints and undermine the productivity of network planning functions. Whilst the introduction of more comprehensive techniques to determine security contributions from distributed generation (in ER P2/6) potentially complicates security assessments, the relatively slow penetration of new distributed generation has meant that experience to date has been limited.

Another claimed benefit to DNOs regarding the existence of a national planning standard (reinforced by each distribution licence) relates to network reinforcement and development requirements. Environmental concerns result in increased scrutiny of network development initiatives. The availability of a well established and easily understood (deterministic) national network planning standard can assist DNOs to demonstrate the necessity of their network development priorities.

A consequence of the long asset lives associated with most primary distribution assets (typically >40 years) coupled with planning criteria requiring the provision of differential levels of network redundancy relative to group demand size, is that DNOs must adopt long-term and sustainable perspectives when planning networks to accommodate future load growth within the ratings of primary equipment.

In addition to assisting the planning functions of DNOs, ER P2/6 also provides a benchmark for regulatory authorities when assessing DNO investment forecasts. As all DNO network investments should be consistent with the planning standard, it provides the regulator with a reference point from which value insights can be obtained, i.e. how much network is being provided for particular levels of investment.

Over the past 30 years, the electricity distribution networks of Britain have delivered secure and reliable supplies to customers. This performance is directly related to the network planning and operating practices of the DNOs. The distribution network performance indices for Britain compare favourably with the networks from other developed countries (as shown in Section 4). Consequently, it can be inferred that ER P2/5 and ER P2/6 have been effective in delivering secure networks to date. The key issue to be addressed going forward is whether these standards will remain fit-for-purpose in the future as customer expectations develop, network usage patterns change, asset replacement programmes escalate and with increases in the aggregate capacity of distributed generation.

3.8 Limitations of ER P2/5 and ER P2/6

As discussed above, although ER P2/5 and P2/6 were intended to provide a consistent distribution network planning framework, this cannot always be achieved. The most significant reasons for variations are outlined in the following sections.

3.8.1 Frequency of interruption

ER P2/6 specifies the duration of interruptions but does not specify frequency. Anecdotal information suggests that frequency was intended to be part of the standard at one stage of development but that this was deleted before P2/5 was approved. An indication that this was intended can be inferred from ACE Report 51. Appendix F of ACE Report 51 includes maximum limits to frequency of interruptions, the number of which decreases as the Group Demand increases; ranging between 5 int/yr for Group Demands up to 1MW and 0.1 int/yr for Group Demands over 1500MW.

In addition, some in the industry have argued that frequency is considered implicitly in some instances because P2/6 states that Group Demands greater than 60MW must be reinstated “immediately”, implying that, although a circuit outage has occurred, an interruption is not seen by the end-customer. However, “immediately” is defined as: “loss of supply should not exceed one minute”. Consequently the interruption is seen and customers do experience loss of supply, even if the DNOs need not count it.

One possible reason for not including interruption frequency in ER P2/5 was that frequency and duration would have to be assessed differently. Durations are post-interruption and can be controlled and managed by engineering personnel to a very great extent. Consequently, the durations in P2/5 and P2/6 are simply specified values and appropriate resources can be planned or provided to achieve these and do not require any reliability assessments to be made. These assessments were undertaken in the 1970s using the computer programs mentioned previously to determine acceptable and achievable values of duration. Conversely, frequency of interruption is a random event, not controlled or managed by engineering personnel. Frequencies can be specified in tables of a security standard, but how these are considered and compared during the planning process requires assessment of the reliability of the network being considered, and typically requires computer modelling or simplified reliability evaluation techniques. This restriction may have been a constraint during the 1970s, although is far less relevant today.

A useful development of the current network planning framework (from a customer perspective) would be to specify maximum expected interruption frequencies. Ideally, it would be helpful for the planning standard to contain such guidance as in ACE Report 51. However, the licence compliance implications of such inclusion may present a barrier, and thus favour alternative approaches, e.g. inclusion in future Guaranteed Standards or incentive arrangements. Before incorporation within the planning framework, it will be essential to determine appropriate interruption frequencies through further modelling and analysis.

3.8.2 Deterministic assessments

ER P2/5 and ER P2/6 are deterministic standards and therefore do not account explicitly for the stochastic variations of interruptions. This is often misunderstood and ER P2/5 and ER P2/6 are sometimes regarded as probabilistic standards. There is no doubt that the Electricity Council sought to take account of the probabilistic nature of system failures in a more formal way and did adopt reliability evaluation techniques and computer programs to decide upon the values specified in Tables 1 and 2 of ER P2/5. However, although these values may be based on reliability evaluations, they are used deterministically without recognising the stochastic nature of system behaviour. For example, the values are equally applicable to the system in the north of Scotland which operates in an adverse environment and with a low customer density, and to the urban area of London which operates in a favourable environment and with a high customer density.

3.8.3 Reliability criteria.

In the 1970s and subsequent years, the electricity industry regarded Expected Energy Not Supplied (EENS) to be the most appropriate index for assessing reliability[10]. The main reason was that it was a severity index dependent on frequency, duration and load, and hence incorporated the three primary reliability parameters. It was also an index to which the electricity supply industry placed a monetary value, namely a reinforcement scheme could be justified if the implied cost[11] was between acceptable limits. Anecdotally, the range of implied cost varied between £0.50 - £3/kWh saved by the scheme. Consequently EENS was used in the development of P2/5 to determine the values that should be included in both Tables 1 and 2. There is now concern that this index may not be appropriate and indices based in some way on frequency and duration may be more appropriate. Examples of using "implied cost" are described in ACE Report 51. A high-level evaluation of different proxy suitability is provided in Section 4.

3.8.4 Network parameters

Despite the objective of establishing "consistency" in system design, a set of deterministic parameters as in Table 1 of ER P2/6 do not necessarily ensure customers are treated on an equal basis. Examples of network parameters and components which prevent consistency include:-

- Cables compared with overhead lines;
- Heavy construction compared with light;
- Short lines compared with long ones;
- Calm environmental locations compared with adverse;
- Urban areas compared with rural; and
- Valleys compared with hilly regions.

In all these cases, the former will always have a lower failure rate than the latter.

10 ACE Report 51 states 'The most useful indicator of the loss of supply to consumers, when evaluating reliability of supply investment, is considered to be expected energy not supplied when required, measured as "kWh lost"……….If a planned system reinforcement affects the network, it is convenient to term the predicted change in energy not supplied "kWh saved".'.

11 Implied cost is defined in ACE Report 51 as $(C_a + C_m – S_l)/ E$ where the numerator is the cost of not deferring the reinforcement for one year and the denominator is the expected kWh saved in the first year as the result of the reinforcement (C_a = capital component, C_m = operation and maintenance component, S_l = savings in system losses, E = energy saved).

3.8.5 Market liberalisation considerations

As has already been discussed, the principles underpinning ER P2/5 and P2/6 were established in the pre-privatisation era of the British Electricity Supply industry and have not been amended since market restructuring. These principles assumed that one party would be responsible for the planning, design, specification, implementation and subsequent operation of the relevant distribution assets.

With the arrival of competition in connections and the emergence of independent distribution network operators, the requirements for 3rd parties to interface with the ex-PES DNOs has increased, especially with respect to LV network development. In situations where independent 3rd parties are responsible for network developments, competitive pressures can incentivise low initial capital cost designs, especially where the local ex-PES DNO is subsequently expected to adopt assets installed by the 3rd parties.

From a compliance perspective, such low-cost approaches align with the minimum planning standard although may not be optimised from the life-cycle cost and network security perspectives. It should be reiterated that for these Classes of Supply, many of the ex-PES DNOs have historically planned beyond the minimum standard.

Taken to the extreme, the long-term implications of low (initial) cost approaches is that network security may be lower than for other equivalent customers with a DNOs authorised area, network performance could also be lower (losses, fault restoration), whereas maintenance requirements may be increased.

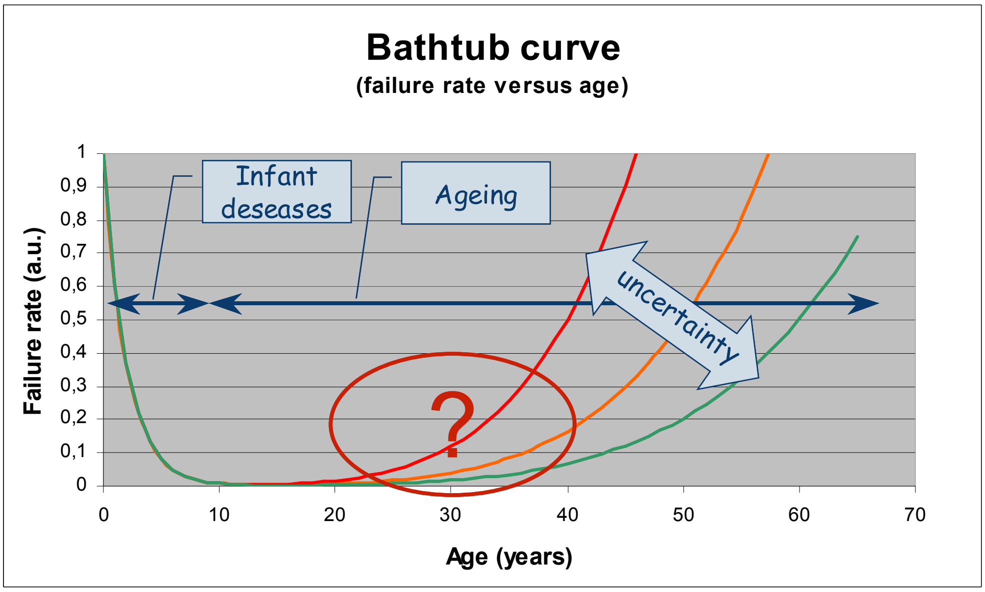
The commercial drivers associated with competition incentivise network designs more closely aligned to the minimum planning requirement. These developments could potentially erode the security of supplies to customers in future, albeit in an invisible manner to customers and the regulator. Some ex-PES DNOs have established guidelines for 3rd party network installations to ensure an element of consistency with other customers within their authorised areas.

The fundamental question associated with this issue relates to the level at which the minimum planning requirement has been set historically and whether this remains appropriate for the future in a liberalised market environment, i.e. is the minimum planning requirement as currently specified in ER P2/6 appropriate for customers now or in future?

3.8.6 Network failure characteristics

As the planning standards were not intended to address operational considerations, variable network component failure characteristics and fault rates are not considered in the methodology underpinning ER P2/5 (and hence P2/6). Figure 4 illustrates the classical ‘Bathtub’ curves for network component failure rates with a period of increasing uncertainty emerging towards the end of the asset life. Considerable work can be undertaken to reduce such uncertainties based on sampling techniques and statistical analyses to assist replacement prioritisation. However, the asset condition assumptions adopted in the planning standards relate to the centre section of the bathtub curve which is characterised by low and predictable failure rates.

Figure 4 – Typical variations in equipment failure rates over time



As many of the assets employed on distribution networks are now over 40 years old, the uncertainties associated with asset failure rates are becoming more uncertain, and thus the assumption of low and predictable failure rates is becoming less valid. These considerations could undermine security of supply with respect to both planned and unplanned outages.

As all British DNOs are currently accelerating their asset renewal programmes, it is relevant to consider security of supply considerations during extended construction outage periods rather than the 'maintenance' outages assumed in ER P2/6. This issue is explored in more depth in Section 3.10.

3.9 Operational implications of planning standards

As stated previously, ER P2/5 and P2/6 are network planning standards, not operational ones. Therefore they predetermine a design, rather than monitor its operation. This is an important distinction. A planning standard simply implies that, if the design conforms with a specified set of conditions, then the designer has satisfied the standard. This does not mean that these conditions will be satisfied under all operational circumstances. If violations occur during the operational phase then perhaps one or more operational standards will not be satisfied, but this does not mean the design standard has been violated. Violations could mean that the embedded generation was insufficient at that time, or that insufficient network capacity was available due to the network outage being greater than assumed in the design standard. It follows that the design standard is intended to minimise these violations, not necessarily to eliminate them.

3.10 Practical application of ER P2/6 and compliance

A number of practical considerations have emerged with respect to the application of ER P2/6 in recent years. These primarily relate to:

- Network loading assumptions; and
- Definitional ambiguities.

3.10.1 Network Loading Assumptions

ER P2/5 and ER P2/6 require consideration of peak network loading scenarios to determine compliance with the planning standard. Historically, the peak loading condition was aligned with Average Cold Spell (ACS) conditions and a significant difference was assumed between the maximum and minimum seasonal network loadings.

For a number of DNOs, there has been a requirement to revisit the validity these critical network loading assumptions. In the South of England and especially in urban areas, the rapid growth of air conditioning loads has resulted in the emergence of summer rather than winter peak load scenarios. Such changes in asset utilisation can be significant as the thermal rating of equipment reduces with rising ambient temperatures. This becomes more pronounced during prolonged hot spells in city centres due to the ‘heat island’ effect undermining dissipation. The emergence of summer peak loadings effectively changes the critical load scenarios assumed by ER P2/6 and some DNOs have already started to plan on this basis. Consequently, there is a strong argument that the planning standard should not specify when the peak loading condition may arise. Investigations in the Dutch market have confirmed that it is the DNOs responsibility to determine the critical load scenarios impacting networks and then to plan accordingly.

An implication of summer load growth is increased asset utilisation with smaller differences between the summer and winter peak loading conditions. Whilst higher overall asset utilisation may be regarded as a positive feature of changing energy usage patterns, operational complexities associated with outage planning can arise. Historically DNOs could rely on reduced network demand during the summer months to schedule outages whilst maintaining a high level of network security, especially for the largest Classes of Supply. Increases in summer loading thus utilise capacity on the circuits retained in service during outage periods and potentially reduce network security.

A useful development of the current planning standard would be to make DNOs responsible for assessing the critical network loading conditions relevant to their networks. In reality, such an amendment would serve to reflect current DNO practice and remove a potentially inaccurate assumption regarding the timing of peak loadings.

3.10.2 ER P2/6 definitional ambiguities

3.10.2.1 Group Demand

The planning requirements defined in ER P2/6 are dependent on the Class of Supply under consideration. Class of Supply is directly linked to the magnitude of the associated Group Demand (<1 MW, 1 – 12 MW, 12 – 60 MW etc). However, Group Demand is not defined in the planning standard so interpretation depends on local practices and network topology.

In instances where networks are predominantly radial with relatively little interconnection, the determination of Group Demand is usually straightforward. Where networks are meshed or highly interconnected, the definition and monitoring of Group Demands requires judgement on the behalf of the DNO. This uncertainty regarding the magnitude of Group Demands is greatest for the largest Group Demands on a DNO system, i.e. EHV distribution assets.

Planning requirement ambiguities can arise in circumstances where maximum Group Demands are close to the thresholds separating Classes of Supply or where load growth has resulted in a threshold being exceeded. In such situations, network security provision becomes dependent on the boundaries between different Classes of Supply, transfer capacities, critical loading conditions, availability of security contributions from distributed generation and frequency of compliance assessment by DNOs.

Where load growth or compliance reassessment could result in the reclassification of a Group Demand between different Classes of Supply, the financial and investment implications to the DNO can be considerable. This is especially relevant in circumstances where peak Group Demands are close to the Class A-B or Class D (>100 MW) – Class E boundary. In both instances, the network implications can be profound due to the emergence of new n-1 and n-2 planning requirements respectively. Consequently, during assessments where Group Demands are close to Class of Supply thresholds, the network reinforcement requirement can be dependent on the local interpretation of Group Demand.

The extent to which DNOs reassess compliance with ER P2/6 varies. As far as can be determined, all DNOs identify areas within their networks where compliance is becoming marginal and emphasis is placed on monitoring these locations. Compliance assessment techniques include analysis of feeder-level current data, annual half-hourly energy flow tracking and load forecasting. Other DNOs adopt an approach to compliance linked to emergent network development requirements, i.e. compliance is reassessed when there is a requirement to extend or reinforce networks. Some DNOs have indicated that historically, examples of marginal non-compliance would be monitored for a period of 12 months or more to ensure the validity of the initial assessment. However, one DNO indicated that this approach may now be less attractive due to equipment lead times and outage scheduling.

In order to improve transparency and to clarify the compliance requirements of ER P2/6 for network operators (including transmission) and the regulator, it would be helpful for representatives of all the relevant stakeholders to establish agreed definitions of Group Demand boundaries for inclusion in a revised planning standard or other appropriate industry documentation.

3.10.2.2 Transfer capacity

The ambiguities relating to Group Demand definitions in meshed networks also apply to Transfer Capacity. In instances where network security assessments indicate marginal compliance with the planning standard, DNOs must then consider the availability of transfer capacity from other Demand Groups. In circumstances where networks can be interconnected, the definition of what constitutes transfer capacity is unclear. Similarly where potentially interconnected networks are being assessed, a relevant consideration relates to whether a single demand group is being considered or alternatively multiple demand groups with significant transfer capacity. As for Group Demand definitions, clarifications and guidance within the planning standard could represent a useful development.

A separate issue relating to the availability (and use) of transfer capacity has emerged at the interface with the transmission system. On occasion, the Transmission System Operator (TSO) can request the use of Extra High Voltage (EHV) transfer capacity on distribution systems. Whilst not strictly a planning issue, requirements for DNOs to provide such transfer capacity could benefit from clarification to ensure that the overall risks apparent to both network operators (and the corresponding customer groups) are clearly understood. Such a combined approach should ensure that risk mitigation is optimised between respective parties. Some DNOs have indicated concern that the provision of EHV transfer capacity to the TSO can sometime reduce security to downstream customers and also increase DNO risk exposures. Whilst this issue is perhaps best resolved outside the distribution planning standard, clarifications of the interface requirements between DNOs and the TSO could benefit customers by ensuring that network security risks are optimised in advance of any network reconfiguration.

3.10.2.3 Outage classification and duration

In addition to the outage management complexities caused by the capacity headroom reduction associated with changes in energy usage, further difficulties can arise for DNOs with respect to outage scheduling and management.

As outlined in Section 3.8, both ER P2/5 and ER P2/6 appear to assume periods of stable network reliability where network outages are only required for maintenance and short-term fault restoration. Consequently, the assumptions for Classes of Supply D and E, is that outages will be maintenance related and any supply interruptions to customers will be short. For both of these Supply Classes (>100 MW, i.e. circa 100,000 customers), networks remain compliant during a second circuit outage condition, even where 33% of customers may remain off supply for the duration of an outage. Whilst this may be appropriate for short-term maintenance outages, the risk of prolonged supply interruption quickly escalates in line with outage duration.

The acceleration of major asset replacement programmes introduce risks not envisaged when the planning standards were developed. Typical asset replacement initiatives underway at present involve overhead line re-conductoring, transformer replacements, cable replacements and substation refurbishments. All such works potentially require longer construction outages on circuits than simple maintenance, thus exposing potentially large numbers of customers to an increased risk of loss of supply unless the DNO establishes comprehensive contingency measures at the outage planning stage for the emergency restorations.

The development of mitigation techniques to avoid losses of supply to large numbers of customers for extended periods could require DNOs to increase holdings of strategic spares, make more frequent use of temporary overhead line structures and becoming more reliant on off-line build approaches (especially for substations). Investigations in the Dutch market have revealed a Grid Code requirement which explicitly addresses this issue of prolonged second circuit outages during the construction periods. At the highest distribution voltages, partial losses of supply are only acceptable for periods of up to 6 hours maximum. For more extended periods, Dutch DNOs face an onerous and potentially costly requirement to maintain at least n-1 network security for the duration of any construction outage. In many instances this requires the DNO to erect temporary lines as contingency measures.

The lack of differentiation between construction and maintenance outages in British distribution planning standards appears a significant shortcoming approaching an era of considerable asset replacement. The possibility of second circuit outages taking days (possibly weeks) to rectify for the larger demand groups is regarded as credible, especially when reliant upon heavily loaded ageing assets. The risks of such events are further explored quantitatively in Section 5 to demonstrate the requirement to explicitly acknowledge such scenarios within future planning standards in order that the security risks to customers during extended network outages (especially at EHV) can be mitigated.

3.10.3 Network evolution paths

ER P2/6 does not provide details of specific network designs required for the delivery of the prescribed security levels.

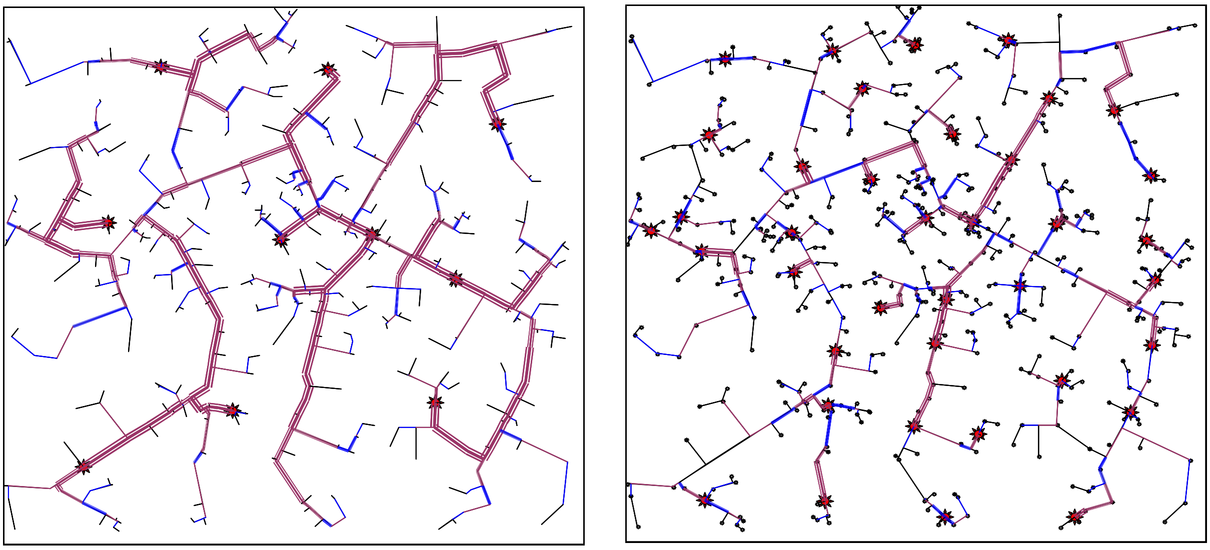
After WWII, the British electricity supply industry expanded significantly to support economic development. A variety of different distribution network designs, planning and expansion philosophies were adopted in different regions. These range from fully radial systems comprised of 132kV, (66kV) 33kV, 11kV (6.6kV) and LV (there are also some small segments of the network that operates on non-standard voltages) to networks that use direct 132/11 kV transformation or networks that operate meshed at both 11kV and 0.4kV. All these different designs philosophies meet ER P2/6.

Clearly, ER P2/6 allows a variety of network designs that may result in different cost, losses and reliability performance profiles. To illustrate this feature of ER P2/6 a high-level exercise that contrasts two different network design strategies was undertaken. A generic distribution network planning tool was used to analyse the performance characteristics of two alternative design approaches for supply of a typical urban distribution network: (i) application of direct transformation of 132/11kV used to supply the 11kV network, and (ii) a design in which the 11 kV network is supplied via 33/11kV substations (that are supplied from 132/33kV substations). The position of 11/0.4kV substations, layouts of HV and LV network layouts are identical in both cases. These are presented in Figure 5.

Figure 5 – Alternative design strategies to supply an urban 11kV network (i) through direct transformation 132/11kV and (ii) using 33/11kV substations (supplied by 132/33kV substations)

HV Network supplied from 132/11kV substations

HV Network supplied from 33/11 KV substations



The area studied covers an urban area with load density of 5MVA/km^2 of area 7x7 km^2. Given the differences in rating between 132/11kV and 33/11kV substations, there will be approximately 4 times fewer substations (denoted by stars in the above diagrams) in case (i) than in the case of the application of a 33kV level. As a result, 11 kV feeders in case (i) will be longer and will supply larger numbers of customers (and hence be more heavily loaded) than for case (ii). These length and loading considerations will tend to undermine quality of supply characteristics and cable losses, but should be less capital intensive due to avoidance of the 33kV voltage level and reduced number of substations.

Results are summarised in Table 8 that presents equipment costs (including maintenance costs), cost of losses and the total costs. Cost of equipment consists of cable installation costs, which include cost of digging trenches, laying and connecting the cables; purchasing costs of cables, which are given for different cable cross-sections (95, 185 and 300 mm^2) and cost of substations, which include cost of transformers and cost of accompanying equipment (circuit breakers, fuses, protection, etc.), labour and maintenance cost. The total network losses are composed of losses in cables and of losses in transformers (which are further divided into fixed and variable losses). The total cost is the sum of all these components that are then annuitised and expressed as £/year.

From the results it can be seen that the cost of the LV network dominates overall costs for both designs. This is due to extensive LV feeder lengths and the number of distribution substations involved. Since there are more substations in network (ii), cables used will be less loaded and will have a smaller cross-section area when compared with cables in network 1 (which leads to a slightly reduced cost of cables when compared to network (i). Regarding the cost of substations, it is important to consider that the cost of substations has a significant fixed cost component.

Losses in cables in network 1 to network 2 are very different. As indicated, large numbers of substations lead to shorter feeders, fewer consumers per feeder, hence, lower current and hence lower losses. However, due to the increase in the number of substations, transformer losses also increase (especially Iron losses). Therefore, network (ii) has overall higher losses since it has higher number of transformers even though these are of lower ratings than in network (i).

The total length of the 33kV network required to connect all 33/11kV substations was estimated and the costs of cables (installation and purchase cost of cables) was estimated. This was added to the total cost of the network (ii) in order to evaluate the costs of direct transformation from 132kV to 11kV.

Table 8 – Comparison of key characteristics of the two alternative network design approaches

		Network (i)		Network (ii)	
		Quantity	Cost (£/year)	Quantity	Cost (£/year)
Density (MVA/km^2)		5		5	
Consumers		2,127,600		2,127,600	
Consumption (MWh)		10,746,987		10,746,987	
LV	Cable length (km)	19,030	69,522,600	19,030	69,522,600
	Annual losses in cables (MWh)	95,500	3,025,800	95,500	3,025,800
	Substations per km^2	10		10	
	Number of substations	5,000	9,519,800	5,000	9,519,800
	Total annual losses (MWh)	126,700	3,634,100	126,700	3,634,100
	Total		**85,702,400**		**85,702,400**
HV	Cable length (km)	1,091	5,473,921	1,091	4,566,342
	Cable annual losses (MWh)	10,327	332,513	3,358	106,860
	Substations per km^2	0.2		0.8	
	Number of substations	100	4,399,782	380	7,188,972
	Total annual losses (MWh)	52,710	1,577,958	80,145	2,268,653
	Total		**11,784,175**		**14,130,827**
33 kV	Cable length (km)			660	4,012,400
	Total				**4,012,400**
Total	**33kV + HV**				**18,143,227**
Total	**33kV + HV + LV**		**97,486,575**		**103,845,627**

Using this modelling approach and converting the annuitised cost estimates, it was found that the overall asset cost of network (i) was less expensive then network (ii) by approximately £64m.

In order to compare the CI and CML performance of the two networks we assume the average length of feeders in network (i) is about two times longer than in network (ii). Furthermore it is assumed that both networks have the same number of fault breaking devices. In network (ii) fault breaking devices are deployed only in the EHV/HV substation while in network (i) one mid-point circuit breaker is also installed. One mid-point fault breaking device reduces CI and CML to 75% of the original values. Given that longer feeders on average have two times more customers the CI and CML for network (i) are about 50% more than for network (ii). The results of such calculation are presented in Table 9. In this particular case the CI and CML for network (i) are about 40% more than for network (ii). A cable failure rate of 0.5 faults/year.km was assumed.

Table 9 – Estimated ECI and ECML

HV parameters	Network 1	Network 2
Number of consumers	2,127,600	2,127,600
Cables length (km)	1091	1091
Number of substations	100	380
Number of feeder per substation	6	3
Average feeder length (km)	1.82	0.957
Average number of consumers per feeder	3546	1866
Contribution of HV network to CI (i./100c.y.)	6.8	4.8
Contribution of HV network to CML (m./c.y.)	4.1	2.9

4. Network performance output measures

4.1 Background

Network operators have been required to assess the past performance of their networks in terms of specified parameters and quantitative measures since privatisation. These have been used to identify how well DNOs satisfied customer expectations, to compare system performances against set targets, and to enable comparison of the performances between individual companies. The specified parameters were designated originally by the two terms: Security and Availability. The corresponding measures for quantifying these terms are Customer Interruptions (CI) and Customer Minutes Lost (CML)[12] as discussed in Section 2.3. These terms and indices are now used extensively by Ofgem and DNOs at system level and for particular parts of the system, as a means for comparing companies, for comparing different parts of a specific company (e.g. urban with rural), and for assessing the impact of implementing alternative schemes and strategies.

These indices are established metrics in the UK electricity market. However, similar indices were already in use in power system reliability: these originally being defined in North America and used subsequently around the world. These indices are known as SAIFI, SAIDI, etc, where:-

- SAIFI: System average interruption frequency index
- SAIDI: System average interruption duration index

SAIFI is equivalent to Security and CI, and SAIDI is equivalent to Availability and CML. It should be noted that these North American terms do not include "customer" in the index, only "system". This is an important difference, since system indices are not strictly load point (or customer) indices, although they are clearly customer-oriented. This distinction is discussed in the next section.

4.2 Load Point and System Indices

The three primary indices associated with power system networks are: failure rate (or frequency[13]), outage duration and annual unavailability (or outage time) of each load point in the system. These indices[14] can be measured (for past performance) or evaluated (for future performance) for each load point. All such indices are not deterministic values but are expected or average values of an underlying probability distribution, which is generally unknown, and therefore these represent only the long-run average values.

12 These measures are the complementary values for the terms being quantified, e.g. as Availability increases, the corresponding measure (CML) decreases.

13 Rate and frequency are conceptually different, although numerically very close for power system networks.

14 Generally, the value of rate is evaluated for future predicted performance but deemed to be equal to frequency, and the value of frequency is directly assessed for past performance.

These three primary indices are fundamentally important, particularly to individual customers, and form the base values from which further indices are evaluated. However they do not give a complete picture of system behaviour or, importantly, the severity of interruptions. For instance, the same values would be evaluated irrespective of the number of customers or the level of demand at a particular load point. For this reason, additional indices have been defined and both can be measured and evaluated.

When evaluated for each load point, these additional indices are also load point indices, but assess the severity of interruptions at each load point. The UK supply industry, during the latter part of the 20th century accepted five load point indices; these being failure rate (frequency), outage duration, unavailability (annual outage time), average load interrupted and expected energy not supplied (EENS).

Additional indices can also be evaluated for the system or part of the system, such as for a Group or a feeder or set of feeders. These are known as system indices, because they assess how the overall system or part of the system behaves. These are evaluated from load point indices and include customer-oriented indices (such as SAIFI, SAIDI, CI and CML) and load/energy-oriented indices (such as average load interrupted and EENS). These indices are listed in Table 10.

Table 10 – List of Load Point and System Indices

Type of Index	Load Point Indices	System Indices
Frequency	Failure rate or frequency	CI or SAIFI
Duration	Outage duration	CML/CI or CAIDI
Duration	Unavailability/annual outage time	CML or SAIDI
Load	Average load interrupted	Average load interrupted
Energy	Expected energy not supplied	Expected energy not supplied
"blue" = customer indices, "red" = company indices		

The following points should be noted:-

- Load point indices represent the average behaviour of individual load points. Therefore the relevant frequency and duration indices represent the impact of system behaviour on the individual customers attached to that load point.

- System indices are aggregated indices that represent the average behaviour of that part of the system that has been aggregated. They are evaluated from the indices of the load points included in the aggregation. Therefore the relevant frequency and duration indices represent the impact of system behaviour on the "average" customer of that part of the system – a customer who does not really exist

- Load point frequency is identical to the CI at that load point. Similarly load point unavailability is identical to the CML at that load point.

- Real individual customers are only concerned with the number and duration of the interruptions they experience, or are likely to experience. They are not concerned with the load they did not impose on the system or the amount of energy they did not consume during interruptions. Therefore they are only concerned with the first three load point indices listed in the second column of Table 10.

- The remaining load point indices and all the system indices listed in Table 10 are of interest only to the DNO and regulatory bodies.

4.3 Strengths of CI and CML

CIs and CMLs have now been evaluated for some 16 years in the British supply industry and these indices serve a valuable purpose in monitoring system behaviour and also in assisting in predicting future system behaviour. This confirms and aligns with the international acceptance and use of SAIFI and SAIDI. These indices have enabled the regulator and DNOs to:

- comparing and rank different companies;

- comparing different investment strategies;

- comparing different reinforcement and design strategies;

- comparing different maintenance strategies; and

- comparing different parts of a system or different feeders within a system, e.g.:- urban areas and rural areas.

CIs and CMLs therefore form a powerful set of indices for the management and strategic development of distribution networks. The implementation of incentive arrangements for CIs and CMLs has delivered significant improvements to the quality of supply experienced by the average customer connected to a DNO network. This performance improvement is explored further in Section 4.4. However, it should be recognised that the CI/CML framework is not suitable for all quality of supply related applications as explored further in Section 4.5.

4.4 Impact of IIS on network design and operation

4.4.1 System design and performance

As discussed earlier, ER P2/6 does not require network redundancy at low voltage (LV) and the duration of outages caused by LV faults is determined by component repair and replacement times. High Voltage (HV) networks are generally designed as meshed but operated in radial mode. The consequence of this design feature is that, generally, faults on the HV network will cause interruptions to some customers although the network configuration enables restorations to be implemented rapidly, within 3 hours, as required by ER P2/6. Networks operating at EHV are designed to be operated in a meshed configuration, so that single faults would not normally lead to an interruption to end customers.

These network design practices, driven by ER P2/6, effectively determine quality of service characteristics as experienced by end customers. The impact of these design practices is reflected in the network performance statistics. Figure 6 and Figure 7 summarise the distribution of Customer Interruption (CI) and Customer Minutes Lost (CML) according to voltage level.

Clearly, the performance of medium and low voltage networks has a dominant effect on the overall quality of service. The vast majority of CIs (about 85%) and CMLs (about 90%), have their cause in LV and HV networks. In GB, the average number of CIs is approximately 85 for every 100 customers each year. For CMLs, the average figure is approximately 85 minutes per annum. These statistics are primarily driven by the radial design of these networks.

Figure 6 – Average proportion of Customer Interruptions by voltage in GB 2005/2006

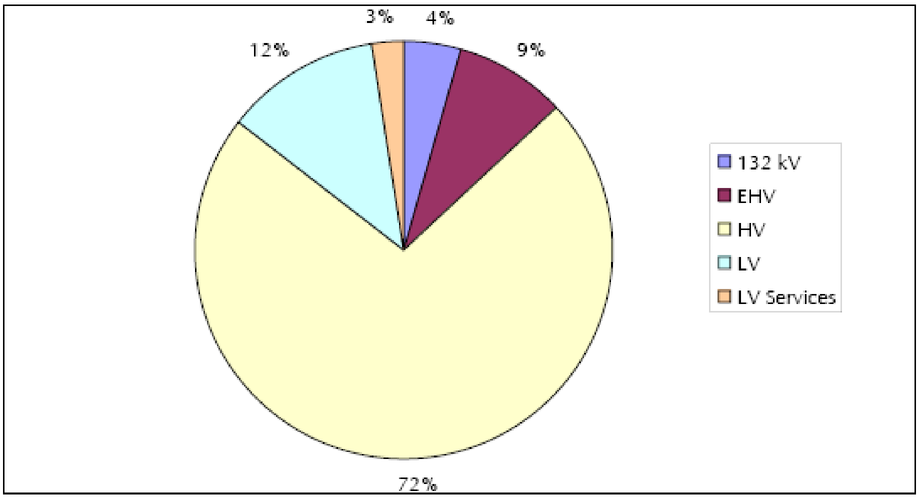
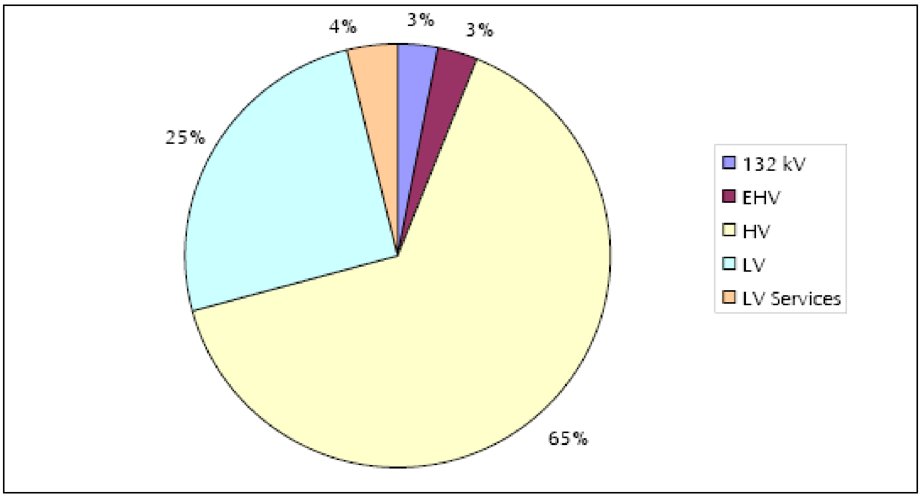


Figure 7 – Average proportion of Customer Minutes Lost by voltage level in GB 2005/2006



IIS targets incentivise DNOs to reduce the average number of CI/CMLs on electricity distribution networks. Consequently, DNOs evaluate the regulatory target and incentive framework to determine the most costs effective methods of achieving quality of supply improvements. DNOs model IIS related investments to prioritise the most effective quality of supply related initiatives to be pursued during a particular price control period. Should regulatory targets or incentive rates change, the scale and investment priorities also change accordingly. Once a DNO has established the hierarchy of IIS related investments (usually early in a price control period) it is advantageous for the DNO to implement these initiatives promptly to maximise future revenues and performance, subject to resource constraints.

Features of the IIS have prompted consistent network investment strategies amongst DNOs. As customer interruptions need only be logged where these exceed 3 minutes in duration, it is advantageous to restore supplies rapidly through network automation and remote control, particularly for HV circuits. Whilst the impact of a 2 minute interruption to a customer will be virtually identical to a 4 minute interruption, this distinction is highly significant to a DNO in terms of CI performance. Another benefit of network automation and remote control is that it also improves CML performance. The ability to concurrently improve both CI and CML performance has influenced DNO investment priorities and resulted in the widespread deployment of secondary assets on HV networks, i.e. quality of supply performance improvement has not required significant investment in primary assets (yet).

As ER P2/6 does not require network redundancy for LV circuits, supply restoration is usually dependent on the time taken to effect repairs to the network. Such repairs obviously require manual intervention on the part of DNO (or contractor) personnel. Consequently, CML performance improvements associated with LV distribution require responsive and flexible field-based capabilities focussed on supply restoration.

To date, DNO IIS related investments have sought to address the most effective 'quick-wins' in terms of performance improvement. These investments have been predominantly focussed on HV network automation and remote control. After exhausting such HV automation opportunities, it will be logical to address LV network performance improvements although such investments may be more costly due to requirement to reconfigure (and potentially duplicate) primary assets. The extent to which DNOs will pursue such strategies in future will depend on the level of targets and incentives rates. As opportunities for such 'quick-wins' diminish, the setting of appropriate cost-reflective targets will become an increasing challenge for the economic regulator.

Since implementation, the IIS has focussed DNO attention upon HV (and to lesser extent LV) networks. This has resulted in many LV and HV circuits being designed beyond the ER P2/6 minimum requirement. By contrast, there is less scope to effect IIS performance improvements through investments in EHV networks. This is attributable to the high reliability of such networks arising as a consequence of ER P2/6 redundancy requirements and extensive network automation. Quality of supply related incidents arising from EHV networks are therefore regarded as low probability: high impact events relative to HV/LV networks. Consequently, it can be concluded that the IIS has been particularly influential with respect to HV/LV network design, whereas EHV design has tended to be driven by planning standards. For a significant proportion of LV and HV networks, the requirements of ER P2/6 have effectively been superseded for Classes of Supply A, B and C.

A potential future risk associated with reliance on an incentive scheme for network design is that a disproportionate focus could be placed on short-term network performance. Such incentive arrangements adequately address frequent low impact interruptions. However, such arrangements do not adequately address low probability high impact events typified by the larger Demand Groups. Consequently, over-reliance on quality of supply incentive schemes to influence network design could be to the detriment of long-term EHV network planning and security of supply to customers.

4.4.2 Evolution of quality of supply performance in GB

Historically, quality of supply was regulated through the Guaranteed and Overall Standards of performance. Guaranteed Standards entitle consumers to compensation for receiving service below specified thresholds, while the Overall Standards monitored system level performance for each distribution company. Consequently, significant progress was made with regards to quality of supply. Between 1990 and 2002:

- national average CIs fell from 123.6 to 85.5; and
- national average CMLs fell from 229.3 to 83.2

Information and Incentive Project was first introduced in April 2002 to set each DNO with specific targets for the quality of supply measures CI and CML based on individual DNOs' past performance. The initial IIP incentive scheme, linked the quality of supply performance of DNOs to their allowed revenue (+/-2% of exposed revenue) applied from 1 April 2002 to 31 March 2005. The IIP included mechanisms that penalised companies for not meeting their quality of supply targets and rewarded companies that exceed them. The introduction of the IIP resulted in a significant improvement in network reliability performance in Britain as shown in Figure 8 and Figure 9.

Figure 8 – Illustration of improving average CI performance for all DNOs 2001 -2006

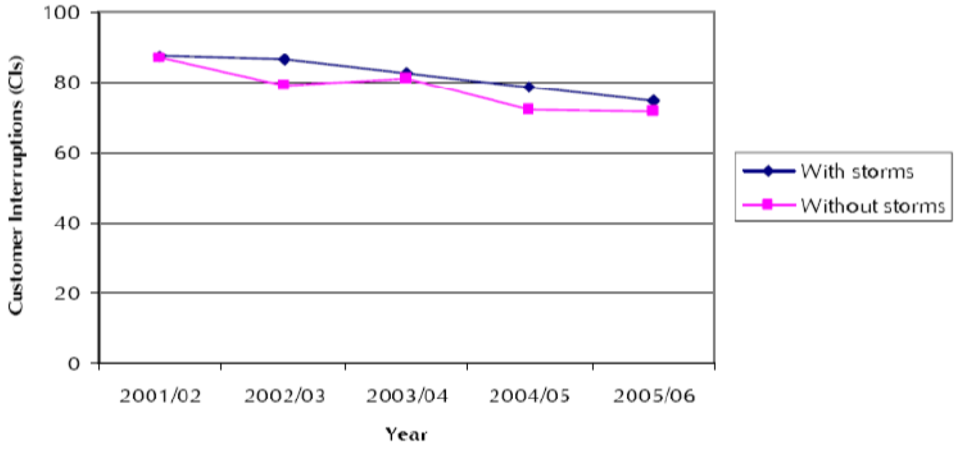
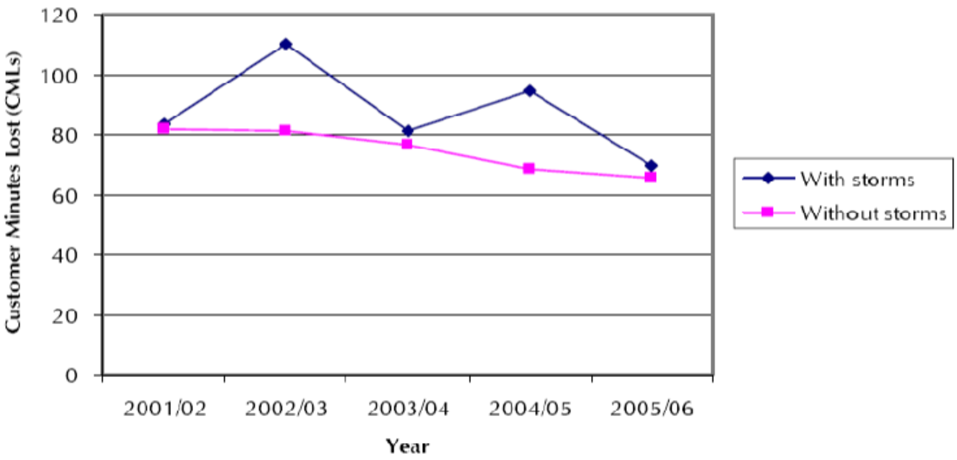


Figure 9 – Illustration of improving average CML performance for all DNOs 2001 -2006



Further information confirming the continued performance improvement of British distribution networks is available in the CEER's, Third Benchmarking Report on Quality of Electricity Supply 2005 as shown in Figure 10 and Figure 11, and performance metrics for British DNOs continue to compare well with other European countries.

Figure 10 – Unplanned customer interruptions for European DNOs 1999 -2004

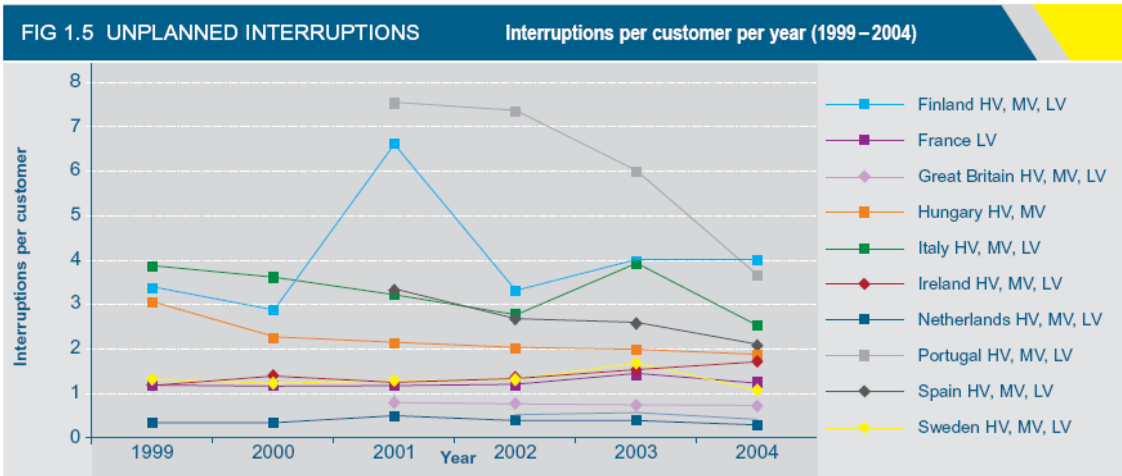
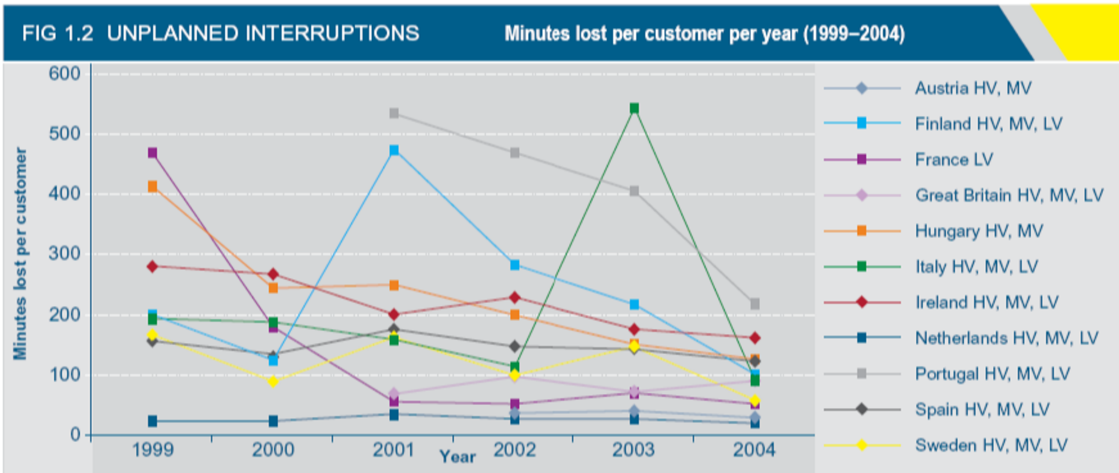


Figure 11 – Unplanned customer minutes lost for European DNOs 1999 -2004



4.4.3 Measures taken by DNOs to improve reliability performance

DNO investments to improve quality of supply in recent years indicate that a range of measures have been applied. These range from introducing relatively low-cost techniques including:

- development of more effective operational incident response practices;
- application of latest mobile technology to deploy appropriate staff to rectify faults promptly;
- installation of additional switching devices on high risk circuits;
- extending remote control;
- introduction of automation schemes;
- tree cutting programmes;

- introduction of remotely monitored fault passage indicators;
- replacement of drop out expulsion fuses with auto-sectionalisers on the HV overhead line network; and
- improved earth fault protection.

In addition, more capital intensive techniques have also been implemented to improve quality of supply, including:

- The introduction of targeted asset replacement and refurbishment programmes, such as upgrading of less reliable 'light construction' overhead lines, targeted replacement of particular types of underground cables;
- undergrounding of highly exposed sections of OH lines supplying significant number of customers; and
- Optimising holdings of strategic spares.

4.4.4 Network performance disaggregation and benchmarking

Ofgem, in collaboration with the DNOs, is disaggregating and benchmarking circuits to compare the performance and to identify the scope for further improvements. This disaggregation process recognizes the following network physical characteristics as performance drivers:

- Proportion of circuit overhead length;
- Circuit length; and
- Number of customers.

When evaluating the performance of these disaggregated networks, OFGEM identifies the following factors to explain variations in different DNO performance indices:

- management performance;
- local environmental differences (e.g. tree density);
- other differences in network design; and,
- historic network investment (e.g. some DNOs invested in large volumes of LV Consac cable, which has performed significantly worse than was generally expected).

This additional information and disaggregated data should provide further insights regarding the causes of CI/CMLs and prove invaluable to the regulator when setting future targets.

4.5 Weaknesses of CIs and CMLs

There are no fundamental weaknesses in the concept of CIs and CMLs and as explained above, these indices can be invaluable. The weaknesses relate to potentially inappropriate application. CIs and CMLs are evaluated by aggregating those load point indices that exist in the part of the system for which the CI and CML are required. These values are therefore averages of the load point indices included in the aggregated part of the system. These indices do not indicate the behaviour of the individual load points and do not indicate the impact of the system on individual customers attached to specific load points. They also do not distinguish between different types of customers or their activities. Therefore CI/CMLs do not reflect the behaviour of the system seen from the perspective of customers and types of customers, nor are they intended to do so.

Individual customers are only concerned with the number and duration (F&D) of the interruptions they experience or are likely to experience, and the impact that such interruptions have on their activity. They are not concerned with the severity of the events and therefore are not concerned with measures such as load disconnected and energy not supplied. In addition they are not concerned with where in the system the fault has occurred nor the number of other customers affected (except that this confirms it is the public electricity supply rather than their own premises that is the cause). The following points follow from these considerations.

Firstly individual customers are concerned with interruption Frequency and Duration indices and not average CIs and CMLs. Secondly CI and CML (also F&D) fail to recognise, or take account of, the consequences of interruptions. This latter aspect needs further evaluation.

All DNOs have targets for reducing CIs and CMLs over a period, and it is only reasonable for a DNO to take the most cost-effective approach to achieve these targets. These reductions can be achieved by reducing the number of outage events (generally difficult and costly), by reducing the duration of such events (often difficult and costly) and by ensuring the greatest number of customers are restored as soon as possible (often the easiest and cheapest). This encourages DNOs to restore supply points having a greater number of customers before those having fewer. This approach treats all customers as equally important, and ignores the consequences of interruptions on customer activities. However, the consequence of an interruption on a residential customer is usually one of inconvenience to that person(s), unless the interruption is prolonged beyond several hours. On the other hand, the consequence of an interruption on a commercial or industrial customer could be very severe. This consequence may affect the metered customer only and have little impact on others, e.g. a corner shop, the customers of which simply go to the next shop, or may affect many people (hundreds ++) such as those attending a theatre, a sporting event or using public transport. It follows therefore that in reality not all customers are equal, and some are more important than others. In the latter case, a question has arisen whether the “customer” is the one being metered or whether those attending the event should also be counted. It is logical that only the metered customer should be recognised by the DNO, and therefore additional considerations are required to reflect the consequential impact.

These additional considerations lead to the concept of societal impact, or customer worth of supply. Considerable activity has taken place worldwide on this topic with a summary of the knowledge published in a CIGRE Technical Report.[15] The available results show that residential customers place low values to worth of supply (perhaps a few pounds) whereas commercial and industrial customers place a worth varying between thousands and hundreds of thousands of pounds. If this concept is factored into DNO targets, then a remarkable difference in asset management and system restoration may be established. This is probably beyond the scope of the present activity, but should remain as an important future development. For this reason, the remaining part of this section centres only on a discussion and comparison of CIs, CMLs and F&D.

As discussed in more detail in Section 3 of this Report, it is believed that the original purpose of P2/5 and hence P2/6 was to ensure that all customers received a minimum level of security commensurate with the cost of providing that level, and to ensure that all companies used consistently the same approach and assessment. The criterion used to assess reliability during the creation of P2/5 (and therefore also P2/6) was EENS. Should it be decided that radical changes are required to the planning standard to reflect individual customer needs and expectations. If these are to be seen from the customer perspective, which can be different from that of a DNO, it seems much more appropriate for the assessment to be based in some way on a frequency and duration (F&D) approach.

Since CIs and CMLs are frequency and duration based, it is logical to consider whether these may be used as the criteria for determining customer security (seen from their perspective). This would be an additional benefit of these two indices. However, as stated above, these indices are system indices, not load-point and therefore not customer-perspective indices. For this reason, the impact of system behaviour on one load point and the customers attached to it can be masked by the impact on others in the same assessment group. This is illustrated for a simple example of two load points in Table 11. It is also worth noting that, since CIs and CMLs are only based on frequency, duration and the number of customers, these indices do not address severity indices such as load and energy not supplied.

Table 11 shows that, because load point A has 99 customers and load point B has only one customer, the CIs and CMLs are dominated by the indices of load point A. Even when load point B has 4 interruptions of 60 minutes, the overall CI and CML are still almost identical to that of load point A. If the number of customers at load point A is increased, this masking effect increases significantly. If the intention is to retain the original objective of P2/5, then a criterion based on system indices, or aggregation of load points, has significant problems.

15 " Methods to consider customer interruption costs in power system analysis". CIGRE Task Force 38.06.01. CIGRE Technical Brochure 191, Paris, August 2001.

Table 11 – Illustrative variations in CIs and CMLs

case	load point A 99 customers		load point B 1 customer		Combined CI	Combined CML
	int/yr.cust	min/int	int/yr.cust	min/int	int/yr.cust	min/yr
1	2	5	2	60	2	11.1
2	2	5	2	30	2	10.5
3	2	5	1	60	1.99	10.5
4	2	2.5	2	60	2	6.15
5	2	1	2	60	2	3.18
6	1	5	2	60	1.01	6.15
7	1	5	3	60	1.02	6.75
8	1	5	4	60	1.03	7.35

It is true that the frequency and duration indices of a load point are obviously the same as the CI and CML at that load point. However this:-

- confuses terms used for load points and for the system;
- complicates the concept of frequency and duration; and
- creates the impression that CIs and CMLs are useful generally for this purpose instead of only load point values.

It is therefore important to separate system indices from load point indices and have different terms for them – keeping CI and CML as system indices (aggregated load point indices) and F&D as load point indices.

The results in Table 11 can be related back to the above discussion on societal impact and worth of supply, where the residential customers can be viewed as load point A and the theatre, for instance, as load point B. The masking effect can be reduced or eliminated by including weighting factors that take into account the value that individual customers place on their worth of supply. For instance, if the worth of supply for customers at load point B was 100 times greater than that of those at load point A, the two load points would become comparable with each other.

As discussed above, CIs and CMLs are useful performance indicators for groups of feeders or the entire system. However, these indices do not capture the spectrum of performances seen by individual customers within the group (system). To demonstrate this we have analysed a sample of 100 real 11kV feeders. Failure rates for overhead line sections are assumed to be 0.1 faults/year.km and for cables is 0.05 faults/year.km. The system indices for all feeders are: expected customers interruptions is 0.95 faults/year.customer (i.e. 95 CIs) and the expected CML is 98 minutes/year.customer. These are long term average values for the entire population of these 100 feeders.

Reliability indices for each busbar in the network that feeds a distribution substation, seen by all consumers connected to this substation, are calculated and presented in the form of probability density functions. Figure 12 shows a probability density function of expected customers' interruptions. Along the horizontal axis is the expected customer interruptions per customer (rather than per 100 customers) while on the vertical axis is the corresponding percentage of customers. It can be seen that the most customers will experience 0.3 or 0.4 faults per year although there are some customers that will experience 5 faults per year. However, the average value for all customers is 0.95 faults per year.

Figure 13 shows a probability density function of expected customer minutes lost. The majority of users will not have a supply for about 10 or 20 minutes. However, there are customers that could expect to be interrupted for more than 1000 minutes. The value of 98 minutes corresponds to the average value across all customers.

Figure 14 shows a probability density function of expected energy not supplied. Similar conclusions can be drawn (note the similarity in shapes of the three probability density functions).

Figure 12 – Probability density function of expected customers' interruptions

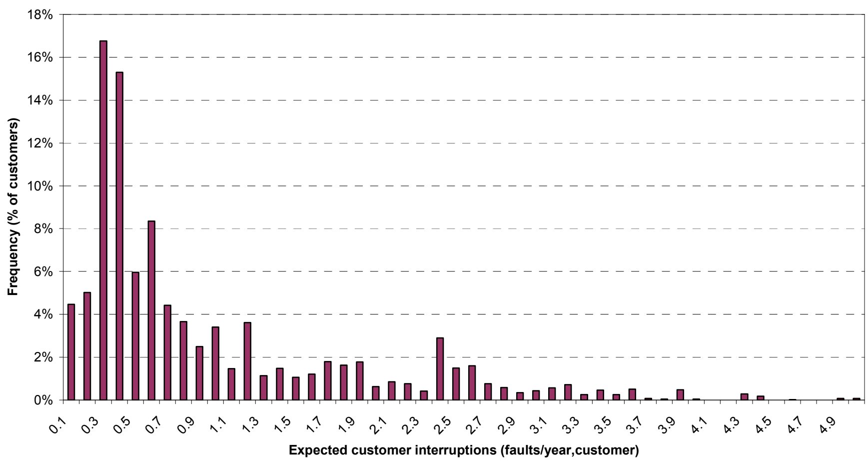


Figure 13 – Probability density function of expected customer minutes lost

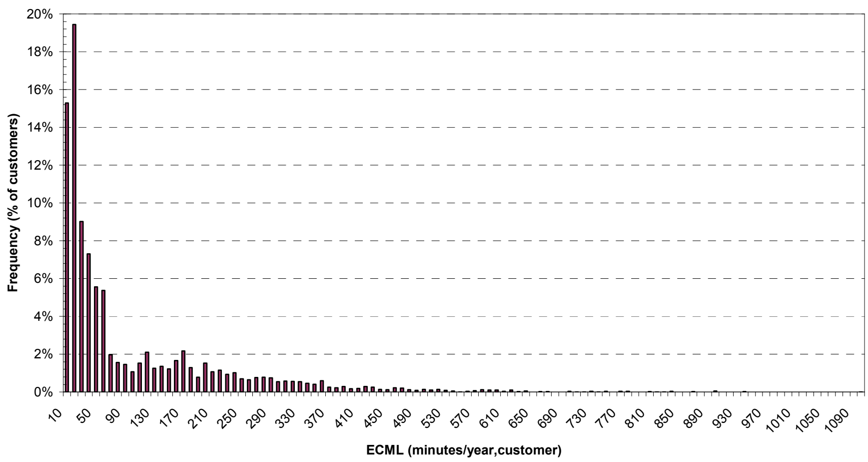
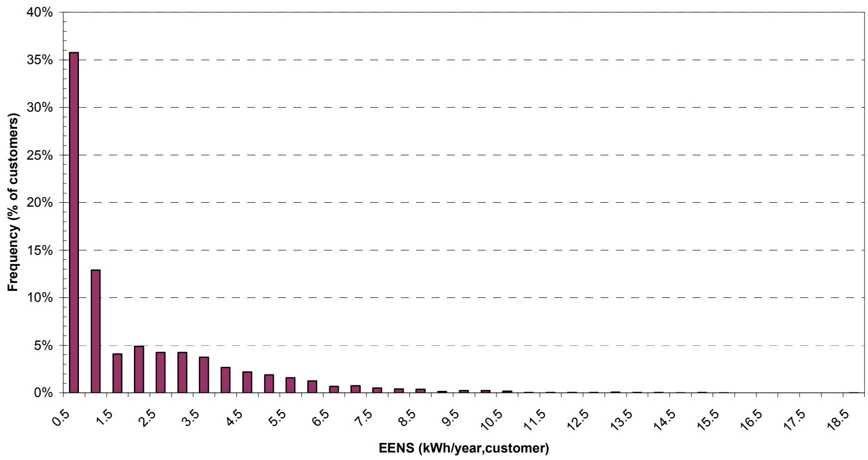


Figure 14 – Probability density function of expected energy not supplied



It is possible to estimate the customer outage costs associated with these interruptions. For this we use the results of the investigations carried out in the UK in early 90s. Figure 15 shows customer damage functions for residential, commercial, industrial, and large users. In this example a residential customer damage function is used (as shown in the left chart in Figure 15).

Figure 16 shows probability density function of customer outage costs. It can be seen that for majority of customers the outage cost is not significant while there are small number of customers which experience a significant outage cost.

Figure 15 – Customer damage function for residential, commercial, industrial and large users

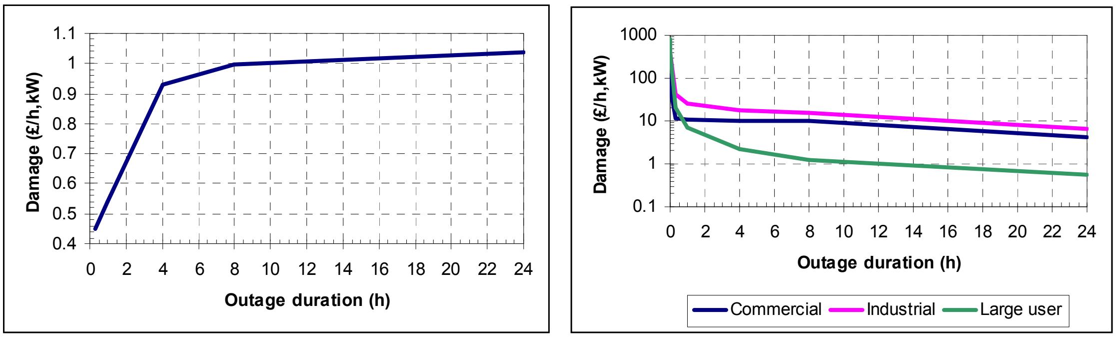
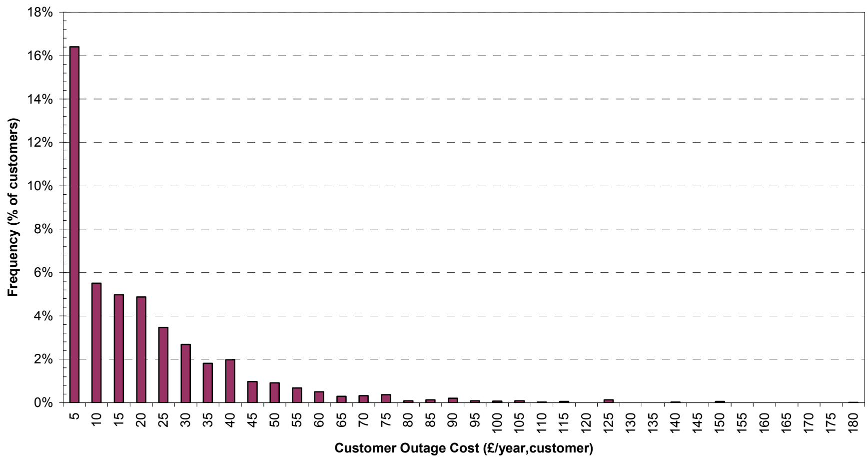


Figure 16 – Probability density function of customer outage cost for residential users



This analysis demonstrates that there can be significant variations in performance experienced by individual customers and that the system indices such as CIs and CMLs do not convey this information as these are intended for different purpose, i.e. to quantify the average performance across large groups of customers. This can be considered as a weakness of the *application* of CIs and CMLs when discussing performance actually received by customers (rather that the weakness of the indices themselves).

As discussed previously, DNO revenues are linked to the Interruption Incentive Scheme. Improvements in the quality of supply delivered to the average DNO customer results in increased revenues to the DNO. Consequently, DNOs are incentivised to identify methods by which network performance can be improved for large populations of customers. By contrast, performance improvements for small numbers of customers can be less attractive as the improvements achieved are diluted when averaged across all customers located in a DNO area. What is important from the DNO revenue perspective is the incremental change in the average performance delivered to all customers. A consequence of the CI/CML framework is that DNOs are incentivised to invest in areas which deliver the best incremental increase in network performance rather than in areas where customers may be experiencing a lower quality of supply. It follows that investment in areas with higher population densities (e.g. urban) may deliver better CI/CML performance improvements than investments in rural areas. Therefore it has been recognised that the IIS may incentivise DNOs to improve network performance for customer already receiving a high quality of supply. This issue is clarified further in the example below where two investment scenarios are compared:

- deploying mid-point circuit breakers in a feeder in an urban network; and
- deploying mid-point circuit breakers in a feeder in a rural network.

The assumed data is provided in Table 12.

Table 12 – Feeders data

Feeder area	**Urban**	**Rural**
Conductor type	Underground cable	Overhead line
Number of customers	4,000	300
Feeder length (km)	1	5
Failure rate (faults/year.km)	0.05	0.1
Switching time (hours)	1	1

It was assumed that adding a mid-point circuit breaker reduces CIs and CMLs to 75% as in an ideal situation with uniform distribution of customers along the feeder. Furthermore to simplify the calculation of CML, it was assumed that the supply to all customers can be restored in switching time (which may be more difficult to achieve in rural than in urban areas). The results of calculation are summarised in Table 13.

Table 13 – Results

Feeder area	Urban	Rural
Average CI seen by customers before improvement (i./100c.y.)	5	50
Average CML seen by customers before improvement (m./c.y.)	3	6
Total CI on feeder before improvement (i./y.)	200	150
Total CML on feeder before improvement (m./y.)	12,000	9,000
Average CI seen by customers after improvement (i./100c.y.)	3.75	37.5
Average CML seen by customers after improvement (m./c.y.)	2.25	4.5
Total CI on feeder after improvement (i./y.)	150	112.5
Total CML on feeder after improvement (m./y.)	9,000	6,750
Total reduced CI on feeder (i./y.)	50	37.5
Total reduced CML on feeder (m./y.)	3,000	2,250
Reduced CIs penalties (£/year)	365	274
Reduced CML penalties (£/year)	288	216
Total reduced penalties (£/year)	653	490
Capitalised total reduced penalties (£)	**6,530**	**4,900**

From these results, it can be observed that, from the DNO perspective, it is more effective to install the mid-point circuit breaker first in an urban network, even though these customers already experience a better quality of service than rural customers (on average ten times fewer interruptions and half the duration given the assumptions in the illustration).

4.6 Consistency of performance incentives with planning standards

Whilst the IIS is primarily a customer number driven initiative, this could be regarded as theoretically inconsistent with the methodology underpinning ER P2/6. In the planning standard, network redundancy requirements have been determined on the basis of a proxy for the value of supply reliability. This proxy is Expected Energy Not Supplied (EENS). Simplistic comparisons from individual customer perspectives would suggest EENS and the IIS may be inconsistent. With respect to reliability and supply restoration priorities, an EENS based approach would incentivise DNOs to concentrate efforts on the largest customers in their areas whereas the IIS clearly incentivises DNOs to address large numbers of smaller customers. However, the application of the EENS criteria to different sized Classes of Supply (Group Demand) containing many different customer groups can be shown to be broadly comparable with the IIS framework as demonstrated in the example below.

Investigations have been undertaken to illustrate any correlations between various indices. In this example, the expected energy not supplied (EENS) to a homogenous population of customers, is calculated as a sum of the products of energy not supplied and probability that corresponds to system states in which the available network capacity is less than given demand. This is expressed in the following relationship (1)

$$EENS = \sum_{i \in \alpha_{NMS}} p_i \cdot ens_i \cdot E \qquad (1)$$

where:

p_i - probability of system being in state i,

ens_i - percentage of energy not supplied if system is in state i,

E - total annual energy,

α_{NMS} - set of system state indexes where available capacity is less than peak demand.

The expected number of customer minutes lost (CML) can be calculated as a sum of the products of the proportion customers that are not supplied and the probability that corresponds to system states in which the available network capacity is less than given load demand, as expressed below (2)

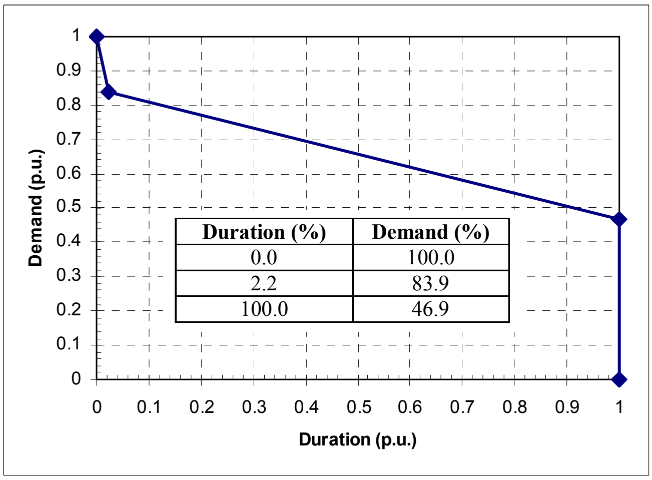
$$CML = 8760 \cdot 60 \cdot \sum_{i \in \alpha_{NMS}} p_i \cdot CNS_i \qquad (2)$$

where:

CNS_i - proportion of customers being disconnected if system is in state i.

For the purpose of examining the extent of correlation between CMLs and EENS, we have considered a simple generic situation of a group of customers with a normalised load duration curve (LDC) presented in Figure 17. This group of customers is supplied by a network which available capacity may vary from zero (when all network elements fail) to full capacity (when all network components are working) depending on the availability of the constituent parts the network.

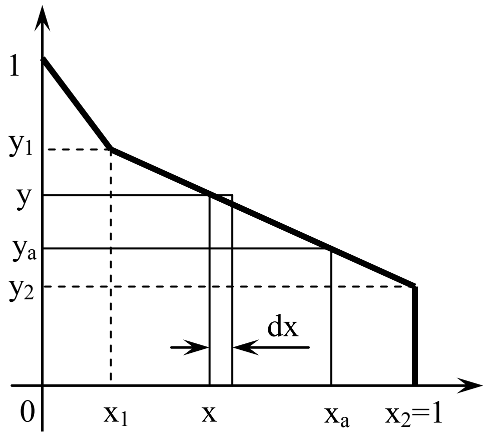
Figure 17 – Normalised load duration curve (load factor is 65.98%, as used in ER P2/6)



For the load duration curve and all possible available network capacities, three parameters are calculated and presented in Table 14. Column duration represents a percentage of time (duration) for which demand is above available network capacity (note that the available network capacity is given as percentage of peak demand). Column ens, energy not supplied, represents a percentage of annual energy above available network capacity. The last column represents *estimated* average percentage of disconnected customers for a given network capacity (customers not supplied, CNS).

Principle of the assessment of the percentage of customers that are not supplied for a given network capacity is given in Figure 18.

Figure 18 – Principle of calculation of percentage of not supplied customers



If available capacity of a particular system state is denoted as y_a then the percentage of customers not supplied (CNS) could be considered to be approximately proportional to the difference between the minimum capacity required to be available to supply all customers (y) and the available capacity y_a for any point on the load duration curve. This can be expressed in per unit values (or percentages) using the ratio between the two quantities. This logic leads to the following expression for the evaluation of expected number of customers (in percentage) that are disconnected for a given capacity available:

$$CNS = 100 \cdot \int_0^1 \frac{y - y_a}{y} \cdot dx =$$

$$= \begin{cases} \left(x_a - y_a \dfrac{x_1 - 0}{y_1 - 1} \left(\ln(y_a) - \ln(1) \right) \right) \cdot 100, & y_a \geq y_1 \\ \left(x_a - y_a \dfrac{x_1 - 0}{y_1 - 1} \left(\ln(y_1) - \ln(1) \right) - y_a \dfrac{x_2 - x_1}{y_2 - y_1} \left(\ln(y_a) - \ln(y_1) \right) \right) \cdot 100, & y_1 \geq y_a \geq y_2 \\ \left(1 - y_a \dfrac{x_1 - 0}{y_1 - 1} \left(\ln(y_1) - \ln(1) \right) - y_a \dfrac{x_2 - x_1}{y_2 - y_1} \left(\ln(y_2) - \ln(y_1) \right) \right) \cdot 100, & y_2 \geq y_a \end{cases}$$

Note from Table 14 the significant correlation between energy not supplied and customers not supplied (as defined in this report). Consequently it follows that in this example there is a close correlation between EENS and CMLs. It should be stressed that this finding cannot be generalised to be valid for all possible customer mixes. However, it can be expected that many situations will exist in which such a significant correlation, between percentage energy not supplied and percentage of customers not supplied, may be achieved.

The modelling approach adopted in this example assumed that, following an outage, all customers that could theoretically be reconnected were reconnected. It is acknowledged that this reconnection rate may be difficult to achieve in practice. Therefore the Customer not Supplied values presented in Table 14, represent the lower bound on the percentage of affected customers.

Table 14 – Reliability characterisation of normalised load duration curve

Capacity available (%)	Duration (%)	ens (%)	Customers Not Supplied (%)
100	0.00	0.00	0
90	1.37	0.10	0.07
80	12.51	0.70	0.52
70	38.94	4.60	3.75
60	65.37	12.51	10.76
50	91.81	24.42	22.20
40	100.00	39.38	37.55
30	100.00	54.53	53.16
20	100.00	69.69	68.77
10	100.00	84.84	84.39
0	100.00	100.00	100.00

Given that expected customer interruptions (CI) depends on the probabilities of all states and transition rates leading to the states where available capacity is less than peak demand a similar conclusion cannot be drawn. Furthermore, restoration and repair times will play an important role in the amount of CMLs although this may not affect CIs. Hence the correlation between CIs and CMLs may be weak.

Consequently, it can be seen that the IIS framework may be considered to be broadly consistent with ER P2/6 when quality of supply incentives for large numbers of customers are compared to planning requirements for different Classes of Supply.

4.7 Implications of ER P2/6 and IIS on network design

In this section the appropriateness of existing high-level network design principles as driven by ER P2/6 and the IIS incentive framework are considered. In this context, the analysis and examples has sought to confirm the most appropriate level of network *redundancy* (as a key aspect of network design) associated with various demand groups supplied through networks operating at difference voltages. Whilst the examples chosen to compare different network investment drivers are simple (largely radial) in nature, the conclusions drawn are also relevant to more complex network configurations.

4.7.1 LV network design philosophy (N-0 and N-1)

At LV, for demand groups less than 1 MW, ER P2/6 recommends no redundancy. This means that the time required to restore supplies to customers interrupted by a fault on a LV network, will be driven by repair times.

Figure 19 shows a possible LV underground feeder where two cables are buried in the same trench. One of the cables is used to supply customers while another one is used as a reserve. The main supplying cable is sectionalised. As an example, two sections are shown in Figure 19.

Figure 20 shows a corresponding Markov model of system states (ignoring overlapping failures).

Table 15 summarises the equations for the evaluation of associated reliability indices. It is assumed that the spare cable is in service when needed and common mode faults are not taken into account to maintain simplicity.

Figure 19 – LV feeder with a reserve cable

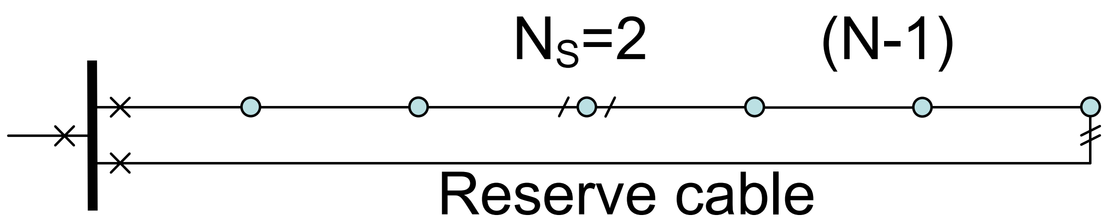


Figure 20 – Markov model of LV feeder with a spare cable

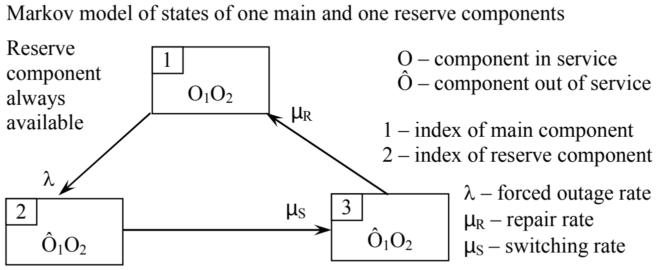


Table 15 – Reliability indices equations for a feeder with a reserve cable

Failure rate	$FR = FR_0 x N_C x L$
Transition rate	$TR = 1/(1/FR+MTTR_S/8760 + MTTR_R/8760)$
EENS	$N_C x E_C x(MTTR_S/8760 + MTTR_R/(8760xN_S))xTR$
CI	100xTR
CML	$60x(MTTR_S + MTTR_R/N_S)xTR$
CML no reserve	$60x(MTTR_S+(NS+1)xMTTR_R/(2xN_S))xTR$

FR_0 – failure rate faults/year,km
N_C – number of customers
L – length of part of cable between two groups of customers
$MTTR_S$ – mean time to restore supply in switching time
$MTTR_R$ – mean time to restore supply in repair time
E_C – annual consumption per customer
N_S – number of sections

Regarding the numerical values of the key performance driving parameters, we assume a failure rate of feeder is 0.05/year.km, $MTTR_S$ 1hs or 3hs, $MTTR_R$ 10hs, L = 20 m. Furthermore we assume that there are 60 customers on the feeder each with annual consumption is 3500 kWh. The results are shown in Table 16. As anticipated, the expected customer interruptions remain unchanged. Note that there is an improvement in CML that comes from the application of sectionalising techniques and is not related to the existence of the reserve cable. However, the improvement is greater in case if there is a reserve cable.

The benefits of this arrangement with the main LV cable split into six sections. This arrangement saves 15 CML for sectionalizing and further 15 CML for adding a reserve cable and an Normally Open Point if average switching time is 1 hour. The corresponding capitalised benefit, at a feeder level, is about £864 (=15x0.096x10x60) for sectionalizing and the same for the reserve cable (assuming the present incentive regime rates). The cost of 0.4 kV cable is £6,000/km which in this case gives that the cost of spare cable is £7,200, that is higher than the benefits in this particular case. However, for feeders with larger number of customers this may be a viable proposition. Furthermore, if the IIS incentive rates increase in future, this may stimulate the network designs with higher levels of redundancy in LV networks, particularly those with very large number of customers or systems supplying high value loads.

Table 16 – Results for an example of LV feeder and use of a reserve cable

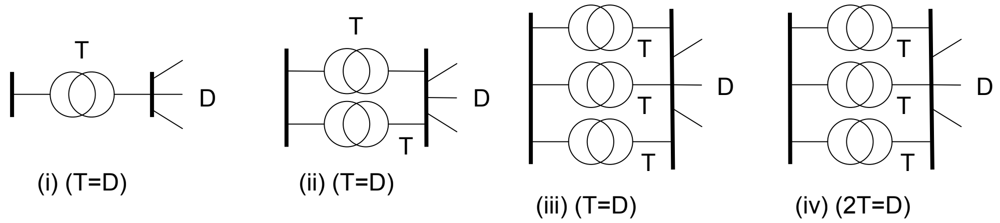
	N_S	1	2	3	4	6
EENS (kWh) (Reserve cable installed)		15.8	8.6	6.2	5.0	3.8
CI (int/year.100 cust.) (Reserve cable installed)		6	6	6	6	6
CML (min/year.customer) Reserve cable installed	**$MTTR_S$ = 1h**	39.6	21.6	15.6	12.6	9.6
	$MTTR_S$ = 3h	46.8	28.8	22.8	19.8	16.8
CML (min/year.customer) No reserve cable installed	**$MTTR_S$ = 1h**	39.6	30.6	27.6	26.1	24.6
	$MTTR_S$ = 3h	46.8	37.8	34.8	33.3	31.8

Total annual demand is 210,000 kWh

4.7.2 Substation redundancy

In this section, the benefits and costs of substation asset redundancy are evaluated and for this purpose four general arrangements are considered as shown in Figure 21 (the corresponding results are also used elsewhere in this report). In the first case (i) there is no redundancy (the transformer rating (T) is the same as the peak demand (D)) and a fault on the transformer will lead to an interruption to connected customers and the duration of the outage will be driven by the repair time (standby generators may be used to restore the supply to interrupted customers more quickly). In the second case (ii) there are two transformers and each can supply all of the demand. There are three transformers in cases (iii) and (iv). In (iii,) each transformer can supply the entire demand (one out of three is sufficient), while in case (iv) two out of three transformers are required to supply the demand.

Figure 21 – Transformer circuit configurations



Formulas for the calculation of reliability parameters due to forced transformers outages are shown in. Table 17. It can be seen that with the increased redundancy, all reliability parameters improve although the key driver for redundancy of transformers is CML. We also observe a relatively strong correlation between EENS and CML. In these simplified examples the impact of any transfer capability is ignored.

Table 17 – The expected values of reliability parameters due to transformers outages without transfer capability

Installed capacity	Demand	EENS (%)	CI	CML
D	D	(1-A)	100x8760(1-A)/MTTR	60x8760(1-A)
2xD	D	$(1\text{-}A)^2$	$100x8760x2(1\text{-}A)^2$/MTTR	$60x8760(1\text{-}A)^2$
3xD	D	$(1\text{-}A)^3$	$100x8760x3(1\text{-}A)^3$/MTTR	$60x8760(1\text{-}A)^3$
3x0.5D	D	$\approx 0.75(1\text{-}A)^2$	$\approx 2.3x100x8760(1\text{-}A)^2$/MTTR	$\approx 0.67x60x8760(1\text{-}A)^2$

Where:

D – peak demand
A – transformer availability
MTTR – mean time to repair in hours
EENS – expected energy not supplied
CI – expected number of interruptions per year and per 100 customers
CML – expected duration in minutes of outages per year and per customer

Table 18 shows results of examples where a transformer failure rate is 0.02/year with different values for repair times. Note that for the example with a repair time of 6 months (which corresponds to an availability of 99%), using one transformer per substation would result in an extremely high CML value of 5256 while a design with 2 transformers would reduce the CML to 52 (which would also be prohibitively high to be used in practice, given that this is in the order of the total system CMLs). Applications with three transformers with full n-2 redundancy would reduce CMLs to 0.53. Using the configuration with 3 transformers, while two are needed for meeting peak demand, would result in 35 CMLs. Note that by incrementing the number of transformers by one improves CML performance by a factor of 100. Table 18 shows that reducing repair times improves the CML performance as expected.

Transformer repair (or replacement) times are dependent upon ratings and voltage levels. Replacement of very large transformers may require weeks while replacement of HV/LV transformers may be accomplished in hours which inevitably has an impact on the need for redundancy.

Table 18 – A numerical example of Table 17 if transformer forced failure rate is 0.02 per year

Availability MTTR	Installed capacity	EENS (%)	CI	CML
99.00% 6 months	D	1.0000	1.980	5256.00
	2xD	0.0100	0.040	52.56
	3xD	0.0001	0.001	0.53
	3x0.5D	0.0075	0.046	35.22
99.50% 3 months	D	0.5000	1.990	2628.00
	2xD	0.0025	0.020	13.14
	3xD	0.0000	0.000	0.07
	3x0.5D	0.0019	0.023	8.80
99.90% 18 days	D	0.1000	1.998	525.60
	2xD	0.0001	0.004	0.53
	3xD	0.0000	0.000	0.00
	3x0.5D	0.0001	0.005	0.35
99.98% 88 hours	D	0.0200	2.000	105.12
	2xD	0.0000	0.001	0.02
	3xD	0.0000	0.000	0.00
	3x0.5D	0.0000	0.001	0.01
99.99% 44 hours	D	0.0100	2.000	52.56
	2xD	0.0000	0.000	0.01
	3xD	0.0000	0.000	0.00
	3x0.5D	0.0000	0.000	0.00
99.996% 16 hours	D	0.0037	2.000	19.20
	2xD	0.0000	0.000	0.00
99.996% 8 hours	D	0.0018	2.000	9.60
	2xD	0.0000	0.000	0.00
99.9993% 3 hours	D	0.0007	2.000	3.60
	2xD	0.0000	0.000	0.00

Table 19 shows the increase in values of reliability indices due to planned outages for a network configuration with a single transformer.

A single transformer per substation can be used in cases where a spare is available or a significant number of customers can be transferred. The smallest value of 24 CMLs is obtained in the example with a planned outage rate of 0.1 outages/year (frequency of maintenance is once in 10 years) with the maintenance lasting not more than several hours (even in this case the contribution of the substation to the overall CMLs would be 24 per annum, which is very significant). Furthermore, in the absence of transfer capability, the transformers installed would need to be maintenance free to avoid the prohibitively high CML shown in Table 19. Should maintenance free transfers be installed, a n-0 design strategy could be applied to HV/LV substations.

Table 19 – An example of additional values of reliability parameters due to planned outage for a single transformer

Installed capacity	Planned outage rate (1/year)	Planned MTTR (h)	Planned availability	EENS (%)	CI	CML
D	1	66	99.25	0.7478	99.3	3930
		44	99.50	0.4998	99.5	2627
		20	99.77	0.2278	99.8	1197
		4	99.95	0.0456	100.0	240
D	0.5	66	99.62	0.3753	49.8	1973
		44	99.75	0.2505	49.9	1317
		20	99.89	0.1140	49.9	599
		4	99.98	0.0228	50.0	120
D	0.25	66	99.81	0.1880	25.0	988
		44	99.87	0.1254	25.0	659
		20	99.94	0.0570	25.0	300
		4	99.99	0.0114	25.0	60
D	0.1	66	99.92	0.0753	10.0	396
		44	99.95	0.0502	10.0	264
		20	99.98	0.0228	10.0	120
		4	99.995	0.0046	10.0	24

The impact of maintenance on network redundancy requirements was also investigated. A conventional Markov model representing the reliability state space diagram with transitions among the system states used in this evaluation is provided in Figure 22.

Figure 22 – Markov model of two transformers including planned outage that is used in this study

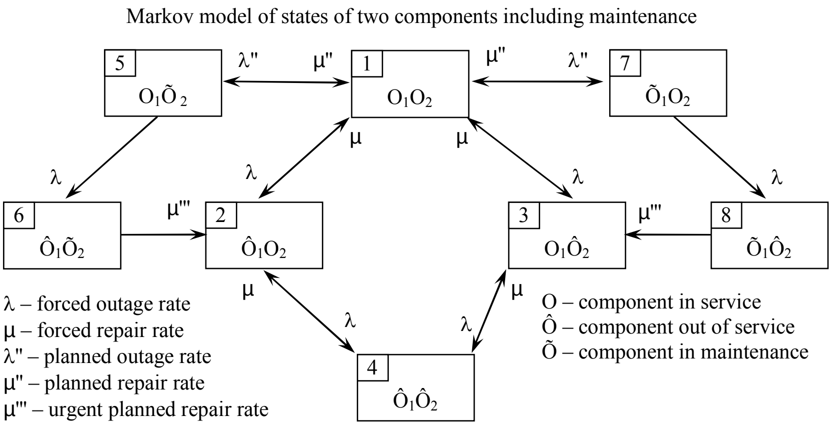


Table 20 provides values for reliability indices as impacted by forced and planned transformer outages, where two transformers are installed per substation. We observe that maintenance activities do not increase the values of reliability parameters to an unacceptable extent.

Table 20 – Reliability parameters for substations with two transformers, a forced outage rate of 0.02/year and planned outage rate of 0.25 per year

Installed capacity	Forced Availability MTTR	Planned MTTR (h)	Planned availability (%)	EENS (%)	CI	CML
2D	99.50% 3 months	66	99.81	0.0026	0.027	13.41
		44	99.87	0.0025	0.025	13.25
		20	99.94	0.0025	0.022	13.16
		4	99.99	0.0025	0.020	13.14
	99.90% 18 days	66	99.81	0.0002	0.011	0.82
		44	99.87	0.0001	0.009	0.66
		20	99.94	0.0001	0.006	0.55
		4	99.99	0.0001	0.004	0.53

4.7.3 Redundancy in HV/LV substation design

This example investigates the consequences of adopting a (n-1) network design in HV/LV substations instead of the (n-0) required for Class of Supply A by ER P2/6. This example assumes that a HV/LV transformer of 630 kVA can supply 400 customers with a failure rate of 0.02 faults per year and average repair (replacement) time of three hours. These transformers are assumed to be maintenance free (to avoid prohibitive CMLs). For the (n-0) design of one transformer per substation, an average CI value of 2 was calculated with a corresponding CML value of 3.6 as shown in Table 18. If a (n-1) configuration is adopted, these CI and CML values are practically reduced to zero giving a benefit of 2 CIs and 3.6 CMLs accordingly. Therefore the capitalised CI benefit is £584 (2x0.073x10x400) and the capitalised CML benefit is £1382 (3.6x0.096x10x400). This amounts to £1966 which does not support a purchase of an additional transformer at a cost of approximately £4500. This should be contrasted with the cost of indoor substation 630 kV that is about £20,000 while and outdoor one would be in the order of £10,000. Consequently, the current practice of no redundancy of assets at the HV/LV substation interface represents an appropriate and economic network design.

4.7.4 HV network design

Figure 23 shows different configurations of HV feeders which have been analysed. Case (i) has only one circuit breaker for all feeders. In case (ii) a feeder circuit breaker is introduced. In case (iii) a normally open point is introduced with the ability to sectionalise circuits such that N-1 redundancy is achieved (assuming that cable capacities are adequate). Expressions for evaluations of reliability indices are given in Table 21.

Figure 23 – Feeder configurations

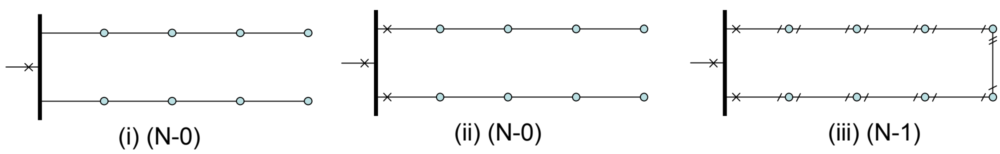


Table 21 – Expressions for calculation of reliability indices for feeder configurations shown in Figure 23

Case	Unavailability – U	EENS	CI	CML
(i)	$1/(8760/(FRxN_FxN_{DT/F}x LxMTTR_R)+1)$	$UxN_FxN_{DT/F}xE_{DT}$	$\approx 100x8760xU/MTTR_R$	$60x8760xU$
(ii)	$1/(8760/(FRxN_FxN_{DT/F}x LxMTTR_R)+1)$	$UxN_{DT/F}xE_{DT}$	$\approx 100x8760xU/(MTTR_RxN_F)$	$60x8760xU/N_F$
(iii)	$1/(8760/(FRx(N_FxN_{DT/F}+ N_F/2)xLxMTTR_S)+1)$	$UxN_{DT/F}xE_{DT}$	$\approx 100x8760xU/(MTTR_SxN_F)$	$60x8760xU/N_F$

FR – failure rate of one section (1/year,km)
N_F – number of feeders
$N_{DT/F}$ – number of distribution transformers per feeder
L – section length (km)
$MTTR_R$ – mean time to restore in repair time
$MTTR_S$ – mean time to restore in switching time
E_{DT} – average annual energy supplied through a distribution transformer

This analysis assumed an underground feeder failure rate of 0.05 faults/year,km with a mean time to repair of 10 hours, a mean time to restore supplies via switching of 1 hour, a section length of 0.5 km. It was assumed that there are eight feeders and each feeder supplies five distribution substations. Annual energy consumption through a distribution transformer is assumed to be 500 (customers) x 3500 kWh. The results are shown in Table 22. Note that in this example, CIs and CMLs are not functions of customer numbers. The costs and benefits of adopting an option (iii) configuration relative to an option (ii) design is around £6 per customer per year (=(75-9)x0.096–(15-12.5)x 0.073) or capitalised around £60 per customer or £1.2m (=60x500x8x5) per eight feeders. This improvement would justify 80 disconnectors, a Normally Open Point (including the necessary extensions of the cable network to reach neighbouring feeders) and cover the increases in operating expenditure involved. It is also useful to note that the calculated CML performance for option (ii) is poor compared with existing urban networks. This high-level assessment illustrates (and supports) the effectiveness of the actions taken by DNOs with respect to increased automation and remote control on 11 kV feeders which has resulted in significant reductions in CMLs and CIs since the incentive regime was introduced.

Table 22 – Reliability indices for consideration of HV network redundancy

Case	U (%)	EENS (kWh)	EENS (%)	CI	CML
(i)	0.1140	79,818	0.1140	99.9	599
(ii)	0.1140	9,977	0.0143	12.5	75
(iii)	0.0137	1,198	0.0017	15.0	9

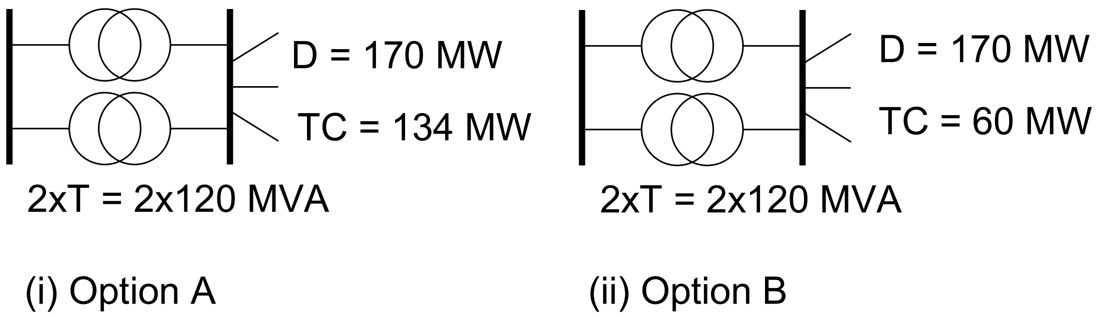
Total annual demand of eight feeder customers is 70,000,000 kWh.

Consistent with the earlier analysis regarding the performance of substations, a high correlation between EENS and CML is visible.

4.7.5 Transfer capacity for large demand groups (EHV networks)

In this example we evaluate the impact on reliability indices for a group demand of 170 MW (power factor of 0.95) as shown in Figure 24. The demand is supplied through two transformers of 120 MVA, 1.3 cyclic rating. There are two options for transfer capability: (i) 134 MW and (ii) 60 MW. Transformers reliability parameters are: forced outage rate 0.02 per year, average repair time 6 months, planned outage rate 0.5 per year, planned outage duration 66 hours.

Figure 24 – Substation options A and B



For Option A, the first and second circuit outages conditions are as follows:

- (FCO): 1 x 1.3 x 0.95 x 120 + 134 = 282 MW, and
- (SCO): 0 x 1.3 x 0.95 x 120 + 134 = 134 MW.

For Option B, the first and second circuit outages conditions are as follows:

- (FCO): 1 x 1.3 x 0.95 x 120 + 60 = 208 MW, and
- (SCO): 0 x 1.3 x 0.95 x 120 + 60 = 60 MW.

For the Group Demand of 170 MW the conditions with respect to supply restoration are as follows:

- (FCO): (a) Immediately at least 150 MW and (b) The remaining in 3 hours.
- (SCO): (a) At least 57 MW within 3 hours and (b) The remaining demand to be restored in time of planned outage.

From the above it can be concluded that both options satisfy ER P2/6.

The Markov models used in the reliability calculation for Options A and B are given in Figure 22.

The reliability indices for these two options are presented in Table 23. For Option A, it is assumed that during the maintenance of one transformer with an outage on the other, all customers continue to be supplied as the maintenance period peak demand is assumed to be 134 MW. However this is not possible for Option B as in the event of one transformer being on planned outage superimposed with a forced outage on another, some of customers would need to wait for planned outage to finish before their supply can be restored. This results in a significant increase of expected CMLs. The cost of the increased CML is about £21 per customer or for 170,000 customers £3.57m which is more than the cost of an additional 120 MVA transformer which could be used to enhance transfer capacity.

Table 23 – Reliability indices for two options of supplying group demand.

Option	EENS (%)	CI	CML
A: 2x120MVA + 134MW	0.0001	0.000	0.36
B: 2x120MVA + 60MW	0.0045	0.022	22.60

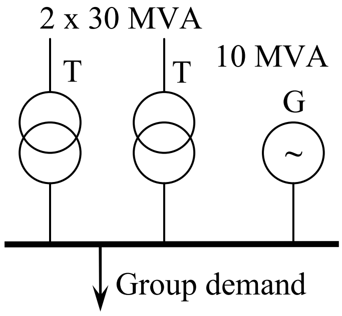
This analysis suggests the transfer capacity capable of supplying full load (134MW in the above case) could bring significant CML benefits over a design with reduced transfer capacity, as allowed by ER P2/6. Given the issues of increased summer demand and construction outage management, it would be clearly appropriate to review the staged restoration process in case of SCO and examine if this should be removed from the standard.

4.8 Consistency of DG security contributions with performance incentive regime

The methodology by which Table 2 of ER P2/5 was updated determines the capacity of a perfect circuit which, when substituted for the distributed generation, gives the same level of expected energy not supplied (EENS). This capacity is the effective contribution of the generation system. This approach is identical in concept with that used in developing ER P2/5.

In this example the appropriateness of the EENS index is compared with CI/CML based indices when deriving the contribution of DG to network performance. To illustrate this we consider a network configuration that comprises of two 30MVA circuits and 10MW distributed generation supplying the group demand as schematically shown in Figure 25. The critical design criterion of the circuits is the 30MVA transformer with a cyclic rating factor of 1.3 and a power factor of 0.95. Hence, each circuit has a cyclic rating of 37.05MW and both circuits a cyclic rating of 74.1MW. The circuit availability is assumed as 98%. Transfer capacity is neglected.

Figure 25 – Group demand supplied through two transformer feeders and generation



The case study comprises five cases in which a Group Demand is supplied by two circuits supported by different generation combinations with equivalent total capacity. The generation option modelled included:

(i): no generation (abbreviated as 'base'),

(ii): eight 1.25MW landfill gas generation units, each with a typical availability of 90% (8 LGs),

(iii): eight 1.25MW sewage gas spark ignition generation units, each with a typical availability of 60% (8 CHPs),

(iv): one 10MW gas turbine with a typical availability of 80% (1 GT),

(v): 10MW of wind generation with a typical availability of 35% (wind).

The results for all cases are shown in Table 24.

Table 24 – Results for example on impacts of distributed generation

Case	Group demand (MW)	CML (min./year, customer)	EENS (kWh/year, customer)	COC (£/year, consumer)
(i) base	37.05	210	4.666	9.32
(ii) 8 LGs	44.95	212	4.710	9.38
(iii) 8 CHPs	42.55	216	4.843	9.55
(iv) 1 GT	42.35	222	5.048	9.83
(v) wind	39.45	215	4.817	9.42

It is assumed that the generation plant operates continuously. According to ER P2/6, the effective contribution of generation is calculated based on the number of units and the unit type (or the unit availability). Hence, the effective contribution of generation was calculated for each configuration. The highest effective contribution was provided by eight generation units with high availability. The firm capacity of the system is calculated as the sum of the cyclic rating of one circuit and the effective contribution of generation. The group demand for each case is set to firm capacity of that case.

The calculated CML indices are in the region circa 200 (given the assumption of no transfer capacity available and relatively low circuit availability). It can be observed that the CML indices of all cases vary in rather narrow range (from 210 to 222 minutes). The highest CML index is observed in case with one generation unit and it is only about 5% higher than the one observed in the base case.

The annual EENS is about 5kWh per customer (it can be observed that the EENS vary from 4.66 in the base case to 5.1 in the '1 GT' case) with the highest percentage increase observed of about 8% in the '1 GT' case. Again, there is a relatively high correlation between EENS and CML.

The annual customer outage cost (COC) is found to vary in a narrow range between £9.32 and £9.83 per consumer. The highest value is obtained in the '1 GT' case and represents an increase of about 5%.

The development of ER P2/6 to include security contributions from modern generation technologies was based on EENS criteria. Calculations based on expected CMLs do not result in significant changes to the levels of security estimated using the EENS criteria.

5. Future network design considerations

5.1 Customer and societal security perspectives

5.1.1 Customer Worth of Supply

It is expected that the utilisation of the customer interruption cost data in electricity supply planning and corresponding regulatory decision-making process will increase in order to balance investment requirements to maintain acceptable levels of supply security. Considerable work has been done around the world on the determination of consumer costs associated with the electric energy supply interruptions. In the following sections, some of the relevant work and methodologies to assess customer interruption costs are described and how such data can be utilised when planning/designing distribution networks.

Two studies[16] [17] have recently been undertaken in the UK to improve the understanding of the services which are valued by electricity customers, the relative priorities placed on different outputs and customers' willingness to pay for improvements. Based on consumer surveys, these studies reveal that both domestic and business consumers have indicated high expectations in terms of quality of service (minimum number of interruptions) and rapid restoration of power (reducing duration of an interruption), and compensation following power failure events. It is also indicated that end users (consumers) are less concerned with the amount of energy not served during such an event.

From the consumer perspective, perceptions of system security are influenced by:

- The number of interruptions experienced;
- The duration of these interruptions; and
- The costs incurred as a result of the interruptions.

These studies indicated that consumers are prepared to pay for reductions in frequency of interruption and that both domestic and business consumers also value a reduction in the duration of power cuts.

The impact and cost of interruptions from a customer's perspective is related to the degree to which activities are dependent on electricity. In turn, this dependency is a function of both customer and interruption characteristics which include:

- Frequency;
- Duration;

16 Accent Marketing & Research, Expectations of Electricity DNOs & WTP for Improvements in Service Stage 1 Quantitative Research Findings, Final Report, September 2003
17 Accent Marketing & Research, Consumer Expectations of DNOs and WTP for Improvements in Service, Report June 2004

- Time of occurrence of interruption;
- Type; planned or unplanned; and
- Type of customer e.g. domestic, industrial, commercial etc

Moreover, the impact of an outage is also dependent upon the attitude and the preparedness of the customers, which is related to existing system security levels. In general, customers who receive high quality service are less prepared for interruptions, which may therefore have a higher cost when an interruption occurs. Due to the highly sensitive nature of some business (e.g., financial institutions) and community (e.g., hospitals) activities, such entities often choose to have a redundant and independent (backup) supply source to avoid irrecoverable losses. This imposes additional costs for the provision of contingency measures (estimates suggests that there may be more than 10 GW of stand by generation in the UK).

Since privatisation, Distribution Network Operators (DNOs) have been required to assess past performance of their networks in terms of specified parameters and quantitative measures. These have been used to identify how well DNOs satisfied customer expectations, to compare system performances against set targets, and to enable comparison of the performances between individual companies.

Other system oriented indices include Energy Not Served (ENS). The level of electricity not supplied gives an indication of the overall robustness of a country's electricity networks. For most countries the information generally relates to transmission networks only[18]. More recent developments consider that end-customers (consumers) are less concerned with the energy not received during an interruption and its associated cost but are much more concerned with the costs associated with the inability to perform their activities during the interruption[19]. Respondents to OFGEM's consultation paper on distribution price review[20] of 1999 also stressed that more detailed targets should be set and that these should be more rigorous than the existing targets.

5.1.2 Application of Frequency and Duration interruption indices

It has been suggested that the existing standards do not adequately address the customer's concerns over the system security. To redress this, Customer Outage Cost (COC) has been introduced as a criterion for providing additional justification for alternative distribution system plans, designs or operating policies. This is defined as *the total costs incurred by all the customers connected to a particular network or service area.* These are calculated from the Customer Interruption Cost (CIC)[21]

[18] Council of European Energy Regulators (CEER), Third benchmarking report on quality of electricity supply, 2005

[19] Billinton R, Economic Cost of Non-Supply, IEEE 2002

[20] OFGEM (former OFFER), Reviews of public electricity suppliers 1998 to 2000, Distribution price control review, Consultation paper, 1999

[21] Customer interruption cost result from an interruption in electricity supply as perceived by an individual customer (system independent).

and take into consideration the network performance data and loading information. They are therefore customer mix and system dependent.

5.1.2.1 Evaluation of Customer Outage Costs:

A variety of methods[22] have been utilised to evaluate the impacts of electricity supply interruptions. These methods can be grouped into three broad categories:

- **Indirect analytical methods:** Indirect analytical methods evaluate interruption costs by inference from associated indices or variables such as; electrical supply rates or tariffs, foregone production, foregone leisure time etc. The advantages of these and other similar methods are that they are reasonably straight-forward to apply, make use of readily available data, and, consequently, are inexpensive to implement. Their disadvantages are that most are based on severely limiting and often unrealistic assumptions, and most offer generic global rather than specific results.

- **Case Studies:** The second category of outage cost assessment is to conduct after-the-fact case studies of specific outages. This approach has been limited to major large-scale blackouts such as the 1977 New York blackout. The merit of this approach is that the interruption cost values relate to customer experiences of real interruptions rather than hypothetical scenarios. Their downside is number of case studies and resulting data sets are very small and the customer outage costs generally relate to very large scale or wide spread interruptions.

- **Customer Surveys:** The third approach that has been used to assess direct short-term customer interruption costs is that of customer surveys. With this method, customers are asked to estimate their costs or losses due to supply outages of varying duration and frequency at different times of the day and year. The strength of the method employing customer surveys lies in the fact that the customer is in the best position to assess the losses. Obviously, this method is beset with all the problems of questionnaire surveys, and the cost and effort of undertaking surveys is significantly higher than using the other approaches outlined earlier.

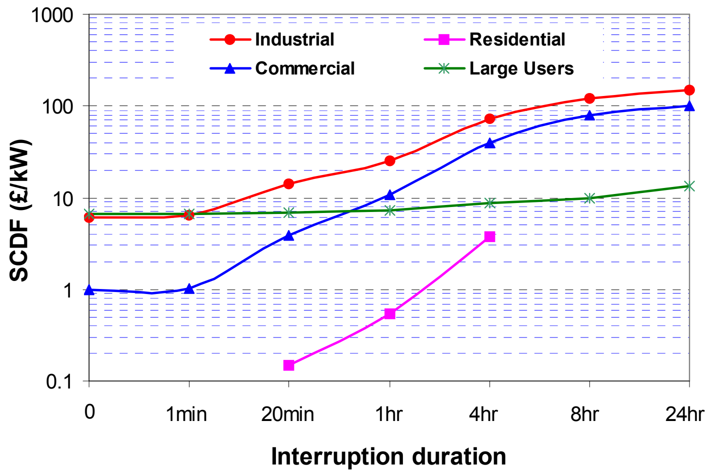
The customer survey based approach can obtain estimates of the CIC per interruption for each consumer sector[23]. The CIC data is collated according to each sector and normalized with respect to either the customers' annual energy consumption or with respect to their peak demand. These normalised costs are then appropriately weighted to yield a composite value for the overall sector. These costs (for the entire range of durations considered) are referred to as the Sector Customer Damage Functions (SCDF). The SCDF is defined as the sectors' normalised cost due to supply interruption duration for the customer mix supplied. It represents the costs an average customer in a

22 Cigre: Methods to consider customer interruption costs in power system analysis, August 2001, Task Force 38.06.01

23 Sector is a broad category which describes the main usage of electricity. It may refer to commercial, residential, industrial, agricultural etc

sector would incur per kWh consumed annually or per kilowatt of peak demand. Figure 26 shows the SCDFs of four sectors in UK developed through the extensive surveys[24,25].

Figure 26 – Graphical illustration of Sector Customer Damage Functions



A relatively simplified application of the above SCDFs was employed for the distribution price control period 2000-2005 by the UK regulator[26]. The application of these customer damage functions to compute customer outage costs requires contingency enumeration, i.e. the expected frequency and duration of various levels of interruptions needs to be determined. These can be determined using the frequency and duration models[27].

5.1.2.2 Optimum DN Capacity - Cost-Benefit Analysis

It is widely accepted that it is neither technically nor economically feasible for a power system to ensure that electricity is continuously available on demand. Instead, the basic function of a power system is to supply power that satisfies the system load and energy requirement economically and also at acceptable levels of continuity and quality. Low levels of investment can result in generally unreliable supplies, while excessive investment can result in unnecessary expenditure with a resulting increase in the cost of electricity to customers. Figure 27 shows how the security of distribution networks is impacted by different network developments.

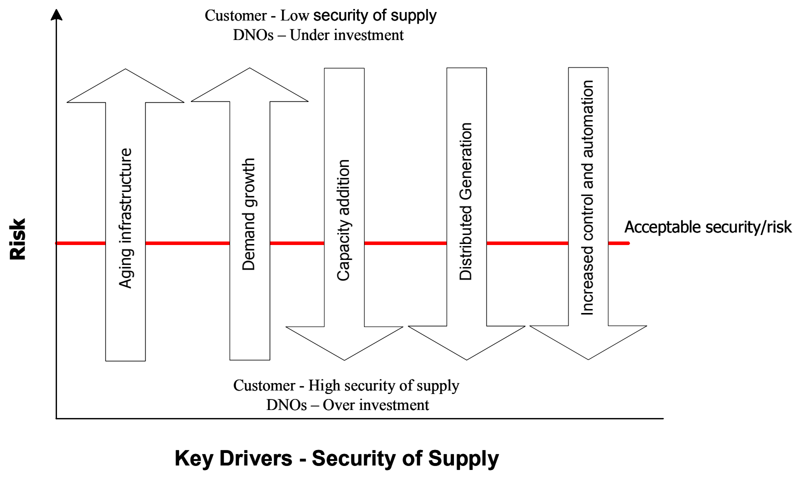
24 K K Kariuki, R N Allan, Evaluation of reliability worth and value of lost load, IEE Proc.-Generation Transmission and Distribution, Vol. 143, No. 2, p.p. 171 – 180, 1996

25 Kariuki, K. K. and Allan, R. N., Factors affecting customer outage costs due to electric service interruptions, IEE proceedings Generation Transmission & Distribution, PP. 521-528, 1996

26 OFGEM (former OFFER), Reviews of public electricity suppliers 1998 to 2000, Distribution price control review, Consultation paper, 1999

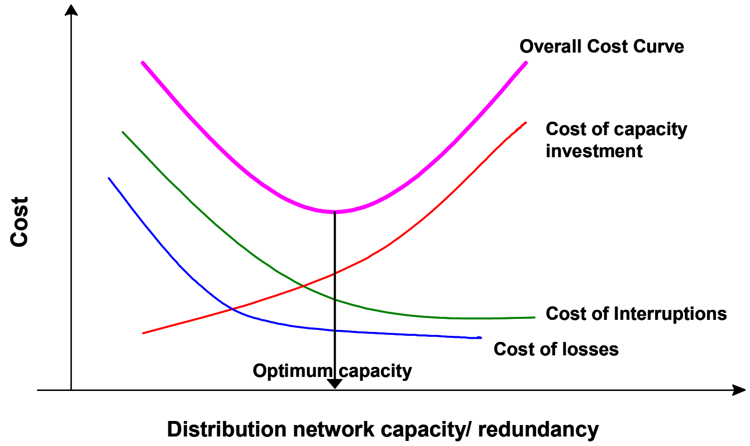
27 Billinton, R. and Allan, R. N., Reliability evaluation of power systems, Plenum Press, 1984

Figure 27 – Factors affecting security of distribution networks



The trade-off between the additional investments in distribution networks and savings in the cost of interruption and losses can provide the optimum investments levels that would result in minimum overall system costs (as indicated in Figure 28) with desired levels of system security.

Figure 28 – Optimisation of distribution network capacity



5.2 Requirements for planning standards

As already discussed, historic DNO design practices and the introduction of IIS has resulted in many LV and HV circuits being designed beyond the ER P2/6 minimum requirement. In this context, ER P2/6 is no longer the main driver for design and investment in the smaller demand groups for the bulk of DNO infrastructure. Given the significant impact of LV and HV circuits on overall network performance, as measured by CIs and CMLs, planning standards may be considered less relevant and hence unnecessary (in the Dutch market, standards only apply to the design of EHV networks supplying large demand groups). Although having a standard for the lower network voltages may not be critical for the vast majority of networks, the standard does prescribe a minimum level of assets required to be installed to meet demand of *every* consumer and could also be interpreted to implicitly reflect a form of minimum expected performance. This particular feature may be considered to be desirable by the regulator and the industry.

As discussed above EHV networks contribute little, *on average*, to the overall CI/CML performance in the long run, and hence IIS incentive scheme may not be appropriate for driving the design and investment in these networks. High reliability performance of the underlying network design is driven by the redundancy requirements and extensive network automation, as required by ER P2/6. Hence, interruptions that arise from EHV networks can be regarded as low probability but could potentially have high impact particularly when compared with HV/LV networks.

In order to conceptually examine the consequences that may arise from a framework that relied only on output incentive measures without a specific minimum network design standard, a DNO with 2,000,000 customers has been evaluated with various designs of EHV/HV substations. Ratings of typical transformers were assumed to be 90MVA so that each of the transformers could supply about 80,000 customers. According to ER P2/6, there will be approximately 25 EHV/HV substations with two transformers each. We contrast this situation with a hypothetical case in which the DNO network is supplied through 20 EHV/HV substations containing two transformers and 5 EHV/HV substations containing only one transformer, with one single transformer kept as a reserve (spare) across the five single-transformer substations. This design assumes no need to comply with ER P2/6. In order to assess possible consequences to the DNO and customers in a quantitative manner, a transformer failure rate of 0.02 faults/year with average repair time of three months was assumed without any transfer capability available. It was also assumed that the spare transformer could be installed on average in 16 hours. The cost of the transformer and associated equipment was assumed to be £25/kVA.

To analyse the new situation we refer to Table 18 that is summarised here in the form of Table 25 for the purpose of the example:

Table 25 – Reliability indices for different EHV/HV substation designs (Table 18 extract)

Availability MTTR	Installed capacity	EENS (%)	CI	CML
99.50% 3 months	D	0.5000	1.990	2628.00
	2xD	0.0025	0.020	13.14
	3xD	0.0000	0.000	0.07
	3x0.5D	0.0019	0.023	8.80
99.996% 16 hours	D	0.0037	2.000	19.20
	2xD	0.0000	0.000	0.00

The performance of the system containing 20 substations with two transformers and 5 substations with one transformer is: CML 14.35 m./c.y. (= 19.2x5/25 + 13.14x20/25) and CI 0.416 i./100c.y. (= 2x5/25 + 0.02x20/25) looking only at failures of the transformers in the substations. If this solution is compared with a solution of having two transformers in substations it can be seen that the difference, in the long term, is about 1.2CMLs (=14.35-13.14) and about 0.4 CIs (=0.416-0.02) (see table above). The penalty, on average, is about £230.4k for CMLs and £58.4k for CIs (as at present) which totals at £289k per year, or about £2.89m capitalised. This is at the level of the cost of one transformer that is installed in the substation (circa £2.25m). In the long-run the saving arising from investment would be about £6m (=4x2.25-2.89).

However, application of annual average values may not be appropriate for relatively infrequent events, as the cost of actual outage event to both DNO and customers may be very significant. To estimate the risk the DNO may face, we considered a case with one of these five transformers actually failing. Probability of one of these five transformers (in single transformer substations) failing in the course of a single year (assuming all in working order at the beginning of the year) is about 9.1% ($= 5 \times (1-e^{-0.02}) \times e^{-4x0.02}$). In that case the additional CMLs would be 38.4 (=16x60/25) and additional CIs are 4 (=100/25) at the company level. The penalty associated with such event actually occurring while assuming the existing incentive rates, is about £8m. To compare, the benefit of deferring the purchase of four transformers for one year is about £0.9m (=4x2.25/10). The DNO might decide to take such risk in the short run (in practice this risk may be possible to significantly reduce by having some transfer capability available).

To investigate the risk and cost associated with customers further, an approach based on the Value Of Lost Load (VOLL) was adopted. The EENS is 0.00274% (=0.0037x5/25 + 0.0025x20/25). If annual consumption of one customer is assumed to be approximately 3,500 kWh/year then during 16 hours the EENS is 6.4 kWh per customer. For VOLL of £30/kWh it equates to £192 per customer and for 80,000 customers this equates to £15.36m.

Although this is a simple and conceptual exercise, and the figures used reflect present performance rates (these may be modified in future) the example does illustrate significance of the planning standard in this area. Given the relatively low contribution of the EHV system to overall CI/CML performance, the absence of a design standard would require DNOs to balance the risk involved from possible CML/CI related penalties associated with significant outages with the capital gains from postponement of investment. This could lead to reduction in reliability characteristics of EHV networks (as in the example above), particularly in the short-run. As a result some groups of customers may be exposed to significantly higher risks (and cost) of interruptions of supply, while this would not necessarily be visible to the affected customers or to the regulator.

In order for robust incentive-based arrangements to be developed, potentially superseding requirements for a planning standard, it will be necessary to more accurately understand customer outage costs for a range of customers and the failure distributions of network components and systems. This information is not yet readily available to either DNOs or the regulator, thus undermining the feasibility of adopting purely incentive based arrangements in the short-term.

5.3 Deterministic and probabilistic approaches to distribution network planning

There are a number of potential weaknesses regarding the application of deterministic standards for distribution network planning. Deterministic standards are typically based on pre-specified contingency arrangements to apply following particular network events. Consequently, only a subset of conceivable network states can be considered by deterministic approaches.

In addition, the probability of different networks events occurring is not usually considered within deterministic planning standards. This is especially relevant when considering the availability of network security (or potential capacity shortfalls) under different loading conditions. Whilst peak loadings are usually taken as the critical planning conditions, the duration of these peaks is often relatively short, e.g. a few hours per year. There is a risk that the blind application of deterministic standards could result in inefficient network design and sub-optimal investment decisions.

A more sophisticated approach to network planning involves the adoption of probabilistic techniques with the aim of minimising total expected ‘system’ costs across all potential system states. Such system costs are optimised with respect to:

- Investment;
- Operational costs; and
- Outage costs (to customers).

Typically, probabilistic approaches allocate a consequence and probability to possible network events, which are assumed to occur on a stochastic basis. The associated investment requirements are based on well established costs of network expansion and reinforcement. As discussed in Section 3.4, whilst ER P2/6 is a deterministic standard, it was originally derived from a methodology based on probabilistic assessments.

In order to undertake robust probabilistic network planning, it is necessary to adopt modelling techniques such as Monte-Carlo simulations which have significantly greater input data requirements, e.g. fault probability distributions, demand variations over time and particularly customer outage costs for different customer groups. These data requirements go beyond those of deterministic standards, and in many cases, such information is not (yet) readily available to a DNO.

Should sufficient input data actually be available for modelling, network planners would then be required to interpret acceptable levels of network adequacy (capacity availability under different loadings for a variety of network states). Inevitably, the increased analysis requirement for network planners adopting probabilistic approaches needs to be considered relative to the potential reduction in overall system costs. The DNO resourcing implications regarding the adoption of probabilistic approaches would also need to be evaluated before implementation.

The form of a potential probabilistic network planning standard would be to prescribe minimum levels system performance. Planning criteria could include:

- 95% of interruptions to be restored in 3 hours;
- 95% of customers not to experience more than 2 interruptions per year; and
- Proportion of demand to be supported for a proportion of time, e.g. 100% demand to be supported 99% of time, 50% of demand to be supported 99.95% of time etc.

Whilst such planning arrangements could be regarded as attractive from a customer perspective, the monitoring and compliance aspects for the both the DNO and regulator may prove to be operationally challenging.

Another implementation difficulty associated with probabilistic analysis relates to network reliability. As the reliability of distribution network components is typically high, the availability of statistically significant and reliable fault distribution data could present a problem, especially when considering small groups of customers. Consequently, probabilistic approaches are best suited to larger customer (demand) groups. However, due to the uncertainties associated with input data and requirements for DNOs to develop new capabilities and planning tools, it would appear sensible for any new probabilistic techniques to be implemented on an incremental basis, where input data is known with a degree of certainty.

It is foreseen that probabilistic approaches could be developed to complement the current deterministic arrangements, following further research into failure probabilities and customer outage costs for different customer groups. Indeed such combined approaches could be accommodated within the current planning framework, thus enabling a controlled migration to a probabilistic approach should the benefits be demonstrated to justify the additional complexity. The authors are not aware of any DNOs adopting probabilistic planning approaches to date which may also be linked to an absence of corresponding commercial planning tools.

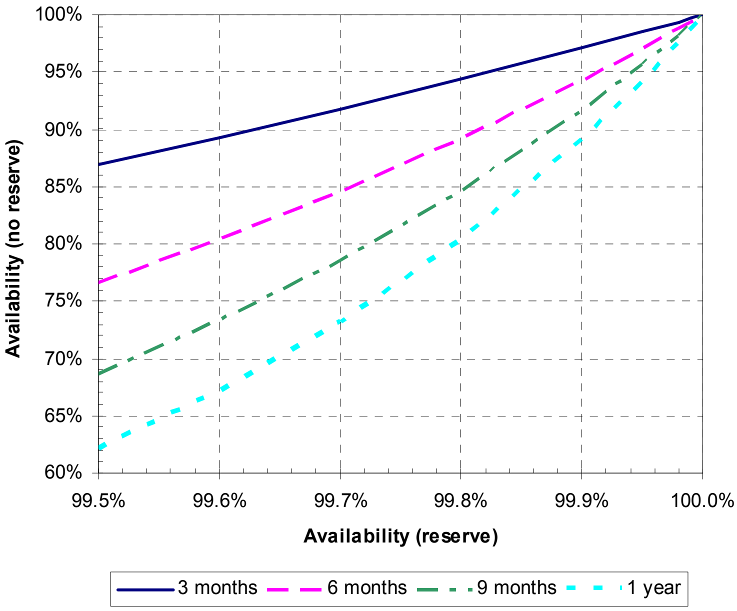
It is recommended that further work be undertaken to determine the relative merits of probabilistic approaches relative to the current deterministic arrangements as set out in ER P2/6.

5.4 Risks associated with extended 'construction' outages

As discussed in Section 3, it is important to consider security of supply characteristics during extended construction outage periods as all DNOs are currently accelerating their asset renewal programmes and ER P2/6 specifically refers 'maintenance' outages only. This section provides an example of the issues associated with construction outages for large Demand Groups (D and E) to support concerns regarding the increased risk exposures for both DNOs and customers.

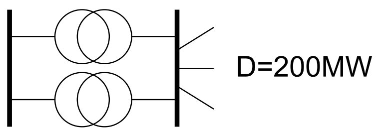
Figure 29 shows an example of how the availability of a network component changes depending on time required to replace the component under a construction outage scenario. The x-axis represents the availability where a spare component is readily available (assuming that the component on outage can be replaced with a spare one on average in three days). On the y-axis, values corresponding to an equivalent (new) availability of the in service component can be calculated. For example, if availability of component was 99.8% for average replacement time of 3 days, a new availability of the same component is about 94% if the average replacement time is three months and drops nearly to 80% if average delivery time is one year. This may be of concern if a failed component cannot be replaced promptly due to extended production lead times etc.

Figure 29 – Comparison of availability with and without reserve. When there is a reserve available it is assumed that element is changed on average in three days time.



In the following example, an illustrative construction outage scenario is investigated. Figure 30 shows a grid supply substation consisting of two transformers each rated at 240 MVA (with a cyclic rating factor 1.3). The transformer forced outage rate is assumed to be 0.02 faults/year and MTTR is 88 hours. Group Demand is assumed to be 200 MW at a power factor of 0.95. This substation is assumed to supply 200,000 customers out of a total of 2,000,000 connected to the DNO's entire network. Should a fault arise, there is secure and instantaneously available transfer capacity of 100 MW. If a transformer outage occurs during the installation of another one, the full supply can be restored in 88 hours.

Figure 30 – Grid supply substation



The substation is ER P2/6 compliant as all conditions are satisfied:

- Under no outage condition, demand is satisfied.

  2 x 240 x 0.95 = 456MW > 200 MW

- First circuit outage condition requires that at least 180MW of group demand is restored immediately and the remaining demand is restored within 3 hours. Requirement is also satisfied.

  1 x 1.3 x 240 x 0.95 + 100 = 396 MW > 200 MW > 180 MW

- Second circuit outage condition requires that at least 67MW is restored within 3 hours and the remaining demand is restored following completion of the planned outage. There is 100 MW of transfer capacity available which satisfies this condition.

Should one transformer be subject to a construction outage and the other develops a fault during peak loading conditions, only half of the impacted customers can be transferred to the alternate supply (transfer capacity), while the remaining half will not be supplied for 88 hours. This gives an additional CML of 264 minutes/year.customer (88x60x100,000/2,000,000). Applying the 10% weighting factor to the resultant CMLs (see Table 5) the event will worsen company's overall CML performance by 26.4 minutes/year.customer. The revenue reduction for such an event equates to £5,068,800.

The potential penalty is clearly high and would have a significant impact on DNO profitability. However, the probability of such event happening is low. Assuming a construction outage lasting for 3 months, the probability of the other transformer failing during that period would be only 0.5%.

In order to make informed decisions as to how to manage and implement construction outages, DNOs need to undertake risk assessment exercises. Depending on the level of confidence in their evaluations (requiring numerous assumptions) and the company's attitude towards risk, risk mitigation strategies may vary between DNOs and over time. As a result, some DNOs, with insufficient confidence regarding input data assumptions, combined with a risk adverse position, may prefer to install temporary network infrastructure to reduce exposures. Conversely, other DNOs with a higher confidence in their ability to manage failures post-event (assuming that their evaluation supports a reactive approach), combined with a less risk adverse attitude, may decide not to install temporary assets but rely on post-fault restoration techniques. These decisions require a trade-off between the savings associated with avoiding contingency arrangements relative to the costs associated with possible regulatory penalties.

As ER P2/6 does not explicitly address construction outages, there is a requirement to understand and quantify the increased risks of interruptions that are driven by different outage management practices. It will be important to quantify the cost of alternative strategies for mitigating risks so that appropriate decisions can be made in relation to contingency arrangements. Given the increasing activity associated with asset replacement, this issue requires further in-depth consideration.

5.5 Common-mode faults – EHV network example

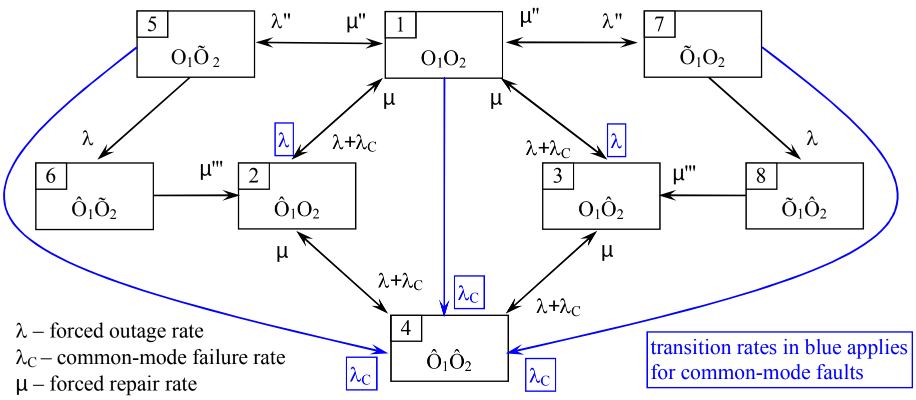
ER P2/6 does not address explicitly common-mode faults. These may be relevant when considering OH circuits on the same route or the laying multiple cables (that are expected to provide redundancy for one another) in the same trench.

To evaluate the importance of common mode failures, two overhead lines circuits, each 10 km in length, have been modelled. A failure rate 0.1 faults/year.km and average repair rate of 16 hours has been assumed. Each of the lines is capable of carrying the full load. To carry out the calculations we assume that the failure rate of a pole fault is (a) 1/10 or (b) 1/100 of the forced failure rate and that average repair time remains unchanged irrespective of the nature of the outage (single or double), which is probably optimistic. Maintenance is assumed to be undertaken once in four years and lasts on average for ten hours. We examine two cases, case (i) with two lines are completely separate and there is no common mode failure and (ii) when these two lines are on the same route.

In order to examine the significance of these scenarios, a Markov model was developed as shown in Figure 31.

Figure 31 – Markov model of two overhead lines (i) on a different routes and (ii) on the same route (blue transition rates applies)

Markov model of states of two components including maintenance and common-mode faults



λ – forced outage rate
λ_C – common-mode failure rate
μ – forced repair rate
λ" – planned outage rate
μ" – planned repair rate
μ''' – urgent planned repair rate

O – component in service
Ô – component out of service
Õ – component in maintenance

A summary of this analysis is provided in Table 26. It can be observed that, in this example, majority of CIs and CMLs originate in common-mode faults. Even where the failure rate of common-mode faults is 100 times lower than the failure rate of a single overhead line, the values of reliability indices are more than three times higher. This is attributable to the avoidance of interruptions where one line remains in service, i.e. interruptions occur when both lines are faulty or a fault is superimposed on a maintenance activity.

Table 26 – Results for example with overhead line on the same route

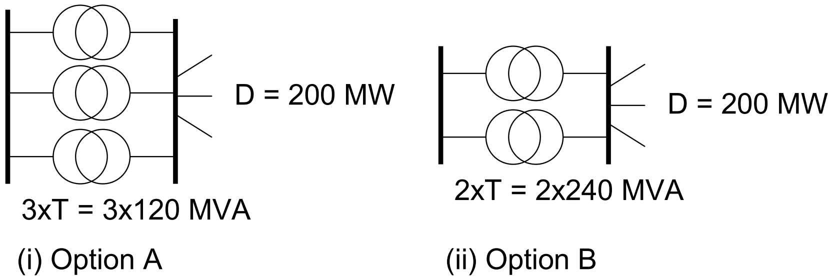
Case	Failure rate (faults/year)	Common mode failure rate (faults/year)	EENS (%)	CI	CML
(i)(a)	0.1x10 = 1	0.1	0.0005	0.503	2.49
(ii)(a)	1	0.1	0.0095	10.438	50.17
(i)(b)	1	0.01	0.0004	0.429	2.13
(ii)(b)	1	0.01	0.0013	1.422	6.90

ER P2/6 does not specify how required levels of redundancy should be delivered, and it does not prevent reserve circuits being exposed to common mode faults, which can significantly degrade CI/CML performance. The performance incentive regime may encourage more attention to this issue in future. However, it is likely that there are existing assets exposed to common mode faults which may significantly reduce the value of redundancy available. This may be a particularly material issue for large demand groups, exposed to potentially high risks of common mode failures and it is recommended that this issue be examined in more detail.

5.6 Interface between distribution and transmission

In this section, the impact of substation design at the interface between DNOs and the transmission system is evaluated from an asset renewal perspective. Some DNOs have concerns that reducing the numbers of transformers (e.g. from 3 to 2) at a Grid Supply Point interface substation may increase exposures to CI / CML penalties. In order to examine this question, two typical configurations have been evaluated for a group demand of 200 MW as shown in Figure 32, with a transfer capability of 80MW available in both cases.

Figure 32 – Substation options A and B



We first identify the total capacity of these configurations according to ER P2/6 criteria. The peak demand of 200MW aligns with Group Demand D and both FCO and SCO conditions apply:

Option A: first and second circuit outages conditions are as follows:

- (FCO): 2 x 1.3 x 0.95 x 120 + 80 = 376 MW, and
- (SCO): 1 x 1.3 x 0.95 x 120 + 80 = 228 MW.

Option B: first and second circuit outages conditions are as follows:

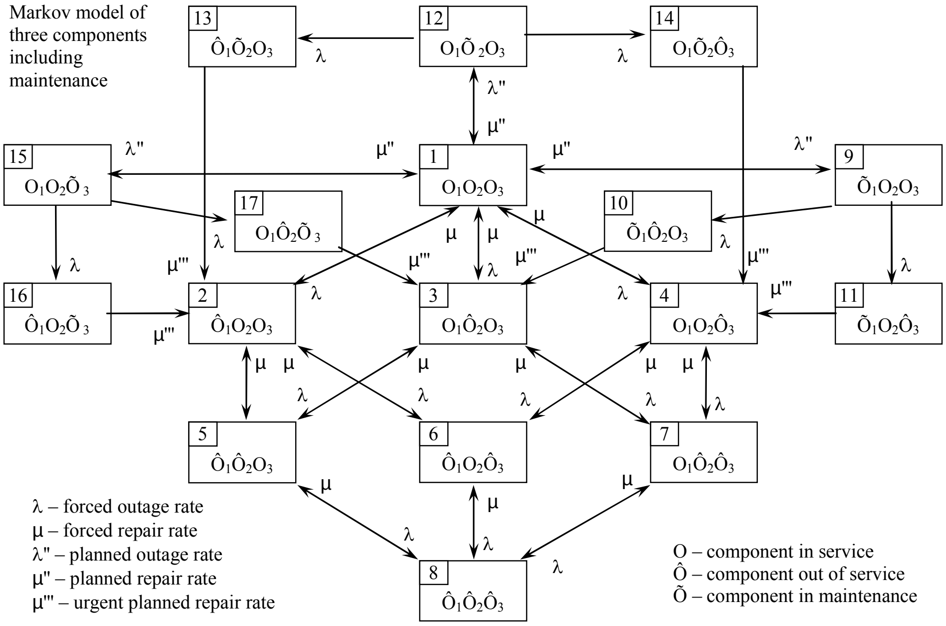
- (FCO): 1 x 1.3 x 0.95 x 240 + 80 = 376 MW, and
- (SCO): 0 x 1.3 x 0.95 x 240 + 80 = 80 MW.

For the group demand of 200 MW the conditions for supply restoration, according to ER P2/6, are as follows:

- (FCO): (a) Immediately at least 180 MW and (b) The remaining 20MW in 3 hours.
- (SCO): (a) At least 67 MW within 3 hours and (b) The remaining in restore time of planned outage.

From the above, it can be seen that both options satisfy ER P2/6. In order to analyse the CI /CML performance of these configurations the Markov reliability model shown in Figure 33 was developed. The model considers both forced outages and maintenance with respective transition rates (reliability parameters are: forced outage rate 0.02 per year, average repair time 6 months, planned outage rate 0.5 per year, planned outage duration 66 hours).

Figure 33 – Markov model for three transformers including planned outage



The results of the reliability assessment for these two options are given in Table 27. From this assessment we conclude that replacing option A design with the option B configuration will in the long run increases the total system CMLs by approximately 5. Given the present incentive mechanism rate levels it would seem justified to opt for more secure designs. Although the example is generic and simplistic in nature, it suggests that there may be issues at the interface between DNOs (i.e. ER P2/6) and the transmission network (i.e. GB SQSS) that would be worth clarifying and addressing more explicitly through appropriate industry led forums.

Table 27 – Reliability indices for the two options to supply a Group Demand.

Option	EENS (%)	CI	CML
A: 3x120MVA + 80MW	0.0000	0.0001	0.02
B: 2x240MVA + 80MW	0.0010	0.0090	4.96

5.7 Impact of large-scale deployment of distributed generation

5.7.1 Network security contributions from distributed generation

DNO consultation has revealed that the rate of deployment of new distributed generation has remained relatively low since the implementation of ER P2/6. Consequently, no examples of distributed generation being used to secure Group Demands as detailed ER P2/6 were identified.

The lack of an established framework by which DNOs can reward generators for the provision of security contributions has been identified as a potential barrier. In addition, the current regulatory arrangements associated with distribution do not incentivise DNOs to make payments to generators for network security contributions.

Examples of DNOs procuring network security contributions from distributed generation have been identified in the Dutch electricity market. Whilst not a commonplace practice, Dutch DNOs do make payments to distributed generators to maintain or alter their operating regimes to support networks and provide security, especially during network outages. Such arrangements are typically agreed with individual generators beforehand for a defined period of time and often do not require the generator to alter operating profiles. The types of generation considered for the provision of network security are typically high-availability conventional technologies and intermittent wind generation not considered. These approaches provide incremental revenue to the generator and enhanced security to the DNO, i.e. mutual benefits for both parties. To date, Dutch DNOs have not sought to impose delivery related liabilities on the generator.

One GB DNO confirmed that situations arise where load growth makes ER P2/6 compliance marginal and it is in these situations that security contributions from generation are evaluated in greater detail. However, the requirement to assess compliance based upon gross 'latent' demand excluding distributed generation (of which only a proportion of the aggregate capacity can be considered for security contribution), can make compliance more challenging than under P2/5. In addition, such evaluations demand comprehensive data regarding the size, number and type of generators available within a Demand Group.

5.7.2 Connection requirements for distributed generation

Both ER P2/5 and ER P2/6 are silent regarding the network redundancy requirements for generator connections which contrasts with the transmission system planning requirements as defined in the GB Security and Quality of Supply Standard (SQSS). The rationale for inclusion of generator connection criteria in the SQSS relates to the relative size and availability of generators and the potential system operation requirement to support large demand groups with a relatively small portfolio of large generators.

As the ratings of distributed generators tend to be significantly smaller than transmission connected units, the ability of individual generators to secure demand is more limited. In the event that multiple distributed generators were being used to secure demand collectively, the contribution of individual generators would be less significant than in a transmission context. Also, as distributed generators are often well embedded within distribution networks (electrically remote from the transmission network), their ability to supply larger geographic areas is further constrained. Consequently, it is less important that connection criteria for distributed generation be formally defined in the planning standard.

The current approach for agreeing distributed generation connection requirements is through bilateral negotiations between the DNO and the generator. In situations where a generator requires a secure connection to the distribution network, agreement can usually be reached with the relevant DNO to provide such a connection (subject to the payment of additional costs). Experience to date has been that distributed generators have not typically sought additional redundancy in their connections to DNO networks.

From a network design perspective, it would appear reasonable for the distribution planning standard to remain silent regarding generator connection criteria and for differences in generator connection requirements to remain a matter for the DNO and relevant generator.

5.7.3 Transmission - DNO ‘Sandwich’ arrangement

ER P2/6 is a demand driven network design standard which does not address the security of networks for power transfers originating from generation. The DNO Licence does not place any obligations on DNOs to provide a particular level of security to generator customers.

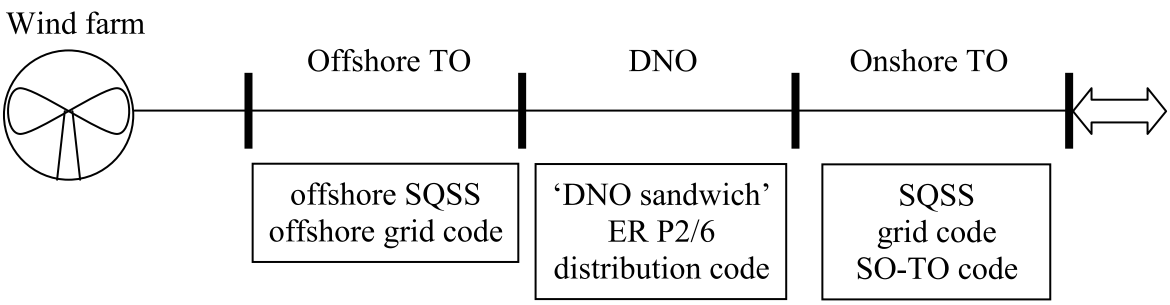
The ‘DNO sandwich’ is a term used where distribution networks are required to transfer power between transmission operators. It is particularly relevant where potential offshore transmission networks are connected to distribution networks at 132 kV in circumstances where connection to the onshore transmission network is not possible as shown in Figure 34. This is an emerging issue particularly associated with developments in offshore generation.

Although this potential network configuration involving offshore generation has emerged only recently, there are a number of high-level issues requiring consideration, including the applicability of an offshore Security and Quality of Supply Standard where the offshore transmission system is connected to a distribution network in the absence of standards to securely transport the power flows from such generation. As the current arrangements may not provide sufficient certainly for the developments in offshore wind, it is becoming important to understand requirements and to quantify the appropriate levels of network security to transport outputs from distributed generators.

There are a number of detailed questions to be considered regarding potential DNO Sandwich arrangements including, clarity with respect to compensation payments should DNO network capacity be insufficient to accommodate such power flows (and which parties would be liable), the differences in security standards at the connection between offshore network and a DNO network, relationship between offshore TO and DNO etc.

A possible development path, should a significant capacity of new generation require distribution networks to transport outputs, would be to review the existing industry codes, practices and governance procedures followed by the development of an SQSS for onshore distribution networks.

Figure 34 – 'DNO sandwich'



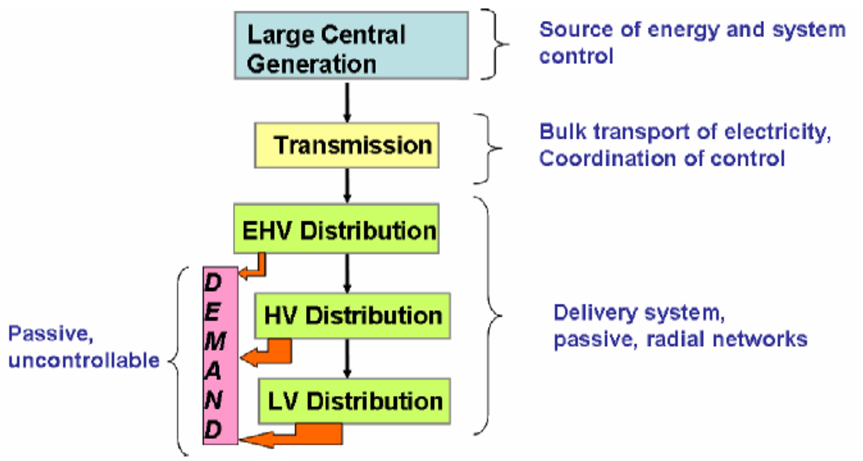
5.7.4 Distributed generation and network design in future

The need to respond to climate change, improve efficiency of the system and increase fuel diversity and enhance security of supply, coupled with rapidly aging assets and recent development in ICT, may open up the question of the strategy for infrastructure replacement in particular the design and investment in future electricity networks. This coincidence of factors may present a real opportunity to re-examine the philosophy of the traditional approaches to system operation and design and develop a policy that will provide secure, efficient and sustainable future energy supply.

5.7.4.1 Present system design and operation philosophy

In common with most industrialised countries, the UK system has been design to support the post world war II economic growth and the development in generation technology. Figure 35 shows a schematic diagram of the structure of the traditional electricity system with its four main sectors: generation, bulk transmission, distribution and consumption.

Figure 35: Schematic diagram of the power system with four main power sectors: generation, bulk transmission, distribution and consumption.



The system is characterised by small numbers of very large generators, mainly coal, oil, hydro and nuclear, and more recently gas based generation. Typical power station ratings would be from a few hundred MWs to a couple of thousand of MWs. These stations are connected to a very high voltage transmission network. The structure of the electricity transmission and distribution networks was driven by an overall design philosophy developed to support large-scale generation technologies.

The traditional role of the transmission system is to provide bulk transport of electricity from these large stations to demands centres, cities. The electricity is then taken over by the distribution networks that, through a number of voltage transformations (typically EHV, HV and LV) provide the final delivery of electricity to consumers. The flow is unidirectional from higher to lower voltage levels.

5.7.4.2 Drivers for increased contribution from DG

The UK is committed to respond to climate change challenge and the energy sector, and in particular the electricity, sector will be required to deliver the changes necessary. In the last decade, the UK has supported deployment of DG (distributed generation) of various technologies (particularly renewables and CHP) to reduce carbon emissions and the need to improve system efficiency. These generation technologies range from kW size domestic PV and micro CHP systems to several hundred MWs of wind generation connected to EHV (extra high voltage) distribution networks (132kV), as shown in Figure 36[28].

Given that the key function of a network is to provide secure and efficient transport of electricity from generation (production) to demand (consumption), the position (location) of generation relative to

[28] Some of the very large wind farms may be connected directly to transmission networks

demand is the dominant factor driving the design and operation of electricity networks. Furthermore, the type of generation technology used, together with the pattern of usage, will make an impact on the actual network operation and development. Finally, advances in technology may open up new opportunities for achieving further improvement in efficiency of operation and investment in distribution networks. Hence, the position of generation relative to demand and the amount of power to be transported, are the key factors driving the design and operation of electricity networks. If there were very substation changes in the location of future generation, e.g. if significant proportion of generation is to migrate from transmission to distribution networks, this may radically change the way in which distribution networks should be design.

Figure 36 Connection of various forms and sizes of distributed generation to distribution networks

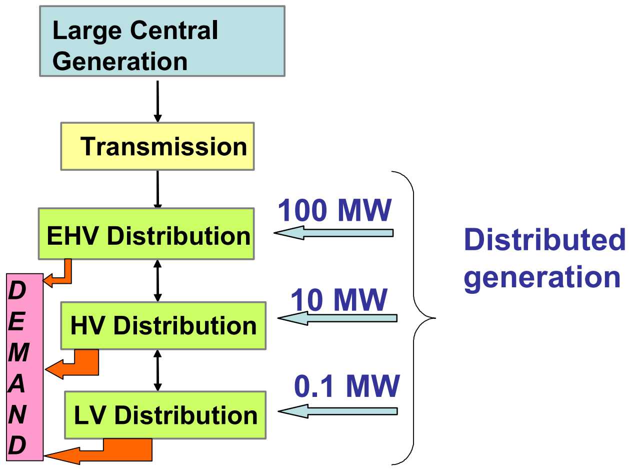


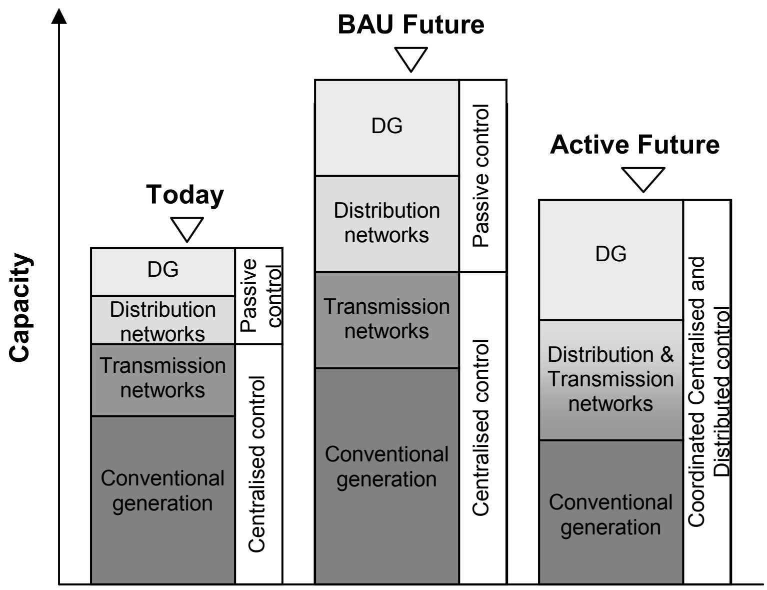
Figure 36 also illustrates the fact that locations and sizes of future generation will have an impact on network design and investment.

5.7.4.3 Integration of DG in network operation and development

The current policy of installing distributed generation has been focused on connection rather than integration; typically, DG has been installed with a "fit and forget" approach, based on the legacy of a passive distribution network. Under this regime, DG is not visible to the system so whilst it can displace energy produced by centralised generation it cannot displace its capacity. Without active management at the distribution level or representation to the transmission system, DG lacks the conditions required to provide system support and security activities, so centralised generation capacity must be retained to perform this function. With growing pressure to increase DG penetration, this passive approach will lead to rising costs for investment and operation of the system and ultimately impact the pace of DG adoption.

Figure 37 shows a schematic representation of the capacities of DG, distribution and transmission networks as well as central generation of today's system and its future development under two alternative scenarios both with increased penetration of DG. The Business as Usual (BAU) future represents system development under a traditional system paradigm characterised by centralised control and passive distribution networks as today. The alternative, Active Future represents the system capacities with DG and the demand side fully integrated into system operation under a decentralised operating paradigm which allows DG to participate in both energy markets and system management. DG and the demand side will take responsibility for delivery of system support services alongside central generation. In this approach, DG will be able to displace not only energy produced by central generation but also its controllability and capacity and also substitute for both transmission and distribution network assets.

Figure 37: Relative levels of system capacity under centralised and distributed control strategies



5.7.4.4 BAU future

Under the BAU future, large-scale penetration of DG will displace a significant amount of the energy produced by large conventional plant. However, if DGs and demand side are not integrated in system operation, conventional generation will continue to be necessary for provision of system support services (e.g. load following, frequency and voltage regulation, reserves) required to maintain security and integrity of the system. This implies that a high level of DG will not be able to displace the capacity of conventional plant as indicated in Figure 37. Given that DG is connected to the distribution networks, maintaining the traditional passive operation of these networks and the philosophy of centralised control will necessitate increase in capacities of both transmission and distribution networks.

5.7.4.5 Active future scenarios

By fully integrating DG and the demand side into network operation as proposed in the "Active Future", DG and the demand side could take the responsibility for delivery of system support services, taking over the role of central generation. In this case DG will be able to displace not only energy produced by central generation but also its controllability, reducing the capacity of central generation as in shown in Figure 37. To achieve this, the operating practice of distribution networks will need to change from passive to active. This will necessitate a shift from the traditional central control philosophy to a new control paradigm of coordinated centralised and distributed control.

A radical departure from the present large scale based generation system to a system supplied by distributed medium and small size CHP, together with various forms of renewable generation, would be driven by the prospect of significantly increasing the efficiency of the overall energy supply system. This would be primarily achieved, in the main, by making use of rejected heat from medium and/or small size thermal based electricity generation, i.e. CHP, to supply space and water heating demand (i.e. CHP).

We recognise that the design of distributed power supply systems that involves CHP technologies should need to consider the interaction between heat and electricity production and demand and, in future, the relationship with the transport sector. However, for the purpose of this report we briefly discuss only the role of the electricity networks in such a future.

It is well known that there are significant benefits of electricity distribution networks because the alternative of balancing electricity demand and supply at a household level would be very inefficient. The capacity of an electricity system supplying several thousand households would be only about 10% of the total capacity that would be required if each individual household were to be self sufficient. Clearly, distribution networks are essential for achieving this significant benefit of load diversity.

Notwithstanding the case made for LV and HV distribution networks, the need for higher voltage level destruction networks may reduce. This is in stark contrast with the present philosophy of the network design in which the level of redundancy increases with the voltage level. In such future, a radically new network design principles will need to be developed[29].

Distributed architectures should provide a better quality of service and a higher level of security than centralised or hierarchical arrangements. This could be achieved with a distributed power systems because a very large number of generators would be available and accessible through multiple paths through the network. Traditional network operation philosophies are not designed to take advantage of the improvements in quality and security of supply potentially offered by the introduction of highly distributed energy systems.

[29] This is however very unlikely to be case in the context of the UK situation. This is because significant transmission infrastructure will be required in any case to facilitate the transport of massive amounts of power produced by remote large on and offshore wind farms and, in future, by other marine technologies. If several (tens of) GWs of wind power produced in Scotland and from offshore wind farms (and other renewables) is to be efficiently transported to remote load centres (e.g. South East), high voltage transmission network and distribution networks will be required, as these large amounts of power cannot be transported at lower voltage levels.

This future requires significant Information and Communication Technology (ICT) capabilities to facilitate interaction between a large thousands (potentially millions) of DG units and the system operators, as well as new decision support tools to interpret and act upon the new information presented by integrated DG. This will bring an increase in complexity of system operation; however, with the correct development and innovation this new paradigm of shared centralised and distributed control should facilitate the development of more reliable, cost effective and sustainable systems that achieve maximum utilisation of all the resources connected within them.

5.7.4.6 Islanding

In future, there could be opportunities for DG to improve service quality on 11kV and 0.4 kV networks, given the contribution of such networks to Quality of Service statistics. In order for DG to improve service quality on such networks however, the generation must also be connected at 11kV or 0.4kV, thus restricting opportunities to relatively small sized generation. A key requirement for DG, to reduce the impact of outages, is islanded operating capability.

As referred to in Section 5.1 of this report, the maximum benefit is limited to the Customer Outage Cost (COC) of the base case network without islanding. Hence, if the network performance without DG is assumed to be commensurate with the average annual British distribution network (CI/customer ≈ 0.9, CML ≈ 60 minutes) then the maximum potential benefit is of the order of the magnitude of the corresponding COCs. The COCs of the average British distribution network are found to range between £1.4/kW and £19.0/kW for residential and commercial customers respectively. These values indicate the maximum potential benefit of an uninterrupted transition into islanded mode.

Islanded operation during abnormal network conditions is only economic if the associated costs do not exceed the benefit. The maximum expenditure on equipment to enable DG islanding is therefore limited by the associated benefit. Considering a typical asset lifetime and discount rate the capitalised values of the islanding benefits are around £15/kW for residential and £200/kW for commercial customers. Therefore, islanded operation of small-scale DG, such as 2kW DG supplying one household, would permit an expenditure of around £30 to upgrade the system for islanded operation. On the other hand, a 1MW network area of commercial customers would support an investment of around £200,000 to enable islanding. These values are averages; the permissible expenditure can be higher in network areas with a lower quality of service and reliable DG, and vice versa.

In this context it should be mentioned that energy production is generally the main income source for most DG. However, in future some generators could market the islanded operation service and open up a secondary income source. In present networks, islanded operation is relatively expensive since the costs of the generation plant and additional system automation must be borne. But in future, large numbers of DG could already be connected to actively managed distribution networks. Hence, the costs to exploit the benefits of an islanded mode are expected to be lower since only the costs of additional automation and control must be met. This in turn could then impact the design of higher voltage distribution networks and lead to a reduce asset based in these networks.

5.7.5 Impact of Demand Side Participation on future network deign

In order to supply demand that varies daily and seasonally, and given that demand is largely uncontrollable and interruptions very costly, installed generation capacity must be able to meet maximum (peak) demand. In addition, there needs to be sufficient capacity available to deal with the generation failures and unpredicted demand increases. Historically, a capacity margin of around 20% was considered sufficient to provide adequate generation security. Given the average demand across the year, the average utilisation of the generation capacity is below 55%. This relatively low average plant utilisation provides significant scope for the adoption of demand side measures as loading shifting from peak to off-peak periods reduces generation capacity requirements whilst simultaneously increasing the utilisation of the remaining generating plant and hence increases the efficiency of generation investment.

Similarly, the design and structure of electricity networks has been driven by an overall design philosophy developed to support large-scale generation technologies. Given the network design principles, the distribution system is able to continue to function after a loss of a single circuit (for the largest Demand Groups). Following an unplanned outage, the remaining circuits assume the extra load and must not become overloaded. This means that under normal operation, during the peak load conditions, circuits in the network generally operate below 50% of the peak loading. This network design philosophy is based on the assumption of uncontrollable demand.

5.7.5.1 Changes to network design / operation through Demand Side Participation

There are a number of drivers that may encourage increased Demand Side Participation (DSP) in future, including climate change and ageing electricity infrastructure. Recently, there have been major advances made in information, communication, metering technologies (smart metering) accompanied by the development of enhanced functionality within electrical appliances (e.g. smart appliances), that could enable the wider deployment of DSP in future.

These developments could facilitate radical changes in both network operation and design philosophy. Network security is traditionally achieved through preventative measures: the system is designed to withstand credible outages (specified in accordance with the security standards), with no need for any immediate corrective action to be taken following the outage. An advantage this network planning (and operation) philosophy is simplicity of operation, albeit achieved at the expense of investment costs and asset utilisation. An alternative approach would be to operate the network with reduced capacity (hence with higher utilisation), provided that overloads after outages of circuits can be avoided through appropriate corrective actions. This could be achieved by redistributing loads across time at appropriate locations. By enabling networks to operate with lower capacities, the corresponding distribution network investment requirement can be reduced whilst maintaining appropriate levels of security. In this context DSP could facilitate a change in network operating philosophy from preventive to corrective.

In general, DSP could bring a spectrum of potential benefits to distribution networks in terms of

- deferring new network investment;
- increasing distributed generation connection capacities;
- relieving voltage constrained power transfer problems;
- relieving congestion in distribution substations;
- simplifying outage management whilst enhancing the quality and security of supply to critical load customers, and
- providing corresponding carbon emission reductions.

The use of DSP for unlocking unused network capacity and for system support services has not been widely implemented. The value of the benefits of DSP technologies in releasing latent network capacity is not yet well understood and quantified although initial studies demonstrate that the potential may be significant[30]. More work is required to examine the value and practicalities of DSP implementation in this context. Our initial studies indicate that the value of controlling transmission and distribution networks using DSP in a corrective mode could be significant, but this will strongly depend on existing levels of network capacity (system stress) and generation fuel cost differentials[31]. Should significant demand side capabilities emerge, a more radical review of the current network design philosophy will inevitably be required.

[30] A Jayantilal, G Strbac, " Load Control Services in Management of Power System Security Costs", IEE Proc, Gen.Trans.Dist , Vol 146, No.2, May 1999. (269-275)

[31] G Strbac, S Ahmed, D Kirschen, R N Allan, "A Method for Computing the Value of Corrective Security", IEEE Trans. Power Systems, Vol.13, No3, August 1998. (1096-1102)

6. Conclusions

The following sections provide conclusions from this study and evolutionary options for the future development of the current planning arrangements.

6.1 Requirements for a network planning standard

The Interruption Incentive Scheme (IIS) has become an influential driver of HV/LV network design and the requirements of ER P2/6 have effectively been superseded for Classes of Supply A, B and C. For these Classes, DNOs typically plan their networks beyond the minimum planning requirement, and the IIS has reinforced this approach. Although the IIS has adequately addressed frequent low-impact supply interruptions originating on LV/HV networks, it may not adequately protect customers with respect to low probability / high-impact events for the larger Classes of Supply, should the planning standard requirements be removed.

The contribution of EHV networks to long-run output measure performance is low, hence the IIS is insufficient to drive EHV design and investment alone. An over-reliance on incentive arrangements as a driver for network planning is that customers could be exposed to higher risks (and costs) of supply interruptions. Consequently, it would appears sensible to retain both a planning standard and an output performance incentive framework to deliver appropriate levels of security at EHV and a high quality of service to customers connected at HV/LV.

It should be recognised that ER P2/5 supported a variety of network designs in terms of voltage levels and interconnection capability. These design strategies have implications for network performance, costs and losses. Divergent approaches have evolved between different DNOs and there is no evidence to suggest designs will converge in future.

6.2 Supply interruption frequency to individual customers

A significant omission from ER P2/6 is the absence of planning guidance regarding supply interruption frequency for individual customers. A useful development of the current planning framework (from a customer perspective), would be to specify maximum expected interruption frequencies. Ideally, it would be helpful for the planning standard to contain such guidance as in ACE Report 51. However, the licence compliance implications of such inclusion may present a barrier, and thus favour alternative approaches, e.g. inclusion in future Guaranteed Standards or incentive arrangements. Before incorporation within the planning framework, it will be essential to determine appropriate interruption frequencies through further modelling and analysis.

The IIS and Guaranteed Standards of Performance provide some customer protection for interruption frequency although the Customer Interruption (CI) and Customer Minutes Lost (CML) output measures are not ideal as these are average system indices rather than individual load point indices and therefore reflect the impact of system behaviour on the "average" customer – a customer who in reality does not exist.

6.3 Critical network loadings

The critical network loading condition adopted in ER P2/6 is assumed to occur during an Average Cold Spell. Changes in network usage have resulted in this assumption becoming invalid for particular network areas. A useful development of the current planning standard would be to make DNOs responsible for assessing the critical network loading conditions relevant to their networks.

A further implication of summer load growth is increased asset utilisation with reduced differences between the summer and winter peak loading conditions. The issue of increased summer loading is further complicated by the reduced equipment ratings of network components due to the higher ambient temperatures.

6.4 Group Demands and Transfer Capacity

In order to improve transparency and to clarify the compliance requirements for network operators (including transmission) and the regulator, it would be helpful for representatives of all the relevant stakeholders to establish agreed definitions/principles for Group Demand boundaries and associated Transfer Capacities for inclusion in any revised planning standard.

6.5 Transmission / Distribution network interface considerations

A further issue regarding transfer capacity applies at the interface between the transmission system with distribution networks. Requirements for DNOs to provide transfer capacity would benefit from clarification to ensure that risks apparent to each network operator are clearly understood and that co-ordinated approaches to risk mitigation are be adopted.

Analysis has demonstrated that Grid Supply Point arrangements can impact the expected IIS performance of a DNO. It can be attractive for TOs to rationalise transformer arrangements at a Grid Supply Points (e.g. reducing transformer numbers from 3 to 2). Reliability calculations reveal that such developments can increase CI/CML exposures for DNOs. It would be useful to establish co-ordination procedures between DNOs and TOs in order to quantify these risks.

6.6 Minimum planning requirements and lifecycle costing

The IIS drives distribution network design for the smallest Demand Groups and DNOs typically design beyond the minimum planning requirement, whereas low (initial) capital cost network designs aligned with the minimum planning standard, may not be optimised from lifecycle cost or network security perspectives. In a liberalised electricity market, 3rd parties may be responsible for network design without any ongoing network management responsibilities and therefore low capital cost solutions can be attractive, although the outcome from a customer perspective may be sub-optimal in the long-run.

A further benefit of robust, low-loss electricity network infrastructure is flexibility regarding the sustainable development of the UK electricity system. Such networks are readily able to accommodate the uncertainties associated future generation portfolios in terms of type, size, location and performance. In order to ensure optimised network designs are implemented, it will be increasingly important to consider lifecycle costing when reinforcing and extending networks.

6.7 Construction outages

Analysis has revealed that construction outages for the larger Demand Groups (D and E) can impose significantly increased risk exposures for both DNOs and customers. As ER P2/6 does not explicitly address the duration of outages, there is a requirement to understand and quantify the increased risks of customer interruptions that are driven by different DNO outage management practices under construction outage scenarios. It will be important to quantify the cost of alternative strategies for mitigating such risks so that appropriate decisions can be made in relation to contingency arrangements. Ideally ER P2/6 could be amended to differentiate between maintenance and construction outages and to provide guidance on risk mitigation.

The possibility of second circuit outages taking days (possibly weeks) to rectify for the larger demand groups is regarded as credible, especially when reliant upon heavily loaded ageing assets. It is interesting to note that the Dutch Grid Code specifically acknowledges the risks associated with extended outages on EHV networks, requiring DNOs to maintain n-1 security during outages beyond 6 hours in duration. Given the issues of increased summer demand and construction outage management, it would be appropriate to review whether the staged restoration process for Second Circuit Outages as specified by ER P2/6 should be removed or amended.

6.8 Common mode failures

ER P2/6 does not specify how the required levels of redundancy should be delivered, and it does not prevent reserve circuits being exposed to common mode faults, which can significantly degrade CI/CML performance. This may be a particularly material issue for large demand groups, exposed to potentially high risks of common mode failures and it is recommended that this issue be examined in more detail.

6.9 Consistency and correlations between the planning and incentive frameworks

The underlying methodology underpinning ER P2/6 is based on the concept of Expected Energy Not Supplied (EENS). High-level analysis has confirmed a significant correlation between energy not supplied and customers not supplied and it therefore follows there is a similar correlation between EENS and CMLs. Supply restoration and repair times have been demonstrated to significantly impact CMLs whilst not affecting CIs. Correlations between CIs and CMLs are weaker.

Overall, the IIS framework can be considered to be broadly consistent with ER P2/6 when quality of supply incentives for large numbers of customers are compared to planning requirements for different Classes of Supply, especially with respect to average interruption durations.

6.10 CML implications for network design

IIS related investments have predominantly focussed on HV network automation and remote control. After exhausting such HV automation opportunities, it will be logical to address LV network performance improvements although such investments may be more costly due to requirement to reconfigure (and potentially duplicate) primary assets. The extent to which DNOs will pursue such strategies in future will depend on the level of targets and incentives rates. As opportunities for 'quick-wins' diminish, the setting of appropriate cost-reflective targets will become increasingly challenging for the economic regulator.

6.10.1 Substation redundancy

Analysis has revealed that substation redundancy requirements are significantly impacted by equipment repair times. High-level examples demonstrate that extended repair times can result in high CML exposures. Reductions in asset repair/replacement times can be demonstrated to reduce CML exposures accordingly. Analysis confirms redundancy requirements to be greatest for the larger Demand Groups which is consistent with ER P2/6.

6.10.2 Maintenance outages

Analysis demonstrates that maintenance outages incur considerable IIS penalties where no redundant circuits are available to maintain supplies. Consequently, LV networks must be designed to be virtually maintenance-free. Conversely, where two or more transformers are installed per substation, maintenance outages do not adversely impact IIS performance.

6.10.3 LV networks

For LV networks, improvements in CML performance can be achieved using sectionalising techniques followed by the installation of reserve cables. Analysis reveals the cost-effectiveness of sectionalising LV circuits. The economics of installing reserve LV cables appear to be marginal under the current IIS arrangements. However, for circuits with large numbers of customers, the installation of reserve cables may be viable.

6.10.4 Redundancy in HV/LV substation design

ER P2/6 requires no substation redundancy (n-0) for Class of Supply A. IIS exposure evaluations have confirmed that adopting a (n-1) network design in HV/LV substations instead of the typical (n-0) arrangement does not justify adding an additional substation transformer. Consequently, the current practice of no redundant assets at the HV/LV interface represents an appropriate network design under the current IIS framework.

Similar analysis demonstrates the validity and effectiveness of the actions taken by DNOs with respect to increased automation and remote control on 11 kV feeders which has resulted in significant reductions in CMLs and CIs since the incentive arrangements were introduced.

6.11 Distributed generation

6.11.1 Security contributions from distributed generation

No examples of distributed generation being used to secure Demand Groups have been identified. The lack of an established framework by which DNOs can reward generators for the provision of security contributions has been identified as a barrier. However, examples of DNOs procuring short-term network security contributions from distributed generation were identified in the Dutch electricity market with generators being rewarded accordingly.

6.11.2 Generation connection criteria

ER P2/6 is silent regarding the network redundancy requirements for generator connections. In the event that multiple distributed generators were being used to secure demand collectively, the contribution of individual generators would be less significant than in a transmission context. Consequently, it is less important that connection criteria for distributed generation be formally defined in the planning standard.

6.11.3 Energy exports and transfers across distribution networks

ER P2/6 does not address the security of power transfers originating from generation. DNOs are not currently required to provide a particular level of security to generator customers. Should offshore transmission networks emerge, distribution networks may be required to transfer energy between transmission operators. In such circumstances, the applicability of the offshore Security and Quality of Supply Standard could be undermined in the absence of requirements to securely transport the power flows from such generation across distribution networks. As the current arrangements may not provide sufficient certainty for the developments in offshore wind, it will be important to understand these requirements and to quantify the appropriate levels of network security to transport the output from generators.

7. Recommendations

Prioritised recommendations regarding the development of the distribution network planning framework arising from this study are summarised below in descending order of importance:

Planning framework: It is recommended that a distribution network planning standard for use by British DNOs is retained. A planning, design and operational framework comprising an evolutionary development of ER P2/6 complemented by regulatory incentive arrangements can deliver appropriate levels of network security at EHV and a high quality of service to customers connected at HV/LV. Further work needs to be undertaken to determine whether an incentive based approaches could remove the requirement for a planning standard in future. Current shortfalls in input data quality mean that adoption of incentive based approaches would be premature.

Critical network loadings: It is recommended that distribution planning standard should make DNOs responsible for the determination and assessment of the critical network loading conditions and corresponding equipment ratings relevant to their networks (summer or winter) and that references to Average Cold Spell Criteria be removed.

Construction outage risk and Second Circuit Outage provisions: In order to expose and minimise the escalating network security risk to customers associated with extended construction outages, it is recommended that further work be undertaken to quantify these risks (and implied costs) against the current planning requirements. Following further analysis, it may be appropriate to consider removal of the staged restoration criteria for Second Circuit Outages. In the interim, consideration should be given to explicitly acknowledging the increased network security risk associated with extended construction outages. Ideally, future versions of the planning standard should differentiate between maintenance and construction outages and provide guidance regarding risk mitigation.

Energy exports and transfers across distribution networks: In future, it may be important quantify distribution network security required to transport the output from offshore generation connected via distribution networks. A possible development path to accommodate such a scenario would be to ensure that the industry codes and governance procedures for both transmission (on and offshore) and distribution are developed on a consistent basis.

Design practices at the Transmission/ Distribution interface: Design practices on the transmission system can impact distribution network performance. It is recommended that co-ordination procedures are established between the Transmission Owners and DNOs to ensure substation designs consider the network performance implications for customers.

Operational co-ordination between DNOs and the TSO: It is recommended that requirements for DNOs to provide transfer capacity to the TSO are clarified in order that the risks apparent to the respective network operators (and the corresponding customer groups) are clearly understood and that co-ordinated approaches to risk mitigation can be adopted.

Frequency of Supply Interruptions to customers: It is recommended that the distribution planning framework (planning standard, Guaranteed Standards or incentive arrangements) be developed to specify maximum expected interruption frequencies for individual customers. The determination of appropriate provisions will require further modelling and analysis.

Lifecycle costing: In order to ensure network performance and costs are optimised in the long-run, it is recommended that DNOs increasingly adopt lifecycle costing practices when reinforcing and extending their networks.

Group Demand and Transfer Capacity definitions: In order to improve transparency and to clarify the compliance requirements for network operators (including transmission) and the regulator, it is recommended that agreed interpretations of Group Demand boundaries and associated Transfer Capacities are established between the relevant stakeholders.

Common Mode Failures: It is recommended that the risks associated with common mode failures be investigated further. Should these risks be confirmed to be material, it is recommended that ER P2/6 be amended to include guidance regarding the minimisation of Common Mode Failure risks.

Distributed Generation Connection Criteria: It is recommended that connection requirements continue to be agreed on a bilateral basis between generators and DNOs. It is not essential for the distribution planning standard to contain prescriptive guidance with respect to generator connection criteria.