Review of Distribution Network Security Standards

Extended Summary Report

To the Energy Networks Association

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Imperial College London

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1 CONTEXT

The UK electricity system is facing exceptional challenges in the coming decades. Meeting the medium and longer-term carbon emission reduction targets will require intensive expansion of the use of low carbon electricity generation and demand technologies. In the context of the targets proposed by the UK Climate Change Committee (greenhouse gas emission reductions of at least 80% in 2050) it is expected that the electricity sector would be significantly decarbonised by 2030, with potentially increased levels of electricity production and demand driven by the incorporation of segments of heat and transport sectors into the electricity system.

Delivering these targets cost effectively will require fundamental review of the historical philosophy of network operation and design. Existing distribution networks, designed in accordance with the historic deterministic standards, have broadly delivered secure and reliable supplies to customers. However, the key issue regarding the future evolution of the standards is associated with the question of *cost effectiveness* of the use of existing assets and the role that advanced, non-network technologies and intelligence based control could play in the future development and delivery of security of supply to consumers. A fundamental review of the *philosophy* of distribution network operation and design is hence carried out to inform the industry, consumers, regulator and government, and facilitate a cost effective delivery of the UK Government energy policy objectives.

Distribution Code Review Panel[1] P2 Working Group (DCRP P2 WG) through the Energy Network Association[2] (ENA) engaged a consortium consisting of DNV GL[3], Imperial College London (ICL)[4] and NERA[5] (the Consortium) in a project to carry out a full back to basics review of Engineering Recommendation P2/6. This engagement with the Consortium covers Phase 1 of a two phase project that may ultimately result in a new fully codified standard.

Phase 1 is essentially a comprehensive research, analysis and modelling engagement and consultation process carried out by the Consortium with direction and support provided by the DCRP P2 WG and the ENA. The objective of Phase 1 is to identify and agree a range of options for a future UK security standard and agree on the most appropriate approach that should be taken into Phase 2 which will focus on the development of the new standard if considered appropriate.

1 The Distribution Code Review Panel (DCRP) is the body responsible for overseeing the maintenance and development of the Distribution Code and its subordinate documents. Those subordinate documents include the Engineering Recommendation P2/6. The ENA is the service provider to the DCRP for the physical maintenance of the Code and its subordinate documents.

2 Energy Networks Association is the industry body for UK energy transmission and distribution licence holders and is the voice and agent of the energy networks sector. ENA acts as a strategic focus and channel of communication for the industry and aims to promote the interests, growth, good standing and competitiveness of the industry. They also provide a forum for discussion among company members, and so facilitate communication and sharing of experience across the energy networks sector

3 DNV GL is a Global certification and advisory business working in the maritime, oil and gas, business assurance and energy sectors.

4 Imperial College London is a university of world-class education and research in science, engineering and medicine, with particular regard to their application in industry, commerce and healthcare.

5 NERA Economic Consulting is a global firm of experts dedicated to applying economic, finance, and quantitative principles to complex business and legal challenges.

The process to deliver the Phase 1 objectives consists of a number of work streams. This document reports on the outputs from sub-work streams 2.1 to 2.6 of work stream 2 involving the identification, research and evaluation of options for a future UK network security standard to potentially succeed Engineering Recommendation P2/6[6].

Overall, this report addresses two key questions:

- Is the present network design standard efficient? Does it deliver good value for money to most network customers for most of the time? In other words, does it balance the cost of network infrastructure with the security benefits delivered to distribution network customers?
- Given that the present network design standards require that the network security is provided through asset redundancy, will this impose a barrier for innovation in network operation and design, and prevent implementation of technically effective and economically efficient solutions that enhance the utilisation of the existing network assets and maximise value for money to network customers?

The outputs of the analysis feed into the Options Report.

[6] Full detail of the analysis conduced can be found in the "Extended report - Review of Distribution Network Security Standards"

2 KEY FINDINGS OF THE STUDY

Based on the results of comprehensive studies carried out, including relevant literature surveys, a set of key conclusions can be listed as follows:

Cost effectiveness of the present network security standard

- The present security standards tend to be conservative, dealing with worst case scenarios. This implies that the present security standard would be cost effective only for “extreme” cases with high failure rates, long restore/repair times and low upgrade costs. In most cases however, particularly at the HV level, the existing networks (both feeders and substations) could accommodate demand growth in the short term, relaxing the N-1 requirement up to the point where the reinforcement becomes economically justified. For reliable HV networks, with low failure rate and low restore/repair times, the peak load can nearly be doubled without the need for network reinforcement. The potential benefits of relaxing the N-1 security constraints at the GB level could reach up to £4bn to £7bn by 2030 in case of significant load growth at LV and HV level (high decarbonisation scenario), as shown in Table 5.20 and subsequent paragraphs. For more details see Section 5.7.

- The optimal level of network redundancy is case specific, depending on many parameters (reliability characteristics, investment cost, cost of supply interruptions[7], mitigation measures) and therefore it may be difficult to implement “one size fits all” standard with the expectation to be cost-effective in all cases. On the other hand, implementation of a deterministic standard could deliver simplicity and transparency, which are very important, particularly for customers to clearly understand the investment decisions that DNOs make. In addition, case specific analysis would increase indirect design costs which must be borne by customers through either connection or DUoS charges. It is worth noting that the balance between case specific cost-benefit analysis and a simple deterministic standard could be informed by stakeholder engagement.

- The studies have demonstrated that networks with low reliability performance (i.e. higher failure rates, longer time to restore or repair), low upgrade cost, and high outage costs (high VoLL) tend to require a higher degree of redundancy compared with networks with relatively higher reliability, higher upgrade cost, and lower outage cost.

- For networks supplying larger demand groups, higher degree of redundancy is found to be efficient. Although this trend is consistent with the present standard, it does not necessarily validate the efficiency of the present standard. More details are given in Section 5.

- The requirements for network upgrade due to demand growth are also lower when corrective measures such as mobile generation and load-transfer capability are used. The costs of such corrective and preventive measures are taken into account in the analysis.

[7] Alternative approaches for quantification of interruptions cost are discussed. As discussed, VoLL of 17,000 £/MWh adopted by DECC and Ofgem is used as the central figure in this work. It is important to note that very comprehensive sensitive analysis is carried out to inform the robustness of the proposition.

- Enhancing the utilisation of the existing network will in turn degrade the service quality, increasing Customer Interruptions (CI), Customer Minutes Lost (CML), and Energy Not Supplied (ENS). Customers' expectations in any decision need to be considered. The analysis demonstrated that it is still beneficial (in financial terms) to defer the investment if possible. It is worth mentioning that the VoLL for some HV UG network with high reliability and high upgrade cost, may need to be more than £3,500,000/MWh and as high as £64,900,000/MWh, to maintain N-1 degree of security (see Table 5.1).

Generation driven distribution network investment

- The analysis demonstrates that there would be no need for network redundancy to secure distributed generation (DG) output, assuming that the impact of the loss of DG at the national level is marginal (this is likely to be the case, given that the system is operated to cope with a loss of 1,320MW of nuclear power). This implies that an N-0 security level would be adequate for DG as the cost of generation curtailment is typically much lower than the network reinforcement cost and the Value of Lost Generation (VoLG) is typically two orders of magnitude lower than the VoLL. More details are given in Section 6.
- On the other hand, significant penetration of DG may cause reverse power flows that may pose additional interruption risks for demand customers, increasing the possibility of supply interruptions. Reinforcing the network to resolve this problem is unlikely to be the most cost effective solution even in the worst case scenario being studied (i.e. low network reliability performance) as the use of smart system protection schemes, i.e. intertripping schemes, can limit the negative impact of the reverse power flows on demand reliability. The ability to use intertripping schemes depends on the location of existing generation in the network. However, smart protection systems may be exposed to failures of real-time communication and control systems, which are also considered in the analysis, and redundancy in protection is shown to provide efficient solutions.

Value of automation

- The analysis carried out confirmed that automation can significantly reduce the CML and CI indicators. The analysis demonstrated that reliability performance of the HV networks could be improved (56% reduction in CMLs and 88% reduction in CIs) when compared to manual switching due to significantly shorter supply restoration times (details are in Section 8 of main report). This benefit of automation might not be very significant for circuits with very high reliability.

Contribution of Distributed Energy Resources to network security

- DER (Demand Side Response, Distributed Generation and Energy Storage) can support network flow and voltage management and hence substitute for network reinforcement (provided that cost is lower than network reinforcement cost). However, the actual capacity contribution of DER is demonstrated to depend on both underlying network reliability characteristics and DER parameters including availability, size, number of DER sites and technical characteristics (e.g. ability to operate in islanding mode). For energy limited sources, such as energy storage, the amount of energy that can be stored will be an important parameter for determining the capacity contribution. Modelling developed and studies performed for a wide range of network parameters and characteristics of demand and generation led DSR and energy storage plants, can be used for quantifying the security contribution and ability to displace network reinforcement, provided that DER solutions are cost effective. For more details see Section 7.

Smart management of network overloads through disconnection of non-essential loads

- At present, network overloads would be managed through demand disconnections, with some of consumers being completely disconnected and some consumers fully supplied. The roll-out of smart metering will provide a unique opportunity for smarter management by switching off *non-essential loads* when network is stressed while keeping supply of essential loads. This would result in a significant enhancement of the reliability of supply delivered by the existing network, as more consumers will have their essential load supplied during network stresses. Furthermore, this will open up the potential for customer choice driven network design. The analysis demonstrated that the integration of consumers' preferences in network planning would yield an equitable outcome - consumers with lower flexibility would enjoy higher security of supply at the expense of higher DUoS charges, while consumers with greater flexibility would be rewarded for their flexibility through lower DUoS charges. The proposed framework increases the overall reliability levels without the need for additional network capacity, as it would allow serving of the critical loads during network congestion in contrast to the traditional practice leading to complete curtailment of some consumers' demand. Implementing smart management of network overloads through disconnection of non-essential loads could further enhance the network utilisation and eliminate the need for network reinforcement leading to additional savings of about £2-3bn at the GB level by 2030. Implementation barriers may be further elaborated in the Options Report.

Enhancing network assets utilisation

- The definition of capacity in the standards may allow emergency loading of network assets, for both transformers and cables, as they potentially can provide additional capacity in the short-term and reduce the amount of demand to be interrupted. This analysis suggests that it may be cost effective to increase the life-loss of the assets by overloading these during emergency conditions as most of the time the assets are operated below the nominal rating. It should be noted that DNOs, take the emergency loading into account, particularly in the case of transformers. We note that additional sensors and analysis might be needed to increase assets observability and support management of overloads.

- In addition, the definition of capacity in the standards may also allow and guide the use of dynamic line rating technologies as work carried out within several LCNF projects demonstrated significant potential.

- Furthermore, we find that voltage management may be important as network capability is frequently constrained by voltage rather than by thermal (current) limits, particularly in LV networks. If the voltage drop beyond current statutory limit is of 10% was acceptable during emergency conditions, this could enhance network utilisation. In other words, allowing higher levels of voltage drop would release significant latent capacity which is currently constrained by voltage limits. Therefore it may be efficient to reduce the lower voltage limit as a strategy to accommodate increased demand and facilitate integration of DG by alleviating voltage rise effects. In addition to enhancing network utilisation, lowering the voltage limit can be used as a strategy to reduce network loading. Recent academic work demonstrated that most of the domestic devices could safely operate at 85% of the nominal voltage at reduced power. Increasing the upper limit is not recommended due to security reasons and failure of some devices during the tests [149].

Impact of construction outages and asset replacement

- The study demonstrates that it would be economically efficient to provide provisional supply and reduce risks of consumer interruption during asset replacement. Longer construction outages will expose the system to greater risks which in turn, increases the value of developing provisional load-transfer as a risk mitigation measure. In this context, it may appropriate to consider including guidance for asset replacement in future network security standards.

Long-term optimal design of distribution networks

- Network losses are an important factor to be considered in planning the capacity and design of future distribution networks. The analysis demonstrated that the capacity of distribution network may need to be oversized significantly above the peak demand requirements in order to reduce losses, given that the savings in losses exceed the extra cost of oversizing the network. For example, studies have shown that an optimally sized LV cable would be operated at maximum demand no higher than 12-25% of its thermal rating. Loss-inclusive network design clearly requires a much greater capacity of network components, which would be significantly above the peak component loading.

- Taking advantage of the large spare capacity, in the long-term the analysis demonstrated that it would be cost effective to potentially increase redundancy of LV and HV distribution networks beyond the level prescribed by the present standard. The CBA carried out demonstrates that costs of the additional network assets needed to increase the connectivity and enhance reliability may be lower than the savings in EENS delivered by the new design. Table 2.1 shows that the optimal degrees of network redundancy should be significantly greater than the minimum redundancy prescribed by the present standards.

Table 2.1 The range of optimal degree of redundancy needed at various voltage levels

Voltage level	Overhead networks	Underground networks
LV	N-1	N-1
HV	N-0:N-1.75	N-1
EHV	N-1:N-1.75	N-1:N-1.75
132 kV	N-1:N-2	N-1:N-2

Distribution network resilience

- Diversity in the portfolio of technologies, network and non-network, will not only reduce the total system costs (cost of investments in network assets, availability and utilisation costs of DSR/DG/ES and cost of expected energy not supplied), but could reduce exposure to Common Mode Failures (CMF) and High-Impact Low-Probability (HILP) events, improving the distribution network resilience. The study demonstrates that the concept of Conditional Value at Risk (CVaR) could be applied to limit the probability of large outages; this may result in marginal increase of network investment and/or DSR costs, while reducing the consequences of high impact outages. In the context of developing the future security standards addressing the CMF and HILP issues, a number of options have been identified, including the following:

  - *Robust design of distribution substation with balanced portfolio of network and non-network solutions* - considering customer density and scale of demand, this may particularly relevant for urban networks; related work has been carried out by the ENA Urban Reliability working group indicating the importance of reducing the risks associated with HILP for Central Business Districts.
  - *Emergency operation and investment actions to deal with HILP is also considered* - analysis carried out demonstrated that the use of emergency operation and investment actions, such as provision of mobile generators and temporary transfer cables, can cost-effectively reduce the impact of HILP significantly; resource constraints [117] should also be considered especially during the restoration of the system after a HILP event.
  - *Expanding the scope of the risk assessment to consider cyber-physical systems (CPSs)* - this analysis demonstrated that the failure of ICT infrastructure may cause CMF which renders multiple sources (e.g. DSR or special protection schemes that require communication) providing network services unavailable.

  However, it is still an open question whether the assessment of CMF and HILP should be included in the standards for the following reasons:

  - There is a lack of comprehensive data to derive CMF and HILP parameters (e.g. frequency and scale of impact) that can be used to consider cost effective mitigation measures.
  - The impact of a certain hazard is very case specific. For example, the risk of having flood in plateau areas may be much lower compared with lowland areas, and the impact on urban networks will be different in comparison with sparse rural networks. Different networks may be exposed to different types of hazards. Hence the justification of investment via CBA may be very case specific.
  - It is difficult to define rigorously the basis of appropriate risk level thresholds and establish corresponding confidence in the process by all relevant stakeholders.

Robust distribution network planning under uncertainty

- Given the uncertainty associated with demand and generation growth, and the significant economies of scale associated with network reinforcement, it will be important to consider benefits of both strategic and incremental approaches to network development. Hence, it may be cost effective to consider compliance with the network reliability standard in the context of uncertainty in growth of future demand.

- A number of distribution network planning approaches to address short-term and/or long-term uncertainty are demonstrated (e.g. min-max regret approach, CVaR optimisation) and could be used to inform the planning strategy taking into account different risk attitudes. Furthermore, investment in flexible technologies such as DSR as an alternative to conventional reinforcements to facilitate cost effective response to uncertainty is also demonstrated.

Analysis assumptions

- The analysis carried out is based on current asset costs provided by DNOs (Section 15.2), reliability parameters provided by DNOs (Section 15.5), losses at system marginal price and a VoLL of £17,000/MWh (value adopted by the UK government for all Electricity Market Reform related analysis used by DECC and Ofgem) with a sensitivity value of £34,000/MWh. Furthermore, a comprehensive range of studies have been carried out with the aim to estimate the breakeven value of VoLL at which the existing network would be upgraded cost effectively. The studies are carried out on generic configurations of HV, EHV, and 132 kV networks that provide conservative estimates of optimal level of network redundancy.

3 DRIVERS AND OBJECTIVE FOR REVIEWING THE PRESENT SECURITY STANDARDS

Electricity distribution networks are capital-intensive systems and timely and economically efficient investments to respond to increased demand for capacity and services are crucial for maintaining efficiency and reliability of supply. Optimal investment strategies have to be developed considering not only the current and future needs of the system but also the emergence of new technologies that can enhance the efficiency of planning and operation. Given the time horizon considered, the level of uncertainty can be considerable and appropriate risk management strategies should be put in place for planning and designing the networks. The key drivers for the review of the distribution network planning standards include decarbonisation of generation and demand technologies and emergence of smart grid technologies that could reduce the need for network reinforcement by increasing the utilisation of the existing assets and improving the network reliability performance. Furthermore, since a significant proportion of distribution network assets in the UK were deployed several decades ago, some of these assets may be approaching the end of their useful life and may need to be replaced in coming years / decades. It is therefore timely to carry out a fundamental review of the historical philosophy of network operation and design standards and investigate alternative options for development of future security standards.

The key objective of this work is to inform the debate regarding the options for the evolution of the present distribution network design standard in order to support the development of efficient, secure and sustainable electricity distribution networks and facilitate cost effective transition to a low carbon future.

There are a number of identified *potential* weaknesses of the present standards. These are described as follows:

- ***Deterministic:*** The degree of security provided by the deterministic security criteria, using generic rules applied to all conditions, may not be optimal in individual instances as the cost of providing the prescribed level of redundancy is not compared with the reliability profile (cost) delivered (the standard however does allow a departure from defined levels of security subject to detailed risk and economic studies). It should be noted that the deterministic nature of P2/6 constitutes also a strength, in terms of simplicity and transparency.
- ***Binary approach to risk:*** Furthermore, the binary approach to risk in the present deterministic standard is potentially problematic: system operation in a particular condition is considered to be exposed to no risk at all if the occurrence of faults, from a preselected set of contingences, does not violate the network operational limits. On the other hand, the system is considered to operate at an unacceptable level of risk if the occurrence of a credible contingency would cause some violations of operating limits. Clearly, neither of these is correct, as the system is indeed exposed to risks of failure and outages even if no preselected contingency leads to violations of operating constraints, and the risk of some violations may be acceptable if these can be eliminated by an appropriate (post

fault) corrective action, that can include a fast response of flexible demand or some form of distributed generation or energy storage.

- ***Impact of construction outages:*** the lack of differentiation between construction and maintenance outages in the present distribution planning standards may present a significant problem given the expectation of considerable asset replacement. This affects the demand groups from B upwards and it is likely to affect particularly large Demand Groups.
- ***Redundancy:*** In many cases, asset redundancy may not be a very good proxy for actual security delivered. In this context, it is important to recognise that deterministic standards assume that all contingencies are equally likely, which is clearly problematic: for example, faults on a long line are much more frequent than failures of a closely monitored transformer. The analysis carried out demonstrated the importance of considering different failure rates associated with different asset categories, but also the significance of uncertainty associated with asset failure rates and restoration times.
- ***Impact of Common Mode Failures:*** The present standard does not consider Common Mode Failures (CMF) and High Impact Low Probability (HILP) events. There is growing interest in understanding and enhancing resilience of future distribution networks.
- ***Non-network solutions providing network capacity:*** There is a significant potential for incorporating non-network solutions (such as flexible generation and demand, new storage technologies, dynamic line rating, automatic network monitoring, control based on new information and communication technologies etc.) in the operation and design of future distribution networks. It is not however clear to what extent the application of such solutions changes the security of supply delivered to the end consumers. This is however critical for quantifying the ability of non-network solutions to substitute network assets. Although some improvements of the existing network design standards have been made to recognise the contribution that distributed generation could make to network security, this has been carried out without reviewing the fundamental principles on which the standard is based.
- ***Smart load management and user driven choice of reliability***: At present, potential network overloads are managed by demand disconnections, with some of consumers being completely disconnected and some consumers fully supplied. The roll-out of smart metering will provide a unique opportunity for smarter management by switching off *non-essential loads* when network is stressed while keeping supply of essential loads. Furthermore, the introduction of smart metering may facilitate reliability-based choices of consumption.

Although the standards have served the industry well for the past several decades, in the light of these identified weaknesses, two key questions arise:

- Is the present network design standard still efficient and fit for the future? Does it deliver value for money to all network customers? In other words, does it balance the cost of network infrastructure with the security benefits delivered to distribution network customers?

- Given that the present network design standards require network security to be provided through asset redundancy, will this impose a barrier for innovation in network operation and design and prevent implementation of technically effective and economically efficient solutions that enhance the utilisation of the existing network assets and maximise value for money to network customers?

In order to address these questions, the fundamental cost-benefit analysis was established for assessing the reliability and cost performance of various network design and emergency operation strategies, taking into account a range of techniques or technologies recently developed, such as smart technologies (e.g. demand side response, smart protection schemes etc.), as well as advanced modelling and stochastic optimisation techniques that can inform the development of least-cost solutions.

4 COST-BENEFIT APPROACH TO DISTRIBUTION NETWORK PLANNING

The key objective of this work is to identify alternative approaches to updating existing and developing new distribution network design and operation standards, This includes characterising and quantifying the service quality delivered to end customers that is compared with network investment costs.

Given the probabilistic nature of network failures, a probabilistic Cost-Benefit Analysis (CBA) framework is a benchmark for assessing different options for the development of network design and operation standards. As indicated in Figure 4.1, a probabilistic approach can provide the basis for risks of supply interruptions to be understood, quantified and managed through optimising network design (capacity, configuration, degree of redundancy) and emergency operation strategies that should be made available to network users in both operational and investment time horizons. Essentially, this approach will enable the costs of investment (both for network assets and non-network technologies) and maintenance to be balanced against the reduction in operation costs which include the cost of interruptions (loss of supply), cost of constraints (e.g. DG curtailment), cost of operational measures such as the cost of providing emergency generators and demand management, and the cost of losses. The cost effectiveness of preventive and corrective measures in managing the risk can also be assessed using this framework.

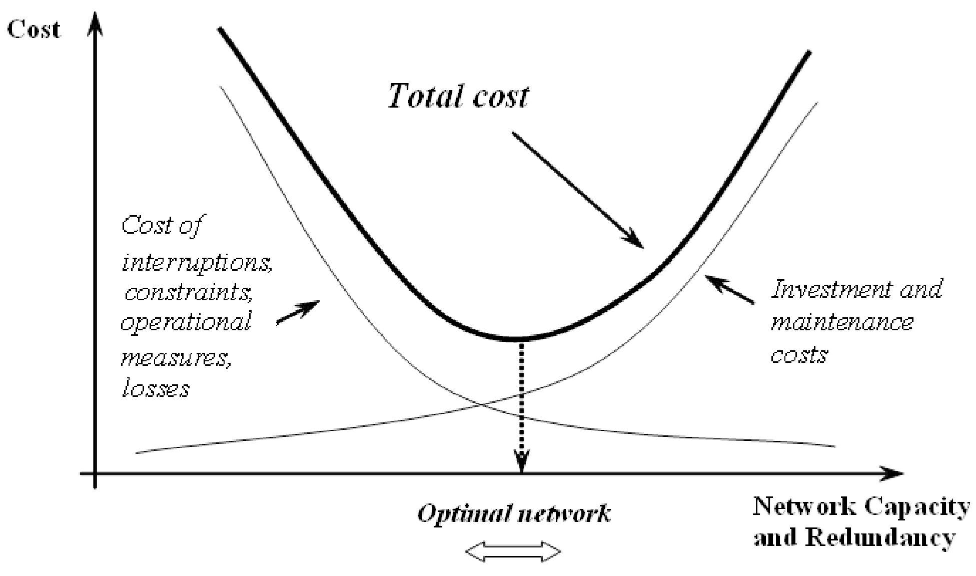


Figure 4.1: Probabilistic cost-benefit analysis framework for distribution network operation and planning

In order to identify the drivers for certain network design and operation strategies and their impact on the reliability and cost performance of the system in question taking into account relevant uncertainty, a range of sensitivity studies is carried out. Analysis is carried out for a range of network reliability parameters (e.g. failure rates, restoration and repair times, common-mode failure rates, high-impact-low-probability factor), characteristics of emergency operation measures (e.g. capacity, deployment time of emergency generation, load-transfer capability, DSR services), cost of investment and operation measures, and the Value of Lost Load (VoLL). The impact of uncertainty in future system background (e.g. demand growth) has also been taken into account.

A broad spectrum of comprehensive case studies have been carried out using a range of network planning and reliability assessment tools. The studies analyse the performance of alternative distribution network design philosophies considering the quality of service delivered to end consumers and the associated network investment and outage costs, while optimising the use of advanced network control technologies (e.g. active network management, dynamic line rating) as well as demand side response, distributed generation and energy storage technologies. The results of the studies may be used to inform the debate and develop options for the evolution of the present distribution network design standard in order to facilitate cost effective transition to a low carbon future. Whilst our analysis considers existing and new networks explicitly, the methodology could be applied to evolving networks.

5 COST EFFECTIVENESS OF THE PRESENT NETWORK SECURITY STANDARD

The cost effectiveness of maintaining the present security standard has been re-examined and evaluated. By performing CBA, decisions to reinforce the network due to increased demand can be justified only if the cost of reinforcement is lower than its benefits. A range of studies has been carried out with the aim to estimate the *breakeven value of VoLL* at which the existing network would be upgraded cost effectively, and to estimate the least-cost redundancy levels.

Based on the range of Imperial College models for assessing distribution network reliability performance, load-point security indices have been evaluated including expected values of the key indices based on Markov models and also their distributions through full Monte Carlo based models. A set of different customer damage functions, expressing the dependency of the cost of interruptions on their duration and unserved energy or customer peak demand, are analysed. For various customer damage functions different equivalent VoLL values are determined. It is important to stress that there are no widely agreed customer damage functions parameters, while there is agreed VoLL, used by the government and the regulator (both nationally and internationally). The resulting cost of interruption is compared with the cost of interruption if a constant VoLL of £17,000/MWh (value adopted by the UK government for all Electricity Market Reform related analysis) is applied. It has been found that the ratio between the two can vary significantly. This demonstrates that different approaches to costing un-served energy may result in different network designs. Lower values of VoLL will drive lower optimal degree of redundancy. For various CDFs estimated equivalent VoLL might be lower than values used in this report. This will lead to a lower optimal degree of redundancy and in that sense results of the analysis carried out are conservative. Furthermore, possible smart demand shedding would drive even lower equivalent VoLL and hence optimal degree of redundancy would be even lower. A range of studies have been carried out with the aim to estimate the breakeven value of VoLL at which the existing network would be upgraded cost effectively. This enables clear assessment of the optimal degree of redundancy for different customer interruption cost to be determined (that may also correspond to different customer damage functions).

According to London Economics report [33] the central VoLL of £17,000/MWh is attributable to a mix of residential and commercial consumers, while industrial customers would have lower VoLL and hence a lower level of redundancy than proposed in this report may be applicable. On the other hand, predominantly commercial consumers would be characterised with higher value of VoLL and given the conservative approach adopted in this work, analysis is also carried out with VoLL of £34,000/MWh. In order to provide the insights of the impact of different values of VoLL on the degree of redundancy, the breakeven value of VoLL at which the existing network would be upgraded cost effectively, is also determined. This can be used to inform the debate regarding the question of “who/what are future distribution networks being built for?”. This is also important in accounting for uncertainties around the value of avoided interruptions (including how this varies across customer classes) and the corresponding impact on the network planning decisions.

The studies are carried out on generic configurations of HV, EHV, and 132 kV networks that provide conservative estimates of optimal level of network redundancy (note that the present security of supply standard does not require redundancy in LV networks).

It should be pointed out that the impact of reduced redundancy on EENS and associate cost will be greater than the impact on outage duration (CML). This is due to the increase in *both* customers supply interruption duration as well *as severity* of the outage given the load increase. Frequency of interruptions strictly does not change. Given the greater impact of reduced redundancy on EENS the associated cost would also increase more than the increase in cost associated with CML. In this context, approach used will produce conservative results regarding the optimal level of redundancy.

Sequential Monte Carlo analysis was carried out to determine the impact of reducing the level of network redundancy prescribed by the present standard on the frequency and duration of customer interruptions. Some sensitivity analysis was carried out to demonstrate the impact of various key parameters and assess the robustness of the present practice. The analysis shows the following:

- The present network security standard is found to be generally conservative - in most cases distribution networks may accommodate higher levels of demand before reinforcement is economically justified. On the hand, P2/6 is seen as the minimum design needed which DNOs might wish to exceed.
- The optimal level of redundancy is very case specific, depending on many parameters, particularly on network reliability characteristics, investment cost, VoLL, and operational parameters of mitigation measures. VoLL is a proxy for the inconvenience customers experience during outages. Analysis of the breakeven VoLL shows that in some instances design is robust for a wide range of VoLL.

More detailed findings can be found in the following sections.

5.1 Breakeven VoLL for HV networks to justify network upgrade

Figure 5.1 shows the generic configuration of a radial HV network with a Normally Open Point that provides an alternative infeed if a fault occurs at one of the feeders. A meshed configuration may be induced through fast restoration times (facilitated by automation), and assuming appropriate protection systems. This configuration is used in the studies to evaluate the consequences of reducing levels of redundancy, namely: N-0.75, N-0.5, N-0.25 and N-0 by increasing the load connected to the test network. A degree of redundancy is denoted as *N-x*. In this context x is a proportion of spare capacity based on the initial loading. For example, if the peak load of the HV feeder of capacity of 4WM is initially 2 MW (under normal operating conditions) the network is N-1 compliant. If the peak load of the feeder is doubled (i.e. 4 MW which is equal to the rating of the feeder), this would correspond to redundancy level of N-0. In case that load per feeder is 2.5 MW (total load of the network is 5 MW) means the degree of redundancy is N-0.75.

The key objective of the studies is to determine the *breakeven value of VoLL* at which the network reinforcement is economically justified for different levels of network redundancy considered. Breakeven VoLL is the value of VoLL for which savings from reduced EENS and reduced cost of mobile generation balances with the cost of upgrade investment. For clarity purposes, the interrupted supply is initially restored via switching, the subsequent demand is resupplied by mobile generation subject to its available capacity, and if there is still unsupplied demand, it would be supplied within the urgent repair time. This also includes cost of network losses that are dependent on the network redundancy.

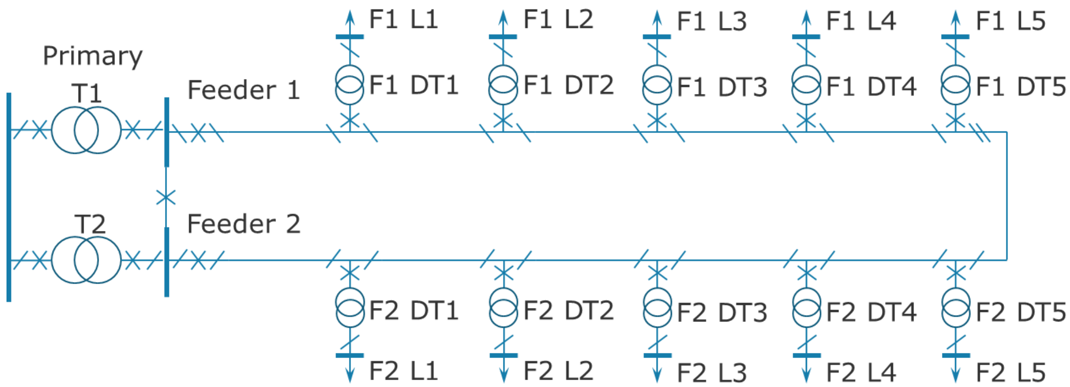


Figure 5.1 HV network case studies

Breakeven values of VoLLs evaluated for this network are presented in Table 5.1 and these depend on a number of factors, such as degree of network redundancy, network failure rates and restauration and repair times, demand load factors and network upgrade cost, The values of breakeven VoLLs are written in blue or green if they are less than or equal to £17,000/MWh and £34,000/MWh respectively. Many studies are conducted to estimate value of reliability and VoLL [1-57]. The VoLL of £17,000/MWh is the central value adopted by the DECC and Ofgem and used in EMR (from London Economics report). The VoLL of £34,000/MWh is used as a sensitivity value to assess the robustness of the results and potentially to represent more sensitive areas (e.g. city centre).

It is worth highlighting that for networks of high reliability, with failure rates of 2%/km.year and restore/repair times of 3h and 24h respectively, the breakeven VoLL that would justify reinforcement from level of redundancy of N-0.75 to N-1 would need to between £3,576,921/MWh (for high load factor and low upgrade network cost) and £64,859,361/MWh (for low load factor and high network upgrade cost). This reinforcement would be clearly inefficient as the breakeven values of VoLL that would justify this are much higher than the reference value of VoLL of £17,000/MWh (adopted by DECC and OFGEM) that is used in this study.

Table 5.1: Breakeven VoLL (£/MWh) for HV underground feeders with initial feeder peak load of 2,500 kW

Degree of redundancy	Failure rate (%/km.year)	MTT Restore/Repair (hours)	Low load factor		High load factor	
			Low upgrade cost	High upgrade cost	Low upgrade cost	High upgrade cost
N-0.75	2%	3/24	40,686,822	64,859,361	3,576,921	6,114,226
	2%	12/120	12,926,389	20,608,107	915,317	1,568,137
	10%	3/24	10,196,137	16,255,357	733,764	1,257,097
	10%	12/120	LN	LN	212,850	368,909
N-0.5	2%	3/24	7,295,924	11,779,032	555,781	982,839
	2%	12/120	1,916,449	3,099,264	135,362	242,594
	10%	3/24	1,533,341	2,479,705	108,683	194,780
	10%	12/120	528,304	861,759	23,875	46,253
N-0.25	2%	3/24	3,085,006	4,909,514	363,291	620,179
	2%	12/120	770,278	1,232,751	84,866	149,105
	10%	3/24	618,198	989,363	68,165	119,762
	10%	12/120	156,332	257,911	11,241	24,378
N-0	2%	3/24	1,038,007	1,691,831	156,183	283,275
	2%	12/120	249,489	413,631	34,397	66,144
	10%	3/24	200,284	332,053	27,620	53,113
	10%	12/120	40,406	74,597	2,296	8,743

Given the central value of VoLL at £17,000/MWh, demand of the network can be increased by 75%, until it reaches N-0.25 level of redundancy before the case for reinforcement can be justified in the case of the network with low reliability (failure rate: 10%/year and MTTR: 12/120 hours) and for a load profile with a high load factor. In cases with lower failure rates or MTTR, demand of the network can be doubled (N-0). However, if the VoLL is £34,000/MWh, in the case of high failure rate and high MTTR, the load can increase by 50%. For a load profile with a low load factor, demand can be doubled (N-0) even for a VoLL of £34,000/MWh. It should be pointed out that degree of redundancy for HV network according to present standard is N-1.

5.2 *Optimal degree of redundancy for HV networks*

For a set of the examined cases, the optimal degree of redundancy for HV networks is determined using the CBA principle. Selective results are presented in Table 5.2. Two VoLLs are used, i.e. £17,000/MWh and £34,000/MWh. The results are presented in the following format - for example, N-0:N-0.25/N-0.25:N-0.5 means that the optimal degree of redundancy is between N-0 and N-0.25 for VoLL of £17,000/MWh while it is between N-0.25 and N-0.5 for VoLL of £34,000/MWh. This implies that if the VoLL is 17,000/MWh, it will be justifiable to increase the load by 75% (N-0.25) to 100% (N-0). If the VoLL is £34,000/MWh, it will be justifiable to increase the load by 50% (N-0.5) to 75% (N-0.25) before the upgrade is necessary. If there is no '/' symbol, the degree of redundancy presented is valid for both values of VoLL. Clearly, the optimal degree of redundancy is typically lower for a load profile with the low load factor as the energy not supplied following the outage is lower. The observed difference can be up to between 0.5 and 0.75 for overhead networks and up to between 0.25 and 0.5 for underground networks.

Table 5.2: Optimal degree of redundancy for HV networks

Construction	Failure rate (%/km.year)	MTT (hours) Restore/Repair	Feeder N-1 Peak Demand (kW) 500	2,500	5,000
Overhead	5	3/24	N-0 N-0	N-0 N-0:N-0.75/N-0.25:N-0.75	N-0 N-0.25:N-0.75/N-0.5:N-0.75
		12/120	N-0 N-0:N-0.25	N-0:N-0.25 N-0.5:N-1	N-0:N-0.25/N-0.25:N-0.5 N-0.5:N-1/N-0.75:N-1
	20	3/24	N-0 N-0:N-0.25	N-0:N-0.25 N-0.5:N-1	N-0:N-0.25/N-0.25:N-0.5 N-0.5:N-1/N-0.75:N-1
		12/120	N-0 N-0.5	N-0.25:N-0.5 N-0.75:N-1	N-0.25:N-0.5/N-0.25:N-1 N-0.75:N-1/N-1
Underground	2	3/24	N-0 N-0	N-0 N-0	N-0 N-0
		12/120	N-0 N-0	N-0 N-0	N-0 N-0/N-0:N-0.25
	10	3/24	N-0 N-0	N-0 N-0	N-0 N-0/N-0:N-0.25
		12/120	N-0 N-0	N-0 N-0.25:N-0.5	N-0/N-0:N-0.25 N-0.25:N-0.5/N-0.5:N-0.75

As expected, degree of redundancy tend to increase with increase in demand supplied by the network (from 500kW to 5000kW). Also levels of network redundancy is higher in overhead networks due to lower reliability (larger failure rates) and lower network reinforcement costs, when compared with underground feeders.

Table 5.3 shows the optimal degree of redundancy for primary substations. The upper values in the table cells correspond to the load profile with a low load factor and the lower values to the load profile with a high load factor. For two- and three-transformer substations with greater failure rate circuits, a bit greater degree of redundancy is optimal. This is not observed in substation with four-transformers. Impact on the degree of redundancy by the VoLL selection is observed for the two-transformer substation design and greater failure rates. For a VoLL of £17,000/MWh the optimal degree of redundancy is between N-0.5 and N-0.75 while for a VoLL of £34,000/MWh the optimal degree of redundancy is N-0.75.

Table 5.3: Optimal degree of redundancy for primary substations (N-0 denotes double loading of N-1 redundancy level)

Transformer feeder cable length (km)	Failure rate	Two-transformer substation	Three-transformer substation	Four-transformer substation
1	Min	N-0.5 N-0.5/N-0.5:N-0.75	N-0.5 N-0.5	N-0.75 N-0.75
	Max	N-0.5:N-0.75/N-0.75 N-0.5:N-0.75/N-0.75	N-0.5:N-0.75 N-0.5:N-0.75	N-0.75 N-0.75
5	Min	N-0.5 N-0.5	N-0.5 N-0.5	N-0.75 N-0.75
	Max	N-0.5:N-0.75/N-0.75 N-0.5:N-0.75/N-0.75	N-0.5:N-0.75 N-0.5:N-0.75	N-0.75 N-0.75

There is a potential for overloading one primary transformer circuit due to an outage of the other transformer circuit. If tripped, the excess load would be disconnected and the transformer circuit is reconnected. Table 5.4 shows the optimal degree of redundancy of two-transformer primary substations for different times needed to disconnect excess load and reconnect the tripped transformer circuit. Three different durations of excess load disconnection and transformer circuit reconnection are considered: zero (fully automated), 1 minute and 10 minutes (remote control via SCADA system). It can be seen that the impact of this time is marginal for transformer circuits with high reliability. For transformer circuits with low reliability, a small impact can be observed for a load profile with a high load factor when moving from the 1 minute to the 10 minute case, where the optimal degree of redundancy increases from N-0.5:N-0.75 to N-0.75 for a VoLL of £17,0000.

Table 5.4: Optimal degree of redundancy for two transformer primary substations for different durations to excess load disconnection; N-0 denotes double loading of N-1

Transformer feeder cable length (km)	Failure rate	Time to excess load disconnection 0 minutes	Time to excess load disconnection 1 minute	Time to excess load disconnection 10 minutes
1	Min	N-0.5 N-0.5/N-0.5:N-0.75	N-0.5 N-0.5/N-0.5:N-0.75	N-0.5 N-0.5/N-0.5:N-0.75
	Max	N-0.5:N-0.75/N-0.75 N-0.5:N-0.75/N-0.75	N-0.5:N-0.75/N-0.75 N-0.5:N-0.75/N-0.75	N-0.5:N-0.75/N-0.75 N-0.75/N-0.75:N-1
5	Min	N-0.5 N-0.5	N-0.5 N-0.5	N-0.5 N-0.5/N-0.5:N-0.75
	Max	N-0.5:N-0.75/N-0.75 N-0.5:N-0.75/N-0.75	N-0.5:N-0.75/N-0.75 N-0.5:N-0.75/N-0.75	N-0.5:N-0.75/N-0.75 N-0.75/N-0.75:N-1

The approach is tested for an EHV/HV substation example from ACE 51 [165] with similar results. In this example the optimal degree of redundancy is about N-0.5 or N-0.67 depending on the VoLL used at that time (1979).

The results demonstrate clearly the following:

- For highly reliable overhead and underground networks, including those supported by mobile generation (with MTTR of 3/24 h), a lower degree of redundancy would be acceptable, allowing the peak demand to increase up to 100% (redundancy level N-0). The assumption is that underground cables do not need maintenance. Maintenance of circuit breakers might need double busbar configuration or alternative solutions including backup mobile generation.
- The degree of redundancy tends to increase in cases with: higher VoLL, higher failure rates and longer restauration and repair times (including cases without provision of mobile generation), high level of peak demand and low upgrade cost. Therefore, it is expected that cases with higher degree of redundancy are observed in overhead rather than in underground networks considering that the reliability and the upgrade cost of overhead networks are lower than the respective parameters associated with underground networks. The results show that in many instances underground networks could be operated with N-0 degree of redundancy (no redundancy). N-0 may not drive increase in cost of maintenance if this is carried out during off peak conduction, as primary substation would have two transformers given the present N-1 standard. Even if standby generation is used, the corresponding increase in cost may not justify network reinforcement and increase in network redundancy, but it may require consideration of noise and pollution impact. In some special cases provisional supplies may be considered.
- The provision of mobile generation which enables rapid restoration of supply (MTTR of 3/24 h) allows the network to be operated with lower degree of redundancy even if the failure rate is relatively high. Improving the speed of supply restoration is key for allowing

higher utilisation of the assets. A maximum of 10 MW of mobile generation is considered in the case studies, which could be deployed on average within 4.5 hours. Transfer capability of 20% is assumed. More details are provided in Sections 3.2 and 3.3.

- N-1 as dictated by the present standards is suitable in networks with very low reliability performance (this indicates conservative approach taken by the present standards).
- The economically efficient degree of redundancy to upgrade existing substations is between N-0.75 and N-0.5. The impact of the time to reconnect a transformer circuit which tripped during an overload is marginal (provided that the load is reconnected within SCADA time scale).

5.3 Impact of reduced redundancy on network performance

Objective of this section is to investigate the impact on the reliability of supply, if the present security of standard is relaxed (not N-1 compliance). By using the same approach as described previously (increasing the load), we simulate the system with lower degrees of redundancy. It can be expected that the number and duration of interruptions customers would experience will increase. A set of studies has been performed to understand the impact of operating with different redundancy, namely N-0.75, N-0.5, N-0.25 and N-0 on the reliability performance. Modelling based on time-sequential Monte Carlo simulation is used for the evaluation the ranges of the indices CI, CML and cost of ENS (going beyond long-term averages). Topology of the test network is shown in Figure 5.1. Table 5.5 shows input parameters for four considered cases. It is assumed that all HV circuits are equipped with automation. This is why for all four cases switching time is 2 minutes. The intention of this study is to illustrate the possible impact on CI and CML for different optimal degree of redundancy.

Table 5.5 Case study parameters for network with N-1 feeder peak demand of 2,500 kW

Parameter	Case A	Case B	Case C	Case D
Construction	Overhead	Underground	Overhead	Overhead
Failure rate (%/km.year)	5	10	20	5
Switching time (minutes)	2 and 30	2 and 30	2 and 30	2 and 30
MTT Repair (hours)	24	24	24	24
MTT Restore (hours)	24	24	3	3
Least-cost degree of redundancy	N-0.75	N-0.5	N-0.25	N-0

Three of the selected networks are overhead and one underground. For two of them (A and D), the failure rates are at the minimum value considered (i.e. 5%) and the other two (B and C) are at the maximum. For case A and B, the restoration time is 24 h while for case C and D, the restoration time is 3 h (with mobile generation) that reduces the impact of outages. The parameters of the cases are selected such that all cases are optimal (with the optimal degree of redundancy).

Estimated expected CMLs are shown in Table 5.6 for four cases. Each case considers two switching times in which fault is isolated and supply restored to customers where possible. Two redundancy levels are considered, the optimal and N-1. Frequency of outages do not depend on degree of redundancy and CI would be the same. The difference would be observed in case of switching time of 2 minutes for which supply outage shorter than 3 minutes will not be counted towards CI [166].

Table 5.6. CML for different cases; ST – switching time

Case	Redundancy level	CML (min/cust.y)	
		ST=30 min	ST=2 min
A	N-1	8.4	~ 0
	N-0.75	9.8	1.6
B	N-1	17.2	~ 0
	N-0.5	39.5	23.7
C	N-1	33.1	~ 0
	N-0.25	46.8	17.1
D	N-1	8.4	~ 0
	N-0	14.9	7.7

In case of N-1 redundancy level and switching time of two minutes the estimated CMLs are nearly zero given the supply to all customers affected by a single HV network fault are restored within three minutes [166]. For switching time of 30 minutes, CML increases if degree of redundancy is reduced from N-1 given that supply to all customers could not be restored within switching time.

Table 5.7 shows the expected values of increase in CML (ΔCML). For case A, ΔCML is 1.6 minutes on average per consumer where automation is implemented. For case B it is 23.7, for C 17.1 and D 7.7.

Table 5.7: Increase of CML if the P2/6 N-1 design requirement is relaxed; ST – switching time

Case	ΔCML, ST=30 minutes	ΔCML, ST=2 minutes
A	1.3	1.6
B	22.3	23.7
C	13.7	17.1
D	6.5	7.7

The greatest increase in CML is observed in case B given the longest restoration time compared with cases C and D and greater failure rate compared with case A. The smallest increase in CML is for Case A given the largest optimal degree of redundancy.

Cumulative probability of CML for case C and switching time of 30 minutes is shown in Figure 5.2. Blue curve is for N-1 degree of redundancy and orange for N-0.25.

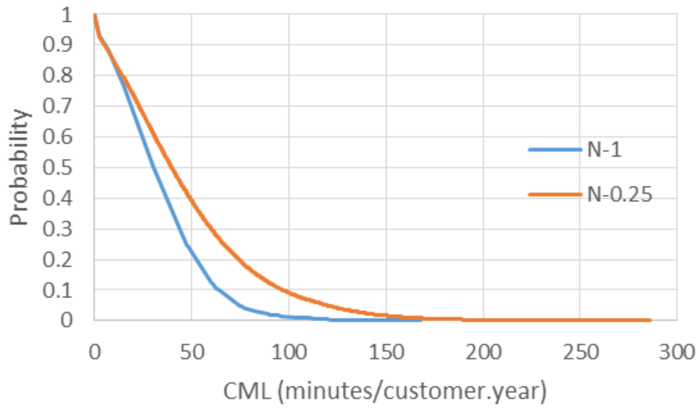


Figure 5.2. Cumulative probability of CML for case C and switching time of 30 minutes

The possible increase in CML due to relaxation of P2 conditions can be observed. For example, probability of CML exceeding 100 customer minutes per customer per year for N-1 degree of redundancy is about 1.0% while for N-0.25 degree of redundancy it is about 9.2%. The average value for N-1 is 33.1 and for N-0.25 46.8 minutes per customer per year as shown in Table 5.6. Table 5.8 shows the probability of different CML realisations. For two-minute switching time case and degree of redundancy of N-1, CML is close to zero and hence not shown in the Table.

Table 5.8. Probability of CML exceeding specified values; for two-minute switching time the CML for N-1 degree of redundancy is close to 0 given three-minute threshold [166].

Switching time (min)	Case	Degree of redundancy	Number of years in 100 years for which CML is above specified value in minutes/customer.year				
			20	30	40	50	100
30	A	N-1	10.4	1.9	1.9	0.3	0.1
		N-0.75	12.8	5.1	3.7	2.0	0.4
	B	N-1	29.6	9.8	9.8	2.7	0.3
		N-0.5	39.6	28.9	24.5	19.3	10.1
	C	N-1	64.4	37.1	37.1	18.0	1.0
		N-0.25	70.1	56.6	50.1	37.7	9.2
	D	N-1	11.0	1.9	1.9	0.3	0.0
		N-0	23.0	17.6	13.4	9.9	1.2
2	A	N-0.75	2.1	1.5	1.1	0.9	0.3
	B	N-0.5	19.2	16.6	14.6	13.0	7.6
	C	N-0.25	30.9	23.7	17.4	12.0	1.5
	D	N-0	13.8	10.9	8.4	6.0	0.4

It can be observed that CML in case C might exceed 100 minutes per customer per year in about 9.2 years per 100 years for economically efficient N-0.25 degree of redundancy while it is 1.0 for N-1. The greater number of additional years that CML might exceed 100 minutes per customer per year is for Case B given that supply restoration takes longer in Case B compared to Case C, see Table 5.5.

Table 5.9 shows the expected value not supplied and the cost of interruption when the VoLL is £17,000/MWh. 'Switching' EENS is EENS of customers whose supplies are restored during switching time. 'Thermal' EENS is part of EENS which originates from interruptions of customers which have to wait for repair or alternative supply following FCO given there is no sufficient capacity to restore supply to all customers all the time. Switching and thermal EENS are related to FCO only. Hence total EENS is summation of switching EENS, thermal EENS and other overlapping outages. EENS from overlapping outages is relatively modest and hence not shown for simplicity.

Table 5.9. Results of EENS for case A, B, C, D compared with the corresponding N-1 redundancy and for switching time of 2 minutes

Case	Redundancy level	EENS (MWh/year)	Switching EENS (MWh/year)	Thermal EENS (MWh/year)	EENS*VoLL (£/year)
A	N-1	0.032	0.032	0.000	541
	N-0.75	0.176	0.036	0.127	2,987
B	N-1	0.106	0.057	0.000	1,808
	N-0.5	2.486	0.086	2.322	42,265
C	N-1	0.112	0.108	0.000	1,898
	N-0.25	2.089	0.200	1.858	35,510
D	N-1	0.027	0.027	0.000	451
	N-0	1.014	0.057	0.955	17,238

In case A, the expected cost of interruptions increases from £541 to £2,987 i.e. for £2,447. EENS for customers for which supply is restored by network reconfiguration increases from 0.032 to 0.036MWh per year, which represents 13% increase. EENS due to lack of feeder capacity is 0.127 MWh per year which represents 73% of the total EENS.

In case B, the demand is increased by 50% and expected cost of interruptions increases from £1,808 to £42,265. EENS of customers for which supply is restored by network reconfiguration increases from 0.057 to 0.086MWh per year, which represents 50% increase i.e. same as demand increase. EENS due to lack of feeder capacity is about 2.3 MWh per year which represents 93% of the total EENS.

In case C, the expected cost of interruptions increases from £1,898 to £35,510. EENS of customers for which supply is restored by network reconfiguration increases from 0.108 to 0.200MWh per year, which represents 85% increase i.e. similar as demand increase. EENS due to lack of feeder capacity is about 1.85 MWh per year which represents 89% of the total EENS. This is a bit smaller than the corresponding value in case B. This is due to availability of mobile generation in case C but not in B. Otherwise increase would be much higher.

In case D, the cost of interruptions increases from £451 to £17,238. EENS of customers for which supply is restored by network reconfiguration increases from 0.027 to 0.057 MWh per year, which represents about 115% increase while EENS due to insufficient feeder capacity is about 1 MWh per year which represents 94% of the total EENS.

Cumulative probability of ENS for case C with switching time of 30 minutes is shown in Figure 5.3. The blue curve is for N-1 degree of redundancy while orange for N-0.25.

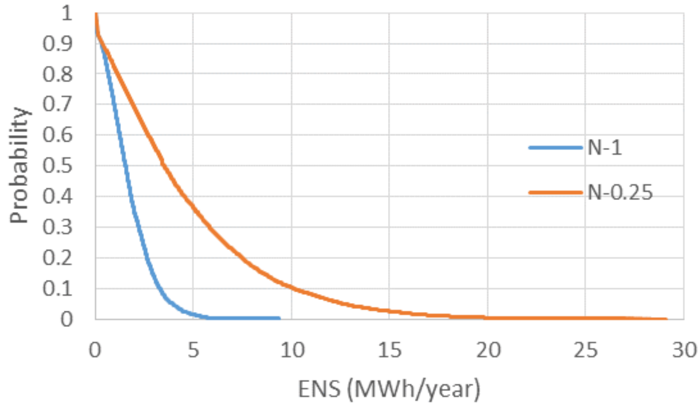


Figure 5.3. Cumulative probability of ENS for case C with switching time of 30 minutes

It can be seen that the expected energy for N-0.25 degree of redundancy would increase. For example the probability of ENS exceeding 10 MWh/year for N-1 degree of redundancy is practically zero. However, for N-0.25 it is about 10% (it may occur once in ten years on average). Table 5.10 shows the probability of ENS exceeding expected and two times expected values.

Table 5.10. Probability of ENS exceeding specified values

Switching time (min)	Case	Degree of redundancy	Number of years in 100 years for which ENS is above specified value in MWh/year				
			2	3	4	5	10
30	A	N-1	2.0	0.3	0.1	0.1	0.0
		N-0.75	7.9	3.2	1.8	1.2	0.3
	B	N-1	9.7	2.2	0.5	0.3	0.1
		N-0.5	36.6	25.9	20.6	17.5	9.5
	C	N-1	35.4	14.0	4.6	1.5	0.0
		N-0.25	68.6	55.8	45.2	36.6	10.3
	D	N-1	2.1	0.2	0.0	0.0	0.0
		N-0	24.6	18.9	15.0	12.3	3.2
2	A	N-1	0.0	0.0	0.0	0.0	0.0
		N-0.75	2.1	1.4	1.0	0.8	0.2
	B	N-1	0.2	0.2	0.2	0.2	0.1
		N-0.5	19.5	16.9	14.8	13.1	7.8
	C	N-1	0.0	0.0	0.0	0.0	0.0
		N-0.25	33.2	26.5	20.8	15.5	2.9
	D	N-1	0.0	0.0	0.0	0.0	0.0
		N-0	15.0	12.5	10.3	8.3	1.9

For example, for Case C and switching time of 30 minutes ENS of more than 10 MWh/year could occur about 10 times per 100 years more in N-0.25 when compared with N-1 degree of redundancy.

In general comparing N-1 and economically efficient designs, CI increases given the use of automation. This happens as switching which takes place within 3 minutes now is insufficient to avoid CIs. To some extent, driving a network harder than N-1 will reduce the customer benefits from deploying automation. Due to the reduction in redundancy, load curtailment is needed when demand is greater than feeder thermal capacity and hence CML will increase. Increase in EENS is greater than in CML, given the demand increase which is not relevant for CML even if the number of connected customers increase with the demand increase. Emergency mobile generation is used in cases C and D which accounts for a relatively lower increase of EENS compared with case B. Clearly, use of mobile generation facilitates reduction in network redundancy.

5.4 ACE 51 Illustrative example of reinforcement of an urban HV network

Figure 5.4 shows one dual-circuit transformer-feeder system. Two circuits with capacity of 24 MW each, supply demand of 36 MW at peak at unity power factor.

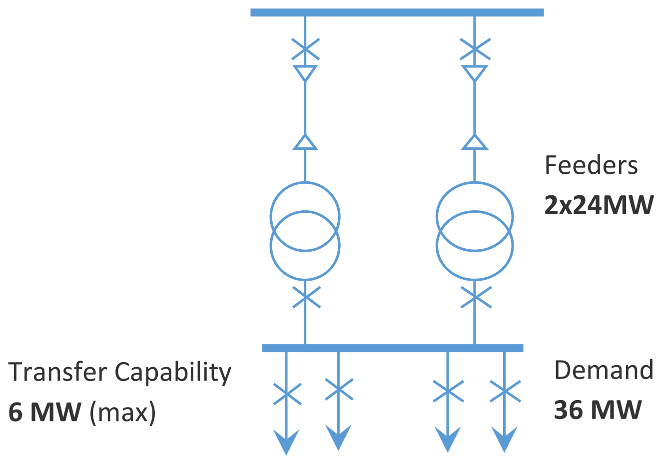


Figure 5.4. Dual-circuit transformer-feeder system

Component reliability parameters are given in Table 5.11. The additional data and assumptions are as follows:

- The load that can be transferred away from the substation using the 11 kV system is one-sixth of the substation load, giving the load transferable at the time of maximum demand as 6 MW
- The maintenance outages for the transformer feeder are 32 hours every 4 years and the restoration time, should a fault occur on a related circuit during maintenance is, 4 hours

- The time to complete load transfer via the 11 kV network subsequent to a fault is two hours
- After any busbar fault, half the busbar will be restored in two hours. Any subsequent switching and repair are included in the single-circuit transformer-feeder outage data
- The urgent repair time, subsequent to load transfer switching, for overlapping fault outages and single circuit outages is 53 hours
- The substation supplies ten HV feeders, each of which accounts for an equal proportion of load on the substation
- Load factor over the whole year 57%
- Normalised annual load duration curve is shown in Figure 5.5
- Load factor over summer maintenance period 58%
- Ratio of summer maximum demand to the all-year maximum demand 62/74=84%.

Table 5.11. Reliability parameters

Asset	Fault rate (%/year)	Average outage duration (h)
33 kV busbar	0.1	2
33 kV circuit breaker	0.3	76
33 kV cable – 4 km	10	200
33/11 kV transformer	1.5	350
11 kV circuit breaker	0.3	24
11 kV busbar	0.1	2

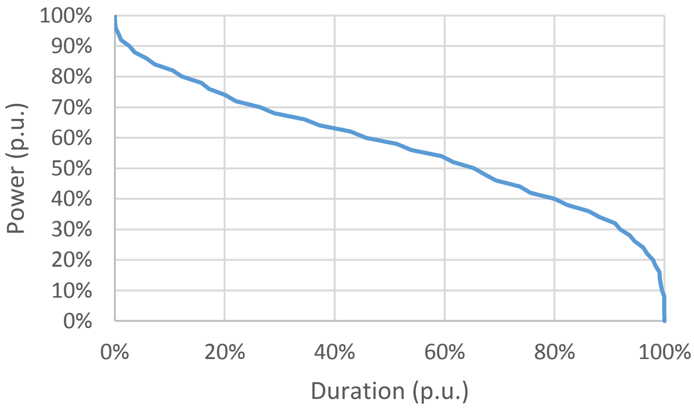


Figure 5.5. Normalised annual load duration curve

Assuming like-for-like annuitized replacement cost of £45.3k and savings in system losses as in ACE 51 report, the breakeven VoLL is shown in Table 5.12.

Table 5.12. Breakeven VoLL

Redundancy	ACE 51 min	ACE 51 max	This report
N-1	Very large	Very large	Very large
N-0.67	8,900	36,827	6,278
N-0.5	2,623	4,393	2,248

Using the approach described in ACE 51 minimum and maximum breakeven VoLL is calculated. Minimum is when all load is disconnected following overload and maximum when close-load monitoring with automatic load shedding brings load within network capacity. Assuming that the VoLL, as used in ACE 51 report for this particular example, is less than £5,860/MWh it can be concluded that the optimal degree of redundancy is about between N-0.67 and N-0.5. For comparison, VoLL of £2,000/MWh was used in the pool electricity market in 1990. It can be seen that the approach applied in this report is more conservative when compared to ACE 51.

ACE 51 considers the reinforcement of an urban HV system by the installation of an EHV/HV substation as shown in Figure 5.6. Three identical primary substations, each one as in Figure 5.4, supply demand in the area. Case for installation of another primary substation is investigated. The impact of different load levels is analysed. Considered load levels are 72, 84, 96 and 108 MW with each primary peak between 24 and 36 MW.

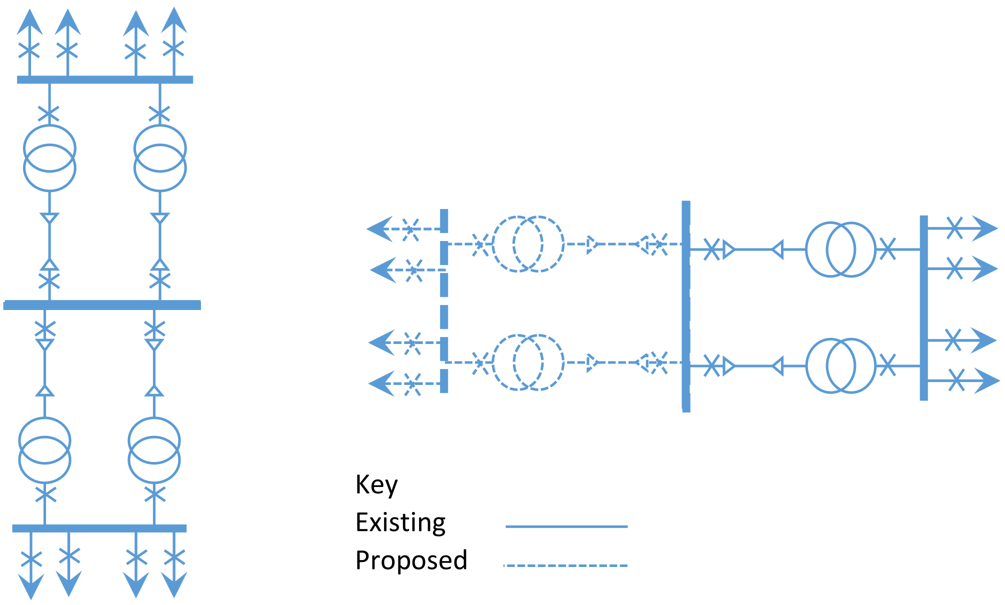


Figure 5.6. Schematic layout of 33/11 kV substations

The ACE 51 results are summarised in Table 5.13 for each of group load. Annuitized cost of reinforcement (calculated at 1975 prices) and operation and maintenance is offset by the savings in system losses and cost of not deferring reinforcement for one year is obtained. The MWh saved per year is estimated from reliability of supplies with three and four primary substations. Dividing cost of not deferring the reinforcement for one year with MWh saved per year the cost per kWh saved is obtained.

Table 5.13. MWh saved per year and cost per kWh saved

Group load (MW)		72	84	96	108
Cost of capital plus operation and maintenance (£000)		43.8	44.3	44.8	45.3
Savings in system losses (£000)	EHV	5.4	8.0	10.9	14.3
	HV	5.0	5.8	6.9	7.5
	Total	10.4	13.8	17.8	21.8
Cost of not deferring the reinforcement for one year (£000)		33.4	30.5	27.0	23.5
MWh saved per year	EHV	0.01	0.34	3.89	20.89
	HV	0.54	0.63	0.72	0.81
	Total	0.55	0.97	4.61	21.70
Cost per kWh saved (£)		60.7	31.4	5.86	1.08

Cost per kWh saved (at the bottom of the Table) is equivalent to the breakeven VoLL used in this report. It is stated that the VoLL would not exceed £5.86/kWh and hence it would be economically efficient to delay reinforcement until (at least) 96 MW (N-0.67) is reached. It should be noted that the same optimal degree of redundancy is estimated for a single primary substation scheme as shown in Table 5.12. Again, for comparison, pool based market in 1990 assumes the VoLL of £2,000/MWh.

5.5 Optimal degree of redundancy for EHV networks

The topology of the EHV network, with up to 3 primary substations as shown in Figure 5.7, is used in this study to investigate the optimal degree of redundancy for EHV networks. Typically, the primary substation consists of two transformers (or more) which are fed from different EHV feeders. If one of the feeders is out of service, the load can be supplied by the other functional feeder.

The sensitivity of key parameters such as the network construction (OHL or UGC), failure rate, section length, loading and load transfer capability, and common-mode outages of parallel sections on the optimal degree of redundancy, has been investigated. The number of primary substations is also varied between 1 and 3 and the configuration of the network in Figure 5.7 is adjusted accordingly. The studies assume that outages could can happen at individual network components (sections, transformers, and busbars). The fault of one circuit might momentarily overload the second circuit until protection is activated to disconnect all customers. Common mode failures have also been considered (for example common-mode failures of parallel sections)

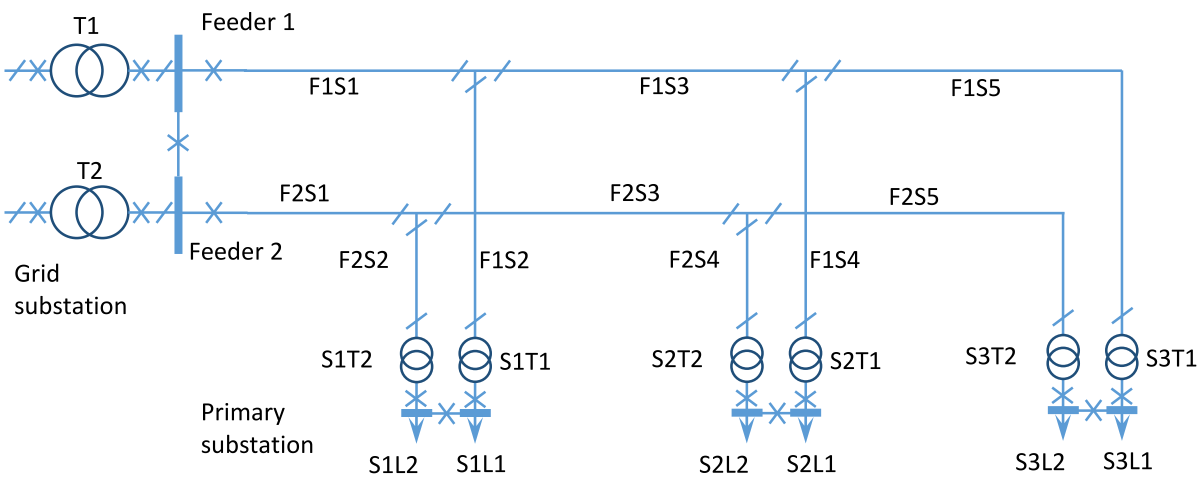


Figure 5.7: The topology of an EHV network with 3 primary substations used in the study

Table 5.14 shows optimal degrees of redundancy for EHV OH networks, which vary from N-0.5 to N-1 for cases with peak loading of 7.5 MVA, and from N-0.75 to N-1 for cases with peak loading of 20 MVA. Note that the upper values in the table cells correspond to the load profile with a low load factor and the lower values to the load profile with a high load factor. The first three columns in the Table define the number of primaries in the scheme, section lengths and failure rates respectively. The optimal degree of redundancy is shown for four load transfer capabilities: 0, 10, 20 and 30%. Again, this indicates the opportunity to accommodate increased peak load up to a certain degree without upgrading the networks. The impact of the load profile on the optimal degree of redundancy is significant and the difference between optimal degrees of redundancy could be between 0.5 and 0.75. A small impact of the load transfer capability is observed, up to 0.25. The observed increase in the optimal degree of redundancy driven by increase in peak demand ranges between 0.25 and 0.5. An increasing number of supplied primary substations increases the optimal degree of redundancy for up to 0.5 for networks with greater failure rate. In networks with lower failure rate the optimal degree of redundancy is lower.

Table 5.15 shows the optimal degree of redundancy for bulk supply substations. The optimal degree of redundancy for a two-transformer substation depends on the circuit failure rate, the length of the transformer feeder cable, the load profile and the VoLL. For greater failure rates the optimal degree of redundancy is greater for about 0 to 0.25 for shorter feeder cables and about 0.25 to 0.5 for longer feeder cables. There is no significant difference observed for different load profiles except the case of longer feeder cable and lower failure rate where the difference is between 0.25 and 0.5. A small difference is observed for the VoLL of £34,000/MWh and lower failure rate, while a higher difference of about 0.25 to 0.5 is observed for higher failure rates and a load profile with a high load factor. For three- and four-transformer substations there is no observed impact of the transformer feeder cable length, failure rate and losses. The optimal degree of redundancy is about the total rating of such a substation.

Table 5.14: Optimal degree of redundancy for EHV Overhead networks with VoLL of £17,000/MWh

Number of primaries	Section length (km) Main/Spur	Failure rate	Transformer peak loading 7.5 MVA Load transfer 0	10%	20%	30%	Transformer peak loading 20 MVA Load Transfer 0	10%	20%	30%
1	4	Min	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.25:N-0.5	N-0 N-0.25:N-0.5	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75
	14	Min	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0:N-0.25 N-0.75:N-1
	20	Min	N-0 N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0:N-0.25 N-1
	30	Min	N-0:N-0.25 N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1
	4	Max	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75	N-0 N-0.75	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	14	Max	N-0.25:N-0.5 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	20	Max	N-0.25:N-0.5 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	30	Max	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-1 N-1	N-1 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1
2	4/0	Min	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.5	N-0 N-0.25:N-0.5	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-0.75:N-1	N-0.25 N-0.75:N-1
	4/0	Max	N-0.25:N-0.5 N-1	N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75:N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5 N-1
	4/10	Min	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	20/0	Min	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.5:N-0.75 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	20/10	Min	N-0:N-0.25 N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.5:N-0.75 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	4/10	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0.25 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5 N-1
	20/0	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0:N-0.25 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	20/10	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-0.75:N-1	N-0:N-0.25 N-0.75:N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
3	4/0	Min	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.5	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-0.75:N-1	N-0.25:N-0.5 N-0.75:N-1
	4/0	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-0.75:N-1	N-0.25 N-0.75	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1
	4/10	Min	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	20/0	Min	N-0:N-0.25 N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.5 N-1	N-0.5 N-1	N-0.5 N-1	N-0.25:N-0.5 N-1
	20/10	Min	N-0.25 N-0.75	N-0:N-0.25 N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0.5 N-1	N-0.5 N-1	N-0.5 N-1	N-0.25:N-0.5 N-1
	4/10	Max	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1
	20/0	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	20/10	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-0.75:N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1

Table 5.15: Optimal degree of redundancy for bulk supply substations for two values of the VoLL £17,000/MWh / £34,000/MWh; N-0 denotes double loading of N-1

Transformer feeder cable length (km)	Failure rate	Two-transformer substation	Three-transformer substation	Four-transformer substation
1	Min	N-0.5 N-0.5/N-0.5:N-0.75	N-0.5 N-0.5/N-0.5:N-0.75	N-0.75 N-0.75
	Max	N-0.5:N-0.75/N-0.75 N-0.5:N-0.75/N-1	N-0.5 N-0.5/N-0.5:N-0.75	N-0.75 N-0.75
5	Min	N-0:N-0.25/N-0.5 N-0.5	N-0.5 N-0.5	N-0.75 N-0.75
	Max	N-0.5:N-0.75/N-0.75 N-0.5:N-0.75/N-1	N-0.5 N-0.5/N-0.5:N-0.75	N-0.75 N-0.75

Our key observations are listed as follows:

- The ability to transfer load improves the reliability performance and enables a lower degree of redundancy to be justified. For example, in the first row (case no 1 of Table 5.14), the degree of redundancy decreases from N-0.5 (no load transfer capability) to N-0.25 (load transfer capability of 30%). This trend can be observed in all cases.
- Longer section lengths tend to increase the degree of redundancy required. In contrast to the cases of HV networks where the section lengths do not impact degree of redundancy (as higher failure rates are combined with higher network replacement costs, so the effect of length is cancelled out), in this case study the impact of an increase in section length to the reliability performance may exceed the cost of upgrade; therefore, a higher degree of redundancy may be needed.
- As observed in the previous studies, the network with higher loading (i.e. 20 MVA) tends to require a higher degree of redundancy. In this case, most of the results for 20 MVA peak load suggest N-1 as the appropriate level of redundancy for the system in question. The observed trend indicates that an increasing rating and load would result in a greater optimal degree of redundancy. For example, for 60 MVA substations, the optimal redundancy might be slightly greater than for 40 MVA substations.
- Similarly, the cases with lower failure rates are justified to have a lower degree of redundancy. For example, in the case with a network section length of 4 km, no load transfer capability, and a peak load of 7.5 MVA, the optimal degree of redundancy for the case with minimum and maximum failure rates are N-0.5 and N-1 respectively.

Table 5.16 shows the optimal degree of redundancy for EHV underground networks when the VoLL is £17,000/MWh. The impact of the load profile on the optimal degree of redundancy is significant: the difference between optimal degrees of redundancy could be between 0.5 and 0.75. A small impact of the load transfer capability is observed of up to 0.25. The observed increase of the optimal degree of redundancy due to greater loading can be between 0.25 and 0.5. The optimal degree of redundancy increases for up to 0.5 for networks with greater failure rate. In networks with lower failure rate the optimal degree of redundancy is lower.

Because of the fact that UG networks are characterised by higher reliability and larger reinforcement cost when compared to overhead networks, the optimal redundancy level for underground networks tends to be lower. With a VoLL of £17,000/MWh, the optimal degree of redundancy varies between N-0 and N-1 for different cases. For cases with a peak load of 7.5 MVA, it varies between N-0 and N-0.75, and no case justifies an N-1 design. The performed analysis assumes that load shedding is implemented which prevents network overloads. It is interesting to observe that even at the EHV level, where the system serves a relatively large number of customers, N-0 could be still justified in some relatively extreme cases (while the present security standards requires N-1 redundancy level). The analysis assumes two transformers per substation and at least 20% load transfer for N-0 to be justified for highly reliable EHV networks. In this analysis it is assumed that maintenance would be possible to conduct during minimum demand conditions, which would not lead to asset overloads during power transfers.

Table 5.16: Optimal degree of redundancy for EHV UG networks when the VoLL is £17,000/MWh

Number of primaries	Section length (km) Main/Spur	Failure rate	Transformer peak loading 7.5 MVA				Transformer peak loading 20 MVA			
			Load transfer				Load Transfer			
			0	10%	20%	30%	0	10%	20%	30%
1	4	Min	N-0 N-0.25:N-0.5	N-0 N-0:N-0.25	N-0 N-0:N-0.25	N-0 N-0	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75
	14, 20, 30	Min	N-0 N-0.25:N-0.5	N-0 N-0.25	N-0 N-0:N-0.25	N-0 N-0	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75
	4	Max	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.25:N-0.5	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1
	14, 20	Max	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.5	N-0 N-0.25:N-0.5	N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1
	30	Max	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.5	N-0 N-0.25:N-0.5	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0 N-0.75:N-1
2	4/0, 4/10, 20/0 20/10	Min	N-0 N-0.25:N-0.5	N-0 N-0.25	N-0 N-0:N-0.25	N-0 N-0	N-0:N-0.25 N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75
	4/0, 4/10	Max	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.25:N-0.5	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-0.75:N-1
	20/0, 20/10	Max	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.25:N-0.5	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0:N-0.25 N-0.75:N-1
3	4/0, 4/10	Min	N-0 N-0.25:N-0.5	N-0 N-0.25:N-0.5	N-0 N-0:N-0.25	N-0 N-0:N-0.25	N-0:N-0.25 N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75
	20/0, 20/10	Min	N-0 N-0.25:N-0.5	N-0 N-0.25:N-0.5	N-0 N-0:N-0.25	N-0 N-0:N-0.25	N-0.25 N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75
	4/0	Max	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.5	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-0.75:N-1
	4/10	Max	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.5	N-0.5:N-1 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-0.75:N-1
	20/0, 20/10	Max	N-0:N-0.25 N-0.5:N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.5	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1

We also observe that a higher degree of redundancy would be justified with higher failure rates, and lower levels of network control capability (e.g. transferring loads to alternative healthy circuits), which is consistent with findings from the studies discussed previously. Furthermore, higher level of VoLL (£34,000/MWh), would justify higher degree of redundancy.

5.6 Optimal degree of redundancy for 132 kV networks

Similar studies have been carried on a generic configuration of 132 kV networks. The topology of 132 kV networks is similar to the configuration of EHV networks where double transformer feeders feed two-transformer grid substations (see Figure 5.8). The sensitivity of key parameters such as the network construction (overhead or underground), failure rates, section lengths, loading and load transfers, and common-mode outages of parallel sections on the optimal degree of redundancy have been investigated.

The results of the studies with a VoLL of £17,000/MWh for the 132kV OH network are presented in Table 5.17. The upper value in table cells corresponds to the optimal degree of redundancy for low load factor demand and the lower value to the optimal degree of redundancy for high load factor demand. The greatest observed difference between optimal degrees of redundancy is for single bulk supply substations where the optimal degree of redundancy for low load factor demand is about N-0 and for high load factor demand is about N-1 (although difference is typically between 0.5 and 0.75). Other parameters, such as loading level, load transfer capability, circuit length and failure rate, number of connected bulk supply substations, have relatively marginal impact on the level of redundancy. For load transfers of

10, 20 and 30% the assumption has been that the SCADA remote control / intrertripping scheme would be completed in 10 minutes.

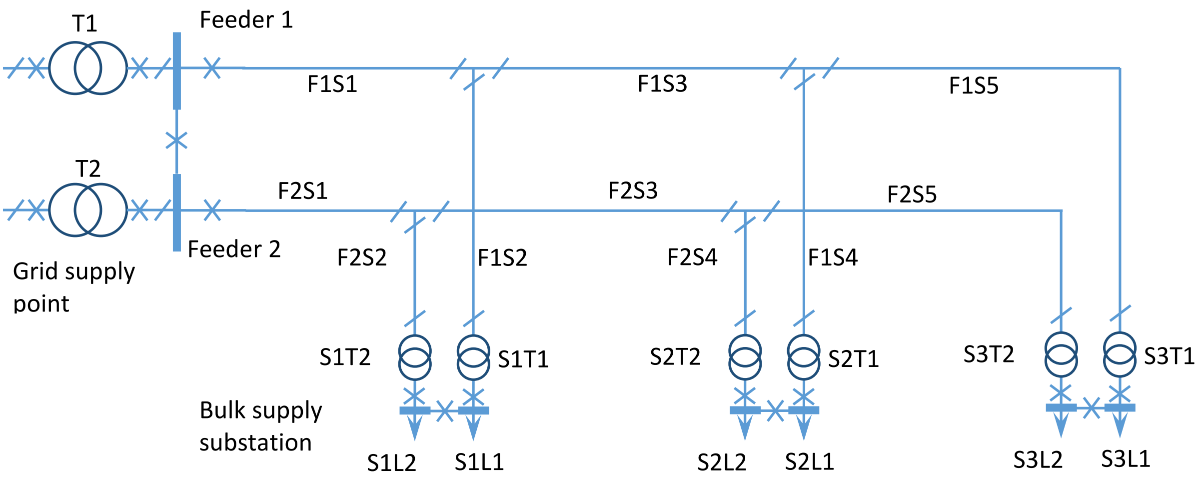


Figure 5.8: The illustrative topology of a 132 kV network with 3 bulk supply substations used in the study

Table 5.17: Optimal Redundancy, 132kV Overhead, VoLL £17,000/MWh

Number of grid substations	Section length (km) Main/Spur	Failure rate	Transformer peak loading 22.5 MVA				Transformer peak loading 45 MVA			
			Load transfer				Load Transfer			
			0	10%	20%	30%	0	10%	20%	30%
1	8	Min	N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75:N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1
	18	Min	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1
	30, 40	Min	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1
	8	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.5:N-0.75 N-1	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	18	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	30	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	40	Max	N-0.25:N-0.5 N-1	N-0:N-0.25 N-1	N-0 N-1	N-0 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1
2	8/0	Min	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75:N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	8/10	Min	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0.5 N-1	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	30/0, 30/10	Min	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0.5 N-1	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	8/0	Max	N-0.5 N-1	N-0.5 N-1	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1
	8/10	Max	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5 N-1	N-0.5 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1
	30/0, 30/10	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
3	8/0	Min	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-0.75:N-1	N-0.5 N-1	N-0.5 N-1	N-0.5 N-1	N-0.25:N-0.5 N-1
	8/10	Min	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.5:N-0.75 N-1	N-0.5 N-1	N-0.5 N-1	N-0.5 N-1
	30/0	Min	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1
	30/10	Min	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.5 N-1	N-0.5 N-1	N-0.5 N-1	N-0.5 N-1
	8/0	Max	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1
	8/10	Max	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1
	30/0	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	30/10	Max	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1	N-0.5:N-0.75 N-1

The results of the sensitivity studies for the 132kV underground networks for cases with a VoLL of £17,000/MWh are presented in Table 5.18. As before, the upper value in table cells corresponds to the optimal degree of redundancy for the low load factor demand and the lower values to the optimal degree of redundancy for the high load factor demand. The analysis shows that the load factor of demand is a major driving factor for the degree of redundancy. Differences in redundancy levels are relatively marginal for different loadings, network lengths and numbers of bulk supply substations. It should be noted, that given the high network voltage level, demand diversity is likely to be significant and hence the load factor of demand is likely to be high.

Table 5.18: Optimal degree of redundancy for 132 kV UG networks with VoLL of £17,000/MWh; 'N-' term is omitted for simplicity

Number of grid substations	Section length (km) Main/Spur	Failure rate	Transformer peak loading 22.5 MVA				Transformer peak loading 45 MVA			
			Load transfer				Load Transfer			
			0	10%	20%	30%	0	10%	20%	30%
1	8, 18, 30, 40	Min	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0 N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75
	8, 18	Max	N-0:N-0.25 N-1	N-0 N-0.75:N-1	N-0 N-0.75	N-0 N-0.75	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1
	30, 40	Max	N-0:N-0.25 N-1	N-0 N-0.75:N-1	N-0 N-0.75	N-0 N-0.75	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0 N-1
2	8/0, 8/10, 30/0 30/10	Min	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5	N-0:N-0.25 N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75
	8/0, 8/10	Max	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75	N-0:N-0.25 N-0.75	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0.25 N-1
	30/0, 30/10	Max	N-0:N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1	N-0 N-0.75	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0.25 N-1	N-0:N-0.25 N-1
3	8/0, 8/10, 30/0 30/10	Min	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0 N-0.5:N-0.75	N-0:N-0.25 N-0.75	N-0:N-0.25 N-0.75	N-0:N-0.25 N-0.5:N-0.75	N-0 N-0.5:N-0.75
	8/0	Max	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	8/10	Max	N-0.25:N-0.5 N-1	N-0.25 N-1	N-0.25 N-0.75:N-1	N-0:N-0.25 N-0.75	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1
	30/0	Max	N-0.25 N-1	N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1
	30/10	Max	N-0.25 N-1	N-0.25 N-1	N-0:N-0.25 N-1	N-0:N-0.25 N-0.75:N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25:N-0.5 N-1	N-0.25 N-1

From the results, it can be concluded that a higher degree of redundancy is generally required in a system with higher peak demand, higher number of primaries, longer section length (which implies a higher failure rate), lower load transfer capability (or slower restoration from mobile units) and higher VoLL. As UG networks are characterised by higher reliability and larger reinforcement cost compared to overhead networks, the optimal redundancy level for underground networks tends to be lower when compared with overhead networks. The results indicate that there is room for increasing the loading of the 132 kV assets which consequently reduces its degree of redundancy; however, this would be appropriate given relatively high network reliability of the underground networks combined with relatively high upgrade costs.

5.7 Potential savings of avoiding security-driven network reinforcements

The objective of this section is to estimate the maximum level of potential savings at the GB level, if existing P2 security standard driven constraints are relaxed, leading to increased utilisation of the existing distribution networks to the level that optimally balances savings in avoided network reinforcement against increased cost of interruptions and losses.

The analysis is based on the Committee on Climate Change "core decarbonisation" (CD) and "delayed electrification" (DE) pathways, which assume different deployment levels of low-carbon demand technologies [161] through electrification of segments of heat and transport sectors. HV and LV distribution networks in this analysis are modelled using representative network models, based on statistics and fractal theory, calibrated against real GB networks. Representative network models reproduce realistic network topologies and network lengths and therefore allow for the characterisation of distribution networks of different types. For the purpose of mapping the entire GB distribution network, 10 representative networks are used to evaluate the GB distribution network reinforcement costs. The 10 representative networks capture the key statistical properties of typical network topologies that can range from high-load density city/town networks to low-density rural networks. The design parameters of the representative networks closely match those of realistic distribution networks of similar topologies. It can be seen that representative network models closely map the GB aggregate values of LV and HV distribution networks as shown in Table 5.19. The number of primary transformers is estimated from the Regulatory Reporting Pack [163].

Table 5.19: Mapping of representative networks (RN) onto actual GB distribution networks

Parameter	GB value	RN value	Discrepancy (%)
Number of connected customers	29,416,113	29,410,374	-0.02%
Overhead LV network length (km)	64,929	64,905	-0.04%
Underground LV network length (km)	327,609	327,822	0.07%
Number of PMT	343,857	343,848	-0.00%
Number of GMT	230,465	230,323	-0.06%
Overhead LV network length per PMT (m)	189	189	-0.03%
Underground LV network length per GMT (m)	1,422	1,423	0.13%
Overhead HV network length (km)	169,119	167,354	-1.04%
Underground HV network length (km)	140,736	138,778	-1.39%
Number of primary transformers	9,473	9,989	5,44%

The reinforcement cost of in EHV and 132 and above networks is estimated at 60% of the reinforcement cost of HV networks and primary substations. According to the Reporting and Regulatory Pack spreadsheets (DPCR5), the cost of the assets operating at EHV and above is about 60% of the cost of HV network assets (as presented in Table 15.2 of Appendix B [163]). For estimating the cost of losses, an electricity price of £48.42/MWh is used as suggested in [164]. Potential savings from avoidance or deferral of reinforcement of HV networks (including HV feeders and primary substations) through increasing the utilisation of existing assets are estimated while considering the increase in losses and increase in customer interruption costs (using a VoLL of 17,000£/MWh).

Enhancing the utilisation of the existing distribution network (reducing the degree of network redundancy) will lead to increase in Customer Interruption Cost (CIC). The increase in a CIC is estimated for HV, EHV and 132 kV networks. The increase in EENS, driven by reduced redundancy, in HV overhead and underground networks are estimated for different degree of redundancy and for load profiles with low and high load factors and for minimum and maximum failure rates. The interpolation is used to estimate the CIC for increase of demand of 170% (Core Decarbonisation scenario) and 141% (Delayed Electrification scenario)[8]. Capitalisation factor 10 is used to capitalise cost of losses and customer interruption cost (considering amount of losses and outages in 2030).

For EHV and 132 kV networks the average customer outage cost is estimated from all considered cases by weighted average taking into account the proportion of overhead and underground networks and transformer ratings [162]. This is carried out for different degrees of redundancy. Total network replacement cost is estimated from the assets register [163].

Table 5.20 shows the estimated range of potential benefits of relaxing P2 conditions. Range is obtained from results for two scenarios Core Decarbonisation and Delayed Electrification. Results are given for different HV network degree of redundancy from N-0.75 to N-0 and for up to N-0.5 for primary substations and N-0.75 for EHV and 132 kV networks.

Table 5.20. Potential benefit (£m) of avoiding reinforcement of networks due to security standard constraints at GB level; benefits are shown in black while costs in red

Benefit/cost (£m)		HV network degree of redundancy			
		N-0.75	N-0.5	N-0.25	N-0
HV network		1,755 – 2,708	3,234 – 5,740	5,186 – 7,072	6,215 – 7,099
EHV and 132 kV networks		1,773 – 3,922	2,715 – 4,181	2,715 – 4,181	2,715 – 4,181
Losses		690 – 780	1,219 – 1,705	1,419 – 2,287	1,423 – 2,451
Customer outage cost	HV	11 – 17	219 – 389	978 – 1,334	1,172 – 1,339
	EHV and 132 kV	776 – 1,458	776 – 1,458	776 – 1,458	776 – 1,458
Total		**2,051 – 4,375**	**3,249 – 6,855**	**3,860 – 7,042**	**4,531 – 7,060**

Potential benefits range from £2-7 billion depending on range of optimal degree of redundancy of HV networks. The greater benefit is observed in Delayed Electrification scenario given that in Core Decarbonisation scenario as in case of greater loading some part of the network would need to be upgraded even if P2 is relaxed. It can be observed that the estimated maximum benefit is relatively similar for N-0.5 to N-0 degree of redundancy of HV network.

Considered "Delayed Electrification" (DE) pathway is comparable with a FES Gone Green scenario. Very high deployment of low-carbon technologies does not necessary result in high savings. Importantly in scenario with lower level of low-carbon technologies deployed, higher savings are observed i.e. greater savings are observed for Delayed Electrification than for Core Decarbonisation pathway even though Core Decarbonisation pathway assumes significantly higher penetration level of EVs and HPs. It is interesting to note that for higher penetration of LCT technologies network would need to be upgraded even if N-1 condition is relaxed.

[8] Bottom up demand profiles of HP and EV are based on trials carried out in LCNF projects, data obtained from Carbon Trust CHP trials, and driving patterns recorded by the Department of Transport.

Overall, this analysis suggests that between 42% and 67% of load related expenditure can be saved if the network redundancy is reduced from the present N-1 to economically efficient level[9].

The modelling is also carried out to analyse the impact of peak demand reduction through smart control of low carbon technologies. In this demand-side response scenario, the savings of relaxing the present security constraints are potentially increased by additional £0.8bn – £1bn at the GB level by 2030, without taking into account the cost of implementing demand-side response.

Additional potential benefits that would be derived from smart load disconnections is implemented is estimated through illustrative example. It is assumed that 10% of essential load for which supply outage is valued at the VoLL of £17,000/MWh and the remaining non-essential load is valued at £2,000/MWh. Table 5.21 shows the estimated additional potential benefit if optimal degree is reduced assuming reduction of optimal degree of redundancy of 0.25 when smart load disconnection is implemented. For illustrative purposes, it is assumed that optimal degree of redundancy for HV network and primary substations are reduced from N-0.5 to N-0.25 while for EHV and 132 kV networks it is reduced from N-0.75 to N-0.5.

Table 5.21. Potential benefit of relaxing P2 conditions with smart load disconnection if smart load disconnection results in a reduced optimal degree of redundancy; cost of implementing smart load disconnection is not considered; benefits are shown in black while costs in red

Benefit/cost (£m)		Smart load reduction
HV network		1,767 – 1,331
EHV and 132 kV networks		1,522 – 2,278
Losses		200 – 550
Customer outage cost	HV	18 – 114
	EHV and 132 kV	151 – 684
Total increase		**2,073 – 3,372**

It can be observed that the potential benefit of smart disconnections of non-essential loads could be between about £2bn and £3.4bn, which is achieved by avoiding reinforcement in distribution networks. Cost of losses and customer outage cost would increase. It is interesting to observe that cost of interruptions would be reduced as the loads disconnected would be non-essential and corresponding VoLL is lower. In summary, the additional savings driven by smart load disconnections could be between 16% and 23% of the total load related capital expenditure. It should be pointed out that the costs of implementing smart load disconnections is not considered in this analysis.

9 We emphasise that this analysis does not consider asset condition based replacements.

6 GENERATION DRIVEN DISTRIBUTION NETWORK INVESTMENT

Given the growing amount of various forms of distributed generation (DG) being connected to distribution networks and the fact that the security requirements in the present network reliability standards are demand-driven, one of the topics associated with the fundamental review of the standards is related to the impact and treatment of DG. In this context two key subjects are addressed in this study: (a) level of network redundancy driven by DG; and (b) impact of DG on reliability of supply seen by demand.

In order to establish the appropriate framework for generation driven network investment, a range of studies has been carried with the objective to gain insight on the level of *network reliability / redundancy driven by DG*, find and analyse cases where the *reverse power flows may degrade the reliability seen by demand* and identify alternative cost effective solutions combining both traditional network reinforcements and applications of advanced protection solutions to mitigate DG driven demand interruptions [80]-[83].

Analysis carried out demonstrates that no redundancy would be justified for sites that connect generation only as the cost of generation curtailment is two order of magnitude lower than cost of demand curtailment. For distributed generation with high load factors optimal level of redundancy is presented in Table 6.1. Note that increase in redundancy to N-0.25 in HV and EHV networks would be justified only for very unreliable networks with high failure rates and average repair times of 10 days.

Table 6.1. Optimal level of redundancy for networks driven by distributed generation with high load factors

Voltage level	Overhead lines	Underground cables
HV	N-0:0.25	N-0
EHV	N-0:0.25	N-0
132 kV	N-0	N-0

For the analysis of the impact of distributed generation on reliability of demand, case system considered consists of two primary transformers, PV farms of 36 MW, and a demand group of 15,000 domestic customers (Figure 6.1). By modelling the PV output profile in detail, the analysis suggests that for 7.5% of time the PV output will exceed demand. If the reverse flow exceeds the capacity of one of the transformers, the system would be no longer 'N-1' secure as failure in one transformer may trigger overload of the other transformer leading to supply interruption. A set of studies is carried out to investigate whether an increasing redundancy by installing a third transformer can be justified. The results are shown in Figure 6.2. The cost of smart system protection is not taken into account and thus the presented benefit is the gross benefit. None of the scenarios considered justify network reinforcement. The studies lead to the following conclusions:

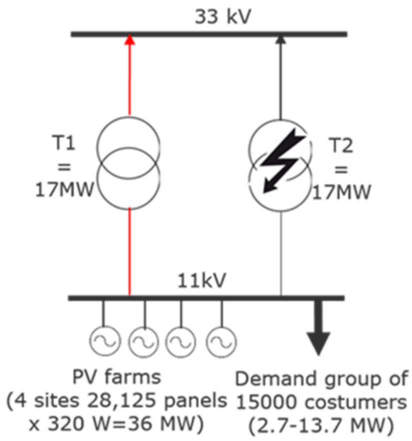


Figure 6.1: A failure in T2 in combination with reverse flows may overload T1

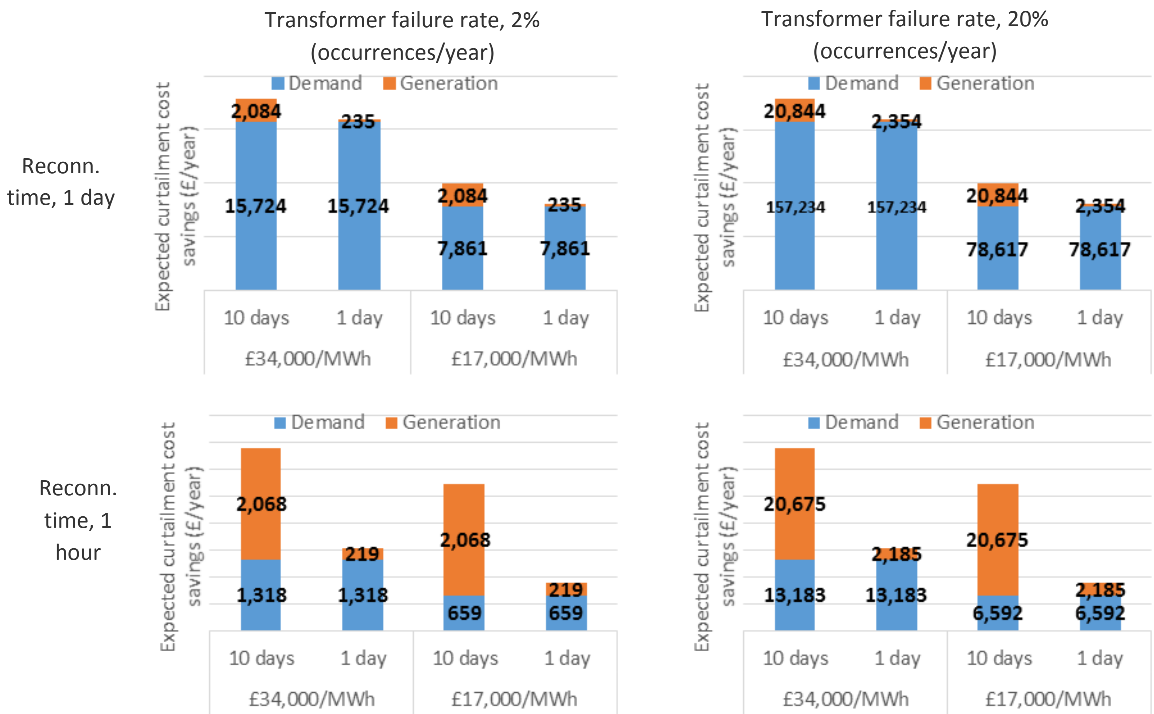


Figure 6.2: Savings in curtailments costs from installing a third transformer

- There is no need for network redundancy to secure DG output, assuming that the impact of losing DG output on the national electricity system is marginal. This implies that a N-0 security level is adequate for DG as the cost of generation curtailment would be typically much lower than the network reinforcement cost, given that the Value of Lost Generation (VoLG) is typically two orders of magnitude lower than the Value of Lost Load (VoLL);
- Network reinforcement may not be cost effective for this problem even in the worst case scenario being studied (i.e. low network reliability performance) as the use of a smart system protection scheme, i.e. intertripping scheme, can limit the negative impact of the reverse power flow on demand reliability. Hence, an N-0 security level might be

appropriate for DG. However, the smart protection scheme may be exposed to failures of its real-time communication and control systems, which are also considered, showing that redundancy in protection would provide efficient solutions.

7 CONTRIBUTION OF DISTRIBUTED ENERGY RESOURCES TO NETWORK SECURITY

The Smart Grid paradigm envisages a wide penetration of Distributed Energy Resources (DER) including demand side response the form of controllable / responsive loads, distributed generators (DG), and Energy Storage (ES). A crucial emerging question is centred on assessing the contribution of these DER technologies to network security i.e. their ability to displace network reinforcement.

The present distribution network planning standard, Engineering Recommendation P2/6 employs a probabilistic approach, denoted as Equivalent Circuit Capacity (ECC) methodology, to determine the security contribution of DG without considering the reliability properties of the actual distribution network [60]. Since the reliability delivered to end consumers is ultimately a property of the system as a whole, including the combined effects of the distribution network and DER, the P2/6 approach offers limited insight into the actual reliability implications associated with the use of DER in particular scenarios.

Studies have been carried out with the objective of assessing quantitatively the security contribution of DER by accounting for the combined effects of the distribution network and DER properties. This is achieved by employing an alternative methodology to the one employed in P2/6, denoted as Effective Load Carrying Capability (ELCC), which has been widely used in the past for quantifying the security contribution of conventional and non-conventional generation technologies [85]-[91]. ELCC is defined as the amount of additional demand that can be supplied due to the presence of DER while maintaining the original risk associated with supply interruptions.

By carrying out a large number of sensitivity analyses, the impact of key factors on the security contribution of DER has been investigated. These include:

- Network related factors, such as the failure rate and repair / restoration times of network assets, the level of network redundancy and the number of parallel network circuits;
- DER related factors, including the relative size of DER, the DER availability, the number of DER facilities, the coincidence in delivery of multiple DER facilities and the ability of DER to operate under islanding conditions.

The approach to calculate the security contribution of DER is illustrated in Figure 7.1.

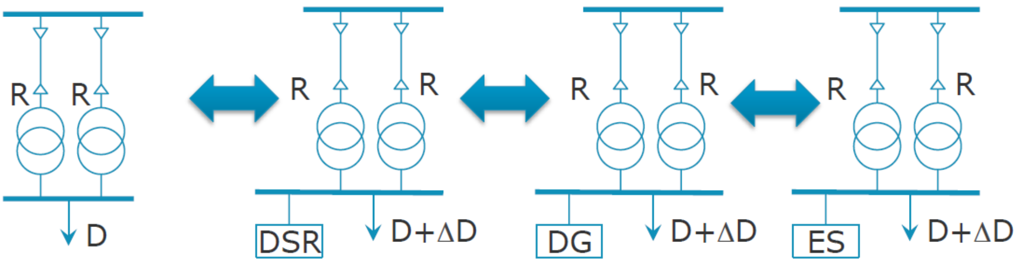


Figure 7.1: The basic concept for assessing the security contribution of DER

For a given demand D and circuit rating R, the value of EENS is calculated. By integrating DER technologies, i.e. DSR, DG, ES, or a combination of these, the increase in peak demand (ΔD) yielding the same value of EENS is calculated. The contribution of DER is equivalent to this increase in peak demand. In this context, the capacity value of DER technologies will be driven by network reliability parameters.

A principle characteristic of DG is that fuel is fully available, and therefore its contribution is driven by the plant reliability. The level of security contribution of ES is driven by its energy capacity size and the fact that ES will need to be charged during low demand periods (if ES needs to supply electricity for prolonged time the contribution may be constrained by the available energy and the need to charge during off-peak periods) of the operational characteristics of DSR are between those of DG and ES. If the load recovery effect is limited then DSR can be modelled as DG, while in the case that the load recovery effect is significant, DSR can be represented as ES.

DG and DSR

One of the key results obtained in the studies, illustrated in Figure 7.2, shows that the security contribution of demand and generation led DSR varies depending on many factors, such as the circuits failure rate and the MTTR. This is in contrast to the fixed value of DG contribution used by the present standards (P2/6).

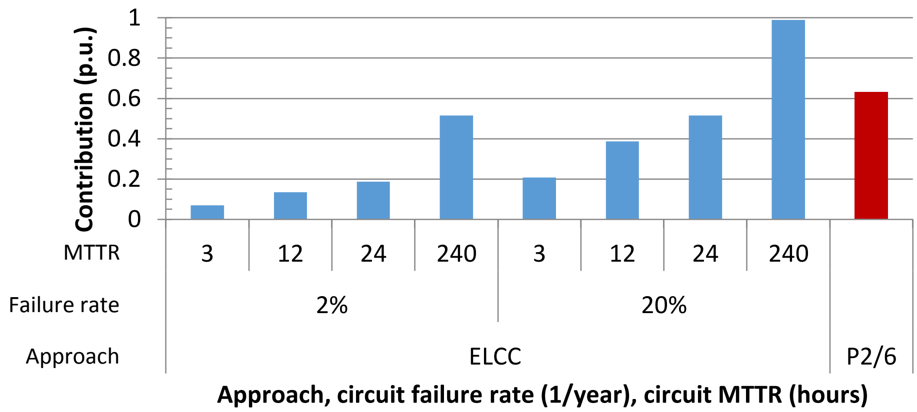


Figure 7.2: Illustration of security contribution of demand or generation led DSR

The case corresponding to Figure 7.2 involves one DSR facility of 2 MW with a compliance of 90%, and two circuits of 20 MVA each supplying demand with N-1 degree of redundancy i.e. reference demand is 20 MW. Figure 7.2 shows that the ELCC contribution of DSR (depends on the network reliability described by the failure rate and MTTR. It can be observed that the ELCC contribution increases from about 7% to about 99% as we move from a very reliable network (with a circuit failure rate of 2% and a MTTR of 3h) to a very unreliable network (with a circuit failure rate of 20% and MTTR of 240h). It should be noted that the cases with restauration time of 240h are very extreme and not realistic, and the analysis is carried out for comparison purposes only[10]. A MTTR of 3 hours represents systems where transfer capability and/or use of mobile generation could practically restore supply after a double circuit outage, as is typically the case in HV networks. In such a setup, the contribution of DSR is low, ranging between 7 and 21% depending on the circuits' failure rate. In lower voltage levels where restoration times tend to be greater, the DSR contribution also increases. For example, if the MTTR is 24 hours, the DSR contribution to security in this example is between 13 and 39% depending on the circuits' failure rate. The contribution calculated as in the present standard P2/6 is shown in red and is by definition independent from network reliability. In this example, it is equal to 63%, higher than all apart from one ELCC contribution. This highlights the problem of the present standards, which in general may overestimate the security contribution of demand and generation led DSR.

Figure 7.3 shows that the ELCC contribution of DSR depends on the relative size of DSR. The security contribution of DSR is calculated for different scenarios regarding the DSR capacity and a fixed peak demand of 20 MW. As the relative size of DSR with respect to the peak demand increases from 10% (DSR of 2 MW) to 80% (DSR of 16 MW), the contribution of DSR decreases from about 99% to about 34%.

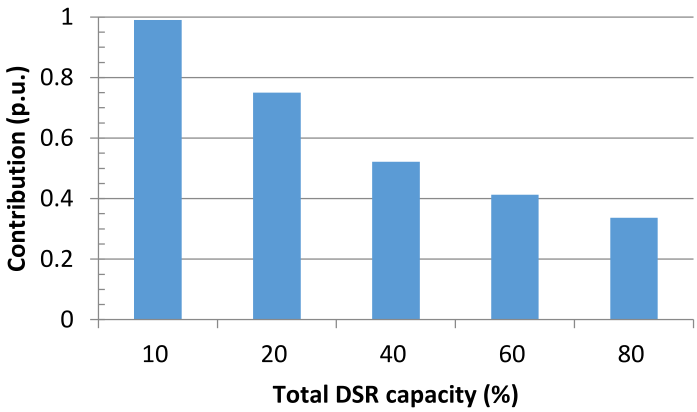


Figure 7.3. Illustration of impact of relative size of DSR on its contribution

This is because savings in EENS by the introduction of DSR are broadly proportional to the DSR size. However, by increasing the peak demand proportionally to the DSR size, resulting in the same p.u. contribution, the increase of EENS beyond the DSR size is driven by the increase of the number of hours that the demand is above the network capacity during a single circuit outage i.e. driven by the shape of demand curve.

Figure 7.4 compares the security contribution of five DSR facilities with a total capacity of 8 MW in different scenarios regarding their coincidence in delivery. Coincidence in delivery is similar in effect to common mode failures due to, for example, ICT failures. Different scenarios regarding the probability of Common Mode Failure (CMF) in delivery of multiple DSR facilities are examined. This is achieved through a probability of forced coincidence, which can take the values 0%, 10%, 25%, 50% and 100%. For example, a 25% probability means that for 25% of the time the multiple DSR facilities act as a single larger DSR facility and for 75% of

10 ELCC contribution could be more than 100% in case of very unreliable networks

the time they act as independent DSR facilities. Increasing the forced coincidence probability directly increases the probabilities of complete system failure (common mode failure) and of faultless performance, at the expense of intermediate states. In this particular case, as the probability of coincidence in delivery increases from 0% to 100%, the contribution of DSR decreases from about 32% to about 5%. This is due to the fact that multiple DSR facilities with an increasing coincidence in delivery tend to resemble more to a single larger DSR facility and therefore (based on the above results) are characterised by a smaller contribution. The analysis shown is for a two 15 MVA circuit system with a circuit failure rate of 10% and a MTTR of 24 hours.

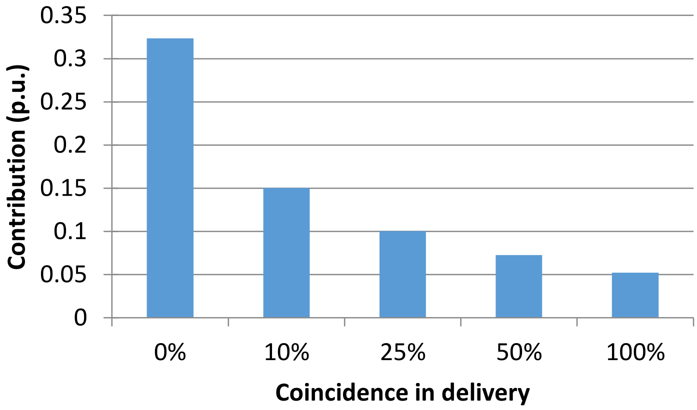


Figure 7.4. Illustration of impact of coincidence in delivery on DSR contribution

It should be noted that even for a relatively small coincidence in delivery of 10%, the DSR contribution has reduced significantly from about 32% to about 15%. When coincidence in delivery is increased further we observe further reductions in capacity contribution although the drop is reduced in magnitude. In summary, coincidence in delivery is an important driver of DSR contribution to security of supply.

As the results are case specific and vary in a wide range, it is difficult to establish a simple deterministic contribution table. The key findings stemming from the wide range of sensitivity studies carried out regarding the security contribution of demand and generation led DSR are:

- The contribution of DSR increases with an increasing failure rate and mean time to repair (MTTR) of the network assets. This effect is much more prominent under N-1 and N-0 network redundancy and much less significant under intermediate network redundancy levels.
- The correlation between DSR contribution and network redundancy levels is lumpy and does not exhibit a smooth trend.
- The number of parallel network circuits (above two) does not have a very significant impact on DSR contribution.
- The contribution of DSR decreases as its relative size with respect to the peak demand is increased.
- The contribution of DSR increases with the increase in DSR availability.

- The contribution of DSR of a fixed total capacity increases as the number of DSR facilities increases
- Coincidence in delivery, common mode failures, reduce capacity contribution of DSR.
- The ability of DSR to operate under islanding conditions has a significant positive impact on its contribution under N-1 network redundancy, while the impact is very marginal under lower network redundancy levels (as in networks with reduced network redundancy levels, contribution of DSR could be significant following a single circuit outage)

Energy storage

In order to determine the degree to which ES can contribute to security of supply, a novel probabilistic framework is proposed based on sequential simulations. A large number of simulations of the network equipped with a storage plant are carried out on a reference distribution network with two transformers of 10 MW each and a peak demand of 10 MW (under the N-1 redundancy level – higher peak demands are used for lower redundancy levels). The studies conducted showed that ES security contribution can be significant, but it is largely dependent on a number of factors:

- Technical characteristics of the storage plant i.e. energy capacity and power rating
- Energy efficiency of the storage plant
- Network availability expressed in terms of outage and repair rates of transformers
- Magnitude and temporal characteristics of the demand pattern
- Redundancy level at which the network is being operated (e.g. N-0.5 instead of a strict N-1 criterion is applied)

For example, in Figure 7.5 we show the ELCC for storage plants of different power ratings and energy capacities under the reliability scenario of MTBF (Mean Time Between Failures) of 1 year and MTTR (Mean Time to Restore/Repair) of 3 hours (note that power rating is expressed as a share of the peak demand). In the case of plants with 20% power rating the contribution is very close to 100%. This is because the plants can store enough energy to cope with single and double outage events.

In the case of plants with 50% power rating, the contribution is 48%, 72% and 100% for an energy capacity of 2 hours, 5 hours and 10 hours, respectively. This is because achieving a 100% contribution requires an increasing amount of stored charge to cope with outage events since the energy import capability is also significantly reduced.

Finally, the contribution of plants with 100% power rating is reduced further to 34%, 52% and 68% for an energy capacity of 2 hours, 5 hours and 10 hours, respectively. This reduction is due to the increased impact that the reduced energy import capability has on the system's ability to sustain single outage events.

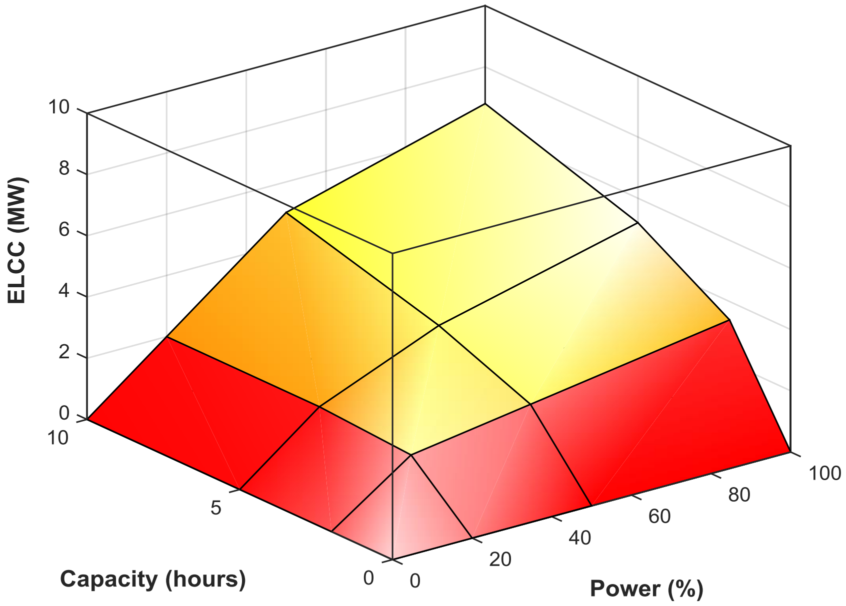


Figure 7.5: ELCC for different storage plants under reliability scenario MTBF = 1 year and MTTR = 3 hours. N-1 level of network redundancy.

In general, the security contribution is determined by the plant's ability to support demand under single and double outage conditions. It follows that a key factor in determining ES contribution is the duration of transformer outages; the longer the outage duration, the more energy is required from ES. This is evident from the study results, where the same plant is shown to have reduced security contribution as the duration of outage increases. For the same reason, plants with increased energy capacity have increased security contribution since they can sustain a larger demand increase during the outage duration. However it is harder for plants with high power rating to reach high contribution levels, in terms of normalised ELCC, since demand increase due to ELCC starts compromising the plant's capability to re-charge during low demand periods.

Results are shown in Figure 7.6 for nine different storage plants of varying size (where power rating is expressed as a share of the peak demand). It shows the contribution of storage to security of supply for different sizes and reliability levels. For example size 20% 2h means that the power rating of storage is 20% of basecase peak demand and storage capacity could be depleted in 2 hours. Reliability level represents the duration of needed contribution expressed in hours. As expected, the larger the energy capacity, the higher the security contribution in absolute terms. However, for plants with larger power ratings it is increasingly difficult to achieve higher contribution since the increased demand levels interfere with the plant's capability to charge from the upstream network due to reduced import capability. Furthermore, the longer it takes to restore network assets the less ES security contribution becomes since the duration of double outages, during which ES can only rely on its already stored energy, increases. In a similar vein, during single outage events, the storage plant's ability to re-charge and replenish its energy content is compromised.

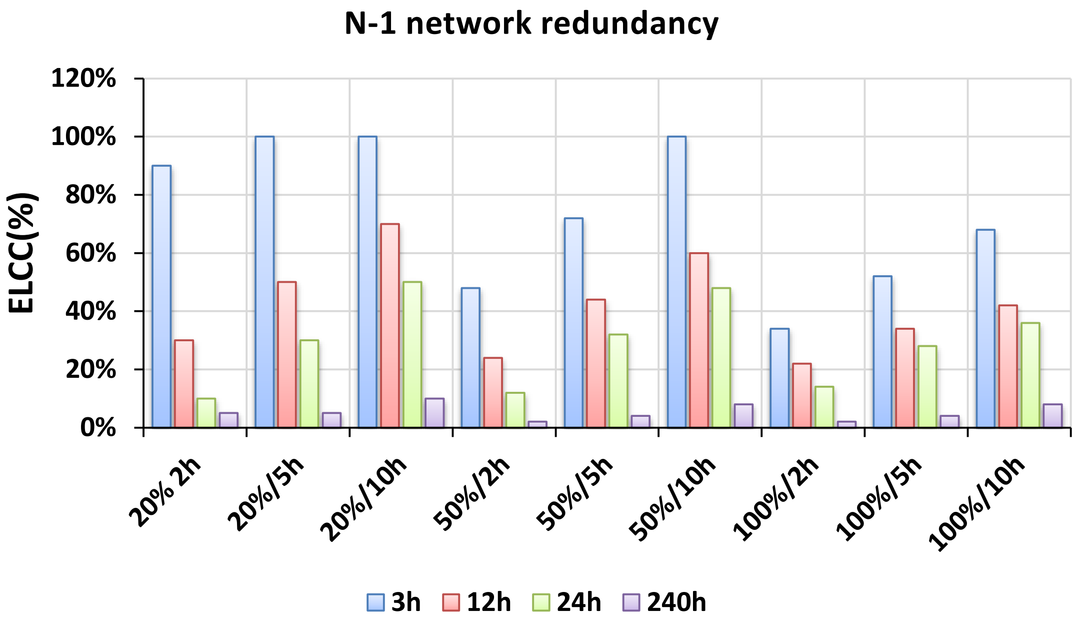


Figure 7.6: Normalized ELCC for storage plants of different sizes across four reliability levels under the N-1 network redundancy scenario.

In contrast to duration, the effect of frequency of outages is shown to be less pronounced. Although very frequent disruptions can result in the ES constantly engaging in discharging duty and thus consistently being at a low state-of-charge, transformers are in general resilient and rarely fail. As a result, it is possible to state that on average, most realistically-sized storage plants can return to their full energy capacity before the next outage event occurs. For this reason, there is little difference between the examined outage frequencies.

We show that another important factor of security contribution is the level of network redundancy. Figure 7.7 presents the ES security contribution across different plant sizes for different levels of redundancy (N-1, N-0.75, N-0.5 and N-0.25) in the case of networks where the supply can be restored on average in 3 hours (MTTR = 3 hours). When operating under a relaxed redundancy level, a fundamental difference to N-1 operation arises; single outage events lead to demand curtailment in the 'network-only' basecase. Most importantly, in some cases, deployment of ES can not only ensure that EENS due to the ELCC demand increase is equal to zero, but also assist in reducing basecase EENS. As a result, the amount of energy curtailment during double outage conditions can be increased by the amount that EENS due to single outages has been reduced. When compared with the basecase, installing a storage plant would decrease EENS resulting from single circuit outages (redundancy level is lower than N-1 in the basecase). In order to match the reference EENS, the group demand could be increased, which would increase the contribution of overlapping outages to EENS. In general, this can lead to an increased security contribution of storage. Another direct implication of this effect is that ES can potentially have an ELCC above its power rating (i.e. normalised ELCC > 100%). However, there is also another effect at play that must be highlighted: when operating under a relaxed security standard, system load is at increased levels, meaning that the available energy import capacity of the network is reduced at all times compared to an N-1 system. This can compromise the ES ability to withstand single outages through periodic charging/discharging cycles.

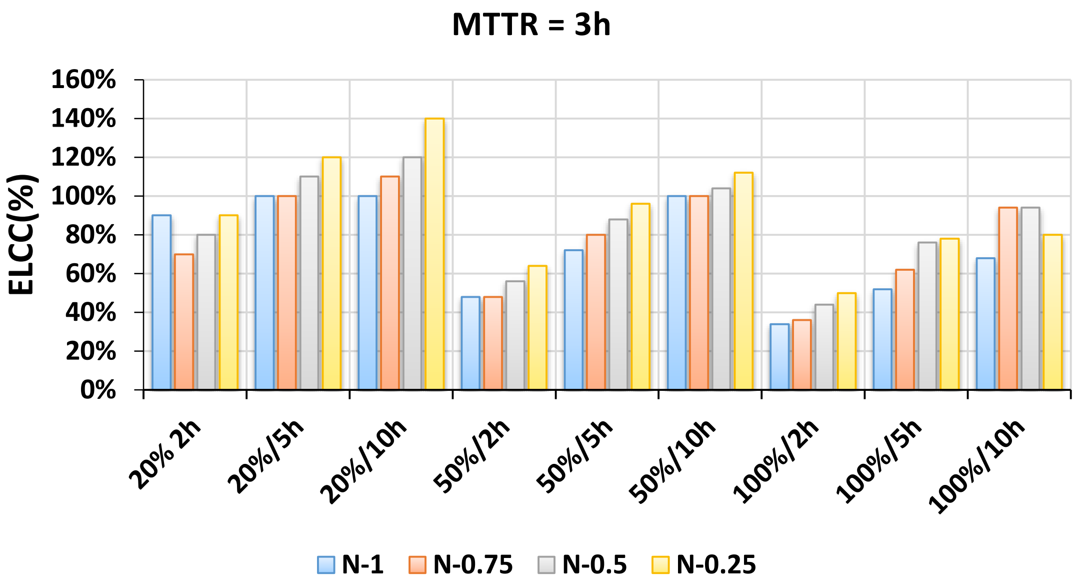


Figure 7.7: Normalized ELCC for storage plants of different sizes across four network redundancy levels when transformers' MTTR = 3 hours.

The storage's ability to operate in islanding mode is also very significant under the N-1 redundancy level. However, the effect of islanding operation is much reduced when examining cases of relaxed network redundancy because the bulk of EENS is driven by single outage events.

The efficiency of the storage plant is shown to have minimal impact in cases of small energy capacity but can have a supressing effect for larger-sized plants. This is because a low charging efficiency implies that more energy is required to charge to the same level of energy. As a result, in cases of large plants there may not be enough energy available to re-charge to high-enough energy levels until discharging actions must be performed.

Finally, the undertaken analysis demonstrates that flatter demand profiles lead to reduced ES security contribution. This effect is due to the reduced re-charging capability during low-demand periods; a flatter demand profile means that the storage plant cannot import as much energy overnight thus compromising its ability to withstand single outage events via periodic re-charging.

8 VALUE OF AUTOMATION

In order to maximise the opportunities arising from asset replacement and new installations it is currently being considered to extend the coverage of automation on the secondary distribution network. This would significantly contribute to improving the performance of the network, improve service to customers and help to meet customer interruption (CI) and customer minutes lost (CML) targets.

With advances in automation systems, adding more automation to the secondary distribution network opens significant opportunities for supply restoration within the shortest possible time. Investment in automated switching devices enables faster re-configuration of the distribution network, thus avoiding prolonged customer supply interruptions and reducing the time required to switch customers to an alternative supply.

A set of studies have been carried out with the objective to assess the business case for automation for different equipment costs, network availability parameters and VoLL and estimate the materiality at the GB level. It is important to highlight that many GB feeders are already automated. The results of the studies expressed through the value of automation for different VoLLs are illustrated in Figure 8.1. The graph shows the gross annual savings per feeder by implementing automation, divided by the number of secondary sites. Feeders are then presented in relation to the corresponding savings made.

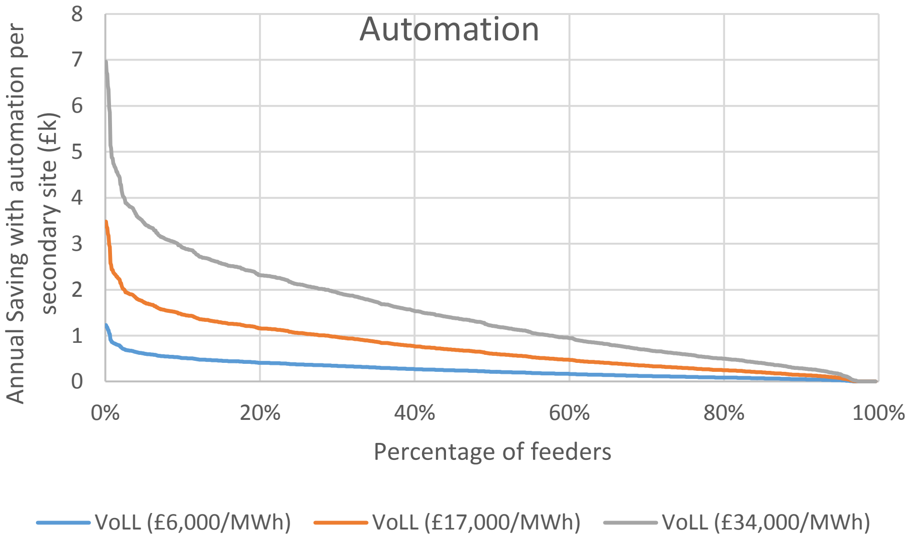


Figure 8.1: Value of automation

Figure 8.1 shows the potential annual savings per secondary site when fault isolation is conducted remotely for three different VoLLs, i.e. £6,000/MWh, £17,000/MWh and £34,000/MWh. The first feeder on the x-axis is the feeder that would gain the largest benefit from the automation scheme, and the last feeder is the feeder that would gain the lowest benefit from the scheme. The results show that, using a VoLL of £17,000/MWh, the maximum savings from automation are about £3.5k per year per feeder. The total area under the curves is the total EENS reduction due to automation. The results can be used to determine whether the automation scheme can be justified economically.

The potential annual savings depend linearly on the VoLL. The larger the VoLL, the higher the annual saving is, and therefore the business case for implementing remote control or automation schemes is also higher. This shows a correlation between the demand for security, reflected in the VoLL, and the business case for remote control and automation schemes.

Overall, the results demonstrate that automation would improve network reliability performance and reduce the impact of faults on customer's quality of supply. The results indicate that automation can significantly reduce the CML and CI indicators by 56%and 88% respectively due to significantly shorter resupply times when compared to manual switching.

There are a number of parameters that need to be considered in evaluating the value of remote switching and automation, including: circuits availability, failure rate, mean time to restore/repair, network construction (UG or OH), switching time, VoLL, cost of automation, number of distribution sites per feeder and feeder length.

The cost-efficient level of installation of remotely controlled or automated switchgear greatly depends on the assumed level of VoLL as well as on the cost of installing new equipment. For example, for low cost of network automation and a VoLL of £17,000/MWh, 60% of HV feeders should be automated. A high VoLL and a low installation cost yield a strong business case for deploying automated switchgear, while if the VoLL is low and the cost of installing advanced switching schemes is high, or the network reliability is high, installation of automated or remote switching may not be justified.

Table 8.1 shows the percentage of GB UG feeders for which the benefits of automation exceed the cost of automation for different VoLLs. For instance, it is found that about 58% feeders would benefit from having automation installed if the cost of automation per distribution site is £500/year and the VoLL is £17,000/kWh. For the same VoLL however, if the cost of automation per distribution site is £2,000/year, only 2% of UG feeders would be cost-efficient to automate.

Table 8.1: Percentage of UG feeders where benefits of automation are greater than cost of automation

Cost of automation per secondary site (£k/year)	VoLL (£6,000/MWh)	VoLL (£17,000/MWh)	VoLL (£34,000/MWh)
0.5	11%	58%	80%
1	1%	28%	58%
2	0%	2%	28%
3	0%	0%	2%
5	0%	0%	1%

Table 8.2 shows the percentage of OH feeders where the benefits of automation exceed the cost of automation for different VoLLs. For low cost of automation and a high VoLL, 91% of HV OH feeders should be automated; while if the cost of automation is £2,000/year and VoLL is £17,000/MWh, then only 5% of OH feeders would be cost-efficient to automate.

Table 8.2: Percentage of OH feeders where benefits of automation are greater than cost of automation

Cost of automation per secondary site (£k/year)	VoLL (£6,000/MWh)	VoLL (£17,000/MWh)	VoLL (£34,000/MWh)
0.5	13%	56%	83%
1	0%	20%	56%
2	0%	5%	20%
3	0%	0%	12%
5	0%	0%	1%

9 ENHANCING ASSETS UTILISATION

In the above analysis, assets are never loaded above the nominal rating. In this section, the use of dynamic line rating and overloading capability of cables and transformers [67]-[76] is discussed as alternative solutions to enhance the utilisation of the assets that should be considered in operation and planning of distribution networks.

Application of Dynamic Line Rating

The current planning and operational practises use static seasonal ratings for Over Head Lines. Traditionally, the static ratings have been determined using conservative assumptions with regards to the ambient temperature and cooling forces [153], [156]-[157]. Consequently, these practises would generally lead to lower network ratings and utilisation than the actual line capability, but on the other hand, during extreme conditions such as hot days, the assumptions may not be conservative enough and the actual network capacity may be actually lower than the static capacity.

With the latest technology developments, it is now plausible to determine the actual network capability in real time taking into account all important weather conditions that pose cooling/heating effects to bare OH conductors. Important weather parameters include: wind speed and its direction, solar radiation and ambient temperature. Figure 9.1 shows the real-time ampacity of OHL between Primary A and Primary B, with data being recorded for 10 days in winter. The real-time ampacity varies quite significantly and most of the times well above the static capacity of 443 A. However there are occurrences where the real-time capacity is actually below the static capacity.

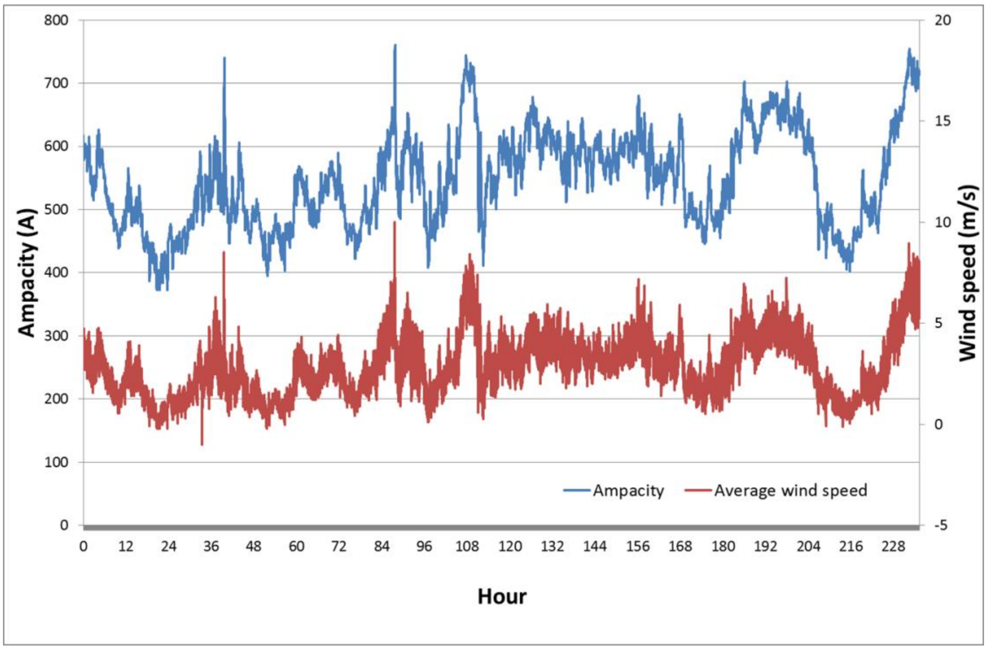


Figure 9.1: Real-time ampacity of OH lines and wind speed over a period of 10 winter days

Thus, the benefit of the dynamic line rating technology lies in determining the actual capability of the network and therefore preventing over- or under-estimation of the line capacity and allowing the system operator to fully utilise the existing assets. As shown in Figure 9.1, the capacity increase during windy conditions can be substantial as the actual capacity can be 60% higher than the static capacity, providing significant additional headroom. In the context of security of supply, the additional headroom given by DLR can reduce the load curtailment and the CML of the customers. It is important to note that this headroom is temporary depending on the weather, thus the DLR technology is suitable for systems with variable, weather-dependant loads and generation systems such as wind power.

A special precaution is needed as the peak of DG output, depending on the DG technology, may have negative correlation with the real-time ampacity of the conductor. In the case of solar power for example, the maximum output may be correlated with hot ambient temperatures and high solar heating to the conductor, reducing the actual conductor capacity.

There are a number of successful pilot projects of DLR, i.e. LCNF Flexible Plug-Play, Flexible Networks, Customer Led Network Revolution and Connecting Renewable Energy in Lincolnshire, which demonstrated the potential applications of this technology to maximise the utilisation of existing assets and facilitate cost-efficient integration of DG in distribution networks. One of the challenges of incorporating DLR into security standards is understanding what rating to use and correlate it to DLR reliability.

Overloading capability of transformers

The standard BS IEC 60076-7:2005 provides certain room for power transformers to operate beyond their nominal rating. The operation of power transformers is mainly constrained by current and temperature limitations. Therefore, the ambient temperature may have substantial impact on the transformer's conductor and oil temperature, especially if there is no cooling mechanism applied. The steady-state loading limits of the transformer under different loading modes for different ambient temperatures are shown in Figure 9.2. It can be concluded that a higher ambient temperature reduces the maximum loading capability of transformers[11].

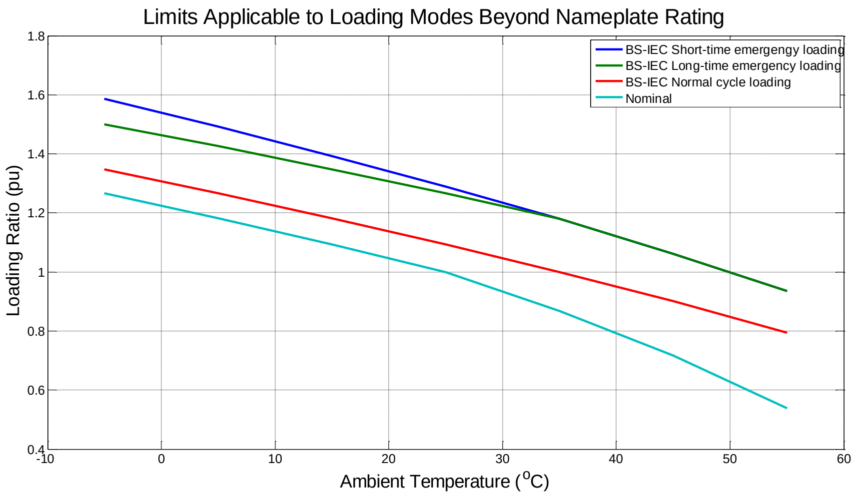


Figure 9.2: Maximum transformer's loading capability for various loading modes

[11] In addition to the 3 loading modes, a nominal loading mode is added. The nominal loading mode has two restrictions only: (i) the maximum limit of hot spot temperature is 110 Celsius, and (ii) the maximum top oil temperature is 90 Celsius.

Operating transformers beyond its nominal rating increases their aging rate. Therefore, the decision to run power transformers beyond their nominal rating must consider this increased aging rate and the reduction in transformers' lifetime. It is shown in [160] that the accelerated aging of primary transformers is not an issue for the types of load profiles typically seen on SP Energy Networks distribution networks. Our studies indicate that the frequency of operating transformers at high loading is relatively small in comparison to the frequency of operating transformers much below their nominal rating, and thus the impact on the lifetime of the transformers is relatively marginal. This additional capacity that can be used during emergency conditions may contribute positively to security and reduce demand for new assets. The analysis is based on the assumed load profile and increase of loss of transformer life. Long-time emergency loading of prolonged outages, such as planned outages, are analysed.

Utilising the cyclic rating of cables to provide additional capacity

Similar to transformers, the aging rate of a cable is also determined primarily by its operating temperature which is a function of the cable's load. The lifetime of a cable is linked with operating temperatures. Operating below the nominal temperature will extend the lifetime of the cable. Operating at higher temperature increases the aging rate and therefore reduces the lifetime of the cable. The analysis of cyclic rating is based on the condition that the cable temperature would not increase beyond the maximum continuous operating temperature.

The results of the studies show that for the specific cable under the assumptions taken in the study, the cyclic rating can reach 1.2. This means that the cable can be loaded 20% more than its ratings without increasing its operating temperature above the nominal temperature. For emergency conditions, the emergency cyclic rating could be increased above its nominal rating. It is important to highlight that these results are valid only for a particular load factor; different cyclic and emergency factors might be applied for different demand patterns.

The impact of increasing the loading of the cable has been assessed and the results are shown in Figure 9.3. As long as the operating temperature does not exceed the nominal temperature, operating at cyclic factor of 1.2 would not reduce the lifetime of the cable. However, operating with higher cyclic factors, for example during emergency conditions, can reduce the lifetime of the cable by more than 20 times during the peak load.

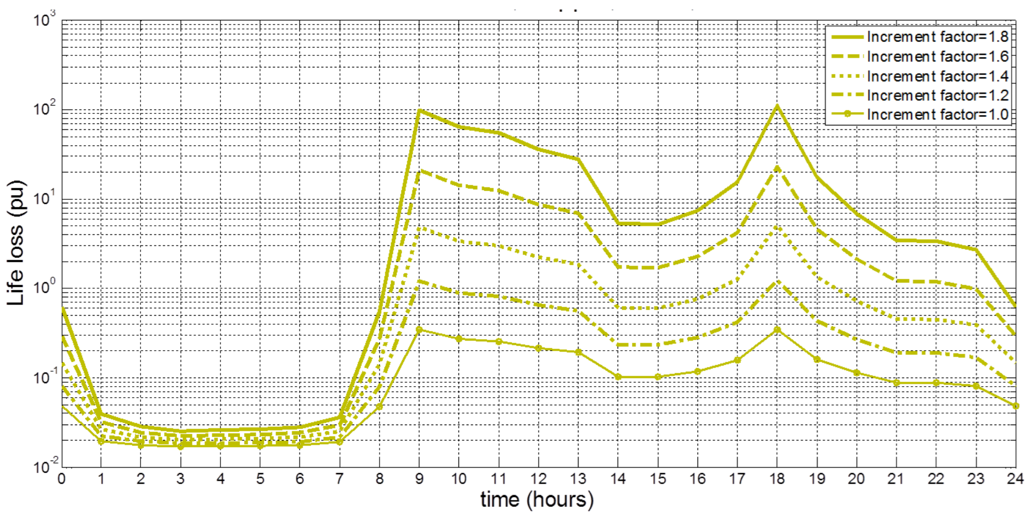


Figure 9.3: Impact of increasing utilisation of a cable on its lifetime

Having the temperature of the cable lower than its nominal temperature before the peak load improves the cyclic rating of the cable. The fact that distribution network cables generally have relatively low utilisation factors, due to the nature of the load profile, provides the opportunity to accommodate higher peak load by exploiting the cable's cyclic rating. Additional cable monitoring and integration of this concept on the Distribution Management System will be required.

By utilising the cyclic capacity of the cable optimally may defer network reinforcement and/or minimise the supply interruptions due to capacity shortage during contingency conditions. This approach may provide a more efficient alternative than the traditional network reinforcement; however it requires balancing between the cost associated with the loss of life driven by overloading the cables and the network reinforcement cost. Optimisation of cyclic capacity of the cables may require implementation of the additional measurement infrastructure.

Role of voltage control and benefit of widening voltage limit

The capacity of the distribution network, especially at lower voltages, is frequently constrained by voltage rather than by thermal limits. This case can be observed particularly in the rural/semi-urban areas, where the length of the network is relatively long and the impedance is high, and in tapered networks. Under-voltage problems in peak demand conditions or voltage rise problems caused by DG limit the amount of new load or DG that can be connected to the network even when there is sufficient headroom in network thermal capacity. In order to release the latent capacity, efficient voltage management is crucial.

In contrast to the current planning and operational approach that determines the network capacity and voltage control in a conservative fashion, the integration of flexible voltage control technologies may provide opportunities for making use of the latent capacity and create a new headroom which is currently not accessible. There are a number of voltage control strategies that can be exploited further. These include: reactive power management; area based coordinated voltage control of On Load Tap Changing Transformers (OLTCs); application of voltage regulators and seasonal voltage set-point settings; DSR based voltage control. Voltage control strategies are typically included as part of the active network management in the smart grid framework. In addition to the smart-grid concept, another approach to solve voltage problems is to widen the voltage limits and to apply voltage control driven load reduction under emergency conditions. For example, the CLASS project estimated that the exponential coefficient for real power-voltage dependency is between 0.87 and 1.93 with an average of 1.33 for mainly domestic consumers.

As demonstrated in earlier studies, the potential advantage of this approach are in its efficiency, as it would enable delivery of additional capacity at no (or very) lost. The key findings from the literature surveys conducted include:

- Reduction of the minimum voltage limit can enhance the utilisation of existing network capacity. Therefore lowering the lower voltage limit can be used as a strategy to accommodate increase in demand and generation. This is illustrated in Figure 9.4 which clearly demonstrates that the capacity of the network is constrained by the voltage limit rather than by the thermal limit. In order to exploit further the thermal limit, a lower voltage limit should be applied. As indicated in these figures network capacity can be doubled by releasing latent capacity which is constrained by voltage limits.

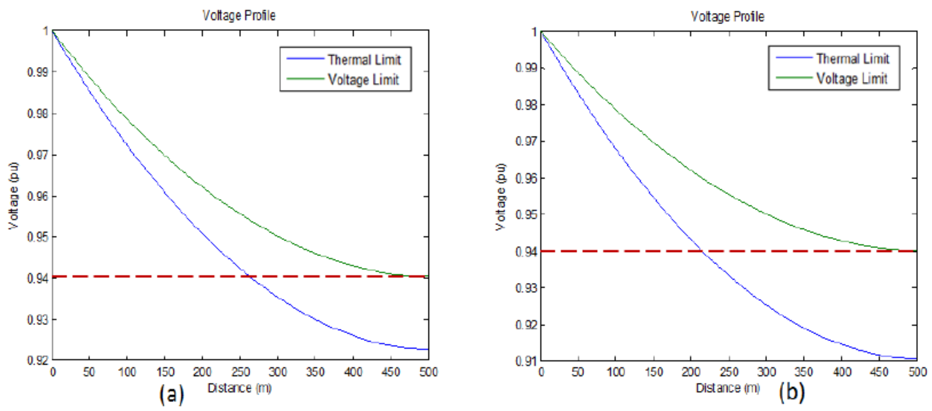


Figure 9.4: Voltage profiles for LV feeders with (a) 300 mm2 and (b) 185 mm2 cables under different loading conditions

- Recent academic work demonstrated that most domestic devices can operate at 85% of the current nominal voltage.
- Increasing the upper limit is not recommended due to security reasons and failure of some devices during the tests.
- Lowering operating voltage can be used as an emergency voltage control strategy to lower the loads.

10 IMPACT OF CONSTRUCTION OUTAGES AND ASSET REPLACEMENT ON DISTRIBUTION NETWORK DESIGN AND PLANNING STRATEGIES

As all DNOs are involved in asset renewal programmes, understanding the security of supply characteristics during extended construction outage periods is critical. 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. For example, installing provisional supplies is not something that NIE have ever considered. These decisions require a trade-off between the savings associated with avoiding contingency arrangements and the costs associated with possible regulatory penalties. If DNOs moved towards operating a lower level of redundancy at EHV or HV networks it will become increasing difficult to isolate the existing networks for asset replacement.

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. Therefore, a range of studies has been carried out to address the issues associated with construction outages for Demand Groups (C and D) in order to identify concerns regarding the increased risk exposures for both DNOs and customers.

In order to illustrate a business case for provisional supply during construction outages an illustrative example shown in Figure 10.1 is constructed.

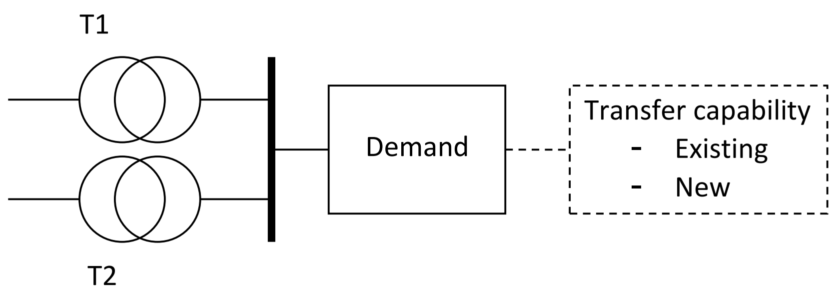


Figure 10.1: A simple system used to illustrate the management of risk during construction outages

The breakeven cost of transfer capacity / provisional supply is estimated as the expected value of interruption. If the cost of transfer capacity is lower than the breakeven cost the solution is cost-effective. Shall one transformer be subject to a construction outage and the other develops a fault, some of the impacted customers can be transferred to an alternate supply source (transfer capacity). It is assumed that the transfer capacity is available instantaneously. The remaining customers will not be supplied until repair is completed or supply is restored by other means, which is represented by the MTTR. Two investment options can be considered for mitigation of the risk construction outages might pose. The first one is investment in greater transfer capability and the second one is reduction of post-outage supply restoration time.

One of the key results of the studies evaluating the potential benefit of provisional supply to support the risk management in construction outages is presented in Figure 10.2. This is for construction outages lasting 3 months per transformer, transformers rating of 90 MVA, failure rate of 20% and MTT Restore of 60 h, peak demand of 100% of transformer rating, mobile generation of 10 MW deployed in 7 hours on average, existing transfer capacity of 20% of transformer rating, and VoLL of £17,000/MWh. If additional 75% of new transfer capability is installed, the potential benefit is about £4,000,000. If the cost of new transfer capability is lower, then proportion of this benefit might be derived.

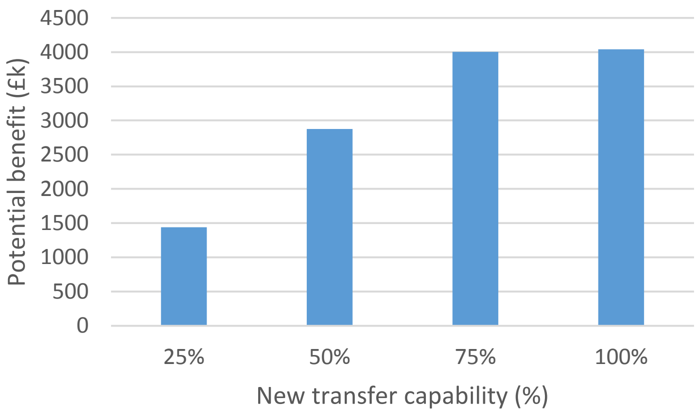


Figure 10.2: Potential benefit of provisional supply

The key findings of our study are as follows:

- The potential benefit of provisional supply is high in a system with low reliability (high failure rate, high MTTR), high load, and long period of construction outages and vice versa. The potential benefit is also proportional to the VoLL. The study demonstrates that it would be economically efficient to provide provisional supply and reduce risk of consumer interruption during asset replacement.
- The potential benefit of constructing provisional supply with capacity of 75% of transformer rating is about £4m for construction outages lasting three months per transformer. Longer construction outages will expose the system to greater risk which in turn increases the value of developing provisional load-transfer as a risk mitigation measure considered in this study.
- The benefit increases linearly with the increased load-transfer capability until it reaches a saturation level; this means that further increasing the capability will not bring further

benefit. For example, the potential benefit of provisional supply with capacity of 75% and 100% of transformer rating are relatively similar due to the presence of existing load-transfer capability and the potential to apply mobile generation that would limit the exposure to interruptions. This implies that a careful reliability analysis is necessary to prevent overinvestment which would not bring appropriate benefits.

11 RESILIENCE OF DISTRIBUTION NETWORKS

The electricity system may be exposed to "non-credible" contingencies which occur rarely but the impact could be very significant leading to very prolonged outages, driven particularly by Common-Mode Failures (CMF) or High-Impact Low-Probability (HILP) events such as storms, floods, etc. As the threat from extreme weather events is predicted to increase due to the effects of climate change, (although there is a considerable uncertainty surrounding this development), the exposure of electricity system to CMF/HILP events may become more profound and therefore this subject is becoming increasingly important [116]-[145].

Distribution network resilience refers to the ability of the distribution network to reduce its vulnerability to multiple failures due to temporary outages or permanent damages of network and control equipment caused by external hazards or CMF of network assets. However, there is currently a lack of guidance, from the present security standards, for efficiently dealing with HILP and CMF events. Planning against potential strategic shocks from HILP events often relies on 'expert judgement' to identify and provide advice, while the explicit lack of consideration of common-mode failures leads to underestimation of the scale of possible threats to the system and makes the system vulnerable to the CMF events.

In order to stimulate discussions on how HILP and CMF events should be considered, whether inside or outside the future distribution standards, a range of case studies are carried out focusing on the analysis of the impact of HILP and CMF on the network reliability performance. This modelling also include identification of economically-efficient network designs taking into account mitigation measures such as DSR, emergency generation, etc. in both preventive and corrective modes.

A number of conclusions can be derived from the range of studies that has been performed, which can be summarised as follows:

- A portfolio of technologies, network and non-network, will not only reduce the total system costs (summation of cost of investments in network assets, availability and utilisation costs of DSR/DG and cost of expected energy not supplied), but could also reduce exposure to CMF and HILP events.
- The concept of Conditional Value at Risk (CVaR) can be applied to limit the probability of large outages – this will result in increase in network investment and/or DSR costs, while reducing the consequences of high impact outages. CVaR approach is demonstrated and it might be used to assess the impact of common mode failures and HILP events. This might represent the basis for discussion regarding the level of risk that may be acceptable and mitigation measures that may be appropriate. At this point, there is no established / agreed approach to identifying HILP events and developing appropriate mitigation measures (if this is established developed modelling can be applied).
- Modelling carried out illustrated that in some cases it may be economically attractive to increase diversity of supply (at higher costs) in order to reduce the likelihood of larger interruptions caused by common mode failures.

These two points are illustrated using the example shown in Figure 11.1.

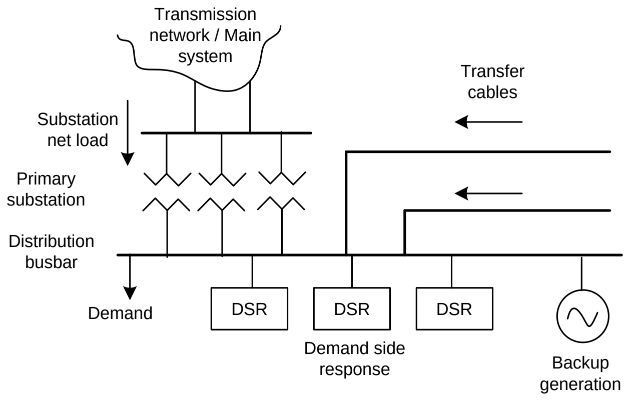


Figure 11.1: Diagram of primary substation with candidate technologies.

A probabilistic CVaR constrained optimisation model has been developed to efficiently design network while limiting risk exposure to HILP events through a balanced portfolio of assets and non-network technologies, producing robust design solutions at the minimum cost. The optimum solution balances (i) the cost of investing in "firm" network infrastructure (e.g. transformers and transfer cables) against (ii) the associated unreliability cost (i.e. cost of energy not supplied) and (iii) the cost of scheduling and utilising DSR facilities that could rapidly respond and avoid overloads (see Figure 11.1). It is also possible to consider emergency (backup) generation, while taking into account constraints associated with the amount that may be available. The studies consider common-mode failure of transformers and DSR facilities.

Three design options including the traditional N-1 design (option E) are analysed as follows:

A. Optimal risk-neutral design under no CMF/HILP: 2 transformers of 34 MW and a 10 MW load-transfer capability are proposed;
D. Optimal risk-neutral design under CMF/HILP: 2 transformers of 35 MW, 2 of 10 MW load-transfer capability, and 3 DSR facilities of 3.33 MW each are proposed, and
E. Traditional N-1 design: 2 transformers of 50MW are proposed.

(Note: options B and C are described in Chapter 10)

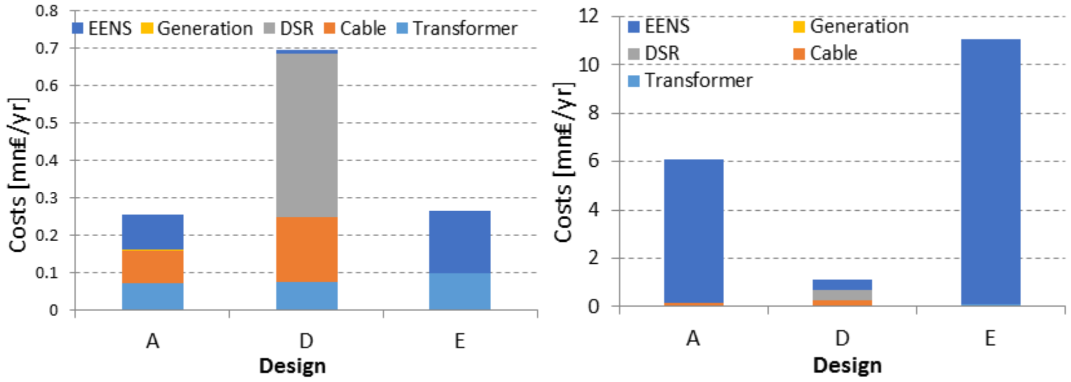
The investment portfolio proposed in each design option is summarised in Table 11.1.

Table 11.1: Investment portfolio of each design option

Infrastructure	A (MW)	D (MW)	E (MW)
Transformer	2x34	2x35	2x50
Transfer Cable	1x10	2x10	0
DSR	0	3x3.33	0

Figure 11.2 shows the cost components of each design option in conditions without and with CMF/HILP. In the condition without CMF/HILP (Figure 11.2, left diagram), option A is the least-cost solution as although the investment cost of option A is higher than the investment cost of option E, it can reduce the EENS by improving the reliability performance of the substation

by having load-transfer capability to the adjacent grid. In conditions without CMF, option A and E have similar total costs, and the cost of option D is highest as it also purchases DSR services. The cost difference between solution D and A is about £0.45 m/year.



(a) Without CMF/HILP (b) With CMF/HILP

Figure 11.2: Cost components of each option in conditions without and with CMF/HILP

However, in the condition with CMF/HILP, the cost of option E, i.e. the design based on the current standards, increases to about £11 m/year due to the increased EENS. The cost of option A also increases to about £6 m/year; for option A the increased EENS is less than for option D since this design has a better reliability performance due to presence of load-transfer capability. Interestingly, the cost of option D increases only slightly and this is because option D, due to its diverse portfolio, has the highest reliability performance. This is demonstrated in Figure 11.3 which shows the probability distribution function of ENS for each design option.

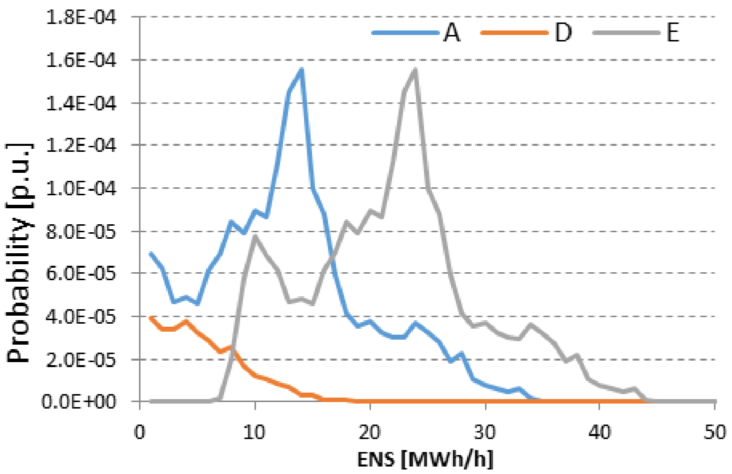


Figure 11.3: Probability distribution function of ENS for each design option

It can be concluded that:

- Optimal risk design considering CMF/HILP (option D) leads to a more resilient network with better reliability performance which significantly reduces the probability of large scale outages. The outcome is similar to the results of risk-averse optimisation employing the CVaR approach.

- Although it is slightly more expensive under no CMF conditions, the additional cost hedges the increased risk in conditions with CMF and HILP.
- A network design based on the present security standards (option E) ignores (underestimates) the risk associated with CMF and HILP, which may lead to less resilient design (without sufficient network redundancy and emergency actions). As a consequence, it may be exposed to CMF/HILP events.
- Interestingly, option E is suboptimal in conditions with CMF or without CMF, albeit it is proved to be less costly in conditions without CMF than option D.

The key parameters that drive the outcome of the studies are: network reliability parameters and costs; characteristics of CMF and HILP; availability, deployment time, and cost of emergency actions.

In the context of developing future security network design standards, a number of options have been identified, including the following:

- *Robust design of distribution substations with balanced portfolio of network and non-network solutions*: Considering the customer density and scale of demand, this may be particularly important for urban networks; some works have been carried out by the ENA Urban Reliability (HILP) working group indicating the importance of reducing the risks associated with HILP for Central Business Districts.
- *Impact assessment of CMF and HILP*: A particular framework/methodology can be established to enable impact assessment of CMF and HILP on the reliability and resilience performance of future electricity distribution networks in the UK.
- *Emergency operation and investment actions to deal with HILP*: The results of the case studies demonstrate that the use of emergency operation and investment actions, such as the provision of mobile generators and transfer cables, could reduce the impact of HILP and the need for preventive (and costly) measures significantly. Resource constraints should also be considered especially during the restoration of the system after a HILP event. Table 11.2 shows the results of one of the studies demonstrating the significant impact of HILP events on the reliability and cost performances of an overhead network. When a HILP event occurs, the failure rate of network components in the study increases by 10 to 50 times compared with the value in normal operating conditions, while the repair time is prolonged 2 to 10 times. If no emergency supply is available, the cost of interruptions could be as high as £2,682,600 per event for the worst case scenario (50 times higher failure rate and 10 times higher repair time). If emergency supply is available, the cost of interruptions can be reduced. For the above case, a saving of £2,585,700 can be achieved if alternative supply could be deployed in 3 hours, as the cost of interruptions reduces to £96,900. The considerable savings obtained indicate that the emergency supply can be very beneficial in dealing with HILP situations. The results also demonstrate that severe HILP events can lead to significant cost of lost load which may justify development of a more resilient network (e.g. undergrounding the overhead network to reduce exposure to adverse weather), but the cost could be also significantly reduced by

providing fast and high capacity of emergency generation especially during very severe HILP events.

Table 11.2: System reliability and cost performances under various HILP and provision of emergency supply scenarios

Network Reliability	HILP MTTR	No emergency supply		Emergency supply			
				3h		24h	
		EENS (MWh/event)	Cost of EENS (£k/event)	EENS (MWh/event)	Cost of EENS (£k/event)	EENS (MWh/event)	Cost of EENS (£k/event)
No HILP	x1	1.33	22.6	1.26	21.4	1.32	22.4
HILP FRx10	x2	3.2	54.4	1.6	27.2	2.6	44.2
	x5	5.1	86.7	1.8	30.6	3.0	51.0
	x10	11.6	197.2	1.8	30.6	4.2	71.4
HILP FRx50	x2	15.4	261.8	3.2	54.4	11.1	188.7
	x5	55.2	938.4	4.7	79.9	19.2	326.4
	x10	157.8	2,682.6	5.7	96.9	27.2	462.4

- *Expanding the scope of risk assessment to consider cyber-physical systems (CPSs)*: We have demonstrated that the failure of ICT infrastructure may cause CMF events which render multiple sources (e.g. DSR, special protection schemes that require communication) providing network services unavailable.

It has been demonstrated, via several illustrative case studies, that consideration of CMF and HILP events would lead to a more resilient network design with more robust construction, through deploying higher degree of network redundancy, and increased application of emergency generation. On the other hand, ignoring CMF and HILP events may lead to high exposure to CMF and HILP events which would increase the risk of supply interruptions.

However, it is still an open question whether the assessment of CMF and HILP events should be included in the standards for the following reasons:

- There is a lack of comprehensive data to derive CMF and HILP events’ parameters (e.g. frequency, scale of impact) that can be used in probabilistic approaches.

- The impact of a certain hazard is network specific. For example, the risk of having flood in plateau areas is much lower compared with lowland areas, and the impact on urban networks will be different with respect to the impact on sparse rural networks. Different networks may be exposed to different types of hazards. Therefore, the justification of the investment via CBA will be case specific.

In any case, it is important that all stakeholders in this area have confidence in the process used to identify and assess risk, so that appropriate decisions can be made on its management.

12 ROBUST DISTRIBUTION NETWORK PLANNING UNDER UNCERTAINTY

New planning standards may need to take into account uncertainty in future development and identify investment strategies that are cost-efficient under different possible future realisations. Previously proposed methodologies [61]-[66], [95], [100]-[117] attempt to determine the best planning solution under the "weighted average" future materialisation, based on the probabilities of occurrence of the different uncertainty evolution scenarios. However, given the capital-intensive and irreversible nature of network investments, planners are generally interested in minimising the risks associated with the planning decisions. Furthermore, it may be difficult to unambiguously determine probabilities of occurrence of different scenarios regarding future evolution.

In these studies, we demonstrate the importance of considering uncertainty for deciding investment and identifying robust network planning solutions across all scenarios. An approach called min-max (or least-worst) regret approach is used in the studies. The approach minimises across all scenarios the maximum regret which represents the extra cost incurred due to the uncertainty with respect to the cost incurred when acting according to the deterministic plan for the corresponding scenario. The min-max regret approach optimally balances two sources of risk: 1) the risk of stranded assets and 2) the risk of incurring fixed reinforcement costs twice.

The studies focus on the uncertainty of future demand growth; the approach itself can include other types of uncertainty. One of the studies was carried out for analysing the network reinforcement needed at Brixton feeders considering the uncertainty of demand as depicted in Figure 12.1.

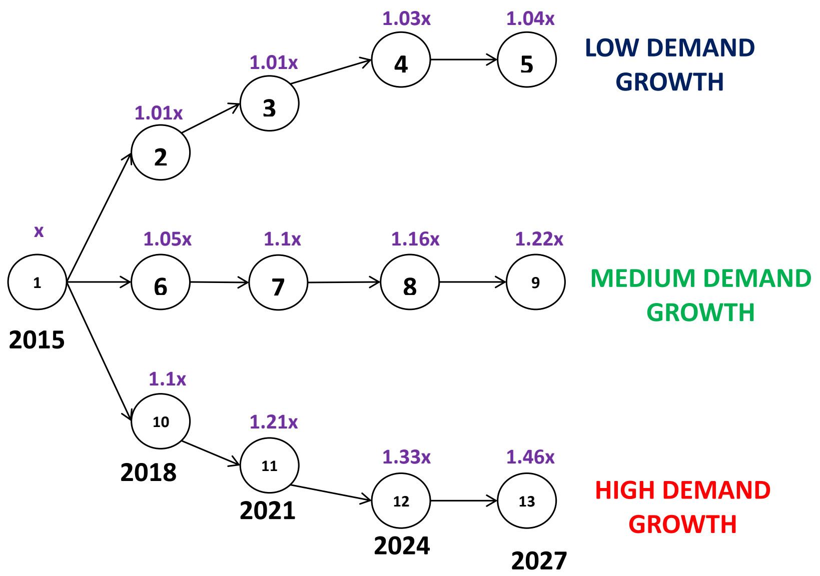


Figure 12.1: A tree scenario considering three future demand growth scenarios

The results of the studies are shown in Figure 12.2.

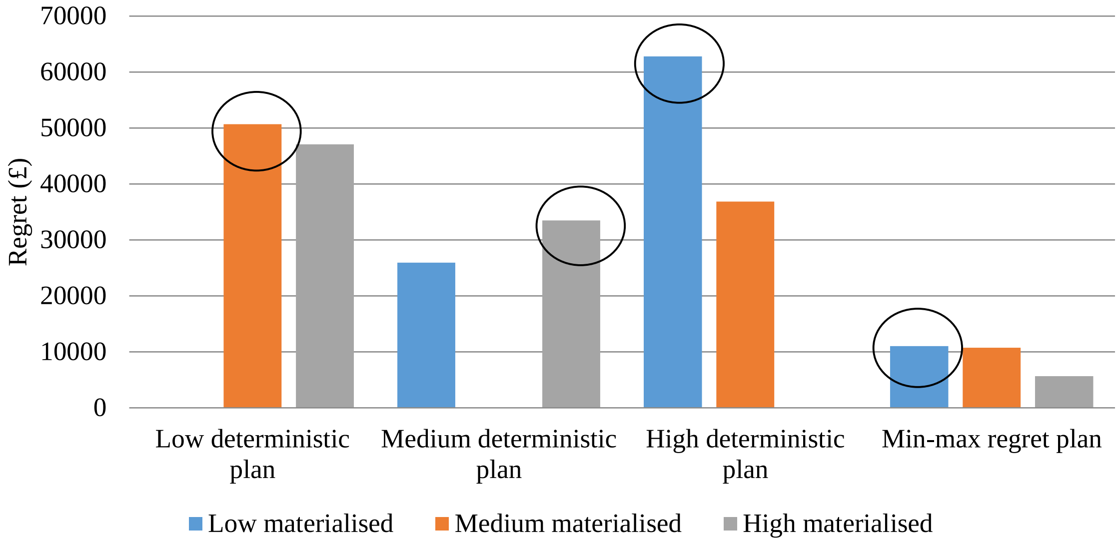


Figure 12.2: Regret portfolio of different plans

For each of the 4 network plans, the maximum regret felt by the planner is indicated with a circle in Figure 12.2. Low/Medium/High deterministic plans are determined by optimising the investment portfolio using the low/medium/high demand growth scenario and assuming there is no uncertainty. Therefore, the regret cost of the plan if the corresponding demand scenario is realised is zero. However, the plan optimised for one demand scenario may not be optimal for different scenarios, therefore yielding regret cost. It is important to highlight that the proposed min-max approach leads to the minimum maximum regret among all possible plans, which is much lower than the maximum regret in each of the 3 deterministic plans. The proposed min-max regret approach also produces network reinforcement solutions which are different to any of the individual deterministic plans.

13 OPTION VALUE OF FLEXIBILITY FOR DISTRIBUTION NETWORK PLANNING UNDER UNCERTAINTY

Uncertainty prevents planners from making fully-informed decisions; commitments made in the present may prove to be unnecessary whereas opportunities that were deemed unattractive at the time may turn out to have been significantly valuable but may be no longer implementable. Decision-making under lack of perfect information entails the prospect of inefficient investments and stranded assets; these considerations have to be carefully balanced to ensure that all risks are optimally managed.

In the presence of increased uncertainty, application of the traditional concept of Net Present Value (NPV) can be sub-optimal for a number of reasons. Most importantly, static valuation frameworks are incapable of identifying openings for strategic investment. Strategic opportunities arise in all dynamic decision framework under uncertainty and are due to the inter-temporal resolution of uncertainty. The inter-temporal resolution of uncertainty refers to the fact that as time goes by, our knowledge about a future uncertain parameter increases through learning. The basic idea is that uncertainty is partially resolved over time and ultimately it would disappear at some point.

The objective of the proposed ‘cost-benefit framework for investment under uncertainty’ is to identify an investment strategy that ensures that the level of service specified by the planning standard in terms of security of supply performance is attained in a cost-efficient manner. The main challenge of applying the proposed framework is the decision on possible future scenarios that should be considered. Once this is established with stakeholders and system experts, the planning standard will fully specify the target level of security of supply for each of the potential future scenarios. The proposed framework can then be applied to identify a cost-efficient strategy to achieve this goal.

In the particular case of distribution planning, a strategic investment can be defined as an investment undertaken to manage uncertainty. It is imperative to highlight that technologies such as demand-side response (DSR) and Soft Open Points can provide a highly flexible solution towards network reinforcement due to the operator’s ability to deploy it faster than major conventional reinforcements (particularly in the case of industrial demand-side support and in the case of household demand following the country-wide rollout of smart meters planned for the coming years) as well as the fact that by controlling different sources of DSR, valuable operational flexibility can be obtained. As a result, smart grid solutions such as DSR may not be the optimal solution in the presence of perfect information, but can be valuable for managing network constraints in the interim, until some major uncertainty has been resolved. Therefore, a direct consequence of relying on a static valuation framework may not account for the full benefit that smart grid solutions may bring to the network.

It can be argued that the existing NPV valuation rule inherently biases towards committing to long-term solutions that exhibit considerable scope for scale economy effects. However, in the event of an unfavourable scenario realisation these capital-intensive investments have an increased stranding risk. Given growing uncertainty in future energy system development, new planning frameworks are required, capable of identifying strategic investments and enabling planners to consider investment in smart grid technologies as an alternative to conventional reinforcements. Otherwise, planning can systematically favour non-flexible large-scale capital projects that may lack the necessary flexibility to enable the adoption of a 'wait-and-see' approach.

In order to study the potentially significant option value of DSR, a set of studies have been carried out on a system depicted in Figure 13.1 (left) with three different demand growth scenarios (right diagram in Figure 13.1). The cost of the third transformer is £605k.

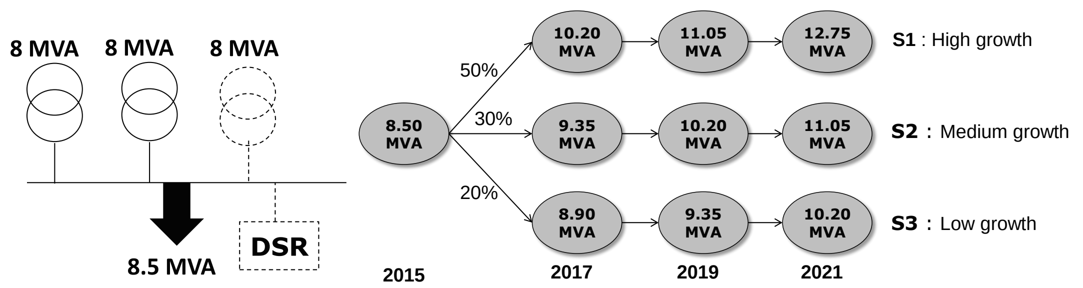


Figure 13.1: An illustrative case study investigating the option value of DSR to deal with uncertainty in future demand growth. The left diagram is the system used and the right diagram shows the scenario tree of the demand growth scenarios.

The results are shown in Figure 13.2. DSR allows the planner to defer the decision to invest in the third transformer until the uncertainty in demand growth is resolved. The expected investment cost is £435k, much lower compared with £605k – the cost of the solution using the NPV approach.

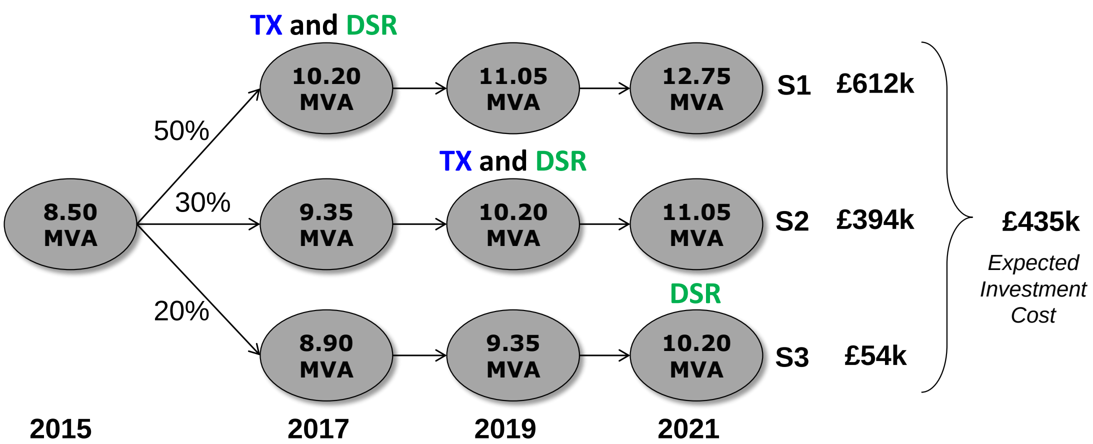


Figure 13.2: Optimal investment strategy when the planner can build both conventional and DSR assets.

The option value of DSR depends on a number of factors including the cost of DSR, DSR availability, contracted amount of DSR, and discount rate, as shown in Figure 13.3. As the cost of DSR increases, the option value of DSR becomes smaller as it becomes less attractive to use. The higher the availability of DSR, the higher the contracted amount of DSR, and in cases with higher discount rate the option value of DSR increases.

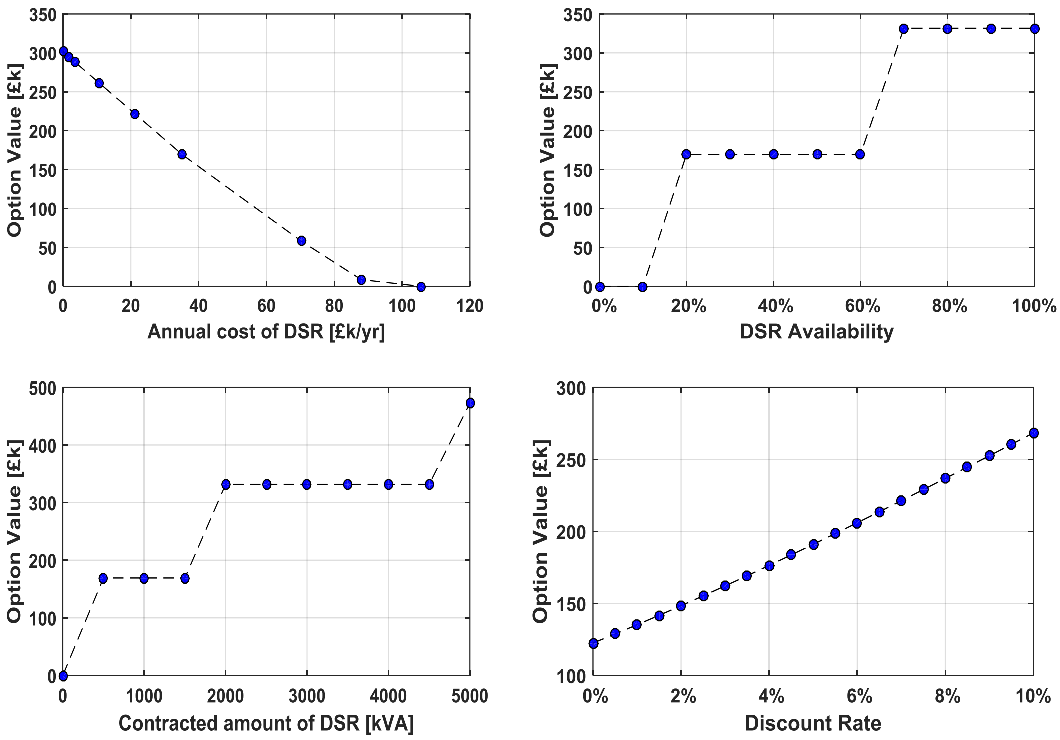


Figure 13.3: Impact of cost of DSR, availability of DSR, contracted amount and discount rate on the option value of DSR

This highlights the importance of incorporating a provision for option value calculation. Cost-benefit analysis should not be undertaken on a fixed projection of the future but on a family of plausible scenarios, enabling deployment of planning solutions that might not be cost effective under the traditional deterministic planning paradigm, but offer flexibility to deal with the uncertainty regarding temporal and locational evolution of demand growth and distributed generation. Adopting a strategic valuation planning framework may be instrumental for achieving large-scale deployment of flexible smart solutions, whose value lies both in the service they can provide but also in the strategic flexibility they offer towards uncertainty management.

14 SMART MANAGEMENT OF NETWORK OVERLOADS THROUGH DISCONNECTION OF NON-ESSENTIAL LOADS - TOWARDS CONSUMER CHOICE DRIVEN NETWORK DESIGN

At present, potential network overloads would be managed by demand disconnections, with some of consumers being completely disconnected and some consumers fully supplied. The roll-out of smart metering will provide a unique opportunity for smarter management by switching off *non-essential loads* when network is stressed while keeping supply of essential loads. This would result in a significant enhancement of the reliability of supply delivered by the existing network, as more consumers will have their essential load supplied during network congestions. Furthermore, this will open up the potential for customer choice driven network design. Building on this opportunity, this section outlines a novel framework facilitating the integration of consumers' choices in distribution network operation and planning decisions. Two distinct modelling approaches are employed to represent the preferences and flexibility of consumers. The first one represents the valuation of different demand levels by the consumers through "price-demand" functions. In the context of this work, this function represents the demand requested by the consumers for different levels of the scarcity price, which is defined as the increment in energy price due to failures in the distribution network, adopting a practice employed in national transmission networks. The second approach captures the ability of some consumers to shift their energy requirements in time accounting for the relevant inconvenience costs.

Case studies have demonstrated that a higher consumers' flexibility results in lower costs of energy not supplied and thus tends to avoid (or at least postpone for the future when demand is increased) the need for network reinforcement. This value of consumers' flexibility is increased with lower network reliability and level of security, as the energy not supplied is increased. Furthermore, studies have demonstrated that the integration of consumers' preferences in network planning yields an equitable outcome; consumers with lower flexibility enjoy higher security of supply at the expense of higher DUoS charges, while consumers with higher flexibility are rewarded for their lower security of supply through lower DUoS charges. Finally the proposed framework increases the overall reliability levels without the need for additional network capacity, as it allows serving of the critical loads during an outage, in contrast to the traditional framework leading to complete shedding of some consumers' demand.

For illustrative purposes, a set of studies have been performed, considering a primary substation with two transformers of 20 MW each (N-1 design), as illustrated in Figure 13.3 (left). Peak demand is 20 MW. Different shapes of the price-demand function modelling different consumers' flexibility levels are illustrated in Figure 13.3 (right). The "Non-Smart" function corresponds to the traditional assumption of constant energy supply valuation, while each of the rest corresponds to a different level of consumers' flexibility, ranging from low (i.e. high valuation of electricity supply) to high (i.e. low valuation of electricity supply). Concerning the model of demand time-shifting, different Values of Shifting Load (VoSL) are considered to represent different levels of time-shifting flexibility.

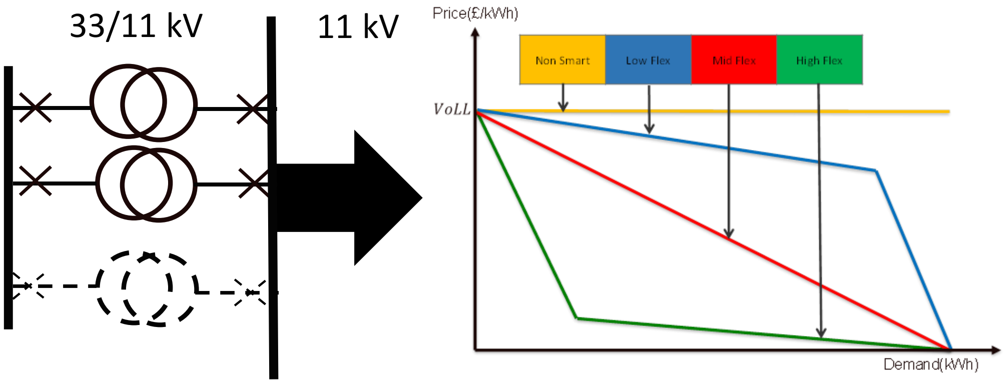


Figure 14.1: Test system and price-demand functions investigated in the case studies

In order to demonstrate the benefit of demand flexibility in avoiding / postponing network reinforcement we have quantified the minimum VoLL for which addition of a third transformer is justified to cope with increased load. The results are presented in Table 14.1. It can be observed that the breakeven VoLL is increased with higher consumers' flexibility, as well as higher network reliability and security level.

Table 14.1: Minimum VoLL (in £/MWh) justifying reinforcement for different consumers' price-demand functions

Network Reliability	Security Level	Non Smart	Low Flex	Mid Flex	High Flex
Low	N-0.75	8,800	36,700	141,700	875,000
	N-0.5	3,400	8,200	29,000	182,100
	N-0.25	1,500	3,100	9,200	59,000
	N-0	700	1,200	3,400	21,500
Medium	N-0.75	44,400	185,900	725,600	4,375,000
	N-0.5	32,300	56,700	196,200	1,275,000
	N-0.25	7,600	15,200	48,300	312,500
	N-0	3,500	6,100	17,300	113,300
High	N-0.75	90,200	386,400	1,487,500	9,296,900
	N-0.5	35,400	85,000	303,600	1,961,500
	N-0.25	15,200	32,700	101,200	625,000
	N-0	7,400	13,100	35,400	229,700

This demonstrates that demand flexibility can influence how distribution network should be designed and operated in a more cost-effective manner, which in turn will affect the distribution network charges that different consumers will face, as shown in Figure 14.2. For more details see Section 11.4.3.

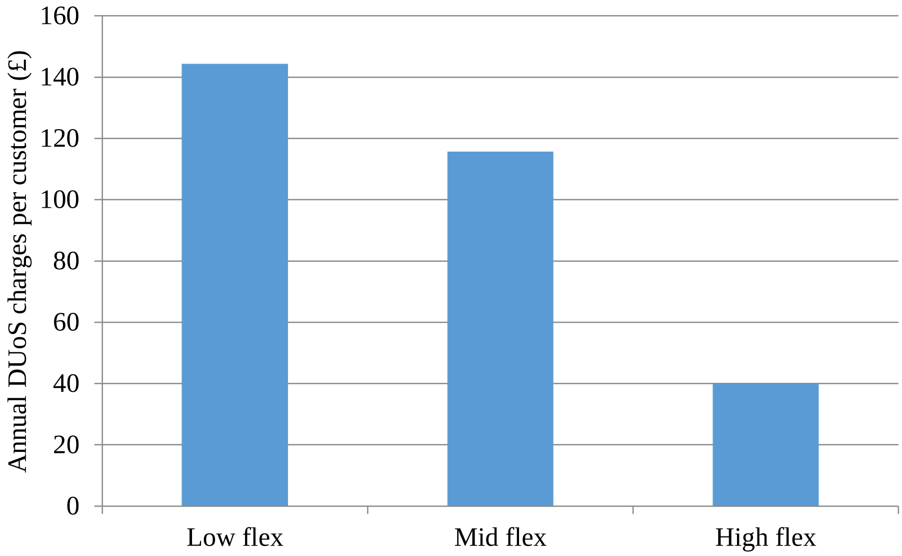


Figure 14.2: Annual DUoS charges for consumers with different price-demand functions

The results show that consumers with lower flexibility (higher valuation of electricity supply) enjoy higher security of supply at the expense of higher network charges, while consumers with higher flexibility (lower valuation of electricity supply) are rewarded for their lower security of supply through lower network charges. The difference between the different customer categories is very significant, as the DUoS charges of a customer with low flexibility is over 3.5 times higher than the charges of a customer with high flexibility.

Implementing smart management of network overloads through disconnection of non-essential loads could further enhance the network utilisation and eliminate the need for network reinforcement leading to savings above £3bn at the GB level by 2030. Implementation barriers may be further elaborated in the Options Report.

15 LONG-TERM OPTIMAL DESIGN OF DISTRIBUTION NETWORKS

Network losses are an important factor to be considered in planning the capacity and design of future distribution networks. Our recent work [157] demonstrated that the capacity of a distribution network may need to be significantly oversized above the peak demand requirements in order to reduce losses, given that the savings in losses exceed the extra cost of oversizing the network.

The loss-driven economically efficient maximum network loading, expressed in percentage of the component rating for overhead lines and underground cables at different voltage levels, is provided in Table 15.1.

Table 15.1: Losses-driven optimal network capacity

Asset		Economically efficient maximum network loading (%)
Cables	LV	12 - 25
	HV	14 - 27
	EHV	17 - 33
	132 kV	31 - 41
OH lines	LV	11 - 19
	HV	13 - 21
	EHV	16 - 25
	132 kV	27 - 32

Table 15.1 indicates that the optimally sized LV cable would be operated at maximum demand no higher than 12-25% of its thermal rating. Similarly, an HV overhead line would be subject to a maximum loading no higher than 13-21% of its thermal rating and so on.

Following the loss-inclusive network design would therefore lead to a situation where there is sufficient spare capacity in the system that can be used to improve security of supply experienced by electricity consumers. In order to utilise the expanded capacity, a suitable distribution network design or topology would be required. In order to determine the optimal design and level of redundancy (or security) taking into account the significantly increased capacity of future networks (following the assumption that they will follow a loss-inclusive design approach), we have carried out CBA, using the framework described previously, on alternative design philosophies of distribution networks at various voltage levels.

Our key observations are as follows:

- The configuration of LV and HV distribution networks in the long-term will require generally a higher degree of redundancy than the level provided by the present standard;
- The principle that a higher level of network security should be provided for networks with higher number of customers remains valid. In this case, the degree of redundancy increases towards higher voltage levels;

- The optimal configuration is case specific as it depends on a number of factors, e.g. the reliability characteristics, investment cost, VoLL, network loading, and mitigation measures considered. It is difficult to establish one rule that fits all cases.

The optimal configurations for different voltage levels are discussed as follows:

15.1 LV network design

Table 15.2 and Table 15.3 show the optimal network configuration for LV overhead and underground networks respectively, illustrated in Figure 15.1, with different reliability characteristics, construction, and VoLL. The long-term planning takes the advantage of the assets spare capacity being installed due to other reasons than security of supply. The CBA only considers cost of the additional assets, which enables utilisation of spare capacity during emergency conditions against the savings in EENS.

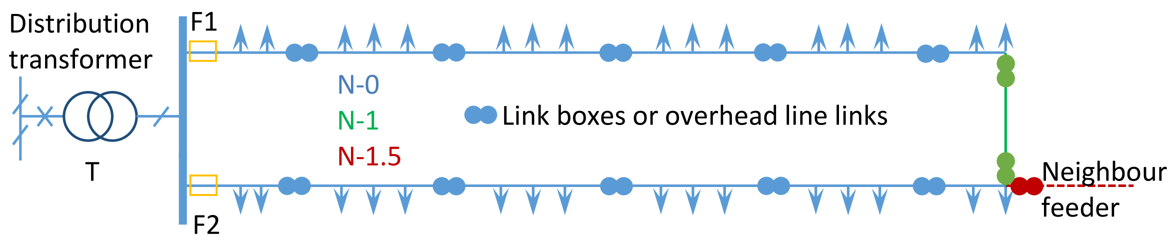


Figure 15.1: A generic LV network system with different configurations to provide certain levels of security of supply

If an additional link is added at the end of the feeder (the green line/cable), the new configuration allows the demand to be supplied from another feeder. This configuration allows N-1 redundancy level to be achieved, provided that the fault is not at the distribution transformer. By adding a connection to a neighbouring feeder (the red line/cable) on top of the N-1 secure configuration, the redundancy level can be improved to 'N-1.5'. In this case, there will be no loss of supply even with two simultaneous outages occurring at different feeders (loss of supply will occur if the two outages occur at the same feeder). Thus, this configuration is more secure than N-1 but less secure than N-2, therefore we refer to it as 'N-1.5' configuration.

Table 15.2. LV overhead network long-term planning optimal redundancy; N-0/N-0:N-1 denotes that for the VoLL of £17,000/MWh economically efficient redundancy is N-0 and for the VoLL of £34,000/MWh is either N-0 for lower cost or N-1 for greater cost of link boxes or line links

Failure rate (%/km.year)	MTT Restore / Repair (hours)	Feeder Peak Demand (kW)		
		10	50	100
10	3/4	N-0	N-1	N-1
	4/4	N-0/N-0:N-1	N-1	N-1
50	3/4	N-1	N-1	N-1
	4/4	N-1	N-1	N-1

The results in Table 15.2 demonstrate that in most cases N-1 design for LV overhead networks is economically efficient except for very low demand and high availability. When lower loading levels are combined with relatively lower availability, as well as when higher loading levels are encountered, the N-1 design is economically efficient.

Table 15.3. LV underground network long-term planning optimal redundancy

Failure rate (%/km.year)	MTT Restore / Repair (hours)	Feeder Peak Demand (kW)	
		50	100
10	3/8	N-0:N-1/N-1	N-1
	8/8	N-1	N-1
50	3/8	N-1	N-1
	8/8	N-1	N-1

The results in Table 15.3 demonstrate that for underground networks the economically efficient design is predominantly N-1, as it is expected to typically supply higher levels of load.

The key drivers giving rise to the N-1 design are higher loading, higher failure rates and longer restoration/repair times as well as greater VoLL. LV network may continue to operate radially but may be reconfigured when needed (post-fault).

15.2 HV network design

A range of studies has been carried out to determine the optimal network configuration for HV networks, using the network shown in Figure 15.2.

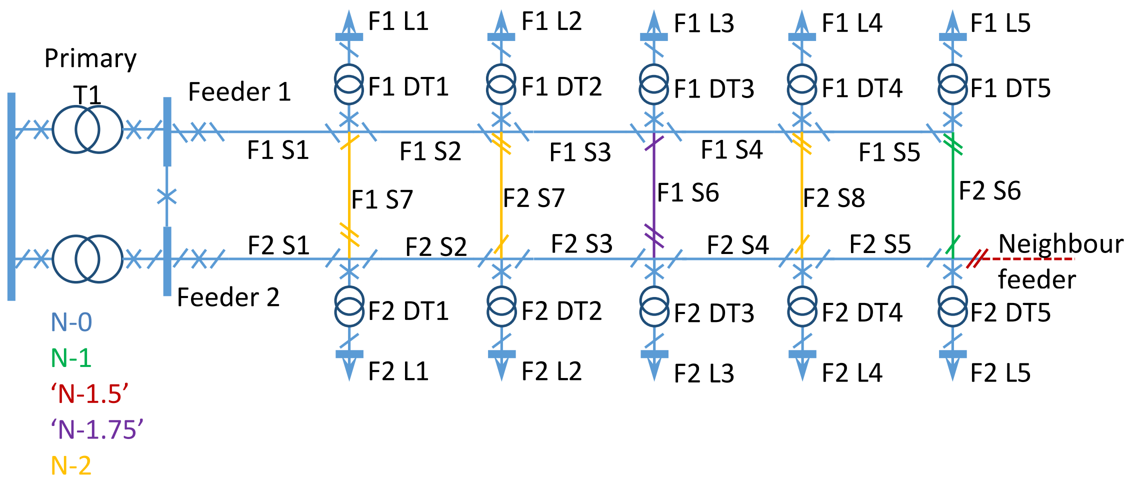


Figure 15.2: A generic HV network system with different configurations to provide certain levels of security of supply

The starting HV network topology is radial topology (N-0) coloured in blue. Fault at one of the sections will result in a loss of supply to some consumers until the component is repaired or an alternative supply is arranged. Connecting the feeders at their ends, as shown in green, and keeping one of the switchgears open allows some of the affected load to be supplied from the other feeder in the case of a fault. The prerequisite for that is that there is sufficient feeder capacity to supply additional load, which is indeed expected to materialise in the case of loss-inclusive design. With this configuration an N-1 redundancy level is achieved given that all load can be supplied after network reconfiguration following a single section outage. It should be pointed out that an outage of a ring main unit results in a loss of supply to the corresponding load that cannot be restored by reconfiguring HV feeders.

Providing a normally open connection from one of the feeders to a neighbouring feeder (coloured in red) allows for the restoration of supply for some of the affected load even in the case of two overlapping outages, such as an outage of one section of feeder 1 and one section of feeder 2. This configuration is denoted as ’N-1.5’. Adding another mid-point NOP section, coloured purple, makes it possible to restore supply by feeder reconfiguration even for some overlapping faults on the same feeder. This topology is therefore denoted as ‘N-1.75’. The final considered configuration, obtained by adding three NOP sections coloured in orange, is denoted as N-2, as in this configuration the supply can be restored though reconfiguration for almost any double overlapping fault. Given the spare network capacity due to loss-inclusive design, it is assumed that the circuit could carry the whole of the demand. It is assumed that in the long-term the network design will adopt the most effective solution.

Table 15.4 shows the optimal configuration for HV overhead networks with different reliability characteristics, construction, and VoLL.

Table 15.4: Long-term planning economically efficient degree of redundancy for HV overhead networks designs; semi colon depicts range of degree of redundancy and slash divides results which differ for two VoLL £17,000/MWh / £34,000/MWh

Section length (km)	Failure rate (%/km.year)	MTT Restore/ Repair (hours)	Feeder Peak Demand (kW)		
			500	2,500	5,000
0.25	5	3/24	N-0/N-1	N-1	N-1
		12/120	N-1	N-1	N-1
	20	3/24	N-1	N-1	N-1
		12/120	N-1	N-1	N-1/N-1.5
1	5	3/24	N-0:N-1/N-1	N-1	N-1
		12/120	N-1	N-1	N-1
	20	3/24	N-1	N-1	N-1
		12/120	N-1/N-1:N-1.5	N-1/N-1:N-1.5	N-1.5:N-1.75/N-1.75

For the overhead feeders the economically efficient degree of redundancy is essentially between N-1 and N-1.5, with the possibility of N-0 prevailing if VoLL is £17,000/MWh, asset upgrade cost is at the lower end, feeders are lightly loaded, failure rates are low and the use of mobile generation is available as an alternative supply during outages. This would suggest that on average applying N-1 redundancy in the existing standard is appropriate for HV design.

Table 15.5 shows the optimal configuration for HV underground networks with different reliability characteristics, construction, and VoLL.

Table 15.5: Long-term planning economically efficient degree of redundancy for HV underground networks designs; semi colon depicts range of degree of redundancy and slash divides results which differ for two VoLL £17,000/MWh / £34,000/MWh

Section length (km)	Failure rate (%/km.year)	MTT Restore/ Repair (hours)	Feeder Peak Demand (kW)	
			2,500	5,000
0.25	2	3/24	N-0/N-0:N-1	N-1
		12/120	N-1	N-1
	10	3/24	N-1	N-1
		12/120	N-1	N-1
1	2	3/24	N-0/N-1	N-1
		12/120	N-1	N-1
	10	3/24	N-1	N-1
		12/120	N-1	N-1/N-1:N-1.5

For underground feeders the optimal design is between N-0 and N-1. Underground networks tend to be more expensive and have lower failure rates than overhead networks. Therefore, the optimal design of underground networks tends to have a lower degree of redundancy.

15.3 EHV network design A

A range of studies has been carried out to determine the optimal network configuration for EHV networks, using the network shown in Figure 15.3. The same set of configurations, as applied on the HV networks, is used in this analysis. This configuration is called “Design A”. This configuration is used in investigation of EHV networks only while analysis in “Design B” below considers primary substations as well. Our analysis investigates different configurations, while providing conservative results regarding the level of redundancy.

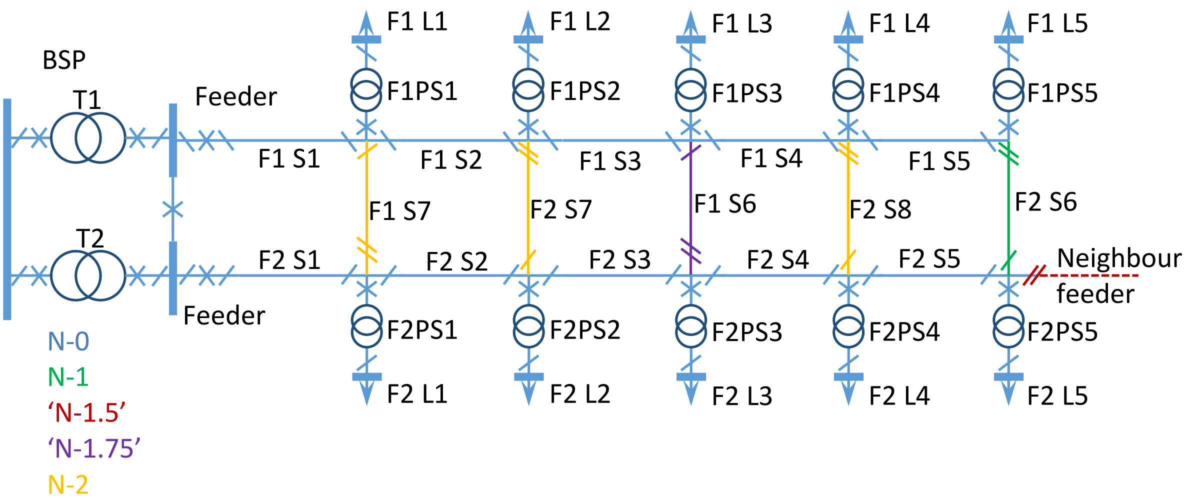


Figure 15.3: A generic EHV network system with different configurations to provide certain levels of security of supply

Table 15.6 shows the long-term planning economically efficient degree of redundancy for EHV network designs for different construction, section lengths, failure rate, mean time to repair and restore, feeder loading and VoLL. The N-1.5:1.75/N-1.75 means that for a VoLL of £17,000/MWh N-1.5 for the higher limit of asset cost and N-1.75 for the lower limit of asset cost is economically efficient, while for a VoLL of £34,000/MWh the economically efficient design is N-1.75 for the whole range of considered asset costs.

Table 15.6: EHV Network optimal redundancy

Construction	Section length (km)	Failure rate (%/km.year)	MTTR (hours)	Transformer Peak Demand (MW)	
				7.5	20
Overhead	2.4	2	6/24	N-1	N-1
			24/24	N-1	N-1
		15	6/24	N-1.5	N-1.5
			24/24	N-1.5	N-1.5:N-1.75/N-1.75
	12	2	6/24	N-1	N-1:N-1.5/N-1.5
			24/24	N-1:N-1.5/N-1.5	N-1.5
		15	6/24	N-1.75	N-1.75
			24/24	N-1.75	N-1.75
Underground	2.4	2	6/24	N-1	N-1
			24/24	N-1	N-1
		8	6/24	N-1	N-1/N-1:N-1.5
			24/24	N-1/N-1:N-1.5	N-1:N-1.5/N-1.5
	12	2	6/24	N-1	N-1
			24/24	N-1	N-1
		8	6/24	N-1:N-1.5/N-1.5	N-1.5
			24/24	N-1.5	N-1.5:N-1.75/N-1.75

The results show that in most cases the optimal network redundancy for EHV is N-1.5. Higher redundancy up to N-1.75 for both OH and UG can be proposed for cases with higher failure rate, higher loading and relatively longer restoration/repair time. For relatively low failure rate and shorter sections N-1 is the economically efficient network design for both overhead and underground networks. As observed in previous studies, UG networks tend to require less redundancy due to lower failure rate and higher network cost. Given that the additional cost of building new network capacity above the minimum design is only relevant for the optimal degree of redundancy analysis, it can be observed that the optimal degree of redundancy for new networks is greater compared to the upgrade of existing networks shown in Table 5.16.

15.4 EHV network design B

Another generic topology of an Extra High Voltage (HV) system, as shown in Figure 15.4, is used to evaluate the performance of various configurations with different levels of redundancy in order to determine the optimal configuration which produces the least-cost solution. In contrast to the previous design, the EHV topology used in this study consists of two transformer feeders that feed into two-transformer primary substations. The main EHV feeders have an option to interconnect with the neighbour grid substation to improve security. In this case, we only consider N-1 and N-2 configurations. This configuration is called "Design B".

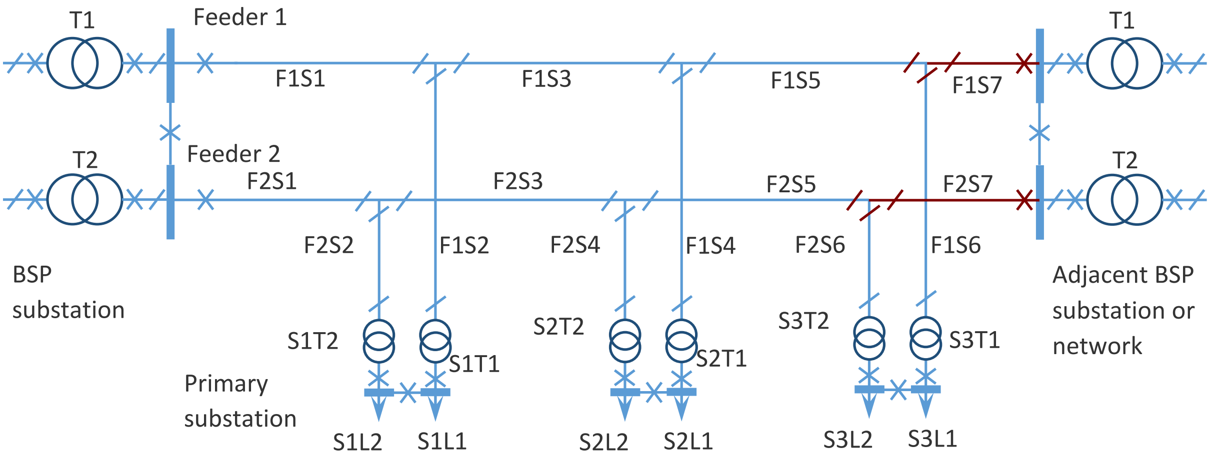


Figure 15.4: EHV Generic network configurations (Three Primary Substations Illustration)

The results (Table 15.7) show that the optimal configuration for the EHV OH network varies between N-1 and N-2 with the majority of cases tending towards N-2. The drivers to choose a higher security level are higher loading, higher failure rate, higher VoLL and also lower network costs.

Table 15.7: Optimal Layout, EHV Overhead (no CMF), VoLL £17,000/MWh / £34,000/MWh

Number of primaries	Section length (km) Main/Spur	Failure rate	Transformer peak loading 7.5 MVA Load transfer				Transformer peak loading 20 MVA Load Transfer			
			0	10%	20%	30%	0	10%	20%	30%
1	4/0, 4/10, 20/0, 20/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	4/0	Max	N-1	N-1	N-1	N-1	N-2	N-2	N-2	N-1/N-2
	4/10	Max	N-2	N-1/N-2	N-1/N-2	N-1/N-2	N-2	N-2	N-2	N-2
	20/0	Max	N-2	N-2	N-1/N-2	N-1/N-2	N-2	N-2	N-2	N-2
	20/10	Max	N-2	N-2	N-2	N-2	N-2	N-2	N-2	N-2
2	4/0, 4/10, 20/0, 20/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	4/0	Max	N-1/N-2	N-1/N-2	N-1	N-1	N-2	N-2	N-2	N-2
	4/10	Max	N-2	N-2	N-2	N-1/N-2	N-2	N-2	N-2	N-2
	20/0	Max	N-2	N-2	N-2	N-2	N-2	N-2	N-2	N-2
	20/10	Max	N-2	N-2	N-2	N-2	N-2	N-2	N-2	N-2
3	4/0, 4/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	20/0	Min	N-1	N-1	N-1	N-1	N-1/N-2	N-1	N-1	N-1
	20/10	Min	N-1	N-1	N-1	N-1	N-1/N-2	N-1/N-2	N-1	N-1
	4/0	Max	N-2	N-1/N-2	N-1/N-2	N-1/N-2	N-2	N-2	N-2	N-2
	4/10	Max	N-2	N-2	N-2	N-2	N-2	N-2	N-2	N-2
	20/0	Max	N-2	N-2	N-2	N-2	N-2	N-2	N-2	N-2
	20/10	Max	N-2	N-2	N-2	N-2	N-2	N-2	N-2	N-2

The results in Table 15.8 show that in most cases the optimal network redundancy for EHV UG is N-1. Higher redundancy up to N-2 can be proposed for cases with higher failure rate, higher loading, relatively longer restoration/repair time, and higher VoLL. This would suggest that the existing standard of applying N-1 redundancy is applicable in most cases.

Table 15.8: Optimal Layout, EHV Underground VoLL £17,000/MWh / £34,000/MWh

Number of primaries	Section length (km) Main/Spur	Failure rate	Transformer peak loading 7.5 MVA Load transfer				Transformer peak loading 20 MVA Load Transfer			
			0	10%	20%	30%	0	10%	20%	30%
1	4/0, 4/10, 20/0, 20/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	4/0	Max	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	4/10	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1	N-1	N-1
	20/0	Max	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	20/10	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1/N-2	N-1	N-1
2	4/0, 4/10, 20/0, 20/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	4/0	Max	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	4/10	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1/N-2	N-1	N-1
	20/0	Max	N-1	N-1	N-1	N-1	N-2	N-1/N-2	N-1/N-2	N-1
	20/10	Max	N-1	N-1	N-1	N-1	N-2	N-2	N-1/N-2	N-1/N-2
3	4/0, 4/10, 20/0, 20/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	4/0	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1	N-1	N-1
	4/10	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1/N-2	N-1	N-1
	20/0	Max	N-1	N-1	N-1	N-1	N-2	N-2	N-2	N-1/N-2
	20/10	Max	N-1	N-1	N-1	N-1	N-2	N-2	N-1/N-2	N-1/N-2

It is observed that UG networks tend to require a lower degree of redundancy compared with OH networks due to the fact that UG networks tend to be more reliable and are characterised by higher investment costs.

15.5 132 kV network design A

Design A is used in this investigation to determine the optimal configuration for 132 kV networks. The findings of the studies are presented in Table 15.9.

Table 15.9: 132 kV Network Optimal Redundancy

Construction	Section length (km)	Failure rate (%/km. year)	MTTR (hours)	Feeder Peak Demand (MW)		
				30	150	300
Overhead	4.8	2	6/24	N-1	N-1	N-1/N-1:N-1.5
			24/24	N-1	N-1:N-1.5/N-1.5	N-1.5
			6/240	N-1:N-1.5/N-1.5	N-1.5:N-1.75/N-1.75	N-1.75
			24/240	N-1.5:N-1.75	N-1.75	N-1.75/N-1.75:N-2
		15	6/24	N-1.5:N-1.75	N-1.75	N-1.75
			24/24	N-1.75	N-1.75	N-1.75
			6/240	N-1.75:N-2/N-2	N-2	N-2
			24/240	N-2	N-2	N-2
	18	2	6/24	N-1	N-1:N-1.5/N-1.5	N-1.5/N-1.5:N-1.75
			24/24	N-1:N-1.5	N-1.5:N-1.75	N-1.5:N-1.75/N-1.75
			6/240	N-1.5:N-1.75/N-1.75	N-1.75	N-1.75/N-1.75:N-2
			24/240	N-1.75	N-1.75:N-2/N-2	N-2
		15	6/24	N-1.75	N-1.75:N-2/N-2	N-2
			24/24	N-1.75:N-2/N-2	N-2	N-2
			6/240	N-2	N-2	N-2
			24/240	N-2	N-2	N-2

Construction	Section length (km)	Failure rate (%/km. year)	MTTR (hours)	Feeder Peak Demand (MW)		
				30	150	300
Underground	4.8	2	6/48	N-1	N-1	N-1
			48/48	N-1	N-1	N-1/N-1:N-1.5
			6/240	N-1	N-1	N-1/N-1:N-1.5
			48/240	N-1	N-1.5	N-1.5:N-1.75/N-1.75
			120/240	N-1/N-1.5	N-1.5:N-1.75/N-1.75	N-1.75
		8	6/48	N-1	N-1/N-1.5	N-1.5
			48/48	N-1/N-1.5	N-1.5:N-1.75/N-1.75	N-1.75
			6/240	N-1/N-1.5	N-1.5:N-1.75/N-1.75	N-1.75
			48/240	N-1.75	N-1.75/N-2	N-2
			120/240	N-1.75	N-2	N-2
	18	2	6/48	N-1	N-1	N-1
			48/48	N-1	N-1:N-1.5/N-1.5	N-1.5
			6/240	N-1	N-1:N-1.5/N-1.5	N-1.5/N-1.5:N-1.75
			48/240	N-1.5	N-1.75	N-1.75
			120/240	N-1.5/N-1.75	N-1.75	N-1.75
		8	6/48	N-1/N-1:N-1.5	N-1.5/N-1.75	N-1.75
			48/48	N-1.5/N-1.75	N-1.75	N-1.75/N-2
			6/240	N-1.5/N-1.75	N-1.75	N-1.75/N-2
			48/240	N-1.75/N-2	N-2	N-2
			120/240	N-1	N-1	N-1/N-1:N-1.5

The results show that in most cases the optimal degree of redundancy for 132 kV networks is about N-1.5 to N-1.75. In networks with relatively higher availability the maximum observed economically efficient degree of redundancy is N-1.75. Higher redundancy up to N-2 for both OH and UG networks can be proposed for cases with higher failure rate, higher loading and relatively longer restoration/repair time. N-1 degree of redundancy is economically efficient for shorter networks with relatively higher availability. As observed in previous studies, UG networks tend to require less redundancy due to lower failure rate and higher network cost.

15.6 132 kV network design B

Design B is used in this investigation to determine the optimal configuration for 132 kV networks. The findings of the studies are presented in Table 15.10.

Table 15.10: Optimal Layout, 132 kV Underground VoLL £17,000/MWh / £34,000/MWh

Number of primaries	Section length (km) Main/Spur	Failure rate	Transformer peak loading 22.5 MVA				Transformer peak loading 45 MVA			
			Load transfer				Load Transfer			
			0	10%	20%	30%	0	10%	20%	30%
1	8/0, 8/10, 30/0, 30/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	8/0	Max	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	8/10	Max	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	30/0	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1	N-1	N-1
	30/10	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1/N-2	N-1/N-2	N-1/N-2
2	8/0, 8/10, 30/0, 30/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1

Number of primaries	Section length (km) Main/Spur	Failure rate	Transformer peak loading 22.5 MVA				Transformer peak loading 45 MVA			
			Load transfer				Load Transfer			
			0	10%	20%	30%	0	10%	20%	30%
	8/0	Max	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	8/10	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1/N-2	N-1	N-1
	30/0	Max	N-1/N-2	N-1/N-2	N-1/N-2	N-1	N-2	N-2	N-2	N-1/N-2
	30/10	Max	N-1/N-2	N-1/N-2	N-1/N-2	N-1/N-2	N-2	N-2	N-2	N-2
3	8/0, 8/10, 30/0, 30/10	Min	N-1	N-1	N-1	N-1	N-1	N-1	N-1	N-1
	8/0	Max	N-1	N-1	N-1	N-1	N-1/N-2	N-1/N-2	N-1/N-2	N-1
	8/10	Max	N-1	N-1	N-1	N-1	N-2	N-1/N-2	N-1/N-2	N-1/N-2
	30/0	Max	N-2	N-2	N-2	N-1/N-2	N-2	N-2	N-2	N-2
	30/10	Max	N-2	N-2	N-2	N-1/N-2	N-2	N-2	N-2	N-2

The results show that in most cases the optimal network redundancy for 132 kV networks is N-1. Higher redundancy up to N-2 can be proposed for cases with higher failure rates, higher loading and relatively longer restoration/repair times.

Table 15.11 summarises the analysis carried out showing the range of optimal long-term degree of redundancy for various voltage levels. In contrast to the present P2 standard that requires a N-1 level for HV (up to 132 kV) networks, and a N-0 level for LV networks, the results of the above studies indicate that for the purpose of long-term network planning it may be beneficial to increase the level of redundancy as shown in Table 15.11, considering that network capacity is already oversized due to losses considerations.

Table 15.11 The range of optimal degree of redundancy needed at various voltage levels

Voltage level	Overhead networks	Underground networks
LV	N-1	N-1
HV	N-0:N-1.75	N-1
EHV	N-1:N-1.75	N-1:N-1.75
132 kV	N-1:N-2	N-1:N-2

It can be seen that in the long term the optimal degrees of network redundancy should be significantly greater than the minimum redundancy prescribed by the present standards – as demonstrated in Section 5, optimal degree of redundancy for existing LV networks is N-0, for existing HV networks is between N-0 and N-0.5, while for existing EHV and 132kV networks it is between N-0.5 and N-1.

15.7 Future network development: enhancing grid security through smart control of district networks

The optimised capacity and level of network redundancy in the future will provide opportunities for enhancing the coordination of various forms of distributed generation, DSR and energy storage technologies across larger regions, further enhancing the controllability of local distribution networks. There is already significant amount of distributed generation serving as a backup source. These resources could be used to facilitate more secure and cost-effective real-time demand-supply balance and control of network flows, hence enhancing the resilience of the local supply. Energy storage technologies may also support demand-supply balancing at the local and national level and control of local network flows. Supported by suitable information and communication technologies (ICT), the above technologies will facilitate a more sophisticated, real-time control of the HV and LV networks, also increasing the utilisation of the upstream transmission infrastructure assets[12].

As a result of the above factors, a paradigm shift in the network design philosophy may be expected, as illustrated in Figure 15.5. Traditionally, the level of redundancy reduces and the time to restore energy supply increases as we move to lower voltage levels. However, the long-term loss-inclusive network design is expected to increase the network redundancy at the LV and HV distribution networks while the controllability provided by distributed technologies at the HV and LV distribution networks may reduce the need for redundancy at the transmission network level. It should be pointed out that at the present distributed generation cannot operate in island mode.

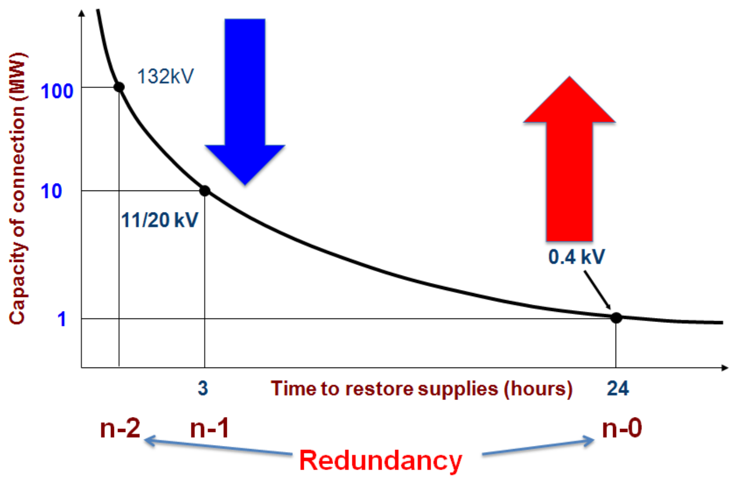


Figure 15.5: Paradigm shift in network design philosophy enabled by web-of-cells / microgrids structures

In this context, concepts of smart district electricity networks (web-of-cells and microgrids) with appropriate enabling technologies may facilitate the paradigm shift in delivering resilience and security of supply from redundancy in assets and preventive control to more intelligent operation at the HV and LV level through corrective control actions supported by a range of enabling technologies and ICT. Smart district electricity networks may be able to mitigate grid disturbances, serve as a grid resource for faster system response and recovery, and strengthen the overall supply resilience to end consumers.

It is important to stress that the development of smart resilient distribution network is in line with the concepts focused on the planning, construction, operation, and management of smart

12 Strbac, G., Moreno, R., Pudjianto, D., Castro, M., "Towards a risk-based network operation and design standards", Power and Energy Society IEEE General Meeting, 2011

cities and energy communities. This is driven by multiple challenges posed by the need to enhance the energy supply resilience in response to growing concerns associated with vulnerability to energy supply interruptions. As a result, there is significant interest in making full use of various forms of local generation (e.g. backup generation) in public or private institutions, combined with various forms of demand-side response and energy storage technologies, as integrating these resources within local district electricity networks would significantly enhance the security of supply delivered to local communities.

16 REFERENCES

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