Review of Distribution Network Security Standards

Extended Report

To the Energy Networks Association

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Table of Contents

1 Context and Objectives of the Study 8

1.1 Context 8

1.2 Drivers and objective for reviewing the present security standards 8

1.3 Key objectives of the study and modelling approach 11

1.4 Specific objectives and scope of the work 12

1.5 Structure of the report 14

2 Cost Effectiveness of Present Network Design Standards 16

2.1 Overview and objective 16

2.2 Breakeven VoLL that would justify security-driven-incremental upgrade of HV networks 18

2.3 Optimal degree of redundancy for HV networks and primary substations 33

2.4 Impact of reduced redundancy on network performance 37

2.5 ACE 51 Illustrative example of reinforcement of an urban HV network 42

2.6 Optimal degree of redundancy for HV spur 45

2.7 Optimal degree of redundancy for EHV networks 47

2.8 Optimal degree of redundancy for 132 kV networks 57

2.9 Potential savings of avoiding security-driven network reinforcements 63

2.10 Conclusions 66

2.11 Appendix: Customer Interruption Cost (CIC) and Value of Lost Load (VoLL) 69

2.12 Appendix: Table of key data 82

2.13 Appendix: Present Service Quality 86

2.14 Appendix: Transfer Capacity Needs 91

3 Asset Replacement 97

3.1 Introduction 97

3.2 Case study 97

3.3 The potential benefit of provisional supply in a network with different reliability characteristics 99

3.4 Potential benefit of provisional supply in a network with different existing transfer capacity 100

3.5 Potential benefit of provisional supply in a network with different levels of peak demand 101

3.6 Impact of mobile generation on the potential benefit of improving the load-transfer capability 102

3.7 Potential benefit of improving load-transfer capability for different VoLLs 104

3.8 Impact of construction-outage duration on the value of new load-transfer capability 105

3.9 Optimal strategy of preventive vs corrective transfer capability 105

3.10 Conclusions 107

4 Contribution of Distributed Energy Resources to Network Security 109

4.1 Introduction 109

4.2 Methodology 111

4.3 Contribution of DSR to network security 112

4.3.1 Description of case studies 112

4.3.2 Impact of network parameters on DSR security contribution 114

4.3.3 Impact of DSR-related factors on DSR security contribution 120

4.3.4 Conclusions 127

4.4 Reliability contribution of energy storage 128

4.4.1 ES security contribution study results 128

4.4.2 Impact of power and energy capability 132

4.4.3 Impact of frequency of outages 136

4.4.4 Impact of duration of outages 137

4.4.5 Impact of network redundancy 140

4.4.6 Impact of capability for islanded operation 142

4.4.7 Impact of energy efficiency 143

4.4.8 Impact of demand shape 144

4.4.9 Conclusions 145

5 Generation-driven Network Design 147

5.1 Introduction 147

5.2 Test system 148

5.3 Modelling and risk quantification 149

5.3.1 Cloud-cover factor distribution 149

5.3.2 Sampling of cloud-cover conditions 150

5.3.3 Risk assessment model 150

5.4 Case studies 150

5.4.1 Impact of storage plant availability 153

5.5 Conclusions and recommendations 153

6 Enhancing Network Asset Utilisation 155

6.1 Overview and objective 155

6.2 Temporary overloading of transformers under peak load or contingency conditions 157

6.3 Utilising the cyclic rating of cables to provide additional capacity 160

6.4 Benefits of voltage control 163

6.4.1 Voltage control in EHV networks 166

6.4.2 Widening the voltage limits and emergency voltage control 169

6.5 Dynamic line rating 171

6.6 Security benefits of advanced protection systems 173

6.7 Conclusions 174

7 Value of Remote Control and Automation 176

7.1 Introduction 176

7.2 Approach 177

7.3 Case study 177

7.3.1 Identifying the value of remote control and automation for individual feeders 180

7.3.2 Value of remote control and automation for different cost of remote control and automation and different VoLLs 182

7.4 Conclusions 186

8 Planning Under Uncertainty 187

8.1 Need for integration of uncertainty in planning standards 187

8.2 Option Value of Demand Side Response 189

8.2.1 Introduction 189

8.2.2 Strategic planning using stochastic models 190

8.2.3 Case Study 191

8.2.4 Conclusions 199

8.3 Option Value of Soft Open Points 200

8.3.1 Introduction 200

8.3.2 Case study 200

8.3.3 Conclusions 206

8.4 Min-max regret approach to address uncertainty 206

8.4.1 Introduction 206

8.4.2 Case study 207

8.4.3 Conclusions 211

9 Risk Associated with Common-mode Failures and High Impact Events 212

9.1 Increasing the robustness of distribution network design against high impact low probability events: a CVaR optimisation approach 213

9.1.1 Introduction 213

9.1.2 The proposed CVaR-based optimisation model 214

9.1.3 Case studies 217

9.1.4 Effect of common mode failure: natural hazards and weather conditions 220

9.1.5 Conclusions 223

9.2 Impact of common-mode failure in Overhead Networks 224

9.2.1 Introduction 224

9.2.2 Impact of common-mode failure on the optimal configuration of EHV networks 225

9.2.3 Impact of common-mode failure on the optimal configuration of 132 kV networks *229*

9.2.4 Conclusions *232*

9.3 Common-mode failure associated with ICT Infrastructure 233

9.3.1 Introduction *233*

9.3.2 Impact of common-mode failure on DSR services *234*

9.3.3 Impact of common-mode failure on a protection system *236*

9.3.4 Conclusions *240*

9.4 Reliability assessment for distribution networks considering High Impact Low Probability events 240

9.4.1 Introduction *240*

9.4.2 Impact of HILP on reliability performance and the use of emergency generation as a mitigation measure *241*

9.4.3 Preventive vs. corrective mode of investment: which one is the optimal strategy for HILP? *246*

9.4.4 Conclusions *252*

9.5 Summary 252

10 Smart Management of Network Overloads Through Disconnection of Non-essential Loads - Towards Consumer Choice Driven Network Design 254

10.1 Motivation 254

10.2 Distribution network planning model 254

10.3 Modelling consumers' preferences and flexibility 255

10.3.1 Price-demand functions *255*

10.3.2 Modelling time shifting of demand *257*

10.4 Case studies 257

10.4.1 Test system *257*

10.4.2 Impact of consumers' preferences on network reinforcement decisions *259*

10.4.3 Impact of consumers' preferences on DUoS charges *261*

10.5 Conclusions 263

11 Long-term Network Planning 265

11.1 LV Network Design 266

11.2 HV Network Design 268

11.3 EHV Network Design 280

11.3.1 Design A *280*

11.3.2 Design B *290*

11.4 132 kV network 292

11.4.1 Design A *292*

11.4.2 Design B *306*

11.5 Comparison with the present P2 standards 308

11.6 Future network development: enhancing grid security through smart control of district networks 309

11.7 Conclusions..311

12 References 313

12.1 Relevant publications from members of the modelling team 319

13 Appendix A – Modelling 323

13.1 Overview..323

13.2 Numerical approach using Monte Carlo Simulation...325

13.3 Storage modelling via chronological Monte Carlo simulation 336

13.4 Non-network technologies portfolios to increase robustness of distribution networks against high impact low probability events caused by natural hazards: A CVaR optimisation approach...342

13.5 Analytical approaches for reliability evaluation 344

13.6 Stochastic planning model for DSR..351

13.7 Option Value of Soft Open Point...352

13.8 Integrating uncertainty into security standards: Min-max regret approach 356

13.9 Contribution to Security of Supply if DSR Cannot Run in Islanding Operation............358

13.10 Dynamic Line Rating...360

13.11 Risk assessment model – PV and reverse power flows 362

13.12 Risk assessment model – Protection system for reverse power flows 365

13.13 The Optimal Portfolio Model...366

13.14 Investing in Corrective Mode to Deal with High Impact Low Probability Natural Hazards.367

13.15 Consumer-driven distribution network planning 369

14 Appendix B – Data and Networks 373

14.1 Typical network topologies...378

14.2 Asset Cost 379

14.3 Detailed Cable and Substation Costs 380

14.4 Load Duration Curve 383

14.5 Generalised Range of Reliability Related Parameters 384

15 Glossary..386

1 CONTEXT AND OBJECTIVES OF THE STUDY

1.1 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. Although the distribution networks, designed in accordance with the historic deterministic standards, have broadly delivered secure and reliable supplies to customers, the key issue regarding the future evolution of the standard is associated with the question of *cost effectiveness* of the use of existing assets and the role that advanced, non-network technologies 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, to facilitate a cost effective delivery of the UK Government energy policy objectives.

Overall, there are two key questions:

- Is the present network design standard efficient? Does it deliver good value for money to most network customers 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 the innovation in the 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?

1.2 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 level 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 as 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, do not violate the network operational limits; while 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. DNOs recognise and have practices to accommodate supply risks that remain even when a system is compliant with the security standard. A compliant system is not assumed to be a zero risk system. For example, there is flexibility in design practices for normal plant ratings to be exceeded temporarily, and for emergency ratings (involving accelerated ageing) to be used – such as for a CER 33/11 kV transformer.

- ***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 that the expectation of considerable asset replacement. This is likely to affect particularly large Demand Groups. The risk of interruptions might increase during construction outages if present security of standards requirements are relaxed.
- ***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 exposed line are much more frequent than failures of a closely monitored transformer. The analysis carried out demonstrated the importance of 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:*** Present standard does not consider Common Mode Failures and High Impact Low Probability events. There is growing interest in understanding and enhancing resilience of future distribution networks.
- ***Non-network technologies 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 and control based on new information and communication technology 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 was carried out without reviewing the fundamental principles on which the standard is based.
- ***Smart network control and user driven choice of reliability:*** 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. If such choice is to be offered to users, understanding of the network reliability profile will be essential (in addition to the development of reliability differentiating charging / reward mechanisms). In the longer time scale, introduction of smart metering may facilitate consumer driven choice of reliability.

1.3 Key objectives of the study and modelling approach

While challenges addressed in this study (Phase 1) are associated with the fundamental principles and identifying alternative options for future standards, the main challenge for future work (Phase 2) will be to develop implementable security standards that will balance the cost efficiency of the standard the complexity of implementation, simplicity and transparency requirements, which will involve further stakeholder engagement enabling in-depth discussion about the strengths and weaknesses of the alternative options.

In the context of the objectives of the study, the overall aim of this work, is to carry out a fundamental cost-benefit analysis, from the first principles, to identify efficient distribution network designs 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) including demand side response, distributed generation and energy storage technologies. It is expected that this will inform the debate 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.

Specifically, this work will identify cost effective distribution network designs which will balance the service quality delivered to end customers against network investment cost. Given the fundamentally probabilistic nature of network failures, probabilistic cost-benefit based frameworks are developed and applied in this study. As indicated in the figure below, probabilistic approach can provide the basis for risks of supply interruptions to be understood, quantified and managed through optimising the amount of the network capacity that should be made available to network users in both operational and investment time horizons. Essentially, this approach will enable the costs of network investment to be balanced against the benefits that the released network capacity delivers to the network users. Losses are considered in the existing as well as in future networks developments.

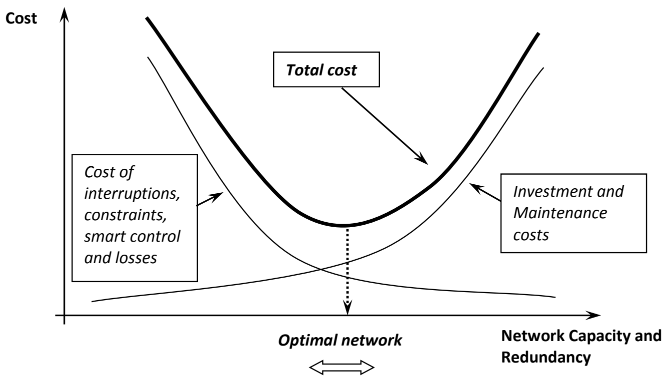

Figure 1.1: Probabilistic cost-benefits analysis framework for distribution network operation and planning (balancing of network operation costs that includes cost of service interruptions, smart control and losses against cost of investment in network assets)

Furthermore, probabilistic approach provides a framework within which both network and non-network solutions, such as flexible demand and generation, can be objectively compared and thus solve network problems. Therefore, this framework would provide a benchmark for assessing economic efficiency of any future standard. The probabilistic modelling framework is applied to assess the importance of common mode failures, risks associated with extended construction outages, role and benefits of infrastructure reserves and provisional supplies.

1.4 Specific objectives and scope of the work

In order to meet the key objectives, a large amount of studies and broad spectrum analyses are needed addressing the key distribution network design problems from different aspects. In order to manage the work effectively, several sub-tasks have been developed with specific objectives and scopes as listed as follows:

Subtask 1: Evaluate the cost effectiveness and review the performance of the present network design standards

The specific objectives of this task are to:

- Assess the value of loss load that can justify the case for network upgrade and identify the key parameters that drive the value of security;
- Identify the optimal degree of redundancy for a range of values of key driving parameters;
- Analyse the results and compared with the present standards.

The objectives are addressed by analysing the results of the comprehensive studies carried out using a set of reliability tools developed by Imperial College for distribution networks with different voltage levels, loading, structure (OH and UG), configurations, and reliability parameters. The performed studies show the economically efficient degree of redundancy for different voltage levels. HV modelling considers different generic restoration times which can indicate the effect different level of load transfers might have. Different levels of load transfers are considered in EHV and 132 kV (note that load transfer can be carried out at the same or lower voltage levels). Any further interaction between networks could reduce the unserved energy without additional cost and in that respect the actual optimal redundancy would be even lower than one derived from studies. The cases chosen and methodology applied provide conservative redundancy levels.

Subtask 2: Asses the benefits of smart grid technologies in supporting efficient distribution network design

In this task, the aim is to demonstrate the benefits of smart grid technologies for improving the efficiency of network investment and operation by enabling higher utilisation of the assets, releasing network latent capacity, and improving network control capability to manage operational constraints. A range of smartgrid technologies is analysed including DLR, overloading capability of transformers and cables, storage, demand and generation led DSR, smart disconnection of non-essential demand. Potential overloading capability of one asset might be limited by the capabilities of the other assets, for example switchgear.

Subtask 3: Investigate the impact of construction outages and asset replacement on distribution network design and planning strategies

The aim of this task is analyse, at a high-level, the impact of construction outages and asset replacement programmes considering risks that are not explicitly recognised in the present planning standards.

Subtask 4: Investigate the impact of distributed generation of reliability driven design of distribution networks

The key objective of this activity is to investigate the extent to which distributed generation may drive network investment in the context of security of supply (distributed generation driven network redundancy).

Subtask 5: Investigate the impact of common-mode failures and high-impact-low-probability events on distribution network operation and planning

The focus of this task is on the impact of simultaneous outages triggered by common-mode failures (CMF) and the increased probability of component failures during high-impact-low-probability (HILP) event. These factors may be important to be considered in the design and planning of future distribution networks. The specific objectives of this task are:

- Illustrate the cases where the CMF may affect considerably the design of distribution networks;
- Demonstrate the potential impact of HILP events on the reliability performance of the distribution networks which may influence future network design;
- Assess the benefits of mitigation measures as to reduce the severity of the faults due to CMF and HILP.

Subtask 6: Assess the impact of uncertainty and demonstrate various approaches for optimising the investment decisions for distribution networks across different scenarios

The main objective of this task is to:

- Demonstrate cases where the uncertainty in future demand growth can influence the investment decisions considering risks of stranded asset;
- Demonstrate that distribution network planning problems could be formulated in different ways depending on the planner’s / investor’s risk attitude;

- Demonstrate the option value of investing in flexible technologies such as DSR to deal with future uncertainty.

Stochastic optimisation approach and the min-max regret approach are used to demonstrate the significance of the problem and quantify the option value of DSR in the case of uncertainty in the future demand growth.

Subtask 7: Determine the long-term optimal design of distribution networks

In this task, the objective is to investigate the optimal long-term design of distribution networks taking into account the impact of losses in the lifetime of the assets. This is relevant for determining the network reinforcement and replacement strategy.

1.5 Structure of the report

This report is organised as follows:

- Chapter 2 reviews the cost effectiveness of present network design standards. 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 results of the studies investigating the optimal degree of redundancy for different distribution network types at different voltage levels are presented and discussed in this chapter. This chapter also presents customer interruption cost literature surveys.
- Chapter 1 discusses the importance of managing the risk of interruptions associated with construction outages. A number of illustrative cases have been performed to identify the drivers and values of investing in risk mitigations measures during the construction-outages.
- Chapter 3 describes the methodology, i.e. Effective Load Carrying Capability (ELCC), used for assessing quantitatively security contribution of demand-led and generation-led DSR and ES technologies taking into account the combined effects of the distribution network and non-network assets reliability properties. A set of study cases has been carried out, analysed and the results are discussed.
- Chapter 4 investigates the economic case of providing network redundancy for distributed generation in the context of security of supply.
- Chapter 6 discusses the potential of smart-grid technologies for enhancing assets utilisation, such as Dynamic Line Rating, active voltage control, etc., for releasing the latent network capacity and improving the utilisation of the assets. The implementation of these technologies may provide efficient alternatives to network reinforcements. Furthermore, the potential applications of a range of smart grid technologies, such as Demand Side Response, Active Network Management, etc., for network control capability to manage

flows, voltages in a more efficient manner are discussed. The implementation of these technologies may provide cost effective alternatives to network reinforcement.

- Chapter 6 examines the results of studies developed to identify and quantify the value (potential benefits) of automation aimed at reducing the restoration time and improving the reliability performance measured by the CI, CML and Expected Energy Not Served indices. In this chapter, we also assess the business case for automation for different equipment costs, network availability parameters, VoLL and assess the materiality at the GB level.
- Chapter 8 provides a range of illustrative case studies in planning distribution networks under uncertainty. A number of approaches used for the study including strategic planning using stochastic model and min-max regret approach are described. The key findings are highlighted to stress its importance.
- Chapter 8 presents a set of examples to demonstrate how the risk associated with common-mode failures and high-impact-low-probability events could be evaluated and managed.
- Chapter 9 analyses a possible framework to integrate the consumers' preferences in future distribution network reliability planning given that 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.
- Chapter 11 describes the results of comprehensive studies that have been carried out to uncover the optimal long-term design of future distribution networks at various voltage levels considering the optimal loss-inclusive network design.
- Appendix A (Methodology) describes the range of analytical and numerical techniques, and optimisation algorithms used in the studies.
- Appendix B (Data) contains key data including the parameters, such as ratings, impedances, fault rate, time to repair, etc. for a spectrum of network assets both for OH and UG networks and the cost data used in the studies.
- Appendix C (Glossary) provides list of used abbreviations.

2 COST EFFECTIVENESS OF PRESENT NETWORK DESIGN STANDARDS

2.1 Overview and objective

As the electricity demand may increase in future, this raises a question whether in the short term it would be economically efficient to upgrade the network following the present security standard or potentially further enhance the utilisation of the existing networks and delay network reinforcement. In order to address this question, the cost and reliability performance of both approaches have been analysed.

The main objective of this section is to identify and evaluate the cost effectiveness of the present security standards in terms of network redundancy required at High Voltage (HV), Extra High Voltage (EHV), and 132 kV level. This analysis focuses on demand growth driven network upgrade requirements, while the issues associated with increased DG penetration and smartgrid technologies are addressed specifically in chapters 4 and 6 respectively.

In order to justify the cost of network upgrade driven by the security requirement, the Probabilistic Cost-Benefits (P-CBA) analysis framework for distribution network operation and planning illustrated in Figure 2.1 is developed.

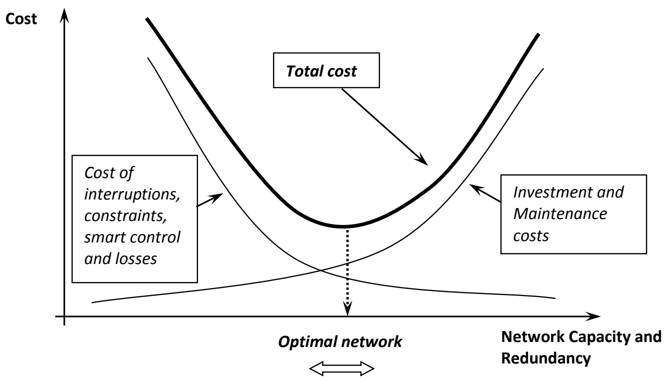

Figure 2.1: Probabilistic cost-benefits analysis framework for distribution network operation and planning (balancing of network operation costs that includes cost of service interruptions, smart control and losses against cost of investment in network assets)

For each network design option several cost components are considered in our analyses including:

- cost of interruptions: which is a measure of the economic losses caused by interruption in the electricity supply;
- cost of operational measures: is the cost of emergency measures such as the cost of providing backup generation (e.g. rental cost);
- cost of network investment which includes the cost of upgrading the network.

Regarding the evaluation of economic losses caused by interruptions 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 Customer Damage Function (CDF) estimated equivalent VoLL might be lower than values used in this report, which would lead to conservative results. 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 costs to be determined (that may also correspond to different customer damage functions).

In order to calculate the cost of interruptions, a range of reliability techniques has been used. Two main approaches to evaluating security have been implemented in this study (i) a numerical approach based on Sequential Monte Carlo simulation (described in Section 13.2) (ii) an analytical approach based on multi state Markov models, (described in Section 13.5). Both models take into the account single and overlapping faults, asset maintenance, restoration processes through fault clearing, network reconfiguration, application of transfer capability of adjacent networks or use of mobile generation. The developed analytical model is used in instances when long-term average values of reliability indices and cost of interruptions are considered appropriate. The analytical model is calibrated against results of Sequential Monte Carlo simulation (see Table 13.5). It is important to highlight that the reliability parameters used in this section, such as failure rates, restoration and repair rates are based on the long-term average values, not considering exceptional events (which are addressed specifically in Chapter 8). Analytical method used in this study is fundamentally similar to the method described in ACE51.

This Section considers economically efficient degree of redundancy for network upgrade including losses. Section 11 considers losses to find the optimal peak network utilisation once decided to upgrade network sections. The savings in losses are compared with the additional cost of installing assets with greater ratings than minimum needed.

A range of studies has been carried out to investigate the cost effectiveness of the present security standards on substations and distribution networks with different voltage levels (HV, EHV, and 132 kV). Moreover, sensitivity studies have been performed to investigate the impact of the following parameters on the optimal degree of network redundancy. Parameters used in the sensitivity studies include:

- Network load (it resembles the impact of different “group demand” in the present security standard;
- Construction type, e.g. Over Head (OH) or Under Ground (UG);
- Network failure rates;
- Restoration and repair times;
- Network upgrade costs;
- The present of emergency supplies; and
- Value of Loss Load (VoLL)[1].

Therefore, the reminder of this chapter is organised as follows:

- Section 2.2 describes the process of quantifying breakeven VoLL at which the existing network would be upgraded cost effectively to comply with the present standards;
- Section 2.3 - 2.8 presents our analysis on the optimal degree of network redundancy for HV, EHV, and 132 kV networks and primary and bulk supply substations. Sets of cases have been developed to assess the impacts of a range of driving parameters.
- In Section 2.9 estimates potential savings of avoiding security-driven network investment in HV networks and primary substations at the GB level.

2.2 Breakeven VoLL that would justify security-driven-incremental upgrade of HV networks

As discussed above, a general consensus on the value of Customer Interruption Costs (CICs) has not been yet achieved, as the values proposed by different sources vary significantly. The main reason is that CICs depend on a large number of diverse factors, which is challenging to unambiguously quantify even by the consumers themselves. These factors include the activities affected by unsupplied energy, the timing (time of day, day of week, month of year) of the supply interruption, the duration of the supply interruption, the frequency of interruptions and the availability of advance warning before the interruption takes place. This lack of consensus is aggravated by the fact that CIC have been quantified in different years in the past, introducing significant difficulties in carrying out comparative analysis (this is further discussed in section 2.11).

Recent report by London Economics estimate the VoLL for domestic, small and medium sized enterprises (SME) and industrial and commercial (I&C) electricity users, which is used in this analysis (the same values are used in the development of Capacity Market, as a part of

[1] More detailed discussion on the derivation and the application of VoLL can be found in section 2.11.

Electricity Market Reform, considered by DECC). This work estimates the VoLL in terms of willingness-to-accept (WTA) payment for an outage and willingness-to-pay (WTP) to avoid an outage. The WTA estimates are larger than the respective WTP estimates, since customers desire a larger monetary amount in order to bear a loss of supply than the one they are willing to pay to retain it. For domestic customers, the statistically significant estimate of the VoLL ranges from £1,651/MWh (WTP) to £11,820/MWh (WTA) for a one-hour electricity outage during Winter Peak conditions with a headline figure of £10,289/MWh. For SME the respective range is from £19,271/MWh (WTP) to £39,213/MWh (WTA) for all conditions with a headline figure of £35,488/MWh and for I&C customers the overall value is about £1,400/MWh. They have derived the load-share weighted average VoLL across domestic and small and medium enterprise users for winter peak weekday as £16,940/MWh. The summary is shown in Table 2.1.

Table 2.1: Headline VoLL in £/MWh

Domestic customers	Small and medium enterprise (SME)	Load-share weighted average across domestic and SME	Industrial and commercial
10,289	35,488	16,940	1,400

In line with the latest analysis and values used in the Electricity Market Reform carried out by the Department of Energy and Climate Change VoLL of £17,000/MWh is used this study as the central value. We have also carried out the analysis using larger value of VoLL (£34,000/MWh) to assess the sensitivity and robustness of identified solutions. More detailed discussions on the CIC and VoLL can be found in section 2.11. Different Customer Damage Functions might results in different cost of interruptions. For various CDFs, estimated equivalent VoLL might be lower than values used in this report (Table 3.51), which would lead to conservative results (lower optimal degree of redundancy).

The key objective of the following studies is to determine the breakeven VoLL at which the network upgrade is economically justified for different levels of network redundancy considered. At this value, the savings from reduced EENS, losses and cost for renting mobile generation are equal to the cost of network upgrade to comply with the present security standards.

Figure 2.2 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. This configuration is used in the studies to evaluate the cost of having different levels of redundancy, namely: N-0.75, N-0.5, N-0.25, N-0 by increasing the load connected to the test network. Considering the present practice uses the N-1 as a reference for the planning, the increased load can only reduce the degree of redundancy. For example, if the peak load of the HV feeder peak is initially 2 MW and the network is N-1 compliant would mean that after any one component out of service network would be able to supply demand in peak condition. This would mean that for an outage at the beginning of one feeder the other feeder would be able also to supply the whole of demand of the first feeder i.e. 4 MW. Hence for N-0 compliant network the peak load of the feeder can be doubled (i.e. 4 MW which is equal to the rating of the feeder) without need for any network reinforcement. This notation is generalised to represent non-integer degree of redundancy. As the existing N-1 design of the network can accommodate 2 MW load per feeder, increasing the load per feeder by 500 kW (total load per feeder is 2.5 MW and total load of the network is 5 MW) means the degree of redundancy becomes N-0.75. This means the spare capacity of the feeder is 75% of spare capacity in case of N-1 degree of redundancy. For the N-0.5 and N-0.25 cases, the spare capacity per feeder are 50% and 25% respectively. For the N-0 case, all capacity is needed to accommodate the peak demand i.e. there is no spare capacity. However, during off-peak condition there would still be spare capacity at the time of fault and only for some of faults proportion of customers may experience longer interruptions. Presence of distributed generation and energy storage might reduce the adverse effects of outages.

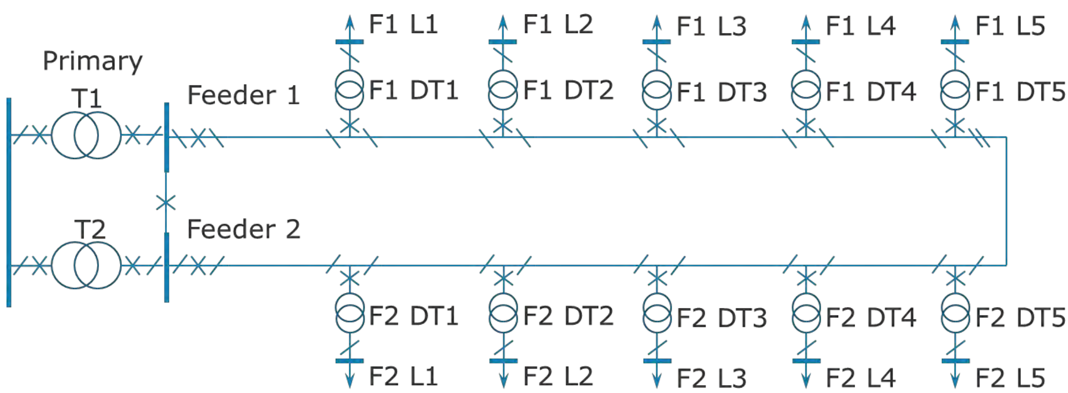

Figure 2.2 HV network case studies

When a fault occurs on a section, for example on Feeder 1 section between F1 DT1 and F1 DT2, feeder circuit breaker will open to break fault current and supply to load points F1 L1 to F1 L5 will be interrupted. Process of locating the faulty section and its isolation will then start. We consider the use of automation, remote control and manual switching in which the section at fault is located and isolated.

After that a supply is restored to F1 L1 by switching on the feeder circuit breaker. It is agreed to use 30 minutes for manual switching for fault isolation and hence in the first stage customers whose supply is restored would experience outage of 30 minutes. Supply for F1 L2 to F1 L5 is restored through a backfeed by closing the NOP located next to F1 DT5. Switching of NOP is assumed to take on average 20 minutes. This means that the customers whose supply is restored from the backfeed would experience outage of 50 minutes. After that, all load points will be resupplied and the repair process would start. The non-urgent repair time is, on average, five days for HV circuits. If during the repair process, an overlapping fault occurs, for example on feeder 1 section between F1 DT4 and F1 DT5, feeder 2 circuit breaker will open and all load connected to feeder 2 and loads F1 L2 to F1 L5 will lose supply. The section with the fault will be isolated by opening the relevant switchgear and all load points connected to feeder 2 and F1 L5 will be resupplied from feeder 2. Load points F1 L2 to F1 L4 will still be out of supply. This would then trigger urgent repair to be carried out. For HV underground circuits, the urgent repair time varies between 6 and 18 hours. In order to speed-up the restoration of supply at load point F1 L2 to F1 L4, it is assumed that a mobile generation would be provided within 3 to 6 h. Different values of Mean Time To Restore and Repair are used in the analysis[2].

HV Underground Networks

Table 2.2 shows the combination of reliability parameters of HV underground cables and overhead lines used in the studies. We have identified that the failure rates, Mean Time to Restore, Mean Time to Repair, and upgrade costs of HV network are the key parameters that drive economically efficient network redundancy. It is found that the results are not sensitive to the section lengths as the cost and the failure rate increase linearly with the increase in length, which cancels out the effect of increasing section length.

In order to quantify the importance of these parameters, the values have been varied with the range shown in Table 2.2 for sensitivity studies. The values are selected from analysing data of the Quality of Supply over 5 year periods from different DNOs. Majority of GB HV feeders have failure rates similar to the minimum failure rate used in this study.

Table 2.2. HV network reliability parameters

Construction	Failure rate OHL/underground (%/km.year)	Mean Time to Restore (h)	Mean Time to Repair (h)
Overhead/ Underground	5 and 20/ 2 and 10	3, 6, 12 and 24	24 and 120

In order to quantify the minimum VoLL that justifies network reinforcement cost for different security levels, a set of studies has been carried out for different degree of redundancy, failure rates, MTTR (as presented in Table 2.2), and a range of upgrade costs (see Table 2.3). It is assumed that feeders are not tapered and that a minimum number, depending on degree of redundancy, of sections would need to be upgraded, for example: for N-0.75 four sections (two per feeder), for N-0.5 six sections and for N-0.25 and below, all sections. Tapering could potentially increase the cost of upgrade, increase breakeven VoLL and decrease economically efficient degree of redundancy. It should be pointed out that a load transfer would apply first, if possible. This analysis is hence focused on cases when load transfer capability is fully used. Load shedding is hence carried out if asset is loaded above nameplate rating and it is assumed that the upgrade length is similar to the length of network section which is being overloaded.

The calculated breakeven VoLL is presented in Table 2.4. 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. The breakeven VoLL for different load profiles including losses are shown. The LN represents large number.

[2] This occurs when the EENS savings driven by upgraded, are lower than the possible increase of the EENS due to increase in probability of the second circuit outage when non-urgent rather than urgent repair time would apply. It is assumed that this situation could be recognised and a small EENS savings achieved which results in a high value for breakeven VoLL

Table 2.3: Range of upgrade costs

Asset category	Cost (£/km)	Range of cost (£/km)
Overhead line	30,000	24,000 – 36,000
Underground cable	110,000	88,000 – 132,000

Table 2.4: Breakeven VoLL (£/MWh) for HV underground feeders with the initial feeder load of 2.5 MW

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%	6/24	20,088,394	32,023,154	1,780,879	3,044,153
	2%	12/24	9,870,442	15,734,592	887,089	1,516,350
	2%	24/24	4,833,156	7,704,408	442,491	755,949
	2%	3/120	54,828,049	87,410,511	3,699,785	6,338,537
	2%	6/120	26,826,633	42,768,797	1,840,763	3,153,628
	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%	6/24	4,749,106	7,571,340	362,799	621,554
	10%	12/24	2,156,318	3,437,745	178,887	306,472
	10%	24/24	967,797	1,542,740	88,605	151,372
	10%	3/120	LN	LN	889,646	1,541,920
	10%	6/120	LN	LN	437,265	757,860
	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%	6/24	3,628,987	5,858,882	277,037	489,910
	2%	12/24	1,804,533	2,913,360	138,253	244,485
	2%	24/24	897,865	1,448,965	69,549	122,591
	2%	3/120	7,784,287	12,588,680	544,446	975,750
	2%	6/120	3,866,729	6,253,239	271,347	486,304
	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%	6/24	753,182	1,218,040	54,089	96,938
	10%	12/24	367,764	594,744	26,930	48,264
	10%	24/24	179,790	290,143	13,927	24,548
	10%	3/120	2,313,630	3,773,947	96,636	187,214
	10%	6/120	1,117,766	1,823,278	48,053	93,094
	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%	6/24	1,536,852	2,445,765	181,107	309,171
	2%	12/24	766,339	1,219,561	90,404	154,330
	2%	24/24	383,698	609,776	45,899	77,829
	2%	3/120	3,104,781	4,968,886	341,117	599,322
	2%	6/120	1,546,150	2,474,456	170,042	298,753
	2%	12/120	770,278	1,232,751	84,866	149,105
	10%	3/24	618,198	989,363	68,165	119,762
	10%	6/24	306,834	491,057	33,958	59,661
	10%	12/24	152,172	243,536	16,933	29,750
	10%	24/24	76,832	122,102	9,191	15,585
	10%	3/120	640,202	1,056,184	45,306	98,256
	10%	6/120	316,989	522,958	22,562	48,930
	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%	6/24	517,481	843,433	77,884	141,261
	2%	12/24	258,267	420,945	38,887	70,530
	2%	24/24	130,336	211,568	20,002	35,811
	2%	3/120	1,003,226	1,663,261	138,168	265,694
	2%	6/120	500,072	829,076	68,898	132,490
	2%	12/120	249,489	413,631	34,397	66,144
	10%	3/24	200,284	332,053	27,620	53,113
	10%	6/24	99,699	165,292	13,768	26,476
	10%	12/24	49,649	82,313	6,870	13,211
	10%	24/24	26,099	42,365	4,005	7,171
	10%	3/120	163,450	301,759	9,237	35,172
	10%	6/120	81,299	150,093	4,604	17,529
	10%	12/120	40,406	74,597	2,296	8,743

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.

The breakeven VoLL decreases when the network is less reliable, characterised by higher failure rate and MTTR. For example, for case of N-0.5 degree of redundancy and load profile with high load factor, failure rate of 10%, MTTR of 24/24, the breakeven VoLL for the low and high upgrade cost scenarios are £13,927/MWh and £24,548/MWh respectively. This means the upgrade is justified if the VoLL is £34,000/MWh. The results are not surprising since the amount of EENS will increase if the network is less reliable, which would result in lower breakeven VoLL. However, for the load profile with low load factor breakeven VoLL is greater and in range between £179,790-594,744/MWh depending on the upgrade cost.

Typical non-urgent repair time in HV network is 120 hours and urgent repair time for HV overhead lines is about 6 hours and for underground cables is between 6-18 hours. Even though supply to all customers in the configuration in Figure 2.2 can be restored, when network is upgraded, following a single outage, given the probability of the second outage increases with a longer repair time, the savings from avoiding interruptions due to thermal constraints are reduced by increase in EENS in overlapping outages. Smaller EENS savings equates to a greater breakeven VoLL. This can be observed in N-0.75 degree of redundancy. At the lower degree of redundancy, increased savings in mobile generation renting cost drives the opposite effect i.e. lower breakeven VoLL for longer repair times. As it can be observed in the Table 2.4, in the case of low load factor and with N-0 degree of redundancy, circuit failure rate of 10%/km.year and MTTRs 3/24 and 3/120 hours, the breakeven VoLLs are between £200,284 and 332,053 per MWh and between £163,450 and £301,759 per MWh respectively.

The results, for underground circuits with an initial feeder load of 2.5 MW, also show breakeven VoLL for cases with a smaller degree of redundancy are lower. For example, for the case of low load factor and with N-0.5, failure rate of 2%, MTTR of 3/24 h, for the low and high upgrade cost scenarios, the breakeven VoLLs are £7,295,924/MWh and £11,779,032/MWh respectively.

Considering the central value of the VoLL is £17,000/MWh, the cases where the upgrade cost can be justified are highlighted in blue, for example, case with N-0.25, high failure rate (10%) and MTTR (24/24). For a HV network with high reliable components, i.e. low failure rate and low MTTR, the loading of the network can be double without reinforcement as the benefit of reinforcing the network is lower than the cost. This indicates that the present security standards are not cost effective in network with low failure rate and low MTTR.

For the VoLL of £34,000/MWh, the network can accommodate cost effectively smaller increase in load (up to N-0.5) in comparison with the previous case. A higher VoLL leads into increased demand for system redundancy.

For a less reliable HV network (e.g. failure rate 10% and MTTR of 12/120 h), the economically efficient upgrade, depending on the cost, is at about N-0.25 or greater degree of redundancy. At N-0.25 degree of redundancy the network upgrade will be economically efficient if the upgrade cost is low and the VoLL about £17,000/MWh. If the upgrade cost is high, the network can be stressed slightly more before the upgrade cost can be justified. The optimal degree of redundancies for considered cases are given in Section 2.3.

Sensitivity studies have been carried out to investigate the impact of peak demand (group demand). Table 2.5 and Table 2.6 show the breakeven VoLL for cases with initial feeder peak load of 500 kW and 5 MW, respectively.

Table 2.5: Breakeven VoLL (£/MWh) for HV underground feeders with, and the initial feeder load of 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	2%	3/24	6,137,088	9,406,209	1,124,481	1,759,938
	2%	6/24	3,059,541	4,689,306	560,748	877,632
	2%	12/24	1,526,972	2,340,364	279,975	438,191
	2%	24/24	765,910	1,172,067	141,309	220,353
	2%	3/120	6,083,787	9,383,966	1,081,953	1,719,582
	2%	6/120	3,032,548	4,677,568	539,520	857,477
	2%	12/120	1,512,956	2,333,666	269,350	428,087
	10%	3/24	1,214,565	1,873,411	216,286	343,751
	10%	6/24	604,598	932,564	107,813	171,351
	10%	12/24	301,080	464,402	53,798	85,503
	10%	24/24	153,367	234,696	28,296	44,124
	10%	3/120	1,157,912	1,849,457	172,881	302,555
	10%	6/120	575,939	919,909	86,160	150,787
	10%	12/120	286,243	457,197	42,972	75,205

In the case with initial feeder load of 500 kW, for a highly reliable HV network, the loading of the network can double without need for reinforcement. For all considered cases the economically efficient degree of redundancy is N-0.

Comparing these and the results in Table 2.4, it is observed that the network with lower load can be operating at lower degree of redundancy which is demonstrated by higher breakeven VoLL needed to justify the upgrade. For example, for low load factor and high reliable networks at N-0, the breakeven VoLL in the low and high-upgrade-cost scenarios can reach, see Table 2.5, £6,137,088/MWh and £9,406,209/MWh respectively.

The results of the studies for the HV network with a larger demand, 5 MW per distribution feeder, are presented in Table 2.6. It can be observed that breakeven VoLL is lower compared with the values for lower demand as savings in EENS increase when demand increases.

Table 2.6: Breakeven VoLL (£/MWh) for HV underground feeders peak load of 5 MW per feeder

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	20,343,411	32,429,680	1,788,461	3,057,113
	2%	6/24	10,044,197	16,011,577	890,439	1,522,077
	2%	12/24	4,935,221	7,867,296	443,545	758,175
	2%	24/24	2,416,578	3,852,204	221,245	377,975
	2%	3/120	27,414,025	43,705,256	1,849,893	3,169,269
	2%	6/120	13,413,317	21,384,399	920,382	1,576,814
	2%	12/120	6,463,195	10,304,053	457,658	784,069
	10%	3/24	5,098,068	8,127,679	366,882	628,549
	10%	6/24	2,374,553	3,785,670	181,399	310,777
	10%	12/24	1,078,159	1,718,872	89,443	153,236
	10%	24/24	483,899	771,370	44,302	75,686
	10%	3/120	LN	LN	444,823	770,960
	10%	6/120	LN	LN	218,632	378,930
	10%	12/120	LN	LN	106,425	184,455
N-0.5	2%	3/24	3,647,962	5,889,516	277,891	491,420
	2%	6/24	1,814,494	2,929,441	138,518	244,955
	2%	12/24	902,267	1,456,680	69,126	122,243
	2%	24/24	448,932	724,483	34,774	61,296
	2%	3/120	3,892,143	6,294,340	272,223	487,875
	2%	6/120	1,933,364	3,126,620	135,673	243,152
	2%	12/120	958,224	1,549,632	67,681	121,297
	10%	3/24	766,670	1,239,853	54,341	97,390
	10%	6/24	376,591	609,020	27,045	48,469
	10%	12/24	183,882	297,372	13,465	24,132
	10%	24/24	89,895	145,071	6,963	12,274
	10%	3/120	1,156,815	1,886,974	48,318	93,607
	10%	6/120	558,883	911,639	24,026	46,547
	10%	12/120	264,152	430,880	11,937	23,126
N-0.25	2%	3/24	1,542,503	2,454,757	181,645	310,089
	2%	6/24	768,426	1,222,882	90,554	154,585
	2%	12/24	383,169	609,780	45,202	77,165
	2%	24/24	191,849	304,888	22,949	38,915
	2%	3/120	1,552,390	2,484,443	170,558	299,661
	2%	6/120	773,075	1,237,228	85,021	149,377
	2%	12/120	385,139	616,376	42,433	74,552
	10%	3/24	309,099	494,682	34,083	59,881
	10%	6/24	153,417	245,529	16,979	29,831
	10%	12/24	76,086	121,768	8,467	14,875
	10%	24/24	38,416	61,051	4,595	7,792
	10%	3/120	320,101	528,092	22,653	49,128
	10%	6/120	158,495	261,479	11,281	24,465
	10%	12/120	78,166	128,955	5,620	12,189
N-0	2%	3/24	519,003	845,915	78,092	141,637
	2%	6/24	258,740	421,717	38,942	70,631
	2%	12/24	129,133	210,473	19,443	35,265
	2%	24/24	65,168	105,784	10,001	17,905
	2%	3/120	501,613	831,631	69,084	132,847
	2%	6/120	250,036	414,538	34,449	66,245
	2%	12/120	124,744	206,815	17,198	33,072
	10%	3/24	100,142	166,026	13,810	26,557
	10%	6/24	49,850	82,646	6,884	13,238
	10%	12/24	24,824	41,156	3,435	6,606
	10%	24/24	13,049	21,182	2,003	3,585
	10%	3/120	81,725	150,880	4,619	17,586
	10%	6/120	40,650	75,047	2,302	8,765
	10%	12/120	20,203	37,298	1,148	4,371

In the case of demand group of 5MW, for a highly reliable HV network, the loading of the network can double without reinforcement as the benefit of reinforcing the network is lower than the cost of upgrade. For less reliable HV network, e.g. failure rate 10% and MTTR of 24/24 h, the economically efficient degree of redundancy can be N-0.5 for high upgrade cost.

Comparing these results with the previous results in Table 2.4, it is observed that the network with high demand tends to require higher degree of security as the economic benefit of EENS reduction due to the upgrade is greater and justifies the cost of the upgrade. This is demonstrated through lower breakeven VoLL needed to justify the upgrade. For example, in Table 2.6, for low load factor, failure rate of 10%/km.year and MTTR 3/120 hours at N-0 degree of redundancy, the breakeven VoLL in the low and high-upgrade-cost scenarios is £81,725/MWh and £150,880/MWh respectively. It is observed that for the same case, the breakeven values (£163,450/MWh and £301,759/MWh respectively) in Table 2.4 are higher. Therefore, the number of considered cases where the breakeven VoLL is less than £17,000/MWh or £34,000/MWh is higher than the number in Table 2.4.

HV Overhead Networks

Similar studies have been carried for a HV overhead networks. It is important to highlight that the upgrade of underground networks is about three times more expensive than the overhead networks, therefore the breakeven VoLL for overhead networks may be expected to be lower. Table 2.7 shows the breakeven VoLL for overhead feeders for demand group of 2.5 MW.

Table 2.7: Breakeven VoLL (£/MWh) for overhead feeders with initial peak load of 2.5 MW per feeder

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	5%	3/24	2,968,757	5,822,100	56,491	336,473
	5%	6/24	1,437,822	2,819,747	28,054	167,095
	5%	12/24	687,456	1,348,185	13,922	82,920
	5%	24/24	326,358	639,727	7,501	41,712
	5%	3/120	9,775,742	19,207,700	40,860	350,958
	5%	6/120	4,292,627	8,434,295	20,248	173,915
	5%	12/120	1,757,509	3,453,212	9,997	85,869
	20%	3/24	1,253,792	2,462,326	11,085	85,349
	20%	6/24	516,979	1,015,297	5,431	41,812
	20%	12/24	204,984	402,568	2,642	20,345
	20%	24/24	81,774	160,294	1,880	10,452
N-0.5	5%	3/24	429,723	928,626	0	38,581
	5%	6/24	212,771	459,795	0	19,220
	5%	12/24	105,095	227,110	0	9,583
	5%	24/24	52,797	112,944	0	5,298
	5%	3/120	478,380	1,079,736	0	22,389
	5%	6/120	235,745	532,092	0	11,149
	5%	12/120	115,221	260,061	0	5,554
	20%	3/24	112,582	251,237	0	6,605
	20%	6/24	54,342	121,270	0	3,280
	20%	12/24	25,892	57,780	0	1,628
	20%	24/24	13,229	28,300	0	1,328
	20%	3/120	308,821	871,718	0	0
	20%	6/120	130,150	367,378	0	0
	20%	12/120	50,833	143,489	0	0
N-0.25	5%	3/24	205,419	405,725	2,361	30,430
	5%	6/24	102,193	201,843	1,177	15,166
	5%	12/24	50,855	100,444	587	7,567
	5%	24/24	26,735	51,409	1,037	4,521
	5%	3/120	167,913	379,515	0	6,561
	5%	6/120	83,451	188,615	0	3,270

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
	5%	12/120	41,426	93,631	0	1,631
	20%	3/24	44,043	95,765	0	3,141
	20%	6/24	21,756	47,306	0	1,564
	20%	12/24	10,715	23,299	0	779
	20%	24/24	6,699	12,881	260	1,133
	20%	3/120	0	61,195	0	0
	20%	6/120	0	30,022	0	0
	20%	12/120	0	14,572	0	0
N-0	5%	3/24	46,351	117,881	0	6,148
	5%	6/24	23,094	58,735	0	3,065
	5%	12/24	11,517	29,290	0	1,530
	5%	24/24	7,119	15,985	0	1,339
	5%	3/120	2,050	75,307	0	0
	5%	6/120	1,021	37,509	0	0
	5%	12/120	509	18,687	0	0
	20%	3/24	3,320	21,462	0	0
	20%	6/24	1,649	10,663	0	0
	20%	12/24	819	5,295	0	0
	20%	24/24	1,784	4,005	0	336

The results clearly show that the case for loading overhead networks with higher peak load is not as strong as the case for the underground network due to lower cost of upgrade. This is shown by significantly lower breakeven VoLL for overhead networks However, the load of reliable HV overhead network can be increased up to N-0.25 and N-0 in the low and high-upgrade-cost scenario respectively.

Sensitivity studies have been carried out to investigate the characteristics of the results on the network with smaller or larger demand groups. Table 2.8 and Table 2.9 show the breakeven VoLL for cases with demand of 500 kW and 5 MW per feeder, respectively.

Table 2.8: Breakeven VoLL (£/MWh) for overhead feeders with initial peak load of 500 kW per feeder

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	5%	3/24	24,575,631	38,842,345	2,067,411	3,467,322
	5%	6/24	11,902,416	18,812,040	1,026,691	1,721,898
	5%	12/24	5,690,816	8,994,465	509,488	854,479
	5%	24/24	2,699,808	4,266,653	254,113	425,167
	5%	3/120	81,142,437	128,302,226	2,235,519	3,786,008
	5%	6/120	35,630,465	56,338,805	1,107,796	1,876,129
	5%	12/120	14,588,007	23,066,521	546,966	926,326
	20%	3/24	10,399,950	16,442,620	538,624	909,944
	20%	6/24	4,288,238	6,779,828	263,869	445,776
	20%	12/24	1,700,298	2,688,221	128,393	216,905
	20%	24/24	676,480	1,069,077	63,672	106,532
	20%	3/120	LN	LN	824,766	1,454,086
	20%	6/120	LN	LN	394,973	696,348
	20%	12/120	LN	LN	184,149	324,660
N-0.5	5%	3/24	4,159,798	6,654,313	316,100	549,738
	5%	6/24	2,059,662	3,294,784	157,472	273,864
	5%	12/24	1,017,344	1,627,417	78,517	136,550
	5%	24/24	503,976	804,712	40,458	69,403
	5%	3/120	4,915,065	7,921,844	281,172	520,717
	5%	6/120	2,422,134	3,903,869	140,017	259,305
	5%	12/120	1,183,822	1,908,023	69,745	129,164
	20%	3/24	1,138,974	1,832,248	72,257	131,554

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
	20%	6/24	549,771	884,407	35,889	65,341
	20%	12/24	261,945	421,387	17,816	32,437
	20%	24/24	126,279	201,633	10,137	17,390
	20%	3/120	4,253,317	7,067,802	33,053	98,909
	20%	6/120	1,792,523	2,978,662	16,384	49,028
	20%	12/120	700,118	1,163,397	8,095	24,224
N-0.25	5%	3/24	1,708,846	2,710,372	196,691	337,035
	5%	6/24	850,129	1,348,375	98,028	167,974
	5%	12/24	423,053	670,998	48,914	83,815
	5%	24/24	214,078	337,449	26,279	43,703
	5%	3/120	1,682,495	2,740,506	138,578	280,737
	5%	6/120	836,180	1,361,999	69,054	139,892
	5%	12/120	415,093	676,118	34,442	69,773
	20%	3/24	418,752	677,362	38,250	73,619
	20%	6/24	206,855	334,603	19,038	36,642
	20%	12/24	101,878	164,796	9,481	18,247
	20%	24/24	53,641	84,553	6,585	10,950
	20%	3/120	382,746	714,058	0	13,972
	20%	6/120	187,771	350,309	0	6,949
	20%	12/120	91,140	170,033	0	3,454
N-0	5%	3/24	563,911	921,565	82,648	152,047
	5%	6/24	280,972	459,175	41,208	75,810
	5%	12/24	140,113	228,978	20,570	37,843
	5%	24/24	73,327	117,655	11,712	20,338
	5%	3/120	463,974	830,262	36,695	106,690
	5%	6/120	231,093	413,531	18,294	53,191
	5%	12/120	115,133	206,025	9,130	26,545
	20%	3/24	121,935	212,648	12,053	29,499
	20%	6/24	60,583	105,654	6,005	14,697
	20%	12/24	30,085	52,467	2,994	7,328
	20%	24/24	18,373	29,480	2,935	5,096
	20%	3/120	10,446	110,698	0	0
	20%	6/120	5,180	54,897	0	0
	20%	12/120	2,561	27,141	0	0

The results indicate that for lower demand, the economically efficient degree of redundancy becomes lower as the breakeven VoLLs are higher. This finding is consistent with the finding in the study with the underground network. For example: in the case of low load factor, N-0.75 degree of redundancy and with the failure rate of 5%, MTTR of 3/24 h, the breakeven VoLL for the low and high-upgrade scenario are £24,575,631/MWh and £38,842,345/MWh respectively. For high load factor breakeven VoLL is order of magnitude lower. For unreliable networks and high load factor considered in the studies, optimal degree of redundancy is between N-0.5 and N-0.75.

For cases with higher demand (i.e. 5 MW), the results are presented in Table 2.9.

Table 2.9: Breakeven VoLL (£/MWh) for overhead feeders with peak load of 5 MW per feeder

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	5%	3/24	1,484,379	2,911,050	28,245	168,237
	5%	6/24	718,911	1,409,873	14,027	83,548
	5%	12/24	343,728	674,093	6,961	41,460
	5%	24/24	163,179	319,863	3,751	20,856
	5%	3/120	4,887,871	9,603,850	20,430	175,479
	5%	6/120	2,146,314	4,217,148	10,124	86,957

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
	5%	12/120	878,755	1,726,606	4,999	42,935
	20%	3/24	626,896	1,231,163	5,543	42,675
	20%	6/24	258,490	507,649	2,715	20,906
	20%	12/24	102,492	201,284	1,321	10,172
	20%	24/24	40,887	80,147	940	5,226
N-0.5	5%	3/24	214,861	464,313	0	19,290
	5%	6/24	106,385	229,898	0	9,610
	5%	12/24	52,548	113,555	0	4,792
	5%	24/24	26,398	56,472	0	2,649
	5%	3/120	239,190	539,868	0	11,194
	5%	6/120	117,872	266,046	0	5,575
	5%	12/120	57,610	130,030	0	2,777
	20%	3/24	56,291	125,619	0	3,302
	20%	6/24	27,171	60,635	0	1,640
	20%	12/24	12,946	28,890	0	814
	20%	24/24	6,615	14,150	0	664
	20%	3/120	154,410	435,859	0	0
	20%	6/120	65,075	183,689	0	0
	20%	12/120	25,417	71,745	0	0
N-0.25	5%	3/24	102,710	202,862	1,180	15,215
	5%	6/24	51,097	100,921	588	7,583
	5%	12/24	25,427	50,222	294	3,784
	5%	24/24	13,368	25,705	518	2,261
	5%	3/120	83,957	189,758	0	3,281
	5%	6/120	41,725	94,307	0	1,635
	5%	12/120	20,713	46,816	0	815
	20%	3/24	22,021	47,882	0	1,571
	20%	6/24	10,878	23,653	0	782
	20%	12/24	5,358	11,649	0	389
	20%	24/24	3,349	6,441	130	566
	20%	3/120	0	30,598	0	0
	20%	6/120	0	15,011	0	0
	20%	12/120	0	7,286	0	0
N-0	5%	3/24	23,175	58,941	0	3,074
	5%	6/24	11,547	29,367	0	1,533
	5%	12/24	5,758	14,645	0	765
	5%	24/24	3,559	7,992	0	670
	5%	3/120	1,025	37,654	0	0
	5%	6/120	510	18,754	0	0
	5%	12/120	254	9,344	0	0
	20%	3/24	1,660	10,731	0	0
	20%	6/24	825	5,332	0	0
	20%	12/24	410	2,648	0	0
	20%	24/24	892	2,003	0	168

The results demonstrate that for the overhead network supplying larger demand, the need for security increases and this is reflected by lower breakeven VoLL as shown in Table 2.9.

Summary for Underground and Overhead Networks

The findings from studies carried out for OH and UG networks are consistent and therefore it can be concluded that the drivers for higher degree of redundancy are:

- High VoLL,
- High failure rate (less reliable network),
- High MTTR (long restauration and repair times),
- Low upgrade cost (cost of reinforcing OH is lower than the cost for UG networks).

The studies also provide evidence that the present security standards may be optimal for OH with low reliability and high demand, but may be too conservative against other cases, e.g. highly reliable UG networks. Clearly, this conclusion is based on the assumption of using the VoLL threshold of £17,000-34,000/MWh. Higher threshold will shift the conclusion towards the present standards, on the other hand, lower threshold will make the case for reducing the degree of redundancy further.

Primary Substations

An economically efficient degree of redundancy for upgrade of primary substation is investigated by comparing the total cost which consists of value of EENS, cost of substation including transformer feeder cables and repair cost for different level of redundancy. Figure 2.3 illustrates primary substation configuration with busbars sectionalising circuit breaker normally closed. In blue a two-transformer substation is assumed. Adding the red part will form three-transformer substation with busbars sectionalising circuit breaker normally open. Adding the green part will form four-transformer substation.

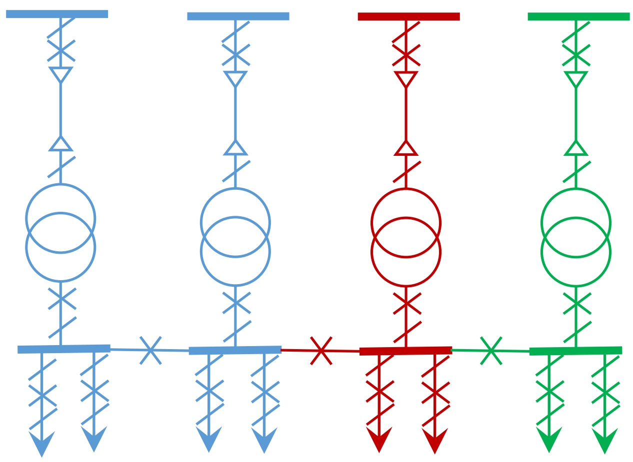

Figure 2.3: Illustration of primary two-transformer (blue), three-transformer (including red) and four-transformer (including green) primary substations

Rating of two-, three- and four-transformer primary substations are 2x30MVA, 3x15MVA and 4x10MVA, respectively. It assumes the same N-1 rating of 30 MVA. Two failure rates of 1% and 10%/year are considered. Average repair cost is £250k. Two lengths of each transformer feeder cable are considered, namely one and five km in length, with failure rates of 2 and 8%/km.year. Average repair cost is £19.5k. Reliability parameters are summarised in Table 2.10. During an outage a load transfer of 20% that can be achieved within 10 minutes is used. It is assumed that mobile generators of total maximum capacity of 10 MW can be deployed on average within 4.5 hours. Maintenance is carried out once every eight years with outage duration of 5 days and urgent maintenance close down time of 9 hours. Mean Time to Restore supply after disconnector fault is assumed 1.5 hours. The average number of repairs per year is estimated for each asset and costed at repair cost.

Table 2.10: Reliability related parameters used in the analysis

Asset	Failure rate (%/unit.year)	Urgent repair time (hours)	Average non-urgent repair time (hours)	Repair cost (£)
EHV underground cable (km)	2-8	24(-72)	120	19,500
EHV/HV transformer	1-10	192	720	250,000
EHV circuit breaker	0.87	12	24	
HV circuit breaker	0.55	6	6	
Disconnector	0.1	Restore time 1.5	12	

Cost used in the analysis is given in Table 2.11. More details are given in Appendix B. Capitalisation factor or 10 is used to convert cost to a per annum value. Costs of land and easements/wayleaves are not included, which would increase breakeven VoLL and reduce optimal redundancy. Hence, the performed analysis is conservative.

Table 2.11: Substation cost including cost of cables and switchgears but excluding land cost

EHV/HV Substation	Cost (£'000/year)	
	Cable 5 km	Cable 1 km
2x30 MVA	285.9	129.9
3x15 MVA	511.4	194.4
4x10 MVA	718.5	259.0

Peak demand is increased from 30 (denoted as degree of redundancy N-1 using two-transformer paradigm), 37.5 (N-0.75), 45 (N-0.5), 52.5 (N-0.25) and 60 MW (N-0). Given that for all systems N-1 total rating is the same total ratings of three-and four-transformer systems are 45 and 40 MVA respectively. This means that three-transformer substation cannot supply load in cases of 52.5 and 60 MW loading. Similarly, four-transformer substation cannot supply load in cases 45 MW and above. The HV network reconfiguration is not considered and given that this would be a low cost option, it is expected to be used first. The conducted studies assume upgrade by adding a transformer feeder which would be broadly similar to the adding one substation with two transformers to alleviate capacity issues across two adjacent sites. The analysis assumes load shedding if transformers would be loaded beyond nameplate rating.

Table 2.12 shows breakeven VoLL for primary substations with transformer feeder cable of 1 and 5 km per each transformer. The values are given for two-, three- and four-transformer substations. The breakeven VoLL is the VoLL which results in the same overall cost if an additional transformer circuit is added. The upper value in Table cells is for the load profile with low load factor and lower value for the load profile with high load factor. It can be seen that breakeven VoLL is greater for load profile with low load factor. The breakeven VoLL is used to derive the optimal degree of redundancy.

Table 2.12: Breakeven VoLL (£/MWh) for EHV/HV substations

Redundancy (two-transformer substation)	Failure rate (%/year)	Two-transformer substation		Three-transformer substation		Four-transformer substation	
		Cable 1 km	Cable 5 km	Cable 1 km	Cable 5 km	Cable 1 km	Cable 5 km
N-1	Min	464,586 300,190	754,051 497,630	992,696 659,442	1,738,703 1,217,319	882,843 591,384	2,080,003 1,496,712
	Max	79,785 53,244	83,851 56,299	610,756 467,360	447,348 365,456	646,317 504,822	642,770 561,907
N-0.75	Min	114,889 80,500	172,099 122,439	99,982 76,724	146,846 113,289	76,575 60,620	146,450 123,647
	Max	47,382 32,485	45,280 30,517	74,287 58,840	66,923 51,900	55,669 47,289	61,857 53,908
N-0.5	Min	5,802 3,348	7,909 3,990	3,911 2,389	5,371 2,852		
	Max	3,571 2,305	3,295 1,830	2,504 1,654	2,326 1,313		
N-0.25	Min	2,903 290	3,180 0				
	Max	1,739 449	1,326 0				
N-0	Min	1,615 0	0 0				
	Max	1,094 0	110 0				

Table 2.13 shows breakeven VoLL for two-transformer primary substations with transformer feeder cable of 1 and 5 km. In case of a single outage and when the load is above rating of the remaining transformer circuit might trip on overload protection or overload might be detected by the operator and the load might be disconnected by remote control. The duration of reconnection of remaining transformer circuit of zero, 1 minute and 10 minutes are considered.

Table 2.13 Breakeven VoLL (£/MWh) for two-transformer EHV/HV substations for different duration needed to bring the load within the capacity

Redundancy	Failure rate	Transformer feeder cable 1 km			Transformer feeder cable 5 km		
		0	1 minute	10 minutes	0	1 minute	10 minutes
N-1	Min	464,586 300,190	464,586 300,190	464,586 300,190	754,051 497,630	754,051 497,630	754,051 497,630
	Max	79,785 53,244	79,785 53,244	79,785 53,244	83,851 56,299	83,851 56,299	83,851 56,299
N-0.75	Min	114,889 80,500	114,507 76,459	111,180 52,666	172,099 122,439	171,500 115,952	166,287 78,511
	Max	47,382 32,485	47,295 31,647	46,528 25,688	45,280 30,517	45,195 29,702	44,438 23,946
N-0.5	Min	5,802 3,348	5,787 3,304	5,662 2,953	7,909 3,990	7,890 3,938	7,719 3,520
	Max	3,571 2,305	3,564 2,280	3,495 2,070	3,295 1,830	3,287 1,809	3,223 1,639

Redundancy	Failure rate	Transformer feeder cable 1 km			Transformer feeder cable 5 km		
		0	1 minute	10 minutes	0	1 minute	10 minutes
N-0.25	Min	**2,903 290**	**2,890 286**	**2,778 251**	**3,180 0**	**3,166 0**	**3,043 0**
	Max	**1,739 449**	**1,732 443**	**1,671 396**	**1,326 0**	**1,320 0**	**1,273 0**
N-0	Min	**1,615 0**	**1,596 0**	**1,441 0**	**0 0**	**0 0**	**0 0**
	Max	**1,094 0**	**1,083 0**	**992 0**	**110 0**	**109 0**	**100 0**

It can be seen that the increase in the reconnection time decreases breakeven VoLL for degree of redundancy other than N-1. For example, breakeven VoLL in case of N-0.75, transformer feeder cable 1 km, and load profile with low load factor is £114,889/MWh if excess load is immediately disconnected and £111,180/MWh if excess load is disconnected and remaining transformer circuit, tripped on overload, reconnected within 10 minutes.

2.3 Optimal degree of redundancy for HV networks and primary substations

The results from Table 2.4 - Table 2.9 have been analysed to derive the optimal degree of redundancy for HV networks. This analysis determines the maximum loading of the networks before the upgrade can be justified and the results are shown in Table 2.14. The results are given for different initial feeder peak demands (demand groups), i.e. 500 kW, 2.5 MW, and 5 MW. The initial feeder peak demand is half the circuit capacity. Please note that there are 5 distribution transformers per feeder (see Figure 2.2).

Two VoLL thresholds are used, as in the previous tables, i.e. £17,000 and £34,000/MWh. The optimal degree of redundancy in Table 2.14 is coded for two values of VoLL separated with '/' as follow. For example, 0:0.25/0.25:0.5 means that the optimal degree of redundancy is between N-0.25 and N-0 for VoLL of £17,000/MWh and is between N-0.5 and N-0.25 for VoLL of £34,000/MWh. Upper values in Table cells are for load profile with low load factor and lower values for load profile with high load factor. The difference between optimal degrees of redundancy is up to about 0.5 to 0.75 for overhead networks and up to about 0.25 to 0.5 for underground networks for higher network loading. This implies that when the VoLL is 17,000/MWh, it will be justified to increase the load, for high load factor, by 75% (N-0.25) to 100% (N-0). If VoLL is £34,000/MWh, it will be justified to increase the load by between 50% (N-0.25) and 75% (N-0.25) before the upgrade is necessary. If there is no '/', the value is valid for both VoLL thresholds. At present, it is not uncommon for networks with multiple points of interconnection to have the peak loading in excess of 50% of the rating e.g. a peak loading of 2/3 the rating which is equivalent to N-0.67.

Table 2.14: Optimal degree of redundancy for HV networks; 'N-' term is omitted for simplicity

Construction	Failure rate (%/km.year)	MTT (hours) Restore/Repair	Feeder N-1 Peak Demand (kW) 500	2,500	5,000
Overhead	5	3/24	0 0	0 0:0.75/0.25:0.75	0 0.25:0.75/0.5:0.75
		6/24	0 0	0 0.25:0.75/0.5:0.75	0:0.25 0.5:0.75/0.5:1
		12/24	0 0/0:0.25	0/0:0.25 0.5:0.75/0.5:1	0:0.25/0:0.5 0.5:1/0.75:1
		24/24	0 0:0.25/0:0.5	0:0.25/0:0.5 0.5:1	0:0.5/0.25:0.5 0.75:1
		3/120	0 0	0 0.5:0.75	0:0.25 0.5:0.75/0.5:1
		6/120	0 0/0:0.25	0:0.25 0.5:0.75/0.5:1	0:0.25 0.5:1
		12/120	0 0:0.25	0:0.25 0.5:1	0:0.25/0.25:0.5 0.5:1/0.75:1
	20	3/24	0 0:0.25	0:0.25 0.5:1	0:0.25/0.25:0.5 0.5:1/0.75:1
		6/24	0 0:0.25/0.25:0.5	0:0.25/0.25:0.5 0.5:1/0.75:1	0.25/0.25:0.5 0.75:1
		12/24	0 0.25:0.5/0.5	0.25:0.5 0.75:1	0.25:0.5/0.5 0.75:1/1
		24/24	0/0:0.25 0.5:0.75	0.25:0.5/0.5:0.75 1	0.5:0.75 1
		3/120	0 0.25:0.5	0:0.25 0.5:1	0:0.25/0.25 0.5:1
		6/120	0 0.25:0.5/0.5	0:0.25/0.25:0.5 0.5:1	0.25:0.5 0.5:1/0.75:1
		12/120	0 0.5	0.25:0.5 0.75:1	0.25:0.5/0.25:1 0.75:1/1
Underground	2	3/24	0 0	0 0	0 0
		6/24	0 0	0 0	0 0
		12/24	0 0	0 0	0 0/0:0.25
		24/24	0 0	0 0:0.25	0 0:0.25/0.25:0.5
		3/120	0 0	0 0	0 0
		6/120	0 0	0 0	0 0
		12/120	0 0	0 0	0 0/0:0.25
	10	3/24	0 0	0 0	0 0/0:0.25
		6/24	0 0	0 0/0:0.25	0 0:0.25/0.25:0.5
		12/24	0 0	0 0:0.25/0.25:0.5	0 0.25:0.5/0.5:0.75
		24/24	0 0	0 0.25:0.5/0.5:0.75	0/0:0.25 0.5:0.75
		3/120	0 0	0 0:0.25	0 0:0.25/0:0.5
		6/120	0 0	0 0:0.25/0:0.5	0 0:0.5/0.25:0.5
		12/120	0 0	0 0.25:0.5	0/0:0.25 0.25:0.5/0.5:0.75

Table 2.15 shows optimal degree of redundancy for primary substations. The upper values in Table cells is for load profile with low load factor and lower values for load profile with high load factor. There is no observed impact on optimal degree of redundancy of load profile and transformer feeder cable length. For two- and three-transformer substations with greater circuit failure rate a bit greater optimal degree of redundancy is observed. This is not observed for four-transformer substation design. Given that N-0 denotes doubling of the peak load compared to N-1, three- and four-transformer optimal degree of redundancy is about the substation total installed rating. Impact of different VoLL is observed for two-transformer substations and greater failure rate. For the VoLL of £17,000/MWh the optimal degree of redundancy is between N-0.5:N-0.75 while for the VoLL of £34,000/MWh the observed optimal degree of redundancy is N-0.75.

Table 2.15: Optimal redundancy for EHV/HV substations; 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-0.75 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 2.16 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.

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 show 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.

Table 2.16: Optimal degree of redundancy for two transformer primary substations for different durations of 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 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.
- 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).

2.4 *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 system operation with smaller degree of redundancy. It can be expected that the number and duration of interruptions customers 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. Time-sequential Monte Carlo simulation is used for the evaluation of CI, CML and cost of ENS. Topology of the network is shown in Figure 2.2. Table 2.17 shows input parameters for four considered cases. The intention of this study is to illustrate the possible impact of different degree of redundancy on CI and CML performance.

Table 2.17 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	2	2	2
MTT Repair (hours)	24	24	24	24
MTT Restore (hours)	24	24	3	3
Least-cost loading level	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) at 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) to reduce 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 2.18 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].

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 2.18. 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

Table 2.19 shows the increase in expected values of CML (ΔCML) driven by reduction in redundancy. 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 2.19: 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 2.4. Blue curve is for N-1 degree of redundancy and orange for N-0.25.

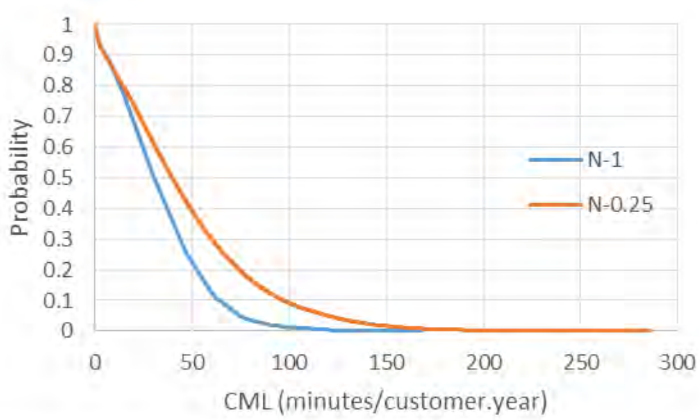

Figure 2.4. Cumulative probability of CML for case C and switching time of 30 minutes

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 2.18. Table 2.20 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 2.20. 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 in 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 2.17.

Table 2.21 shows the expected amount of energy not supplied and the corresponding 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. 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 2.21. Results of EENS for case A, B, C, and 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 reduced redundancy 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 whom 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 reduced redundancy 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 for affected customers increases from 0.108 to 0.200MWh per year, which represents 85% increase i.e. similar as demand increase. EENS due to reduced redundancy 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 application 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 for affected customers 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 2.5. The blue curve is for N-1 degree of redundancy while orange for N-0.25.

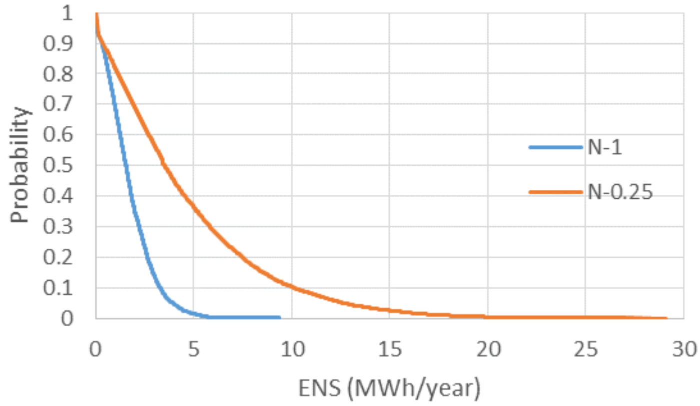

Figure 2.5. Cumulative probability of ENS for case C with switching time of 30 minutes

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 2.22 shows the probability of ENS exceeding expected and two times expected values.

Table 2.22. 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.

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

Figure 2.6 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.

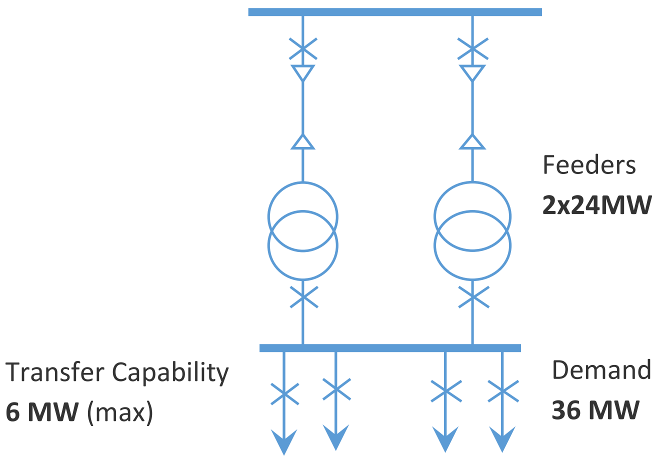

Figure 2.6. Dual-circuit transformer-feeder system

Component reliability parameters are given in Table 2.23. 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 2.7
- Load factor over summer maintenance period 58%
- Ratio of summer maximum demand to the all-year maximum demand 62/74=84%.

Table 2.23. 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

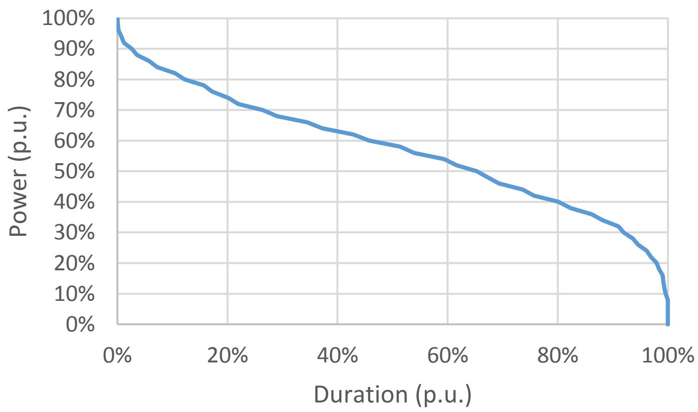

Figure 2.7. Normalised annual load duration curve

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 2.24.

Table 2.24. 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 2.8. Three identical primary substations, each one as in Figure 2.6, 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.

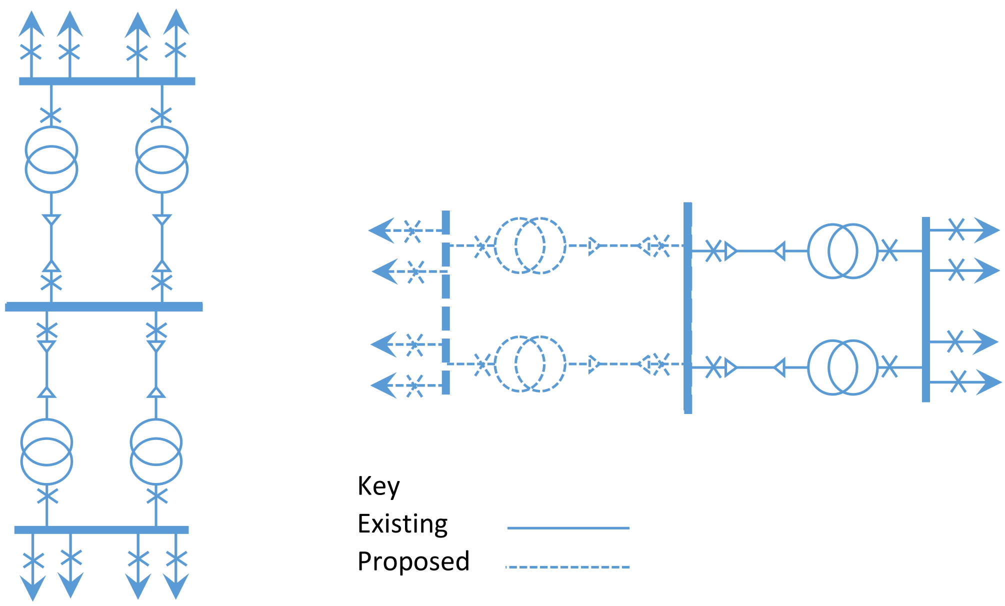

Figure 2.8. Schematic layout of 33/11 kV substations

The ACE 51 results are summarised in Table 2.25 for each of group load. Annuitized cost of reinforcement (calculated for 1975 prices), operation and maintenance is offset by the savings in system losses and cost of not deferring reinforcement for one year is obtained. Energy saved (MWh) per year is estimated from the reliability performance of the system 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 2.25. 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 2.24. Again, for comparison, in the pool based market in 1990 VoLL of £2,000/MWh was used.

2.6 *Optimal degree of redundancy for HV spur*

Another set of studies has been carried out on a HV spur network with an option to add a NOP backfeed connection in order to improve network reliability performance. The diagram of the network used in the study is depicted in Figure 2.9. The sensitivity of key parameters such as number of transformers per spur, peak demand per transformer, and MTTR on the optimal degree of redundancy has been investigated. The ranges of values used in the study for each parameter are presented in Table 2.26. Faults can occur in each section. This study investigates whether P2 is cost effective by estimating at which condition a spur should be backfed (N-1) as in Figure 2.2.

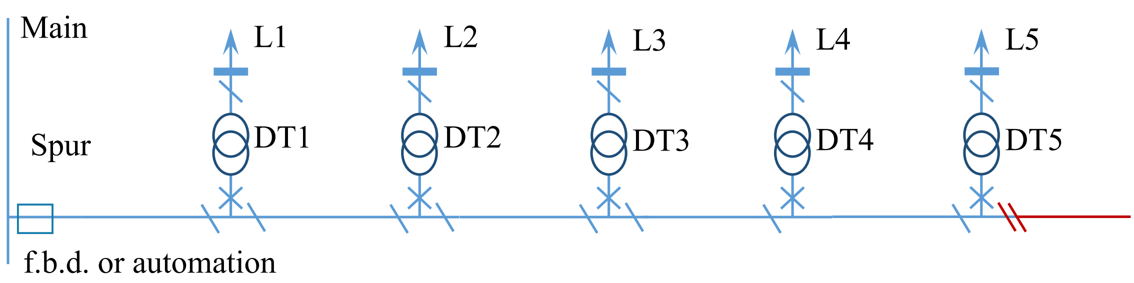

Figure 2.9: The topology of a HV spur used in the study with an option to improve security by adding a back-feed connection

Table 2.26: HV spur network case studies parameters

Parameter	Value
Type of network	Overhead and underground cables
Feeder rating (kW)	For N-0: equal to peak demand For N-1: equal to twice peak demand
Number of transformers per spur	1 and 5
Peak demand per feeder (kW)	50, 250, 1000 and 5000
Failure rate	For OHL: 5% and 20% For UGC: 2% and 10%
MTT Restore (h)	3, 12, 24, 120
MTT Repair (h)	24,120
VoLL (£/kWh)	17,000 and 34,000

In this study, the optimal level of redundancy is calculated by comparing the cost of increasing the redundancy by adding a NOP backfeed connection and its associated benefit computed as the saving in EENS (multiplied by the VoLL). The cost of NOP section includes the cost of spare switchgears in Ring Main Units (RMUs).

The results of the studies with VoLL at £17,000/MWh and £34,000/MWh are presented in Table 2.27. Similar to what we observe in the previous studies, it is found that the results are not sensitive to the section lengths as the cost and the failure rate increase linearly with the increase in length, which cancels out the effect of increasing section length.

Table 2.27: Optimal degree of redundancy for HV spur cases; 'N-' term is omitted for simplicity

Construction	Failure rate (%/km.year)	MTT (hours) Restore/Repair	Feeder Peak Demand (kW)			
			50	250	1,000	5,000
Overhead	5	3/24	0	0	0	0:1/1
		12/120	0	0	0:1/1	1
		24/24	0	0/0:1	1	1
		120/120	0/0:1	1	1	1
	20	3/24	0	0	0:1/1	1
		12/120	0	0:1/1	1	1
		24/24	0	1	1	1
		120/120	1	1	1	1
Underground	2	3/24	0	0	0	0
		12/120	0	0	0	0/0:1
		24/24	0	0	0	0:1/1
		120/120	0	0	0:1/1	1
	10	3/24	0	0	0	0/1
		12/120	0	0	0/0:1	1
		24/24	0	0	0:1/1	1
		120/120	0	1	1	1

The results demonstrate that in the majority of the cases, the optimal degree of redundancy for a HV spur network with relatively low demand is N-0 with the exception where the network reliability is relatively poor (high failure rate) and the MTTR is high. The optimal degree of redundancy shifts to N-1 when demand increases and at 5 MVA peak demand, the majority of the results shows the need to apply N-1 with the exception for underground network where the supply can be restored quickly.

Other findings are consistent with the studies using a generic HV configuration. The results emphasise the following trends observed in the previous studies:

- The degree of redundancy tends to increase in cases with: high VoLL, high failure rates, high MTTR (including cases without provision of mobile generation), high number of customers (reflected by peak demand), and low upgrade cost. Therefore, it is not surprising that that the number of cases for OH with higher degree of redundancy can be found higher than for UG considering that the reliability and the upgrade cost of OH networks are lower than the reliability and upgrade cost of UG networks. The results show that many cases of UG networks can be planned with N-0;
- The provision of mobile generation which enables rapid restoration of supply (MTTR of 3/24 h) allows the network to be operated with less degree of redundancy even if the failure rate is relatively high.
- N-1 as dictated by the present standards is appropriate, in general, for the cases with poor network reliability.

2.7 Optimal degree of redundancy for EHV networks

The same methodology has been applied to investigate the optimal degree of redundancy for EHV networks. The illustrative topology of the EHV network with up to 3 primary substations used in this study is shown in Figure 2.10. 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 rates, section lengths, 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 substation is also varied between 1 and 3 with, the configuration of the network being adjusted accordingly. The EHV networks do not typically service two or more primary substations form a pair of EHV feeders, rather these would i) supply four transformers from three feeders with further interconnection to other groups or ii) have an EHV ring system. Use of larger number of feeders would increase reliability of the network and hence savings in EENS would be smaller if network is upgraded. In addition, presence of larger number of feeders would increase cost for upgrade. The combined effect would mean increase in breakeven VoLL and optimal degree of redundancy would decrease further. Hence, the considered generic network configurations would produce conservative results regarding the levels of network redundancy.

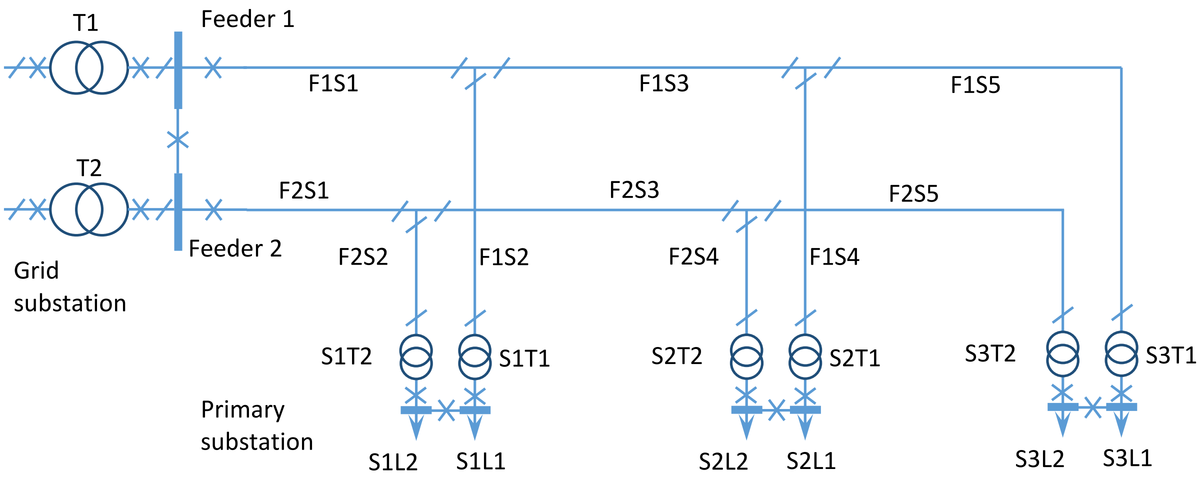

Figure 2.10: The topology of an EHV network with 3 primary substations used in the study

The ranges of values for each parameter used in the sensitivity study are presented in Table 2.28. There is a practical limit of about 45-50MVA that can be serviced by a 33kV cable i.e. it wouldn't be practical to service 3 x 20MW transformers via a single 33kV cable under FCO conditions. Technical limits might inform the final design of the network. However, in consideration of P2 review it is assumed that the standard is technology agnostic (as much as possible). In this context a wide range of parameters is considered. The studies assume that outages could occur in individual network components (sections, transformers, and busbars). Common mode failures are also considered (for example common-mode failure of parallel sections)

Table 2.28: EHV network case studies parameters

Parameter	Value
Type of network	Overhead and underground cables
Feeder rating (MW)	total peak demand
Number of primary substations	1,2 and 3
Peak demand per transformer (MW)	7.5 and 20
Failure rate	OHL 1 km: 2% and 15% UGC 1 km: 2% and 8% Transformer: 1% and 10% Transformer feeder maintenance: 1 per 8 years (9 hours close down time and 120 h outage duration) Busbar section: 0.1%

Parameter	Value
MTT Restore (h)	OHL: 12 UGC: 24 Transformer: 24 Busbar: 2
MTT Repair (h)	OHL: 120 UGC: 120 Transformer: 720 Busbar: 12
Section length (km)	Main: 4 km and 20 km Spur: 0 km and 10 km
VoLL (£/MWh)	17,000 and 34,000

It is assumed that the time to carry out network reconfiguration (of shown network) is within 10 min, and the load transfer via HV networks: 0, 10, 20 and 30% is within 10 min. Mobile generation is also available to restore the supply with the capacity of max 10 MW and it will be available within 4.5 hours on average. We also assume that a temporary cable can be laid or alternative supply or load transfer can be arranged to restore the supply after a transformer outage within 36 hours. The remaining interrupted supply and supply by mobile generation is restored in Mean Time to Restore by repairing asset in Urgent Repair Time. If all interrupted supply is restored and without use of mobile generation then Mean time to Repair is used which is the same as Average Repair Time. Underlying restore and repair time are modelled as distributions and hence Mean Time terminology is used.

In this study, the optimal level of redundancy is calculated by comparing the cost of upgrading the network and its associated benefit computed as the saving in EENS times the VoLL. The cost of upgrade includes the cost of network components involved, the cost of load transfer, mobile generation cost and the temporary cable laying cost, see Appendix B. Transformer upgrade cost is £400k, overhead line is £39-46k/km, underground cable £290k/km, cost of renting mobile generation £2,250/day, cost of temporary cable laying £125k.

The results of the studies with VoLL at £17,000/MWh and £34,000/MWh for the OH network are presented in Table 2.29 and Table 2.30 respectively, and for the UG network are presented in Table 2.31 and Table 2.32 respectively.

EHV overhead networks

Table 2.29 shows optimal degree of redundancy for EHV overhead networks. The difference between optimal degrees of redundancy for different load profiles could be up to 0.75 with lower values in case of load profile with low load factor. The greater load transfer the lower optimal degree of redundancy but the impact is not significant. The lower failure rates drive lower optimal degree of redundancy and similarly, the longer the network length the greater optimal degree of redundancy is observed. Greater loading drives greater optimal degree of redundancy. Length of spur section of the network drives greater degree of redundancy in case of greater failure rate and shorter main section of the network.

Table 2.29: Optimal degree of redundancy for EHV Overhead networks with VoLL of £17,000/MWh; 'N-' term is omitted for simplicity

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	Min	0 0.5:0.75	0 0.5:0.75	0 0.25:0.5	0 0.25:0.5	0:0.25 1	0:0.25 0.75:1	0:0.25 0.75:1	0:0.25 0.75
	14	Min	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25 1	0:0.25 0.75:1
	20	Min	0 0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0:0.25 1
	30	Min	0:0.25 0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 1
	4	Max	0:0.25 1	0:0.25 0.75:1	0:0.25 0.75	0 0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	14	Max	0.25:0.5 1	0:0.25 1	0:0.25 1	0:0.25 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20	Max	0.25:0.5 1	0:0.25 1	0:0.25 1	0:0.25 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	30	Max	0:0.25 1	0:0.25 1	1 1	1 1	0.25:0.5 1	0.25:0.5 1	0:0.25 1	0:0.25 1
2	4/0	Min	0 0.5:0.75	0 0.5	0 0.5	0 0.25:0.5	0.25:0.5 1	0.25:0.5 1	0.25:0.5 0.75:1	0.25 0.75:1
	4/0	Max	0.25:0.5 1	0.25 0.75:1	0:0.25 0.75:1	0:0.25 0.75:1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5 1
	4/10	Min	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20/0	Min	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.5:0.75 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20/10	Min	0:0.25 0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5:0.75 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	4/10	Max	0.25:0.5 1	0.25:0.5 1	0.25 1	0.25 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5 1
	20/0	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0:0.25 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20/10	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 0.75:1	0:0.25 0.75:1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
3	4/0	Min	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5	0 0.5	0.25:0.5 1	0.25:0.5 1	0.25:0.5 0.75:1	0.25:0.5 0.75:1
	4/0	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 0.75:1	0.25 0.75	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	4/10	Min	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20/0	Min	0:0.25 0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5 1	0.5 1	0.5 1	0.25:0.5 1
	20/10	Min	0.25 0.75	0:0.25 0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5 1	0.5 1	0.5 1	0.25:0.5 1
	4/10	Max	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	20/0	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.25:0.5 1	0.25:0.5 1
	20/10	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 0.75:1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1

The results show various degrees of redundancy that can be justified for EHV networks, 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. Again, this indicates the opportunity to utilise the overcapacity of the networks and accommodated increased peak load of such networks without upgrading the networks.

Several key observations can be made regarding the results presented in Table 2.29:

- The ability to transfer load improves the reliability performance and enables lower degree of redundancy to be justified. For example, in the first row (case no 1 of Table 2.29), the degree of redundancy decreases from N-0.5 (no load transfer capability) to N-0.25 (load transfer capability of 30%). This trend is 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 high 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 (in line with present standard).
- As expected, the networks with lower failure rates would be characterised by a lower degree of redundancy. For example the case with network section length of 4 km, no load transfer capability, and peak load of 7.5 MVA, the optimal degree of redundancy for the case with minimum and maximum failure rate scenarios are N-0.5 and N-1 respectively.

The optimal degree of redundancy for EHV overhead networks with the VoLL of £34,000/MWh for the sensitivity studies considered can be found in Table 2.30. Greater the VoLL drives greater optimal degree of redundancy and increase is between 0 and 0.25, i.e. the impact is not significant.

Table 2.30: Optimal degree of redundancy for EHV OH networks with the VoLL of £34,000/MWh; 'N-' term is omitted for simplicity

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	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25 1	0:0.25 0.75:1
	14, 20	Min	0:0.25 0.75	0:0.25 0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	30	Min	0:0.25 0.75	0:0.25 0.75	0 0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	4	Max	0.25 1	0.25 1	0:0.25 1	0:0.25 1	0.5:0.75 1	0.5 1	0.25:0.5 1	0.25:0.5 1
	14	Max	0.25:0.5 1	0.25:0.5 1	0.25 1	0:0.25 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20	Max	0.25:0.5 1	0.25:0.5 1	0:0.25 1	0:0.25 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1

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%
	30	Max	0:0.25 1	0:0.25 1	0:0.25 1	0:0.25 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0:0.25 1
2	4/0	Min	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	4/10	Min	0:0.25 0.75	0:0.25 0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0.5 1	0.5 1	0.25:0.5 1	0.25:0.5 1
	20/0, 20/10	Min	0.25 0.75:1	0:0.25 0.75:1	0:0.25 0.75	0 0.5:0.75	0.5:0.75 1	0.5:0.75 1	0.5 1	0.25:0.5 1
	4/0	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	4/10	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	20/0	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20/10	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
3	4/0	Min	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	4/10	Min	0.25:0.5 0.75:1	0.25 0.75	0:0.25 0.75	0:0.25 0.5:0.75	0.5 1	0.5 1	0.5 1	0.5 1
	20/0, 20/10	Min	0.25:0.5 0.75:1	0.25 0.75:1	0:0.25 0.75:1	0:0.25 0.75	0.5 1	0.5 1	0.5 1	0.5 1
	4/0	Max	0.5:1 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	4/10	Max	0.5:0.75 1	0.5:0.75 1	0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	20/0	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5 1
	20/10	Max	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1

The results presented in Table 2.30 are similar but tend to be characterised by a higher degree of redundancy compared to the ones in Table 2.29 due to higher VoLL threshold (£34,000/MWh). The results also indicate the range of optimal (economically efficient) degree of redundancy between N-0.5 and N-1 which highlights the possibility of loading the EHV networks higher for some cases where appropriate and provide evidences of the conservativeness of the present security standards.

EHV underground networks

The results of the studies carried out on the UG networks are presented in Table 2.31 and Table 2.32 for cases with VoLL of £17,000 and £34,000/MWh respectively.

Table 2.31 shows optimal degree of redundancy for EHV underground networks when the VoLL is £17,000/MWh. The impact of load profile on optimal degree of redundancy is significant and difference between optimal degrees of redundancy could be up to 0.5 to 0.75. Modest impact of load transfer is observed - up to 0.25. Furthermore, increase in optimal degree of redundancy driven by increase in loading is observed (about 0.25 to 0.5). Similarly, increase in the number of supplied primary substations increases 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 2.31: Optimal degree of redundancy for EHV UG networks with VoLL of £17,000/MWh; 'N-' term is omitted for simplicity

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	Min	0 0.25:0.5	0 0:0.25	0 0:0.25	0 0	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75
		Max	0 0.5:0.75	0 0.5:0.75	0 0.5	0 0.25:0.5	0.25:0.5 1	0.25 1	0:0.25 1	0:0.25 0.75:1
	14, 20, 30	Min	0 0.25:0.5	0 0.25	0 0:0.25	0 0	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75
	14, 20	Max	0 0.5:0.75	0 0.5	0 0.5	0 0.25:0.5	0.25 1	0:0.25 1	0:0.25 1	0:0.25 0.75:1
	30	Max	0 0.5:0.75	0 0.5	0 0.5	0 0.25:0.5	0:0.25 1	0:0.25 1	0:0.25 1	0 0.75:1
2	4/0, 4/10, 20/0 20/10	Min	0 0.25:0.5	0 0.25	0 0:0.25	0 0	0:0.25 0.75	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5:0.75
	4/0, 4/10	Max	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5	0 0.25:0.5	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 0.75:1
	20/0, 20/10	Max	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5	0 0.25:0.5	0.25:0.5 1	0.25:0.5 1	0.25 1	0:0.25 0.75:1
3	4/0, 4/10	Min	0 0.25:0.5	0 0.25:0.5	0 0:0.25	0 0:0.25	0:0.25 0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75
	20/0, 20/10	Min	0 0.25:0.5	0 0.25:0.5	0 0:0.25	0 0:0.25	0.25 0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75
	4/0	Max	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5	0 0.5	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 0.75:1
	4/10	Max	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5	0 0.5	0.5:1 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 0.75:1
	20/0, 20/10	Max	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5	0 0.5	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1

Table 2.32 shows optimal degree of redundancy for EHV underground networks when the VoLL is £34,000/MWh. An increase of optimal degree of redundancy between 0 and 0.25 is observed. The impact is not very significant.

Table 2.32: Optimal degree of redundancy for EHV UG networks with VoLL of £34,000/MWh; 'N-' term is omitted for simplicity

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	Min	0 0.5	0 0.25:0.5	0 0.25:0.5	0 0:0.25	0:0.25 0.75:1	0:0.25 0.75:1	0 0.75	0 0.5:0.75
	14, 20, 30	Min	0 0.5	0 0.25:0.5	0 0.25:0.5	0 0:0.25	0:0.25 0.75:1	0:0.25 0.75:1	0 0.75	0 0.5:0.75
	4	Max	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 1

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%
	14	Max	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25 1	0.25 1	0:0.25 1	0:0.25 1
	20	Max	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0:0.25 1	0:0.25 1
	30	Max	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0:0.25 1	0:0.25 1	0:0.25 1
2	4/0	Min	0 0.25:0.5	0 0.25:0.5	0 0.25:0.5	0 0:0.25	0:0.25 0.75:1	0:0.25 0.75:1	0:0.25 0.75	0:0.25 0.5:0.75
	4/10, 20/0, 20/10	Min	0 0.5	0 0.25:0.5	0 0.25:0.5	0 0:0.25	0:0.25 0.75:1	0:0.25 0.75:1	0:0.25 0.75	0:0.25 0.5:0.75
	4/0	Max	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5:0.75 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	4/10	Max	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20/0, 20/10	Max	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
3	4/0	Min	0 0.5	0 0.25:0.5	0 0.25:0.5	0 0:0.5	0.25:0.5 0.75:1	0.25 0.75:1	0.25 0.75:1	0:0.25 0.5:0.75
	4/10, 20/0, 20/10	Min	0 0.5	0 0.25:0.5	0 0.25:0.5	0 0.25:0.5	0.25:0.5 0.75:1	0.25:0.5 0.75:1	0:0.25 0.75:1	0:0.25 0.5:0.75
	4/0	Max	0.25 0.5:0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5 1	0.5 1	0.5 1	0.25:0.5 1
	4/10	Max	0.25 0.5:0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5:0.75 1	0.5:0.75 1	0.5 1	0.25:0.5 1
	20/0	Max	0.25 0.5:0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	20/10	Max	0.25 0.5:0.75	0:0.25 0.5:0.75	0:0.25 0.5:0.75	0 0.5:0.75	0.5:0.75 1	0.5 1	0.25:0.5 1	0.25:0.5 1

It is observer that UG networks are characterised by higher reliability and larger reinforcement cost compared to overhead networks, and hence the optimal redundancy levels for underground networks tend to be lower than those for the overhead networks. With the VoLL (£17,000/MWh), the optimal degree of redundancy varies between N-0 and N-1 for different cases. For cases with the peak load of 7.5 MW, the results vary between N-0 and N-0.75, but no case would justify N-1. For 20 MW peak load there are several cases where N-1 is justified, particularly in case of load profile with high load factor. It is important to highlight that even at the EHV level, where the system serves a relatively large number of customers, N-0 can still be justified in some cases while the present security standards require N-1 to be met.

The drivers for allowing a higher degree of redundancy are also consistent with findings from the studies discussed previously, such as high failure rates, and low network control capability (e.g. transferring loads to alternative healthy feeders). With higher VoLL (£34,000/MWh), higher degree of redundancy can be justified as shown in Table 2.32.

Bulk supply substations

An economically efficient degree of redundancy per bulk supply substation is investigated by comparing the cost of upgrade with savings in costs of interruptions. For illustration, the substation topology studies is similar to the one shown in Figure 2.3.

Rating of two-, three- and four-transformer bulk supply substations are 2x90MVA, 3x45MVA and 4x30MVA, respectively. It assumes the same N-1 rating of 90 MVA. Two failure rates of 1 and 10%/year are considered. Average repair cost is £1,000,000. Each transformer feeder cable is 5 km in length with considered failure rates of 2 and 8%/km.year and average repair cost of £50,000. Reliability parameters are summarised in Table 2.33. During an outage a load transfer of 20% is assumed that can be achieved within 10 minutes. It is assumed that mobile generators of total maximum capacity of 10 MW can be deployed on average within 4.5 hours. Maintenance is carried out every eight year with outage duration of 10 days and urgent maintenance close down time of 12 hours. In addition impact of disconnectors assuming failure rate of 0.1 and mean time to restore supply of 1.5 hours is considered. To estimate annual repair cost, the number of faults per year are estimated and multiplied by the average repair cost. It is assumed that the asset repair will be carried out urgently if there are unsupplied customers or mobile generation was used. Otherwise, repair would be carried within the average non-urgent repair times.

Table 2.33: Reliability related parameters used in the analysis

Asset	Failure rate (%/unit.year)	Urgent repair time (hours)	Average normal repair time (hours)	Repair cost (£'000)
132 kV underground cable (km)	2-8	48-120	120	50
132kV/EHV transformer	1-10	240	720	1,000
132 kV circuit breaker	0.53	24	48	
EHV circuit breaker	0.87	12	24	

Network cost used in the analysis is summarised in Table 2.34. More details are given in Appendix B.

Table 2.34: Substation cost

132kV/EHV Substation	Cost (£'000/year)	
	Cable 5 km	Cable 1km
2x90 MVA	993.5	353.5
3x45 MVA	1,076.7	356.7
4x30 MVA	1,251.8	398.5

Peak demand is increased from 90 (denoted as degree of redundancy N-1 using two-transformer paradigm), 112.5 (N-0.75), 135 (N-0.5), 157.5 (N-0.25) and 180 MW (N-0). Given that for all systems N-1 rating is the same, total ratings of three-and four-transformer systems are 135 and 120 MVA respectively. This means that three-transformer substation cannot supply load in cases of 157.5 and 180 MW loading. Similarly, four-transformer substation cannot supply load in cases 135 MW and above. In the analysis whenever asset rating is exceeded the load is shed. In practice, if loaded to these levels there would be a risk of the transformer / switchgear protection operating and disconnecting supplies to all customers.

Table 2.35 shows breakeven VoLL for bulk supply substations where length of transformer tail cable is 1 and 5 km. The values are given for two-, three- and four-transformer substations. The breakeven VoLL is the VoLL which results in the same overall cost if an additional transformer is added. The upper value in Table cells is breakeven VoLL for the load profile with low load factor and lower value for the load profile with high load factor. It can be seen that breakeven VoLL is greater for the load profile with low load factor. Breakeven VoLL for bulk supply substations with shorter transformer tail cables are lower given relatively high cable cost and hence greater reduction of upgrade cost compared to the savings in EENS.

Table 2.35: Breakeven VoLL (£/MWh) for 132kV/EHV substations

Redundancy (two-transformer substation)	Failure rate (%/year)	Two-transformer substation		Three-transformer substation		Four-transformer substation	
		Tail cable 1 km	Tail cable 5 km	Tail cable 1 km	Tail cable 5 km	Tail cable 1 km	Tail cable 5 km
N-1	**Min**	**155,136** **104,948**	**287,663** **201,902**	**239,485** **156,551**	**620,578** **413,467**	**174,937** **119,548**	**449,218** **323,786**
	Max	**41,857** **28,965**	**37,084** **26,187**	**321,820** **157,718**	**416,157** **179,503**	**241,940** **180,204**	**281,073** **234,703**
N-0.75	**Min**	**107,146** **71,107**	**216,065** **152,966**	**125,442** **81,411**	**297,222** **201,585**	**91,287** **64,327**	**216,453** **163,555**
	Max	**39,261** **26,684**	**35,991** **25,169**	**131,030** **57,877**	**150,099** **58,294**	**115,435** **77,040**	**136,524** **89,296**
N-0.5	**Min**	**11,016** **8,270**	**21,144** **17,668**	**4,879** **3,248**	**10,614** **8,639**		
	Max	**5,703** **4,129**	**6,505** **5,026**	**3,140** **2,026**	**4,116** **3,001**		
N-0.25	**Min**	**10,293** **3,576**	**20,228** **7,735**				
	Max	**4,888** **1,224**	**5,895** **1,899**				
N-0	**Min**	**7,032** **912**	**13,689** **2,237**				
	Max	**2,639** **296**	**3,593** **524**				

Table 2.36 shows optimal degree of redundancy for bulk supply substations. Optimal degree of redundancy for a two-transformer substation depends on the circuit failure rate, length of transformer tail cable, load profile and the VoLL. For greater failure rate the optimal degree of redundancy is greater for about 0 to 0.25 for shorter tail cable, and about 0.25 to 0.5 for longer tail cable. There is no significant difference observed for load profile except in case of longer tail cable and lower failure rate where difference is between 0.25 and 0.5. A small difference is observed for the VoLL of £34,000/MWh and lower failure rate, and relatively higher difference of about 0.25 to 0.5 for higher failure rate and load profile with high load factor. For

three- and four-transformer substations there is no observed impact of transformer tail cable length, failure rate and losses. The optimal degree of redundancy is about the total rating of such substation.

Table 2.36: Optimal degree of redundancy for bulk supply substations

Transformer tail 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

Summary

In summary, the economically efficient degree of redundancy for two-transformer substation is wide and range between N-0 and N-1 depending on the VoLL, substation reliability and cost of substation including repair cost. For three- and four-transformer substations the economically efficient degree of redundancy is between N-0.5 and N-0.75 i.e. close to the total substation rating.

2.8 Optimal degree of redundancy for 132 kV networks

Similar studies have also been carried out on a generic configuration of 132 kV network. The topology of the 132 kV networks is similar to the configuration of the EHV network where double transformer feeders feed two-transformer grid substations (see Figure 2.11). Similar assumptions to ones in Section 2.7 also apply. The sensitivity of key parameters such as the network construction (overhead or underground), failure rate, section length, loading and load transfer, and common-mode outages of parallel sections on the optimal degree of redundancy for 132 kV networks has been investigated. The ranges of values used in the study for each parameter are presented in Table 2.37.

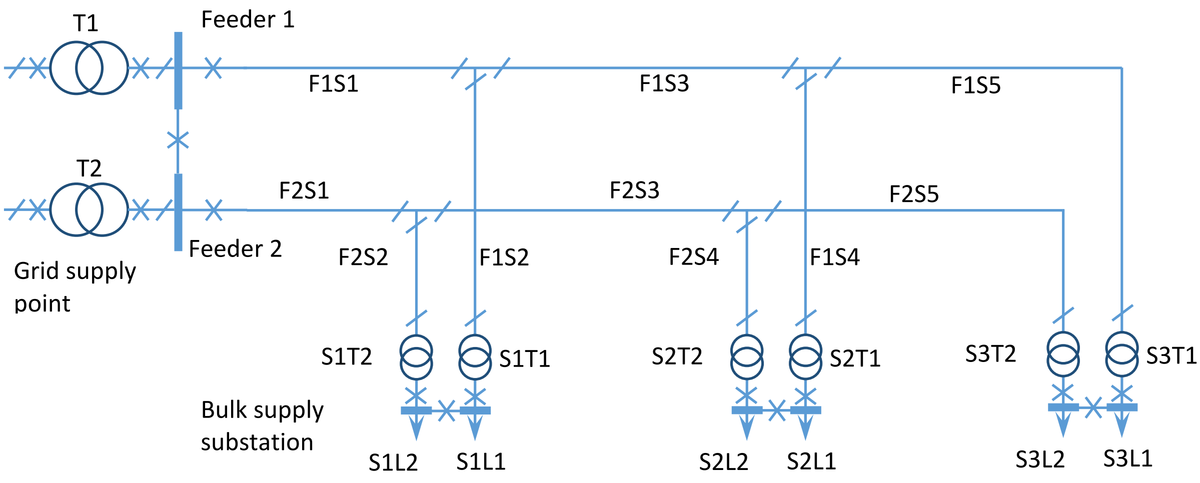

Figure 2.11: The illustrative topology of a 132 kV network with 3 bulk supply substations used in the study

The studies assume that outages can occur at the individual network components (sections, transformers, busbars) considering a single or multiple outages taking into account the common mode failures, for example common-mode failure of parallel sections.

Table 2.37: 132 kV network case studies parameters

Parameter	Value
Type of network	Overhead and underground cables
Feeder rating (MW)	total peak demand
Number of grid substations	1,2 and 3
Peak demand per transformer (MW)	22.5 and 45
Failure rate	OHL 1 km: 2% and 15% UGC 1 km: 2% and 8% Transformer: 1% and 10% Transformer feeder maintenance: 1 per 8 years (18 hours close down time and 240 h outage duration) Busbar section: 0.1%
MTT Restore (h)	OHL: 24 h UGC: 48 h Transformer: 240 h Busbar: 2 h
MTT Repair (h)	OHL: 120 h UGC: 120 h Transformer: 720 h Busbar: 12 h
Section length (km)	Main: 8 km and 30 km Spur: 0 km and 10 km
VoLL (£/MWh)	17,000 and 34,000

It is assumed that network reconfiguration (of shown network) can be carried out within 10 min including the load transfer via HV network of 0, 10, 20 and 30%. Mobile generation is also available to restore the supply with the capacity of max 10 MW and it will be available on average within 4.5 hours. It is important to highlight that the capacity of mobile generation may not be adequate to restore supply to disconnected load especially in the case when peak load is 45 MW. We also assume that a temporary cable can be laid within 36 hours to restore the supply after a transformer outage.

In this study, the optimal level of redundancy is calculated by comparing the cost of upgrading the network and its associated benefit computed as the saving in EENS times the VoLL. The cost of upgrade includes the cost of network components involved, the cost of load transfer, mobile generation cost and the temporary cable laying cost.

The results of the studies with VoLL at £17,000/MWh and £34,000/MWh for the OH network are presented in Table 2.38 and Table 2.39 respectively.

Table 2.38 shows the optimal degree of redundancy for 132 kV overhead networks when the VoLL is £17,000/MWh. The upper value in Table cells is optimal degree of redundancy for load profile with low load factor and the lower value for load profile with high load factor. The greatest observed difference between optimal degrees of redundancy is for single bulk supply substations supplied from a long transformer circuit where optimal degree of redundancy for load profile with low load factor is about N-0 and for load profile with high load factor is about N-1. The difference is typically between 0.5 and 0.75. Only a small dependency on loading level, load transfer, circuit length and failure rate, and number of connected bulk supply substations is observed.

Table 2.38: Optimal Redundancy, 132kV Overhead, VoLL £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	Min	0.25 1	0:0.25 1	0:0.25 0.75:1	0:0.25 0.75:1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 1
	18	Min	0.25:0.5 1	0.25 1	0:0.25 1	0:0.25 0.75:1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 1
	30, 40	Min	0.25:0.5 1	0.25 1	0:0.25 1	0:0.25 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 1
	8	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5 1	0.25:0.5 1	0.25:0.5 1
	18	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	30	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	40	Max	0.25:0.5 1	0:0.25 1	0 1	0 1	0.25:0.5 1	0.25:0.5 1	0:0.25 1	0:0.25 1
2	8/0	Min	0.25:0.5 1	0.25 1	0.25 0.75:1	0:0.25 0.75:1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	8/10	Min	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 1	0.5 1	0.5 1	0.25:0.5 1	0.25:0.5 1
	30/0, 30/10	Min	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25 1	0.5 1	0.5 1	0.25:0.5 1	0.25:0.5 1
	8/0	Max	0.5 1	0.5 1	0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	8/10	Max	0.5:0.75 1	0.5:0.75 1	0.5 1	0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	30/0, 30/10	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
3	8/0	Min	0.25:0.5	0.25:0.5	0.25:0.5	0.25	0.5	0.5	0.5	0.25:0.5

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	1	1	0.75:1	1	1	1	1
	8/10	Min	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5 1	0.5 1	0.5 1
	30/0	Min	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	30/10	Min	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5 1	0.5 1	0.5 1	0.5 1
	8/0	Max	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	8/10	Max	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	30/0	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	30/10	Max	0.5:0.75 1	0.5:0.75 1	0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1

Table 2.39 shows the optimal degree of redundancy for 132 kV overhead networks when the VoLL is £34,000/MWh. The impact on difference between optimal degrees of redundancy due to different load profiles is similar as in case of VoLL of £17,000/MWh.

Table 2.39: Optimal Redundancy, 132 kV Overhead, VoLL £34,000/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	Min	0.25:0.5 1	0.25:0.5 1	0.25 1	0:0.25 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	18	Min	0.25:0.5 1	0.25:0.5 1	0.25 1	0.25 1	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	30, 40	Min	0.25:0.5 1	0.25:0.5 1	0.25 1	0.25 1	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	8	Max	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	18	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	30	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	40	Max	0.25:0.5 1	0.25 1	0:0.25 1	0 1	0.25:0.5 1	0.25:0.5 1	0:0.25 1	0:0.25 1
2	8/0	Min	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5 1	0.5 1	0.5 1	0.5 1
	8/10	Min	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5 1	0.5 1	0.5 1	0.25:0.5 1
	30/0, 30/10	Min	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	8/0	Max	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	8/10	Max	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	30/0, 30/10	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
3	8/0	Min	0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.5 1	0.5 1	0.5 1	0.5 1
	8/10	Min	0.5 1	0.5 1	0.5 1	0.25:0.5 1	0.5:0.75 1	0.5 1	0.5 1	0.5 1
	30/0	Min	0.5:0.75	0.5	0.5	0.25:0.5	0.5:0.75	0.5:0.75	0.5:0.75	0.5:0.75

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	1	1	1	1	1	1	1
	30/10	Min	0.5 1	0.5 1	0.5 1	0.25:0.5 1	0.5 1	0.5 1	0.5 1	0.5 1
	8/0	Max	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	8/10	Max	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1
	30/0	Max	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1	0.25:0.5 1
	30/10	Max	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1	0.5:0.75 1

In most cases, the optimal degree of redundancy for 132 kV overhead network as shown in Table 2.38 and Table 2.39 is N-1 although there is a room to increase loading by 25% in a small number of cases, especially when load transfer capability is significant and failure rates are relatively small. In general, it can be concluded that the implementation of N-1 according to the present security standards for 132 kV overhead network is economically robust across the wide range of conditions analysed.

The results of the sensitivity studies for the 132kV underground networks for cases with the VoLL of £17,000 and £34,000/MWh are presented in Table 2.40 and Table 2.41 respectively.

Table 2.40 shows the optimal degree of redundancy for 132 kV underground networks if the VoLL is £17,000/MWh. As before, the upper value in Table cells is for load profile with low load factor and the lower value for load profile with high load factor.

We observe that in the case of one bulk supply substation with higher failure rate, high loading and with load transfer of 30%, optimal degree of redundancy for the load profile with low load factor is about N-0 while for the load profile with high load factor is about N-1. For lower failure rates the observed difference between optimal degrees of redundancy is lower and it is between 0.5 and 0.75. Only a small difference in range can be observed for different loading, network length and number of bulk supply substations.

Table 2.40: 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	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5	0 0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75
	8, 18	Max	0:0.25 1	0 0.75:1	0 0.75	0 0.75	0:0.25 1	0:0.25 1	0:0.25 1	0:0.25 1
	30, 40	Max	0:0.25 1	0 0.75:1	0 0.75	0 0.75	0:0.25 1	0:0.25 1	0:0.25 1	0 1
2	8/0, 8/10, 30/0 30/10	Min	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75	0 0.5	0:0.25 0.75	0 0.5:0.75	0 0.5:0.75	0 0.5:0.75
	8/0, 8/10	Max	0:0.25 1	0:0.25 0.75:1	0:0.25 0.75	0:0.25 0.75	0.25:0.5 1	0.25:0.5 1	0.25 1	0.25 1
	30/0, 30/10	Max	0:0.25 1	0:0.25 1	0:0.25 0.75:1	0 0.75	0.25:0.5 1	0.25 1	0.25 1	0:0.25 1

<table>
<tr><th rowspan="3">Number of grid substations</th><th rowspan="3">Section length (km)
Main/Spur</th><th rowspan="3">Failure rate</th><th colspan="4">Transformer peak loading 22.5 MVA</th><th colspan="4">Transformer peak loading 45 MVA</th></tr>
<tr><th colspan="4">Load transfer</th><th colspan="4">Load Transfer</th></tr>
<tr><th>0</th><th>10%</th><th>20%</th><th>30%</th><th>0</th><th>10%</th><th>20%</th><th>30%</th></tr>
<tr><td>3</td><td>8/0, 8/10, 30/0
30/10</td><td>Min</td><td>0
0.5:0.75</td><td>0
0.5:0.75</td><td>0
0.5:0.75</td><td>0
0.5:0.75</td><td>0:0.25
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0.75</td><td>0:0.25
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0.5:0.75</td></tr>
<tr><td></td><td>8/0</td><td>Max</td><td>0.25:0.5
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1</td><td>0.25
0.75:1</td><td>0:0.25
0.75</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
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1</td></tr>
<tr><td></td><td>8/10</td><td>Max</td><td>0.25:0.5
1</td><td>0.25
1</td><td>0.25
0.75:1</td><td>0:0.25
0.75</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
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<tr><td></td><td>30/0</td><td>Max</td><td>0.25
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0.75:1</td><td>0.25:0.5
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1</td><td>0:0.25
0.75:1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25
1</td></tr>
</table>

Table 2.41 shows the optimal degree of redundancy for 132 kV underground networks if the VoLL is £34,000/MWh. Similar difference between optimal degrees of redundancy is observed as for VoLL of £17,000/MWh.

Table 2.41: Optimal degree of redundancy for 132 kV UG networks with VoLL of £34,000/MWh; 'N-' term is omitted for simplicity

<table>
<tr><th rowspan="3">Number of grid substations</th><th rowspan="3">Section length (km)
Main/Spur</th><th rowspan="3">Failure rate</th><th colspan="4">Transformer peak loading 22.5 MVA</th><th colspan="4">Transformer peak loading 45 MVA</th></tr>
<tr><th colspan="4">Load transfer</th><th colspan="4">Load Transfer</th></tr>
<tr><th>0</th><th>10%</th><th>20%</th><th>30%</th><th>0</th><th>10%</th><th>20%</th><th>30%</th></tr>
<tr><td>1</td><td>8, 18, 30, 40</td><td>Min</td><td>0
0.5:0.75</td><td>0
0.5:0.75</td><td>0
0.5:0.75</td><td>0
0.5:0.75</td><td>0:0.25
0.75:1</td><td>0
0.75:1</td><td>0
0.75:1</td><td>0
0.5:0.75</td></tr>
<tr><td></td><td>8, 18</td><td>Max</td><td>0:0.25
1</td><td>0:0.25
1</td><td>0:0.25
1</td><td>0
0.75:1</td><td>0.25:0.5
1</td><td>0.25
1</td><td>0.25
1</td><td>0:0.25
1</td></tr>
<tr><td></td><td>30, 40</td><td>Max</td><td>0:0.25
1</td><td>0:0.25
1</td><td>0:0.25
1</td><td>0
0.75:1</td><td>0.25
1</td><td>0.25
1</td><td>0:0.25
1</td><td>0:0.25
1</td></tr>
<tr><td>2</td><td>8/0, 8/10, 30/0
30/10</td><td>Min</td><td>0:0.25
0.75</td><td>0
0.5:0.75</td><td>0
0.5:0.75</td><td>0
0.5:0.75</td><td>0:0.25
0.75:1</td><td>0:0.25
0.75:1</td><td>0:0.25
0.75:1</td><td>0:0.25
0.75</td></tr>
<tr><td></td><td>8/0, 8/10</td><td>Max</td><td>0.25:0.5
1</td><td>0.25
1</td><td>0.25
1</td><td>0:0.25
0.75:1</td><td>0.25:0.5
1</td><td>0.25:0.5
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<tr><td></td><td>30/0, 30/10</td><td>Max</td><td>0.25
1</td><td>0.25
1</td><td>0:0.25
1</td><td>0:0.25
0.75:1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25
1</td><td>0.25
1</td></tr>
<tr><td>3</td><td>8/0, 8/10, 30/0
30/10</td><td>Min</td><td>0:0.25
0.75</td><td>0:0.25
0.75</td><td>0:0.25
0.5:0.75</td><td>0
0.5:0.75</td><td>0.25:0.5
0.75:1</td><td>0.25
0.75:1</td><td>0:0.25
0.75:1</td><td>0:0.25
0.75:1</td></tr>
<tr><td></td><td>8/0</td><td>Max</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25
0.75:1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td></tr>
<tr><td></td><td>8/10</td><td>Max</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25
0.75:1</td><td>0.5
1</td><td>0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td></tr>
<tr><td></td><td>30/0</td><td>Max</td><td>0.25:0.5
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1</td><td>0.25:0.5
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1</td></tr>
<tr><td></td><td>30/10</td><td>Max</td><td>0.25:0.5
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1</td><td>0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td><td>0.25:0.5
1</td></tr>
</table>

The range of optimal redundancy for 132 kV underground network as shown in Table 2.40 and Table 2.41 varies between N-0.5 and N-1 depending on several key parameters, such as network reliability and load transfer capability. The results are less sensitive to the length of the main and spur feeders.

From the results, it can be concluded that higher degree of redundancy is generally required in a system with higher peak demand, longer section length (which implies higher failure rate), lower load transfer capability (or slower restoration from mobile units) and higher VoLL. As underground 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 than for the overhead networks. The results indicated that there is an opportunity for increasing the loading of the 132 kV assets through reducing its degree of redundancy, which is driven by the high reliability of the underground networks and high upgrade costs.

2.9 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 technologies[3] [161].

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 2.42. The number of primary transformers is estimated from the Regulatory Reporting Pack [163].

Table 2.42: 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

[3] Electric Vehicles (EVs) Heat Pumps (HPs)

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, 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)[4]. 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 2.43 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 2.43. 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 some part of the network would need to be upgraded even

4 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.

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.

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[5].

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 2.44 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 2.44. 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**

[5] We emphasise that this analysis does not consider asset condition based replacements.

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.

2.10 Conclusions

We have analysed a spectrum of cases to identify the cost effectiveness of the present network design standard with the objective is to identify whether in the short-term, it would be economically efficient to upgrade the network following the present security standard or further enhance the utilisation of the existing networks and delay network reinforcement.

According to London Economics study 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 lower level of redundancy than proposed in the 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?".

The key findings of our studies can be summarised as follows:

- 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 2.43 and subsequent paragraphs. For more details see Section 2.9.

- The optimal level of network redundancy is case specific, depending on many parameters (reliability characteristics, investment cost, cost of supply interruptions[6], 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. N-0 may not drive increase in cost of maintenance if this is carried out during off peak condition, as primary substation would have 2 transformers given present N-1 standard. Even if standby generation would is used, the corresponding increase in cost would not justify network reinforcement and increase in network redundancy.
- 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.
- 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.
- 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 2.4). Table 2.45 show the estimated increase of CI and CML if the N-1 requirement is relaxed. Detailed discussion can be found in section 2.4. 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 *both* in customers supply interruption duration as well *as severity of the outage*. Frequency of interruptions strictly does not change. Given the greater impact of reduced redundancy on EENS the associated cost would also

[6] 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.

increase more than increase in cost associated with CML. In this context, approach used will produce conservative results regarding the optimal level of redundancy.

Table 2.45: Increase of CI and CML if the P2/6 N-1 design requirement is relaxed

Case	∆ CI	∆CML
A	0.3	1.7
B	3.3	22.2
C	13.2	18.9
D	5.9	8.3

- Table 2.46 shows the economically efficient range of optimal degree of redundancy for primary and bulk supply substation with different number of transformers for different cases, in contrast to the present P2 standard that requires N-1 degree of redundancy. It can be concluded that the present standards do not recognise the opportunity to increase loading of networks in some cases although the standards may be appropriate for other cases.

Table 2.46: The range of optimal degree of redundancy needed at various voltage levels; N-0 denotes double loading of N-1

Voltage level		Primary substation	Bulk supply substation
Economically efficient degree of redundancy for two, three and four-transformer substation	2	N-0:N-0.75	N-0:N-0.75
	3	N-0.5:N-0.75	N-0.5:0.75
	4	N-0.75	N-0.75

The results in Table 2.46 show that it might be economically beneficial to utilise transformers to their rated capacity especially for three and four transformer substations. The optimal degree of redundancy is also driven by the customer perception on the value of security (VoLL) and therefore, a higher VoLL tends to lead to a higher degree of redundancy. Before upgrading substation a solution which mitigates common-mode faults might need considering if not already installed, such as double busbars configuration.

At the GB level, the potential net benefit of avoiding security-driven network investment that could be achieved varies between £4 billion and £7 billion depending on the degree of redundancy as shown in Table 2.43. Very high deployment of low-carbon technologies does not necessary result in high savings. Given high deployment a distribution system may need upgrading anyway, as shown in updated report. IC report consider “Delayed Electrification” (DE) pathway which is comparable with FES scenario. Importantly in scenario with lower level of low-carbon technologies deployed, higher savings are observed. For higher penetration of LCT network might need upgrading anyway even if N-1 condition is relaxed.

2.11 Appendix: Customer Interruption Cost (CIC) and Value of Lost Load (VoLL)

Historically, electricity networks are planned on the basis that all consumers place the same value on continuity of supply and use of their appliances when required. Furthermore, it has been assumed that the continuity of supply is binary: electricity supply is 100% available under normal operating conditions (all devices can be used) or not at all under outage conditions (none of the devices be used). This historic approach is usually characterised by valuing avoided interruptions using a single value of lost load (VoLL), which is widely recognised as an oversimplification. First of all, the estimation of VoLL is subject to considerable uncertainty, driven by the fact that the damage caused by interruptions is different for different classes of consumers, different locations, and different times of the year, week and day. Furthermore, smart metering coupled to in-home energy management devices could change the way customers value supply continuity through facilitating reliability-based consumption choices. By setting design standards that allow networks to be planned in accordance with the differing priorities of different categories of in-house demand, it may be possible to develop and operate networks at lower costs to customers.

Significance of CIC and VoLL

The basis of network planning standards lies in balancing the network investment cost against the customer interruption cost (CIC) in order to identify network capacity levels minimising the total expenditure. This network planning process is illustrated in Figure 2.12. As the level of network capacity and redundancy increases, reliability of supply for the served customers is increased (i.e. customer interruption costs are decreased) at the expense of higher network investment costs. The optimal network capacity achieves the best trade-off between these two cost components. The CIC can be quantified through different measures, such as the cost per interruption (£/interruption), and the Value of Lost Load (VoLL) (£/MWh), representing the estimated value a consumer puts on an unsupplied unit of energy.

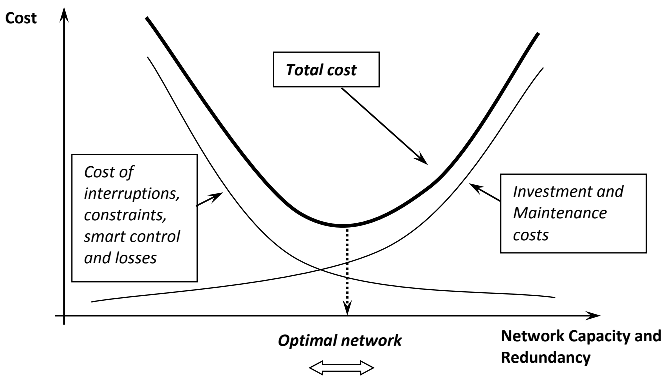


Figure 2.12: Balancing of network investment costs against customer interruption costs for network planning

A large number of studies have employed different approaches to quantify the CIC for different categories of consumers. However, general consensus on the value of CIC has not been yet achieved, as the values proposed by different sources vary significantly. The main reason is that CIC depends on a large number of diverse factors, the cost implications of which cannot be unambiguously quantified even by the consumers themselves. These factors include the activities affected by unsupplied energy, the timing (time of day, day of week, month of year) of the supply interruption, the duration of the supply interruption, the frequency of interruptions and the availability of advance warning before the interruption takes place. The dependency of the interruption costs on the duration of the interruption is captured by the customer damage function (CDF). The CDF represents the value a consumer puts on an unsupplied unit of energy (y-axis) as a function of the duration of interruption (x-axis).

This lack of consensus is aggravated by the fact that CIC have been quantified in different currencies and different years in the past, introducing significant difficulties in comparative analysis. This lack of consensus gives network planners a great deal of freedom in their choice of the CIC parameters for system models. The final selection might be based on averaging different available values or on the values giving the "most sensible" results.

Methodologies for VoLL quantification

Various methodologies have been employed in an effort to quantify the VoLL [46] and these are summarised below:

- *Ratio of Gross Economic Output to Energy Consumption (EO/C)* is a very rough estimate of VoLL and it is calculated by dividing a gross economic measure by the total energy consumed,
- *Customer surveys* (CS) provide the evaluation of the statistically significant VoLL by different customer sectors from data provided directly by the end users,
- *Amalgamated Customer Surveys (ACS)* combine multiple sets of survey data from various regions of a country,
- *Mapped Customer Surveys (MCS)* approach maps data from one country and modify it to suit the context of another country,
- *Black Out Case Study (BOCS)* approach is mainly the post-event analysis of blackouts providing more detailed cost estimates.

As discussed in [46] EO/C approach is simple to use given it uses readily available data but it does not account for all drivers. CS is the preferred approach but it is the high cost and time demanding. ACS is less expensive and less time demand than CS but only captures common key features and lose regional differences. MSC might not capture differences between countries. BOSC provide more detailed cost estimates but findings are limited to the geographic region and to the characteristics of the considered outage.

Examples of VoLL quantification

The published key CIC data summarised in [46] are from Canada [1]-[11], USA [12]-[16], Austria [17]-[18], Denmark [19], Finland [19], Netherlands [20], Norway [21], Iceland [19], Italy [22], Ireland [23], Spain [24], Sweden [25]-[27], Germany [28] and United Kingdom [29]-[33]

are tabulated in the next Section. Additional information could be found in [34]-[38] and for another jurisdictions in [39]-[43]. European guidelines for estimating cost of interruptions can be found in [44]-[45]. A literature survey of consumer interruption cost is presented in [46]-[47]. Customer survey design is described in [48]-[57].

The survey presented by Kariuki and Allan [29] is based on a Preparatory Action survey of British Regional Electricity Company areas (Table 2.47). For Large Users (consumers with demand of at least 8 MW), the cost of an interruption lasting 20 minutes is only slightly higher than the cost of a momentary interruption (<1sec). The industrial processes of these users can be interrupted by a very short outage, and it can take a significant amount of time to restore operations after power supply is restored. As a result, interruptions costs are fairly insensitive to the duration of the outage. Table 2.47 shows four customer damage functions adopted from UK Survey [29] and all values are indexed by RPI-X [58] for 2012. The function represents the cost per unit peak demand of load point according to various demand sectors and outage durations.

Table 2.47: UK Survey [29]

Time	Customer damage function (£/kW)			
	Residential	Commercial	Industrial	Large user
momentary	0.27	1.76	10.95	12.00
1 minute	0.27	1.82	11.51	12.00
20 minutes	0.27	6.92	25.40	12.21
1 hour	0.96	18.95	44.96	12.78
4 hours	6.62	69.48	128.53	15.77
8 hours	14.17	139.98	213.76	17.28
24 hours	44.35	177.94	267.63	23.76

Kariuki and Allan [29] use the results of a UK Survey to convert the customer interruption cost (given in £ per interruption) into a customer damage function (given in £/kW peak and £/MWh demand). Both parameters are given as a function of the interruption duration. It is suggested that this is contrary to the concepts of 'implied cost per kilowatt-hour saved' and VoLL. However, they have identified an expected VoLL of £19,363/MWh across all outage durations with VoLL for a one-hour interruption being £32,480/MWh.

Recent report by London Economics [33] estimate the VoLL for domestic, small and medium sized enterprises (SME) and industrial and commercial (I&C) electricity users. They estimate the VoLL in terms of willingness-to-accept (WTA) payment for an outage and willingness-to-pay (WTP) to avoid an outage. The WTA estimates are larger than the respective WTP estimates, since customers desire a larger monetary amount in order to bear a loss of supply than the one they are willing to pay to retain it. For domestic customers, the statistically significant estimate of the VoLL ranges from £1,651/MWh (WTP) to £11,820/MWh (WTA) for a one hour electricity outage during Winter Peak conditions with a headline figure of £10,289/MWh. For SME the respective range is from £19,271/MWh (WTP) to £39,213/MWh (WTA) for all conditions with a headline figure of £35,488/MWh and for I&C customers the overall value is about £1,400/MWh. They have derived the load-share weighted average VoLL across domestic and small and medium enterprise users for winter, peak, and weekday as £16,940/MWh. The summary is shown in Table 2.48.

Table 2.48: Headline VoLL in £/MWh [33]

Domestic customers	Small and medium enterprise (SME)	Load-share weighted average across domestic and SME	Industrial and commercial
10,289	35,488	16,940	1,400

Headline VoLL is based on an average single customer and as such applied by DECC and Ofgem. However, there is not established consensus on whether VoLL should be a function of customer numbers among world experts in this area. Basing it on a single customer simplified application while if based on customer numbers might better capture severity of an outage. This report considers a sensitivity of VoLL with a value of £34,000/MWh and hence the effect of basing VoLL on customer numbers could be estimated.

The section 2.12 presents a detailed list of studies on the quantification of the VoLL along with the adopted methodology and the identified values of VoLL.

Impact of CIC models on network planning

Models to allow a range of alternative approaches to costing interruptions are developed such as (i) the value of interruptions is simply at VoLL, (ii) the valuation of avoided interruptions is represented by a customer damage function such that value depends on the customer type(s) affected and duration of the outage. The Monte Carlo simulation approach, see section 13.2, is used to assess cost of interruptions in terms of expected values and distributions.

Constant VoLL and duration dependent VoLL

To understand the nature of the value customers might place on interruptions, different customer damage functions (CDFs) are considered, representing the cost per unit of unserved energy as a function of the interruption duration:

- CDF0: Constant value £17,000/MWh (headline value of the VoLL for load-share of residential and small and medium enterprise customers [33])
- CDF1: Constant value £10,289/MWh (headline value for residential customers [33])
- CDF2: Constant value £35,488/MWh (headline value for small and medium enterprise customers [33])
- CDF3: Linearly increasing without capping starting from 0, reaching £54,000/MWh for a duration of 18 hours and continuing further
- CDF4: Linearly increasing without capping starting from 0, reaching £108,000/MWh for a duration of 18 hours and linearly increasing at a slower rate by adding £54,000/MWh for each additional day

- CDF5: Linearly increasing starting from £13,500/MWh, reaching £54,000/MWh for a duration of 18 hours and linearly increasing further without capping.

Figure 2.13 illustrates the curves of customer interruption cost corresponding to CDF0 - CDF5 during the first 24 hours of an interruption.

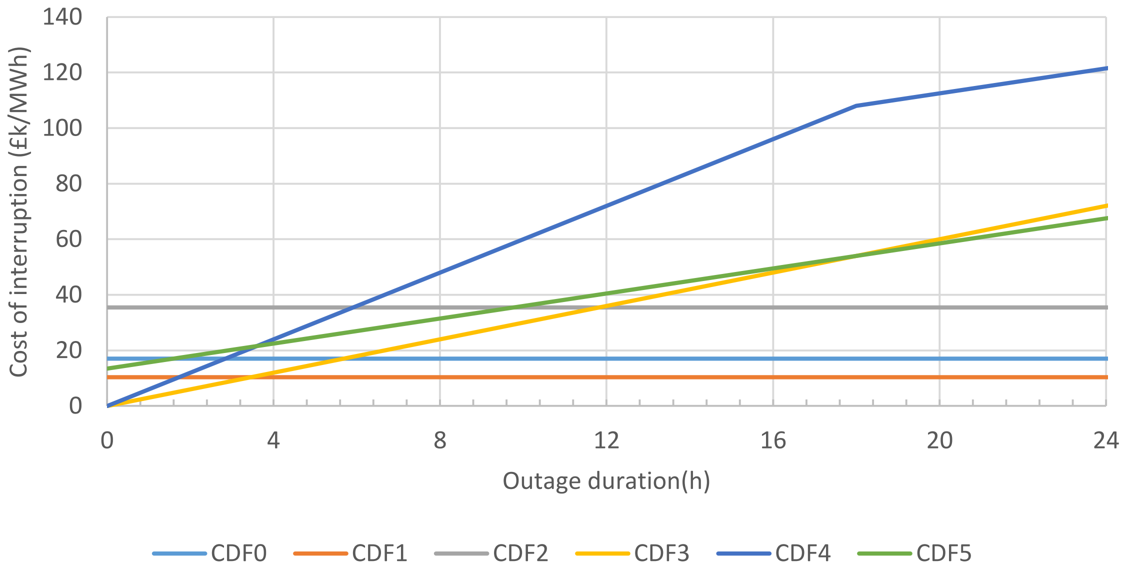


Figure 2.13 Generic customer interruption costs for constant and duration dependent VoLL

Customer damage functions

Customer damage functions presented in [29] are used for this analysis. For these customer damage functions, Table 2.49 shows expected VoLL per sector and for outage durations of 60 and 1000 minutes [29] which is indexed by RPI. It can be seen that VoLL for residential customers increases with duration increase while for other customer types VoLL decreases.

Table 2.49. Sector VoLL (£/MWh) [29] indexed by RPI

Sector	60 minutes outage duration	1000 minutes outage duration
CDF6 residential	2,990	5,610
CDF7 commercial	47,376	30,848
CDF8 industrial	89,912	34,425
CDF9 large user	19,185	2,143

When computing the customer interruption cost using customer damage functions, even though the writers in the original paper stated interruption cost is found unrelated with the amount of unserved energy, in this study the proportion of customer disconnected at a load point is calculated by weighting the power not supplied over the load demand.

Case studies

This section introduces the configuration of the test radial distribution network shown in Figure 2.14. The HV network is connected to an EHV network through a primary substation which is usually composed of bus-bars, 33-11kV transformers and circuit breakers (CB). Following the fault on a feeder section, the switching actions will be carried out to isolate the faulty line by opening the corresponding switchgears and the affected load points can be resupplied by the adjacent branch.

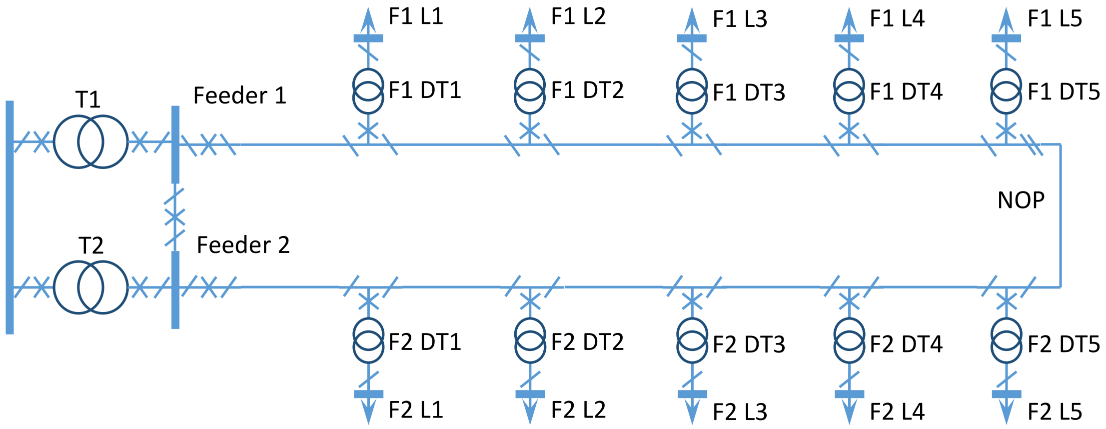


Figure 2.14: An example of radial HV distribution network

Time-sequential Monte Carlo simulation is applied with the test network for conducting the evaluation of customer interruption costs using input parameters shown in Table 2.50.

Table 2.50 Case study parameters for CIC evaluation, HV level

Parameters	Values
Failure rate for overhead lines (%/km.year)	8.4
Switching time (minutes)	30
Normal repair time (hours)	120
Restoration time (hours)	3 and 24
Section length (km)	1
Peak demand of each load point (MW)	500, 625, 750, 875, 1000
Loading level	N-1, N-0.75, N-5, N-0.25, N-0
Feeder capacity (MVA)	5

Figure 2.15 shows the customer interruption cost calculated using different CDFs. It can be observed that for less network redundancy, customer interruption costs increase with all CDFs since system EENS is increasing. Costs corresponding to CDF0 to CDF2 (constant VoLL) are increased more than 4 times when redundancy decreases from N-1 to N-0, same as EENS. Costs corresponding to CDF8 have increased for about 3 times and the greatest increase is for CDF4 followed by CDF3. Costs corresponding to CDF6 to CDF9 increase as system redundancy decreases even though the costing using these methods is not related to unserved energy. This indicates that the duration of outages is increasing as redundancy decreases. The cost to residential, CDF6, customers is lower than that to commercial,

industrial or large users, CDF7, CDF8 and CDF9, respectively. The cost to commercial sectors is lower than that to larger users for N-1 redundancy but higher for N-0 redundancy which might indicate that commercial customers will be affected more by longer outages than large users.

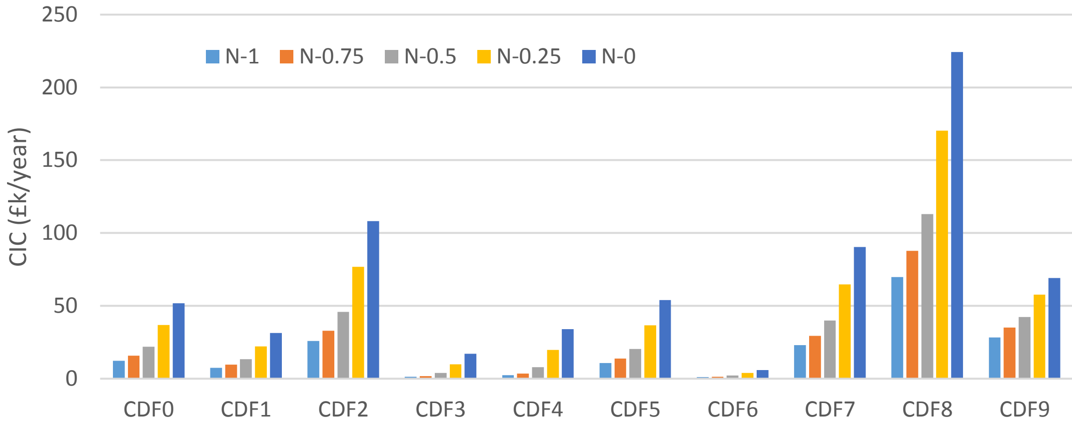


Figure 2.15 Customer interruption cost with constant and outage duration dependent VoLL, HV level

Table 2.51 presents the interruption costs corresponding to the different CDF as a percentage of the costs corresponding to the use of a constant VoLL of £17,000/MWh.

Table 2.51: Interruption costs corresponding to different CDF as a percentage of costs corresponding to VoLL=£17,000/MWh

Redundancy	CDF0	CDF1	CDF2	CDF3	CDF4	CDF5	CDF6	CDF7	CDF8	CDF9
N-1	100%	61%	209%	10%	20%	87%	8%	186%	565%	229%
N-0.75	100%	61%	209%	11%	22%	88%	9%	186%	556%	222%
N-0.5	100%	61%	209%	18%	36%	93%	10%	181%	514%	192%
N-0.25	100%	61%	209%	27%	54%	100%	11%	176%	463%	157%
N-0	100%	61%	209%	33%	66%	104%	12%	174%	432%	133%

The percentages corresponding to CDF0-CDF2 remain constant with the redundancy level given that these CDF are constant with the interruption duration. The percentages corresponding to CDF3 and CDF4 increase about 3 times as the level of redundancy decreases from N-1 to N-0. The percentage for CDF5 increases about 20%. The percentage value for CDF6, representing residential customers, increases about 50%, while the percentage value for CDF7 to CDF9, representing commercial, industrial and large users respectively, decreases.

Evaluation of the expected values of the key indices based on Markov models and also their distributions through full sequential Monte Carlo based models was used to derive equivalent VoLLs form different Customer Damage Functions. 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, and to estimate the least-cost redundancy levels. This enabled equivalent cost of interruption to be compared with the cost of interruption when the central VoLL of £17,000/MWh, adopted by the UK government for the Electricity Market Reform, is applied. In order to assess the robustness of findings, the optimal degree of redundancy is also estimated for higher VoLL of £34,000/MWh) with lower values of VoLL driving lower optimal degree 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.

Customer damage function is appropriate approach and we have analysed a set of different customer damage functions, expressing the dependency of the cost of interruptions on their duration and unserved energy. 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 VoLL. For various CDFs estimated equivalent VoLL might be lower than values used in the report. This will lead to lower optimal degree of redundancy. In that sense results in this report are conservative. Possible smart demand shedding could 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 correspond to different customer damage functions).

The cost of interruption is dependent on the supply interruption duration. Figure 2.16 shows the probability density function for the supply interruption of the customers supplied from the first distribution transformer on a feeder per event. Y-axis represents probability of particular supply interruption duration occurring.

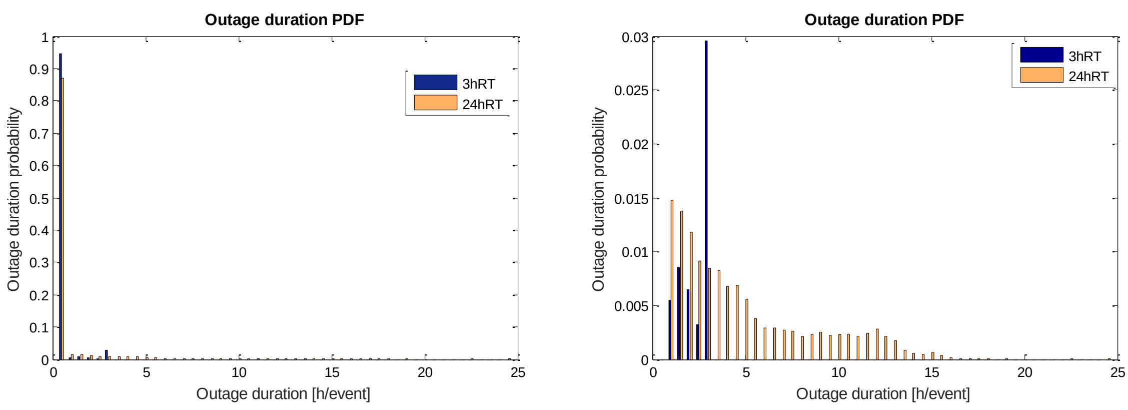
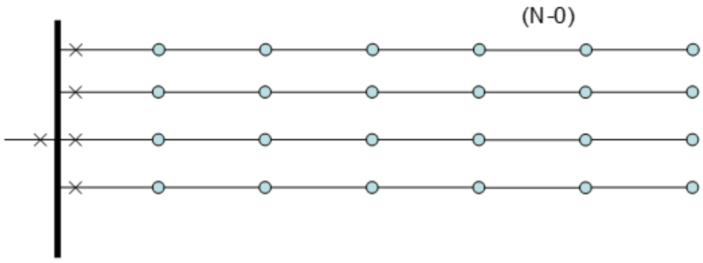


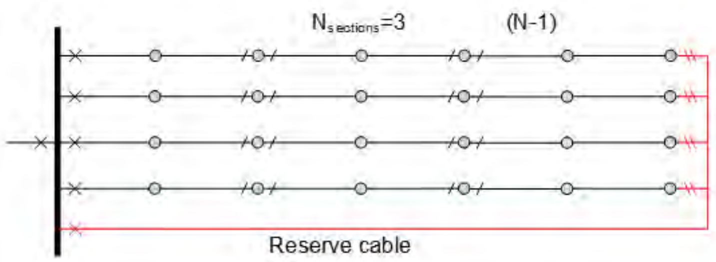
Figure 2.16: Probability density function of supply interruption duration for the customers supplied from the first distribution transformer on a feeder; all outages (left) and without switching related outages (right).

The probability density function of interruption duration is shown for restoration times of 3 and 24 hours. The majority of outages are restored within one hour. When mobile generation is deployed there are also relatively high outage durations lasting about three hours. In case that restoration time is 24 hours there are also significant probability of outages lasting more than 3 hours.

The selection of customer interruption cost parameters can have a profound impact on the planning solution. In the analyses of this report the VoLL of £17,000/MWh is used. This is a conservative value compared to CDFs 1, 3, 4, and 6. Use of those CDFs would result in lower optimal degree of redundancy. Use of CDF 5 would results in similar degree of redundancy. Use of other CDFs might results in a greater optimal degree of redundancy. For sensitivity purposes we have used the VoLL of £34,000/MWh. In some cases this has resulted in a greater optimal degree or redundancy and in the other in broadly the similar optimal degree of redundancy given the ‘steep’ increase of breakeven VoLL. The impact of the differentiated estimation of customer interruption costs is demonstrated through an example on the LV network of Figure 2.17. The planning problem lies in whether to design system with a reserve cable and selecting the optimal number of feeder sections.



a) network with no reserve cable



b) network with reserve cable to enhance security of supply

Figure 2.17: Test network a) without and b) with reserve cable

Test network design a) consists of four radial feeders which does not provide for redundancy in case of a fault while design 2) can provide back-feed to some of customers depending on the number of sections on a feeder.

The following two figures compare the planning solutions for two different selections of the VoLL, namely the ones corresponding to CDF6 and CDF0, respectively. In the first case presented in Figure 2.19, the low VoLL reduces the customer interruption costs and as a result the optimal planning solution lies in not investing in extra reserve cable and switchgears.

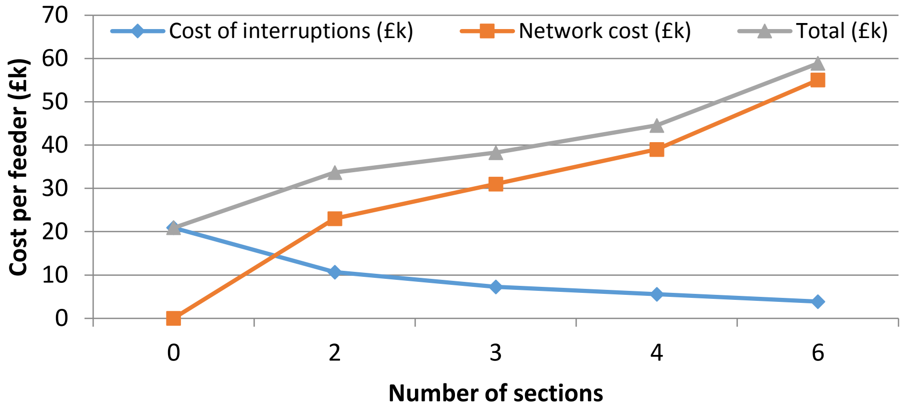


Figure 2.18: Planning solution corresponding to CDF6

In the second case, shown in Figure 2.19, the relatively higher VoLL increases the customer interruption cost and as a result the optimal planning solution lies in investing in reserve cable and creating three feeder sections.

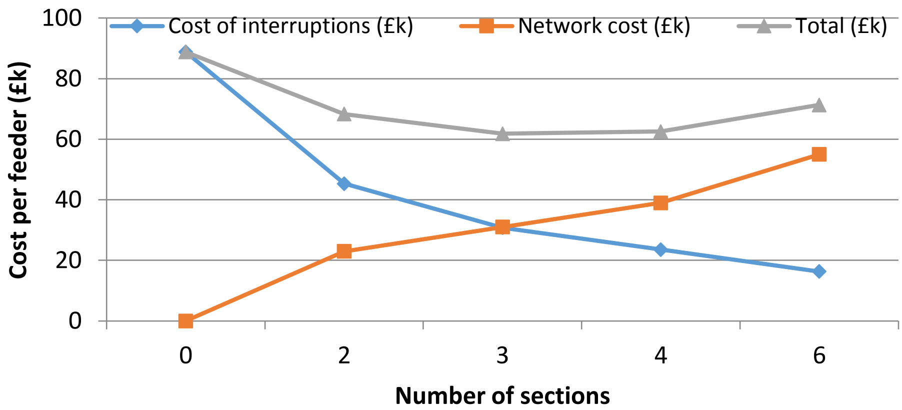


Figure 2.19: Planning solution corresponding to CDF0

This example demonstrates that the selection of different interruption cost estimates can change fundamentally the obtained planning solution.

Reliability indices

Network operators have been required to assess the past performance of their networks in terms of specified parameters and quantitative measures since privatisation [146]. These have been used for customer and system reliability performance, to compare system performances against set targets, and to enable comparison of the performances between individual companies. The specified parameters were designated originally by the two terms: Security and Availability. The corresponding measures for quantifying these terms are Customer

Interruptions (CI) and Customer Minutes Lost (CML)[7]. These terms and indices are now used extensively by Ofgem and DNOs at system level and for particular parts of the system, as a means for comparing performance of companies, performance of different type networks (e.g. urban with rural), and for assessing the impact of implementing alternative supply restauration strategies.

These indices are established metrics in the UK electricity market. However, similar indices have been defined in North America and used internationally. These indices are known as SAIFI, SAIDI, where:

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

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

The three primary indices associated with power system networks are: failure rate (or frequency[8]), outage duration and annual unavailability (or outage time) of each load point in the system. These indices[9] can be measured (for past performance) or evaluated (for future performance) for each load point. All such indices are not deterministic values but are expected or average values of an underlying probability distribution, which is generally unknown, and therefore these represent only the long-run average values.

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

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

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

[7] These measures are the complementary values for the terms being quantified, e.g. as availability increases, the corresponding measure (CML) decreases.
[8] Rate and frequency are conceptually different, although numerically very close for power system networks.
[9] Generally, the value of rate is evaluated for future predicted performance but is deemed to be equal to frequency, and the value of frequency is directly assessed for past performance.

load/energy-oriented indices (such as average load interrupted and EENS). These indices are listed in Table 2.52.

Table 2.52: List of Load Point and System Indices

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

The following points should be noted:

- Load point indices represent the average behaviour of individual load points. Therefore the relevant frequency and duration indices represent the impact of system behaviour on the individual customers connected to that load point.
- System indices are aggregated indices that represent the average behaviour of the part of the system that has been aggregated. These are evaluated from the indices of the load points included in the aggregation. Therefore, the relevant frequency and duration indices represent the impact of system behaviour on the "average" customer of that part of the system.
- Load point frequency is identical to the CI at that load point. Similarly load point unavailability is identical to the CML at that load point.
- Real individual customers are only concerned with the number and duration of the interruptions they experience, or are likely to experience. They are not concerned with the load they did not impose on the system or the amount of energy they did not consume during interruptions. Therefore they are only concerned with the first three load point indices listed in the second column of Table 2.52.
- The remaining load point indices and all the system indices listed in Table 2.52 are of interest only to the DNO and regulatory bodies.

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

- Compare and rank different companies;
- Compare different investment strategies;
- Compare different reinforcement and design strategies;
- Compare different maintenance strategies; and

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

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

The analyses in this report, see Section 6, show a high variability of load point indices depending where on HV feeder they are connected.

Conclusions

A large number of studies have employed different approaches to quantify the customer interruption costs (CIC) for different categories of consumers. However, general consensus on the value of these costs has not been yet reached, as the values proposed by different sources vary significantly. The main reason is that CIC depends on a large number of diverse factors, the cost implications of which cannot be unambiguously quantified even by the consumers themselves. These factors include the activities affected by unsupplied energy, the timing (time of day, day of week, month of year) of the supply interruption, the duration of the supply interruption, the frequency of interruptions and the availability of advance warning before the interruption takes place. This lack of consensus is aggravated by the fact that CIC have been quantified in different currencies and different years in the past, introducing significant difficulties in comparative analysis.

This section has firstly discussed the main methodologies previously employed for the quantification of CIC and VoLL. Secondly, it has discussed the highlights of a comprehensive literature survey on CIC and VoLL quantification, demonstrating the significant variations and the previously discussed lack of consensus. The main outcomes of the latest relevant study in the UK context, by London Economics [33], have been discussed and form the core of the customers' supply valuation assumptions adopted throughout this report. Furthermore, different modelling approaches to cost customer interruptions have been presented and discussed, including constant VoLL as well as interruption duration-dependent VoLL in the form of customer damage functions. Case studies have demonstrated that the adopted model and estimate of interruption costs can have a profound impact on the obtained planning solution. Finally, this section has briefly discussed customer and system reliability indices employed by network operators to assess the performance of their networks.

2.12 Appendix: Table of key data

Table 2.53: List of published CIC data [46]

References	Country	Date of Data	Method	Key Findings €=Euro, C$= Canadian Dollar, $=US Dollar, £= UK Pound, NOK=Norwegian Krone
Nooij et al (2006) [20]	Netherlands	2001	EO/C	Agriculture € 3.90/kWh Manufacturing € 1.87/kWh Construction € 33.05/kWh Transport € 12.2/kWh Services €7.94/kWh Government € 33.50/kWh Residential € 16.38/kWh Total € 8.56/kWh
Leahy et al (2010) [23]	Ireland	2007	EO/C	Industrial € 4/kWh Commercial € 14/kWh Residential € 24.6/kWh Total € 12.9/kWh
Linares et al (2012) [24]	Spain	2008	EO/C	Agriculture € 4.40/kWh Manufacturing € 1.38/kWh Construction € 33.37/kWh Transport € 8.53/kWh Services € 8.47/kWh Government € 6.23/kWh Residential € 8.11/kWh Total € 5.98/kWh
Wacker et al (1989a) [9]	Canada	1980	Customer survey	*1min* *20min* *1hour* *4hours* *8hours* Larger User C$1.80/kW C$2.22/kW C$3.19/kW C$6.89/kW C$10.47/kW Small Industrial C$0.70/kW C$2.88/kW C$5.19/kW C$13.87/kW C$27.60/kW Commercial C$0.28/kW C$2.05/kW C$5.88/kW C$21.51/kW C$63.06/kW Residential - C$0.06/kW C$0.31/kW C $3.16/kW -
Tollefson et al (1994) [7]	Canada	1991	Customer survey	Industrial C$ 6.5264/kW (1 hour interruption) Commercial C$ 15.0650/kW (1 hour interruption) Residential C$ 0.1626 /kW (1 hourinterruption)
Tiedemann (2004a, 2004b) [5][6]	British Columbia, Canada	2000	Customer survey	*20min* *2hours* *4hours* *12hours* $/kWh lost $/kWh lost $/kWh lost $/kWh lost Business 806 299 216 107 Residential 3.23 0.54 0.44 0.18
Kjølle et al (2008) [21]	Norway	2001-2002	Customer survey	Industrial NOK123/KWh not supplied (1hour Interruption) Commercial NOK201.5/KWh not supplied (1hour Interruption) Large Industry NOK 23.8/KWh not supplied (1 hour Interruption) Public service NOK19.9/KWh not supplied (1 hour Interruption) Agriculture NOK16.6/KWh not supplied (1hour Interruption) Residential NOK11.5/KWh not supplied (1 hour Interruption)
Lehtonen et al. (1995) [19]	Denmark	1992-1993	Customer survey	Industrial $22.10/kW (1 hour Interruption) Commercial $8.50/kW (1 hour Interruption) Residential $6.60/kW (1 hour Interruption) Agricultural $66.80/kW (1 hourInterruption)
Lehtonen et al. (1995) [19]	Finland	1992-1993	Customer survey	Industrial $14.50/kW (1 hour Interruption) Commercial $16.40/kW (1 hour Interruption) Residential $2.90/kW (1 hour Interruption) Agricultural $15.50/kW (1 hourInterruption)
Lehtonen et al. (1995) [19]	Iceland	1992-1993	Customer survey	Industrial $12.50/kW (1 hour Interruption) Commercial $21.00/kW (1 hour Interruption) Residential $3.20/kW (1 hour Interruption) Agricultural $5.60/kW (1 hourInterruption)
Bliem (2008) [17]	Austria	2007	Customer survey	Households € 73.5/KWh not supplied (1 hour Interruption) Business € 203.93/KWh not supplied (1 hourInterruption)
Sullivan et al (2012) [15]	Pacific & Gas Electric, San Francisco USA	2012	Customer survey	***Note: SMB = Small and Medium Business*** Cost per Outage Event ***Outage Duration*** ***Residential ($/Event)*** ***SMB ($/Event)*** ***Large Business ($/Event)*** ***Agricultural ($/Event)*** 5 minutes $7.41 $379.8 $454,675 $146.1 1 hour $11.89 $1,848.8 $449,655 $453.5 4 hours $16.82 $4,774.3 $596,675 $1,230.7 8 hours $22.89 $10,568.7 $617,196 $2,549.4 24 hours $31.67 $21,339.4 $1,472,497 $5,842.4
				Cost per Average kW ***Outage Duration*** ***Residential ($/kW)*** ***SMB ($/kW)*** ***Large Business ($/kW)*** ***Agricultural ($/kW)*** 5 minutes $9.75 $43.3 $319.3 $18.1 1 hour $14.86 $205.2 $327.4 $52.1 4 hours $21.03 $540.1 $436.9 $143.9

				8 hours $28.61 $1,136.4 $449.7 $288.7 24 hours $40.09 $2,403.1 $1,047.5 $700.5 <u>Cost per Unserved kWh</u> ***Outage Duration*** \| ***Residential ($/kWh)*** | ***SMB ($/kWh)*** \| ***Large Business ($/kWh)*** | ***Agricultural ($/kWh)*** 5 minutes $123.50 $493.3 $3,769.8 $205.7 1 hour $14.86 $195.6 $318.5 $50.3 4 hours $5.08 $127.5 $107.5 $35.6 8 hours $3.44 $138.4 $55.6 $35.9 24 hours $1.67 $99.7 $43.7 $28.8
Balducci et al (2002) [12]	USA	1992 and 1996 Canadian data	MCS	***20min*** | ***1hour*** | ***4hours*** Industrial $ 6.29/kW $ 13.93/kW $29.94 /kW Commercial $ 4.74/kW $ 12.87/kW $44.37/kW Residential $ 0.03/kW $ 0.15/kW $1.64/kW Transport $ 8.91/kW $ 16.42/kW $45.95/kW Wt. Average $ 3.59/kW $ 8.76/kW $24.90/kW
Sullivan et al (2009) [14]	USA	1989-2005	ACS	**Medium& Large Commercial & Industrial (Av. Consumption = 7,140,501 kWh/year)** ***Momentary*** | ***30min*** | ***1 hour*** | ***4 hours*** | ***8 hours*** *Cost Per Event* $11,756 $15,709 $20,360 $59,188 $93,890 *Cost Per Average kW* $14.4 $19.3 $25.0 $72.6 $115.2 *Cost Per Un-served kWh* $173.1 $38.5 $25.0 $18.2 $14.4 *Cost Per Annual kWh* $1.65E-03 $2.20E-03 $2.85E-03 $8.29E-03 $1.31E-02 **Small Commercial & Industrial (Average Consumption = 19,214kWh/year)** ***Momentary*** | ***30min*** | ***1 hour*** | ***4 hours*** | ***8 hours*** *Cost Per Event* $439 $610 $818 $2,696 $4,768 *Cost Per Average kW* $200.1 $278.1 $373.1 $1,229.2 $2,173.8 *Cost Per Un-served kWh* $2,401.0 $556.3 $373.1 $307.3 $271.7 *Cost Per Annual kWh* $2.28E-02 $3.18E-02 $4.26E-02 $0.1403 $0.2482 **Residential (Average Consumption =13,351kWh/year)** ***Momentary*** | ***30min*** | ***1 hour*** | ***4 hours*** | ***8 hours*** *Cost Per Event* $2.7 $3.3 $3.9 $7.8 $10.7 *Cost Per Average kW* $1.8 $2.2 $2.6 $5.1 $7.1 *Cost Per Un-served kWh* $21.6 $4.4 $2.6 $1.3 $0.9 *Cost Per Annual kWh* $2.06E-04 $2.48E-04 $2.94E-04 $5.81E-04 $8.05E-04
Centolella et al (2010) [13]	USA MidWest	1989-2002	ACS	**Large Commercial & Industrial (Consumption > 1 million kWh/year)** *Agriculture* $24.83/kW (1 hour interruption) *Mining* $77.53/kW (1 hour interruption) *Construction* $24.83/kW (1 hour interruption) *Manufacturing* $42.09/kW (1 hour interruption) *Transport/Communication/Utilities* $24.83/kW (1 hour interruption) *Wholesale/Retail* $24.83/kW (1 hour interruption) *Finance/Real Estate* $24.83/kW (1 hour interruption) *Services* $15.56/kW (1 hour interruption) *Public Admin* $24.83/kW (1 hour interruption) **Small Commercial &Industrial (Consumption < 1 million kWh/year)** *Agriculture* $49.51/kW (1 hour interruption) *Mining* $49.51/kW (1 hour interruption) *Construction* $40.06/kW (1 hour interruption) *Manufacturing* $35.81/kW (1 hour interruption) *Transport/Communication/Utilities* $29.30/kW (1 hour interruption) *Wholesale/Retail* $49.51/kW (1 hour interruption) *Finance/Real Estate* $35.64/kW (1 hour interruption) *Services* $15.25/kW (1 hour interruption) *Public Admin* $33.35/kW (1 hour interruption) **Residential** *Willingness-to-Pay* $1.60/kW(1 hour interruption)
System Control Inc. (1978) [16]	New York City	1977	BOCS	**Direct ($ million)** | **Indirect ($ million)** Business 34.0 160.4 Government (Non-public Services) - 12.5 Consolidated Edison 12.0 65.0 Insurance - 33.5 Public Health Services - 1.5 Other Public Services 9.1 17.26 Westchester County 0.44 - **Total** 55.54 290.16

Table 2.54: List of published CIC data/2

References	**Country**	**Date of Data**	**Method**	**Key Findings** €=Euro, C$= Canadian Dollar, $=US Dollar, £= UK Pound, NOK=Norwegian Krone				
London Economics [33]	UK	2011-2013	Customer survey	VOLL	WTA	WTP		
				Domestic	£6957/MWh-£11820/MWh	£1651/MWh-£2766/MWh		
				small and medium sized businesses (SMEs)	£33358/MWh-£44149/MWh	£19271/MWh-£27859/MWh		
				Industrial and commercial	£1075/MWh -£1654/MWh			
Kariuki and Allan [29]	UK	1992	Customer survey	SCDFs(£/MWh) for per unit annual consumption				
				Duration	Residential	Commercial	Industrial	Large user
				Mom	-	0.46	3.02	1.07
				1min	-	0.48	3.13	1.07
				20min	0.06	1.64	6.32	1.09
				1h	0.21	4.91	11.94	1.36
				4h	1.44	18.13	32.59	1.52
				8h	-	37.06	53.36	1.71
				24h	-	47.58	67.10	2.39
				SCDFs(£/kW) for per unit peak demand				
				Mom	-	0.99	6.15	6.74
				1min	-	1.02	6.47	6.74
				20min	0.15	3.89	14.27	6.86
				1h	0.54	10.65	25.26	7.18
				4h	3.72	39.04	72.22	8.86
				8h	-	78.65	120.11	9.71
				24h	-	99.98	150.38	13.35
Carlsson and Martinsson [25]	Sweden	2004	Customer survey	Willingness to pay to avoid an interruption: worst case scenario (£)	Mean	Median	Max	Share of zero WTP
				Planned interruption				
				1 hour	0.59	0	46.80	0.9
				4 hours	2.66	0	93.60	0.74
				8 hours	7.90	0	187.20	0.51
				24 hours	17.71	4.68	280.80	0.39
				Unplanned interruption				
				1 hour	0.88	0	46.80	0.86
				4 hours	3.49	0	70.20	0.68
				8 hours	10.12	1.40	187.20	0.46
				24 hours	20.87	8.42	280.80	0.36
				Of uncertain duration: between 2 and 6 hours	6.44	0.00	112.32	0.59
Carlsson and Martinsson [26], [27]	Sweden	2007	Customer survey	Duration and day of interruption	November — March	April — October		
				4 hour weekday	£0.69	£1.00		
				8 hours weekday	£1.98	£2.47		
				24 hours weekday	£8.95	£7.24		
				4 hours weekend	£2.76	£1.88		
				8 hours weekend	£3.53	£3.76		
				24 hours weekend	£11.71	£9.85		

(Table continues)

<table>
<tr><th>References</th><th>Country</th><th>Date of Data</th><th>Method</th><th>Key Findings</th></tr>
<tr><td>Bertazzi et al [22]</td><td>Italy</td><td>2003</td><td>Customer survey</td><td>
<table>
<tr><td rowspan="2">Duration of interruption</td><td colspan="3">Domestic customers</td></tr>
<tr><td>Direct costs(£/kW for 3 minute interruption, £/kWh for other, annual consumption)</td><td>WTA(£/kW for 3 minute interruption, £/kWh for other, annual consumption)</td><td>WTP(£/kW for 3 minute interruption, £/kWh for other, annual consumption)</td></tr>
<tr><td>3 mins</td><td>7.3</td><td>4.9</td><td>1.3</td></tr>
<tr><td>1 hour</td><td>23.0</td><td>15.5</td><td>3.4</td></tr>
<tr><td>2 hours</td><td>18.5</td><td>12.6</td><td>2.4</td></tr>
<tr><td>4 hours</td><td>14.3</td><td>10.2</td><td>2.0</td></tr>
<tr><td>8 hours</td><td>8.8</td><td>6.3</td><td>1.2</td></tr>
<tr><td></td><td colspan="3">Business customers</td></tr>
<tr><td>3 mins</td><td>50.1</td><td>31.0</td><td>4.5</td></tr>
<tr><td>1 hour</td><td>107.2</td><td>72.5</td><td>9.7</td></tr>
<tr><td>2 hours</td><td>76.1</td><td>51.9</td><td>7.0</td></tr>
<tr><td>4 hours</td><td>61.0</td><td>44.0</td><td>6.0</td></tr>
<tr><td>8 hours</td><td>36.3</td><td>26.3</td><td>3.6</td></tr>
</table>
</td></tr>
<tr><td>Accent [30], [31], [32]</td><td>UK</td><td>2004-2008</td><td>Customer survey</td><td>
<table>
<tr><td colspan="3">Domestic customer: willingness to pay and to accept for a change in number of annual interruptions(£ per interruption per year)</td></tr>
<tr><td></td><td>Deterioration in service</td><td>Improvement in service</td></tr>
<tr><td>DNOs</td><td>From –£19.52 to –£4.52</td><td>From £4.49 to £15.04</td></tr>
<tr><td colspan="3">Domestic customers' willingness to pay and to accept change in average duration of a power cut by a minute (£ per minute change)</td></tr>
<tr><td></td><td>Deterioration in service</td><td>Improvement in service</td></tr>
<tr><td>DNOs</td><td>From –£0.22 to –£0.04</td><td>From £0.04 to £0.18</td></tr>
</table>
</td></tr>
<tr><td>Bliem (2009) [18]</td><td>Austria</td><td>2009</td><td>Customer survey</td><td>
<table>
<tr><td colspan="3">Summary of estimates on willingness to pay (% of annual bill)</td></tr>
<tr><td>Attribute</td><td>Households</td><td>Businesses</td></tr>
<tr><td>Duration 3 mins</td><td>–1%</td><td>5%</td></tr>
<tr><td>Duration 4h</td><td>–16%</td><td>–10%</td></tr>
<tr><td>Duration 10 h</td><td>–22%</td><td>–20%</td></tr>
<tr><td>Frequency</td><td>–1%</td><td>–6%</td></tr>
<tr><td>Time of day (night)</td><td>–1%</td><td>14%</td></tr>
<tr><td>Day of the week (Sunday)</td><td>–7%</td><td>16%</td></tr>
<tr><td>Notification (yes)</td><td>3%</td><td>–2%</td></tr>
</table>
</td></tr>
<tr><td>Praktiknjo, A.J. et al [28]</td><td>Germany</td><td>2011</td><td>EO/C</td><td>
<table>
<tr><td colspan="2">Estimates of costs of interruption for household customers</td></tr>
<tr><td>Duration of interruption</td><td>VOLL (£/kWh)</td></tr>
<tr><td>1 hour</td><td>13.7</td></tr>
<tr><td>8 hours</td><td>8.1</td></tr>
<tr><td colspan="2">Estimates of costs of interruption for business customers</td></tr>
<tr><td>Sector</td><td>VOLL (£/kWh)</td></tr>
<tr><td>Agriculture</td><td>2.0</td></tr>
<tr><td>Industry</td><td>2.2</td></tr>
<tr><td>Commerce, service and transportation</td><td>14.2</td></tr>
<tr><td>Weighted average</td><td>5.3</td></tr>
</table>
</td></tr>
</table>

2.13 Appendix: Present Service Quality

The analysis of many of GB DNOs quality of service reporting pack is used to derive present service quality customers receive.

Figure 2.20 shows the breakdown of the number of incidents per an average GB DNO for five consecutive years. In total there are 14 GB DNOs of which 12 and 7 reporting packs are used to derive results for 2010/11-2013/14 and 2014/15, respectively. Observed total annual number of incidents is between about 12,500 to 15,000 incidents per year on all voltage levels. There are great number of low voltage non-damage incidents followed by LV underground mains and LV underground services damage. Excluding LV, the greatest number of incidents are HV damage followed by HV non-damage incidents. At EHV and 132kV incidents occur comparably less.

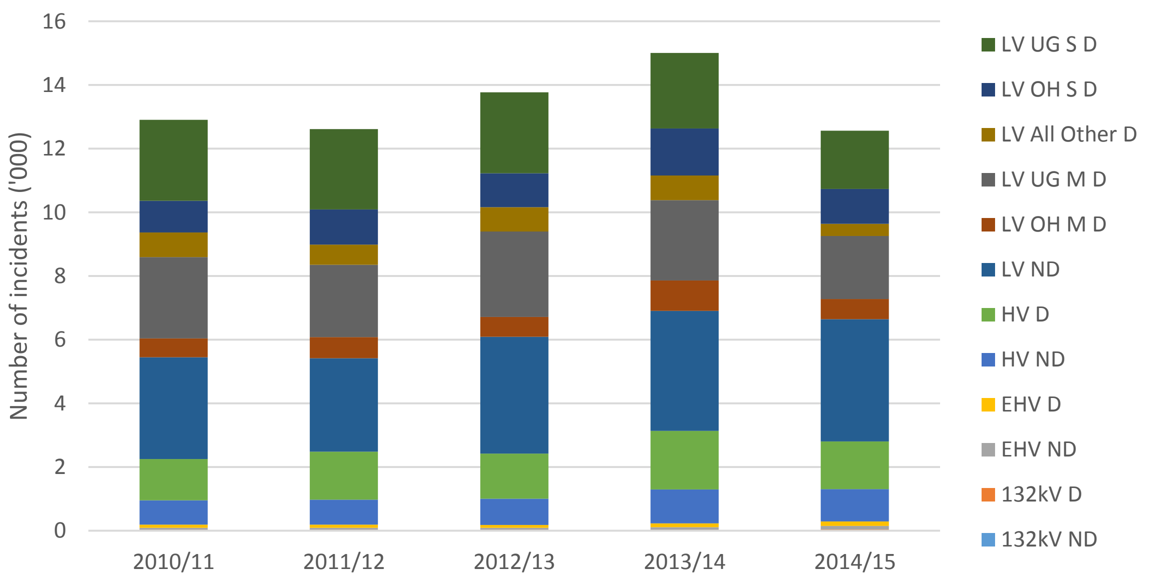


Figure 2.20: Breakdown of the number of incidents for an average GB DNO for five consecutive years; ND – non damage, D – damage, M – mains, S – Services

Figure 2.21 shows breakdown of the Customer Interruptions (per 100 customers) for an average GB DNO for five consecutive years. Range of observed CIs is between 52 and 66 supply interruptions per 100 customers. Majority of CIs are results from HV damage followed by HV non-damage incidents. To illustrate this a pie chart for an average year is shown in Figure 2.22.

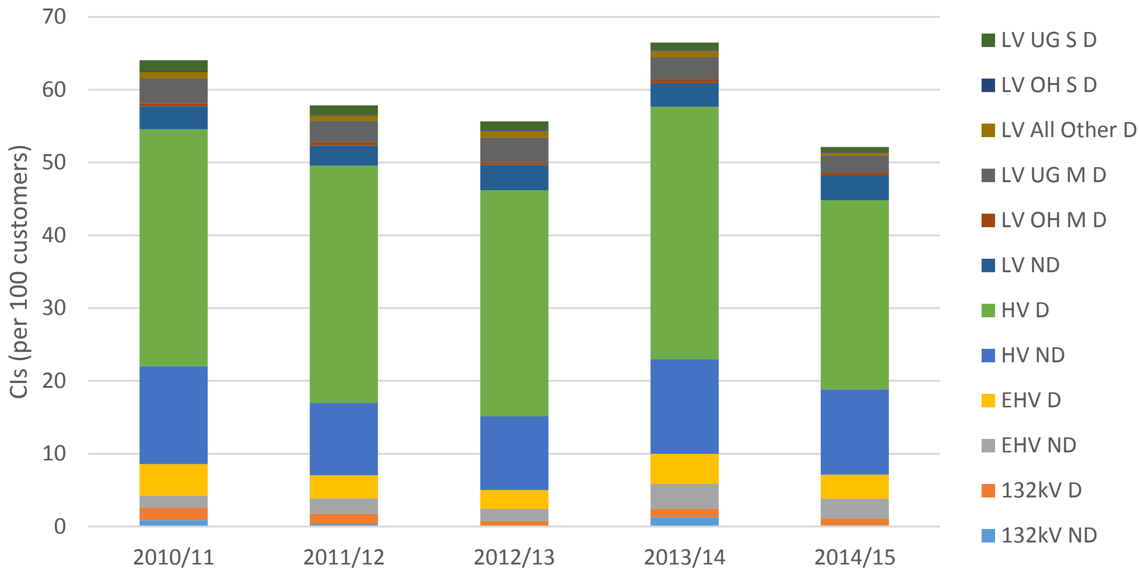


Figure 2.21: Breakdown of the Customer Interruptions (per 100 customers) for an average GB DNO for five consecutive years

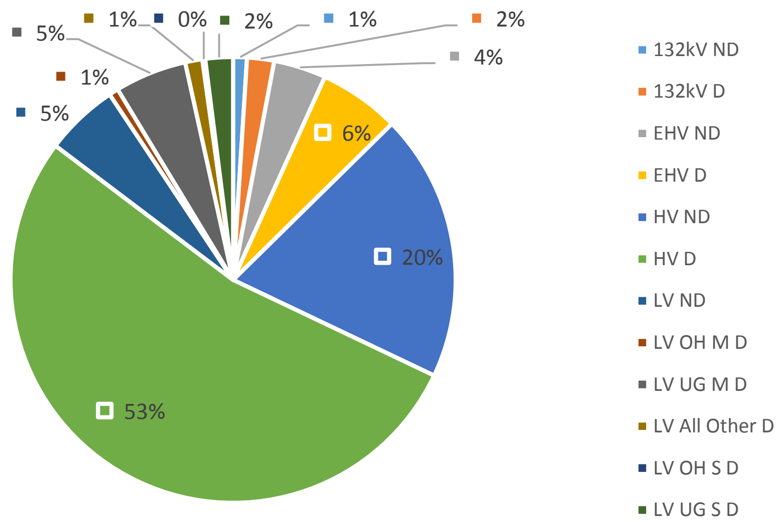


Figure 2.22: Breakdown of Customers Interruptions (per 100 customers) for an average GB DNO for an average year

It can be seen that about 53% of customer interruptions are as a result of HV damage incidents, 20% as a result of HV non damage incidents i.e. in total 73% as a result of HV incidents. The further 6% is from EHV damage, 5% from LV non-damage, 5% from LV underground mains damage, 4% EHV non-damage and 7% from the rest of incidents.

Figure 2.23 shows breakdown of CIs originating from pre-arranged interruptions by voltage level for an average GB DNO for five consecutive years. The values range from about 4.5 to 5 interruptions per 100 customers per year which is about 7-9% of the CIs originating from unplanned interruptions.

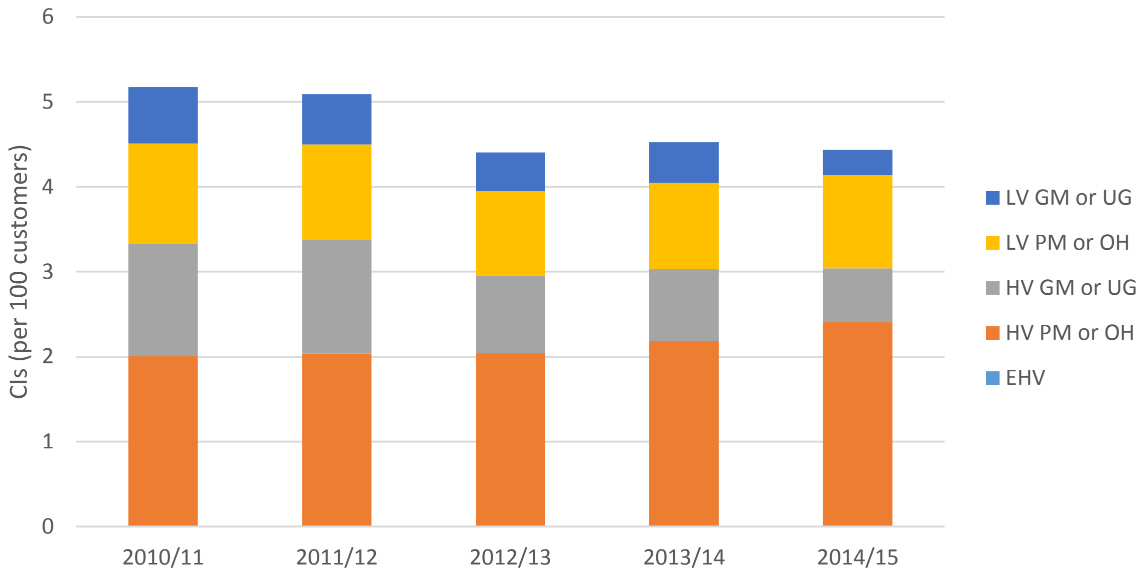


Figure 2.23: Breakdown of Customer Interruptions originating from pre-arranged interruptions by voltage lever for an average GB DNO; GM – Ground Mounted, PM – Pole Mounted, UG – Underground, OH – Overhead

Majority of CIs is from interruptions in relation to incidents at HV pole mounted or overhead assets which is followed by CIs from incidents related to LV pole mounted or overhead assets and HV ground mounted or underground assets. Trend showing reduction of CIs in relation to LV and HV ground mounted or underground assets can be observed. For LV CIs are reduced from about 0.7 in 2010/11 to about 0.3 in 2014/15 and for HV reduction is from about 1.3 to 0.6 interruptions per 100 customers per year.

Figure 2.24 shows breakdown of Customer Minutes Lost (CML) in minutes per customer for an average GB DNO for five consecutive years. It can be seen that variability of CML is greater than variability of CIs. The lowest observed CML is 34 and the highest is 81 customer minutes lost per year. The maximum observed CML is 2.4-fold greater than the minimum. The highest proportion of CML is a result of damage incidents on HV networks. To illustrate the proportion of CML resulting from incidents on different voltage levels and asset types the pie chart shown in Figure 2.25 is created.

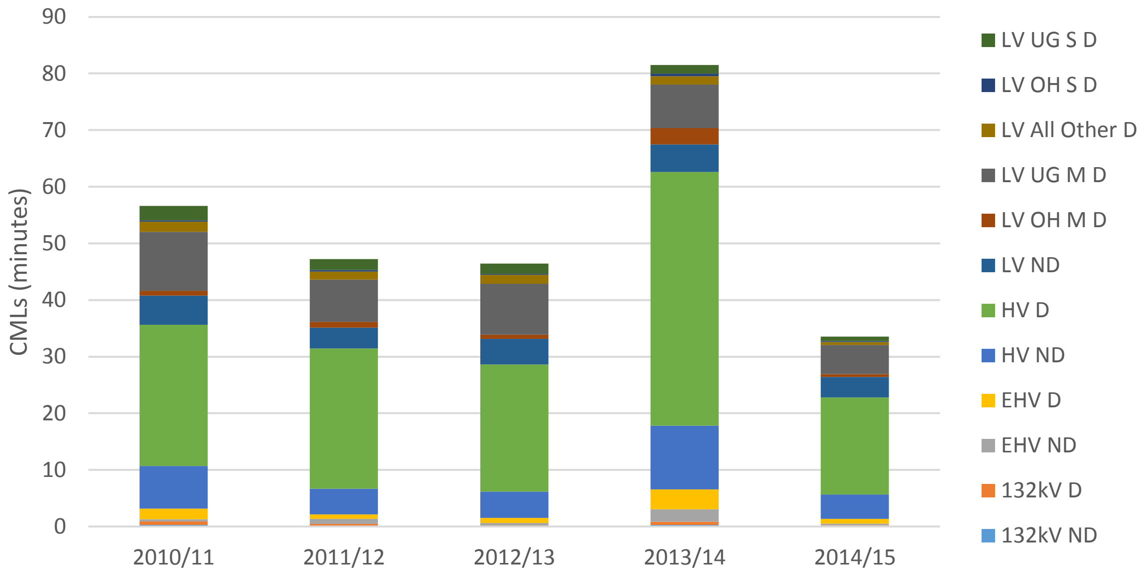


Figure 2.24: Breakdown of Customer Minutes Lost for an average GB DNO for five consecutive years

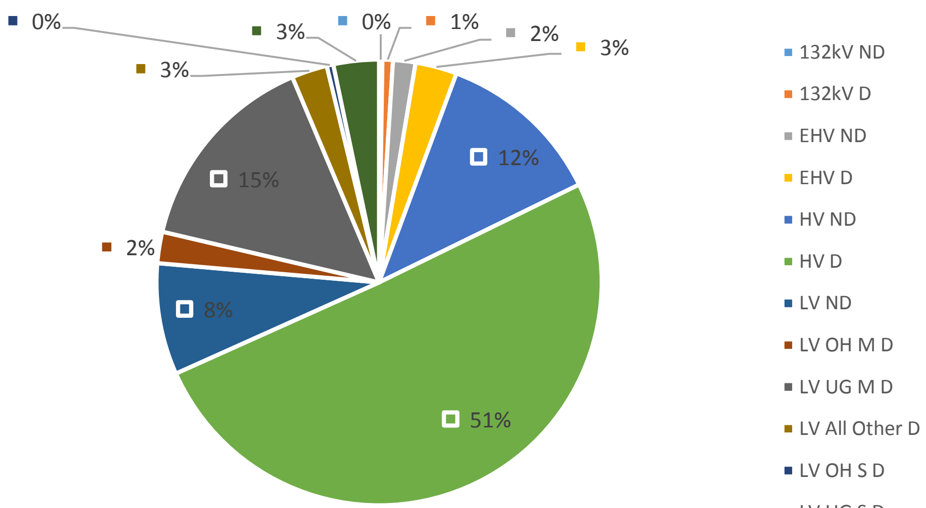


Figure 2.25: Breakdown of Customer Minutes Lost for an average GB DNO and average year

It can be seen that about 51% of CML is a result of damage incidents on HV network. This is followed by 15% resulting from damage incidents on LV underground mains, 12% from HV non-damage incidents, 8% from LV non-damage incidents and 14% from the rest of incidents.

Figure 2.26 shows the breakdown of CML from pre-arranged interruptions by voltage level for an average GB DNO for five consecutive years. The total CML is in range from 10 to 13 customer minutes lost. It is in range of 15-30% of CML resulting from unplanned interruptions.

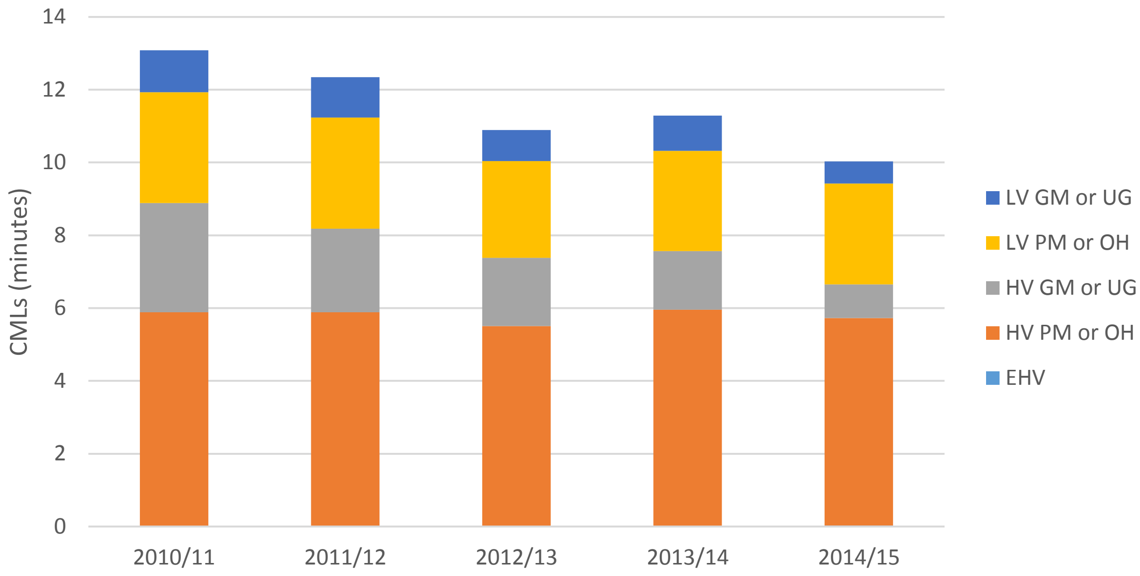


Figure 2.26: Breakdown of Customer Minutes Lost originating from pre-arranged interruptions by voltage level for an average GB DNO; GM – Ground Mounted, PM – Pole Mounted, UG – Underground, OH – Overhead

The majority of CML, about 6 customer minutes lost per year, is due to pre-arranged interruptions at HV Pole Mounted or Overhead assets. This is followed by the contribution from pre-arranged interruptions related to LV Pole Mounted or Overhead assets.

Figure 2.27 shows the percentage of customers off supply for long period in normal and severe weather conditions. In one year in normal weather conditions almost 0.12% of customers were without supply for 18 hours and over. In the other year, in severe weather category 2, about 0.12% of customers were without supply for 48 hours and over. The percentage of customers varies significantly and in 2014/15 there is less than 0.01% of customer is affected.

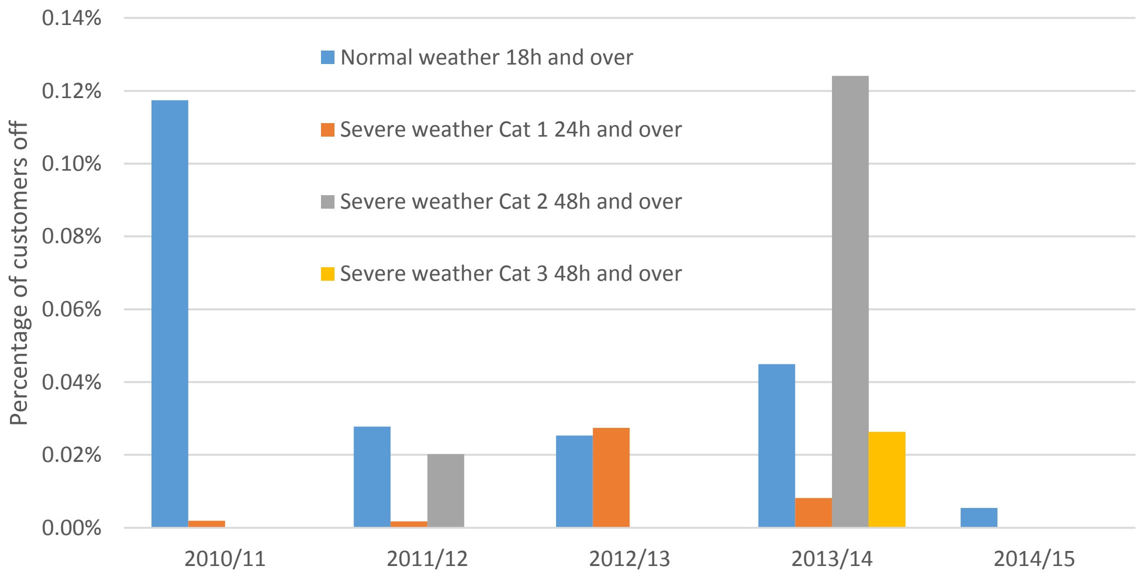


Figure 2.27: Percentage of customers off for long duration in normal and severe weather conditions

In summary there are about 12,500 to 15,000 incidents per year in an average DNO resulting in unplanned CI between 50-65 interruptions per 100 customer and year, prearranged CI between 4 to 5, unplanned CML between 30 and 80 and for prearranged CML between 10 and 13 customer minutes lost per annum. This is summarised in Table 2.55.

Table 2.55: Summary of present service quality of supply per average GB DNO

Parameter	Value
Annual number of incidents	12,500 – 15,000
Unplanned CI	50 – 65
Prearranged CI	4 – 5
Unplanned CML	30 – 80
Prearranged CML	10 – 13

The high number of CI and CML are due to incidents at HV networks (main asset involved) which are about 73% and 63% respectively and at LV networks about 14% and 31% respectively. Prearranged CI are relatively small compared with the unplanned CI. Unplanned CML represents higher proportion compared to prearranged ones. However, difference is relatively smaller than for CI. Small number of incidents is severe weather related. The high impact events are also observed in normal weather conditions.

2.14 Appendix: Transfer Capacity Needs

A set of case studies has been performed on a network shown in Figure 2.10 investigating the potential benefits of Load-Transfer Capability (LTC), which is used to improve the reliability performance of the system. The reduction of EENS attributed to LTC is multiplied by the VoLL of £17,000/MWh in order to determine its potential benefit. Then, the average benefit of LTC can be calculated by dividing its potential benefit with the installed capacity. In this analysis, the cost of an investment needed to achieve desired transfer capacity is excluded from the analysis. The investment in LTC can be justified if cost of the investment is lower than the benefit.

Table 2.56 shows the potential benefit of LTC (expressed in £/MW [transfer] per year) for UG networks with different network reliability parameters (failure rates, MTTR) and lengths supplying different number of primary substations and peak demand. For example if one primary substation is supplied from an adjacent substation 20 km from grid substation and network failure rate is 2%, primary transformer failure rate is 1% and the rest of parameters as per Table 2.56 the potential benefit of LTC is between £280/MW and £3.77k/MW per year in the case with peak demand (per load point) of 7.5 MW and 20 MW respectively (in this example there are two load points per primary substation).

Table 2.56: Potential benefit of LTC for EHV UG network

Number of primary substations	Network failure rate (%/km.year)	Section length (km) Main/ Spur	Load transfer potential benefit (£'000/MW per year) Load point peak demand (MW)	
			7.5	20
1	2%	4/0	0.03	0.40
		4/10	0.16	2.14
		20/0	0.28	3.77
		20/10	0.57	7.45
	8%	4/0	0.53	8.12
		4/10	2.67	37.18
		20/0	4.65	63.70
		20/10	9.11	122.82
2	2%	4/0	0.02	0.32
		4/10	0.14	1.82
		20/0	0.33	4.36
		20/10	0.52	6.87
	8%	4/0	0.44	6.64
		4/10	2.30	32.26
		20/0	5.43	72.93
		20/10	8.62	116.11
3	2%	4/0	0.02	0.32
		4/10	0.13	1.74
		20/0	0.41	5.38
		20/10	0.57	7.49
	8%	4/0	0.44	6.65
		4/10	2.20	30.91
		20/0	6.68	89.18
		20/10	9.39	126.13

There are a number of observations which are listed as follows:

- The key drivers for the value of LTC are:
  - Network reliability parameters: LTC is less needed in a system with high reliability. The longer the network, the probability of having faults is higher.
  - Network loads: the value of LTC is higher in a system with higher load.
- The value of LTC is less sensitive to the number of primary substations.
- For cases with 7.5 MW or 20 MW peak demand per load point, the maximum potential benefit of LTC is £9.39k/MW per year or £126.13k/MW per year respectively. The maximum values are found in cases with failure rate of 8%, section length of 20/10 km, and number of primary substations is 3. In such cases, investment in LTC may be justified.
- The minimum potential benefit of LTC for cases with peak load of 7.5 MW or 20 MW is £0.02k/MW per year or £0.2k/MW per year respectively. The minimum values are found

in cases with failure rate of 2%, section length of 4/0 km, and number of primary substations is 3.

Table 2.57 shows the results of the studies for EHV OH networks.

Table 2.57: Potential benefit of LTC for EHV OH network

Number of primary substations	Failure rate (%/km.year)	Section length (km) Main/Spur	Load transfer potential benefit (£'000/MWtransfer.year)	
			Load point peak demand (MW)	
			7.5	20
1	2%	4/0	0.03	0.24
		4/10	0.16	1.18
		20/0	0.28	2.06
		20/10	0.57	4.04
	15%	4/0	1.11	9.87
		4/10	7.27	54.87
		20/0	13.38	98.63
		20/10	27.47	198.70
2	2%	4/0	0.02	0.19
		4/10	0.14	1.01
		20/0	0.33	2.36
		20/10	0.52	3.72
	15%	4/0	1.04	8.95
		4/10	6.29	47.87
		20/0	17.35	124.98
		20/10	27.48	198.45
3	2%	4/0	0.02	0.20
		4/10	0.13	0.97
		20/0	0.41	2.90
		20/10	0.57	4.04
	15%	4/0	1.15	9.61
		4/10	6.02	45.91
		20/0	22.09	157.99
		20/10	30.48	219.40

The results for OH networks show the same trends as the results of the previous studies for UG networks. However, given a wider range of failure rates considered for OH networks, i.e. 2% and 15%, the maximum potential benefit of LTC for OH network is higher than the ones for UG networks.

For cases with 7.5 MW or 20 MW peak demand per load point, the maximum potential benefit of LTC is £30,480/MW per year or £219,400/MW per year. The maximum values are found in cases with failure rate of 15%, section length of 20/10 km, and number of primary substations is 3.

The minimum potential benefit of LTC for cases with peak load of 7.5 MW or 20 MW is £20/MW per year or £200/MW per year respectively. The minimum values are found in cases with failure rate of 2%, section length of 4/0 km, and number of primary substations is 3. The values are the same for EHV UG networks.

The same set of studies is carried out for 132 kV networks to identify the scale of the potential benefit of LTC under a similar set of assumptions as described previously. For 132 kV networks, the peak demand of 22.5 and 45 MW are used. The section length for the 132 kV networks is also longer than the EHV networks.

Table 2.58: Potential benefit of LTC for 132 kV UG network

Number of grid substations	Failure rate (%/km.year)	Section length (km) Main/ Spur	Load transfer potential benefit (£'000/MW per year) Load point peak demand (MW) 22.5	45
1	2%	8/0	0.77	1.52
		8/10	2.12	4.20
		30/0	4.43	8.77
		30/10	6.92	13.72
	8%	8/0	4.88	9.68
		8/10	18.38	36.40
		30/0	45.35	89.76
		30/10	76.65	151.66
2	2%	8/0	0.59	1.16
		8/10	1.73	3.43
		30/0	4.64	9.19
		30/10	6.39	12.66
	8%	8/0	5.20	10.29
		8/10	15.67	31.04
		30/0	60.85	120.38
		30/10	82.27	162.79
3	2%	8/0	0.58	1.15
		8/10	1.65	3.28
		30/0	5.52	10.92
		30/10	7.02	13.89
	8%	8/0	6.22	12.31
		8/10	15.59	30.88
		30/0	78.98	156.24
		30/10	96.98	191.93

The results for 132 kV networks also show the same trends as the results of the previous studies for EHV networks. However, given the peak loads are higher and the networks are longer, the potential benefits of LTC for 132 kV networks tend to be higher than the ones for EHV networks.

For cases with 22.5 MW or 45 MW peak demand per load point, the maximum potential benefit of LTC is £96.98k/MW per year or £191.93k/MW per year. The maximum values are found in cases with failure rate of 8%, section length of 30/10 km, and number of grid substations is 3.

The minimum potential benefit of LTC for cases with peak load of 22.5 MW or 45 MW is £0.58k/MW per year or £1.15k/MW per year respectively. The minimum values are found in cases with failure rate of 2%, section length of 8/0 km, and number of grid substations is 3.

Table 2.59 shows the results of the studies for EHV OH networks.

Table 2.59: Potential benefit of LTC for 132 kV OH network

Number of grid substations	Failure rate (%/km.year)	Section length (km) Main/ Spur	Load transfer potential benefit (£'000/MWtransfer.year)	
			Load point peak demand (MW)	
			22.5	45
1	2%	8/0	0.58	1.15
		8/10	1.58	3.13
		30/0	3.30	6.57
		30/10	5.18	10.30
	15%	8/0	10.12	20.11
		8/10	42.53	84.45
		30/0	109.58	217.55
		30/10	188.09	373.41
2	2%	8/0	0.45	0.90
		8/10	1.29	2.57
		30/0	3.51	6.98
		30/10	4.82	9.58
	15%	8/0	12.39	24.61
		8/10	37.29	74.06
		30/0	155.81	309.35
		30/10	212.09	421.22
3	2%	8/0	0.45	0.90
		8/10	1.24	2.46
		30/0	4.20	8.33
		30/10	5.31	10.54
	15%	8/0	15.60	30.98
		8/10	37.56	74.60
		30/0	204.64	406.38
		30/10	251.40	499.42

For the 132kv OH networks, cases with 22.5 MW or 45 MW peak demand per load point, the maximum potential benefit of LTC is £251,400/MW per year or £499,420/MW per year. The maximum values are found in cases with failure rate of 15%, section length of 30/10 km, and number of grid substations is 3.

The minimum potential benefit of LTC for cases with peak load of 22.5 MW or 45 MW is £450/MW per year or £900/MW per year respectively. The minimum values are found in cases with failure rate of 2%, section length of 4/0 km, and number of grid substations is 2 or 3.

In summary, the key drivers for the value of LTC are:

- Network reliability parameters: LTC is less needed in a system with high reliability. The longer the network, the probability of having faults is higher.
- Network loads: the value of LTC is higher in a system with higher load.

The value of LTC is less sensitive towards the number of primary substations.

3 ASSET REPLACEMENT

3.1 Introduction

As all DNOs are currently accelerating 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, 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 risk exposures. Conversely, other DNOs with a higher confidence in their ability to manage failures post-event (assuming that their evaluation supports a reactive approach), combined with a less risk adverse attitude, may decide not to install temporary assets but rely on post-fault restoration techniques. These decisions require a trade-off between the savings associated with avoiding contingency arrangements relative to the costs associated with possible regulatory penalties.

As ER P2/6 does not explicitly address construction outages, there is a requirement to understand and quantify the increased risks of interruptions that are driven by different outage management practices. It will be important to quantify the cost of alternative strategies for mitigating risks so that appropriate decisions can be made in relation to contingency arrangements. 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 and to identify risk mitigation measures such as investment in load-transfer capability and operation strategies to reduce post-outage supply restoration time.

It is important to point out that the results of the analysis carried out in Chapter 2 show that in many instances, HV underground networks could be operated with N-0 degree of redundancy (no redundancy). N-0 may not drive increase in cost of construction outage and maintenance if this is carried out during off peak condition, 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 however, provisional supplies may be considered.

In order to inform the development of future security standards addressing this important issue, a range of studies have been performed to identify the drivers and values of investing in risk mitigation measures during the construction-outages.

3.2 Case study

In order to illustrate business cases for provisional supply during construction outages, illustrative examples using the system shown in Figure 3.1 are given below. Should one transformer be subject to a construction outage and the other develops a fault, without provisional supply all loads lose its electricity supply. If the capacity of provisional supply is not sufficient to supply all customers, a partial load-shedding becomes necessary. The remaining customers will not be supplied until the repair is done or supply restored by other means, the time required to restore or repair (MTTR) is considered in the model.

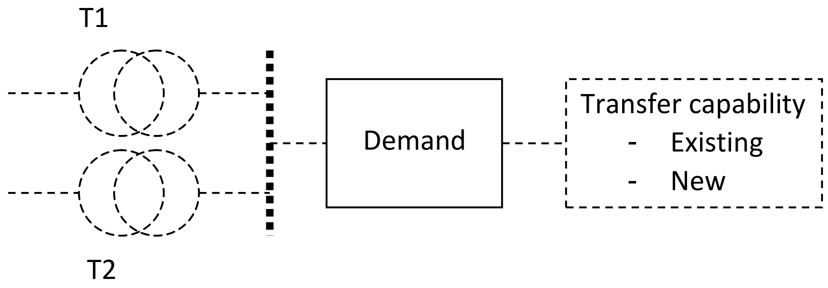


Figure 3.1. Illustration of network topology for management of construction outages example; PD – peak demand, TC – transfer capacity

Two investment options can be considered for mitigation of the risk construction outage might pose. The first one is investment in a greater transfer capability and the second one in a reduction of post-outage supply restoration time. During the unplanned outage of the second transformer, some of the impacted customers can be transferred to an alternate supply source (transfer capacity).

In order to determine whether the decision to invest in the risk mitigation measures can be economically justified, the breakeven cost of the load-transfer capability / provisional supply is calculated. The breakeven cost is equal to the value of reduction in the Expected Energy Not Served (EENS) during the construction period attributed to the new investment. It is worth to highlight that the investment in the risk mitigation measures may improve further the reliability beyond the construction period, if it is installed permanently and not temporary. However, this long-term benefit is excluded from the scope of our study in this section, and therefore it is not quantified. The investment can be justified if the cost of improving the load-transfer capability is lower than the breakeven cost. It is assumed that the load-transfer capability is planned as part of the asset management and available by the time the construction is started.

A set of case studies has been carried out in order to identify the drivers and business cases of the risk mitigation measures considered in this work. Parameters used in the studies are summarised in Table 3.1.

Table 3.1. Parameters for management of construction outages example

Parameter	Value
Transformer rating (MVA)	90
Transformer circuit failure rate (%/year)	2 and 20
MTT Restore supply (hours)	12, 24, 60 and 240
Transformer normal repair time (hours)	720
Contractual window peak demand (as percentage of transformer rating)	50%, 75%, 100%, 125% and 150%
Existing transfer capacity (% of transformer rating)	0, 20, 40, 60

Parameter	Value
New transfer capacity (% of transformer rating)	25, 50, 75 and 100
Total mobile generation capacity (MW)	0, 10 and 15
Average mobile generation deployment (hours)	4.5 and 7
Mobile generation renting cost (£/kW.day)	1 and 3.5
VoLL (£/MWh)	17,000 and 34,000
Construction outage duration (months per transformer)	1, 3 and 6

3.3 The potential benefit of provisional supply in a network with different reliability characteristics

The potential benefit of the provisional supply depends on the reliability characteristics of the transformer in operation. The availability of a transformer with a higher failure rate or MTTR will be lower and therefore the security of the supply depends more on the presence of provisional supply which in turn, increases its value and business cases. The studies use 2 different failure rates for the 90 MVA transformer, i.e. 2% and 20% and three values of MTTR are used, i.e. 12h, 24h, and 60h. Peak demand is 100% of the transformer rating (90 MVA), and we assume the following:

- Duration of the transformer construction outage is 3 months.
- The system already has capability to transfer 20% of demand to adjacent grids.
- In addition, the studies consider the use 10 MW mobile generation. The cost of renting mobile generation is £1/kW.day.

Figure 3.2 shows the results of the studies assuming VoLL of £17,000/MWh for four capacities of the provisional supply (25%, 50%, 75%, and 100%). The potential benefit of provisional supply is calculated as the difference between total costs with and without provisional supply and it is expressed in £ per event. Total cost is the cost of lost load (EENS x VoLL) and cost of renting mobile generation.

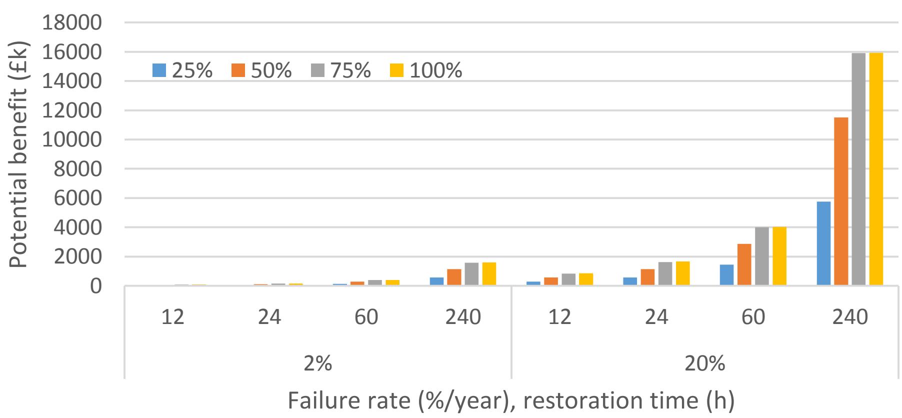


Figure 3.2. Potential benefit of provisional supply in a network with different reliability characteristics; legend – new transfer capability as percentage of transformer rating

The followings are observed:

- As expected, the potential benefit of provisional supply is lower in a system with higher reliability (low failure rate, low MTTR) and vice versa. The potential benefit is modest in the case with the failure rate of 2%/year and MTTR of 12 h. However, the benefit is considerably higher (i.e. circa £4m) in the case with the failure rate of 20%/year and MTTR of 60 h. It is even higher for MTTR of 240 h when it is about £16m for failure rate of 20%/year.
- 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 the same considering there is already an existing transfer capacity of 20% and 10 MW of mobile generation. The analysis assumes minimum use of mobile generation where possible. For example, if post-fault delivered provisional capacity is sufficient the use of mobile generation is reduced as much as possible.

Figure 3.3 shows the value (£/MW installed), on average, of the provisional supply is the highest at 25% capacity and decreases afterwards. While the concept of marginal value can be used to determine the optimal investment, the average value indicates the benefit of the investment on average. The results show that although the potential benefits of having load-transfer capability at 75% and 100% of transformer rating are the same, but their values are different. The latter has a lower value than before

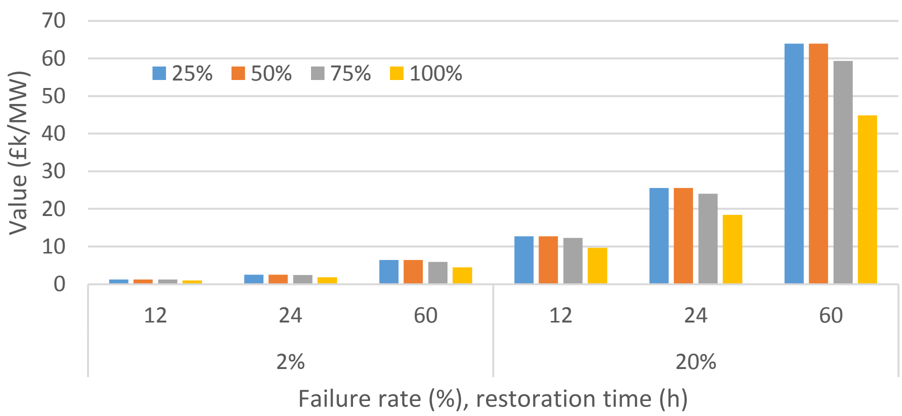


Figure 3.3. Value of provisional supply in a network with different reliability characteristics; legend – new transfer capability as percentage of transformer rating

3.4 *Potential benefit of provisional supply in a network with different existing transfer capacity*

The value of new investment in load-transfer capability depends on the capacity of load-transfer capability that is already present in the system. Different capacities of existing load-transfer capability are used in this study, i.e. 0% (no existing capability), 20%, 40%, and 60% of transformer rating and MTTR of 60 h. The results are shown in Figure 3.4.

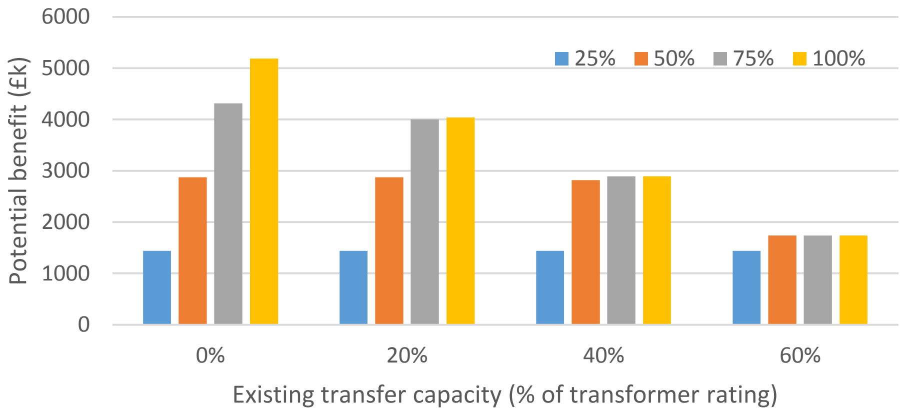


Figure 3.4. Potential benefit of provisional supply in a network with different existing transfer capacity; legend – new transfer capability as percentage of transformer rating

The results show that the potential benefit of new load-transfer capability is lower when load-transfer capability is already present in the system. Without existing load-transfer capability, the potential benefit increases continuously until the capacity reaches 100% of transformer's rating. The maximum potential benefit is found to be circa £5,200k.

If the system already has load-transfer capability of 20%, 40%, and 60% then the maximum benefits of new investment are circa £4,000k, £2,900k, and £1,700k respectively.

3.5 Potential benefit of provisional supply in a network with different levels of peak demand

The potential benefit of improving the transfer capability may also depend on the level of redundancy in the system, which is driven, particularly in these examples, by the level of peak demand. In these studies, different levels of peak demand are used, i.e. 50%, 75%, 100%, 125% and 150% of transformer rating. For these studies, we use the following assumptions: MTTR is 60 h, and existing transfer capacity is 60% of transformer rating. The results are shown in Figure 3.5.

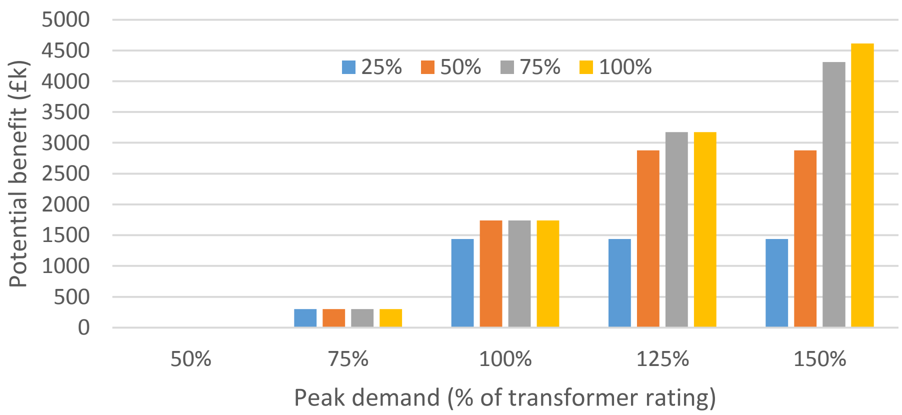


Figure 3.5. Potential benefit of provisional supply in a network with different levels of peak demand (existing transfer capacity: 60% of transformer rating); legend – new transfer capability as percentage of transformer rating

As the system with higher load is exposed more to the risk of losing supply, the potential benefit of new load-transfer capability is found higher in cases with higher peak load. When the peak load increases to 150% of transformer rating, the role of the load-transfer capability is no longer only for emergency action but also to reduce the loading of the transformer in operation. The maximum potential benefit observed in this study is about £4,600k.

On the other hand, the potential benefit of new load-transfer capability decreases to zero in the case where peak load is 50% of transformer rating. It is important to note that in this study, the system has the capability to transfer the load fully if the transformer in operation fails to work.

Another sensitivity study has been carried out using the same scenario as above except the existing transfer capacity is now 40% (instead of 60%). The results are shown in Figure 3.6.

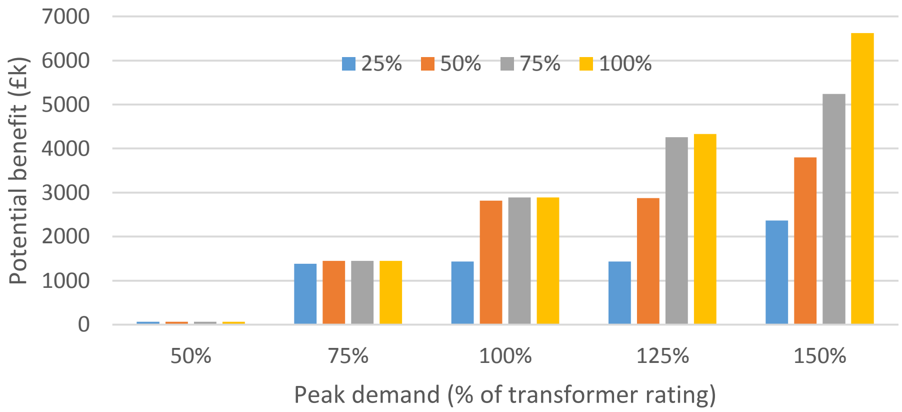


Figure 3.6. Potential benefit of provisional supply in a network with different levels of peak demand (existing transfer capacity: 40% of transformer rating); legend – new transfer capability as percentage of transformer rating

With the existing transfer capability of 40%, the potential benefit of new load-transfer capability is higher than in the previous case, for example: the maximum potential benefit is found to be circa £6,600k, compared with £4,600k found previously.

3.6 Impact of mobile generation on the potential benefit of improving the load-transfer capability

In these studies we analyse the potential benefit of the load-transfer capability in a system with different mobile generation capacities, i.e. 0 (no mobile generation), 10 MW, and 15 MW. For these studies, we use the following assumptions: peak demand is 100% of transformer rating (90 MVA), failure rate is 2%, MTTR is 24 h, and existing transfer capacity is 40% of transformer rating. In this study, the cost of mobile generation and deployment time are considered small, and ignored. The results are shown in Figure 3.7.

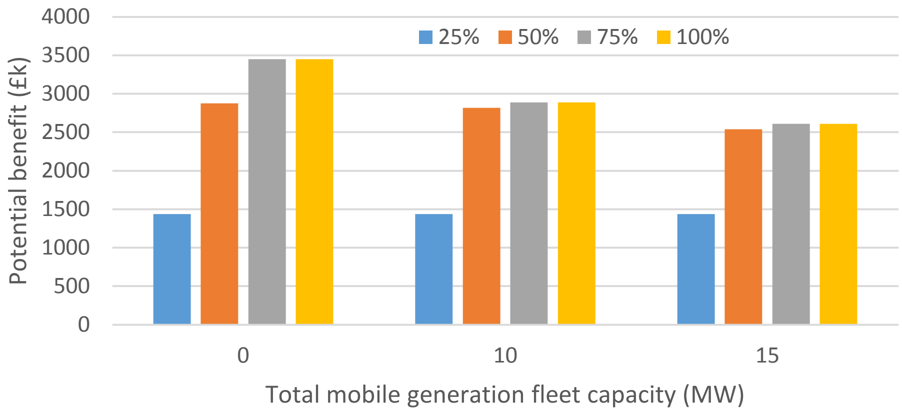


Figure 3.7. Impact of mobile generation on the potential benefit of new load-transfer capability (existing capability is 40%); legend – new transfer capability as percentage of transformer rating

The results show that the presence of mobile generation reduces the potential benefit of the load-transfer capability; the maximum value is found in the case without mobile generation, i.e. circa £3,450k. With 10 MW mobile generation, the maximum value reduces to circa £2,900k and with 15 MW mobile generation, the maximum value reduces further to circa £2,600k. The maximum potential benefit is found at load-transfer capability of 75%.

A set of sensitivity studies has been performed with the same settings as the previous studies except the existing transfer capacity is now set to 20%. The results are shown in Figure 3.8.

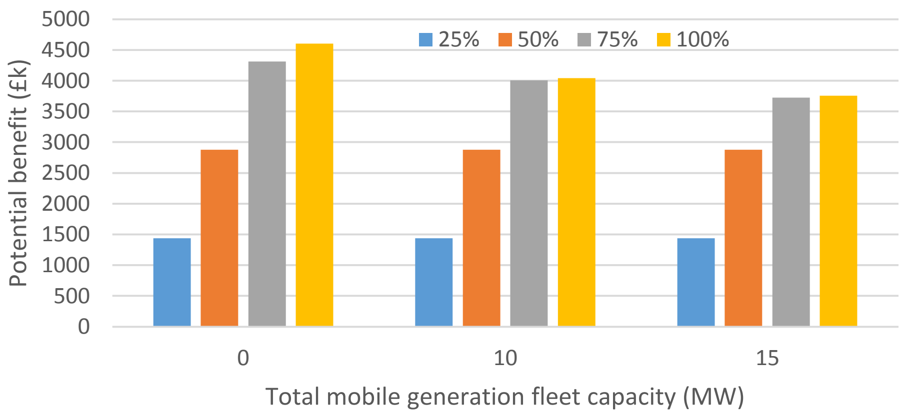


Figure 3.8. Impact of mobile generation on the potential benefit of new load-transfer capability (existing capability is 20%); legend – new transfer capability as percentage of transformer rating

With lower existing load-transfer capability, the business case for new load-transfer capability is higher. The maximum potential benefit increases to £4,600k, found in the case without mobile generation. The maximum benefit decreases with increased capacity of mobile generation.

A set of sensitivity studies has also been performed with the same settings as previous studies except with no existing transfer capacity. The results are shown in Figure 3.9.

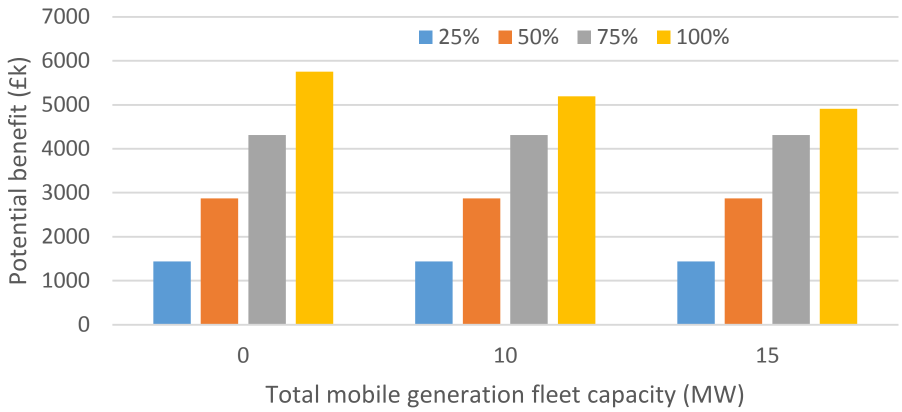


Figure 3.9. Impact of mobile generation on the potential benefit of new load-transfer capability (no existing capability); legend – new transfer capability as percentage of transformer rating

In this case, the business case for new load-transfer capability is stronger, the maximum potential benefit observed is £5,750k, found in the case with no mobile generation and load-transfer capability at 100%. The value again decreases with increased capacity of mobile generation. This trend is consistent with the trend observed in previous cases.

3.7 Potential benefit of improving load-transfer capability for different VoLLs

In these studies we analyse the value of the load-transfer capability in a system with different VoLLs, two values are used: £17,000/MWh and £34,000/MWh. For these studies, we use the following assumptions: peak demand is 100% of transformer rating (90 MVA), failure rate is 2%, MTTR is 24 h, mobile generation of 10 MW deployed in 7 h on average, and existing transfer capacity is 20% of transformer rating. The results are shown in Figure 3.10.

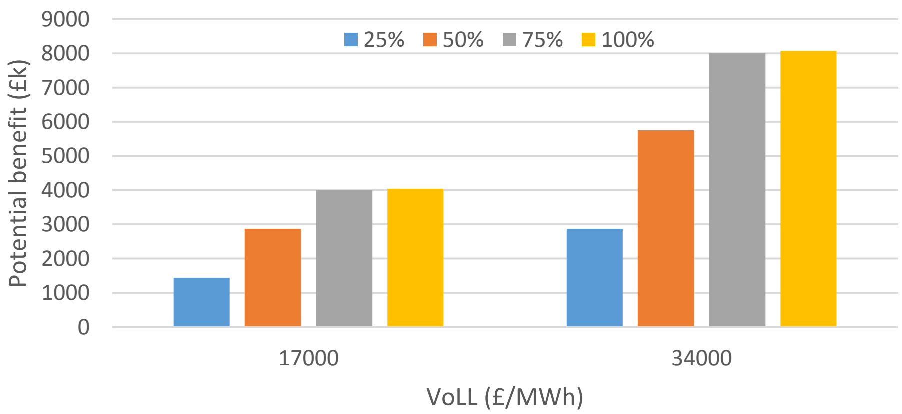


Figure 3.10 Potential benefit of improving load-transfer capability for different VoLLs; legend – new transfer capability as percentage of transformer rating

By doubling the VoLL, the potential benefit is also double. The maximum benefit observed in the case with VoLL of £34,000/MWh is circa £8,100k (2 x the maximum benefit with VoLL £17,000/MWh).

3.8 *Impact of construction-outage duration on the value of new load-transfer capability*

The length of the construction outage will be directly linked with risk exposure and hence potential benefit and value of the provisional supply should increase with the duration of the outage. For these studies, we use the following assumptions: peak demand is 100% of transformer rating (90 MVA), failure rate is 2%, MTTR is 24 h, existing transfer capacity is 40% of transformer rating, and VoLL of £17,000/MWh. The results are shown in Figure 3.11.

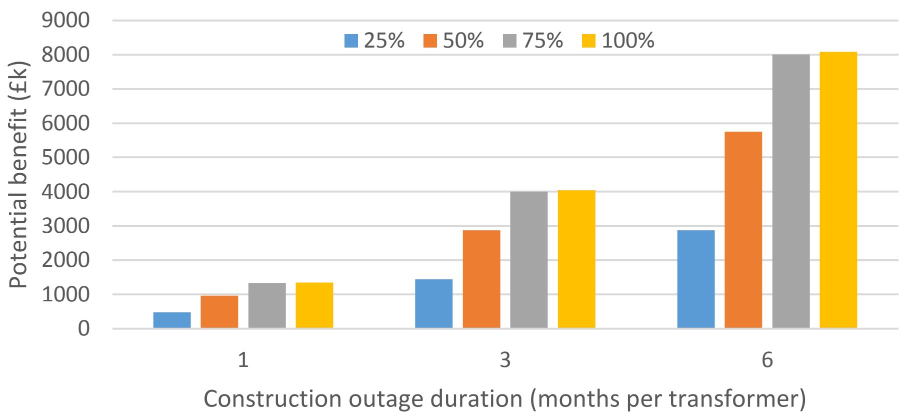


Figure 3.11. Impact of construction-outage duration on the value of new load-transfer capability; legend – new transfer capability as percentage of transformer rating

The results clearly demonstrate stronger business cases for having risk mitigation measures associated with prolonged construction outages. When the construction period of the new transformer is 6 month, the maximum potential benefit of the load-transfer capability is circa £8,100k. However, if the construction period is much shorter, e.g. 1 month, the maximum benefit is £1,350k.

3.9 *Optimal strategy of preventive vs corrective transfer capability*

If an outage occurs on a transformer circuit while the remaining one is in construction outage, supply interruptions could be minimised by the deployment of an array of post-contingency mitigation actions in the form of backup generation and transfer cables that can supply demand from adjacent (unaffected) networks. Alternatively, preventive network investment can minimise both impact of supply interruptions related with construction outages. Hence there is a clear opportunity to compare preventive and corrective (post-contingency) actions that can be undertaken by system operators and planners in order to minimise the impact of construction outages.

There is a number of fundamental questions associated with the portfolio of measures that can increase network resilience against construction outage related failures such as:

- Up to what extent a portfolio of merely post-contingency mitigation actions (such as deployment of backup generation and transfer cables) without the support from ahead and permanent network investment, is efficient to deal with one off event?

- Can network resilience be efficiently improved through network reinforcements rather than through a portfolio of post-contingency mitigation actions?
- How the set of post-contingency measures that may include deployment of provisional cables from neighbouring substations can affect the design of ahead, permanent network infrastructure?
- Overall: what is the right balance between preventive and mitigation (post-contingency) measures that can efficiently improve network resilience?

Answers to these questions are paramount to increase network reliability and thus improve customer experience.

The aforementioned problem is tackled by comparing interruption cost of option of installing provisional transfer capability correctively after the outage occurs or preventively before construction outage starts. There is a risk that the outage of a transformer in service while the other is in construction outage could expose customers to the outage until provisional transfer capability is constructed. The risk might be balanced over many other similar construction outage schemes and benefit on average might be achieved. A separate decision should be made whether the risk is acceptable, which is not part of this analysis.

For illustration, cost of interruption in preventive and corrective mode of investment is shown in Figure 3.12 if during construction outage of one transformer fault occurs on the other transformer. In this example, in a two-transformer substation 2x90 MVA one transformer is in construction outage lasting 3 months per transformer and if a fault occur on the second one. It is assumed that the peak demand during construction outage is 90 MW. The existing transfer capability is 20% of the transformer capacity and mobile generation of total maximum of 10 MW can be deployed within seven hours on average. The restoration time of remaining supply can be achieved on average in 60 hours. It is investigated the potential of new transfer capability than can be deployed preventively or correctively in 36 hours post fault with different available capacity 25, 50, 75 and 100% of transformer rating.

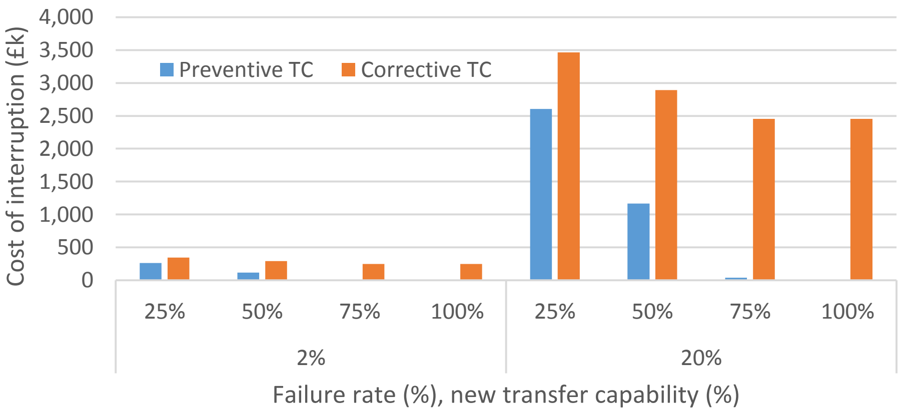


Figure 3.12. Total cost of preventive and corrective transfer capability

Comparison of cost of interruption if new transfer capability is achieved preventively and correctively is shown in Figure 3.12 for two transformer circuit failure rates 2 and 20%/year and four transfer capabilities 25, 50, 75 and 100% of transformer rating. For example, for failure rate of 20%/year and transfer capability of 25% in preventive mode cost of interruption is £2,605k while in corrective mode it is £3,467k. If the difference between implementation cost in preventive and corrective mode is lower than difference in cost of interruption £863k the preventive installation would be preferred option. In case when transfer capability is 50% or 75% the difference in cost is £1,725k and £2,418k, respectively. Given the existing transfer capacity there is no real advantage of having 100% over 75% transfer capability.

To determine cost of corrective transfer capability deployment it should be considered over many construction outages as it is expected to be deployed only in a few of occasions. For illustration, if failure rate is 20%/year it is expected that during 6 months of construction outage on both of transformers the probability of a fault occurring on the other transformer is 10%. If there are 10 construction outage schemes it is expected that on average on one occasion corrective actions would be needed. In probability terms this is equivalent with the cost of corrective action being one tenth of the actual cost.

The above illustrate the concept and different options could be considered such as: (i) do nothing, (ii) prepare option for fast deployment of alternative transfer capability in corrective mode if a fault on transformer in service occurs during construction outage of the other, (iii) preventively install new transfer capability, (iv) combination of the preventive and corrective and (v) avoiding construction outage altogether by, for example, building at a new site and later decommissioning the old one. This is complex problem and solution would depend on many parameters such as cost of each option and if installed additional transfer capability has value other than during the construction outage etc.

Drawback of corrective mode of investment is that if occurs that it is economically efficient on average over many construction outages is that when it occurs during a particular construction outage those customers might be exposed to a prolonged supply interruption.

In the context of developing the future security standards, a further consideration of preventive vs corrective mode of investment needs considering and perhaps specifying thresholds for acceptable risks. In any cases, it is important that all stake-holders in this area have confidence in the process used to identify and assess risk, so that appropriate decisions can be made on its management.

3.10 Conclusions

The analysis in this section has shown that the value of ensuring alternative or provisional supply during construction outages can have considerable economic benefits, particularly in cases where components are characterised by high failure rates and long repair times, and if the VoLL parameter is towards the higher end of the spectrum.

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

As the amount of redundancy required reduces, the less inherent capability there is in the network to cater for construction outages and the greater the need to consider construction outages in detail. Inevitably this will increase cost and/or risks associated with managing construction outages.

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 and benefit of alternative preventive and corrective strategies for mitigating risks so that appropriate decisions can be made in relation to contingency arrangements. Whether it should be explicitly included in the standards is still an open question which might be addressed in the next phase of the project.

4 CONTRIBUTION OF DISTRIBUTED ENERGY RESOURCES TO NETWORK SECURITY

4.1 Introduction

One of the first departures from the historical network planning processes towards achieving network security through both network redundancy and incorporating non-network solutions has been carried out in the UK [60]. Although the focus of this work is on the concepts behind including distributed generation (DG) into distribution network planning, similar approaches are now being considered to be applied to flexible demand technologies and energy storage. The Smart Grid paradigm envisages a penetration of various forms of distribution energy resources (DER), such as demand side response (DSR) technologies in distribution networks, including demand-led DSR in the form of controllable / responsive loads and generation-led DSR in the form of DGs and energy storage (ES) technologies. DSR and grid-scale ES devices are growing in their role in facilitating cost-effective evolution to lower carbon systems due to their ability to provide a wide array of services across all voltage levels. Potential contribution of DG in loss-inclusive designed networks, which will generally have more flexibility to accommodate DG, might not be needed.

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. An illustrative example of this issue is indicated in Figure 4.1, in which several solutions are considered: (a) traditional network reinforcement through network-based solutions (third transformer is for illustrative purposes only), (b) distributed generation-based solution, (c) storage-based solution and (d) demand-side management-based approach (which can for instance include flexible commercial demand).

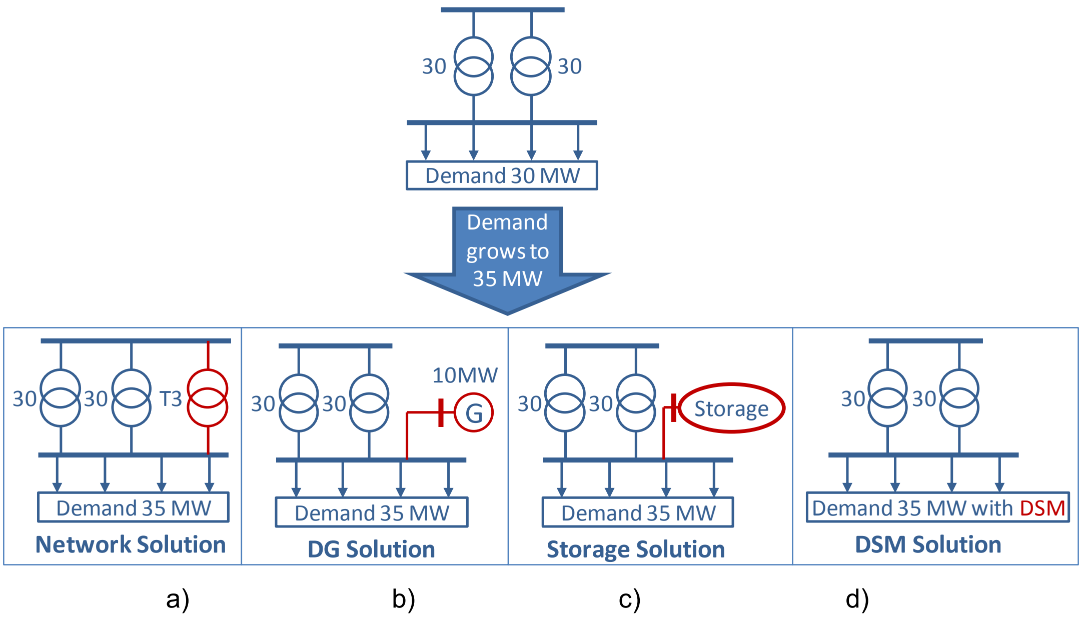


Figure 4.1. Range of network and non-network solutions for resolution of network security problems

In case of load increase, as indicated in the figure, traditional planning approaches would require network reinforcement (e.g. installation of a third transformer) as indicated in the solution (a) of Figure 4.1. Regarding the other 3 non-network solutions, the key question is associated with assessing the ability of these alternative solutions to substitute network reinforcement. In other words the network planners will need to determine the "capacity value" of the alternative non-network solutions, which requires assessment of the reliability performance.

The present distribution network planning standard, Engineering Recommendation P2/6 [60] employs the concept of Equivalent Circuit Capacity (ECC) that is used to quantify the security contribution of DG without considering the reliability properties of the actual distribution network. 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.

This section aims at quantitatively assessing the security contribution of DSR and ES technologies by accounting for the combined effects of the distribution network and non-network properties. This is achieved by employing an alternative methodology, denoted as Effective Load Carrying Capability (ELCC), which has been widely used for quantifying the security contribution of conventional and non-conventional generation technologies [61]-[66].

ELCC is defined as the amount of additional demand that can be supplied due to the presence of DSR or ES while maintaining the original risk associated with supply interruptions. The analysis, in this report, uses the same EENS as the original system without increasing it for the additional load. There is also a possibility of crossing group's boundary whether with the present or any future security standards. In the context of generation led DSR and some demand led DSR, temporal rescheduling effects may be neglected although they are essential for assessing the security contribution of energy storage. The security contribution of DSR according to the approach used in P2/6 depends solely on the DSR parameters and the shape of the load duration curve, while under the ELCC approach it also depends on network reliability parameters.

In the context of DSR and ES technologies, a large number of sensitivity analyses carried out in this section investigate the impact of key factors on their security contribution, including network related features, such as the failure rate and repair / restoration times of network assets, the level of network redundancy and the number of parallel network circuits. Furthermore, relative size of DER technologies, availability, the number of facilities, the coincidence in delivery of multiple facilities and the ability of DER to operate under islanding conditions are considered. For ES, different plant power and energy ratings are also considered.

4.2 Methodology

In contrast with the ECC methodology employed in the P2/6 standard, the ELCC [85] methodology proposed and applied in this report accounts for the combined effects of the distribution network and DSR and ES properties when assessing the security contribution of these non-network technologies. ELCC has been widely used in the past for quantifying the security contribution of conventional and non-conventional generation technologies.

For this reason, we propose the use of ELCC as a suitable capacity credit metric. ELCC is expressed in terms of MW, while normalised ELCC is a percentage and refers to the ratio of ELCC over the DSR or ES power rating. Note that a perfect generator or circuit connection (i.e. no outages, no maintenance downtime, no ramping or minimum generation constraints) has by definition a nominal ELCC of 100%, capable of supporting load growth equal to the power rating without any increase in EENS. ELCC is defined as the amount of additional demand ΔD that can be supplied due to the presence of DSR or ES while maintaining the original risk associated with supply interruptions. The main concept of ELCC is illustrated in Figure 4.2, where a network supplying group demand D is equivalent to the original network plus DSR or ES while demand has been increased by a constant ELCC MW term across the year.

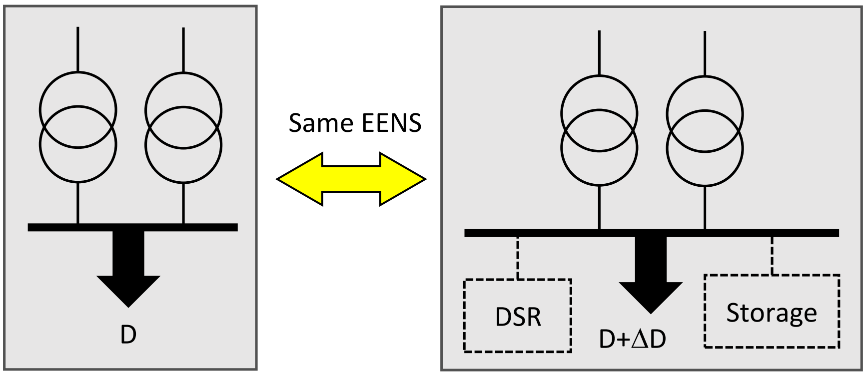


Figure 4.2: Equivalence between original network and network equipped with DSR or ES according to the ELCC capacity credit methodology

The ELCC methodology comprises two steps:

- The supply interruption risk associated with the system without DSR or ES (left part of Figure 4.2) is quantified. In this report, the employed risk measure is the Expected Energy Not Supplied (EENS) which is also used in P2/6.
- The EENS associated with the system including DSR or ES (right part of Figure 4.2) is quantified. This calculation is iteratively performed for different increments ΔD of the Group Demand D until determining the increment which yields the same EENS with the one calculated in the absence of DSR and ES. This increment (divided by the DSR or ES capacity to produce a p.u. value) constitutes the security contribution of DSR and ES.

The evaluation of the capacity credit of generation-led DSR is based on the representation of demand through load duration curves. This is driven by the assumptions that generation-led DSR would have no restrictions regarding fuel availability and their operation is not coupled to past system states. The same approach is used for demand-led DSR with the difference that unsupplied DSR energy is not counted towards EENS. ES is different to DG technologies in a variety of ways, warranting the development of a new capacity credit calculation method. First of all, whereas DG is solely constrained by its technical availability, ES facility must have both sufficient power output capability and energy stored to supply the load. In other words, whereas conventional resources, such as DG, typically face only power constraints, storage facilities can face both power and energy constraints. A second point is that whereas fuel supply of DG is considered unconstrained (e.g. diesel generators operating for relatively short periods of time are considered to have no fuel limitations, but this assumption may be reconsidered when extended operation is required) or stochastic (e.g. wind generators), ES's state-of-charge (SOC) is tightly linked to the network's available transfer capability as well as preceding events. The former consideration relates to the fact that ES does not generate power but rather make use of existing network assets (i.e. transformers) to draw power from the upstream grid. The degree to which this import capability is limited or not determines how much energy can be stored in a given period, for subsequent discharging at a time of need. As such, both the magnitude and the shape of demand are important. In addition, whereas transformer outages do not have an impact on DG's output capability, in the case of ES they do influence substantially its ability to store energy. Given that the ES state-of-charge is coupled to preceding operating points and outage events, a chronological Monte Carlo simulation framework of the system is developed to compute EENS. To alleviate the increased computational burden that this method may entail, an efficient bisection search algorithm is developed to minimize the number of iterations performed until the ELCC value is computed. A pragmatic simplified approach may need to be developed, like a lookup table or a software application, if the security contribution from storage is to be considered on a routine basis.

4.3 Contribution of DSR to network security

4.3.1 Description of case studies

The normalised duration curve of the group demand involved in the case studies is presented in Figure 4.3. Different scenarios are examined regarding its peak demand, ranging from 20 MW to 40 MW with a step of 5 MW.

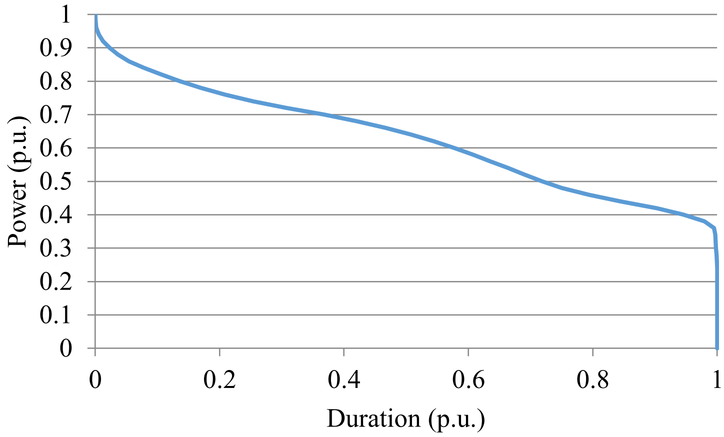


Figure 4.3. Normalised duration curve of group demand

The network supplying the group demand consists of a number of parallel circuits, each with a capacity R, as demonstrated in Figure 4.4. Different scenarios are investigated regarding the number of circuits (2, 3 or 4), the circuit failure rate (2% or 20%, meaning that a circuit failure occurs once every fifty or five years respectively) and the mean time to restore supply (MTTR) the faulty circuit (3h, 12h, 24h or 240h).

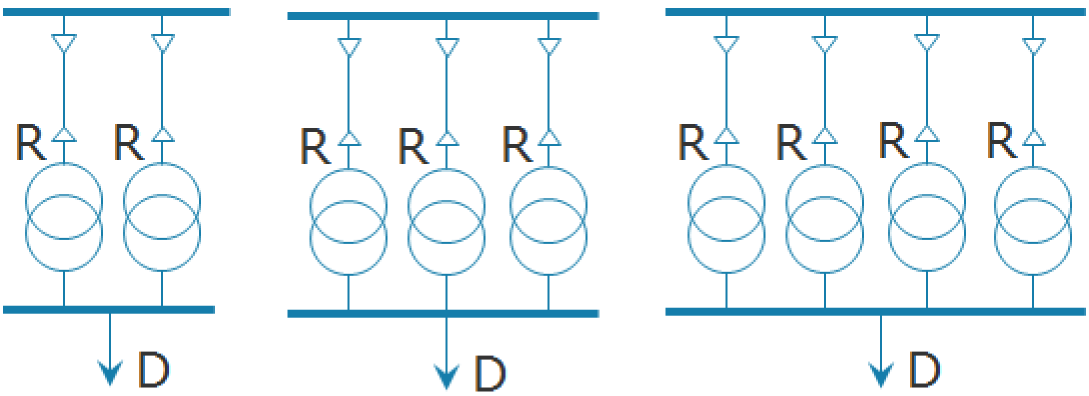


Figure 4.4. Investigated network scenarios

DSR in the case studies involves the ability to reduce the overall demand in the event of a single or multiple circuits' failure. Different scenarios are examined regarding the DSR capacity (2MW, 4 MW, 8 MW, 12 MW or 16 MW), the number of DSR facilities (1, 3 or 5), the DSR availability (60% or 86%), the probability of coincidence in delivery of multiple DSR facilities[10] (ranging from 0% to 100% with a step of 25%; 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 the time they act as independent DSR facilities) and the ability of DSR to operate under islanding conditions (able or unable to operate under islanding conditions).

[10] Coincidence in delivery can be driven by common failures in the communication and control infrastructure of DSR. If for example multiple DSR facilities are operated by the same DSR aggregator and a fault in the communication channel between the aggregator and the DSR facilities occurs, all of them will be unavailable at that time.

We define a base scenario corresponding to a peak demand of 20 MW, 2 parallel circuits of 20 MW each with a failure rate of 20% and a MTTR of 240h, and a single DSR facility of 2 MW with an availability of 60% and ability to operate under islanding conditions. Unless explicitly suggested, these values are employed in the case studies presented below.

The analysis in this section focuses on DSR at a primary substation. It should be noted that the used methodology is applicable for estimation of DSR contribution at different network locations. It is shown below that security contribution is a function of the network where DSR is connected and of the DSR penetration level. Greater penetration levels lead to lower contribution. Hence bespoke studies need to be performed to estimate the contribution of DSR under different conditions.

4.3.2 Impact of network parameters on DSR security contribution

Impact of network reliability

Figure 4.5 to Figure 4.7 compare the security contribution of 60% compliant DSR in different scenarios regarding the failure rate and MTTR of the network circuits and under different network redundancy cases, including a case with N-1 redundancy corresponding to Figure 4.5 (two circuits of 20 MW each, supplying a peak demand of 20 MW), a case with N-0.75 redundancy corresponding to Figure 4.6 (two circuits of 20 MW each, supplying a peak demand of 25 MW) and a case with N-0 redundancy corresponding to Figure 4.7 (two circuits of 20 MW each, supplying a peak demand of 40 MW).

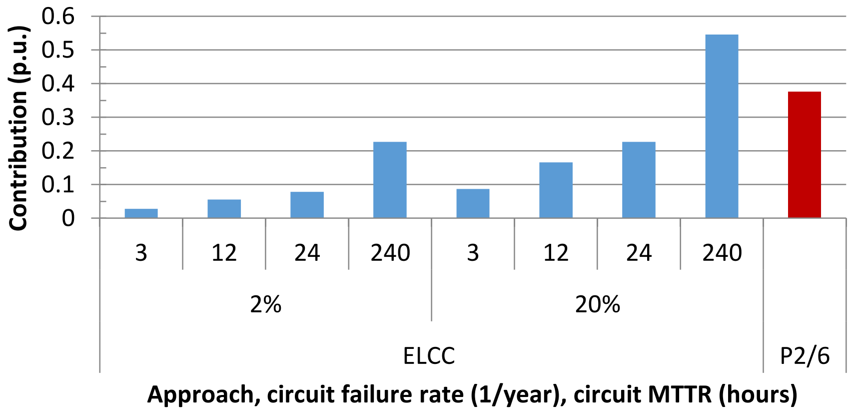


Figure 4.5. Illustration of impact of network reliability on DSR contribution at N-1 redundancy level

Figure 4.5 shows that the ELCC contribution of DSR depends on the network reliability, as described by the circuit failure rate and MTTR. It can be observed that the ELCC contribution increases from about 3% to about 55% 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 a MTTR of 240h). 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 contribution of DSR is minimal, ranging between 3 and 9% 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 8 and 23% depending on the circuits' failure rate. Contribution calculated using the approach applied in P2/6 is shown in red and is by definition independent from network reliability. In this example, it is equal to 38%, higher than all apart from one ELCC contribution.

Figure 4.6 illustrates the impact of network reliability on DSR contribution at N-0.75 redundancy level. It can be seen that the impact of network reliability is negligible. In this instance ELLC contribution is greater than the P2/6 contribution.

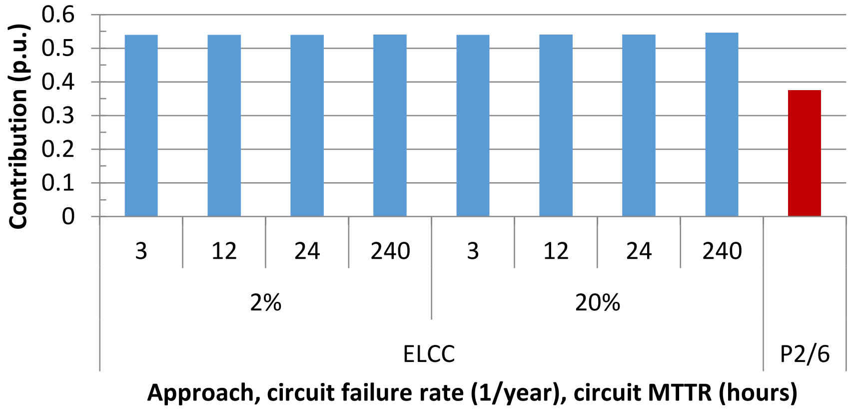


Figure 4.6. Illustration of impact of network reliability on DSR contribution at N-0.75 redundancy level

Figure 4.7 illustrates the impact of network reliability on contribution of 60% compliant DSR at N-0 redundancy level. In this case the contribution again depends significantly on the network reliability parameters with a similar pattern as in the N-1 redundancy scenario.

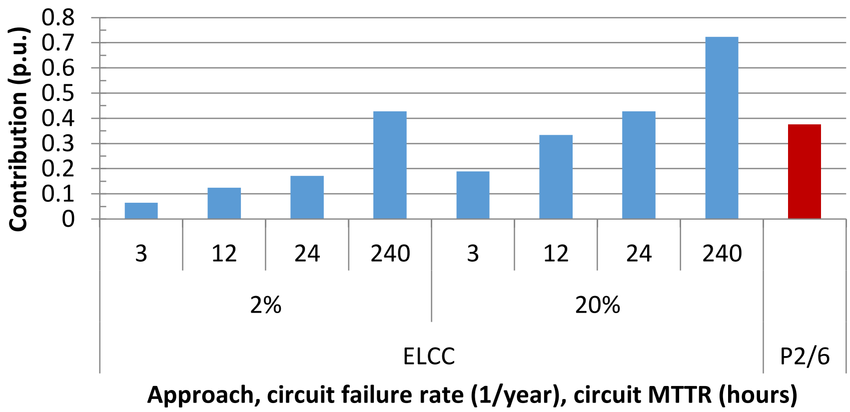


Figure 4.7. Illustration of impact of network reliability on DSR contribution at N-0 redundancy level

The contribution of DSR increases with an increasing failure rate and MTTR of the circuits under every network redundancy scenario. It is observed however that this effect of network reliability on the DSR contribution is much more prominent in the N-1 and N-0 redundancy cases and almost unnoticeable in the N-0.75 case. In the N-1 redundancy case, the DSR contribution increases from about 3% to about 55% as we move from a very reliable network to a very unreliable network. Similarly in the N-0 case, the DSR contribution increases from about 6% to 72%. In the N-0.75 case however, the DSR contribution increases from about 54% to just about 55%, and a similar effect is observed in the N-0.5 and N-0.25 cases which are not presented here for brevity reasons.

In order to explain these effects, we need to examine the origin of EENS without DSR in each of these cases (Figure 4.8-Figure 4.10). In the N-1 redundancy case, the most significant proportion of EENS is driven by events where both circuits are out (Figure 4.8). Given the quadratic relationship between the probability of such events and the circuit availability, the EENS and therefore the DSR contribution increases disproportionately with a decreasing circuit availability.

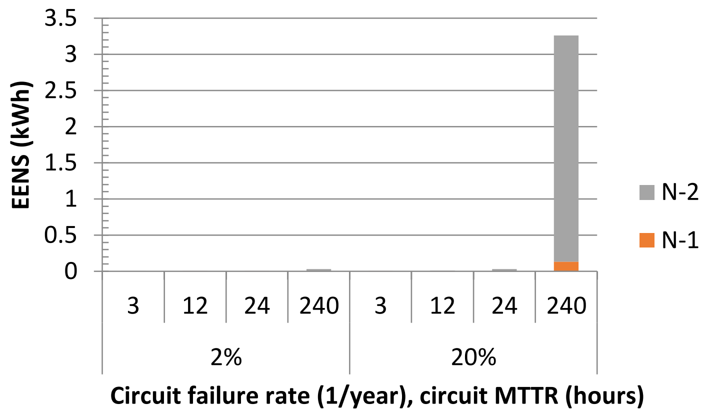


Figure 4.8. Illustration of origin of EENS for N-1 redundancy level; N-1 and N-2 denotes the number of circuits out of service

In the N-0.75 case (and also in the N-0.5 and N-0.25 cases), the most significant proportion of EENS is driven by events where a single circuit is out (Figure 4.9). Given the linear relationship between the probability of such events and the circuit availability, the EENS and the DSR contribution do not increase that much with a decreasing circuit availability.

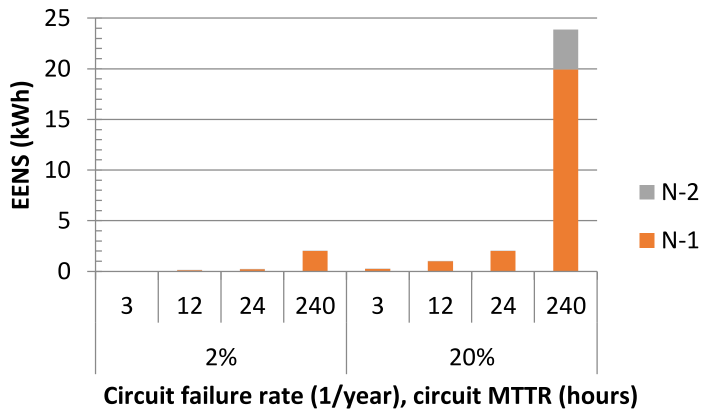


Figure 4.9. Illustration of origin of EENS for N-0.75 redundancy level; N-1 and N-2 denotes the number of circuits out of service

Finally in the N-0 case, a part of EENS corresponds to the normal operating condition where both circuits are in service (Figure 4.10). Given the quadratic relationship between the probability of normal operating condition and the circuit availability, the EENS and therefore the DSR contribution increases disproportionately with a decreasing circuit availability.

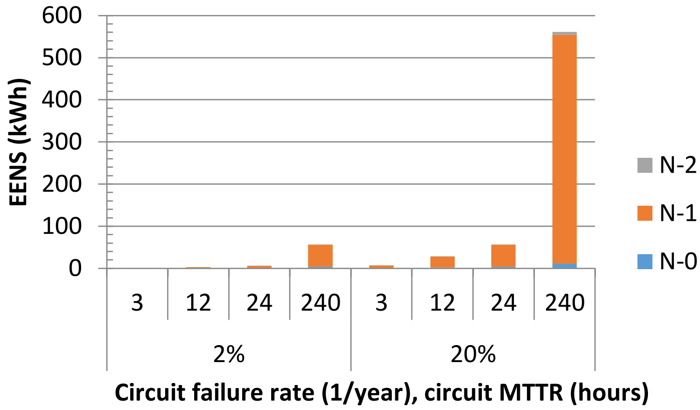


Figure 4.10. Illustration of origin of EENS for N-0 redundancy level; N-0, N-1 and N-2 denotes the number of circuits out of service

Figure 4.11 shows the contribution of 90% compliant DSR at N-1 redundancy level. It can be seen that the contribution is about double in comparison from the ones in Figure 4.5.

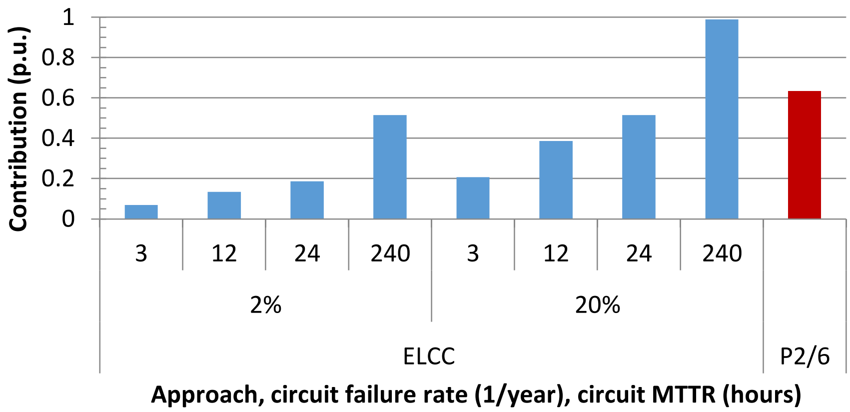


Figure 4.11. Illustration of impact of network reliability on 90% compliant DSR contribution at N-0 redundancy level

Impact of network redundancy

Figure 4.12 compares the security contribution of DSR in different network redundancy cases. The correlation is not smooth, as the DSR contribution is almost identical in the N-1 and N-0.75 cases, increases as we move from N-0.75 to N-0.25 and decreases as we move from N-0.25 to N-0. This lumpy correlation is again associated with the origin of EENS without DSR in each of these cases (Figure 4.13).

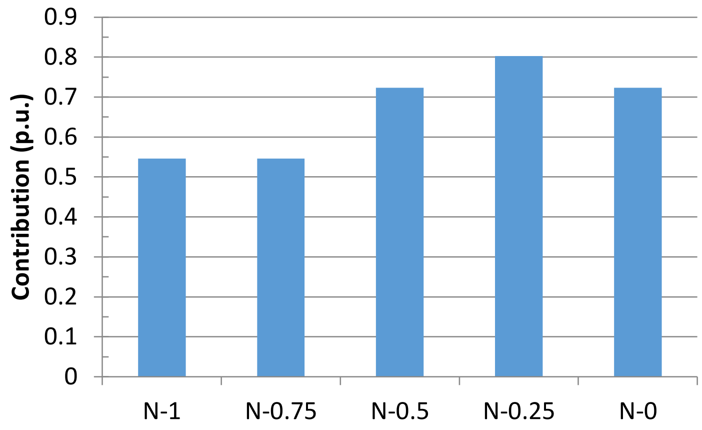


Figure 4.12. Illustration of impact of network redundancy on DSR contribution

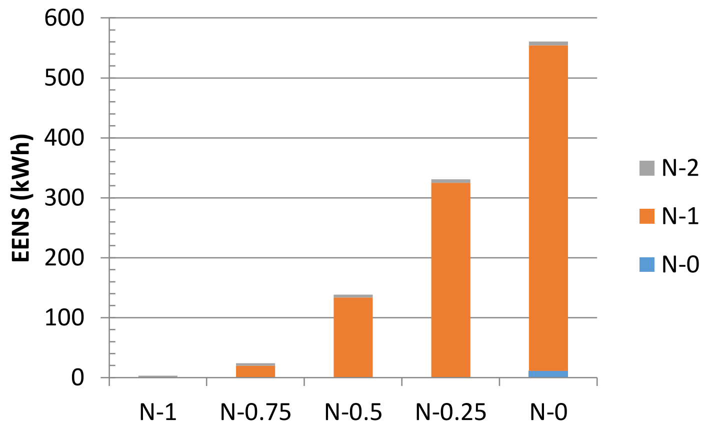


Figure 4.13. Illustration of origin of EENS for different network redundancy levels; N-0, N-1 and N-2 denotes the number of circuits out of service

At N-1 redundancy level, the reference EENS i.e. without DSR, is driven only by outage of both circuits. By introducing DSR, EENS will drop during the whole of the year (both circuits out of service) and by increasing peak demand until EENS matches pre-DSR level the majority of EENS increase will be driven during peak hours (one circuit out of service) but with a greater probability. At N-0.5 redundancy level, by introducing DSR, savings in the EENS when both circuits are in outage are the same as before but there are also savings when one circuit is in outage. This will allow for a greater increase of peak demand to match the starting EENS and hence leads to a greater DSR contribution. At N-0 redundancy level the contribution will drop as increase of EENS is during periods when both circuits are in service which is characterised by a much higher probability i.e. for the same increase of peak demand the EENS will increase significantly. Given that this increase is during peak conditions, the duration of periods where EENS would increase is similar in N-0.5 and N-0 redundancy levels. Hence peak demand needs to increase less for the same increase of EENS, leading to a decrease in contribution.

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Impact of number of circuits

Figure 4.14 compares the security contribution of DSR in different scenarios regarding the number of the parallel network circuits supplying the group demand and under different cases regarding the network reliability and the number of DSR facilities at N-1 redundancy level.

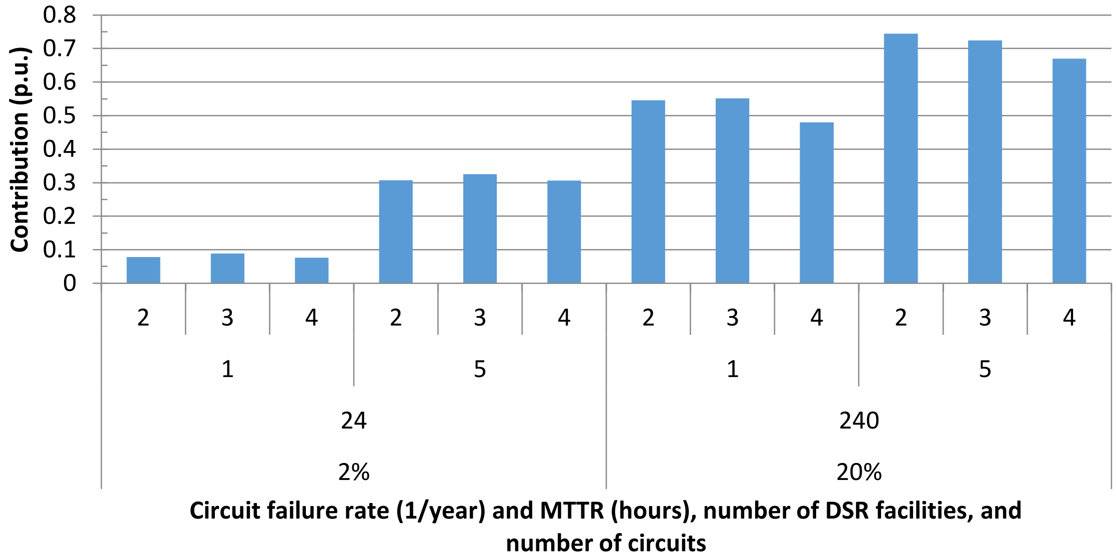


Figure 4.14. Illustration of impact of number of circuits on DSR contribution for different number of DSR facilities and different network reliability

It is evident in every case that the number of circuits does not have a significant impact on DSR contribution. This is because savings in EENS when introducing DSR are related to the system state where both circuits are in outage. For three and four circuit networks the savings in lower states are relatively smaller given the significantly lower probability. For a system with three and four circuits the probability of two circuits in outage is three- and six-fold greater than in a system with two circuits, respectively. Depending on LDC shape durations at which these savings are derived, the contribution might decrease with the increase of number of circuits. By increasing peak demand the majority of increase of EENS will be achieved when one circuit is in outage. Probability of one circuit in outage in systems with three and four circuits is 50% and 100% greater than in systems with two circuits, respectively. However, increase of EENS happens during peak conditions i.e. for a shorter duration but with a significantly higher probability. In this example all these factors broadly balance out, leading to a small variation of DSR contribution with the number of circuits. It can be seen that the DSR contribution depends on the number of DSR facilities. Security contribution for one and for five DSR facilities are shown in the Figure above. This is comparable with the P2/6 philosophy where more units with the same total installed capacity result in a greater contribution of a single unit.

Impact of load profile

A load profile with a low load factor of 45% in addition to a load profile with a high load factor of 63% is also considered. Results are shown in Figure 4.15.

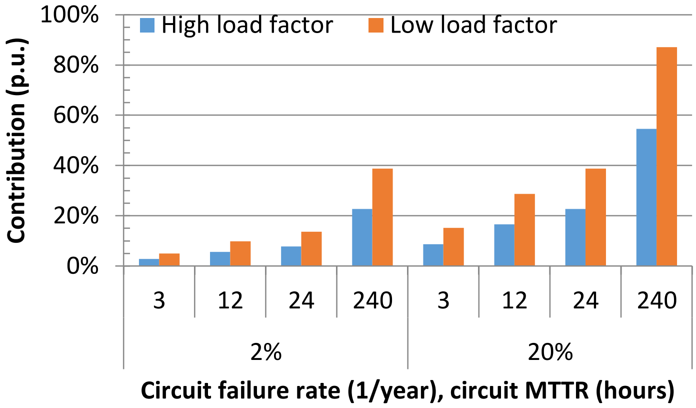


Figure 4.15. Impact of load profile on contribution

It can be seen that contribution of DSR is greater for the case of the load profile with lower load factor by about 60 to 75%.

4.3.3 Impact of DSR-related factors on DSR security contribution

Impact of the relative size of DSR

Figure 4.16 compares the security contribution of DSR in different scenarios regarding the DSR capacity for a reference 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 55% to about 18%. The peak demand is increased from reference value to account for DSR contribution and EENS is calculated. Hence, in case of the DSR capacity being 10% of peak demand its security contribution is about 21 MW, while when total DSR capacity is 80% of peak demand, security contribution is 22.9 MW.

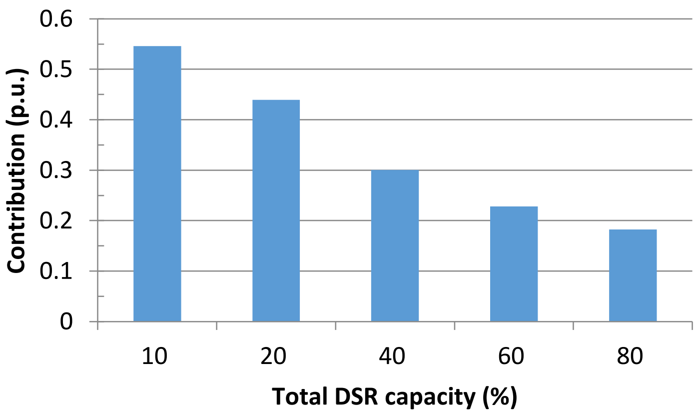


Figure 4.16. Illustration of impact of relative size of DSR on its contribution

This is because savings in EENS by introduction of DSR are broadly proportional to the DSR size. However, by increasing peak demand proportionally to DSR size, resulting in the same p.u. contribution, the increase of EENS beyond the DSR size is driven by the increase of number of hours that the demand is above the network capacity during a single circuit outage i.e. driven by the shape of LDC. Hence a step type shape of LDC during peak condition can be derived for which contribution would be the same for significant range of DSR capacities.

Impact of DSR availability

Figure 4.17 compares the security contribution of DSR in different scenarios regarding the availability of DSR. As the DSR availability increases from 60% (low) to 86% (high), the contribution of DSR increases from about 55% to about 94%, since DSR can provide demand reduction for a larger proportion of time.

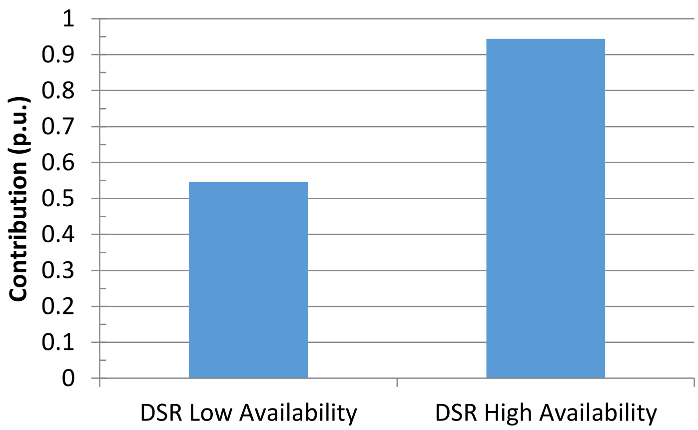


Figure 4.17. Illustration of impact of DSR availability on DSR contribution

Impact of the number of DSR facilities

Figure 4.18 compares the security contribution of DSR in different scenarios regarding the number of DSR facilities, in which the total DSR capacity is the same and equal to 2 MW and the coincidence in delivery is 0%. As the number of DSR facilities increases from a single facility of 2 MW to five facilities of 0.4 MW each, the contribution of DSR increases from about 55% to about 74%. This is due to the fact that the probability of providing a required amount of demand reduction is increased with an increasing number of DSR facilities.

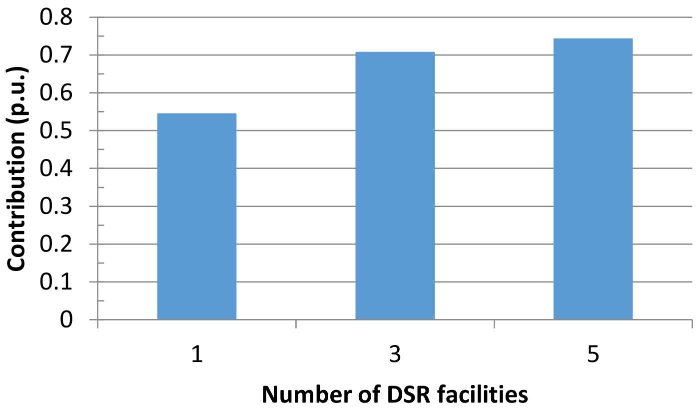


Figure 4.18. Illustration of impact of number of DSR facilities on DSR contribution

Impact of coincidence of delivery of multiple DSR facilities

Figure 4.19 compares the security contribution of six DSR facilities of 1 MW each in different scenarios regarding their coincidence in delivery. For example, coincidence in delivery could result from an ICT failure affecting the aggregators. The impact of a wide range of coincidence in delivery is investigated in this report. It should be noted that this report does not prescribe what coincidence in delivery might be applicable for a particular situation. 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 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 results of the previous subsection) 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.

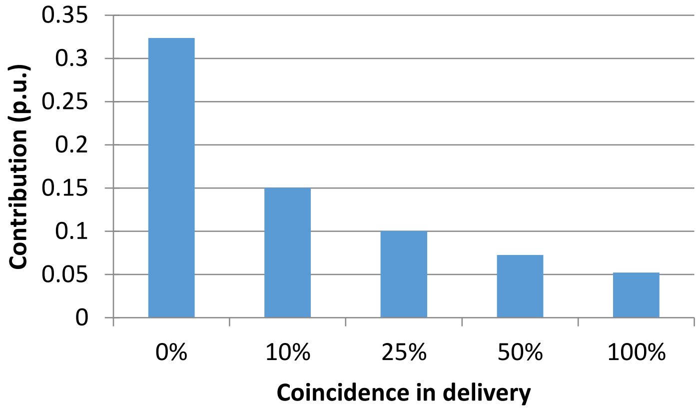


Figure 4.19. Illustration of impact of coincidence in delivery on DSR contribution

It should be noted that even for a relatively small coincidence in delivery of 10%, the DSR contribution has dropped from about 32% to about 15%. When coincidence in delivery is increased from 10% to 25% a further 5% drop of contribution is observed, the same with the reduction of contribution if coincidence in delivery is increased from 25% to 100%. In summary, coincidence of delivery is an important driver of DSR contribution to security of supply.

Probability of delivering contribution

In this study, a two circuit network with a rating of each circuit of 15 MVA, a failure rate of 10% and a MTTR of 24 hours is considered. Different scenarios regarding the number of DSR facilities are considered in which the total DSR capacity is the same and equal to 3 MW and the coincidence in delivery is 0%.

The DSR contributions to security of supply and the probability of actually delivering this contribution based on the P2/6 and ELCC approaches are presented in Figure 4.20. Numbers of DSR facilities are shown in X-axis while Y-axis represents contribution and probability of delivering contribution respectively.

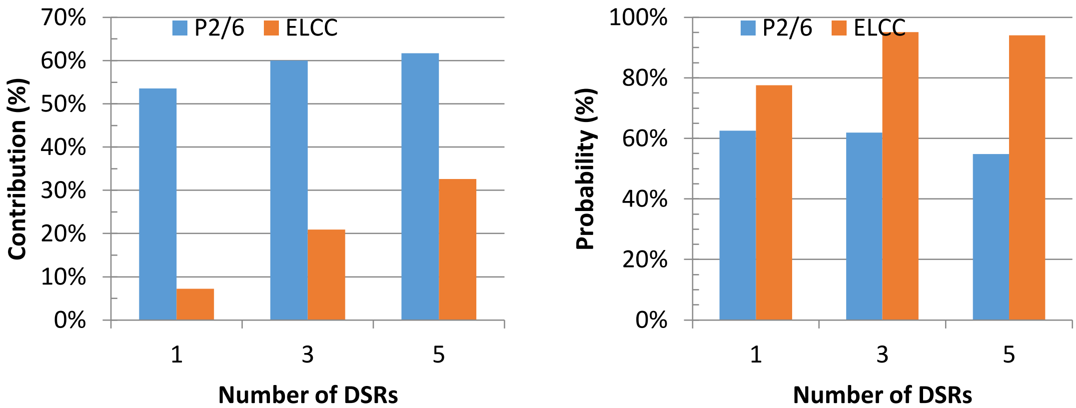


Figure 4.20: Comparison of DSR contribution factors (left) and probability of delivering contribution (right) for different numbers of DSR facilities and different methodological approaches

The DSR contribution estimated by the P2/6 approach increases with the number of DSR facilities from about 54% to about 62%. The probability of delivering this contribution, when needed, decreases from about 63% to about 55%. However, a more significant variation of the DSR contribution with the number of DSR facilities can be observed under the ELCC approach which takes network reliability into consideration. The ELCC contribution increases from about 7% to about 33% for one and five DSR facilities respectively. Furthermore, the ELCC approach results in higher probability of delivering contribution than the P2/6 approach. Probability of delivery is between 78% and 94% for one and five DSR facilities respectively.

Table 4.1 and Figure 4.21 present the EENS calculated by different approaches in a case with three DSR facilities of 1 MW each. The Mean EENS is about 7.8 kWh under the ELCC approach, significantly lower than under the P2/6 approach (33.1 kWh). It can be also observed that the EENS can be significantly higher in a small percentage of cases. For example, under the P2/6 contribution the EENS can be more than 189 KWh in 1% of cases.

Table 4.1: EENS under different approaches

Cumulative probability (%)	**EENS (kWh)**	
	P2/6	**ELCC**
1.0%	**189.5**	**82.9**
5.0%	102.8	33.7
	Mean EENS (kWh)	
33.3%	33.1	
23.8%		7.8

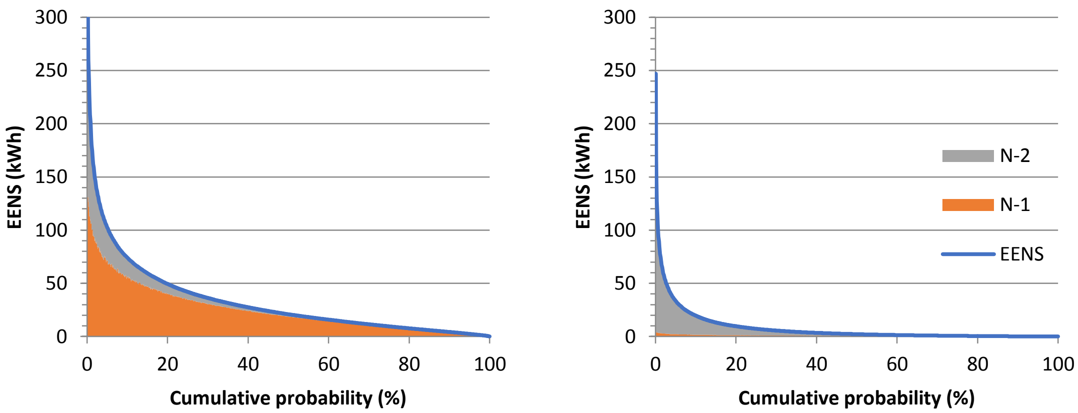


Figure 4.21: Cumulative probability of EENS if contribution is calculated by the P2/6 approach (left) or the ELCC approach (right)

Furthermore, Figure 4.21 demonstrates that under the P2/6 approach significant part of EENS comes from the N-1 condition, while under the ELCC approach the N-2 condition contributes significantly more.

DSR Contractual Redundancy

The security contribution of DSR facilities is subject to their availability limitations, driven by the consumers' actions as well as failures in the communication and control infrastructure of DSR. One way of increasing the probability of delivering the contribution made by DSR facilities is to introduce redundancy by contracting a larger number of DSR facilities. The objective of this section is to investigate the value of DSR contractual redundancy.

The examined example involves supply of the demand by two transformer circuits of 90MVA each. The probability of delivering the contribution of one DSR facility of 10MW is calculated in the case that 0, 1, 2 or 3 extra DSR facilities of the same size are contracted for redundancy. Two alternative scenarios where the compliance of DSR facilities is 60% or 90%, as well as alternative scenarios regarding the failure rate and MTTR of the transformer circuits, are explored.

The probability of delivering the DSR contribution depends only on the compliance of DSR, as shown on Table 1.2. In the case of 60% DSR compliance, the probability of delivering the DSR contribution increases from 60% in the case of no contractual redundancy to 97% in the case of 3 extra contracted DSR facilities. In the case of 90% DSR compliance, this probability is increased from 90% to 100%. These results indicate the significant benefits brought by contractual redundancy in terms of securing that the contracted contribution will be actually delivered.

Table 4.2: Probability of delivering the DSR contribution for alternative contractual redundancy scenarios

DSR compliance (%)	Failure rate (%/year)	MTTR (hours)	Contribution of one DSR facility (%)	Probability of delivering contribution			
				Contractual redundancy			
				0	1	2	3
60%	2%	60	12%	60%	84%	94%	97%
		120	17%				
		180	20%				
		240	23%				
	20%	60	33%				
		120	43%				
		180	50%				
		240	55%				
90%	2%	60	29%	90%	99%	100%	100%
		120	39%				
		180	46%				
		240	52%				
	20%	60	72%				
		120	90%				
		180	98%				
		240	100%[11]				

[11] Contribution is limited to 100% (calculated value was 103%).

The cost of interruption for the consumers depends on the assumed VoLL as well as the number of hours required to manually activate DSR in the case of a failure in the communication and control infrastructure of DSR. The value of contracting one extra DSR facility in terms of annual cost of interruption if the VoLL is equal to £17,000/MWh and one hour is needed to manually activate DSR is presented in Table 4.3. This value is calculated by multiplying the VoLL with the EENS reduction driven by contractual redundancy.

The cost of interruption increases with a lower DSR compliance and a lower network reliability; as a result, the value of contractual redundancy is significantly increased in these scenarios.

Table 4.3: Savings in cost of interruption (£/year) if an additional one hour is needed to manually activate DSR; VoLL is £17,000/MWh

Failure rate (%/year)	MTTR (hours)	DSR compliance 60%	DSR compliance 90%
2%	60	120	59
	120	330	159
	180	592	281
	240	894	418
20%	60	3,239	1,435
	120	8,320	6,002
	180	14,214	12,178
	240	20,605	17,121

Impact of the ability of DSR to operate under islanding conditions

Figure 4.22 compares the security contribution of DSR with and without the ability to operate under islanding conditions and under different network redundancy cases. In the N-1 case, the contribution of DSR decreases from about 55% with the ability to operate under islanding conditions to zero without it. This is because the most significant proportion of EENS in this case is driven by events where both circuits are out and DSR is islanded. In other words, at N-1 redundancy level there would be no decrease of EENS when DSR facilities are introduced if they cannot operate when both circuits are in outage. Hence, zero increase of peak demand is needed to achieve reference EENS resulting in zero contribution.

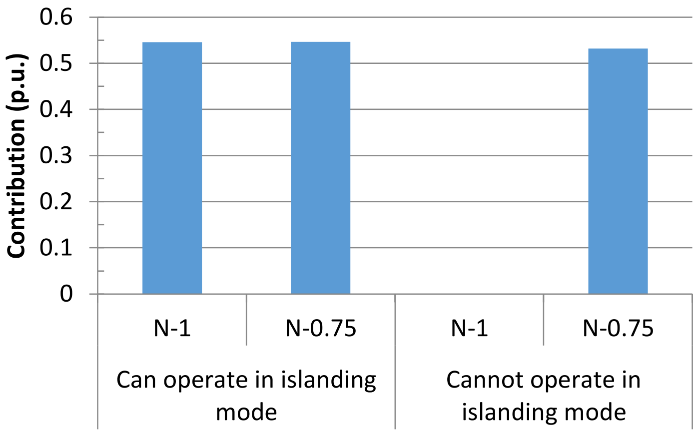


Figure 4.22. Illustration of impact of islanding mode of operation on DSR contribution for different redundancy levels

In the N-0.75 case on the other hand, the ability to operate under islanding conditions does not have a substantial impact on the contribution of DSR as the most significant proportion of EENS is driven by events where a single circuit is out, in which DSR is not islanded. In other words, at N-0.75 redundancy level there would be decrease of EENS when DSR facilities are introduced in cases where one circuit is in outage. Hence a non-zero contribution is derived.

4.3.4 Conclusions

The main conclusions stemming from the case studies examined in this report regarding the security contribution of DSR are the following:

- 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 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 an increasing DSR availability.
- The contribution of DSR of a fixed total capacity increases as the number of DSR facilities increases and their coincidence in delivery decreases.
- Contractual redundancy increases the probability of DSR to deliver a given contribution and reduces the customer interruption costs.

- The ability of DSR to operate under islanding conditions has a significant positive impact on its contribution under N-1 network redundancy and almost no impact under lower network redundancy levels.

4.4 Reliability contribution of energy storage

In this section we set out to quantify energy storage (ES) security contribution under different scenarios and investigate the impact of different parameters. The sequential Monte Carlo modelling framework has been used in all cases to calculate security contribution expressed in terms of ELCC.

All studies have been conducted on a test system consisting of two 10 MW transformers. The initial assumption is that this system is being operated under an N-1 redundancy level, meaning the maximum demand level that occurs throughout the year is equal to 10 MW. The annual demand time series in [59] has been used to capture load variability between different hours of the day, days of the week and seasons. A part of the annual demand time series used is shown in Figure 4.23.

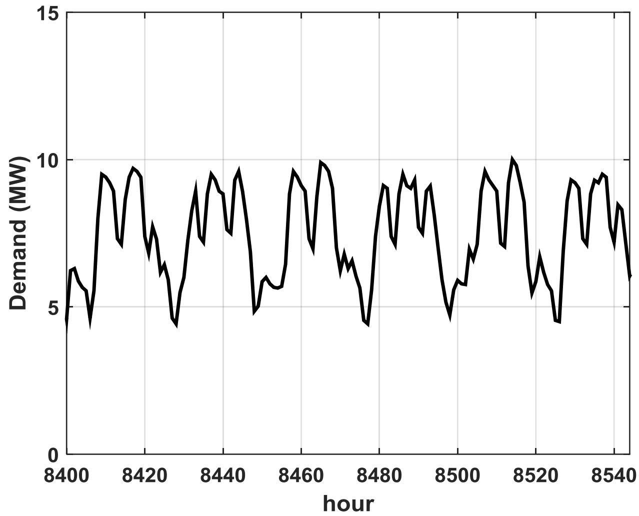


Figure 4.23. Demand for some typical winter days in December from the annual demand pattern used in the system simulations.

A large number of studies have been performed to explore different drivers of storage's contribution to security of supply. In all studies, 100,000 Monte Carlo simulations have been run to determine EENS and subsequently quantify ES security contribution. Note that in most cases, ES security contribution is expressed in terms of the normalised ELCC value, which expresses ELCC as a percentage of the storage plant's power rating.

4.4.1 ES security contribution study results

A total of 8 reliability scenarios have been examined, where each scenario corresponds to a transformer MTBF and MTTR combination. The proportion of time spent in intact, single outage and double outage conditions (denoted π(intact), π(single) and π(double) respectively) for different reliability scenarios are shown in Table 4.4. Note that transformer failures are considered independent. The most reliable network examined is equipped with two transformers, each with MTBF = 5 years and MTTR = 3 hours resulting in a transformer availability α = 99.993%. This network spends on average just 1.2 hours each year in fault conditions. The least reliable network examined is equipped with two transformers, each with MTBF = 1 year and MTTR = 240 hours resulting in a transformer availability of α = 97.333%. This network spends on average 461 hours each year in fault conditions.

Table 4.4: System availability and percentage of time spent in intact, single outage and double outage conditions for different transformer MTBF and MTTR values.

MTBF (y)	MTTR (h)	α	π(intact)	π(single)	π(double)
1	3	99.965%	99.932%	0.068%	<10E-6
1	12	99.863%	99.727%	0.273%	<10E-6
1	24	99.727%	99.454%	0.545%	0.001%
1	240	97.333%	94.738%	5.191%	0.071%
5	3	99.993%	99.986%	0.014%	<10E-6
5	12	99.973%	99.945%	0.055%	<10E-6
5	24	99.945%	99.891%	0.0109%	<10E-6
5	240	99.455%	98.913%	1.084%	0.003%

It is instructive to calculate EENS under basecase conditions (i.e. no ES) for each of the 8 reliability scenarios presented in Table 4.4. Basecase EENS figures are significant because they define the target level of demand curtailment to be achieved under a demand increase of ELCC with the support of ES operation. Results are shown in Table 4.6, where basecase EENS (denoted $EENS^*$) is expressed as the sum of EENS due to single outage events (denoted $EENS^*s$) and double outage events (denoted $EENS^*d$).

As expected, under the N-1 security standard, supply risk is driven exclusively by double transformer outages. Basecase EENS is driven by both outage frequency and duration. In the case of rare outages and fast-repairable transformers, the basecase EENS is very close to 0 MWh due to the low probability of having some demand curtailment. In contrast, the largest basecase EENS is given in the case of the least resilient network; 38.29 MWh when MTBF = 1 year and MTTR = 240 hours. In addition, a relaxed redundancy level may be implemented for cost-efficiency or other reasons. This choice dictates the peak demand serviceable in the basecase. For this particular case study under investigation, which involves 2x10 MW transformers, the peak demand under a relaxed security criterion of the form N-X can be calculated as 10(2-X). For example, N-0.75 results in a peak demand of 12.5 MW, while N-0.25 results in 17.5 MW. As a result, the basecase EENS (see Table 4.5) changes radically for different redundancy levels.

Table 4.5: Basecase EENS and its distribution between demand curtailment due to single and double transformer outages across the eight reliability scenarios examined for network redundancy levels N-1, N-0.75, N-0.5 and N-0.25.

Redundancy	MTBF (y)	MTTR (h)	EENS (MWh)	EENSs (MWh)	EENSd (MWh)
N-1	1	3	0.01	0	0.01
		12	0.10	0	0.10
		24	0.40	0	0.40
		240	38.29	0	38.29
	5	3	<10E-6	0	<10E-6
		12	<10E-6	0	<10E-6
		24	0.02	0	0.02
		240	1.60	0	1.60
N-0.75	1	3	0.44	0.43	0.01
		12	1.87	1.74	0.13
		24	3.96	3.46	0.50
		240	80.84	32.97	47.86
	5	3	0.09	0.09	<10E-6
		12	0.36	0.35	0.01
		24	0.72	0.70	0.02
		240	8.88	6.89	2.00
N-0.5	1	3	3.40	3.39	0.01
		12	13.68	13.53	0.15
		24	27.58	26.98	0.60
		240	314.45	257.01	57.44
	5	3	0.68	0.68	<10E-6
		12	2.72	2.71	0.01
		24	5.44	5.42	0.02
		240	56.07	53.67	2.40
N-0.25	1	3	8.91	8.90	0.01
		12	35.69	35.51	0.18
		24	71.53	70.83	0.70
		240	741.72	574.71	67.01
	5	3	1.78	1.78	<10E-6
		12	7.13	7.12	0.01
		24	14.26	14.23	0.03
		240	143.69	140.89	2.80

Security contribution of storage has been calculated for a total of nine plants of different power and energy capabilities. Note that in all cases the power capability is expressed in terms of the basecase peak demand of 10 MW, while energy capacity in expressed in terms of hours. For example, the 20%/5 h case corresponds to a 2 MW/10 MWh storage plant, while the 100%/10 h corresponds to a 10 MW/100 MWh plant. Security contribution calculations have been carried out across the eight different reliability scenarios and four network redundancy levels. Security contribution results in term of the normalised ELCC values, which express ELCC as a percentage of the storage plant's power rating, are shown in Table 4.6 below.

Table 4.6: Normalized ELCC contribution across different network redundancy and reliability levels for different storage plants.

Redundancy	MTBF (y)	MTTR (h)	20% 2h	20% 5h	20% 10h	50% 2h	50% 5h	50% 10h	100% 2h	100% 5h	100% 10h
N-1	1	3	90%	100%	100%	48%	72%	100%	34%	52%	68%
		12	30%	50%	70%	24%	44%	60%	22%	34%	42%
		24	10%	30%	50%	12%	32%	48%	14%	28%	36%
		240	5%	5%	10%	2%	4%	8%	2%	4%	8%
	5	3	90%	100%	100%	48%	72%	100%	34%	52%	68%
		12	30%	50%	70%	24%	44%	60%	22%	34%	42%
		24	10%	30%	50%	12%	32%	48%	14%	28%	36%
		240	5%	5%	10%	2%	4%	8%	2%	4%	8%
N-0.75	1	3	70%	100%	110%	48%	80%	100%	36%	62%	94%
		12	40%	70%	100%	32%	48%	64%	22%	32%	44%
		24	40%	70%	90%	28%	40%	52%	20%	26%	32%
		240	30%	60%	70%	24%	32%	32%	16%	16%	18%
	5	3	70%	100%	110%	48%	80%	100%	36%	62%	94%
		12	40%	70%	100%	32%	48%	64%	22%	32%	44%
		24	40%	70%	90%	28%	40%	52%	20%	26%	32%
		240	30%	60%	70%	24%	32%	32%	16%	16%	18%
N-0.5	1	3	80%	110%	120%	56%	88%	104%	44%	76%	94%
		12	40%	70%	90%	28%	48%	64%	20%	34%	50%
		24	30%	60%	70%	24%	36%	48%	16%	24%	34%
		240	20%	40%	50%	16%	24%	24%	12%	12%	14%
	5	3	80%	110%	120%	56%	88%	104%	44%	76%	94%
		12	40%	70%	90%	28%	48%	64%	20%	34%	50%
		24	30%	60%	70%	24%	36%	48%	16%	24%	34%
		240	20%	40%	50%	16%	24%	24%	12%	12%	14%
N-0.25	1	3	90%	120%	140%	64%	96%	112%	50%	78%	80%
		12	40%	60%	80%	24%	44%	64%	20%	34%	52%
		24	30%	40%	60%	20%	28%	44%	14%	22%	34%
		240	20%	30%	40%	12%	16%	16%	8%	8%	10%
	5	3	90%	120%	140%	64%	96%	112%	50%	78%	80%
		12	40%	60%	80%	24%	44%	64%	20%	34%	52%
		24	30%	40%	60%	20%	28%	44%	14%	22%	34%
		240	20%	30%	40%	12%	16%	16%	8%	8%	10%

As can be seen above, security contribution varies considerably according to the size of the plant, the duration to restore network assets as well as the redundancy level. As expected, the larger the energy capacity of the network, 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.

Regarding network redundancy, the main impact of operating under a reduced redundancy level is that ES can contribute in reducing basecase EENS during single outage events (which by definition give no demand curtailment under N-1) resulting in contribution above 100%. However, in cases where network redundancy is severely relaxed, the increased basecase demand compromises storages ability to re-charge, leading to a suppressed security credit. Having a normalised ELCC > 100% means that the storage plant can support an increase in demand beyond its maximum power output while maintaining security at the basecase level. This can occur only in cases of reduced network redundancy e.g. N-0.75 etc. The reason for this is that that storage can reduce load curtailment during single outage events compared to the basecase. This is not possible when network redundancy is at N-1 because by definition, a single outage event does not lead to load curtailment. Since storage can improve security of supply in the basecase, it can decrease security of supply under double outage events, while overall supply risk stays the same. In some cases, this is achieved when extra demand is increased beyond the power rating of the storage plant. This demand increase above ELCC is bound to be curtailed and result in increased EENS, but since the plant can improve on EENS of single outage events, it is possible to do this while maintaining basecase EENS value.

In the following sections we proceed to further analyse the results obtained and identify the main trends driving ES security contribution. In particular we focus on the impact of power and energy capability, network reliability (frequency and duration of transformer outages) and level of network redundancy.

4.4.2 Impact of power and energy capability

In this section, an extended sensitivity study is undertaken with respect to the storage plant's power rating and energy capacity. Nine different storage plant sizes have been examined and their ELCC calculated when added to a network with two 10 MW transformers with MTBF of 1 year, MTTR of 3 and 12 hours and network redundancy of N-1 and N-0.75.

In Figure 4.24 we show ELCC for storage plants of different power rating and energy capacity under the reliability scenario of MTBF = 1 year and MTTR 3 hours. 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 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; 34%, 52% and 68% for 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.

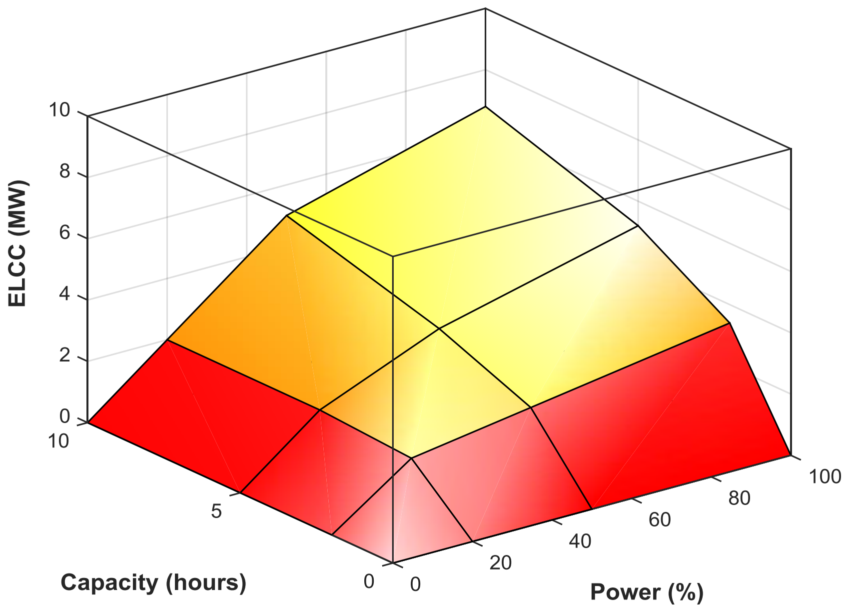


Figure 4.24: ELCC for different storage plants under reliability scenario MTBF = 1 year and MTTR = 3 hours. N-1 level of network redundancy.

In Figure 4.25 we show ELCC under the same reliability scenario, but with a network redundancy level of N-0.75. This system has a considerably larger basecase EENS level since single outage events can lead to loss of load. As shown in Table 4.5, basecase risk level is increased from 0.01 to 0.44 MWh. In the case of the low power/low capacity plant of 20%/2 hours, normalised ELCC contribution is reduced from 90% to 70%. This occurs due to the low contribution during single outage events in winter months; the low energy capacity prohibits the storage of enough energy to sustain supply throughout a 3 hour event in high-demand periods where no energy can be imported from the grid. However, in the case of low power/high capacity plant of 20%/10 hours, the contribution is increased from 100% to 110%.

Note that security contribution above 100% is possible in the case of reduced redundancy levels. This is not possible under the N-1 redundancy level since by definition single outage event do not result in loss of load; this fact is also demonstrated in the basecase EENS values shown in Table 4.5. The N-0.75 level greatly impacts larger sized plants as well, leading to an increase in their contribution. For example, in the particular case of plant with 100% power rating and 10 hour energy capacity, contribution is increased from 68% to 94%. This increase is due to the increased resilience against single outage events.

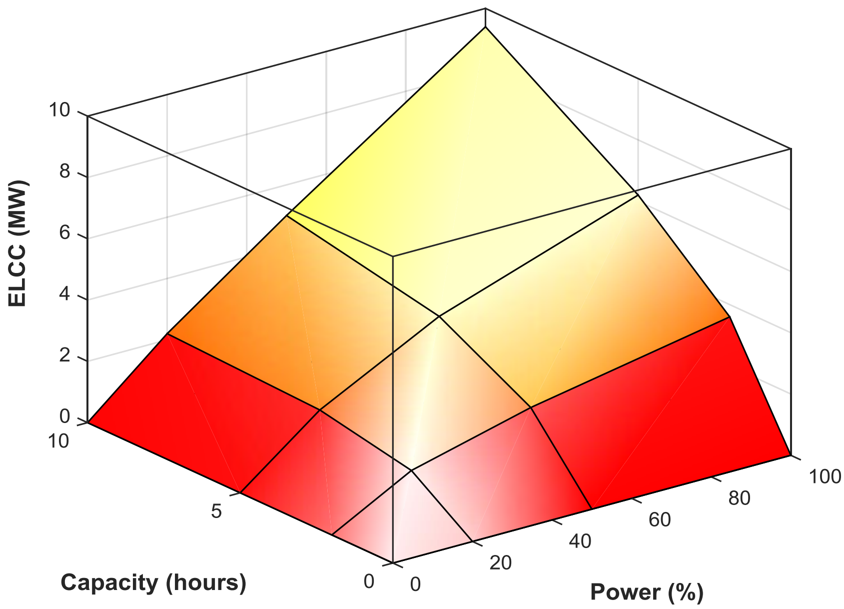


Figure 4.25: ELCC for different storage plants under reliability scenario MTBF = 1 year and MTTR = 3 hours. N-0.75 level of network redundancy.

In the following figures we analyse security contribution under the scenario of less reliable transformers. In particular, MTTR is increased from 3 hours to 12 hours. In Figure 4.26 we show ELCC for storage plants of different power rating and energy capacity under the reliability scenario of MTBF = 1 year and MTTR = 12 hours. As can be seen below, it is clear that the ES security contribution is considerably depressed. This is due to the longer duration of outages; a plant with the same energy capacity will have comparatively less security contribution in the presence of longer lasting outages. Naturally, this reduction effect is more pronounced in the case of smaller-sized plants. For example, the contribution of the 20%/2h plant is reduced from 90% to 30%. This is expected since the 4 MWh capacity can only sustain 0.67 MW (33.3% with respect to the 2 MW rating) of load increase during a double outage lasting 6 hours. Another effect contributing to this ELCC reduction is the inability to prevent loss of load during single outage events taking place in winter; these events last on average 12 hours during which very little re-charging can take place due to increased demand levels. In contrast, plants with higher energy capacity can survive such events by relying on their originally high state-of-charge.

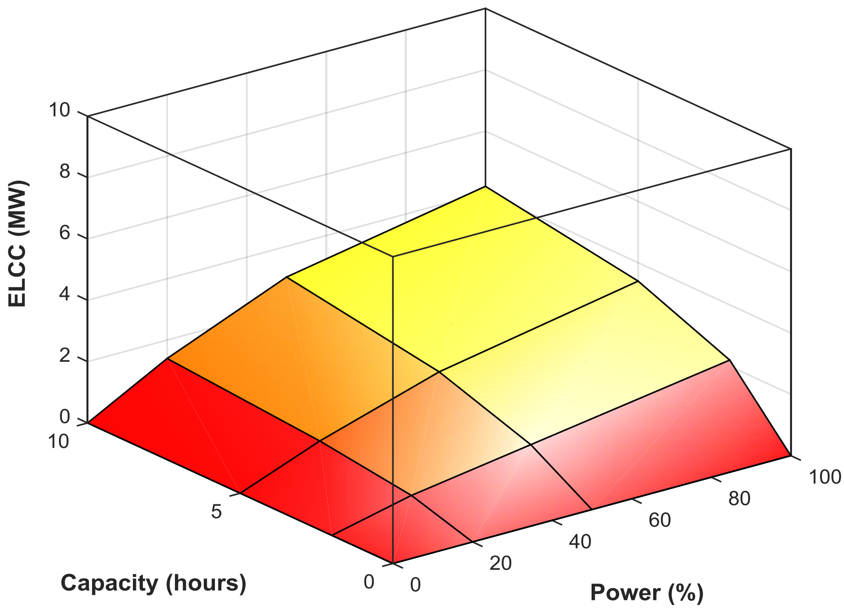


Figure 4.26: ELCC for different storage plants under reliability scenario MTBF = 1 year and MTTR = 12 hours. N-1 level of network redundancy.

In Figure 4.27 we examine storage plants under the same MTBF = 1 year, MTTR = 12 hours reliability scenario, but with N-0.75 redundancy level. As can be seen below, relaxation of network redundancy leads to an increase of security contribution compared to Figure 4.26. This is due to the increase of curtailed demand in the basecase, primarily due to single outage events. However, in contrast to the study shown in Figure 4.25, the prolonged outage duration results in overall reduced contribution levels. The change from N-1 to N-0.75 results in significantly increased contribution in the case of smaller-sized plants. However, the impact is minimal in the case of storage plants with 100% power rating. This is because under N-0.75 conditions and ELCC of 4 MW, the minimum demand level is increased close to 10 MW, essentially preventing re-charging during long-lasting single outages. This effect does not become binding in the case of smaller-sized plants; the extra demand due to ELCC does not interfere with the ability to re-charge during long-lasting single outage events, enabling ES to take advantage of the higher basecase EENS level and increase its contribution.

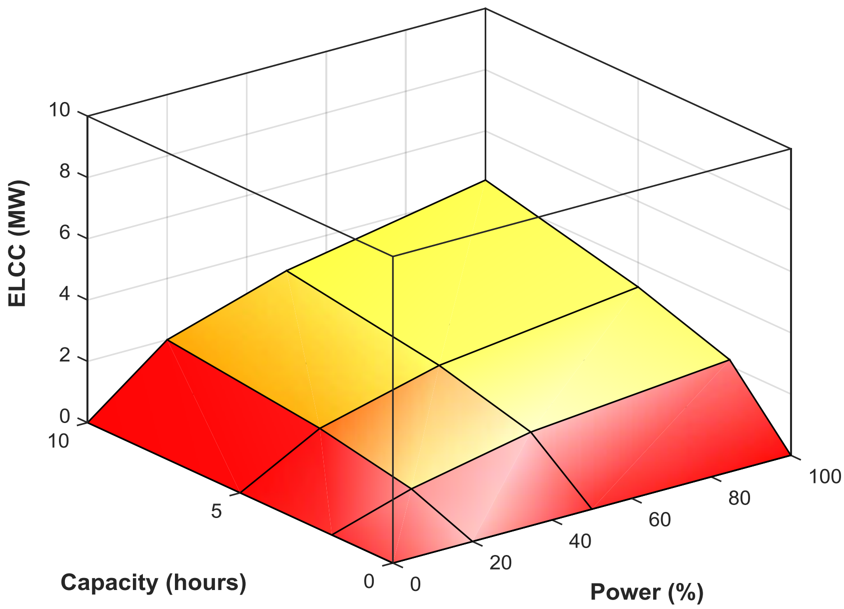


Figure 4.27: ELCC for different storage plants under reliability scenario MTBF = 1 year and MTTR = 12 hours. N-0.75 level of network redundancy.

4.4.3 Impact of frequency of outages

A topic of interest is the impact of frequency of outages. This is being expressed in terms of transformer MTBF. Two scenarios have been analysed in particular; MTBF of 1 year and 5 years. The normalized security contribution of a small, medium and large-sized plant under the previously analysed scenarios is shown across these two outage frequency scenarios in Figure 4.28.

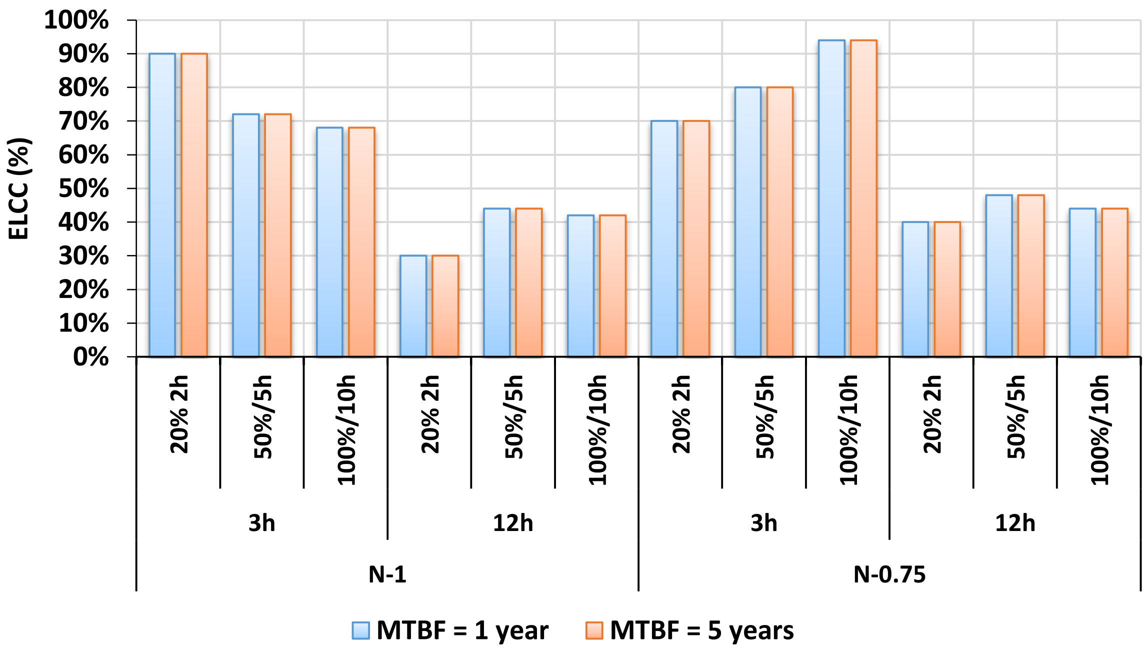


Figure 4.28: Normalised ELCC for different outage frequencies across three storage plant sizes under N-1 and N-0.75.

It is clear that the impact of outage frequency is minimal; there is no difference between ES security contribution under the two scenarios. Although basecase changes significantly according to outage frequency (see Table 4.5), with higher MTBF equating to lower EENS, and 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 rates of 1 and 5 years.

4.4.4 Impact of duration of outages

In contrast to the marginal impact of outage frequency, outage duration is one of the most important drivers of ES security contribution. In Figure 4.29 we present the normalized ELCC values for storage plants of nine different power and energy capabilities across four reliability scenarios. MTTR is a key factor in determining ES contribution; the longer the outage duration, the more energy is required from ES to supply the extra demand due to ELCC. This is evident from the study results, where the same plant is shown to have reduced security contribution as the duration of outage increases. This holds true in the case of all nine plants examined, as shown in Table 4.6. These results are also displayed in Figure 4.29, Figure 4.30, Figure 4.32 and Figure 4.33 for the different network redundancy levels N-1, N-0.75, N-0.5 and N-0.25 respectively.

As can be seen below, the ELCC value is bounded by the amount of energy that can be serviced during a double outage assuming 100% state-of-charge. For example, in the case of the 1 year/240hours scenario, the average duration of a double outage is 120 hours. This results in most plants having very reduced security contribution since the amount of energy required to sustain such a long outage is incredibly large. As a result, the contribution of the largest 100%/10h plant is just 8% (corresponding to 0.8 MW), very close to the upper bound of 100MWh/120 hours = 0.833 MW. In addition, another important observation is that achieving a high ELCC rating becomes increasingly difficult as the ES power rating increases. This is because the amount of energy needed to sustain a double outage increases substantially as a function of the extra demand ELCC. For example, during a 12-hour double outage, ES must be able to supply 12*ELCC MWh to ensure all extra demand is fully served and does not increase supply risk compared to the base case. At the same time, due to possible preceding transformer failures, it is not guaranteed that the storage plant will be at its full capacity when entering a double outage event. In addition, in the case of ES with small energy capacity, it is very likely that even under single outage conditions, the plant has had enough time to charge back to its maximum capability. Larger plants need considerably more energy to charge up to full state-of-charge.

It is important to note that the significance of the effects described above renders the use of chronological simulation approaches essential; aggregate network availability metrics cannot accommodate ES operation modelling under different outage duration conditions.

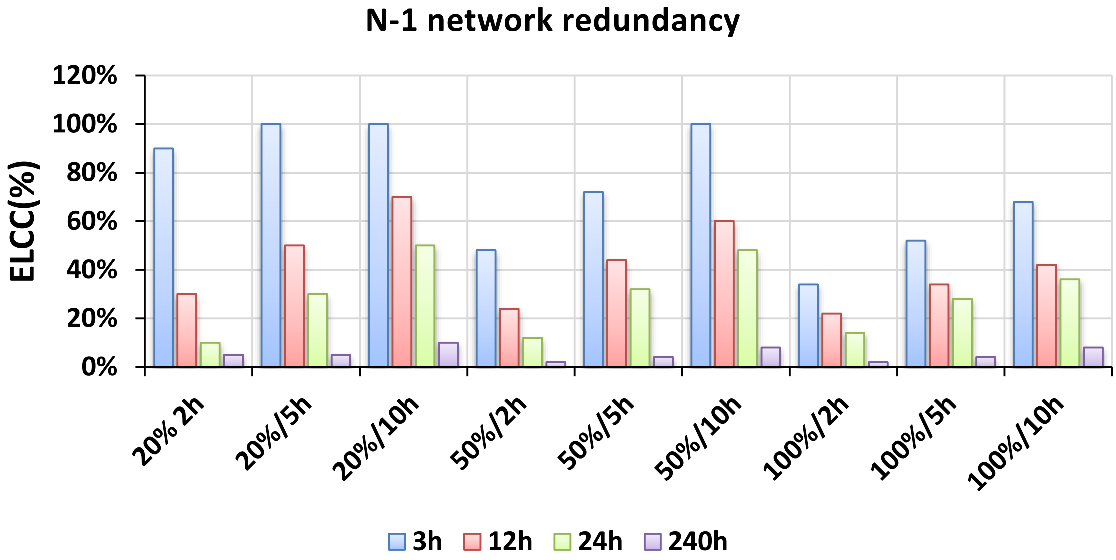


Figure 4.29: Normalized ELCC for storage plants of different sizes across four reliability levels under the N-1 network redundancy scenario.

In the following figures, we present the security contribution of the nine studies plants across four reliability scenarios in the case of relaxed redundancy levels. ES security contribution under N-0.75 is shown in Figure 4.29. It is evident that the main patterns identified earlier persist; the longer the outage the duration (i.e. higher MTTR), the lower the ES security contribution. However, the impact of applying N-0.75 is substantial. First of all, the contribution of all plants is increased due to the ability to support security of supply during single outage events. Notably, in some cases this effect can drive normalised security contribution above 100%. However there is an exception in the case of the 20%/2h plant, whose contribution is reduced under N-0.75. As explained earlier, this occurs due to the low contribution during single outage events in winter months; the low energy capacity prohibits the storage of enough energy to sustain supply throughout a 3 hour event in high-demand periods where no energy can be imported from the grid.

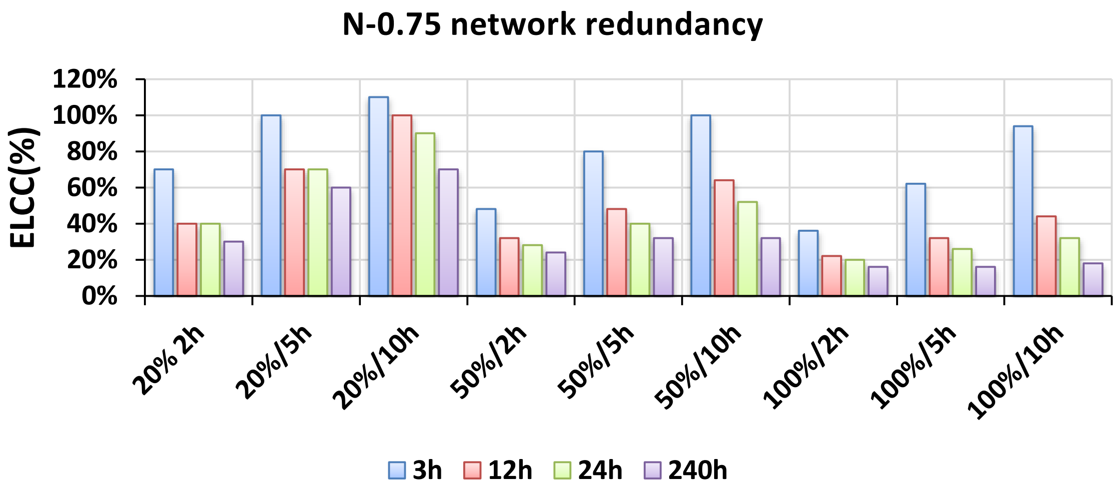


Figure 4.30: Normalized ELCC for storage plants of different sizes across four reliability levels under the N-0.75 network redundancy scenario

As shown in Figure 4.31, ES security contribution is depressed under N-0.5 due to the reduced capability to import energy from the grid. In particular, under N-0.5 the overall demand levels in the basecase are considerably increased with a peak of 15 MW and a daily minimum demand level averaging at about 7 MW. As a result, the amount of network capacity that can be used for re-charging purposes during single outage events is less compared to N-0.5, resulting in a reduced ability to support a large demand increase due to ELCC.

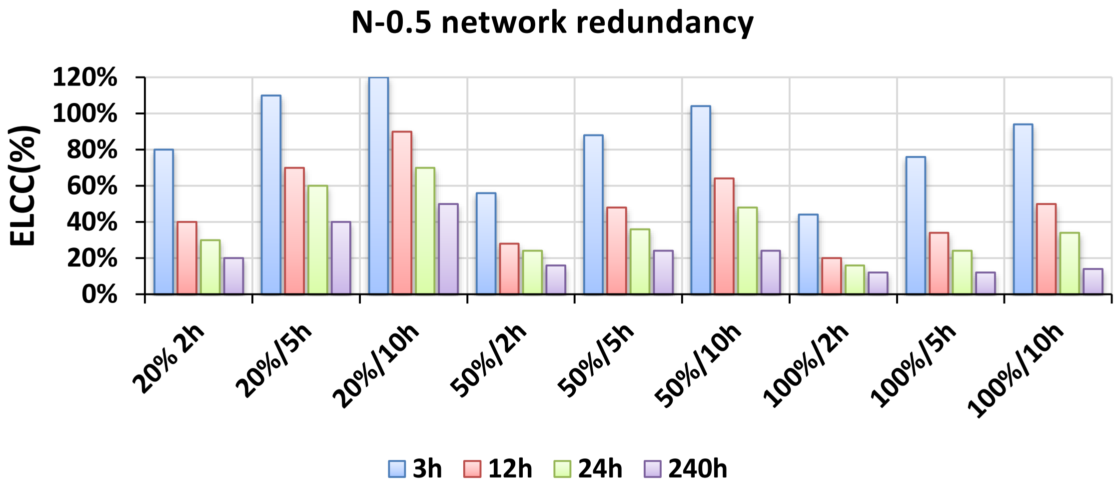


Figure 4.32: Normalized ELCC for storage plants of different sizes across four reliability levels under the N-0.5 network redundancy scenario.

Under the N-0.25 redundancy level, as shown in Figure 4.32, the afore-mentioned pattern persists. The energy import capability is reduced even further, leading to lower ES contribution when compared to Figure 4.33.

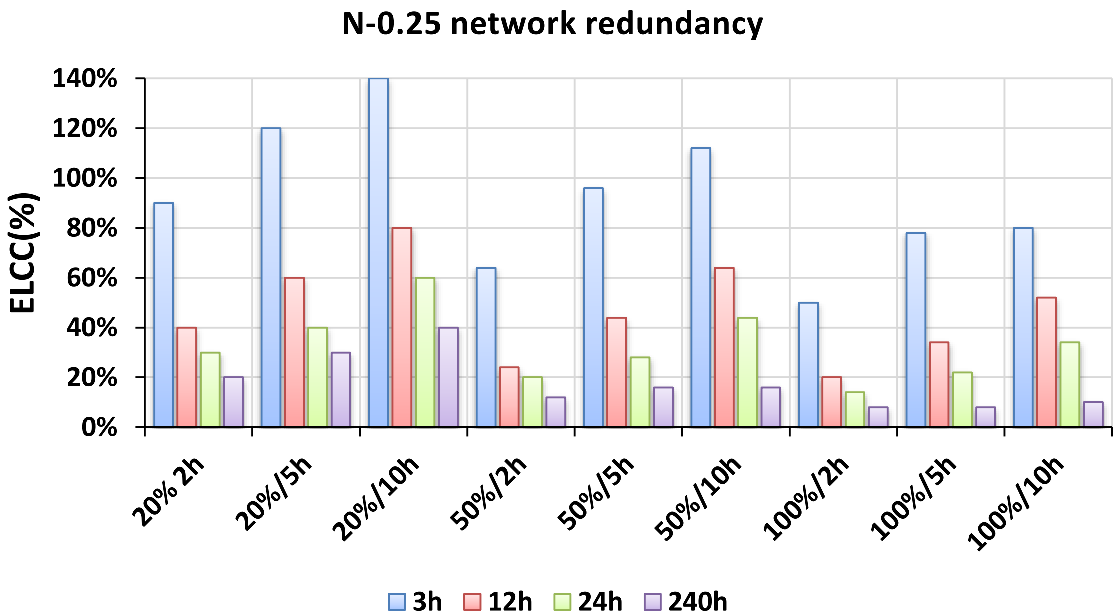


Figure 4.33: Normalized ELCC for storage plants of different sizes across four reliability levels under the N-0.25 network redundancy scenario.

4.4.5 Impact of network redundancy

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' base case. For example, under N-0.75, a part of the peak demand of 12.5 MW may not be serviceable with only one 10 MW transformer in operation. The base case EENS can be viewed as the sum of EENS due to single (denoted as EENS*s) and EENS due to double outage events (denoted EENS*d). Most importantly, in 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 base case $EENS^s$. As a result, the amount of energy curtailment during double outage conditions can be increased by the amount that EENS*s has been reduced. In general, this can lead to an increased security contribution of storage.

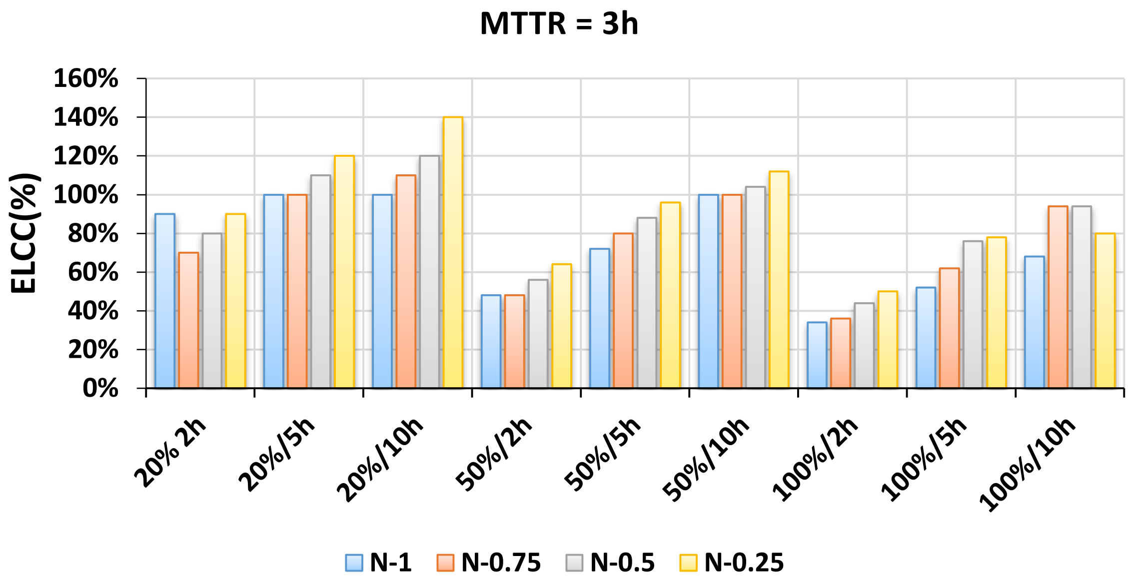


Figure 4.34: Normalized ELCC for storage plants of different sizes across four network redundancy levels when transformers' MTTR = 3 hours.

Another direct implication of this effect is that ES can potentially have an ELCC above its power rating (i.e. normalised ELCC > 100%), whereas this is not possible under an N-1 security standard. 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. In addition, once this effect becomes binding the ES will have a lower expected state-of-charge when entering double outages, thus reducing ELCC.

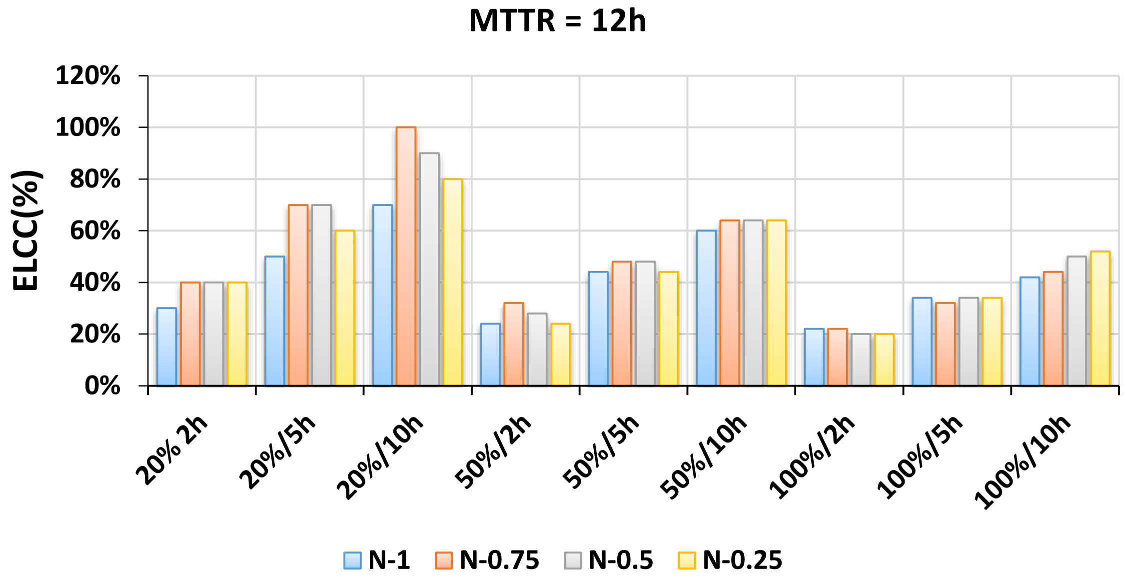


Figure 4.35: Normalized ELCC for storage plants of different sizes across four network redundancy levels when transformers' MTTR = 12 hours.

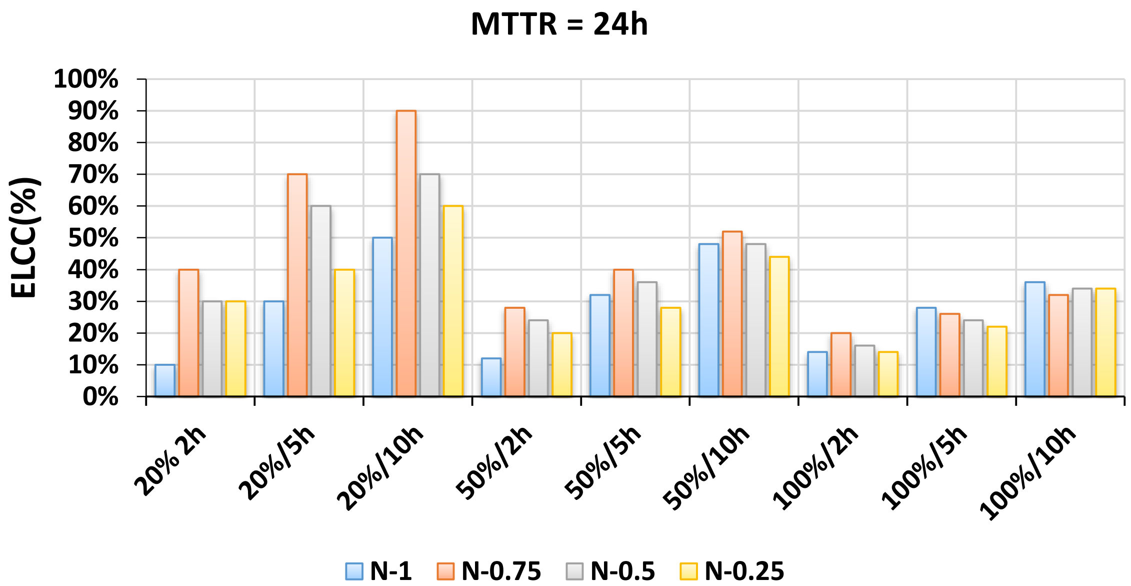


Figure 4.36: Normalized ELCC for storage plants of different sizes across four network redundancy levels when transformers' MTTR = 24 hours.

As shown below in Figure 4.38, when MTTR is increased to 240 hours, the overall effect is that ES security contribution is reduced due to longer outage durations. In addition, the impact of reducing network redundancy is even more pronounced in this reliability scenario. In particular, when comparing between N-1 and N-0.75 levels, the increase in ES contribution is substantial. However, as also observed in the MTTR = 24h case, shown in Figure 4.37, security contribution of storage when operating under N-0.5 or N-0.25 redundancy level is considerably reduced compared to the N-0.75 scenario. This reduction is attributed to the reduced capability to import energy from the grid during single outage events, leading to a reduced capability to support this extra demand through periodic re-charging cycles.

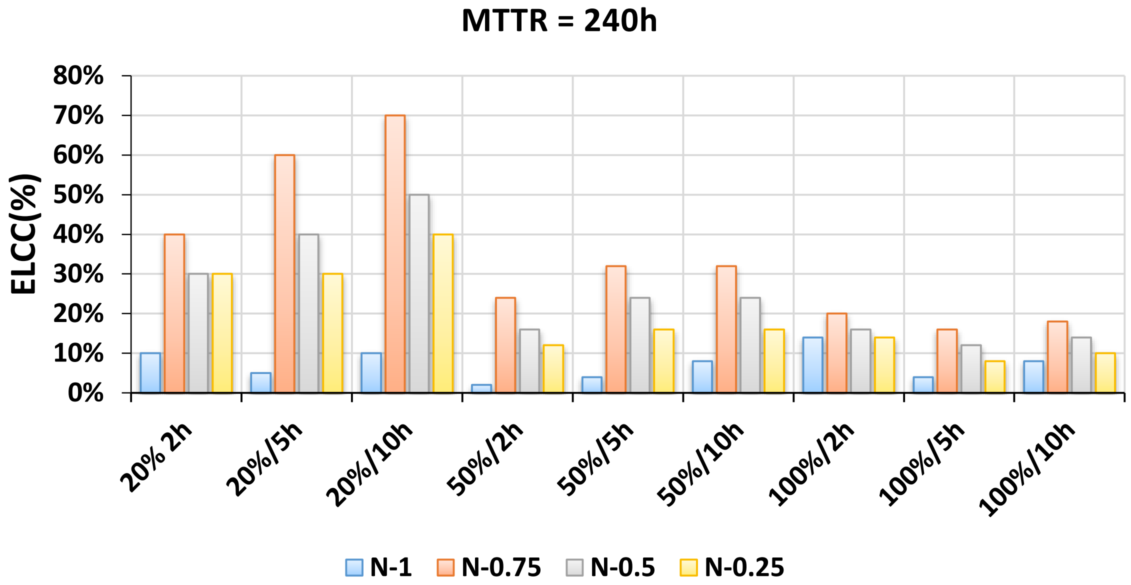


Figure 4.38: Normalized ELCC for storage plants of different sizes across four network redundancy levels when transformers' MTTR = 240 hours.

4.4.6 Impact of capability for islanded operation

In the preceding analysis we have assumed that ES can operate under islanding conditions i.e. under double outage conditions, when no connection to the grid is available. Figure 4.40 compares the security contribution of storage with and without the ability to operate under islanding conditions for different network redundancy cases. We focus on analysing three storage plant sizes under the MTBF = 1 year, MTTR = 12 hours reliability scenario. As can be seen below in Figure 4.39, in the N-1 case, the contribution of ES decreases from the original level down to zero when operation under islanding conditions is disabled. This is because the most significant proportion of EENS is driven by events where both transformers are in outage and ES is islanded. As such, the storage plant cannot contribute to security of supply and demand cannot increase beyond the base case level of 10 MW without further increasing EENS. Note that this effect applies to all storage plant sizes and reliability scenarios. In the N-0.75 case on the other hand, the ability to operate under islanding conditions does not have a substantial impact on the contribution of ES as the most significant proportion of EENS is driven by events where a single transformer is out. During these single outage events, storage can contribute in security of supply and a non-zero contribution can be derived.

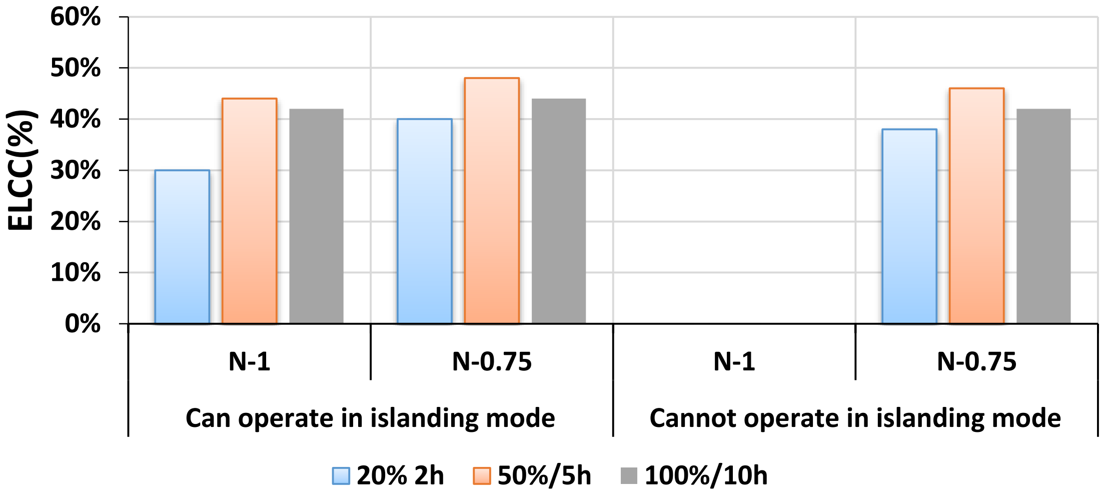


Figure 4.40: Impact of islanding mode of operation on ES contribution of storage plants of three different sizes. Reliability scenario analysed involves transformers with MTBF = 1 year, MTBF = 12 hours.

4.4.7 Impact of energy efficiency

In this section we investigate the impact of charging efficiency of ES security contribution. Four efficiency levels have been examined for the MTBF = 1 year, MTTR = 24 hours case study. Results for the N-1 security criterion are shown in Figure 4.41. Note that charging efficiency η = 80% means that during charging only 80% of the available energy can be used to increase ES state-of-charge. As a result, charging to the maximum level takes a longer time compared to a perfectly efficient plant. The main effect of reduced efficiency is that storage will have a lower SOC when entering a double outage event. However, as shown in Figure 4.41 this effect becomes binding only at plants with very large energy capacity. Specifically, the seven smaller-sized plants do not experience a penalty in their security contribution when efficiency is reduced. This is because although a small plant will use more energy to fully charge and may take longer to do so, it is very likely that it will reach its maximum SOC before discharging needs to take place. On the other hand, large plants such as the 100%/10h (which in this case study equates to a 100 MWh energy capacity), are more probable to not be fully charged when energy must be discharged. It follows that large plants will consistently be at lower SOC when entering double outage events or may not be capable of ensuring EENS = 0 during single outage events when ELCC is high.

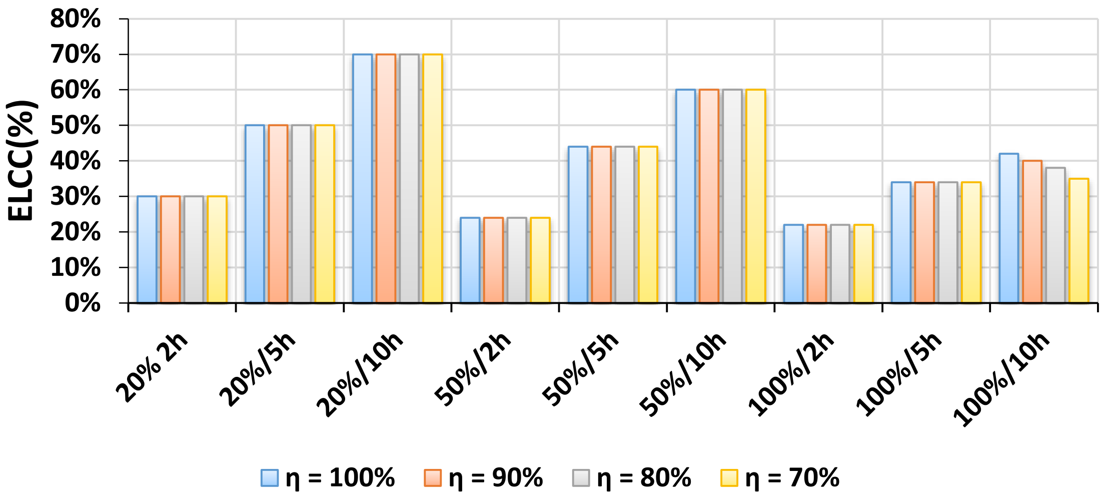


Figure 4.41: Normalized ELCC for nine storage plants across four efficiency levels. MTBF = 1 year, MTTR = 12 hours.

4.4.8 Impact of demand shape

In this study we propose the adoption of three profiles; typical demand profile, peaky demand profile and flat demand profile. To create these profiles, the original demand time series used as the typical demand profile, while two flatter demand profiles have been constructed by applying a flatness factor of φ = 0.7 and 0.3. A few representative days of the three demand scenarios are shown in Figure 4.42 below.

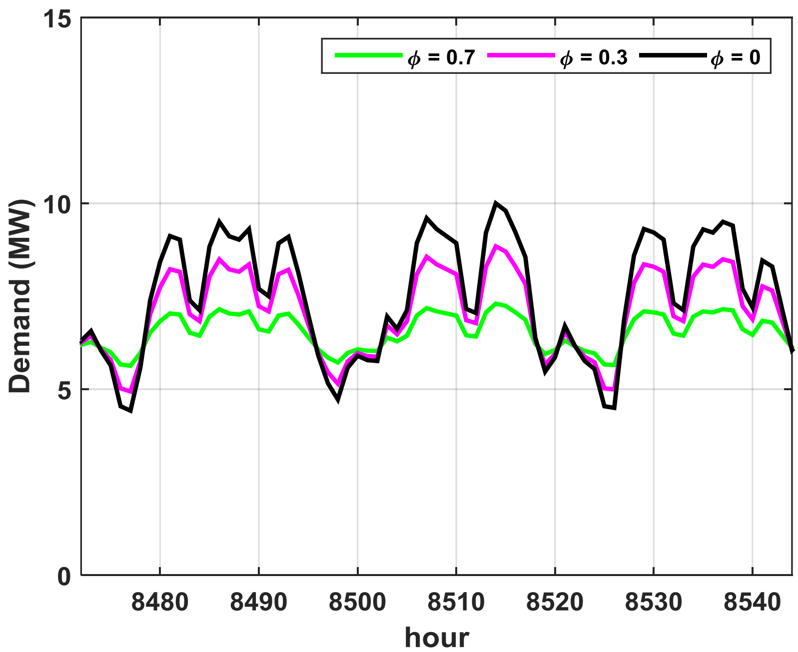


Figure 4.42: Demand across the three high-demand winter days for different flatness factors ϕ. Note that ϕ=0 refers to the original demand shape, while increasing ϕ results in an increasingly flat demand shape.

ES security contribution as a function of demand flatness under N-1 secure operation is shown in Figure 4.43 below. Demand flatness impacts ES security contribution through the increased minimum demand level that arises during single outage events. A flatter demand shape means that during single outage conditions, less energy can be imported from the upstream grid due to binding power constraints. For example, in the case of φ=0.3, the minimum demand level is increased from 3 to 4 MW. As a result, although the same amount of energy is available for charging, less energy is accessible due to binding power constraints leading to a reduced security contribution.

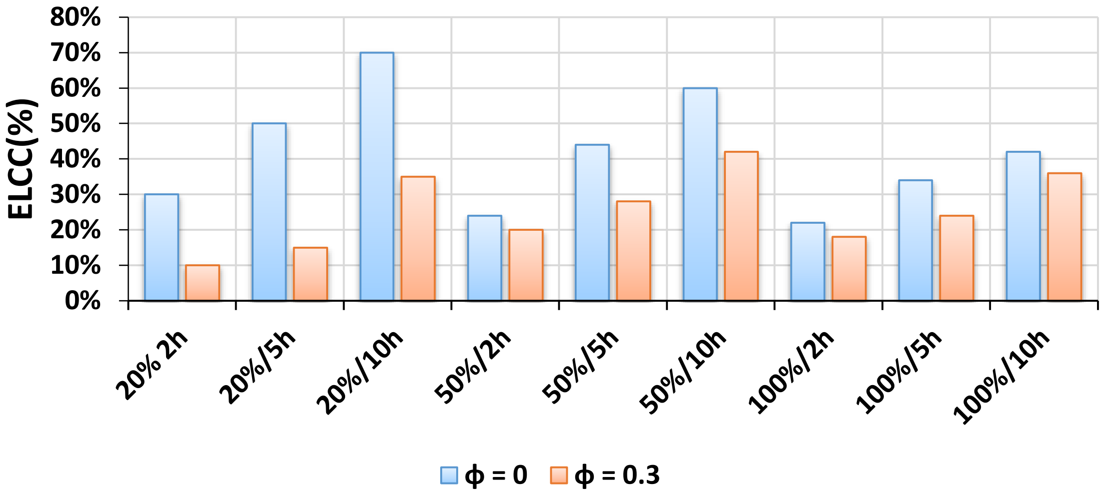


Figure 4.43: Normalized ELCC for nine storage plants across three demand shapes under N-1. MTBF = 1 year, MTTR = 12 hours.

The above effect highlights the importance of considering demand shape when evaluating potential ES contribution to different distribution systems and demonstrates the need for using a chronological representation of demand as opposed to the current P2/6 standard which relies exclusively on demand representation through duration curves.

4.4.9 Conclusions

The studies conducted showed that ES security contribution can be significant in cases, but is largely dependent on a number of factors, namely power and energy rating, time taken to restore network faults, level of network redundancy, capability to operate in islanding conditions, energy efficiency and demand shape.

In general, 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.

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.

Impact of redundancy level of the existing network is also shown to be a substantial factor in ES security contribution. When operating under a relaxed redundancy level (e.g. N-0.75) there is a fundamental difference when compared to N-1 operation; single outages give rise to demand curtailment in the 'network-only' basecase. As such, ES can alleviate demand curtailment taking place in the basecase and lead to increased security contribution. A direct implication of this effect is that ES can potentially have an ELCC above its power rating (i.e. normalised ELCC > 100%), whereas this is not possible under an N-1 security standard. However, there is also another effect at play that must be highlighted. When operating under a relaxed redundancy level, 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. AS a result, security contribution can be reduced in cases of significant redundancy relaxation e.g. N-0.25.

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.

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 when charging efficiency is low, 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.

5 GENERATION-DRIVEN NETWORK DESIGN

5.1 Introduction

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 key topics associated with the fundamental review of the standards is related to the impact and treatment of distributed generation. In this context two key subjects are addressed in this study: (a) the level of network redundancy driven by DG; and (b) the impact of DG on reliability of supply seen by demand, related to the potentially increased risks that higher penetrations of DG connected to networks could impose on demand customers.

It is evident that the connection of significant amounts of DG may lead to reverse power flows, resulting in distribution networks exporting power to other parts of the network. The variable nature of end-user loads and the variability of renewable sources of generation (e.g. wind or solar) in particular may translate into power flows dynamically reversing according to different operating conditions. Under these circumstances, DG-driven power flow reversals may cause flow constraints under circuit outage conditions, an effect that is not explicitly considered in current distribution network planning standards.

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 5.1. 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 5.1. 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, this section aims at providing insights into the outage risks associated with an increase in DG to the point where reverse flows may exceed the connection capacity under circuit outage conditions, thus potentially justifying an increase in network redundancy. A year-round reliability analysis is performed in a sample distribution system with a relatively large installed PV capacity, so that reverse flows occur regularly over the year. Historical PV generation levels and demand are sampled randomly according to a controllable correlation parameter. A simple fault and restoration model is used in order to quantify demand and generation curtailment costs associated with circuit outage scenarios under reverse flow conditions. Sensitivity analyses based on different values of VoLL, outage durations and fault rates are performed. The addition of a third transformer is then considered in order to reduce the expected curtailment costs, and the benefits and costs associated with such a solution are quantified. Conclusions and recommendations are provided at the end of the section, highlighting that network reinforcements driven by DG are not generally economically justifiable.

5.2 Test system

The operational risks from DG-driven reverse flows are illustrated on a simple test system. As illustrated in Figure 5.1, the model is composed of a distribution system at 11 kV connected to the rest of the network via a primary substation with two identical 33/11 kV transformers with a capacity of 17 MW each (only active power is considered). The distribution system has a significant amount of HV-connected photovoltaic power, composed of 4 farms with 28,125 panels of 320 W each yielding a total installed capacity of 36 MW. An annual hourly clear-sky irradiance profile is based on a model for a PV installation[12]. As described in more detail in Section 5.3, this profile is combined with a sampling model from historical cloud conditions in order to produce generation levels at each PV farm. The resulting aggregate annual PV profile has a peak output of around 22 MW, while the PV generates non-zero power for around 4,500 hours of the year. For details about the PV output modelling methodology see section 13.11.

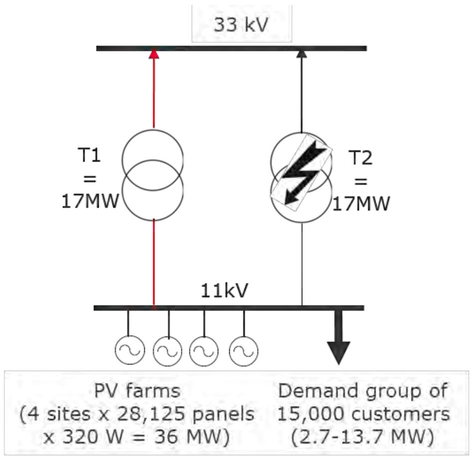


Figure 5.1: Test network. A failure in T2 (T1) in combination with reverse flows may overload T1 (T2)

The demand group is composed of 15,000 domestic customers with an annual load profile constructed based on the half-hourly Elexon Profile Class 1 data, which defines average customer loads for weekdays, Saturdays and Sundays at five seasons (autumn, winter, spring, summer and high summer). To construct an annual load profile we assume that each period has 13 weeks, apart from summer (8 weeks) and high summer (5 weeks). The resulting minimum and maximum aggregated demand is 2.7 and 13.7 MW, respectively.

In this model, operating conditions with high PV generation and low-medium demand at the distribution bus result in power flowing upstream towards the rest of the network. As the transformers are identical, it is assumed that any reverse flow exceeding 17 MW (50% of the total capacity) places the system in a state where a fault in a single transformer results in overloading the remaining transformer. Each transformer is equipped with a protection system

[12] Imperial College London, "Experiment on Photovoltaic Energy Conversion", Internal document, Dept. Elect. Eng., Imperial College London, London, UK

that instantly disconnects it in case of overloading and the PV farms cannot support islanding operation, so that transformer disconnections result in a loss of supply to all customers.

When this situation occurs, restorative actions composed of two processes will be carried out. The first process aims to restore the supply to the disconnected customers. Two PV farms will be also reconnected, which is the maximum PV generation that would not overload the remaining transformer. The operational procedure for responding to a transformer protection operation might vary between DNOs. A Control Engineer would need to be very confident that the transformer had tripped on overcurrent protection rather than any other transformer protection such as Buchholz protection. Restoring supplies to demand customers might not take place in SCADA switching time. This process is assumed to take either 1 or 24 hours in our sensitivity analysis. The other two PV farms remain disconnected from the distribution system in order to prevent excessive reverse power flows while the system is in the 'N-1' configuration. The second process involves repairing or replacing the faulty transformer, which is assumed to take either 1 day or 10 days. After the faulty transformer has been repaired or replaced, the remaining disconnected PV farms are reconnected to the system. At this point the network returns to normal operation. Single transformer faults are considered to occur randomly with a rate of 0.02 faults/year (one fault occurring every 50 years) or 0.2 (one fault occurring every 5 years).

We further assume that two PV farms will be disconnected after *any* single transformer fault – even when it does not immediately trigger further disconnections. This limits the maximum reverse power flows, thus preventing future overloads of the remaining transformer. The two PV farms are reconnected after the transformer has been repaired. The model considers single and multiple failures of transformers. Demand curtailment is valued at £17,000/MWh or £34,000/MWh, whereas PV generation curtailment is valued at £80/MWh (in line with the pre-2016 combined feed-in and export tariffs).

5.3 Modelling and risk quantification

In this section we present the key concepts behind PV modelling and risk assessment. More details on the mathematical model formulation can be found in Appendix A Section 13.11. Monte Carlo simulation has been applied in order to simulate transformer outages, including common mode failures.

5.3.1 Cloud-cover factor distribution

The irradiance that a PV panel receives in a given moment depends on the cloud-cover conditions. A distribution of historical cloud-cover conditions is used, based on cloud-cover factors recorded every minute during three years[13].

The cloud factor is defined as the ratio between the average irradiance measurement and the clear-sky irradiance. In some cases the measured irradiance may exceed the clear-sky

[13] Imperial College London, "Experiment on Photovoltaic Energy Conversion", Internal document, Dept. Elect. Eng., Imperial College London, London, UK

irradiance due to a phenomenon known as the *cloud-edge effect*, in which the edges of clouds have a lens effect on the incoming solar radiation, resulting in cloud factors exceeding 1. The cloud factor is ill-defined for time intervals with near-zero clear-sky irradiance, i.e. around sunrise and sunset: small irradiance measurement errors result in large fluctuations in computed cloud factors. Those unreliable values are ignored in the construction of the cloud-cover model distribution.

5.3.2 Sampling of cloud-cover conditions

Our probabilistic risk assessment is based on a state sampling Monte Carlo procedure in which cloud-cover factors are sampled simultaneously for the different PV farms with a variable correlation coefficient. For nearby PV farms, cloud conditions are expected to be highly correlated (correlation coefficient close to 1), but not identical (correlation less than 1). The sampling procedure is explained in Appendix A Section 13.11, but in summary consists of the following steps. First, four random variables are sampled according to a multivariate standard normal distribution with specified correlation coefficients. The random variables are individually transformed to uniform random variables using the probability integral transform, and finally an inverse transform is used to map these uniform random variables to the historically observed cloud factor distribution.

5.3.3 Risk assessment model

The samples produced with the method above produce a set of instantaneous cloud cover conditions for the PV sites. Transformer faults are characterised by the fault rates, with an explicit provision for a common mode failure (at the distribution bus) that results in a simultaneous outage of both transformers. Under these considerations, the annual fault cost exposure is computed as the sum of the expected fault costs across all operating hours. The expected fault costs associated with a single outage for a particular hour are computed with the Monte Carlo average cost over the full set of sampled cloud conditions. The value of this function takes into account whether the other transformer is overloaded (and disconnected) or not, as explained in Section 5.2.

In line with the fault restoration model, the costs associated with loss of the remaining transformer when it gets overloaded, are computed over the reconnection time as the sum of lost revenue due to generation curtailment and the cost of demand curtailment (estimated through the VoLL). On the other hand, when there is no post-fault overloading, the fault costs are limited to the disconnection of two PV farms during the repair time of the faulty transformer. Details of the fault cost exposure calculation are given in Appendix A Section 13.11.

5.4 Case studies

The following case studies are based on simulations combining 100 sampled cloud conditions and hourly annual profiles for the clear-sky irradiance and demand. The results are shown in Table 5.2 and Table 5.3. Each table corresponds to a different VoLL and considers different reconnection times for the disconnected customers (first restoration process described in Section 5.2). Within each table, we show insights into the curtailment costs (£/year) for the different transformer failure rates and transformer repair times (second restoration process described in Section 5.2) under consideration. Costs can be triggered by either single or common transformer faults, and can be associated with generation and demand curtailments. The tables show each of these cost components, in addition to the total expected curtailment costs.

Table 5.2: Expected curtailment cost (VOLL = £17,000/MWh)

Transformer failure rate (occurrences/year)	Repair time (days)	Total curtailment cost (£/year)					
		Reconnection time = 1 day			Reconnection time = 1 hr		
		Generation	Demand	Total	Generation	Demand	Total
0.02	1	238	8,407	8,645	221	1,204	1,425
0.02	10	2,105	13,113	15,218	2,088	5,911	7,999
0.2	1	2,376	84,064	86,440	2,207	12,039	14,246
0.2	10	21,050	131,130	152,180	20,881	59,105	79,986

Table 5.3: Expected curtailment cost (VOLL = £34,000/MWh)

Transformer failure rate (occurrences/year)	Repair time (days)	Total curtailment cost (£/year)					
		Reconnection time = 1 day			Reconnection time = 1 hr		
		Generation	Demand	Total	Generation	Demand	Total
0.02	1	238	16,813	17,051	221	2,407	2,628
0.02	10	2,105	26,226	28,331	2,088	11,821	13,909
0.2	1	2,376	168,129	170,505	2,207	24,078	26,285
0.2	10	21,050	262,259	283,309	20,881	118,209	139,090

As expected, low transformer failure rates, short reconnection and repair times and low VoLL all lead to relatively low expected curtailment costs in the test system. Consequently, we observe the minimum total curtailment cost occurring in the first row of Table 5.2 (£1,354/year) and the maximum in the fourth row of Table 5.3 (£252,456/year). However, the proportions of costs driven by single and common faults greatly depend on the parameters used. Likewise, the magnitudes of both generation and demand side curtailment costs also depend on the chosen model parameters.

In all the case studies, *the demand curtailment costs are significantly larger than those associated with generation curtailment*. Overall, this is highly related to the high cost of demand interruptions (VoLL) that is two orders of magnitude higher than that of generation. It is clear that the economically efficient network design for DG is N-0, i.e. no redundancy can be justified for connection of DG.

We note that short repair times reduce more (in relative terms) the generation curtailment costs than the demand curtailment costs, as two PV farms will be preventively disconnected after *any* single transformer fault – even when it does not trigger further disconnections -- and they are reconnected only after the transformer has been repaired.

In order to reduce curtailment costs, increasing network redundancy can be considered. Therefore, we next investigate the benefits from installing a third transformer in the test system, which eliminates any curtailment in case of single faults, as two transformers have sufficient capacity to transfer peak reverse flows. The savings in curtailment costs after installing a third transformer are shown in Figure 5.2

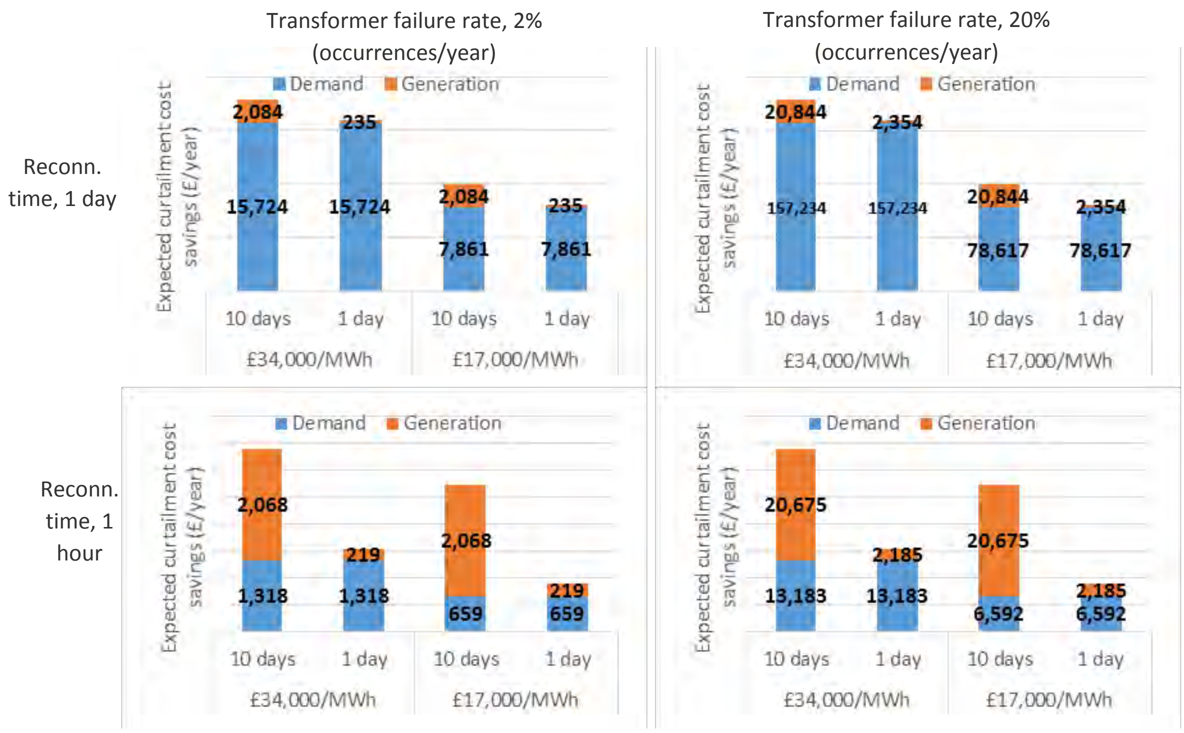


Figure 5.2: Savings in curtailments costs from installing a third transformer

Numerical values of curtailment cost savings are also provided in Table 5.4 and Table 5.5. It is clear that the savings in curtailment costs greatly depend on the model parameters. Expectedly, case studies that result in larger costs associated with single transformer faults benefit more from the installation of a third transformer. Also, generation and demand curtailment savings are proportional to the generation and the demand side costs shown in our previous analysis. Although faults with reverse power flows may result in costly customer disconnection events, their frequency of occurrence is low, meaning that traditional network reinforcements are not generally economically justifiable. For example, assuming that the cost of installing a third transformer is £170,000/year, none of the scenarios economically justify its installation.

Table 5.4: Savings in curtailment cost upon installing third transformer (VoLL = £17,000/MWh)

Transformer failure rate (occurrences/year)	Repair time (days)	Savings in curtailment cost (£/year)					
		Reconnection time = 1 day			Reconnection time = 1 hr		
		Generation	Demand	Total	Generation	Demand	Total
0.02	1	235	7,861	8,096	219	659	878
0.02	10	2,084	7,861	9,945	2,068	659	2,727
0.2	1	2,354	78,617	80,971	2,185	6,592	8,777
0.2	10	20,844	78,617	99,461	20,675	6,592	27,267

Table 5.5: Savings in curtailment cost upon installing third transformer (VoLL = £34,000/MWh)

Transformer failure rate (occurrences/year)	Repair time (days)	Savings in curtailment cost (£/year)					
		Reconnection time = 1 day			Reconnection time = 1 hr		
		Generation	Demand	Total	Generation	Demand	Total
0.02	1	235	15,724	15,959	219	1,318	1,537
0.02	10	2,084	15,724	17,808	2,068	1,318	3,386
0.2	1	2,354	157,234	159,588	2,185	13,183	15,368
0.2	10	20,844	157,234	178,078	20,675	13,183	33,858

5.4.1 Impact of storage plant availability

All preceding analysis has been carried out on the premise of a perfectly available ES. Of course in practice, all assets are subject to technical failures thus reducing their actual security contribution. A parameter that greatly determines the severity that storage plant outages have on security contribution is the post-fault state-of-charge status. In particular, there is a substantial difference between outages that allow ES to preserve its original SOC throughout the outage and resume post-fault operation with previously-stored energy still available and outages that result in the ES being 'cleared' of its accumulated charge and having to start its post-fault operation with an empty storage tank. Naturally, the latter case is more binding, resulting in a reduction of ES security contribution. In addition, dependence between plant failures and environmental variables such as time of the year, weather conditions, which in cases are correlated with electrical consumption (e.g. load due to electric heating) and other factors is an important driver of security contribution.

5.5 Conclusions and recommendations

The connection of significant amounts of distributed generation may result in distribution nodes exporting power to other parts of the network. Moreover, the variable nature of end-user loads and the variability of renewable sources of generation (e.g. PV) may result in power flows dynamically reversing according to different operating conditions. The security standards that ensure redundancy to supply customer demand under circuit outage conditions may not adequately protect against circuit outages in combination with significant reverse power flows driven by DG.

We have introduced a distribution network model to illustrate the risks associated with an increase of variable distributed generation to the point where reverse flows may exceed the connection capacity under circuit outage conditions. The model includes variable PV generation and demand which are connected to the rest of the network through two identical transformers. A correlated sampling technique is used to sample the cloud cover for different PV sites. A simple fault and restoration model is used to compute annual expected interruptions costs related to post-fault overloading under reverse flow conditions.

Monte Carlo simulations are used to estimate the expected costs from service interruptions with different parameter values. Studies confirmed the intuition that curtailment costs due to reverse flows are the greatest when high transformer failure rate, long reconnection and repair time and high VoLL are combined. However, the magnitude of costs driven by single and common faults significantly depend on the parameters used. For example, short reconnection times (e.g. automated remote reconnection) and quick repair times considerably reduce the proportion of costs from single faults, when compared to the respective costs from common faults. Curtailment costs on both the generation and demand side also depend on the parameter values. In all case studies, *the demand curtailment costs are significantly larger than those associated with generation curtailment*. Overall, this is highly related to the high cost of demand interruptions (VoLL), which is two orders of magnitude higher than that of generation. It is clear that the economically efficient network design for DG is N-0, i.e. no redundancy can be justified for connection of DG. Prolonged outages such as maintenance and construction outages will drive greater associated generation curtailment cost which could be considered on a case-by-case basis.

Next, we investigated the potential economic benefits from increasing redundancy in the test system. The scenarios analysed have shown considerable savings, especially for the cases where the demand curtailment costs are dominated by single transformer faults. Although faults with reverse power flows may result in costly customer disconnection events, their frequency of occurrence is relatively low, meaning that traditional network reinforcements are not generally economically justifiable. As a strategy to reduce the curtailment costs at a lower cost, the use of a Corrective Protection System has been investigated in Section 9.3.3.

6 ENHANCING NETWORK ASSET UTILISATION

6.1 Overview and objective

Under the traditional or passive management distribution network planning regime, networks were designed to operate with minimum real-time management, and with an in-built capability to deal with the expected worst-case conditions. Any operational issues were effectively resolved at the planning stage, with relatively high investment into network components resulting in high redundancy and low network utilisation since worst-case conditions occur very rarely. The aggravation of rare, worst-case conditions by the wide penetration of DG and new transport and heating demand poses significant questions regarding the economic sustainability of this regime.

In these terms, an alternative active management regime could significantly improve the utilisation and cost-effectiveness of distribution networks. Under this approach, rather than planning and operating the network in anticipation of worst-case conditions, Distribution network operators can deal with constraints during different system conditions by taking into account the dynamic nature of generation and demand and exercising real-time control through a number of flexible components, similarly to what is done in the transmission network. Hence, the use of existing assets is maximised and the required investment may be considerably lower. On the other hand, additional information, communication and control assets required for active control need to be included in the distribution investment and operating costs, while higher network utilisation will also have an adverse impact on network losses.

This co-ordinated, system-level voltage and flow control could be based on an advanced controller that allows this integrated operation to be implemented. The controls may be implemented either using central Distribution Management System controllers, such as the one depicted in Figure 6.1(e.g. one for each 33/11 kV substation), or by distributing the control functions among the various controllers associated with each item of plant (i.e. DER actions, tap changers); this choice is largely an issue of implementation. The required control actions are slow (e.g. change of tap changer set-point or DER active and reactive power dispatch), so low-cost, slow communication systems would be appropriate. The overall control system should be arranged in a hierarchy with the controllers of the 33/11 kV substations communicating upwards to similar equipment in 132/33 kV substations etc. and the higher-level network control systems.

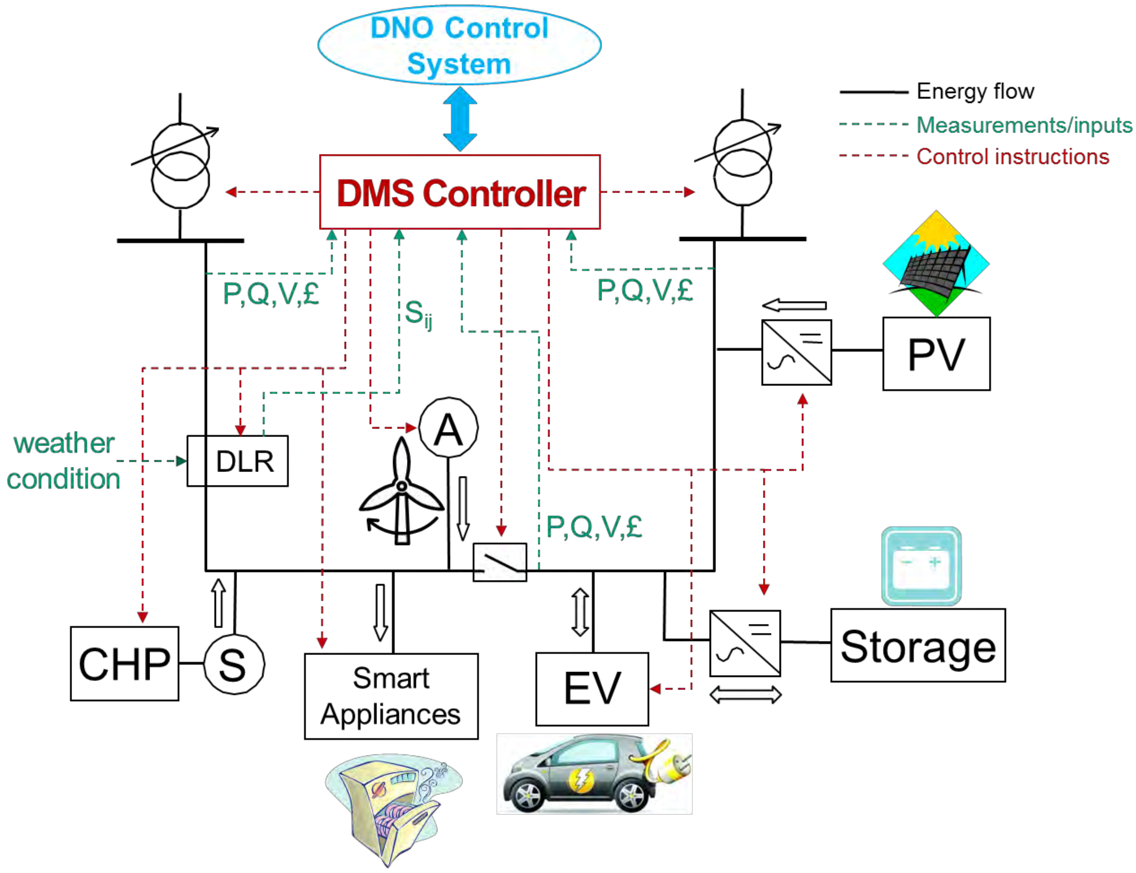


Figure 6.1. Active distribution network operation

The DMS Controller in the above example takes the following information as inputs: (i) measurements for network flows and voltages (P, Q, V), (ii) contract costs for constraining generation on and off (£), (iii) network topology i.e. the states of switches in the network, and (iv) dynamic capacity of network (S_{ij}). Where there are no local measurements available, the network conditions are assessed using the controller's State Estimation module. Control instructions issued by the DMS controller include: transformer tap positions, DER schedules (P, Q), voltage control actions and switching actions. In addition to basic electrical measurements such as voltage or power, the advanced network control functionalities, such as Dynamic Line Rating (DLR) will require additional information such as local weather data relevant to the sections covered by the DLR applications. The DMS controller would also be capable of altering the network topology such as controlling the Normally Open Points in response to interruptions to normal supply conditions, through its Post-Fault Reconfiguration functionality.

Active management of distribution networks could generate significant savings in network cost when accommodating new types of load and distributed generation. Although the cost associated with the operation of active distribution networks needs to be quantified, it is expected that the benefits will considerably outweigh the cost of its implementation. While there is a growing interest in incorporating non-network solutions 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 clearly critical for quantifying the ability of non-network solutions to substitute network assets.

Whilst there is data on the reliability of traditional network assets, there is less data available on the newer technologies and ICT infrastructure which will add to the complexity of the risk modelling / CBA assessment. However, sensitivity analysis might be of use to guide the robustness of conclusions.

The objective of this section is to explore cost-efficient alternative strategies/technologies that can reduce the need for new network investment by maximising the utilisation of the installed network capacity to accommodate demand growth or to facilitate the integration of DG into the overall system. In this context, the remainder of this chapter discusses the number of potential technologies/strategies that could be employed to achieve the objective; these include:

- Temporary overloading of transformers under peak load or contingency conditions;
- Utilising the cyclic and emergency rating of cables to provide additional capacity;
- The application of wide-area dynamic voltage control;
- Widening the voltage limits especially the lower limit to alleviate the voltage rise problem caused by DG while accommodating more loads; and
- Dynamic Line Rating.

Another enabling technology that can enhance the capacity utilisation of the network is a smart protection system, a discussion on this topic can be found in Section 5.3 of the report.

6.2 Temporary overloading of transformers under peak load or contingency conditions

The standard BS IEC 60076-7:2005 [67] provides certain room for power transformers to operate beyond their rating. According to the standard, there are three permissible loading conditions:

A. **Normal** Loading: higher ambient temperature or a higher-than-rated load current can be temporarily applied during part of the cycle, but, from the point of view of relative thermal ageing rate (according to the mathematical model), this loading is equivalent to the rated load at normal ambient temperature. This is achieved by taking advantage of low ambient temperatures or low load currents during the rest of the load cycle.

B. **Long-time Emergency** Loading: this involves loading resulting from the prolonged outage of some system elements that will not be reconnected before the transformer reaches a new and higher steady-state temperature.

C. **Short-time** Emergency Loading: this includes unusually heavy loading of a transient nature (less than 30 min) due to the occurrence of one or more unlikely events which seriously disturb normal system loading.

The operation of power transformers are mainly constrained by the current and temperature limitations [68]. 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 6.2. It is evident that a higher ambient temperature reduces the maximum loading capability of a transformer.[14]

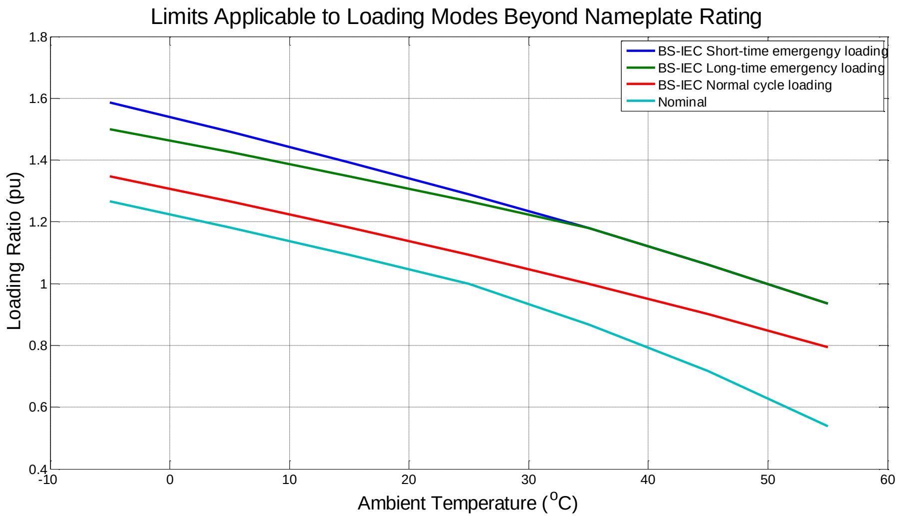


Figure 6.2. Maximum transformer's loading capability for various loading modes

Operating transformer beyond its nominal rating increases the ageing rate, which is determined primarily by the temperature of hot spot point of the conductor. Figure 6.3 shows the life loss of transformers under maximum loading of different modes. Depending on the extent of overloading, the life loss increases non-linearly. Operating under short-time emergency loading, the loss of life can be up to 50 times the normal ageing rate. Operating at maximum normal loading, the ageing rate can be nearly three times the nominal ageing rate. The results also indicate that operating at higher current, even at lower ambient temperature increases the ageing rate of transformers.

[14] 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.

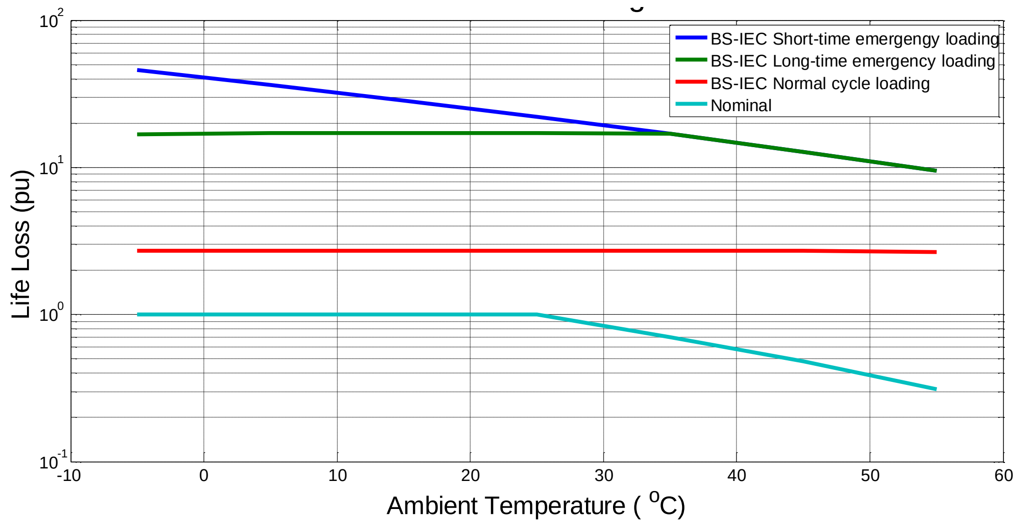


Figure 6.3. Life-loss of transformers for various loading conditions

Therefore, the decision to run power transformers beyond their nominal rating must consider this increased ageing rate and reduction of transformer's lifetime. A study on the transformers' life loss in a year's operation was carried out using the Low Carbon London's trial data from one substation. The substation has 4x15 MVA 132/11 kV oil-filled transformers without an additional cooling mechanism. The loading and temperature of each transformer and the ambient (outdoor) temperature were recorded; these are shown in Figure 6.4 and the recorded peak demand reached 63 MVA during 6th of February. This means that there is no redundancy if the capacity of the substation is calculated based on the nameplate capacity. In the event of 1 transformer out-of-service during peak demand condition, the remaining three transformers have to cope with 21 MVA load each, which is 40% higher load than their nameplate capacity. In this condition, the transformers can still operate within normal or long-term emergency loading if they need to operate more than 30 minutes. Higher loading is permitted within the short-term emergency loading for a period less than 30 minutes.

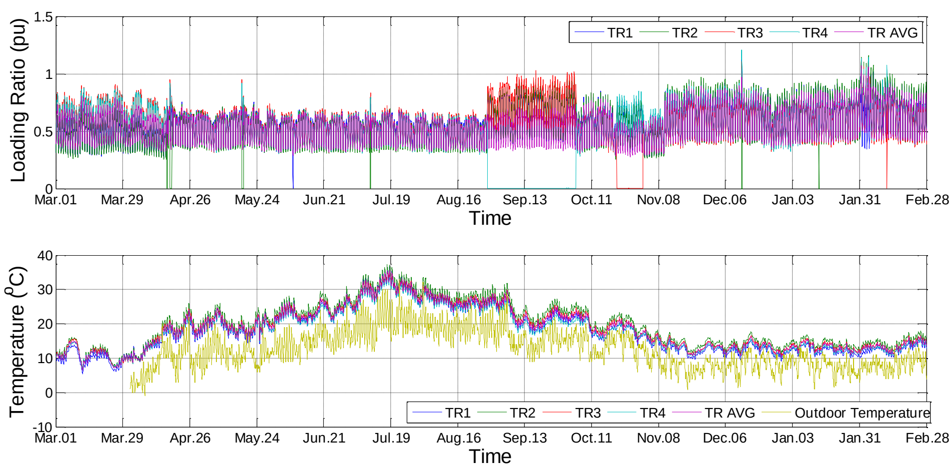


Figure 6.4. Year-round ambient temperature, transformers' loading and temperature at the 132/11 kV substation

The ambient temperature (indoor temperature of the substation for this case) was recorded to enable real-time loading capability of the transformers. It is important to highlight that since the peak-load conditions in the UK are in winter, this helps to enhance loading capability of the transformers.

Based on the average temperature and loading of the transformers, the average ageing rate of transformers at Merton was assessed; the results are shown in Figure 6.5. During most of the time, the transformers were loaded below their maximum nominal loading capacity which prolongs the lifetime of transformers. There are several occasions where one transformer was out-of-service, for example: TR4 was out-of-service for more than 1 month between the end of August and beginning of October, this resulted in higher loading for the other three transformers and consequently higher ageing rate. Higher loading during peak demand conditions in the beginning of February also produced visibly higher ageing rates which reduce transformers' lifetime faster than the normal rate.

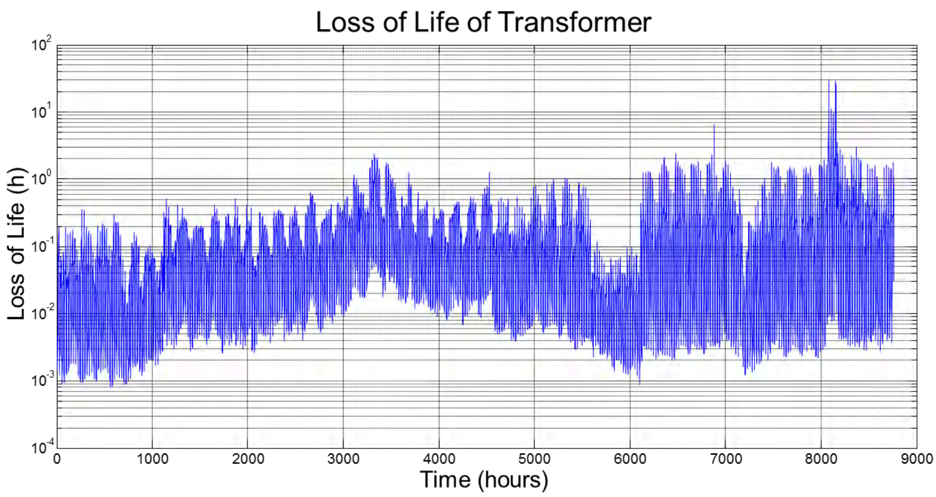


Figure 6.5. Life-loss of transformers for various loading conditions

The approach considers load profile and relevant loss of life in long-term emergency loading condition. However, since the frequency of operating transformers at high loading is relatively small in comparison to the frequency where transformers are loaded much below their nominal rating, the impact on the lifetime of the transformers is generally marginal.

6.3 Utilising the cyclic rating of cables to provide additional capacity

Similar to transformers, the ageing 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 calculated based on a certain nominal operating temperature. Operating below this temperature will extend the lifetime of the cable. Operating at higher temperature increases the ageing rate of the insulation and therefore reduces the lifetime of the cable [69], [70]. Figure 6.6 shows the nonlinear relationship between the cable's life-loss and the cable's operating temperature[15].

In the emergency loading conditions, the operating temperature is permitted to reach 130°C. However, operating at such temperature increases the risk of cable's failure and significantly reduces the lifetime of the cable by 30 times. Therefore, operating at this condition is only acceptable for short period of times in emergency conditions.

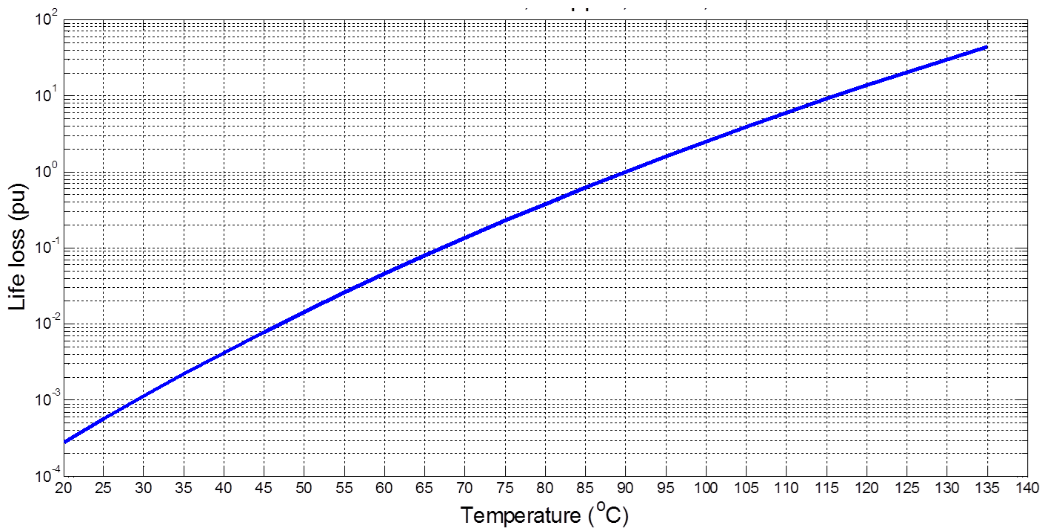
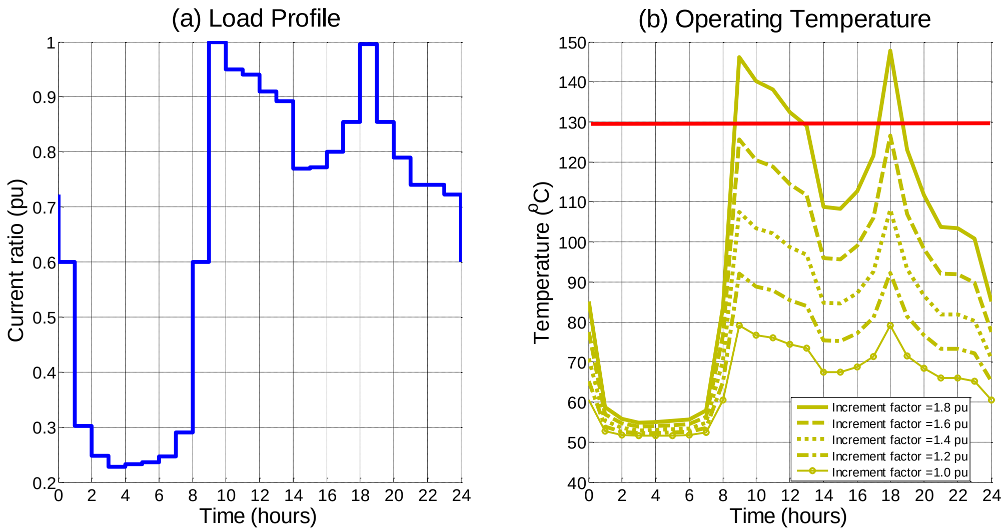


Figure 6.6. Loss of cable's life as a function of its operating temperature

In order to determine the extended rating of the cable which is permitted or called as the cyclic rating [71]-[73], the loading profile shown in Figure 6.7(a) is used. It should be noted that the change in the future load cycle could impact on cable rating. Operating temperature of the cable for different loading conditions is obtained by multiplying the load profile in (a) by some factors, i.e. 1.0, 1.2, 1.4, 1.6, and 1.8. The results are shown in Figure 6.7(b).

[15] 185 mm^2 one core 11 kV XLPE cable with nominal temperature of 90 °C is used in this study. Soil temperature is 15 °C and its thermal resistivity is 1.2.



(a) Load profile of the cable (b) Operating temperature

Figure 6.7. Operating temperature of the cable for different loading conditions

The results show that for the specific cable under the assumptions taken in this study, the cyclic rating is 1.2. This means that the cable can be loaded 20% more than its ratings without increasing its operating temperature above the nominal temperature. Under emergency conditions, the cyclic rating could be slightly above 60% of its nominal rating. It is important to highlight that these results are valid only for the assumed load factor; different cyclic and emergency factors might be applied for different loading patterns.

The impact of increasing the loading of the cable has been calculated and the results are shown in Figure 6.8. As long as the operating temperature does not exceed the nominal temperature, operating at a cyclic factor of 1.2 does not reduce the lifetime of the cable. However, operating with higher cyclic factors, for example during the emergency condition can reduce the lifetime of the cable by more than 20 times during the peak load.

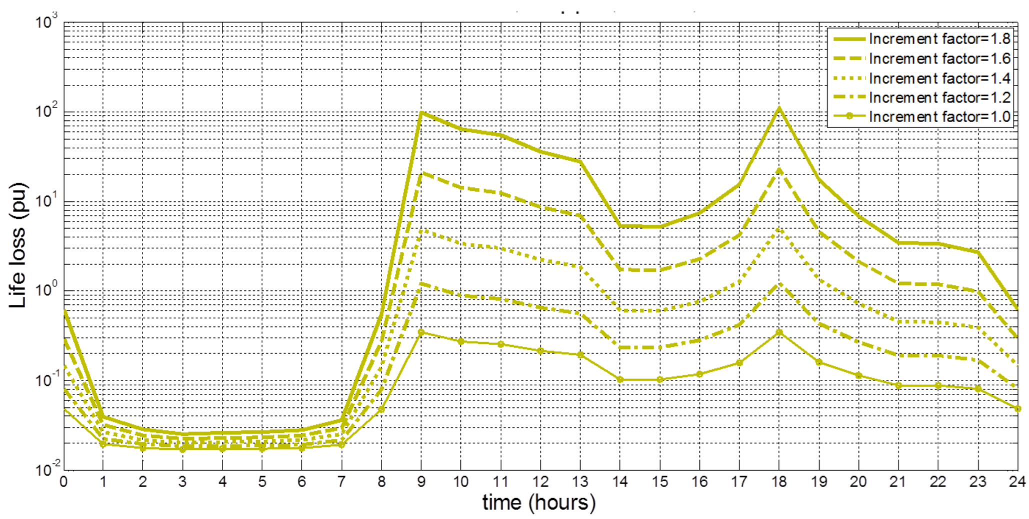


Figure 6.8. Life-loss of the cable

Having the temperature of the cable lower than its nominal temperature before the peak load improves the cyclic rating of the cable. As the distribution network cables generally have relatively low utilisation factors due to the nature of the load profile, it 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 needed.

6.4 Benefits of voltage control

There are a number of voltage control strategies that can be exploited to maximise network capability to accommodate the increased loads or DG. The strategies include:

- Reactive power management: absorbing reactive power can be very beneficial in controlling the voltage rise effect, especially in weak overhead networks with embedded generation. By absorbing reactive power, an increase of the output of active power can be realised. This approach is effective for HV networks where the network resistance is relatively small compared to network reactance.
- Area based coordinated voltage control of On Load Tap Changing Transformers (OLTCs): present voltage control in distribution networks is primarily carried out by OLTCs. Clearly, the voltage rise effect in distribution networks with distributed generation can therefore be controlled by OLTCs (by reducing the voltage at times of high generation output). However, the present voltage control policy is designed for passive networks with strictly unidirectional power flows. Alternative voltage control practices that go beyond the present local voltage control, such as an area-based control of OLTC has been considered and studied by SEDG [149]. The results of the studies show that this form of control is likely to bring the largest benefits in terms of the increase of embedded generation that can be connected to weak distribution networks.
- Application of voltage regulators: In the context of the voltage rise effect, minimum load – maximum generation conditions are usually critical for the amount of generation that can be connected. However, it may also be necessary to consider maximum load – maximum generation conditions. This is because, the use of OLTC transformers to reduce the voltage on the feeder where the generator is connected, may produce an unacceptably low voltage on adjacent feeders that supply load. In this case it may be beneficial to separate the control of voltage on feeders which supply load, from the control of voltage on feeder to which the generator is connected. This can be achieved by the application of voltage regulators on appropriate feeders.

The previous work in this area clearly shows significant benefits of active control of distribution network. The most beneficial are schemes with area based voltage control by OLTCs and voltage regulators achieving a 3 fold increase in the capacity of embedded generation that can be connected.

Another study demonstrates the benefits of voltage control and coordinated grid operation in reducing the network reinforcement costs in the future driven by partial electrification of heating and transport sectors. The studies analyse the impact of increased electricity peak demand, mainly caused by fuel switch from part of transport fleets and heating sector to electricity, on distribution network reinforcement cost from 2010 to 2050. Distribution networks in this analysis are modelled using Imperial's fractal network models calibrated against realistic GB networks [150], [151]. Fractal models reproduce realistic network topologies and network lengths and therefore allow for the characterisation of distribution networks of different types. For the purpose of the analysis presented in this report, we have developed 10 representative networks, mapping the entire GB distribution network, in order to evaluate the reinforcement and network losses for the whole of GB.

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.

The results of the study are shown in Figure 6.9.

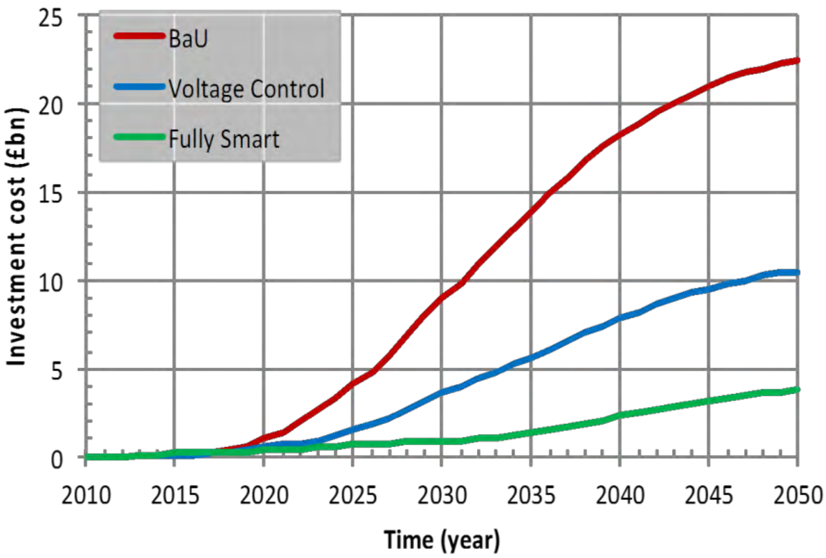


Figure 6.9. LV distribution network reinforcement cost in GB

The results show that the distribution network will require significant reinforcement from 2020 onwards due to the increased peak demand. Majority of the reinforcement is needed to address voltage problems, and therefore by implementing active voltage control at HV and LV networks, significant amount of capacity (and costs) can be saved. It is important to highlight that there is no active voltage control at LV networks at present, while the capacity of the network is mainly constrained by voltage, as discussed previously. By implementing voltage control, the accumulated savings for GB by 2050 are estimated around £12 billion.

Table 6.1 shows LV distribution network reinforcement cost in GB for 2030.

Table 6.1: LV distribution network reinforcement cost in GB for 2030

Control	Reinforcement cost (£bn)
BaU	9
Voltage Control	4
Fully Smart	1

It can be seen that voltage control has potential benefit of about £5bn savings in reinforcement compared to BaU scenario. Fully smart can potentially bring additional £3bn in savings.

Another study investigated the impact of PV penetration on distribution network reinforcement. The reinforcement due to voltage constraints was recorded. Figure 6.10 shows the voltage-driven reinforcement length and cost in the case where PV generation is installed in 50% of consumer locations. The x-axis shows the number of feeders that needs to be reinforced due to voltage rise effect of high PV penetration. The first y-axis (left) shows the length of the feeder in km that needs to be upgraded while the second y-axis shows the upgrade cost per feeder.

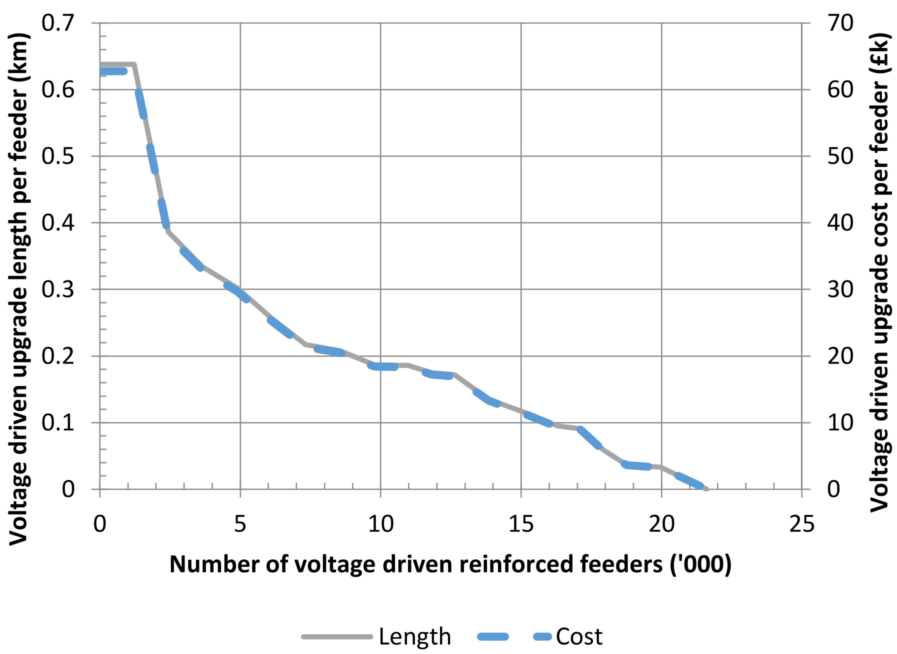


Figure 6.10. Voltage-driven reinforcement per feeder (km and £) for 50% penetration of PV generation

The study can be used to inform the market size of the voltage control devices; for example: there are around 9000 feeder sections of 200 m length that need to be reinforced. The associated cost of the reinforcement is £20,000, which indicates the maximum potential savings if the problem can be solved using alternative solutions such as voltage control.

Other studies investigating the benefits of different voltage control schemes within the ANM framework and the potential benefits of widening the voltage limits are described in the following sections.

6.4.1 Voltage control in EHV networks

Introduction of various smart-grid technologies and corresponding active network management techniques is aimed at enhancing network utilisation, reducing network costs and timescales of connecting new low carbon generation and demand technologies. Enhancing the ability of existing distribution networks to integrate new generation and demand through smart grid concepts will in many cases lead to increased utilisation of the network and a consequent increase in losses. In other cases, losses, at least in terms of percentage of units distributed, may decrease.

A previous study considered alternative active network management techniques to facilitate connection of a wind farm to the existing 33 kV network shown in Figure 6.11. The 33 kV network is fed from a 132 kV network (busbar 1) through a transformer fitted with an on-load tap changer (OLTC). Loads are connected to busbars 2, 3, 4 and 5. The load at busbar 2 represents the aggregated loads of the remaining part of the system. Embedded wind generation is connected at busbar 6, where power factor correction capacitors are also connected. In this case, voltage rise at the point of connection of the embedded wind generator is the key barrier that limits the amount of generation that can be connected to the existing network.

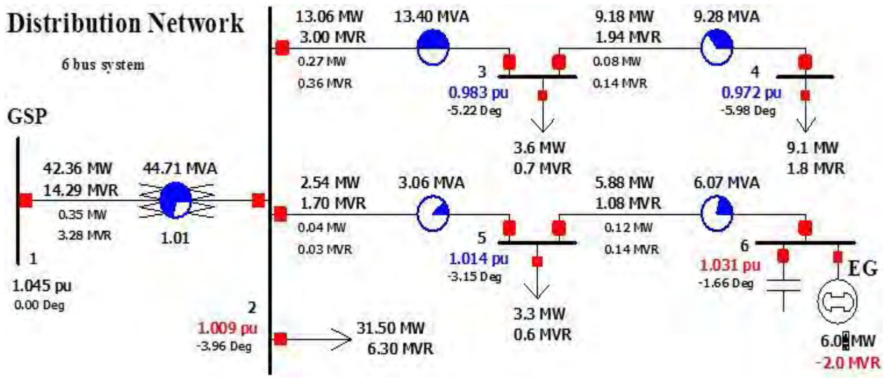


Figure 6.11. 33 kV network model showing maximum loading conditions

The benefits of four active network management techniques in term of enhancing the ability of the network to accommodate increased penetration of wind generation are modelled: generation curtailment, power factor (PF) compensation, area-based OLTC voltage control, and in-line voltage regulators. The results are shown in Figure 6.12 where the top left chart is for generation curtailment, top right for power factor compensation, bottom left for area-based OLTC voltage control, and bottom right for area-based OLTC voltage control and in-line voltage regulation. X-axis represents the wind generation penetration level from 4 to 20 MW, while Y-axis presents wind generation annual energy.

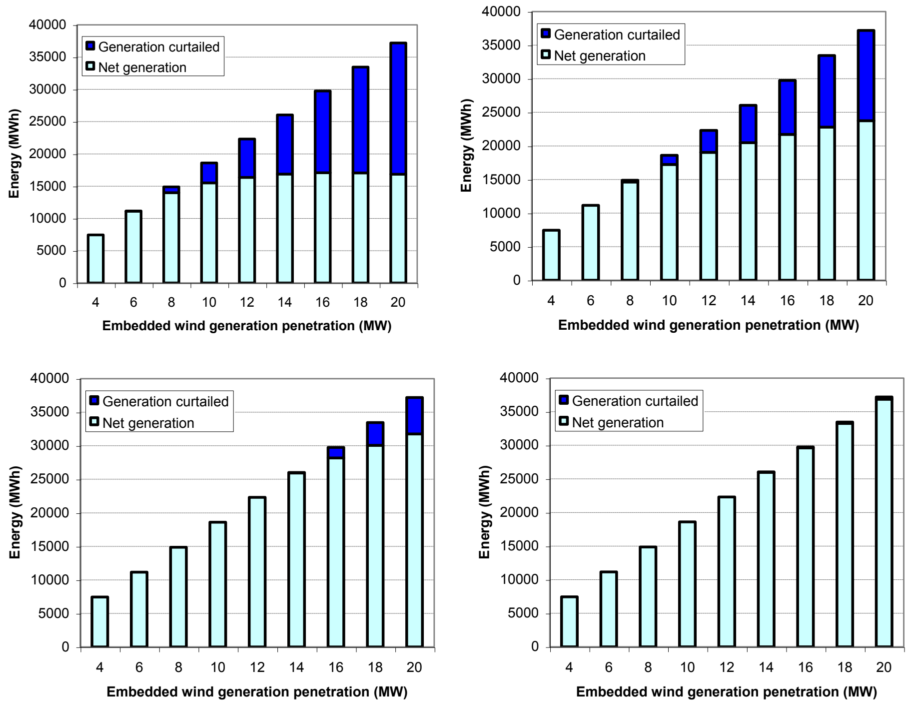


Figure 6.12. Benefits of four alternative ANM schemes: generation curtailment only (tl), power factor compensation (tr), area-based OLTC voltage control (bl), and area-based OLTC with in-line voltage regulation

For each set of measures the wind generation capacity is increased from 4 MW to 20 MW in 2 MW steps and the annual energy produced is calculated. The base case is provided by applying the standard limit to the increase in voltage at the connection point which would only allow 6 MW of wind capacity to be connected. In Figure 6.12 the lighter bars represent the net energy generated in the course of one year, while the darker bars represent the curtailed energy.

In the first ANM scheme, generation curtailment and power factor compensation (power factor is 0.98) is applied at the wind farm. The OLTC transformer maintains a constant voltage at its terminals. The top left chart in Figure 6.12 shows the resultant *annual* energy produced and curtailed with installed capacity from 4 MW to 20 MW. Based on the passive management, the capacity of Distributed Generation (DG) allowed for connection is generally limited by the extreme conditions of minimum loading and maximum generation output. This condition only allows 6 MW of generation to be connected while connecting generation with higher power ratings will lead to increase in generation curtailment to manage the violation of voltage limits at the connection point.

Similarly in the second ANM scheme, generation curtailment and power factor compensation (power factor is 0.95) is applied at the wind farm. The OLTC transformer maintains a constant voltage at its terminals. The results are shown on top right chart in Figure 6.12. In this case, the net energy generated is increasing beyond 8 MW, as the energy curtailed for installations larger than 10-12 MW is significant. Comparing this case with the previous clearly shows the benefits of operating with lower power factors. In other words, a request to operate wind farms with unity power factor will limit the amount of generation that can be connected. There are also concerns about the impact of distributed generation on the transmission network, which may impact reactive power control objectives, particularly at times of light load.

In the third ANM scheme, an area-based voltage control by OLTC is considered with the tap position optimised to minimise generation curtailment. Year round analysis shows that wind generation levels up to 14 MW can be achieved with virtually no energy curtailed. This technique of voltage regulation will require a distribution management system with appropriate communication systems.

The final ANM scheme considered the minimising of generation curtailment by applying area-based voltage control by OLTC and in line voltage regulator. In this case, the control of voltage on feeders which supply load is separated from the control of voltage on the feeder to which the generator is connected by the application of a voltage regulator on the feeder connected to the wind farm. This allows an independent voltage regulation on feeders with loads by the OLTC, while the voltage regulator controls the voltage on the feeder with the wind farm. The modelling shows that this allows up to 20 MW of generation capacity to be connected with almost no curtailment.

In summary, we observe that the least effective ANM scheme is generation curtailment and power factor compensation (around of 8 MW of generation would be connected), while the most effective one would involve area based voltage control and the application of in-line voltage regulation (around 20 MW of wind generation can be connected to the network).

Given the interest in this study, an analysis of losses has been carried out to illustrate how different active network management techniques used to connect a wind generator may affect losses as shown in Figure 6.13.

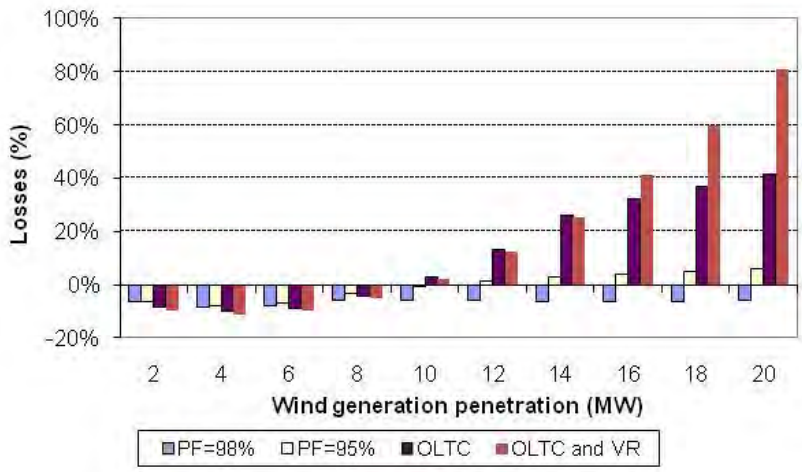


Figure 6.13. Impact of ANM schemes on network losses for various level of penetration of wind generation

We observe that for low penetration of wind, losses are smaller but increasing in line with increased wind penetration. For high penetration of wind, the application of advanced active management techniques that would maximise the utilisation of existing networks may increase losses in the local network.

6.4.2 Widening the voltage limits and emergency voltage control

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

There is a range of solutions for these problems. The use of tap-changing transformers including in-line voltage regulator, reactive compensation, active network management to curtail DG output in order to limit the voltage rise effect, and DSR have been researched extensively in the past but this still requires additional investments in the forms of active network control and ICT infrastructure although the costs are lower than reinforcing the network.

The current planning and operational practice provides opportunities for non-conventional methods to access the latent capacity and create additional headroom. 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; DSR based voltage control. The voltage control strategies are typically included as part of the active network management in the smart-grid framework. In addition to 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.

As demonstrated in earlier studies [149], [152], the advantage of this approach is in its efficiency, as it does not require new investment. The findings from the literature surveys conducted on this area are summarised as follows:

- Reduction of minimum voltage limit can enhance the utilisation of existing network capacity. Network capacity can be double (by releasing latent capacity which is constrained previously by voltage requirements. Therefore lowering further the voltage limit can be used as a strategy to accommodate increased demand and to facilitate integration of DG by alleviating voltage rise effect.
- This is illustrated in Figure 6.14 where it clearly demonstrates that the capacity of the network is constrained by the voltage limit rather than the thermal limit. In order to use more optimally the thermal limit, a lower voltage limit should be applied.

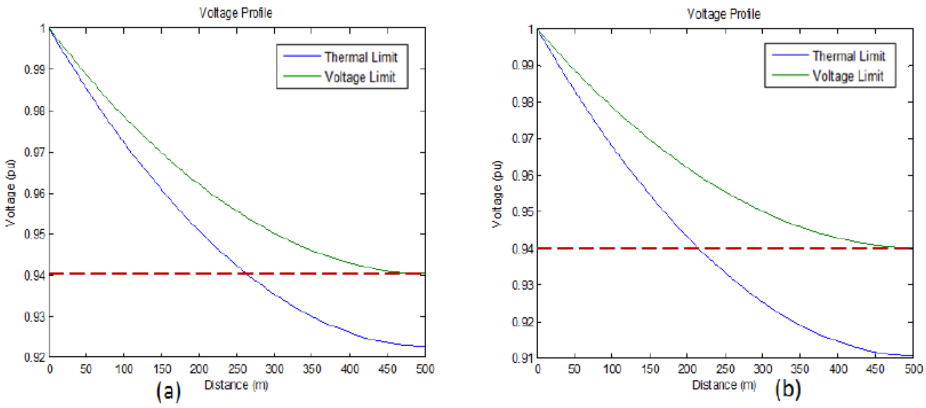


Figure 6.14. Voltage profiles for LV feeders with (a) 300 mm² and (b) 185 mm² cables under different loading conditions

- Reduction of the minimum voltage can improve utilisation of the network capacity (constrained by its thermal capacity). Network capacity can be double (by releasing latent capacity which was previously constrained by voltage requirements).
- Most of the 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 the operating voltage can be used as an emergency voltage control to lower the loads.

Lowering the operating voltage also affects the power consumption of most of the domestic devices except the ones with power factor correction or constant power. This implies that the loads can be reduced if necessary, for example in emergency situations, by reducing the voltage within its permissible limits. The sensitivity of active and reactive power load from domestic devices on different operating voltages is shown in Figure 6.15.

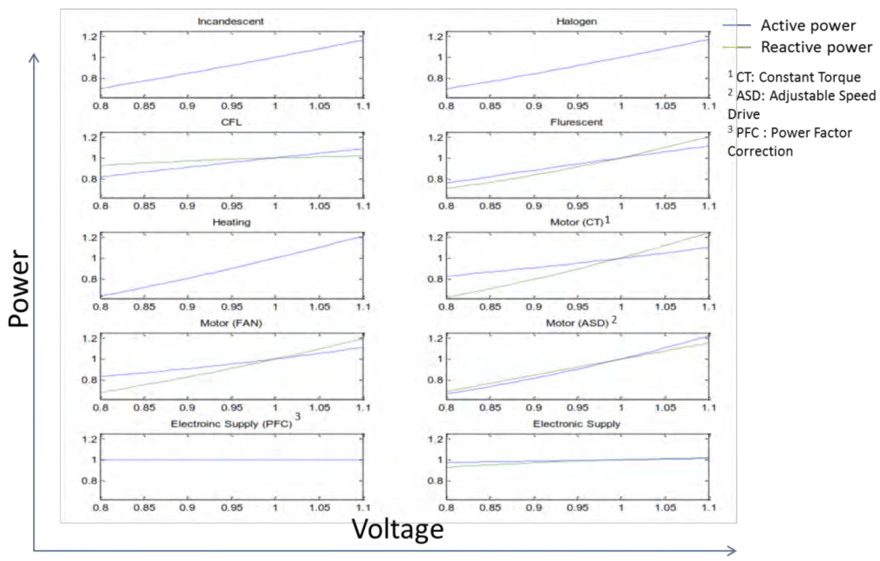


Figure 6.15. Sensitivity of domestic active and reactive power consumption on operating voltages

Figure 6.15 shows that the power consumption of lighting, heating and motor based loads can be reduced substantially (5-20%) by 10% reduction in its operating voltage. However, electronics-based loads, which currently represent about 26% of domestic loads and are expected to grow in the future, are less sensitive to the voltage.

The outcome from the Customer Load Active System Services (CLASS) project [152] also demonstrates that:

- a 1% voltage reduction at a primary substation produces a seasonal average real power reduction of between 1.3% and 1.36%
- a 1% voltage reduction at a primary substation produces an average seasonal reactive power reduction of between 5.54% and 5.83%.

6.5 Dynamic line rating

Dynamic Line Rating is a well-known technology for a transmission system and its application on distribution network has gained a lot of interest recently; some LCNF projects have explored the use of this technology for solving distribution network problems. In contrast to the use of seasonal static capacities, based on “conservative” assumptions with regards to the weather conditions used to derive the capacities, the DLR technology enables computation of the real-time ampacity of the conductor. This visibility is important for the system operator (and planner) who manages the flows within the network capacity constraints. It prevents underestimation or overestimation of the network capacity and therefore facilitates the utilisation optimisation of the existing network capacity.

The real-time ampacity of the overhead bare conductors depend on many parameters, for example:

- Wind speed;
- Angle between wind and conductor;
- Diameter of the conductor; and
- Ambient temperature.

The real-time ampacity can be calculated using the modelling approach, (see section 13.10) which is derived from the IEEE standard [153]. The use of sensors would enhance the observability and increase confidence in DLR.

In order to illustrate the potential benefits from DLR, some examples are taken from the experience learnt in the LCNF Flexible Plug and Play (FPP) project [154]. In the FPP project, a set of field-trial data has been collected from a number of sites, including variation of ampacity, wind velocity, wind direction, ambient temperature and solar radiation data. The wind power is calculated using the wind speed power curve and the wind speed data.

Figure 6.16 shows that the dynamic ampacity of one OH conductor measured during the field-trial period.

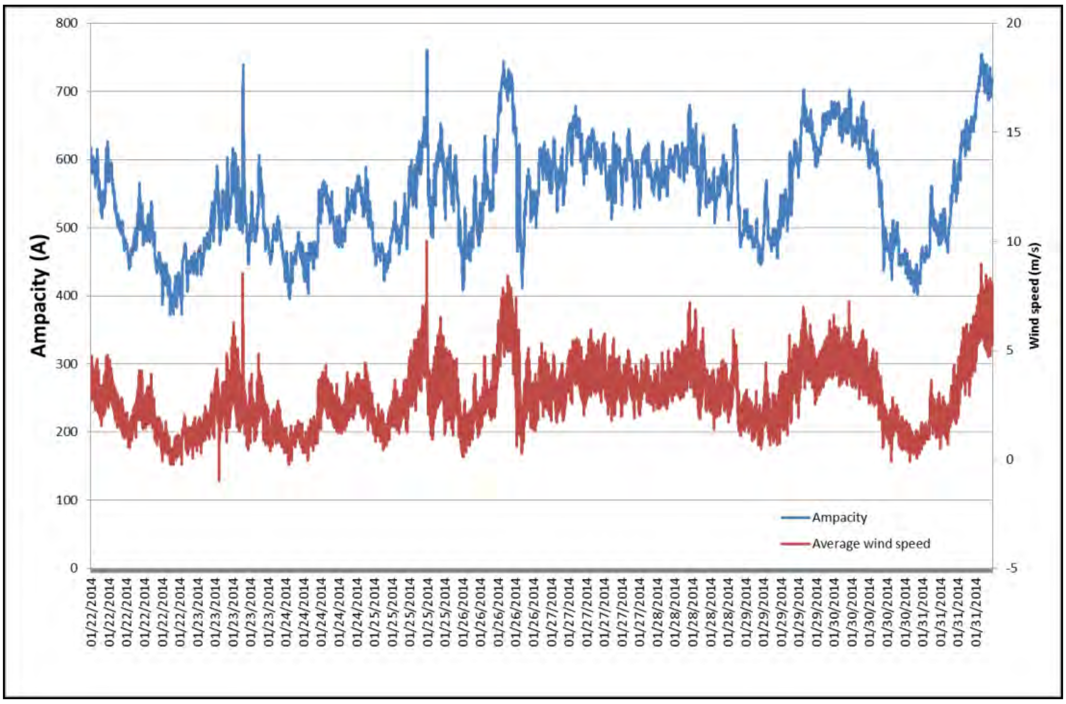


Figure 6.16. The correlation between the dynamic capacity of the conductor and wind profile [Source: FPP trial data, from 22/01/2014 to 31/01/2014, 1 min resolution]

The results demonstrate the ampacity of the conductor varies from approximately 400 A at 0 m/s wind speed to approximately between 700 A and 750 A at 7-9 m/s wind speed that suggests an increased capacity by around 80%. This “latent” capacity can only be unlocked using DLR technologies; the static approach used for deriving the seasonal capacity will not be optimal to use as it generally underestimates the real ampacity and in other extreme conditions, e.g. very hot days, it may overestimates the capacity exposing the system into risk.

The use of DLR to solve network capacity problems had been tested on a real EHV distribution network in the LCNF Flexible Plug and Play project.

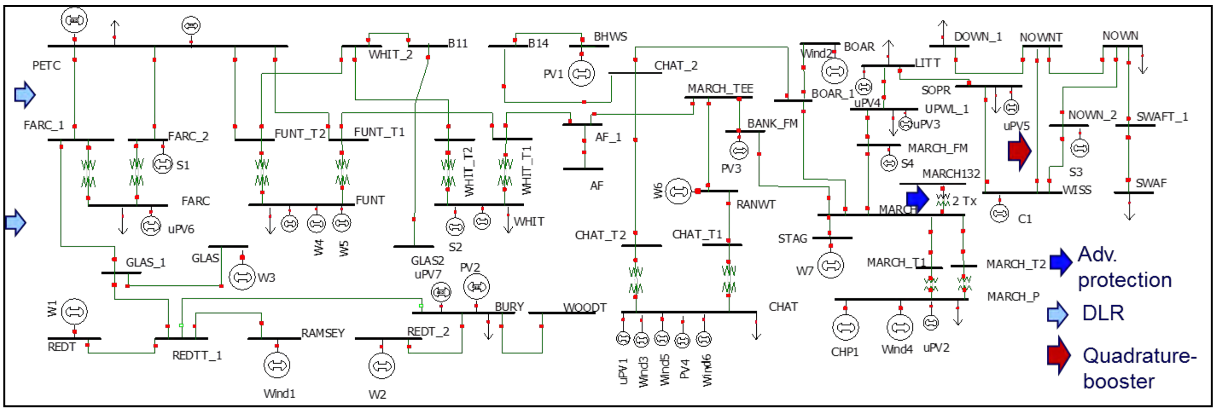


Figure 6.17. Smart solution to improve network utilisation

DLR has been selected as a least-cost solution to solve the thermal capacity problem observed in the network between Peterborough Central (PETC) and Glassmoor (GLAS_1) as depicted in Figure 6.17. Figure 6.18 shows the power flows and the dynamic capacity of line PETC-FARC_1 across all considered operating conditions.

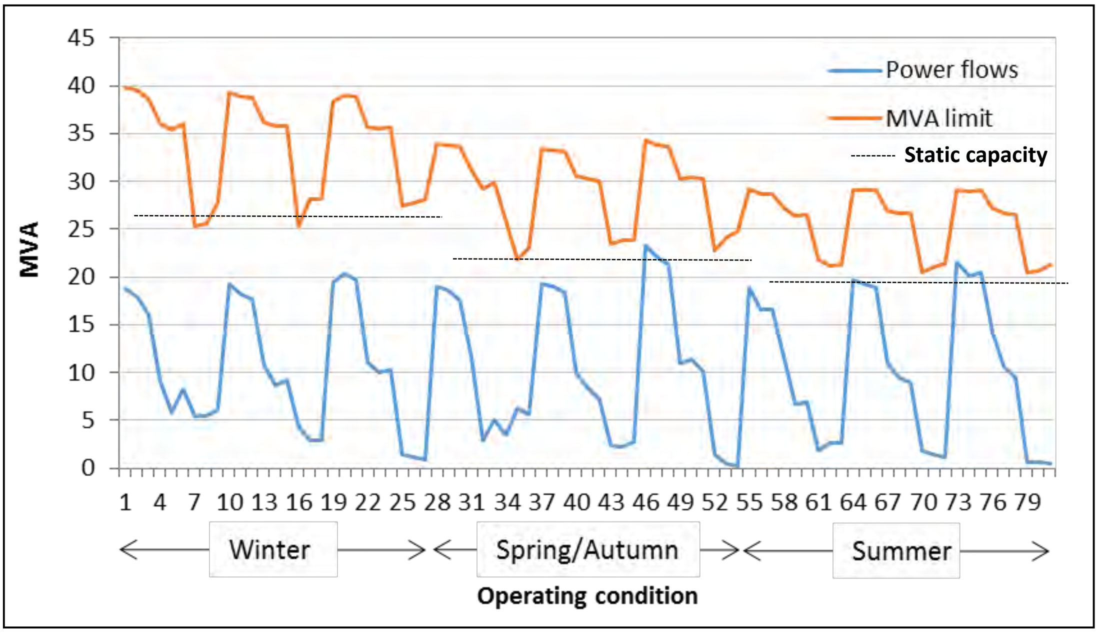


Figure 6.18 Power flows and the dynamic rating of line PETC-FARC_1

The static capacity of the line is 25.3 MVA in winter, 21.5 MVA in spring/autumn, and 19 MVA in summer. It is observed that the static line capacity was exceeded at some occasions, especially during low capacity in summer. Taking advantage of the wind cooling effect, the dynamic line capacity is actually larger and able to accommodate the power flows across all operating conditions and therefore it mitigates the need for network reinforcement.

Greenwood and Taylor [155], [156] also demonstrate that the application of DLR can improve considerably the network reliability performance.

6.6 Security benefits of advanced protection systems

Security and reliability criteria in distribution networks in the UK are presently met through network infrastructure redundancy, which may result in inefficient investment. A fundamental question is whether this approach allocates investments in an economically efficient manner, especially in the context of the rise of DG and growing development of smart network solutions and non-network technologies. Although some developments have been made in terms of considering the security contribution of DG, the security requirements are primarily demand-driven, assuming the flow of power from high voltage towards low voltage levels.

The connection of significant amounts of DG may reverse power flows. The variability of customer demand and the variability of renewable output (e.g. wind or solar) may lead to power flows dynamically reversing according to different operating conditions. In this case the DG-driven reverse power flow may be subject to flow constraints under circuit outage conditions.

It may not be economically justified to address the risk due to reverse power flows using traditional network reinforcements. Alternately, non-network technologies may represent more cost effective solution for designing secure and reliable networks. These corrective systems may rapidly reduce the exporting power flow when a circuit fault occurs, for example by disconnecting DG. The objective of such a corrective security system is to avoid potential post-fault overloading in the remaining circuits. However, they may entail additional risks due to reliance on real-time communication and control, which may malfunction and affect the overall reliability performance.

Advanced protection system could enhance reliability of existing networks and hence could be considered in the scope of a new security standard.

6.7 Conclusions

The findings can be summarised as follows:

- **Temporary overloading of transformers under peak load or contingency conditions**
    - BS IEC 60076-7:2005 allows transformers to be loaded beyond their nameplate rating subject to transformer's current limits and temperature limits of transformer's component for example: top oil, and hot-spot metallic components including the conductor.
    - Ambient temperature (and cooling mechanisms) affects the real-time capacity of transformers.
    - Loading the transformer beyond their nameplate rating can be a cost effective way as countermeasure for premature network reinforcement decisions.
    - Lifetime losses
        - Normal loading: up to 2.8 h per 1 operation hour
        - Long-time emergency loading: 10 – 18 h per 1 operation hour
        - Short-time emergency loading: 10 – 60 h per 1 operation hour (note: it should be less than 30 mins/occurrence)
    - Trial data from one substation shows that transformers are normally operated below its normal loading which extends the lifetime of the transformers but in emergency and peak demand conditions transformers can be overloaded, at the expense of its shorter life time. However, the benefit of operating below its normal loading is likely to exceed the cost of operating in emergency loading.
    - It is generally accepted practice to operate transformers above the nameplate rating, hence the potential benefits may not be as great as expected. It is also worth remembering that the rating of switchgear is typically co-ordinated with the transformer rating and can be the limiting item in the chain. Expenditure on switchgear may be required to release latent transformer capacity.
- **Utilising the cyclic rating of cables to provide additional capacity**

- Having the temperature of the cable lower than its nominal temperature before the peak load improves the cyclic rating of the cable. As the distribution network cables generally have relatively low utilisation factors due to the nature of the load profile, it provides the opportunity to accommodate higher peak load by exploiting the cable's cyclic rating.
- Using the typical load profile, our studies find that a cable can be loaded 20% more and in the emergency conditions, it can be loaded slightly more than 60%.

- **Widening the voltage limits, emergency voltage control, and wide-area dynamic voltage control**

  - At LV, network capability is frequently constrained by voltage rather than by the network thermal (current) limits.
  - Reduction of minimum voltage limit can be considered to enable the utilisation of installed network capacity. Network capacity can be double (by releasing latent capacity which is constrained previously by voltage requirements. Therefore lowering the lower voltage limit can be used as a strategy to accommodate increased demand and to facilitate integration of DG by alleviating voltage rise effect
  - Reduction of the minimum voltage can improve utilisation of the network capacity (constrained by its thermal capacity). Network capacity can be double (by releasing latent capacity which is constrained previously by voltage requirement)
  - Most of the 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 to lower the loads.

- **Dynamic Line Rating**

  - DLR enables the visibility of the dynamic real ampacity of the OH bare conductors and therefore allows the usage optimisation of the existing capacity and improvement of the network reliability performance.
  - Application of DLR on distribution networks has been tested on a number of systems with promising results.

- **Security benefits of advanced protection systems**

  - Advanced protection allows corrective actions to prevent overloading during the contingent conditions and enables fully utilisation of the capacity. However, they may entail additional risks due to reliance on real-time communication and control, which may malfunction and affect the overall reliability performance. Advanced protection systems could enhance reliability of existing networks and hence could be considered in the scope of a new security standard (discussed further in Section 6.6).

7 VALUE OF REMOTE CONTROL AND AUTOMATION

7.1 Introduction

With advances in automation systems, adding more remote control or automation to the secondary distribution network opens significant opportunities for supply restoration within the shortest possible time while at the same time further reduces the cost of operation by reducing the manpower required for system operation. Investment in automated or remotely controlled switching devices enables a 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. 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. CI and CML are defined as follows:

- CI is the average number of interruptions experienced (per 100 customers).
- CML is the number of minutes of lost supply (per customer).

CI and CML form the basis of the reliability and availability indicator. CI and CML are lagging indicators of network investment. A network which is kept in good condition will have fewer and shorter interruptions. Over the time a network will degrade and, after a time, have more frequent and lengthy faults which will be reflected in CI and CML performance. In addition third party damage occurs as well. In practice it's difficult to maintain a HV cable to avoid age and condition related failures. There is financial incentive for DNOs to improve CI and CML, performance better than the target results in a financial reward and performance worse than the target results in a penalty.

Since most of distribution network assets in the UK were installed in the late 1960s – 1970s, these assets might have, depending on their condition, reached the end of their lifetime and need to be replaced. Thus, there is a massive opportunity arising from asset replacement and new installations to apply remote control and automation on distribution networks. Remote control refers to an ability to remotely switch on and off switchgears. Automation could be achieved by use of scripts to automatically send signals for remote control of switchgears. In this example it is assumed that automation could control all switchgears. As the asset replacement has started to roll-out, many of GB feeders are already automated at present.

The key objectives of our studies are to

- identify and quantify the potential benefits of automation for reducing the restoration time and therefore improving the reliability performance of the electrical distribution system measured by the CI,CML and Expected Energy Not Served (EENS) indices and for reducing the associated interruption costs;
- assess the business case for automation for different equipment costs, network availability parameters, VoLL and assess the materiality at the GB level.

7.2 Approach

In order to achieve the objectives we have carried out comprehensive studies using the following approach:

- Step 1: carry out Monte Carlo simulation, see section 13.2, on HV feeders of different characteristics for two cases: (i) cases without remote control/automation and (ii) cases with remote control/automation. For each case, Expected Energy Not Served (EENS), CI and CML for each load point are recorded.
- Step 2: calculate the improvement of CI, CML, and EENS due to remote control/automation.
- Step 3: calculate expected cost savings (i.e. reduction of EENS x VoLL) due to remote control/automation for different values of VoLL
- Step 4: assess the breakeven cost of automation per distribution site in order to provide information about the upper limit of cost of enabling remote control/automation which can still be justified (i.e. lower than its benefits).
- Step 5: assess the impact of automation, in terms at the improvement of reliability performances and reduction of interruption costs at the GB level. This is carried out by running step 1 to step 4, for all identified characteristic HV feeders in the GB, then the results are multiplied by the respective numbers of HV feeders which have been obtained from GB DNOs Quality of Service HV Disaggregation spreadsheets [84].

A set of sensitivity studies has also been carried out by applying certain ranges of equipment costs, and network availability parameters in order to address uncertainty in those parameters and analyse how the results will change with different input parameters.

7.3 Case study

Our studies use a set of data and topology of an actual GB HV network which involve a combination of overhead lines (OHL) and underground cables (UGC). A Monte Carlo simulation technique is employed to simulate the outages of network sections and re-establishing supply by switching actions, using mobile generation and finally repairing the affected section. Failure rates, average repair times (Mean Time To Repair, MTTR), mobile generation deployment times and switching actions are treated as statistical variables. Failure rates are modelled using exponential distribution while other statistical variables are assumed to be normally distributed with standard deviation equal to the third of their mean value.

Benefits of investing in remote control and automation are estimated based on the value of Expected Energy Not Supplied (EENS) for several values of Value of Lost Load (VoLL), namely £6,000/MWh, £17,000/MWh and £34,000/MWh. The studies also consider four different implementation costs for remote control and automation: £500/site.year, £1,000/site.year, £2,000/site.year and £3,000/site.year. These cost points are compared to the potential gross benefits of remote control and automation, from which the number of feeders is estimated where net benefit could be achieved.

Table 7.1 shows the assumed failure rates and repair times used in the studies, see Appendix B, while Table 7.2 presents the assumptions on the duration of switching actions. Mobile generation is assumed deployed in average in 3 hours. It should be noted that the use of urgent rather than average repair times and the lower end of the manual restoration timescales will tend to reduce the modelled benefits of automation.

Table 7.1. Failure rates and repair times for underground cables and overhead lines considered in the studies

Construction	Failure rate (%/km.year)			Urgent repair time (h)
	Min	Average	Maximum	
Underground cable	2	4.8	10	6
Overhead lines	5	8.4	20	6

Table 7.2. Mean duration of switching actions considered in the studies

Switching	Feeder resupply time (minutes)	Backfeed resupply time (minutes)
Automation	2	2
Remote control	10	10
Manual switching	30	50

Data used in the studies indicate that the failure rate of OHL is (about) twice the failure rate of UGC; e.g. the range of failure rate for OHL used in these studies is between 5% and 20%/km per year while for UGC, the range is between 2% and 10%/km per year.

Data also show significant improvement in the restoration process due to remote control and automation, For example, with remote control and automation, the time needed for feeder resupply can be reduced considerably from 30 minutes with manual switching to 10 minutes with remote control and even reduces further to 2 minutes with automation. Time needed to resupply via backfeed also reduces significantly from 50 minutes with manual switching to 10 minutes with remote control and reduces further to 2 minutes with automation.

Figure 7.1 shows the scatter plot of the expected values of CI and CML for each feeder in the analysed network for different switching approaches. Red markers represent manual switching, blue ones are for remote control and green markers denote automated switching. Values have been obtained using average failure rates from Table 7.1.

It is expected that customers experience different quality of service. This is demonstrated by the wide range of CIs and CMLs customers might experience produced by the model. The expected values differ depending on which feeder customers are connected to. Customers connected to spurs might wait longer for resupply as spur by definition is not N-1 secure. The implementation of remote control slightly reduces the likelihood of long interruptions but not the likelihood of three or more interruptions per year. Automated switching on the other hand significantly reduces the likelihood of three or more countable interruptions.

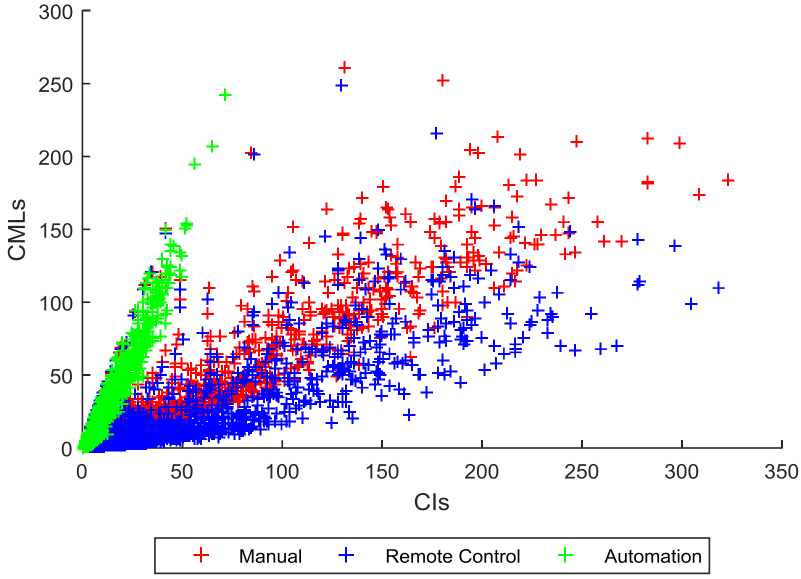


Figure 7.1. Scatter plot of expected values of CI and CML per feeder for different switching actions

It can be observed that remote control generally improves the CML performance. Automation on the other hand significantly improves CI performance by reducing expected outage duration below 3 minutes. It can also be seen that the correlation between CI and CML increases with automated switching and the range of CIs different customers might experience reduces considerably.

Figure 7.2 shows the scatter plot of expected values for CI and CML per feeder for different switching actions using average failure rates, but now with the deployment of mobile generation.

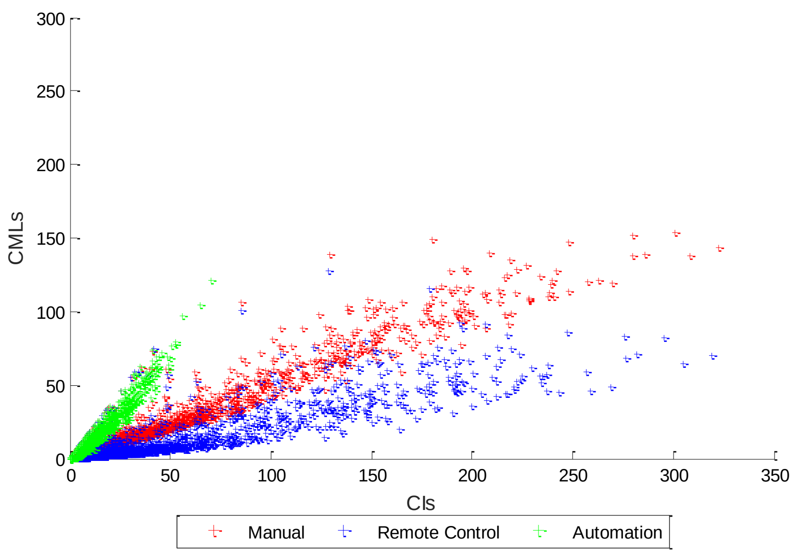


Figure 7.2. Scatter plot of expected values of CI and CML per feeder for different switching actions using average failure rate and mobile generation

As expected, the use of mobile generation to restore supply reduces the overall CML by shortening interruption of supply. CI does not change as the same number of faults occur in both cases. Given that CML are now lower than in Figure 7.1, the reduction of CML due to remote control seems to be more profound even though in the absolute terms the reduction is the same. Without mobile generation CML has reduced in both cases for about 15 minutes per customer and year. Without use of mobile generation this equates to about 44% reduction and with use to about 56%.

The range of CIs and CMLs observed in the studies are summarised in Table 7.3.

Table 7.3. Range of CIs and CMLs observed in the studies

Indices	Reliability case	Manual	Remote control		Automation	
			Value	Reduction	Value	Reduction
CI	λ -Minimum	25.89	25.55	0.34	3.33	22.56
	λ -Average	53.76	52.95	0.81	6.67	47.09
	λ -Maximum	177.81	116.14	61.67	14.85	162.96
	λ–Average (with mobile generation)	53.74	52.98	0.76	6.68	47.06
CML	λ -Minimum	16.82	9.72	7.10	7.80	9.02
	λ -Average	34.15	19.18	14.97	15.19	18.96
	λ -Maximum	75.56	42.97	32.59	34.23	41.33
	λ–Average (with mobile generation)	27.04	12.08	14.96	8.08	18.96

Note: λ = failure rate

The results demonstrate that for cases with the average failure rate, CI improvement due to the application of remote control or automation is 0.8 or 47.1 interruptions per 100 customers respectively. The majority of improvement is observed in cases with automation; it is important to note that when electricity supply can be restored within less than 3 minutes, the interruption is not counted towards CI. For the corresponding CML, the improvement is about 15.0 or 19.0 minutes per customer per year when remote control or automation is used, respectively. The scale of CI and CML improvement are the same for both with and without the use of mobile generation. It should also be noted that the use of mobile generation improves overall CML performance by 7.1 customer minutes per year.

The studies also demonstrate that in a system with higher network reliability, e.g. the case with the minimum failure rate, the benefits from remote control and automation are less. For example, the reduction of CI and CML due to automation in the case with minimum failure rate is 22.6 interruptions and 9 minutes respectively, lower than the benefit found in the case with average failure rate. On the other hand, in a less reliable system, e.g. with the maximum failure rate, the reduction of CI and CML due to automation can be considerably higher, i.e. 163.0 interruptions and 41.3 minutes respectively, higher than the benefit found in the case with average failure rate.

7.3.1 Identifying the value of remote control and automation for individual feeders

The contribution per feeder in reducing CI, CML, and EENS by deploying remote control or automation has been calculated and the impact of different failure rates on this contribution has been analysed for UG and OH feeders. The approach for remote control and automation are the same and for simplicity only approach for automation is discussed in the rest of this section.

The contribution to the reduction of CI, CML, EENS due to automation in HV UG networks for different failure rates are presented in Figure 7.3. The x-axis is the feeders used in the studies and the y-axis is the contribution of a particular feeder to the reduction of system CI, CML, and EENS. The feeder which has the highest contribution is put first followed by the feeder which has the second highest contribution, and so on until all feeders (100%) are put in the graph. The area below the curve is the reduction of system CI /CML/EENS as shown in Table 7.3.

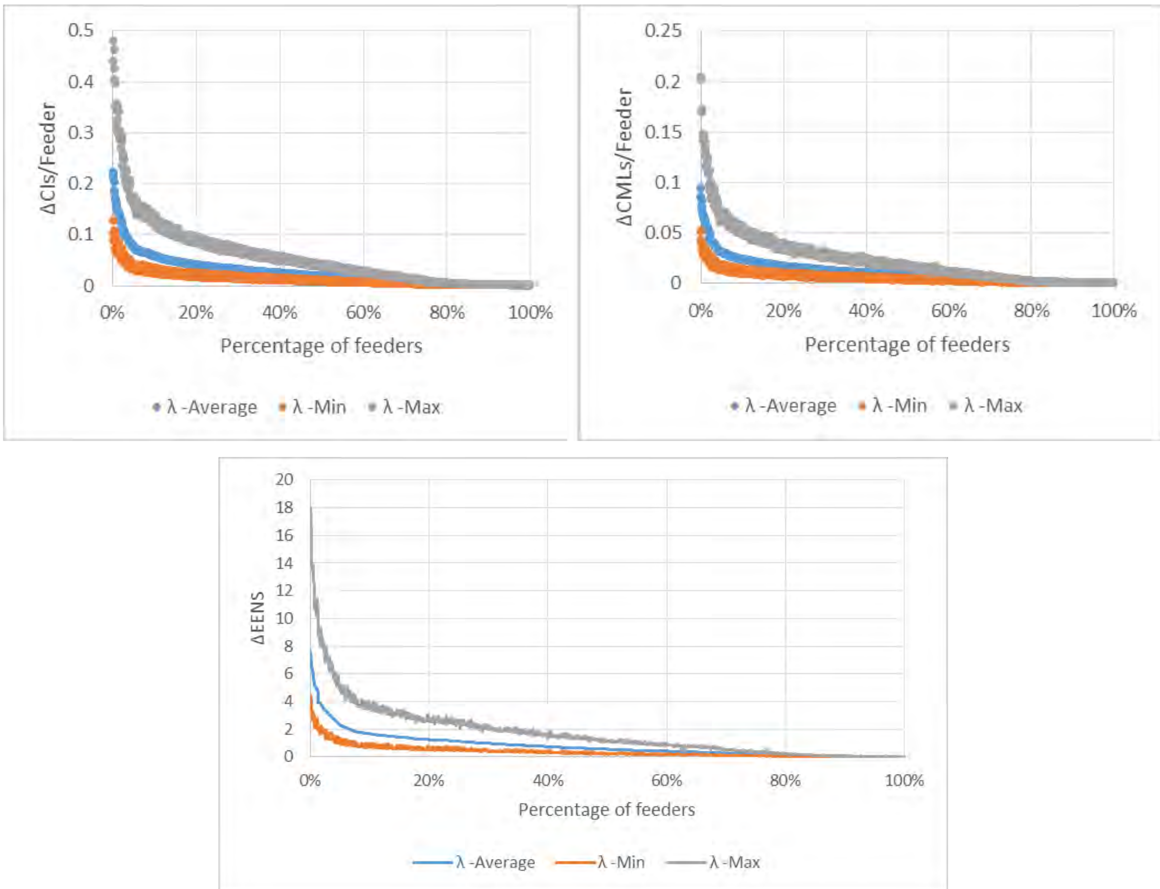


Figure 7.3. Contribution to the reduction of system CI, CML, EENS per UG feeder for different failure rates

The results show the following:

- The scale of the benefit of automation is different for different feeders. For example, for cases with the average failure rate, only around 20% of feeders can gain more than 1 MWh of EENS reduction by doing automation. The rest of feeders will gain only less than 1 MWh reduction. This indicates that automation should be carried out for selective feeders according to the priority and not all feeders need to be automated.
- The maximum benefit due to automation for CI, CML, and EENS reduction per feeder are circa 0.48 interruptions, 0.2 customer-minute, and 7.8 MWh/year respectively.

- Consistent with the previous findings, the benefit of automation is higher in a less reliable system and vice versa. In the less reliable system, the number of feeders which are potential to be automated is higher.

Similarly, the contribution to the reduction of CI, CML, EENS due to automation in HV OH networks for different failure rates are presented in Figure 7.4.

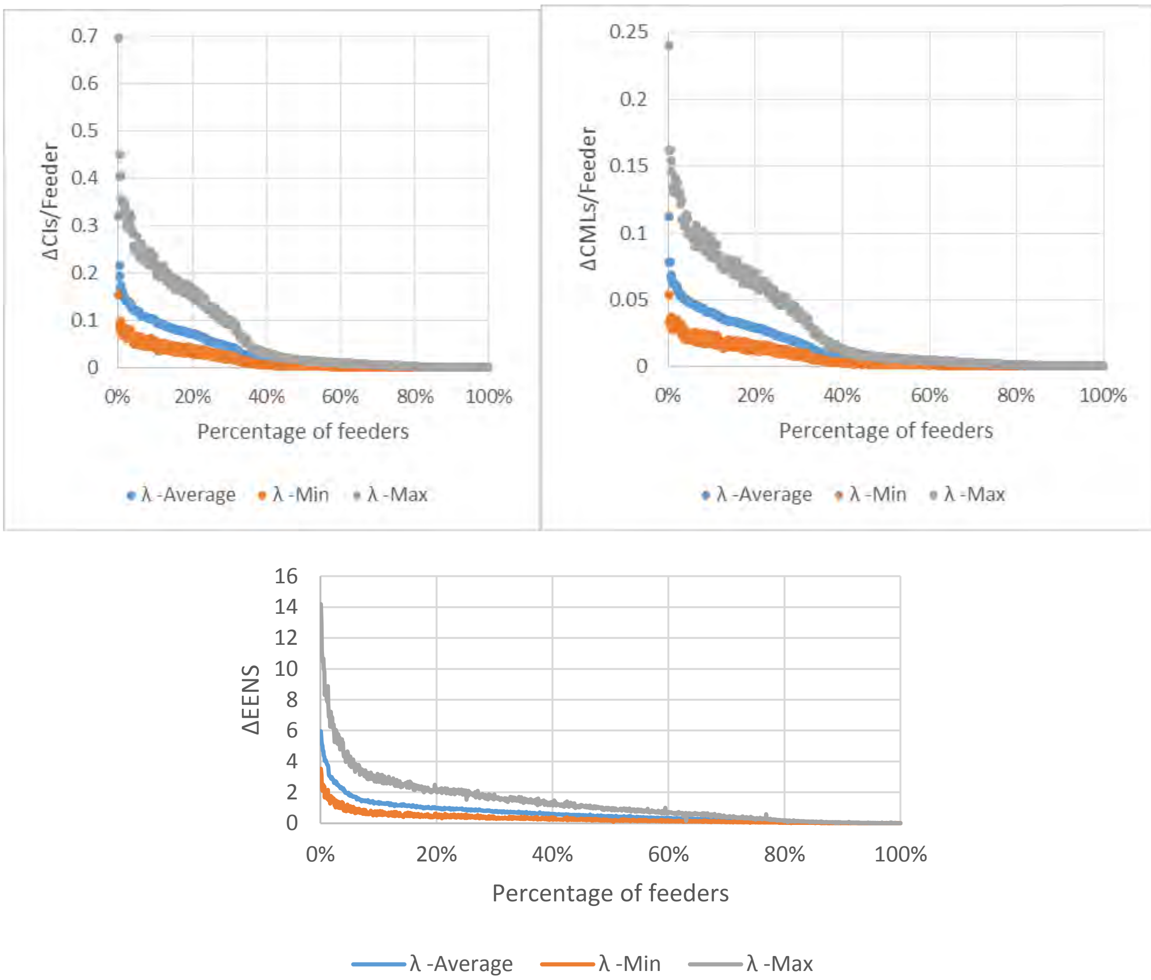


Figure 7.4. Contribution to the reduction of CI, CML, EENS per OH feeder for different failure rates

The results for OH feeders show the same trends as the results for UG feeders with the exception that the shape of its distribution is less "peaky"; this is due to the characteristics of OH which is slightly less reliable than UG. For OH feeders, the results also show the maximum benefit due to automation for CI, CML, and EENS reduction per feeder are circa 0.32 interruptions, 0.12 customer-minute, and 4.8 MWh/year respectively.

7.3.2 Value of remote control and automation for different cost of remote control and automation and different VoLLs

Figure 7.5 shows the potential annual savings per secondary site when fault isolation is conducted remotely for four different VoLLs, i.e. £6,000/MWh, £17,000/MWh and £34,000/MWh. Secondary site is a location where distribution transformer(s) are i.e. load point of the HV network. Similar to the previous figures, the first feeder on the x-axis is the feeder that gains the largest benefit from the remote control scheme, and the last feeder is the feeder that gains the lowest benefit from the scheme. The results show that, using VoLL of £17,000/MWh, the maximum savings are about £2.7k per year per feeder. The benefit drops rapidly to about £1.6k per feeder, after which the drop becomes more linear. The results can be used to determine whether the remote control scheme can be justified economically.

The potential annual savings depend linearly on the VoLLs. The larger the VoLLs, the higher the annual saving is, and therefore the business case for implementing remote control scheme is also higher. This shows a correlation between demand for security, reflected in the VoLL, with the business case for remote control (and automation) scheme but only for cases where the cost of remote control or automation installation can be justified.

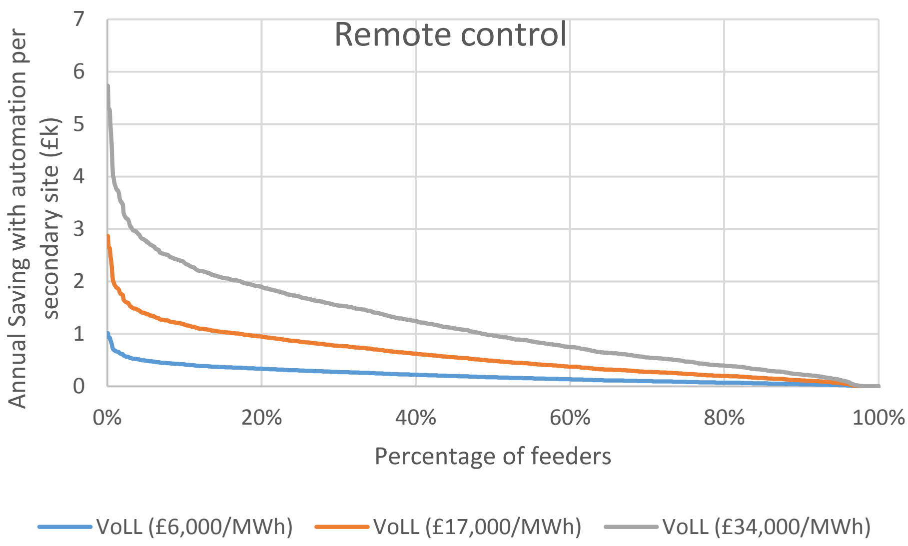


Figure 7.5. Potential savings of remote control

Table 7.4 and Table 7.5 show the percentage of UG and OH feeders respectively, where the benefits of installing remote control would outweigh its cost, for different levels of VoLL. About 49% UG feeders would benefit from remote control if the installation cost of remote control per distribution site is £500k/year and VoLL is £17,000/MWh. For the same VoLL, if the cost of remote control per distribution site is £2k/year, only 1% of feeders would be cost-efficient to control remotely.

Table 7.4: Percentage of UG feeders where benefit of remote control is greater than cost

Cost of remote control per secondary site (£k/year)	VoLL (£6,000/MWh)	VoLL (£17,000/MWh)	VoLL (£34,000/MWh)
0.5	4%	49%	74%
1	0%	17%	49%
2	0%	1%	17%
3	0%	0%	3%
5	0%	0%	0%

Considering that OH feeders are less reliable than UG feeders, the percentage of the OH feeders that potentially get benefits from automation is slightly larger than the results for the UG feeders. With high VoLL and low cost of automation, about 77% of HV OH feeders should be automated.

Table 7.5: Percentage of OH feeders where benefit of remote control is greater than cost (OH)

Cost of remote control per secondary site (£k/year)	VoLL (£6,000/MWh)	VoLL (£17,000/MWh)	VoLL (£34,000/MWh)
0.5	7%	41%	77%
1	0%	14%	41%
2	0%	1%	14%
3	0%	0%	6%
5	0%	0%	0%

Figure 7.6 is similar to Figure 7.5 but for automation instead of remote control scheme. The values are calculated for three different VoLL levels. For instance, with VoLL equal to £34,000/MWh, about 20% of feeders in the network have the annual savings per site equal to or greater than £2,300 per site. For VoLL of £17,000/MWh the maximum savings observed are about £3.5k per feeder. This quickly drops to about £2k per feeder, after which the drop to zero is more linear.

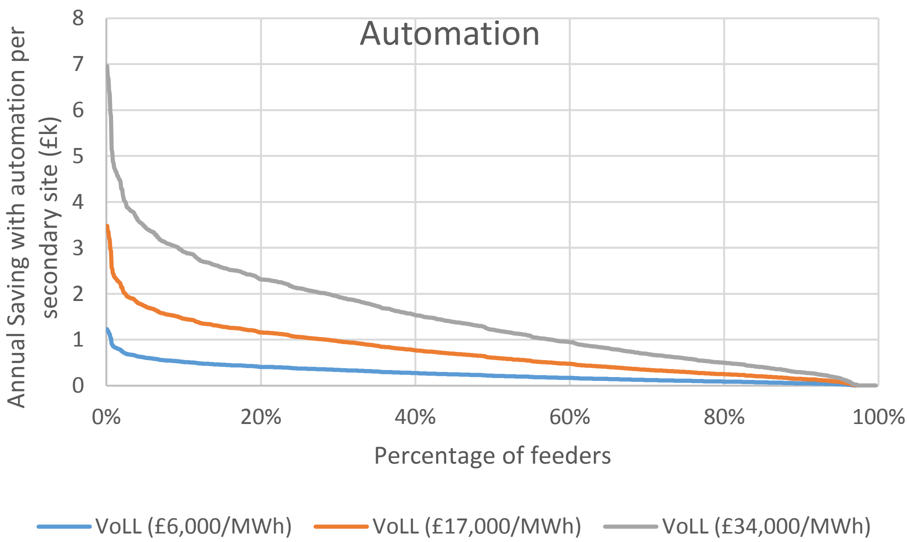


Figure 7.6. Potential savings of automation

Table 7.6 shows the percentage of UG feeders where 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 VoLL is £17,000/MWh. For the same VoLL however, if the cost of automation per distribution site is £2k/year, only 2% of UG feeders would be cost-efficient to automate.

Table 7.6: Percentage of UG feeders where benefits of automation is 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 7.7 shows the percentage of OH feeders where benefits of automation exceed the cost of automation for different VoLLs. For low cost of automation and high VoLL, 91% of HV OH feeders should be automated; while if the cost of automation is £2k/year and VoLL is £17,000/MWh, then only 5% of OH feeders would be cost-efficient to automate.

Table 7.7: Percentage of OH feeders where benefits of automation is 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%

Table 7.8 shows the percentage of UG feeders where benefits of automation in comparison to remote control exceed the cost of automation for different VoLLs. For instance, it is found that about 28% feeders would benefit from having automation installed if the cost of automation per distribution site is £200/year and VoLL is £17,000/MWh. For the same VoLL however, if the cost of automation per distribution site is £1k/year, none of UG feeders would be cost-efficient to automate.

Table 7.8: Percentage of UG feeders where benefits of automation is 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)
0.2	1%	28%	57%
0.4	0%	3%	28%
0.5	0%	1%	17%
1	0%	0%	1%

Table 7.9 shows the percentage of OH feeders where benefits of automation in comparison to remote control exceed the cost of automation for different VoLLs. For low cost of automation and high VoLL, 80% of HV OH feeders should be automated; while if the cost of automation is £1k/year and VoLL is £17,000/MWh, then none of OH feeders would be cost-efficient to automate.

Table 7.9: Percentage of OH feeders where benefits of automation is 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)
0.2	1%	22%	57%
0.4	0%	6%	22%
0.5	0%	2%	15%
1	0%	0%	2%

It should be noted that this study assumes that none of the feeders' switchgears is either remotely controlled or automated. In practice, the incentive to reduce CI and CML has already driven some investment in remote control and automation of feeders and hence some feeders, especially new ones, already have remote control switchgears which might be also automated.

7.4 Conclusions

A large number of numerical studies on an actual GB HV distribution network have been carried out in order to identify and quantify the benefits of remote control and automated switching to improve the CI and CML performance of the systems and reduce the expected energy not served (EENS). Some observations can be derived from the exercise and analysis that have been performed in this project; these include the following:

- In general, remote control and automation would improve network reliability performance and reduce impact of faults on customer's quality of supply. The results indicate that both remotely controlled switching and automation can significantly reduce the CML indicator (by 44% and 56%, respectively), due to significantly shorter resupply times when compared to manual switching. On the other hand, the CI performance was only marginally improved by remote control (i.e. 1.5% reduction), whereas automated switching dramatically reduced the number of interruptions by 88%. This benefit of automation might not be very significant for circuits with very high reliability.
- Drivers for remote control and automation scheme are: network reliability (circuits availability, failure rate, Mean Time To Restore/Repair), 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, tor low cost of network automation and VoLL of £17,000/MWh, circa 60% of HV feeders should be automated. High VoLL and low installation cost give a strong business case of deploying automated switchgear, while if 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. Clearly, a more precise estimate of the installation cost would provide a much clearer picture on the potential market for remote and automated switching in future distribution networks.

8 PLANNING UNDER UNCERTAINTY

8.1 Need for integration of uncertainty in planning standards

Historically, distribution network planning has involved little uncertainty regarding future development. Until now, planning has mainly been an exercise of meeting future demand growth projections at minimum cost while ensuring adequate power quality and security of supply. However, this landscape is set to change drastically over the coming decades due to the increasing penetration of low carbon generation and demand technologies and deployment of smart grid technologies. Furthermore, customer demand patterns are expected to change considerably with the impending electrification of heat and transport sectors through the widespread adoption of heat pumps and plug-in electric vehicles. As a result of the above drivers, significant amounts of investment will be required to enable distribution networks to handle a wide variety of operating points while making optimal use of smart technologies.

However, the biggest challenge in realising this transition in a cost-efficient manner is the increased uncertainty that surrounds future generation and demand developments. This uncertainty is preventing 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. In many cases, this situation is further aggravated by the practical realities of the problem at hand. For example, future demand and distributed generation connections are increasingly hard to predict and the anticipatory investment would be the only viable option for the timely accommodation of new entrants as reinforcing urban distribution network can be a very lengthy process subject to planning permissions, significant civil works etc. 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. In the particular case of distribution planning, a strategic investment can be defined as an investment undertaken to manage uncertainty. 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.

Recently, there have been efforts to explicitly consider uncertainty by moving beyond the typically-used NPV framework, as also applied to the current security standard, and towards modified valuation frameworks, particularly including Real Options Analysis (ROA) [61]. Although a step in the right direction, such methods are severely limited to a small number of candidate strategies defined a priori. When defining a set of candidate investments a priori, we do not examine cost/benefit of all possible investments but choose just a subset to be analysed based on some heuristic criterion. This practice may result in sub-optimal solutions given that a candidate not analysed might be the optimal solution. In reality, a very large number of strategic opportunities can arise in all irreversible dynamic decision systems due to the inter-temporal resolution of uncertainty and the possibility for exercising recourse adaptations to the original decisions following the revelation of new information [62], [63]. 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. For example, when we set out to predict now the uptake of electrical vehicles in 2030, we are bound to make a less accurate prediction than if we were given the same task in year 2029. The basic idea is that uncertainty is partially resolved over time and ultimately disappears at some point. For example, the uncertainty around electrical vehicle uptake in 2030 is fully resolved by 2031. In addition, distribution network planning can entail decisions with respect to numerous asset types beyond reconductoring and transformer upgrades, such as demand-side response, soft open points etc. It follows that defining a priori a set of candidate strategies is severely self-limiting and may bias decision in the wrong direction. Instead, the optimal strategy must be the result of optimisation techniques that can guarantee on the basis of all currently-available information.

There are three main classes of optimisation methodologies for addressing uncertainty; stochastic (also known as probabilistic), risk-constrained and robust. Stochastic planning is the case where each scenario node is attributed a probability of occurrence; the planner's objective is the minimization of expected system cost over all realisations. This constitutes a risk-neutral case, but the consideration of the uncertainty structure will inherently make use of any available flexibility so as to limit the risk of adverse realisations and improve plan adaptability. In a similar vein, suitable constraints with respect to risk metrics such as the expected shortfall (also known as Conditional Value-at-Risk) can be included to render the planner risk-averse. Although the aforementioned approaches rely on a probabilistic description of future developments which is not available, they can be useful in identifying attractive investment strategies, especially when combined with extensive sensitivity analysis on the probability assumptions, see section 13.4.

Robust decision methods in the context of system planning mainly refer to two variants; optimisation against uncertainty intervals and utilisation of the regret concept. The former guarantees optimal performance given a deterministic description of the uncertainty state space (i.e. no probability function). However, it lends itself mostly to static descriptions of uncertainty and cannot take advantage of its inter-temporal resolution structure which is an important characteristic of dynamic system planning. The latter identifies the optimal planning strategy so as to minimize a planner's worst-case regret, see section 13.8; regret is defined in terms of the optimal solution under the assumption of perfect foresight. It is important to highlight that the worst-case is not defined a priori, but will eventually depend on the planner's decisions. Naturally, regret approaches can be overly conservative and in cases be driven exclusively by adverse scenarios that may be very unlikely to occur. However, the attractiveness of adopting a 'min-max regret' decision criterion lies in its intuitive application within a regulated framework. The appropriateness of the undertaken investment decisions is eventually judged on an ex-post basis, after uncertainty has been resolved, and is compared with the most cost-efficient course of action that could have been taken instead. Adopting a min-max regret planning framework constitutes an important first step towards the explicit incorporation of uncertainty in the planning and regulatory framework.

The role of the proposed cost-benefit frameworks 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 frameworks is the definition of 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.

8.2 Option Value of Demand Side Response

8.2.1 Introduction

It is imperative to highlight that in the case of planning under uncertainty, smart grid technologies can be viewed as a highly flexible solution for network reinforcement due to the operator's ability to deploy them faster than major conventional reinforcements, as well as the fact that they can offer valuable operational flexibility. It should be noted that whilst some smart grid technologies might be quicker to install than traditional assets, this is not necessarily always the case. For example it might be far quicker to install a new section of 33kV or 11kV cable in the highway than to try to get 500 customers signed up to a DSM contract. As a result, a direct consequence of relying on a traditional static valuation framework is that smart grid solutions which may not be the optimal solution in the presence of perfect information, but can be incredibly valuable for managing network constraints in the interim, until some major uncertainty has been resolved, are not attributed the full benefit they bring to the network. Instead, 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.

One of smart grid technologies with a particularly high flexibility potential is demand side response (DSR), including both residential DSR driven by the envisaged country-wide rollout of smart meters in the coming years as well as DSR of industrial and commercial consumers. In this part of the report we present a stochastic optimisation methodology to assess the value of DSR in a planning framework accounting for uncertainty. The stochastic planning model is outlined in Section 8.2.2. In Section 8.2.3 we clearly demonstrate through a case study the shortfalls of static valuation frameworks, present the way that DSR can facilitate the adoption of a 'wait-and-see' strategy and render it economically beneficial by providing network managing in the interim, until commitment to a long-term conventional project (e.g. building a new substation transformer) is justified. Section 8.2.4 summarizes and concludes this part of the report.

8.2.2 Strategic planning using stochastic models

Stochastic programming is a generic framework for describing decision problems under uncertainty, see section 13.6. Although there are numerous variants of stochastic problems, of most interest to long-term planning problems is the application using scenario trees, where the evolution of uncertain parameters is modelled in a discrete-time manner. A scenario tree is a coherent representation of possible future realizations of uncertainty. It comprises of scenario tree nodes that encapsulate possible states of the uncertain parameters at different times and arcs that capture the possible evolution paths. The main motivation for using this approach is the capability of capturing the planner's *decision flexibility*. Stochastic programming enables us not only to explicitly consider a range of potential future system evolutions, but inherently enables the planner to identify the optimal recourse action for each, as permitted by the structure of inter-temporal uncertainty resolution. In view of this, a flexible decision framework enables a planner to move beyond the concept of a static *investment plan* and instead identify the optimal *investment strategy* which encapsulates a range of contingent courses of actions to be taken according to all possible paths of uncertainty evolution.

Naturally, although a long-term planning strategy defines the optimal decision to be made at each stage (conditional on the uncertainty realisation), the implementable part of the strategy is solely the decision which pertains to the first stage. Note that this decision is unconditional since no uncertainty has been resolved yet. New scenarios should be constructed in the following years and new strategies drawn from the most up-to-date information if available. It follows that planners are by definition mostly interested in the first-stage planning decisions; the optimal 'here-and-now' decision based on all currently available information. In view of the above, we focus on a less-documented yet highly important aspect of considering non-network solutions such as DSR in the distribution-planning problem. These flexible assets introduce the possibility to defer commitment to major conventional reinforcement projects until the need for such investment is fully established. In other words, interim measures like DSR can be useful in 'buying time' until more information regarding system evolution is available, thus rendering viable a 'wait-and-see' strategy that would otherwise be too costly. On the other hand, deterministic approaches assume a perfect knowledge of the future and will tend to favour large-scale projects that enjoy scale economies; therefore there is no scope for uncertainty management. The deterministic planner does not opt for an interim solution since he considers the future fully known and there is no case for deferring investment to offset stranding risk. In the following sections, the above principles are shown using a case study of distribution network planning under uncertainty of future peak demand growth.

8.2.3 Case Study

The presented case study, aimed at illustrating the option value approach, focuses on a single primary substation, shown in Figure 8.1. This substation is currently equipped with two 8 MVA transformers, while the peak demand is 8.5 MVA. The network is being operated under a relaxed N-0.75 security standard, which means that the peak serviceable load is 10 MVA. This relaxed security standard has been determined as the optimal security level following a cost benefit analysis where the cost of outages (determined according to the Value of Lost Load) has been balanced against the cost of network reinforcement. However, load growth above 10 MVA triggers the need for network reinforcement. Currently, the substation is feeding a local community with a recorded peak demand of 8.5 MVA, as shown below.

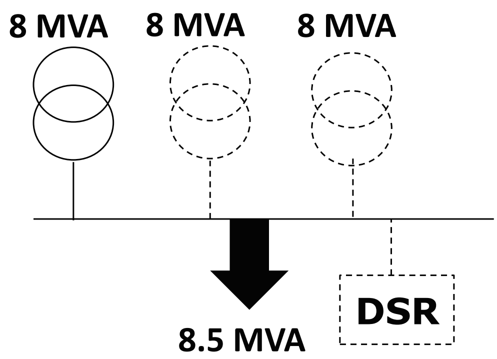


Figure 8.1: Distribution system under study (dotted lines show candidate investments to reinforce the network).

Over the next years, an increase in peak demand is expected. However, there is uncertainty surrounding this evolution. To this end, the scenario tree shown in Figure 8.2 has been constructed to capture three possible peak demand growth scenarios for the period 2015-2022 in a coherent manner. The scenario tree consists of four two-year stages (also referred to as epochs); 2015-2016, 2017-2018, 2019-2020 and 2021-2022. Each scenario tree node shows the peak demand that pertains to both years of the epoch. The three scenario paths are as follows:

- **Scenario 1 (S1)** is the high growth scenario envisaging consistent high growth up to 12.75MVA in the final stage, an increase of 50% on the present peak demand. This is seen as the most probable scenario to materialise and has been given a 50% probability of occurrence.
- **Scenario 2 (S2)** is the medium growth scenario envisaging a peak demand of 11.05MVA in years 2020-2021, an increase of 30% on the present peak demand. This is seen as the second most probable scenario to materialise and has been given a 30% probability of occurrence.
- **Scenario 3 (S3)** is the low growth scenario envisaging peak demand of 10.20 MVA in years 2020-2021, an increase of 20% on the present peak demand. This scenario entails a 20% probability of occurrence.

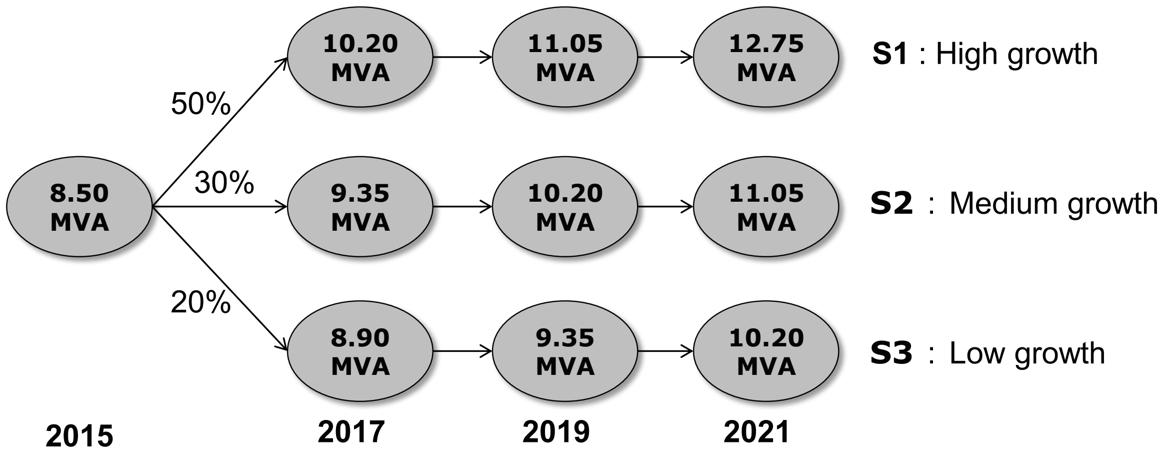


Figure 8.2: Scenario tree showing evolution of peak demand and transition probabilities for each scenario.

To ensure that demand will be met at for a single circuit or DSR outage in the future, the DNO has the following two options for reinforcing the system:

- **Install a new 8 MVA transformer.** The lump present cost of purchasing and installing this transformer is £1.25 million. Using an expected lifetime of 20 years and a discount factor of 3.5%, this is equivalent to an annuitized capital cost of £88k. Most importantly, we assume that the commissioning of the transformer will not be instantaneous; two years will be required to carry out the necessary works including planning process, procuring, major civil works, installation including modification to protection schemes etc.
- **Establish a DSR scheme.** This is an alternative to the conventional reinforcement option. We assume that the DNO has the possibility to enter into a contract with local consumers to curtail their demand when needed. For the purposes of this case study, the amount of curtailable demand (i.e. DSR contract size) is 1,500 kVA. However, we do not consider the entire amount fully reliable; we account for the prospect of some consumers not responding to the DNO's signal to reschedule their consumption by utilizing a 60% availability factor. In other words, the DNO can rely on 900 kVA reduction during peak hours. The annuitized cost of establishing this contract is assumed to be £35k. An annual cost of £35k has been derived on the basis of DSR having a lump cost of £500k and a lifetime of 20 years. Although this is just a cost estimate, the main premise is that DSR is considerably cheaper than installing a new transformer. In addition, due to the lack of need for complex physical works we consider that this DSR scheme can be commissioned instantaneously following its investment decision. It is also assumed that a HV load transfer scheme is not available or it would be more expensive.

In the following sections we showcase results for three studies; deterministic planning, stochastic planning with only conventional assets and stochastic planning with both conventional assets and DSR. The objective of the deterministic and stochastic models is minimisation of investment cost for a single scenario and minimisation of expected investment cost over all scenarios respectively. Note that the models can be expanded to also include the cost of outages and determine the optimal level of network redundancy within a cost-benefit framework.

Deterministic Case Study – Results

We firstly present the optimal investment plan obtained when adopting a naïve *deterministic* approach where the DNO considers only the most probable scenario i.e. high-growth S1. The optimal plan is shown in Figure 8.3. It is worth noting here that whereas stochastic planning problems cannot be solved using a deterministic approach, the opposite is perfectly feasible i.e. solving a deterministic problem using a stochastic optimisation model. This is the case because a deterministic problem can be seen as solving a stochastic problem with a single scenario with a 100% chance of occurring.

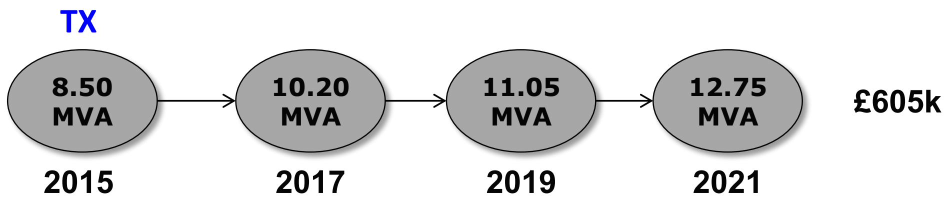


Figure 8.3: Optimal deterministic investment plan when the planner can build only conventional assets

As can be seen above, the optimal plan involves investment in an extra transformer for £605k. Note that the capital cost pertains solely to the 8-year horizon being considered i.e. the annual cost of £88k multiplied by an aggregate discounted factor obtained as the sum of discount factors over the eight-year horizon, 6.87. This commitment is undertaken from the very first stage to ensure that the asset is commissioned by 2016, so as to cover the foreseen peak demand which will exceed the capabilities of the present system once peak demand grows above 10 MVA. It is worth highlighting that there is no value in considering a DSR contract. Although DSR could cover system needs up to 2017, a transformer would need to be constructed for subsequent years. As a result, DSR is not a cost-efficient solution for this particular scenario. However, the possibility for alternative realizations is not considered. In the event that S3 instead of S1 was to materialize, the planner could have accommodated the eventual peak demand at a fraction of the cost through DSR deployment. This highlights the need to consider uncertainty using a stochastic decision framework.

Stochastic I (S-I) Case Study – Results

In this case study (Stochastic I or S-I) we utilize the stochastic planning model and assume that the planner can invest only in conventional assets i.e. installation of an extra 8 MVA transformer. The optimal investment strategy is shown in Figure 8.4.

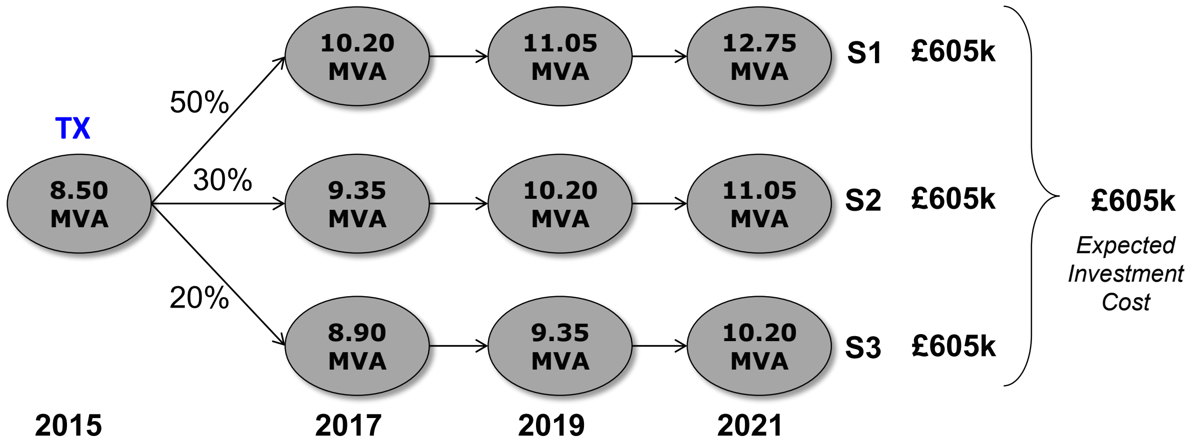


Figure 8.4: Optimal stochastic investment strategy when the planner can build only conventional assets.

As can be seen above, the strategy involves a single first-stage commitment to build an extra transformer. This entails an expected investment cost of £605k. The timing of this decision is driven by S1, which necessitates a capacity reinforcement by year 2016. Since no interim measure such as DSR is available, the planner has no choice but to proceed with this unconditional commitment.

Stochastic II (S-II) Case Study – Results

In this case study (Stochastic II or S-II) we utilize the stochastic planning model and assume that the planner can invest in both conventional assets as well as DSR. The optimal investment strategy is shown in Figure 8.5.

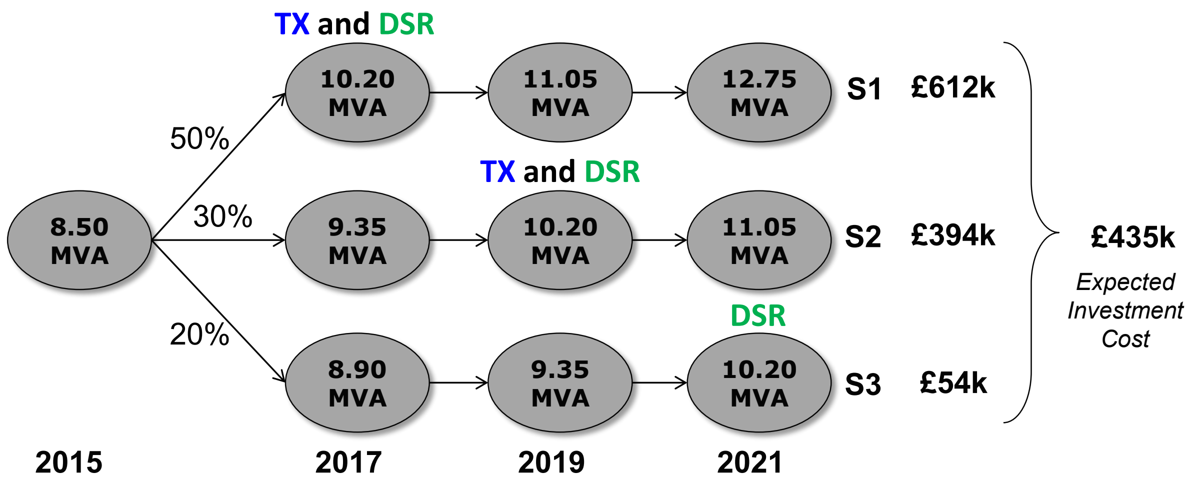


Figure 8.5: Optimal stochastic investment strategy when the planner can build both conventional and DSR assets.

When enabling investment in DSR and considering uncertainty, the optimal investment strategy is radically different. First and foremost, there is no longer a 'here-and-now' decision to be made; the planner has adopted a 'wait-and-see' strategy towards first-stage capital commitments, meaning that it makes economic sense to not make any investment from the very first stage but rather wait for the resolution of uncertainty that occurs later to make more informed decisions.

In the case that S1 materializes, the planner proceeds with building both DSR and an extra transformer. Although the transformer can cover system needs for the entire horizon, its commissioning delay leaves the system unable to cope in the years 2016-2017. To this end, DSR is deployed in 2016 as an interim measure, enabling unconstrained system operation. A similar investment decision is made for S2, but delayed by one epoch.

Note that between building a single transformer in 2016 and building a transformer and DSR in 2018, the planner prefers the latter due to the time value of money and the benefit of capital expenditure deferral by 2 years. This may change subject to the modelling assumptions on asset lifetime, horizon accounting rules and discount factor.

In the case of S3, the peak demand growth can be fully covered by the DSR scheme, deployed in 2020. This scenario highlights the substantial difference with the S-I study due to the availability of DSR. By avoiding the premature commitment to a transformer, the capital expenditure under this realisation drops from £605k to just £54k. Overall, the expected investment cost is now much lower at £435k.

In summary, the key point is that adopting a 'wait-and-see strategy' was not possible in the absence of cost-efficient and sufficiently flexible interim measures like DSR. In the following section, we use the previously-obtained simulation results to quantify the overall benefit of DSR.

Option Value of DSR

As mentioned earlier, when examined in an uncertainty setting, smart technologies can provide system benefits beyond those detected under deterministic studies. This latent value stems from their flexibility to meet adverse scenario realisations without resorting to premature commitments. As seen in the previous case studies, the planner's ability to rely on DSR can have significant impact on the chosen investment strategy, leading to further minimization of costs. To describe this latent value, we choose to use the term option value in a similar vein to its original use in the context of social welfare economics [66].

In this particular case study, the option value of DSR can be calculated as the difference in expected investment cost between stochastic studies S-I and S-II. The resulting difference is the benefit due to the availability of DSR and can be interpreted as the monetary value a planner would be willing to spend to render DSR technology available for deployment. For the system under study, DSR option value can be quantified as £605k - £435k = £170k. In other words, DSR enables a 28% reduction in expected system costs. The net benefit of DSR under each realisation is shown in Table 8.1.

Table 8.1: Quantification of scenario-specific net benefit and option value of DSR.

	Net Benefit of DSR (£k)
Scenario 1	-7
Scenario 2	211
Scenario 3	551
DSR Option Value (£k)	170

These numbers refer to the scenario-specific benefit of adopting the proposed strategy. In particular:

- If we adopt the investment strategy shown in figure 16 and **scenario 1** materializes, the total cost is £605k (build transformer at the very first stage). If instead we had adopted the strategy shown in the figure above, we would have paid £611. In this case, the benefit of adopting the stochastic strategy instead of the deterministic plan does not work in our favour; we lose £605k - £611k = -£7k.
- If we adopt the investment strategy shown in figure 16 and **scenario 2** materializes, the total cost is £605k (build transformer at the very first stage). If instead we had adopted the strategy shown in the figure above, we would have paid £394k; a much smaller sum. In this case, the benefit of adopting the stochastic strategy instead of the deterministic plan is quite substantial and is equal to £605k - £394k = £211k.
- If we adopt the investment strategy shown in figure 16 and **scenario 3** materializes, the total cost is £605k (build transformer at the very first stage). If instead we had adopted the strategy shown in the figure above, we would have paid £54k; a much smaller sum. In this case, the benefit of adopting the stochastic strategy instead of the deterministic plan is very substantial and is equal to £605k - £54k = £511k.
- From the above discussion, it follows that the savings of adopting a stochastic strategy with DSR depends on the eventual scenario realisation. Since we do not know which of the three scenarios will actually materialize, we want to quantify the *expected* savings across all scenarios. This is given as the weighted average: 0.5*(-£7k) + 0.3 *(£211k) + 0.2*(£511k) = £170k.

Naturally, the size of DSR option value depends on a range of parameters. In the following section, we perform sensitivity analysis on four fundamental model parameters to explore how DSR option value changes with respect to capital cost, availability, contract size and discount rate.

Case Study – DSR Option Value Sensitivity Analysis

First we explore how DSR option value changes under different capital costs for DSR. In the base case studies shown in previous sections, an annual cost of £35k was used. We now run several additional case studies where this cost is varied between 0 and £105k/year. The results are shown in Figure 8.6.

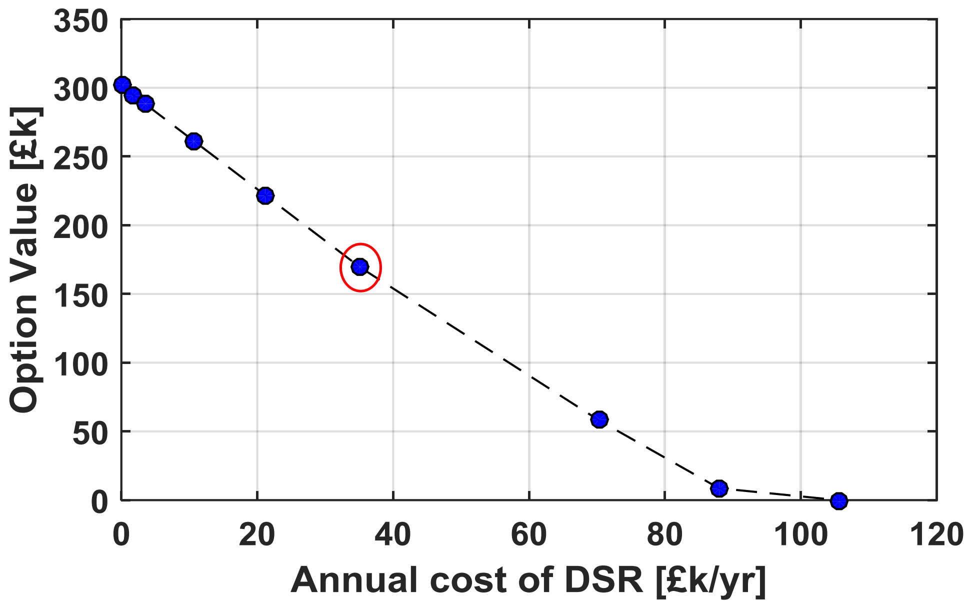


Figure 8.6: Sensitivity analysis of option value of DSR with respect to different investment costs for DSR. Data point corresponding to base case is circled red.

As can be seen above, DSR option value remains larger than zero for a large range of capital values, even in the extreme case that the capital cost of DSR exceeds cost of a new transformer (£88k/year). This is primarily due to assumed DSR's fast commissioning which renders DSR attractive even under very high capital cost. In practice, time required to secure DSR might be prolonged and therefore needs considering.

Next, we explore how DSR's option value changes with respect to the amount of curtailable demand available. This depends on two characteristics; contract size and availability. The results of these two sensitivity analysis are shown in Figure 8.7 and Figure 8.8, respectively.

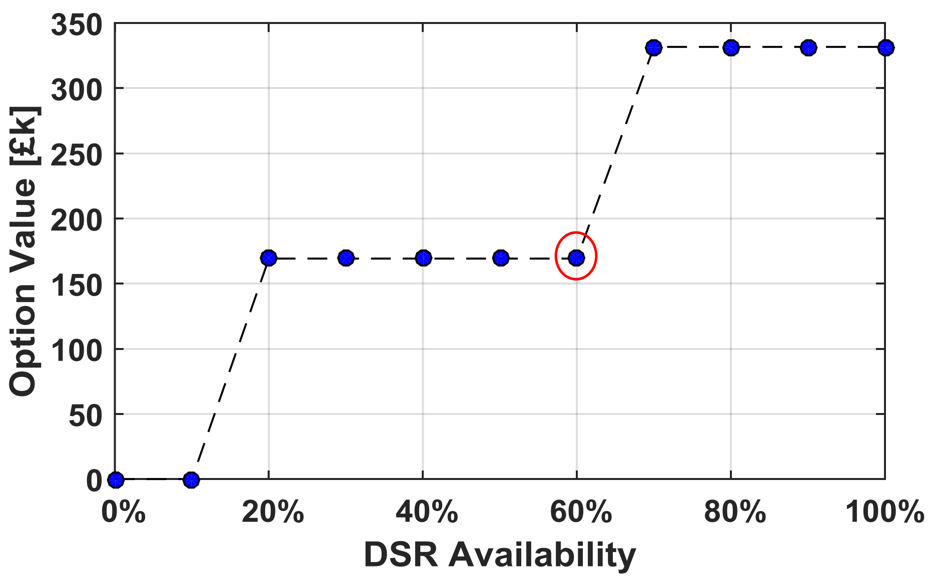


Figure 8.7: Sensitivity analysis of option value of DSR with respect to different DSR availability assumptions. Data point corresponding to base case is circled red.

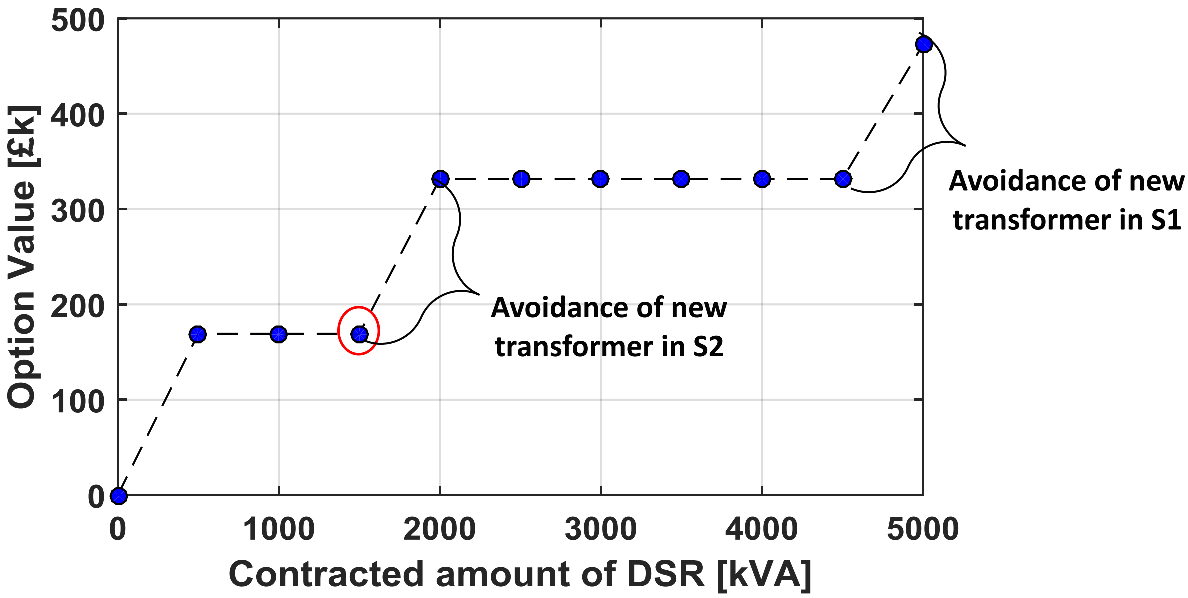


Figure 8.8: Sensitivity analysis of option value of DSR with respect to different assumptions on the contracted amount. Data point corresponding to base case is circled red.

Regarding DSR availability, it is evident that a small increase beyond the assumed 60% has a significant impact on DSR option value. This is because a 70% availability equates to 1,050 kVA dependable response which is enough to fully cover the S2 realization. Note that availability must be at least 20% for DSR to have some benefit, otherwise the dependable response is not enough to warrant deferral or avoidance of the transformer investment. In a similar vein, we can explain the two jumps seen in Figure 8.8, where we consider a 60% availability but examine different contract sizes. The very first jump that occurs for a contract size larger than 500 kVA is due to transformer investment avoidance under S3. The second jump in DSR option value that occurs for contract sizes larger than 2,000 kVA is again due to possibility for transformer avoidance under S2. The last jump occurs for contract sizes larger than 5,000 kVA and is due to the possibility of avoiding commissioning a transformer under S1.

In the last sensitivity analysis, different assumptions regarding the discount rate are made. The discount rate is essentially a measure of how the planner values future costs/benefits compared to present costs/benefits. A discount rate of zero means that the planner is indifferent whether costs are incurred in 2015 or in 2021. A high discount rate means that investment costs will increasingly become cheaper in the future. When the analysis pertains to a commercial entity, discount rate can be regarded as the Weighted Average Cost of Capital (WACC). It follows that DSR option value is largely dependent on the discount rate since the majority of savings due to DSR occur in future years. As can be seen in Figure 8.9 below, the higher the discount rate the larger the option value becomes. For example, when comparing the extreme case of 10% discount rate versus the base case of 3.5%, the DSR option value increases by almost 60%. This is because under a high discount rate, the planner is able to purchase the new transformer at a much cheaper price in the later stages; the investment deferral property is regarded as highly valuable. Conversely, the DSR option value is reduced under the low discount rate assumption. In this case, the planner has less to gain from deferring investment since costs are regarded to stay largely unchanged. Of course, even under a 0% discount rate DSR option value still remains significant due to its ability to enable a 'wait-and-see' strategy that can avoid unnecessary investments under S3.

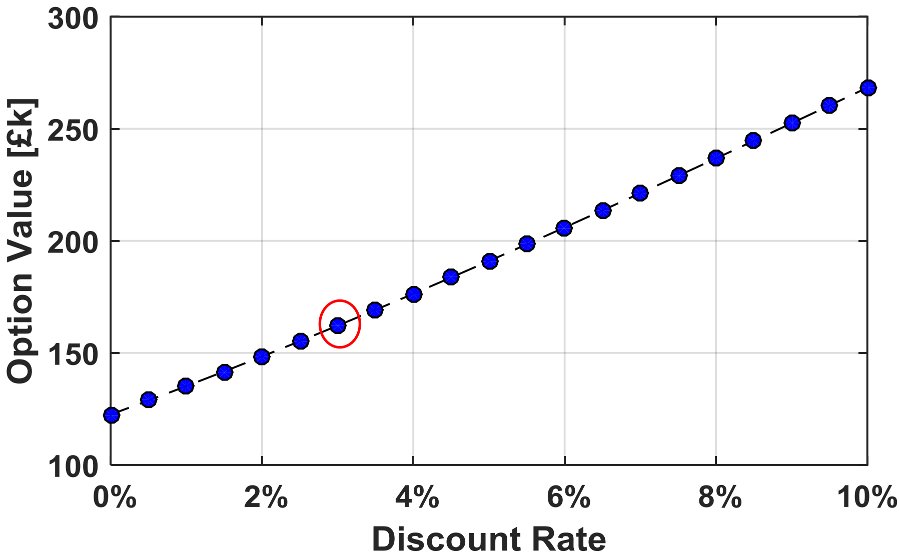


Figure 8.9: Sensitivity analysis of option value of DSR with respect to different discount rates. Data point corresponding to base case is circled red.

8.2.4 Conclusions

The principal conclusion of this analysis is that flexible investment options such as DSR possess significant option value due to their ability to defer and/or avoid premature commitment to capital projects by taking advantage of the inter-temporal resolution of uncertainty. Although DSR may not be the optimal choice under all scenarios, the ability for its contingent deployment can render 'wait-and-see' strategies, which could be deemed unattractive in the absence of cost-efficient interim measure, viable. However, the use of a suitable strategic valuation framework is necessary to uncover this option value.

In contrast, the adoption of traditional static valuation methods such as NPV-based investment decision-making can systematically favour large-scale capital projects that may lack the necessary flexibility to enable the adoption of a 'wait-and-see' approach, thus unduly exposing planners to stranding and over-commitment risks. This highlights the importance of incorporating a provision for option value calculation within the P2/6 standard. This illustrative example demonstrate the possible value of the option value approach. It should be noted that the security standard is focussed on identifying the optimum degree of redundancy rather than the most efficient means of implementing it.

Cost-benefit analysis should not be undertaken on a fixed projection of the future but on a family of plausible scenarios, enabling planners to evaluate the strategic value of a particular investment towards long-term cost-efficiency. Revising P2/6 towards adopting a strategic valuation framework is instrumental for achieving large-scale deployment of flexible smart solutions such as DSR, whose value lies both in the service they can provide but also in the strategic flexibility they offer towards uncertainty management.

8.3 Option Value of Soft Open Points

8.3.1 Introduction

Apart from DSR, smart grid technologies also include active network coordination schemes, controlling in real-time bus voltages and the demand-supply balance through power electronics. In this part of the report, we focus on one of these active network control technologies, namely Soft Open Points (SOP). A SOP is a power electronic device installed in place of normally-open point which is able to provide active power flow control, reactive power compensation and voltage regulation under normal network operating conditions, as well as fast fault isolation and supply restoration under abnormal conditions. Methodology is described in section 13.7. In the same context as in Section 8.2, we examine how they can assist the network planner in managing stranding risks of conventional assets by enhancing the utilization of existing assets and deferring large capital commitments on a conditional basis until a scenario realization suggests they would be economically justified. The reduced commissioning time that characterizes SOP, compared to conventional reinforcements, renders them valuable interim solutions for network management over a number of years, until the uncertainty is partially resolved, thus reducing the risk of asset stranding and over-commitment.

In this context, this part of the report focuses on the benefit that SOP can bring to distribution network planning under uncertainty. We demonstrate that SOP technology constitutes a valuable investment option for enabling cost effective integration of DG under uncertainty. In addition, we show that deterministic approaches, such as the NPV valuation method adopted by the current industry standard P2/6, can systematically undervalue the flexibility that such assets provide; traditional investment valuation techniques are biased towards premature commitment and can pose a significant barrier to the advent of the flexible smart grid paradigm. Note that under the NPV valuation paradigm, possible network development options could be ranked by their net present value, but do not consider exertion of planning flexibility to adapt to the unfolding uncertainty. Through the aid of a case study we clearly demonstrate that SOP can have significant option value which is not captured by static valuation frameworks. To this end, it is imperative to extend the existing planning standard towards flexible valuation frameworks, capable of identifying strategic actions to manage uncertainty.

8.3.2 Case study

We present a case study where the prospect of large PV penetration can lead to voltage rise complications, thus driving investments in the distribution network or requiring active generation curtailment of PV units. We illustrate how radically the optimal investment strategy of a stochastic planner can change when considering SOPs as a candidate investment alternative in addition to reconductoring. We also demonstrate the shortcomings of traditional deterministic methodologies in undervaluing the flexibility benefits of SOPs. The examined Medium Voltage (11 kV) semi-urban overhead distribution network is depicted in Figure 8.10, where the six normally-open points are marked by dotted lines. As we can observe, a total of 6 buses may accommodate some PV capacity, but this happens only in a stochastic manner.

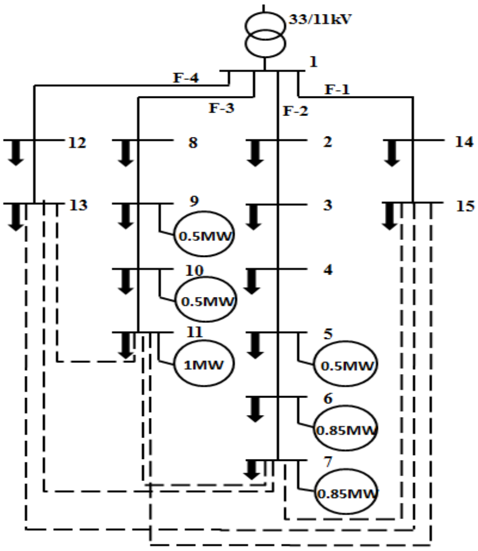


Figure 8.10: Diagram of the semi-urban 11 kV distribution network, showing prospective DG connections. Any section between two buses is considered to be a 1-km length distribution line.

The amount of distributed PV generation to be connected over the six-year horizon (three epochs/stages each of 2-year duration) is uncertain in time, size and location of connection. This uncertainty is captured by the scenario tree in Figure 8.11, constructed based on expert opinion. As can be seen below, uncertainty is expressed using a scenario tree comprising of 7 nodes across 4 scenario paths. Each node represents a state of the exogenous uncertainty source at a given stage (referred to also as epoch). Note that each epoch spans two years; the duration of the investment horizon is six years. The high-penetration scenario that leads to a total connection of 2.2 MW of PV is scenario 1 and has a probability 35% of occurring. Scenario 4 is the scenario capturing the least penetration eventuality, leading to a total connection of 1 MW. It is also important to note that scenarios 1 and 2 relate to PV being built in feeder F-2, while scenarios 3 and 4 refer to the case where PV is installed in feeder F-3. Locational uncertainty is an important feature of this case study and an aspect where SOP deployment can be a very cost-effective solution by introducing topological flexibility in the existing network.

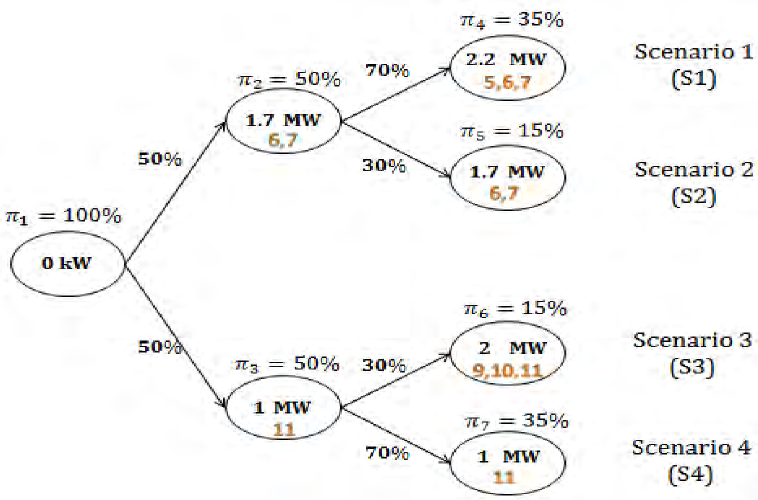


Figure 8.11: Scenario tree, with 7 nodes across 4 scenarios, capturing the uncertainty of PV capacity (MW) and location. Transition probabilities are shown above each arc, while π_m is the probability of node m occurring. Inside each node we show the aggregate PV capacity installed and the buses to which the PV units connect (orange font).

Network operation should take place within statutory voltage limits defined at all buses to be 1.1 and 0.9 p.u. To achieve this, a benchmark value of £100/MWh is selected for the cost of curtailing active generation of PV units. In addition, the planner has two alternatives for investment, as shown in Table 8.2, where the respective investment costs have been estimated according to relevant literature sources. Note that the term 'build time' refers to the number of epochs starting from the epoch at which the decision to invest is taken, up to the epoch at which the investment becomes operational. As a result, an asset with no build time can be regarded as being commissioned instantaneously, whereas an asset with a one epoch delay becomes operational two years later.

The difference in build time between SOPs and the conventional investment (reconductoring) can be attributed to the fact that the latter involves greater network intervention that can be subject to lengthy permitting processes. The SOP technology allows optimal control of active power flow through its two terminals (or ports) and optimal reactive compensation at any of its two terminals; 90% efficiency (in transporting active power from one terminal to the other) and 130 kW / 130 kVAr capacity are used in the case study. The other candidate technology is the reconductoring of a distribution line, which involves the replacement of an existing line with a new lower-resistance conductor. All existing lines have R/X factor equal to two, with a cross-sectional area of 40 mm^2 and R = 0.6 Ω/km; new lines have R/X factor equal to one, 200 mm^2 cross-section and R = 0.12 Ω/km. It assumes the HV circuit rebuild.

Table 8.2: Cost and building time of the two available technologies.

Technology	Build Time (epochs)	Investment Cost
SOP	0	£90,000
Circuit rebuild	1	£65,000 / km

Given that each tree node in Figure 8.11 covers a two-year duration, we need to express the investment and operational costs in annual terms. The former can be easily done by dividing the investment cost by the corresponding number of years comprising an epoch and discounting appropriately. The latter could be ideally calculated by considering the network operation across 8,760 hourly periods. However, in a nonlinear setting this method leads to intractability. Hence, we resort to approximating the seasonal variations across a year by three typical days, each characterized by a combination of demand and a normalized PV generation factor.

Deterministic Case Study – Results

In this section we present the optimal investment decisions for each of the four scenarios (S1-S4) depicted in Figure 8.11 by applying a deterministic planning model. In essence, we solve each scenario path separately, where the transition probabilities between consecutive stages of the same path are set to 1. For each scenario, the optimal investment schedule is obtained. Note that the planner can invest in both technologies shown in Table 8.2. The resulting output is presented in Table 8.3, where [a-b] represents the decision to invest in reconductoring the line that connects bus a to bus b, while TIC and TOC represent total investment and total operational cost across the entire study horizon respectively.

Table 8.3: Results of the deterministic case study

	Investment Decisions			Costs (£k)		
	Epoch 1	**Epoch 2**	**Epoch 3**	**TIC**	**TOC**	**Total**
S1	[2-3],[3-4], [4-5],[5-6]	-	-	127.9	110.9	238.8
S2	[2-3],[3-4], [4-5],[5-6]	-	-	127.9	39.8	167.7
S3	[8-9]	[1-8]	-	52.3	46.7	99.0
S4	[9-10]	-	-	32.0	0	32.0

As shown above, under the assumption of perfect information, the planner chooses to rely exclusively on reconductoring. It is remarkable that SOP technology is fully ignored; a deterministic planner does not consider the possibility of conditional adjustments to the optimal investment policy, thus neglecting the strategic benefits that accompany the SOP technology. Instead the planner strives to make full use of scale economies where available. As a result, since SOP can be viewed more as an interim solution rather than a long-term solution towards mitigating network constraints, it appears to be a less attractive investment option. However, although the planner considers deterministic growth in PV capacity, in reality the eventual scenario realization is uncertain. Hence, in the event that some PV connections do not materialize according to the scenario considered, some of the capital decisions may prove to be unnecessary.

In addition, it is important to note that first-stage commitments are particularly risky since they forego the possibility for strategically exploiting the uncertainty resolution that occurs in the second stage. These are known as ‘here-and-now’ decisions and result in upfront sunk costs without the possibility for recourse. Most importantly, they can dictate the options that are available in the subsequent stages. For example, if the planner decides to follow the optimal investment schedule for scenario 3 and scenario 2 materializes instead, then reconductoring of line [8-9] will have been a stranded investment; the planner will need to re-adjust his capital commitments while also incurring PV curtailment costs in the interim.

Stochastic Case Study – Results

In this section, two stochastic planning studies are carried out. In the first one, line reconductoring is the sole available investment option. In the second one, the planner considers both reconductoring and SOP options. The optimal investment decisions for these two studies are presented in Table 8.4 and Table 8.5 respectively. Note that E{TC} represents the sum of expected investment (E{IC}) and operational (PV curtailment) (E{OC}) costs, while S(a-b) represents the decision to invest in a SOP at the normally-open point between buses a and b.

Table 8.4: Results of the stochastic case study when only investment in reconductoring is allowed

	Investment Decisions			Costs (£k)			
	Epoch 1	**Epoch 2**	**Epoch 3**	**TIC**	**TOC**	**Total**	**E{*}**
S1	[2-3],[3-4], [4-5],[5-6]	-	-	127.9	110.9	238.8	E{TC}=209
S2	[2-3],[3-4], [4-5],[5-6]	-	-	127.9	39.8	167.7	E{IC}= 138
S3	[2-3],[3-4], [4-5],[5-6]	[8-9]	-	148.2	126.8	275	E{OC}= 71
S4	[2-3],[3-4], [4-5],[5-6]	[8-9]	-	148.2	20.6	168.7	

One important note regarding the results presented in the two tables is that the investment decisions follow the resolution of uncertainty. This is why, as seen above, investment decisions for epoch 1 are common across all scenarios; as shown in Figure 8.11, at epoch 1 no uncertainty has been resolved and as such the planner cannot differentiate his decisions without information about which of the two transitions occur at epoch 2. In the case where only conventional reconductoring is allowed, the investment delay inherent in these projects forces the planner to prematurely commit to four reconductoring projects to ensure the system is adequately pre-positioned to deal with the developments occurring at epoch 2.

In this case, the expected total cost is equal to £209k. Comparing the costs between Table 8.4 and Table 8.5, it is evident that the asset stranding that occurs in scenario 3 and 4 has a significant cost; total cost in the case of scenario S4 is increased from £40.9k to £168.7k due to the unnecessary first-stage investments.

Table 8.5: Results of the stochastic case study when investment in both reconductoring and SOP is allowed

	Investment Decisions			Costs (£k)			
	Epoch 1	Epoch 2	Epoch 3	TIC	TOC	Total	E{*}
S1	-	[4-5], S(7-11), S(7-13), S(7-15)	-	192.5	106.0	298.5	E{TC}=172.7
S2	-	[4-5], S(7-11), S(7-13), S(7-15)	-	192.5	39.1	231.6	E{IC}= 110.5
S3	-	[8-9]	S(11-15)	47.6	80.3	127.9	E{OC}= 61.9
S4	-	[8-9]	-	20.3	20.6	40.9	

When the SOP technology becomes available, the optimal investment strategy becomes substantially different. In Table 8.5, we observe that the availability of SOP to the planner leads to reduced investment in reconductoring; only lines 4-5 and 8-9 are chosen for reconductoring, while lines 2-3, 3-4 and 5-6 are no longer reconductored. In addition, only one line per scenario is reconductored as opposed to a minimum of four lines in Table 8.4. Most importantly, no-first stage investment decisions are made, leading to the substantial reduction of stranding risk. What the SOP deployment achieves is to render a 'wait-and-see' strategy viable due to SOP being an efficient interim measure. In the absence of a cost-efficient easy to manage uncertainty in the medium-term, until the locational uncertainty is fully resolved, the planner has no choice but to over-commit.

By comparing the individual scenarios of Table 8.4 and Table 8.5, we can quantify the net benefit of SOP under each scenario, which represents the sum of investment and operation cost savings. As shown in Table 8.6, while the SOP impact is adverse in scenarios S1 and S2, we can observe that it is substantially beneficial for S3 and S4, underlining the significance of SOP for hedging against unfavourable realizations. For instance, scenarios S3 and S4 in Table 8.4 entail a significant number of first-stage conventional investments to cope with PV deployment in F-2, while these scenarios assume that PV deployment will only take place in F-3; SOPs allow hedging against this stranding risk. By comparing Table 8.4 and Table 8.5 we also can quantify the option value of SOP (shown in Table 8.6), representing the expected net benefit accrued from investing in this technology. This term amounts to £209k – £172.7k = £36.3k and reflects a 20% reduction in expected investment cost and a 13% reduction in expected operational cost.

Table 8.6: Quantification of scenario-specific net benefit and option value of SOP

Net Benefit	**S1**	**-£59.7k**
	S2	-£63.9k
	S3	£147.1k
	S4	£127.8k
Option Value		**£36.3k**

8.3.3 Conclusions

Through a case study on a medium-voltage distribution network, the timely need for advanced distribution planning tools is highlighted. We demonstrate the inadequacy of traditional deterministic approaches and show that by considering the possibility to invest in non-network assets, the need for anticipatory commitments can be significantly reduced. Reinforcement needs can be accommodated at a lower cost by taking advantage of the strategic flexibility embedded in such technologies; application of conventional deterministic approaches systematically undervalues this benefit and may lead to unnecessarily high levels of stranding risks. In addition, the strategic benefit of SOP is shown to be substantial. Thus, a significant conclusion that can be drawn is the growing need to adopt a novel valuation framework that can comprehensively accommodate uncertainty and decision flexibility in order to capture the strategic benefits of smart technologies and enable the cost-efficient transition to the smart grid era.

8.4 Min-max regret approach to address uncertainty

8.4.1 Introduction

The stochastic optimisation methodology explored in previous sections addresses uncertainty by determining 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 planning decisions. Furthermore, it may be difficult to unambiguously determine probabilities of occurrence of different scenarios regarding future evolution.

In order to address this concern a min-max regret decision making approach, see section 13.8, is explored in this part of the report. This approach identifies robust network planning solutions without requiring the probabilities of the different scenarios and by minimising the maximum (across all scenarios) regret that the system planner will feel after the materialisation of the uncertain future. The regret felt if scenario i is materialised, represents the extra cost that will be incurred due to the impact of uncertainty, with respect to the cost they would incur if the planner had acted according to the optimal deterministic plan corresponding to scenario i. Essentially, the min-max regret approach optimally balances two sources of risk: 1) the risk of stranded assets, encountered when more network capacity than the one that will be actually required in the uncertain future is procured and 2) the risk of incurring fixed reinforcement costs twice, encountered when less network capacity than the one that will be actually required in the uncertain future is procured. This decision making approach has been developed in a novel analytical framework by Imperial College, employing mixed-integer linear optimisation. As in the stochastic optimisation approach of the previous section, uncertainty is represented through a multi-epoch scenario tree, determining the value of the uncertain parameters at each scenario and each epoch of the planning horizon. One of the key reasons of considering min-max approach is to take a more strategic approach to compliance, and potentially be "over-compliant" for some time in the expectation of load growth (rather than reinforcing the system multiple times).

8.4.2 Case study

The examined study is carried out on the Brixton HV feeders BRXB-SE1 and BRXB-SE3 (Figure 8.12).

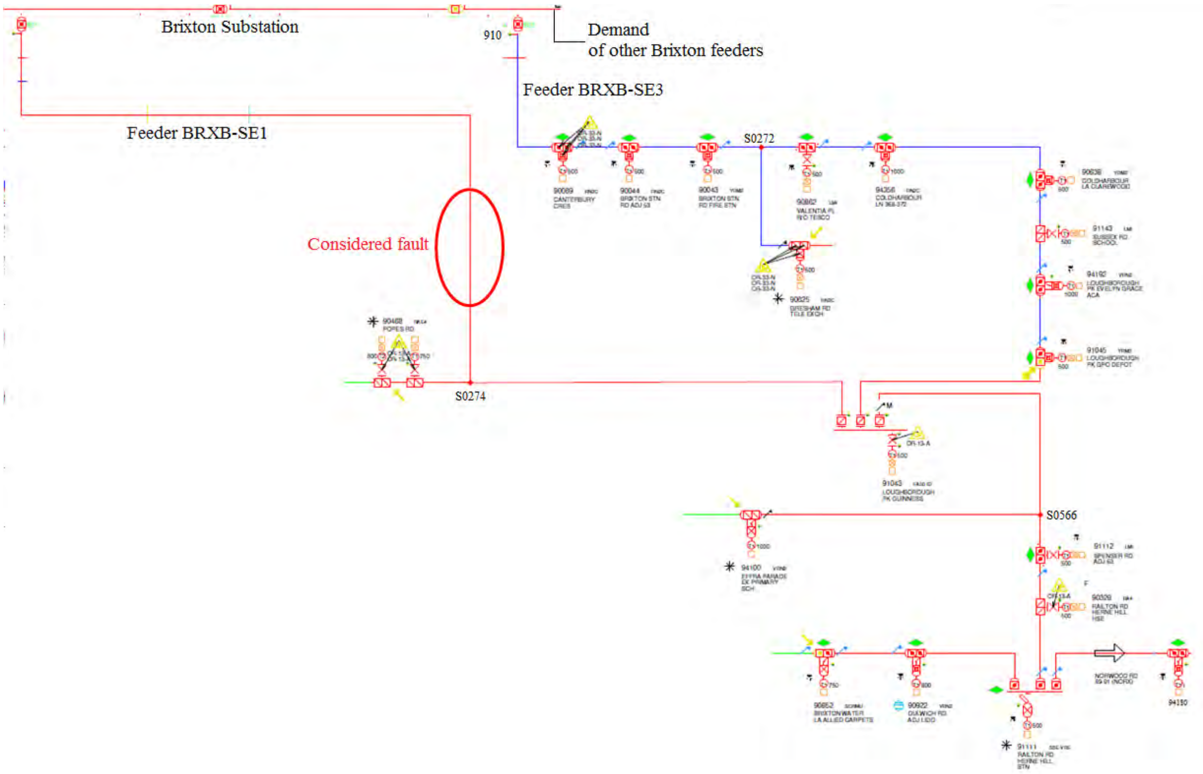


Figure 8.12: Test system

The assumed values of network reinforcement costs at the first epoch (2015) are given in Table 8.7. In order to determine the respective costs at later epochs, an annual discount rate of 3.5% is assumed.

Table 8.7: Network reinforcement costs at each epoch

		2015	2018	2021	2024	2027
Transformer reinforcement	Fixed cost (£)	18,800	16,957	15,294	13,794	12,442
	Variable cost (£/MW)	6,400	5,772	5,206	4,696	4,235
Cable reinforcement	Fixed cost (£/km)	95,300	85,955	77,527	69,925	63,068
	Variable cost (£/km*MW)	2,320	2,093	1,887	1,702	1,535

Future demand growth constitutes the uncertain parameter in the study and the relevant scenario tree is presented in Figure 8.13.

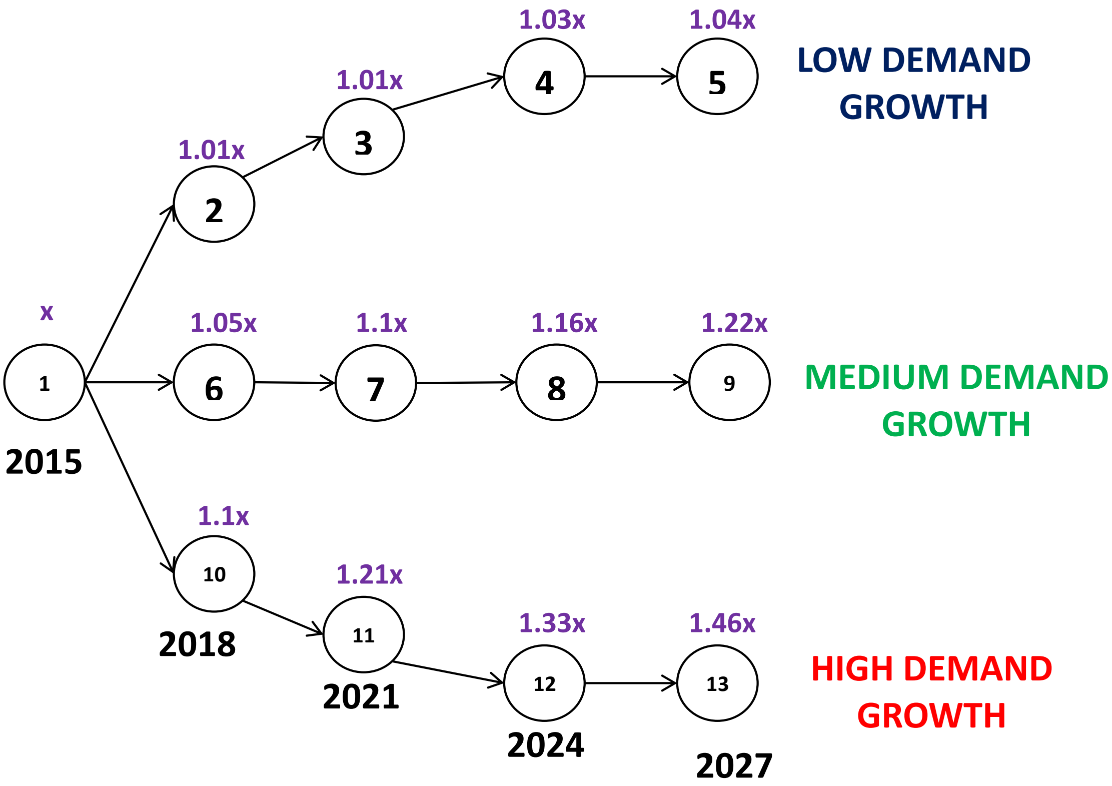


Figure 8.13: Demand growth scenario tree

Under normal operating conditions, the two feeders are connected to different transformers of the Brixton substation and power flows are well below the feeders' and the transformers' thermal capacity. However, when an assumed fault on the top section of feeder BRXB-SE1 occurs, this feeder is connected to the end of feeder BRXB-SE3 through a network reconfiguration scheme in order to secure supply of consumers connected to BRSXB-SE1. Without network reinforcement actions, this results into overload on the transformer where BRXB-SE3 is connected as well as on two top sections of feeder BRXB-SE3 from the first epoch (2015). Furthermore, six more sections of this feeder are overloaded at later epochs in some of the demand growth scenarios (Table 8.8).

Table 8.8: Epoch of assets overloading when no network reinforcement is carried out.

Network asset	Low scenario	Medium scenario	High scenario
Transformer	2015	2015	2015
Section 910-90069	2015	2015	2015
Section 90069-90044	2015	2015	2015
Section 90044-90043	2021	2018	2018
Section 90043-S0272	-	2021	2018
Section S0272-90862	-	2024	2021
Section 90862-94356	-	-	2024
Section 94356-90638	-	-	2027
Section 90638-91143	-	-	2027

The question naturally arising is which network reinforcement decisions should be made at each node of the scenario tree. After 2015, the decision maker has gained knowledge regarding the emerging demand growth path (Figure 13) and can determine with certainty the optimal plan. The most interesting decisions are associated with the first epoch (2015) as at this point the decision maker faces uncertainty regarding future demand growth.

In this section, we compare the deterministic plans corresponding to each scenario and the min-max regret plan with respect to: i) the network reinforcement actions at the first epoch (Table 8.9) and ii) the regret portfolio, i.e. regret felt when each of the 3 scenarios is materialised (Figure 8.14).

In the case of feeder sections reinforcement, the min-max regret plan follows a strategic approach, namely, it involves procuring the highest possible required capacity (capacity under the high demand growth scenario) at the first epoch. In other words, it chooses to experience regret associated with stranded capacity if the low or medium demand growth scenario is materialised. The reason is that the regret associated with stranded capacity is much lower than the regret associated with incurring fixed reinforcement costs twice, since the fixed cost of cables reinforcement is much higher than the respective variable cost.

In the case of the transformer however, the min-max regret plan follows an incremental approach, namely, the capacity procured at the first epoch is higher than the capacity required under the deterministic plan corresponding to the low demand growth scenario and lower than the capacity required under the deterministic plans corresponding to the medium and high demand growth scenarios. In other words, it chooses to balance regret associated with stranded capacity against regret associated with incurring fixed reinforcement costs twice; regret associated with stranded capacity is felt if the low demand growth scenario is materialised and regret associated with incurring fixed reinforcement costs twice is felt if the medium or high demand growth scenario is materialised. The reason behind this differentiation with respect to cables reinforcement is that the ratio between fixed and variable costs of transformers reinforcement is significantly lower than the respective ratio of cables (Table 8.7). Furthermore, the min-max regret approach follows an action that is not adopted by any of the deterministic plans and provides flexibility against the demand growth uncertainty.

Table 8.9: Network reinforcement actions at the first epoch under different plans

	Transformer	Section 910-90069	Section 90069-90044
Low deterministic	2 MW	1 MW	1 MW
Medium deterministic	6 MW	2 MW	2 MW
High deterministic	11 MW	3 MW	3 MW
Min-max regret	3 MW	3 MW	3 MW

Observing Figure 8.14, if the low demand growth scenario is materialised and the planner had decided to act according to the low demand growth deterministic plan, their prediction was accurate and no regret is felt. If however the planner had decided to act according to the medium demand growth deterministic plan, their inaccurate prediction means that they will feel regret (equal to £25,933) since they have decided to procure more network capacity at the first epoch than the one that has actually been required at later epochs (regret of stranded assets). The stranded capacity and thus the associated regret are even higher if the planner had decided to act according to the high demand growth deterministic plan (equal to £62,792). If the planner had decided to act according to the min-max regret plan determined by the proposed algorithm, the regret felt (equal to £10,993) is higher than the zero regret felt under an accurate prediction, but is much lower compared to the two above cases of inaccurate prediction.

If the high demand growth scenario is materialised and the planner had decided to act according to the high demand growth deterministic plan, their prediction was accurate and no regret is felt. If however the planner had decided to act according to the medium demand growth deterministic plan, their inaccurate prediction means that they will feel regret (equal to £33,467) since they have decided to procure less network capacity at the first epoch than the one that has actually been required at later epochs and they need to incur fixed reinforcement costs again at later epochs to procure the extra capacity required. The number of assets requiring extra reinforcement and thus the associated regret are even higher if the planner had decided to act according to the low demand growth deterministic plan (equal to £47,047). If the planner had decided to act according to the min-max regret plan determined by the proposed algorithm, the regret felt (equal to £5,633) is of course higher than the zero regret felt under an accurate prediction, but is much lower compared to the two above cases of inaccurate prediction.

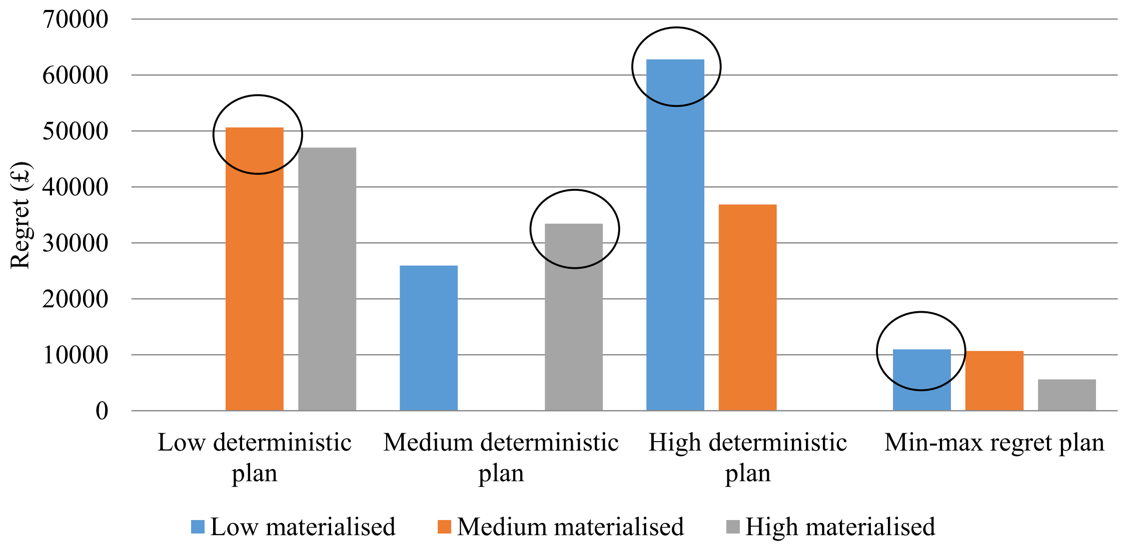


Figure 8.14: Regret portfolio of different plans.

For each of the 4 network plans, the maximum regret felt by the planner is indicated with a circle in Figure 8.14. 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.

8.4.3 Conclusions

In order to address the impact of uncertainty in distribution planning standards and the risks associated with capital-intensive network reinforcement decisions, a novel min-max regret approach has been presented and validated in this section. This approach identifies robust planning solutions by minimising the maximum (across all scenarios) regret that the planner will feel after the materialisation of the uncertain future. Essentially, the min-max regret approach optimally balances two sources of risk: 1) the risk of stranded assets, encountered when more network capacity than the one that will be actually required in the uncertain future is procured and 2) the risk of incurring fixed reinforcement costs twice, encountered when less network capacity than the one that will be actually required in the uncertain future is procured.

These results highlight the need for a new regulatory framework enabling the deployment of planning solutions that might not be cost effective under the traditional deterministic planning paradigm, but offer flexibility to deal with the undeniable uncertainty regarding temporal and locational evolution of demand growth and distributed generation penetration and reduce the resulting risks of capital-intensive planning decisions.

9 RISK ASSOCIATED WITH COMMON-MODE FAILURES AND HIGH IMPACT EVENTS

Electricity systems are exposed to CMF/HILP events, such as storms and floods driven outages which occur rarely but with potentially very significant impact. As the exposure to extreme weather events is envisaged to become more substantial, it is important to analyse CMF/HILP consequences and assess effectiveness of alternative mitigation measures. In this context, the Resilient Electricity Networks for Great Britain (RESNET) project stated to the Science and Technology Committee that [158]:

> "… it is becoming increasingly apparent how **the critical electricity infrastructure must also be resilient to high-impact low-probability events**, such as extremes of weather. In the light of climate change, this is increasingly important as the frequency, intensity and duration of extreme weather events is expected to increase in the future …"

Distribution network resilience refers to the ability of the distribution network to reduce its vulnerability and exposure to multiple failures, due to temporary outages or permanent damages of network and control equipment caused by external hazards and CMF of system components. An array of preventive measures including flood mitigation, use of insulated overhead line conductors, rebuilding lines to an improved construction specification, increasing lightning surge withstand capability, and automated switching to isolate faults and restore supplies, has been considered to increase resilience against extreme weather events.

Although there is an inherent level of resilience associated with current N-1 or N-2 deterministic security standard, this does not explicitly provide guidance regarding CMF/HILP events. In contrast, probabilistic approaches offer a natural way to include the effect of HILP and CMF events within the network design and operational planning framework, where costs and benefits associated with various reliability levels can be compared. Although impacts of CMF/HILP events can be estimated along with their associated corrective actions through mathematical models, the likelihood and probability distribution of CMF/HILP events is very difficult to estimate given the sparse data. A distribution of CMF/HILP events could be assumed and used to estimate the failure rates for various confidence levels to then calculate the range of expected reliability benefits. The expected risk for a specified confidence level could then be estimated.

Once a potential risk has been identified, it can be assessed along with the appropriate mitigation actions. However, it is important that policy makers and consumers have confidence in the process used to identify and assess risk, so that appropriate decisions can be made regarding risk management.

In order to stimulate discussions on how CMF/HILP events should be considered (whether inside or outside the future distribution standards) we developed modelling framework for assessing the impact of CMF/HILP on the reliability performance of the system, its optimal (economically-efficient) design, including consideration of various mitigation measures such as DSR and emergency generation. Additionally, our models can consider installation of network assets in both preventive and corrective modes to deal with CMF/HILP.

The structure of this section is as follows:

- Section 9.1 demonstrates how portfolios of traditional-asset and non-network solutions can be balanced to increase the robustness of distribution networks against HILP events. The concept of Conditional Value at Risk (CVaR) is 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.
- Section 9.2 provides examples on the impact of CMF on the design of EHV and 132 kV OH networks and how mitigation measures such as emergency generation can lessen the impact of CMF.
- Section 9.3 shows the cases where the CMF on ICT infrastructure can affect the reliability performance of the electrical distribution systems and consequently, the amount of resources needed to improve the resilience.
- Section 9.4 provides some examples on the impact of HILP with different severity levels on the reliability performance and cost of Expected Energy Not Served (EENS), taking into account mitigation measures such as deployment of emergency generation. Sensitivity analyses regarding deployment time and supply rate of mobile generation are also presented and discussed. In this section, a set of illustrative case studies on the use of corrective mode to deal with HILP events is also discussed.
- Finally, the summary of the key findings is presented in Section 9.4.4.

9.1 Increasing the robustness of distribution network design against high impact low probability events: a CVaR optimisation approach

9.1.1 Introduction

Current security standards do not consider the effect of CMF/HILP events (in fact, according to deterministic standards system operation in a particular condition is considered to be exposed to no risk at all if electricity network can withstand the occurrence of *credible* contingences); and although more advanced probabilistic standards could (at least in principle) recognise occurrence of CMF/HILP events, these are focused on *average* rather than *extreme* values of performance indicators and this can produce solutions with potentially high risk exposure to CMF/HILP events.

In this analysis, risk exposure of distribution network to CMF/HILP events is explicitly considered, focusing on the role of both network and non-network technologies in improving supply resilience. In order to inform the debate of the relevance of CMF/ HILP in future network planning standards, we propose a new probabilistic "risk-averse" approach which is used to illustrate the relevance of efficient design of "resilient" distribution network through *Conditional Value at Risk* (CVaR) optimisation, which minimises overall costs (investment and operation, including the expected cost of energy not supplied) when explicitly constraining risk exposure to CMF/HILP events. The model optimises the share of assets (e.g. transformers and cables) and smart, non-network technologies (e.g. DSR) and considers an array of multiple operating conditions combined with full enumeration of possible states, including outages from substation infrastructure and DSR facilities that may present CMF/HILP caused by climate phenomena. Hence the main purpose of this work is to:

- Propose a consistent framework for efficiently dealing with CMF/HILP events in probabilistic cost minimisation models to design more resilient substations, and
- Use this framework to study various substation designs along with its cost and reliability performance under the occurrence of natural hazards.

9.1.2 The proposed CVaR-based optimisation model

The developed probabilistic CVaR-constrained optimisation model is used to efficiently design distribution network with limited risk exposure to CMF/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) 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 can rapidly respond after an outage occurs in order to avoid overloads in the remaining infrastructure (see Figure 9.1). It is also possible to include 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.

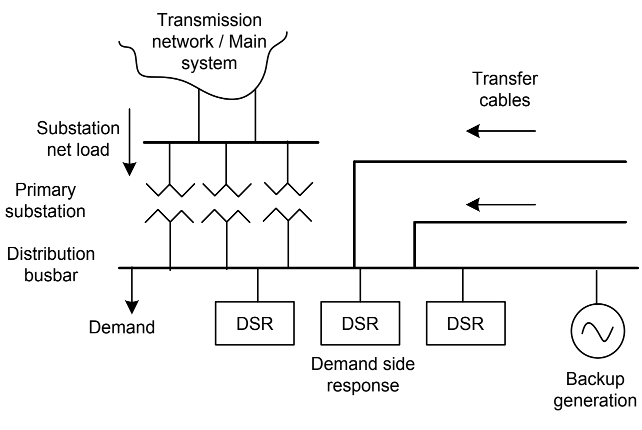


Figure 9.1: Diagram of primary substation with candidate technologies

Any design solution (asset-heavy or non-network solutions) is exposed to risks since substation components such as transformers, transfer cables and DSR facilities (and even backup generation) may fail. Hence several operating states (an operating state is a status of the system given by the availability state of each substation component, the intact system is also an operating state) are modelled in each operating condition throughout the year, which drives a very large number of scenarios. Every scenario may present a particular level of energy not supplied (ENS, chosen reliability indicator) which is considered by the model in the form of two measures: mean value and CVaR. In fact, the proposed model can, apart from penalising the Expected Energy Not Supplied (EENS) in the objective function (i.e. mean value of ENS), explicitly *limit* the conditional expectation of the energy not supplied associated with the worst cases, *constraining risk exposure to CMF/HILP events* and thus determining a *more resilient substation design*. To do so, we use CVaR-constrained optimisation that can explicitly represent the risk aversion of the planner against CMF/HILP events caused by natural hazards and determine a more robust portfolio of assets and no-network solutions. Figure 9.2 illustrates the concept of CVaR used in this work, which is defined as the energy not supplied that is expected in the higher *(1-α)*% of the cases (more details could be found in Section 13.4).

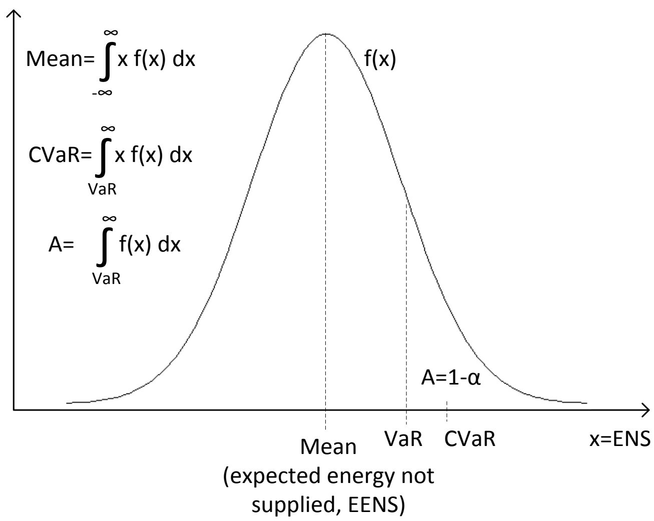


Figure 9.2: CVaR concept proposed for reliability analysis

Outage probabilities (of each outage state $Ns=2^{Nc}$, where Nc is the number of substation components) are calculated by using Forced Outage Rates (FOR) of substation components which, in turn, are obtained from outage and repair rates. Outage probabilities also consider the occurrence of CMF/HILP due to natural hazard that affects the supply system of transformers. For example, if a natural hazard occurs, there will be a CMF/HILP of transformers and demand will need to be supplied from backup generation and transfer cables, apart from DSR actions that can support reduction of demand curtailments. Simultaneous outages may also happen without CMF/HILP, but their likelihoods are smaller.

The model minimises the overall cost of investing in transformers and transfer cables that can be used to import power from neighbouring substations, along with the availability costs of DSR. If substation capacity and DSR do not suffice to cover demand in a particular scenario (i.e. an operating condition under a given outage), demand is curtailed at a cost equal to the value of lost load[16] (VoLL). In addition, transfer cables can also be used to support (rather than to get support from) neighbouring substations, and consequently the model considers that net capacity of transformers has to be sufficient to supply the peak demand plus the net capacity of transfer cables.

16 Use of backup generating units can be used to minimise demand curtailments up to a certain extent.

Regarding the cost function of our proposed optimisation model, it includes:

- Investments in transformers through fixed cost (that depends on number of transformers installed) and variable cost (that depends on MW of installed capacity)
- Investments in cables through fixed cost (that depends on number of cables installed, each cable is assumed to have a given length)
- Availability costs of DSR contracted (similarly to reserve services in £/MW/h). DSR can be contracted to deal with both credible and HILP events.
- Utilisation cost of backup generating unit (whose contribution is limited to a percentage of the peak demand, e.g. 10%). It is assumed that up to 5 MW of generation could be rent.
- Expected energy not supplied

The model's mathematical formulation considers:

- Reliability (outage rates and mean time to repair, i.e. MTTR; exponential distribution) and cost data associated with substation components such as transformers, transfer cables, DSR facilities and backup generating units.
- Common mode failure of transformers and DSR due to climate phenomena
  - Transformers may be affected by natural hazards such as flooding
  - DSR facilities may be affected by the occurrence of weather events that affect the capability of demand to respond by reducing consumption (e.g. during a heat wave or extremely cold weather)
  - Overhead lines might be affected by wind related events
- Representation of demand clustered in 1,000 levels (obtained by using K-Means algorithm)
- Full enumeration of outages of substation components in every demand level (very large optimisation, e.g. 1,000 x 2^9 states = 512,000 states if substation has 9 components)
- Limited risk exposure to HILP events caused by natural hazards (CVaR-constrained optimisation)

Hence our model can balance various investment and operational costs associated with the construction and operation of a distribution network substation, including cost of expected unsupplied demand, while limiting the impact of the worst events through explicit CVaR constraint. This allows us to obtain diversified and balanced portfolios of assets and non-network technologies that are economically efficient, sufficiently secure (in the sense that EENS is minimised along with further costs), and resilient (in the sense that risks of very extreme events caused by natural catastrophes are explicitly limited). Clearly, consideration of risk measures such as CVaR permits evaluation of reliability not only in terms of the average performance indicators (e.g. expected energy not supplied) but also in terms of their extreme values during severe outages, leading to robust design solutions.

One of the key reasons to carry out the analysis based on CVaR, is to demonstrate that it may be appropriate to expand security standards beyond reliability indicators based on *expected values*.

9.1.3 Case studies

Description

Figure 9.3 shows a duration curve of hourly demand data at the level of the primary substation, which was provided by a local Distribution Network Operator. We analyse various options of substation design including up to three transformers, two transfer cables from neighbouring substations (2x10 MW) and three DSR facilities up to a total capacity of 10 MW. In addition, under the occurrence of multiple outages we also consider the possibility to rent backup generating units up to 5 MW per event.

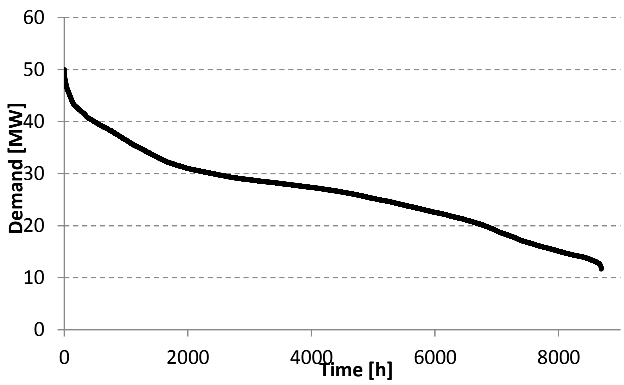


Figure 9.3: Load duration curve (peak demand of 50MW and load factor of 0.53)

Substation infrastructure, such as transformers and transfer cables present an outage rate of 0.2 occ/yr (i.e. one outage every 5 years) and repair time of 240 hours. Also, it is considered that DSR facilities could be unavailable, on average once a year for 1 day. CMF are modelled for both:

- Transformers: that represent the occurrence of natural hazards such as adverse weather conditions or flooding (affecting the supply system of transformers), which may occur say once in 10 years and last for 7 days.
- DSR facilities: that represent occurrence of weather events that affect the availability of demand to respond and thus reduce consumption (e.g. during a heat wave or extremely cold weather), which may occur once a year on average and last for 5 hours. For example, despite being called upon to provide DRS services, customers may not respond (regardless of their contractual obligations) because it may be either too hot or too cold.

Investment cost of transformer is modelled through a fixed cost component equal to £9k/unit/year and a variable cost component of £800/MVA/yr, and investment cost of each 10-MW transfer cable is equal to £88 k/yr. Availability fee of DSR, VoLL and backup generating unit's fuel cost plus rent are equal to £1.7-£5/MW/h, £30,000/MWh, and £200/MWh, respectively. We undertake various sensitivity analyses to demonstrate the robustness of our results.

Developed large-scale optimisation model will process 512,000 states to solve this problem that represent various plausible conditions across a year (combination of 1,000 demand levels and 512 failures types).

CVaR constrained and unconstrained solutions

We determine solutions with and without CVaR constraints, namely risk-averse and risk-neutral solutions respectively, in order to analyse effects of risk-aversion on substation design. In this section, we ignored occurrence of common mode failure (whose effect will be studied in detail in the next section) and consider 2 (rather than 3) transformers.

We observe that while a risk-neutral solution proposes installation of 2 transformers of 34 MW, 1 cable of 10 MW and no commitment of DSR; CVaR optimisation proposes installation of additional technologies so as to *diversify* the design solution. Figure 9.4 shows three optimal design solutions as follows:

A. Risk-neutral design solution, where costs are minimised without CVaR constraints (HILP events are only considered as part of EENS and hence this solution might be more risky in terms of CVaR than solutions B and C).
B. Risk-averse design solution, where costs are minimised and risks are covered through DSR facilities (CVaR ≤ 33 MWh/h). CVaR of 33 MWh/h means that the average ENS associated with worst cases is, at most, 33 MWh/h.
C. Risk-averse solution, where costs are minimised and risks are covered through installation of further transfer cables (CVaR ≤ 26 MWh/h).

Infrastructure	A (MW)	B (MW)	C (MW)
Transformer	2x34	2x33	2x35
Cable	1x10	1x10	2x10
DSR	0	3x0.61	0

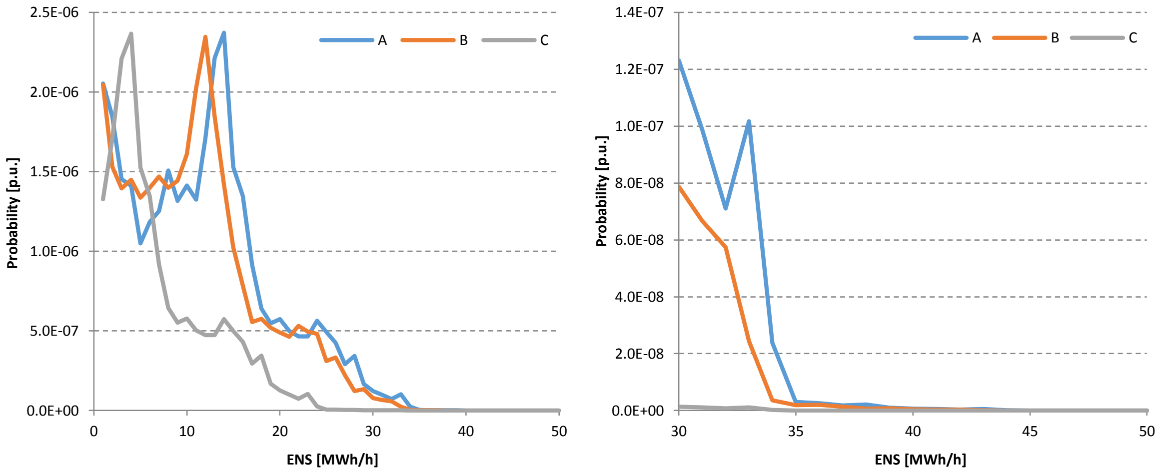


Figure 9.4: ENS PDFs of CVaR constrained and unconstrained solutions shown in the following ranges: (left) 1 ≤ ENS ≤ 50 and (right) 30 ≤ ENS ≤ 50 (1-α is equal to 5E-08 and CVaR is equal to 35 MWh/h in risk-neutral solution; we removed point ENS = 0 in this figure since its probability is significantly higher).

Risk-averse design solutions are characterised by more diversified set of measures through higher levels of investment in one extra cable and/or DSR contracts which can effectively reduce the risk exposure to HILP events, limiting the size of the right "tail" of the probability density function (PDF) associated with ENS, as shown in Figure 9.4. This clearly demonstrates that transfer cables and DSR can effectively provide network resilience by reducing CVaR levels. Moreover, we can also demonstrate that:

- DSR capacity provision increases beyond the levels presented in Figure 9.4 when CVaR is reduced below 26 MWh/h (which is the upper bound of CVaR constraint used to obtained solution C), and
- Increasing capacity contribution from the two transformers (beyond 2x35 MW) has no impact on the risk profile.

All options A, B and C are Pareto efficient[17] and thus final choice will depend on planner's risk aversion (i.e. desired levels of risks to be covered) and costs of various risk mitigation measures[18]. Figure 9.5 shows costs associated with the abovementioned design solutions, where risk-neutral solution is clearly that with the minimum cost.

[17] It is not possible to reduce costs further without increasing CVaR and vice versa.
[18] In this simulation, DSR availability fee is equal to £1.7/MW/h.

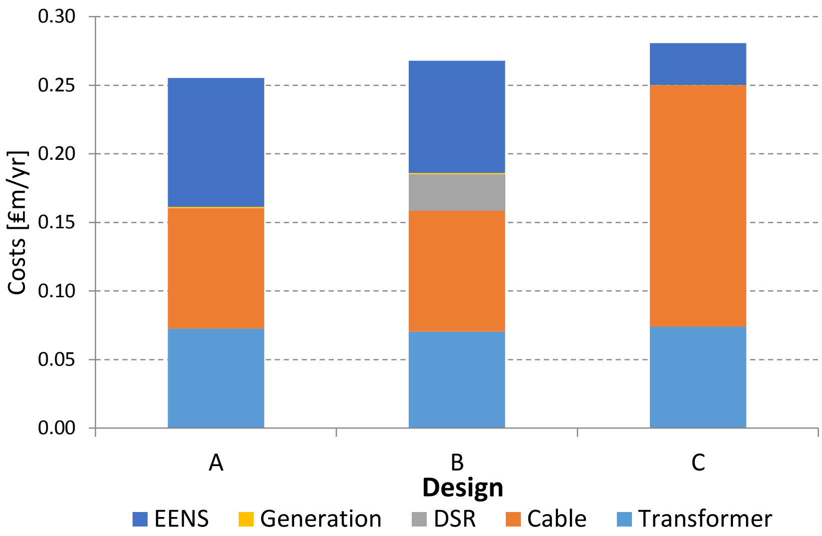


Figure 9.5: Cost components of risk-neutral (A) and two risk-averse design alternatives (B and C)

The extra cost associated with design solutions B and C can be perceived as a "premium" to be paid for hedging against various risk levels and reducing exposure to HILP events.

9.1.4 Effect of common mode failure: natural hazards and weather conditions

Common mode failure of transformers

It may be convenient to reinforce the risk-neutral decision infrastructure determined in previous section when considering the impacts from random natural hazards (e.g. flooding). In fact, if we consider effects of such events on substation design, more network infrastructure is built and more DSR sites are contracted (even under a risk-neutral approach). Furthermore, as we assume that CMF would affect the part of the network that supplies the transformers, a second transfer cable can be built so as to supply demand under the occurrence of a natural hazard. In this context, Figure 9.6 shows the comparison between the three following substation designs:

A. Optimal risk-neutral design under no CMF as shown in previous section,
D. Optimal risk-neutral design under CMF, and
E. Traditional N-1 design: where 2 transformers of 50 MW are built.

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

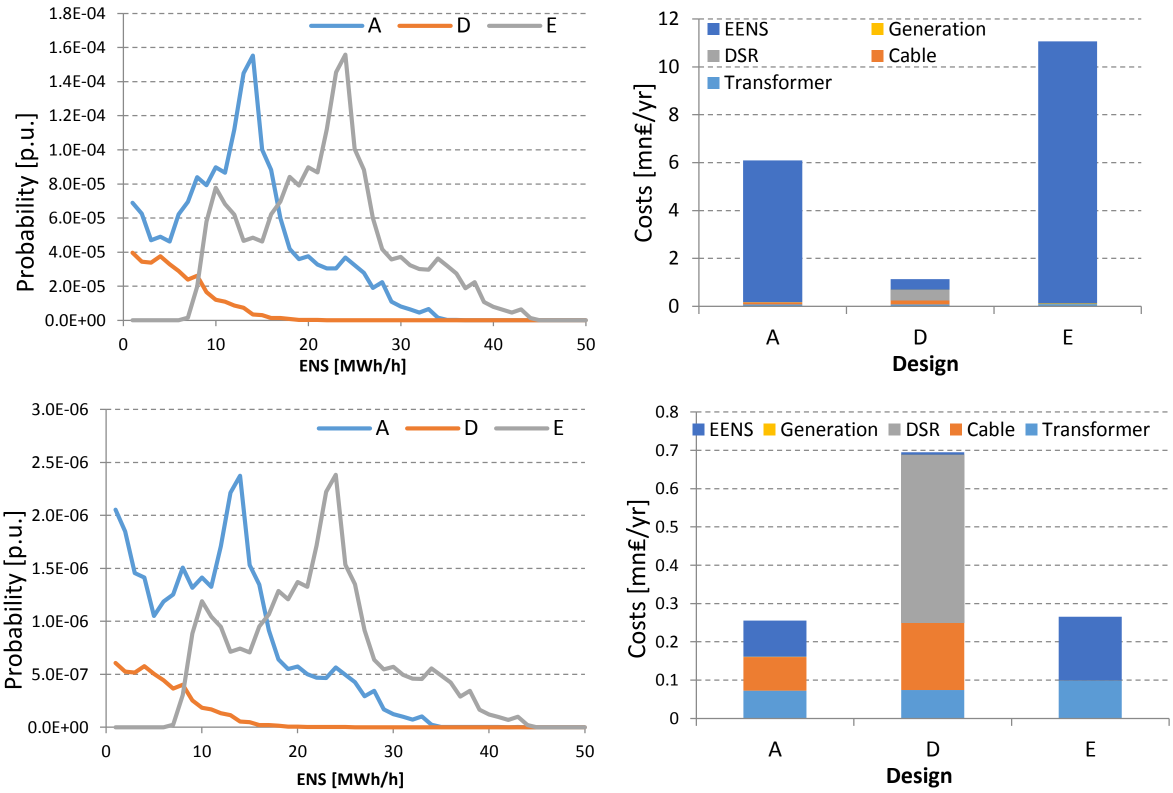


Figure 9.6: Cost components and risk profiles of 3 alternative designs under common mode failure (top), and no common mode failure (bottom).

In Figure 9.6 (top), solution D demonstrates that a second cable and increased volumes of DSR contracts (rather than increased transformer capacity) can effectively provide resilience against CMF (with respect to solution A that does not consider occurrence of CMF), increasing the levels of reliability by reducing both EENS and exposure to HILP events. In addition, although costs associated with infrastructure and DSR increase in solution D, reliability benefits significantly increases (i.e. expected cost of unsupplied demand reduces) if occurrence of CMF is considered. Without CMF (Figure 9.6 (bottom)), solution A becomes more attractive and solution D is proved costly. Interestingly, solution E that represents traditional substation design is suboptimal under both CMF and no CMF, albeit it is proved more efficient than solution D under no CMF.

Common-mode failure of DSR

Apart from the occurrence of common mode failure of transformers, we also investigated the effects of CMF of DSR facilities, where solution D proves very robust. In fact, solution D does not change, even when considering a wide range of frequency/probability for the common-mode event from 1 occ/yr up to 250 occ/yr (and with an average duration of 5h).

Note that solution D, which is obtained through a risk neutral approach and considering effect of CMF of transformers (e.g. flooding), can be also obtained when CMF are ignored if adequate CVaR constraint is introduced. This proves that risk-averse planners will build resilient substations without the need to consider significantly high probability of occurrence of a natural hazard.

Importance of DSR diversification

Risk exposure to HILP events can be reduced by diversifying DSR through several facilities. In fact, if all DSR capacity is managed through a single facility, the probability of curtailing larger amount of demand significantly increases since no demand can be exercised if one DSR facility is unavailable. With diversified DSR (e.g. 3 facilities), levels of demand are still available to be controlled even when some facilities are unavailable. In this context, Figure 9.7 shows PDFs of ENS when same volume of DSR is managed through 1 and 3 facilities (total volume of DSR is equal to 10MW in previous solution D), demonstrating the benefits of having a larger amount of facilities. In effect, EENS increases from 15.37 MWh per year to 17.30 MWh per year when DSR facilities are reduced from 3 to 1.

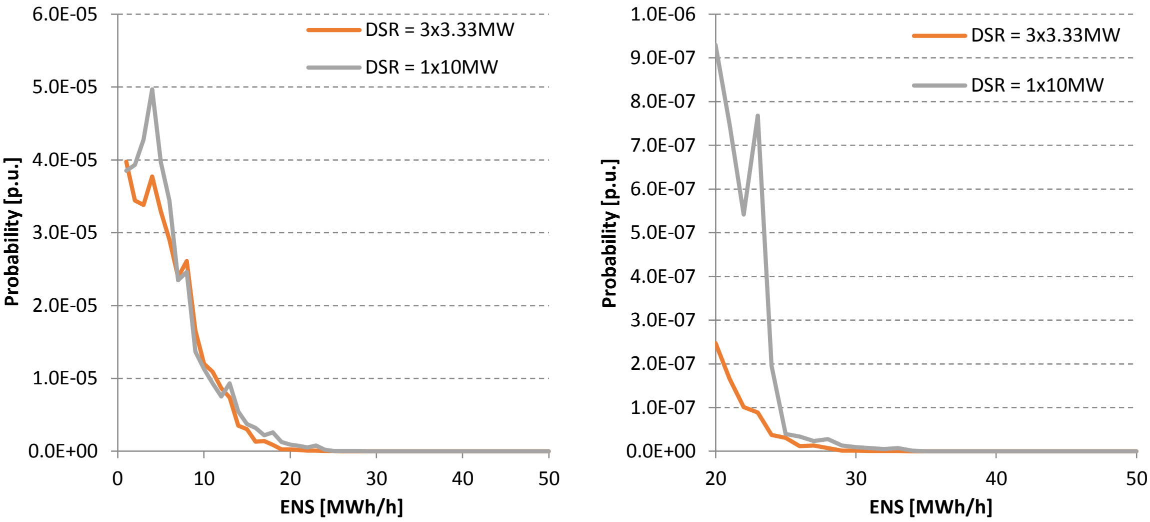


Figure 9.7: ENS PDFs of optimum risk-averse solution (3 DSR facilities, solution D) and alternative design with 1 DSR facility (same net DSR volume), shown in the following ranges: (left) 1 ≤ ENS ≤ 50 and (right) 20 ≤ ENS ≤ 50.

Remarkably, we found that the increase in risk exposure to HILP events due to a reduced number of DSR facilities, cannot be offset by installing larger transformers and in fact the risk profile shown in Figure 9.7 for the case with one DSR facility is kept constant when larger transformers are installed. Moreover, this result demonstrates that installing larger transformers (above 2x35 MW in previous solution D) has no effect on reliability and hence will only increase cost.

Importance of number of transformers

Increasing the number of transformers presents several benefits, including reduction in: (i) EENS, (ii) the need to contract DSR, and (iii) total cost. Figure 9.8 shows comparison of optimal substation designs with 2 (D) and 3 (F) transformers (note that case E was introduced in the previous section).

Infrastructure	D (MW)	F (MW)
Transformer	2x35	3x23.33
Cable	2x10	2x10
DSR	3x3.33	3x2.79

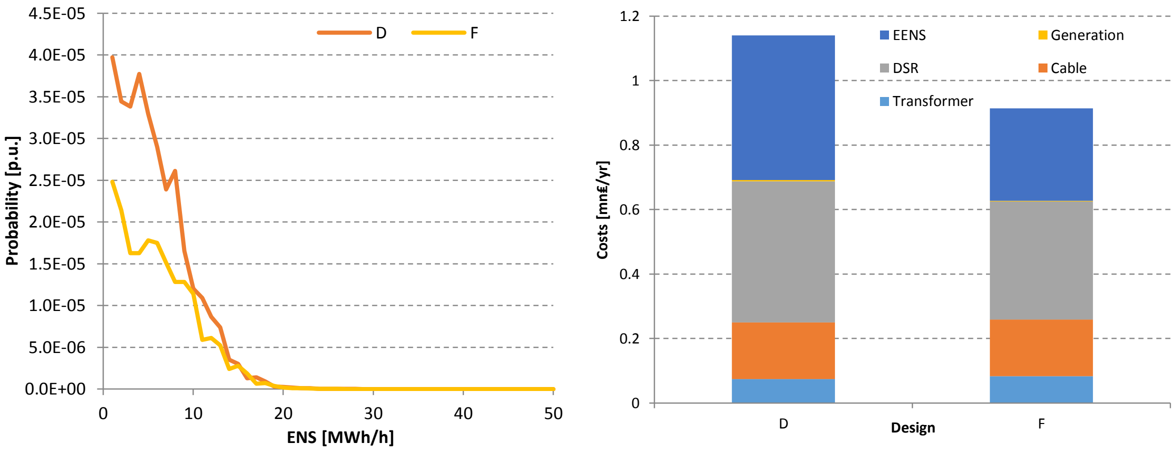


Figure 9.8 Cost components and risks of 2 alternative designs with 2 and 3 transformers

Despite the abovementioned benefits of a 3rd transformer, substation in solution F remains with (almost) the same levels of exposure to HILP events with respect to solution D since transformer capacity will still be affected by the occurrence of common mode failures. Similarly to the optimal design with two transformers, installing larger transformers (above 3x23.33 MW) has no effect on reliability and hence will only increase cost. Therefore, CVaR improvements can be obtained only through an increase in the amount of DSR contracted.

9.1.5 Conclusions

We developed a large-scale probabilistic CVaR-constrained optimisation model to optimally design substations with limited risk exposure to HILP events (caused by natural hazards) through a balanced portfolio of assets and non-network technologies. We show how CVaR concept can be used to consider HILP events in probabilistic cost minimisation models to design more resilient networks against natural hazards. One key point is that diversity in providing supply will increase network resilience. Through several case studies, we demonstrate that:

- CVaR constraint drives robust design solutions at the minimum possible cost. Solution cost increases if levels of planner's risk-aversion (i.e. required robustness) increase.
- Risk aversion (i.e. CVaR constraint) drives increased number of DSR contracts and more transfer cables connected to neighbouring substations (with respect to risk neutral approaches). Hence DSR can mitigate HILP risks by reducing the availability of supply to those customers who had signed up DSR contracts so that other customers remain on supply.
- Risk exposure to HILP events caused by natural hazards can be effectively hedged by increased DSR commitments and installing extra transfer cables, which can efficiently displace "firm" capacity from transformers, saving costs without lessening reliability levels.
- Both reliability and economic performance of substation designs obtained through the proposed model (that present less transformer capacity) are significantly higher than those associated with traditional (N-1) network designs.

- Committing/contracting DSR can be a more effective measure to reduce risk exposure to HILP events than increasing the size of assets, even if DSR facilities are significantly less reliable than network assets.
- In fact, the increase in risk exposure to HILP events due to a reduced number of DSR facilities, cannot be offset by installing larger transformers.
- Installing larger number of transformers presents several benefits, including reduction in: (i) EENS, (ii) the need to contract DSR, and (iii) total cost. However, installation of cables and increased amounts of DSR contracts will always present better reliability performance than transformers against HILP events since common mode failures mainly affect transformer capacity.
- DSR diversification can be a more effective measure to reduce risk exposure to HILP events than “firm” network infrastructure.

Our large-scale model can inform network planners about how the portfolio of network and emerging non-network technologies should be economically balanced, while limiting risk exposure to HILP events caused by natural hazards.

9.2 Impact of common-mode failure in Overhead Networks

9.2.1 Introduction

The present network security standard does not explicitly address CMF, which may be important when there is a single event (cause or mode) that leads to failures of two or more network components, for example, when considering overhead line (OHL) circuits on the same tower or laying multiple cables in the same trench (that are expected to provide redundancy for one another), or the loss of a busbar or switchboard. CMF may impose additional risks especially for large demand groups.

In order to identify the key driving factors and evaluate the impact and materiality of CMF, a set of case studies has been carried out on the generic EHV and 132 kV network configurations focusing on the impact of CMF on OH networks. Weather conditions can have a significant effect on the failure rate of equipment, especially on OHL. This effect may increase the possibility of overlapping/simultaneous outages of two or more components. Also a common-mode outage can occur when a single failure, e.g. the loss of a tower, causes the simultaneous outages of two or more components.

The studies also focus on the EHV and 132 kV networks as the common-mode failure on these voltage levels will affect larger number of customers in comparison to HV and LV networks. Moreover, at HV and LV networks, the provision of mobile generation as a measure to improve the reliability performance will assist in reducing the impact of CMF. Due to limited capacity of the mobile generators, these can be used to restore partially the loads at EHV and 132 kV networks.

9.2.2 Impact of common-mode failure on the optimal configuration of EHV networks

A generic topology of an EHV system, as shown in Figure 9.9, is used to evaluate the reliability performance of various network configurations, associated with different levels of redundancy. The objective of the studies is to determine the optimal configuration which produces the least-cost solution, i.e. by minimising the total cost of upgrade, cost of renting mobile generation, repair cost and the expected cost of interruptions.

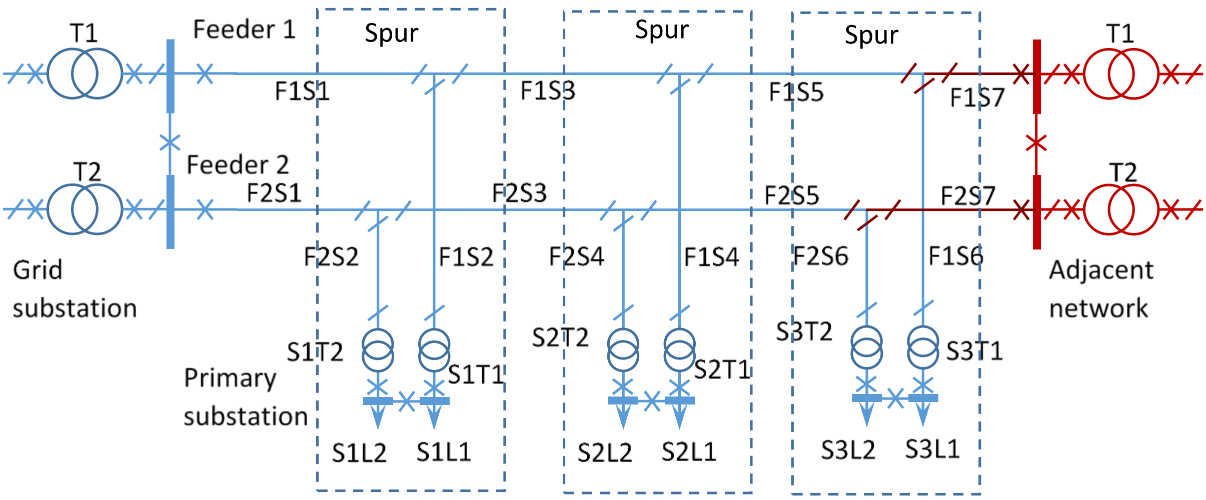


Figure 9.9: EHV Generic network configuration (illustrated for three primary substations) with optional connection to neighbouring grid substation

The topology of the EHV system used in this study consists of EHV overhead network and two-transformer feeders that feed into two-transformer primary substations. The main EHV feeders have an option to interconnect with the neighbouring grid substation to improve the security. In this case, we only consider N-1 and 'N-2' configurations. N-1 configuration denotes topology without the interconnection with the neighbouring grid substation, while 'N-2' denotes topology with interconnection with networks supplied from the adjacent network (highlighted in red). With 'N-2' configuration, the loads are secure against (almost) any of 2 overlapping outages, except the overlapping outages that occur on the two in-feeds in the same spur. In cases where there are no spurs (spur length set to zero), the scheme provides total N-2 redundancy. The considered EHV network consists of main and spurs sections (see Figure 9.9). Spur sections are sections which only supply one primary substation; all other sections are the main sections. It is worth noting that demand can only be transferred to the adjacent substation/network where there is sufficient capacity at the adjacent substation/network. If that substation has been designed to N-0 there may not be any capacity available. This might increases the CMF risks.

Sensitivity studies have been carried out to understand the drivers and quantify the impact of different degrees of common-mode failure on reliability performance and the optimal (least-cost) network configuration. Table 9.1 shows the reliability parameters used in the studies.

Table 9.1. Reliability parameters for EHV studies

Parameter	Values
Type of network	Overhead lines
Number of primary substations	1,2, and 3
Transformer peak demand (MW)	7.5 and 20
Failure rate (%/unit.km)	OHL 1 km: 2% and 15% for single outage and common-mode outage 0, 5% and 10% of single outage failure rate Transformer: 1% and 10% Transformer feeder maintenance: once in 8 years, 9 hours urgent close down time, 120 hours outage duration. Busbars sections: 0.1%
MTT Restore (h)	OHL: 12 (urgent repair time for EHV overhead lines) Transformer: 192 (urgent repair time for EHV/HV transformers) Busbar section: 2 (assumption)
MTT Repair (h)	OHL: 120 (average normal repair time for EHV overhead lines) Transformer: 720 (average normal repair time for EHV/HV transformers) Busbar section: 12 (assumption)
Section length (km)	Main: 4 and 20 Spur: 0 and 10
VoLL (£/MWh)	17,000 and 34,000

The key parameters that have been varied as part of the sensitivity studies are single and CMF rates, network loading, network cost (proportional to section length), and VoLL. Different sets of parameters are used to develop high and low circuit availability scenarios for overhead lines.

Table 9.2 shows the optimal degree of redundancy for each case considered in the study. The section length is presented as the section length of the main / length of spur feeders, for example: 4/0 means the length of one section of the main feeder is 4 km, and there is no spur section, meaning the primary substation is directly teed-off from the main feeder. Another example: section length 4/10 means the length of one section of the main feeder is 4 km, and the length of the one section of the spur feeder is 10 km (distance between the tee-point and the primary substation).

The optimal network configuration is presented as N-1 or N-2 or N-1:2. The last one shows that the optimal solution lies between the N-1 and N-2 as the breakeven VoLL for the N-1 configuration is below the threshold while the breakeven VoLL for the N-2 is higher than the threshold.

The results demonstrate that for a higher degree of common-mode failure, there is a tendency that a higher degree of network redundancy may be needed although, due to non-linearity and lumpiness of the problem, a case with a higher degree of common-mode failure does not necessarily lead to a higher degree of redundancy. For example, for cases with section length: 4/10, failure rate: min, and transformer peak loading 20 MVA, the optimal degree of redundancy shifts from N-1, when the common mode failure is 0% (not considered), to N-2, when the common mode failure is 5% or 10% of the respective single failure rate. On the other hand, the optimal degree of redundancy for networks with higher reliability is less affected by CMF, for example, in cases with section length 4/0 and the peak loading of transformer is 7.5 MVA, the optimal degree of redundancy remains N-1 across cases with CMF rates of 0% till 10%.

Table 9.2. Optimal degree of network redundancy for EHV OH networks with no load-transfer capability

Number of primaries	Section length (km) Main/Spur	Failure rate	Transformer peak loading 7.5 MVA			Transformer peak loading 20 MVA		
			Common mode failure (% of single failure rate)					
			0	5%	10%	0	5%	10%
1	4/0	Min	1	1	1	1	1	1/2
	4/10	Min	1	1	1/2	1	2	2
	20/0	Min	1	1	1	1	1/2	1/2
	20/10	Min	1	1	1	1	1/2	2
	4/0	Max	1	1/2	2	2	2	2
	4/10, 20/0, 20/10	Max	2	2	2	2	2	2
2	4/0	Min	1	1	1	1	2	2
	4/10, 20/0, 20/10	Min	1	1	1/2	1	2	2
	4/0	Max	1/2	2	2	2	2	2
	4/10, 20/0, 20/10	Max	2	2	2	2	2	2
3	4/0	Min	1	1	1/2	1	2	2
	4/10	Min	1	1/2	2	1	2	2
	20/0, 20/10	Min	1	1/2	2	1/2	2	2
	4/0, 4/10, 20/0, 20/10	Max	2	2	2	2	2	2

Other effects regarding how network reliability, network loading, network cost affect the network design, i.e. the optimal degree of redundancy, are consistent with the previous findings in this report, for example: networks with higher loading and/or higher failure rate tend to require more redundancy.

Another set of studies has been carried out with the assumption that 30% of load can be transferred to external neighbouring feeders, reducing the risk of interruptions. The results are shown in Table 9.3.

The results in Table 9.3 show similar trends as observed in the results of previous studies shown in Table 9.2. For example, getting the same cases as those analysed previously, for cases with section length: 4/10, failure rate: min, and transformer peak loading of 20 MVA, the optimal degree of redundancy shifts from N-1, when the CMF rate is 0% (not considered), to between N-1 and N-2 when the CMF rate is 5%, and to N-2, when the CMF rate is 10% of the respective single failure rate. On the other hand, the optimal degree of redundancy for networks with higher reliability is less affected by CMF, for example, in cases with section length 4/0 and the peak loading of transformer is 7.5 MVA or 20 MVA, the optimal degree of redundancy remains N-1 across cases with common-mode failure of 0% till 10%.

Table 9.3. Optimal degree of network redundancy for EHV OH networks with load-transfer capability for VoLL £17,000/MWh / £34,000/MWh

Number of primaries	Section length (km) Main/Spur	Failure rate	Transformer peak loading 7.5 MVA			Transformer peak loading 20 MVA		
			Common mode failure (% of single failure rate)					
			0	5%	10%	0	5%	10%
1	4/0	Min	1	1	1	1	1	1
	4/10	Min	1	1	1	1	1/2	2
	20/0	Min	1	1	1	1	1	1
	20/10	Min	1	1	1	1	1	1/2
	4/0	Max	1	1	1/2	1/2	2	2
	4/10, 20/10	Max	1/2	2	2	2	2	2
	20/10	Max	2	2	2	2	2	2
2	4/0, 4/10, 20/0, 20/10	Min	1	1	1	1	1/2	2
	4/0	Max	1	2	2	2	2	2
	4/10	Max	1/2	2	2	2	2	2
	20/0, 20/10	Max	2	2	2	2	2	2
3	4/0	Min	1	1	1	1	2	2
	4/10, 20/0, 20/10	Min	1	1	1/2	1	2	2
	4/0	Max	1/2	2	2	2	2	2
	4/10, 20/0, 20/10	Max	2	2	2	2	2	2

Due to the load transfer capability, the results in Table 9.3 show lower degree of redundancy in comparison with the results in Table 9.2, hence reducing the impact of CMF. For example, for cases with section length: 4/10, failure rate: min, and transformer peak loading 20 MVA, and no load-transfer capability, the optimal degree of redundancy shifts from N-1, when the common mode failure is 0% (not considered) and to N-2, when the CMF rate is 5% of the respective single failure rate. With load transfer capability, the shift from N-1 to N-2 occurs when we apply a CMF rate of 10% (instead of 5%). This demonstrates that the impact of CMF would be lower in the system with higher reliability.

Figure 9.10 shows the reliability performance for different common-mode failures of an overhead network supplying one primary substation (previously shown in Table 9.2) for transformer peak demands of 7.5 and 20 MW, section lengths 4/0 and 4/10, and minimum and maximum failure rate.

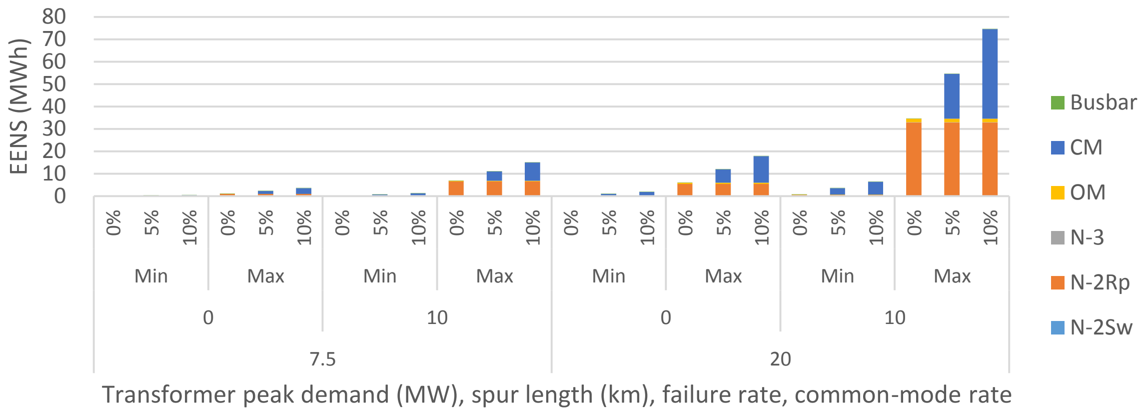


Figure 9.10. EENS for an EHV overhead network supplying one primary and main section length is 4 km

For maximum failure rate and if there is no common-mode outages significant proportion of EENS corresponds to overlapping outages when restoration of supply is carried out by a combination of mobile generation, temporary cable laying (or other alternative method), and urgent asset repair. For maximum failure rate and consideration of common-mode outages, the EENS resulting from common-mode outage becomes more important. Furthermore, for a common-mode failure rate equal to 10% of single outage failure rate, the associated EENS is the highest compared with EENS caused by further outages. This effect is significantly more relevant for shorter lines. Hence, it is recommended that common-mode outages are considered in deriving security standard.

9.2.3 Impact of common-mode failure on the optimal configuration of 132 kV networks

In order to investigate the impact of CMF on 132 kV networks, we have carried out a set of studies with the objective to determine the impact of CMF on the reliability performance and the optimal configuration of the 132 kV networks. The studies use the same approach as described in Section 9.2.2.

The assumed topology of the 132 kV networks is similar to those in Figure 9.9 where the grid and primary transformers are replaced by super grid and grid transformers, respectively, and the EHV network components are replaced by the 132 kV network components.

The assumed parameters are summarised in Table 9.4. The key parameters that have been varied as part of the sensitivity studies are failure rates (single outage and CMF), Mean Time To (MTT) Restore, MTT Repair, network loading, network cost (proportional to section length), and VoLL. Different sets of parameters are used to develop high and low circuit availability scenarios for overhead lines.

Table 9.4. Reliability parameters for 132 kV studies

Parameter	Values
Type of network	Overhead lines
Number of grid substations	1,2, and 3
Transformer peak demand (MW)	22.5 and 45
Failure rate (%/unit.year)	OHL 1 km: 2% and 15% for single outage and common-mode outage 0, 5% and 10% of single outage failure rate Transformer: 1% and 10% Transformer feeder maintenance: once in 8 years, 9 hours urgent close down time, 120 hours outage duration. Busbars sections: 0.1%
MTT Restore (h)	OHL: 24 Transformer: 240 Busbar section: 2
MTT Repair (h)	OHL: 120 Transformer: 720 Busbar section: 12
Section length (km)	Main: 8 and 30 Spur: 0 and 10
VoLL (£/MWh)	17 k and 34 k

Table 9.5 shows the obtained economically efficient degrees of redundancy for different 132 kV overhead network configurations if the VoLL is £17,000/MWh.

Table 9.5. Optimal degree of network redundancy for 132 kV OH networks with no load-transfer capability

Number of grid substations	Section length (km) Main/Spur	Failure rate	Transformer peak loading 22.5 MVA			Transformer peak loading 45 MVA		
			Common mode failure (% of single failure rate)					
			0	5%	10%	0	5%	10%
1	8/0, 8/10	Min	1	1	1	1	1	1/2
	30/0, 30/10	Min	1	1	1/2	1	1/2	2
	8/0	Max	1/2	2	2	2	2	2
	8/10, 30/0, 30/10	Max	2	2	2	2	2	2
2	8/0, 8/10	Min	1	1	1/2	1	1/2	2
	30/0, 30/10	Min	1	2	2	1/2	2	2
	8/0, 8/10, 30/0, 30/10	Max	2	2	2	2	2	2
3	8/0, 8/10	Min	1	1/2	2	1	2	2
	30/0, 30/10	Min	1/2	2	2	2	2	2
	8/0, 8/10, 30/0, 30/10	Max	2	2	2	2	2	2

As observed in the previous studies, the results of our studies on the 132 kV OH networks also suggest that for a higher degree of common-mode failure, there is a tendency that a higher degree of network redundancy may be needed, although due to non-linearity and lumpiness of the problem, a case with a higher degree of CMF does not necessarily lead to a higher degree of redundancy. For example, for cases with section length: 8/0, failure rate: min, and transformer peak loading of 45 MVA, number of grid substation: 3, the optimal degree of redundancy shifts from N-1, when the CMF rate is 0% (not considered), to N-2, when the CMF rate is 5% or 10% of the respective single failure rate. On the other hand, the results are less sensitive in cases with lower loading, for example, in cases with section length 8/0, failure rate: min, the peak loading of transformer is 22.5 MVA, the optimal degree of redundancy remains N-1 across cases with CMF rates of 0% till 10%.

Another set of studies has been carried out with the assumption that 30% of load can be transferred to external neighbouring feeders and therefore reduces the risk of interruption. The results are shown in Table 9.6. As observed in the studies for EHV networks, the availability of load-transfer capability tends to reduce the degree of network redundancy needed.

The results in Table 9.6 show similar trends as observed in previous studies shown in Table 9.5. For example, for cases with section length: 8/0, failure rate: min, and transformer peak loading of 45 MVA, number of grid substation:3, the optimal degree of redundancy shifts from N-1, when the common-mode failure is 0% (not considered), to between N-1 and N-2, when the common-mode failure is 5%, and to N-2, when the common mode failure is 10% of the respective single failure rate. On the other hand, the results are less sensitive in cases with 1 grid substation, for example, in cases with section length 8/0, failure rate: min, the optimal degree of redundancy remains N-1 across cases with common-mode failure of 0% till 10% for different peak loads (i.e. 22.5 and 45 MVA).

Table 9.6. Optimal degree of network redundancy for 132 kV OH network with load-transfer capability

Number of grid substations	Section length (km) Main/Spur	Failure rate	Transformer peak loading 22.5 MVA			Transformer peak loading 45 MVA		
			Common mode failure (% of single failure rate)					
			0	5%	10%	0	5%	10%
1	8/0, 8/10	Min	1	1	1	1	1	1
	30/0, 30/10	Min	1	1	1	1	1/2	1/2
	8/0	Max	1	1/2	2	1/2	2	2
	8/10	Max	1/2	2	2	2	2	2
	30/0, 30/10	Max	2	2	2	2	2	2
2	8/0	Min	1	1	1	1	1	1/2
	8/10	Min	1	1	1	1	1/2	1/2
	30/0, 30/10	Min	1	1/2	2	1	2	2
	8/0, 8/10, 30/0, 30/10	Max	2	2	2	2	2	2
3	8/0, 8/10	Min	1	1	1/2	1	1/2	2
	30/0, 30/10	Min	1	2	2	1/2	2	2
	8/0, 8/10, 30/0, 30/10	Max	2	2	2	2	2	2

As observed in the studies on EHV networks, the load-transfer capability improves the reliability performance of the system and therefore lessens the impact of CMF. For example, for cases with section length: 8/0, failure rate: min, and transformer peak loading 45 MVA, and no load-transfer capability, the optimal degree of redundancy shifts from N-1, when the common mode failure is 0% (not considered) to N-2, when the CMF rate is 5% of the respective single failure rate. With load transfer capability, the shift from N-1 to N-2 occurs when we apply CMF rate of 10% (instead of 5%). This demonstrates (in these cases) that the impact of CMF is less significant in the system with load-transfer capability.

Figure 9.11 shows the reliability performance of different common-mode failures associated with an overhead network that supplies one primary substation with the degree of redundancy shown in Table 9.5, transformer peak demands of 22.5 (BSP 45) and 45 (BSP 90) MW, section lengths 8/0 and 8/10 km, and minimum and maximum failure rates.

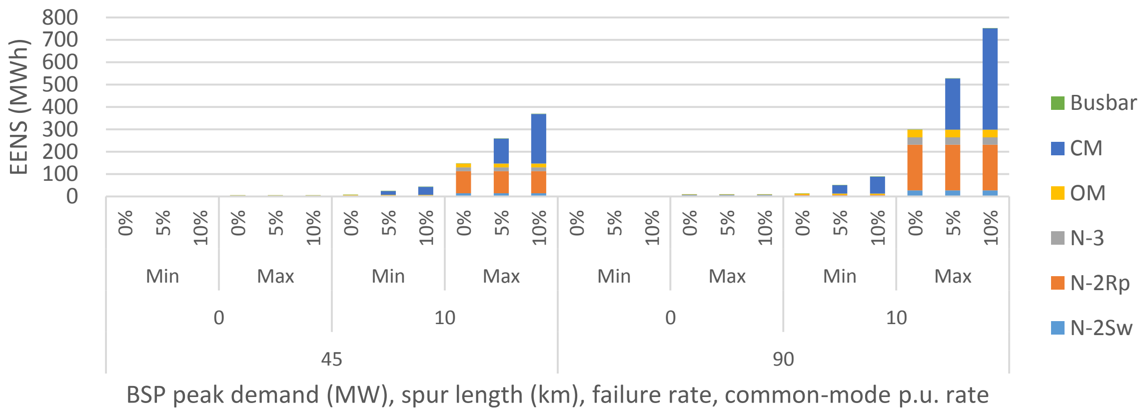


Figure 9.11. EENS for a 132 kV overhead network supplying three BSPs and main section length is 8 km

For the maximum failure rate and if there is no common-mode failures, most EENS corresponds to overlapping outages when restoration of supply is carried out by a combination of mobile generation, temporary cable laying (or other alternative method), and urgent asset repair. For maximum failure rate and consideration of common-mode failures, EENS resulting from common-mode outage becomes more important. Furthermore, for a common mode rate equal to 10% (of corresponding single outage failure) presents an associated EENS that is the highest with respect to EENS from any other outage. This effect is significantly more important for shorter lines. Hence it is recommended that common-mode outages are considered in deriving security standard.

9.2.4 Conclusions

This section evaluates the impact of considering CMF in distribution networks. Case studies are carried out for EHV and 132 kV network configurations and consider different degrees of CMF of overhead lines, busbars and switchgear. The studies investigate the impact of CMF on the optimal degree of redundancy needed for EHV and 132 kV networks. Sensitivity studies have been carried out to investigate the sensitivity of the following parameters: single and common-mode failure rates, MTT Restore, MTT Repair, network loading, network cost (proportional to section length), and VoLL. Different sets of parameters are used to develop high and low circuit availability scenarios for overhead lines.

The results for both EHV and 132 kV networks show consistent trends which can be concluded as follows:

- CMF affects the reliability performance of the system. The higher the CMF rate, the lower the reliability performance, leading to a higher EENS and, in turn to higher degree of network redundancy needed to mitigate the CMF effects; however, due to non-linearity and lumpiness of the problem, a case with a higher degree of CMF does not necessarily lead to a higher degree of redundancy overall;
- Other effects regarding how network reliability, network loading, network cost affect the network design, i.e. the optimal degree of redundancy, are consistent with the previous findings in this report, for example: networks with higher loading and/or higher failure rate tend to require more redundancy.
- Smart and flexible network technologies such as those that enable load-transfer capability can improve the reliability performance of the system and therefore lessen the impact of CMF and in general reduce the need for network redundancy.

Based on these analyses, it can be concluded that without considering CMF, as in the present standards, network planners may underestimate the risk and the network may not be adequately designed when exposed to CMF events. The impact can be significant when large demand groups are exposed to potentially high risks of CMF. It might be difficult to derive general principles to include implicitly CMF because this is likely to be very case specific.

9.3 Common-mode failure associated with ICT Infrastructure

9.3.1 Introduction

The power system is under increasing strain due to renewable and distributed generation sources and the electrification of heat and transport. The only way to avoid costly and inefficient reinforcements and excess emissions is to be smarter about the way we plan and operate the grid. The smart grid offers this opportunity, by making use of ICT at every level. Grid operators replace preventive control actions by corrective actions on the basis of grid visibility and real-time control actions. Aggregators can establish virtual power plants by communicating in real time with contracted distributed resources. End users and smart appliances can respond to prices and control signals in real time, and optimize their behaviour accordingly.

These fundamental changes mean that future smart grids can no longer accurately be analysed as physical systems with a few ‘smart’ extensions. Instead, they should be considered cyber-physical systems (CPSs), where the cyber (i.e. ICT) and physical elements –and their interactions—are both essential to the nature of the system. The resulting CPS is much more complex than traditional power systems, and traditional methods for assessing its reliability must be reconsidered. Experiences with System Integrity Protection Systems show that failures in communication systems do occur, and impact the dependability of protection systems.

The following conceptual framework, adapted from Kjølle and Gjerde [168], may be used to decompose the reliability of such complex systems into its causes and effects.

Threats are external factors that could impact the reliability of the system. As a general rule, threats cannot be addressed within the power system itself. Threats include lightning strikes, hackers, natural wear and tear, etc. The word hazard is often used as an apparent synonym for threat when there is no malicious intent involved.

Vulnerability indicates the extent to which a realised threat affects a system's operation. Vulnerability can be further subdivided into susceptibility (ability of a threat to disrupt the system) and coping capacity (means of restoring normal operation).

Consequences of the system's disruption. For power systems this would consist of the impacts to its customers (demand or generation side).

When qualitative or quantitative estimates are available, the threat-vulnerability-consequence chain can be summarised by a relevant risk metric. For example, the CVaR approach could be used to quantify and 'cap' the risk.

In order to illustrate the risk assessment of cyber-physical distribution networks we have investigated the impact of common mode failures (CMF), triggered by failures on the ICT infrastructure, on the availability of DSR services and protection systems that rely strongly on ICT.

9.3.2 Impact of common-mode failure on DSR services

A significant issue associated with the delivery of DSR security contribution is associated with the CMF in the communication and control infrastructure of DSR, which might render multiple DSR facilities unavailable at the same time (coincidence in delivery). If for example multiple DSR facilities are operated by the same DSR aggregator and a fault in the communication channel between the aggregator and the DSR facilities occurs, all of them will be unavailable at that time. The objective of this section is to investigate the impact of CMF on the security contribution of DSR. The analysis in the report uses generic values for common mode DSR failures to cover the range and demonstrate the importance. Actual values of common mode failures will be probably very site specific and data availability will be an issue for accurate modelling.

The examined example involves supply of the demand by two transformer circuits of 15 MVA each. Six DSR facilities of 0.3 MW, 1 MW or 2 MW each are considered. Different scenarios regarding the probability of Common Mode Failure (CMF) in delivery of multiple DSR facilities are examined, namely 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 the time they act as independent DSR facilities. Clearly the CMF increases the probabilities of complete system failures and of faultless performance, at the expense of intermediate states. Finally, alternative scenarios regarding the failure rate and MTTR of the transformer circuits are explored.

Figure 9.12 presents the DSR security contribution for the different examined scenarios and different methodologies of contribution quantification, namely ELCC and P2/6. First of all, it can be observed that the security contribution calculated through the P2/6 approach does not depend on the DSR size, DSR coincidence in delivery and network reliability, meaning that this approach offers limited insight into the actual reliability implications associated with the use of DSR.

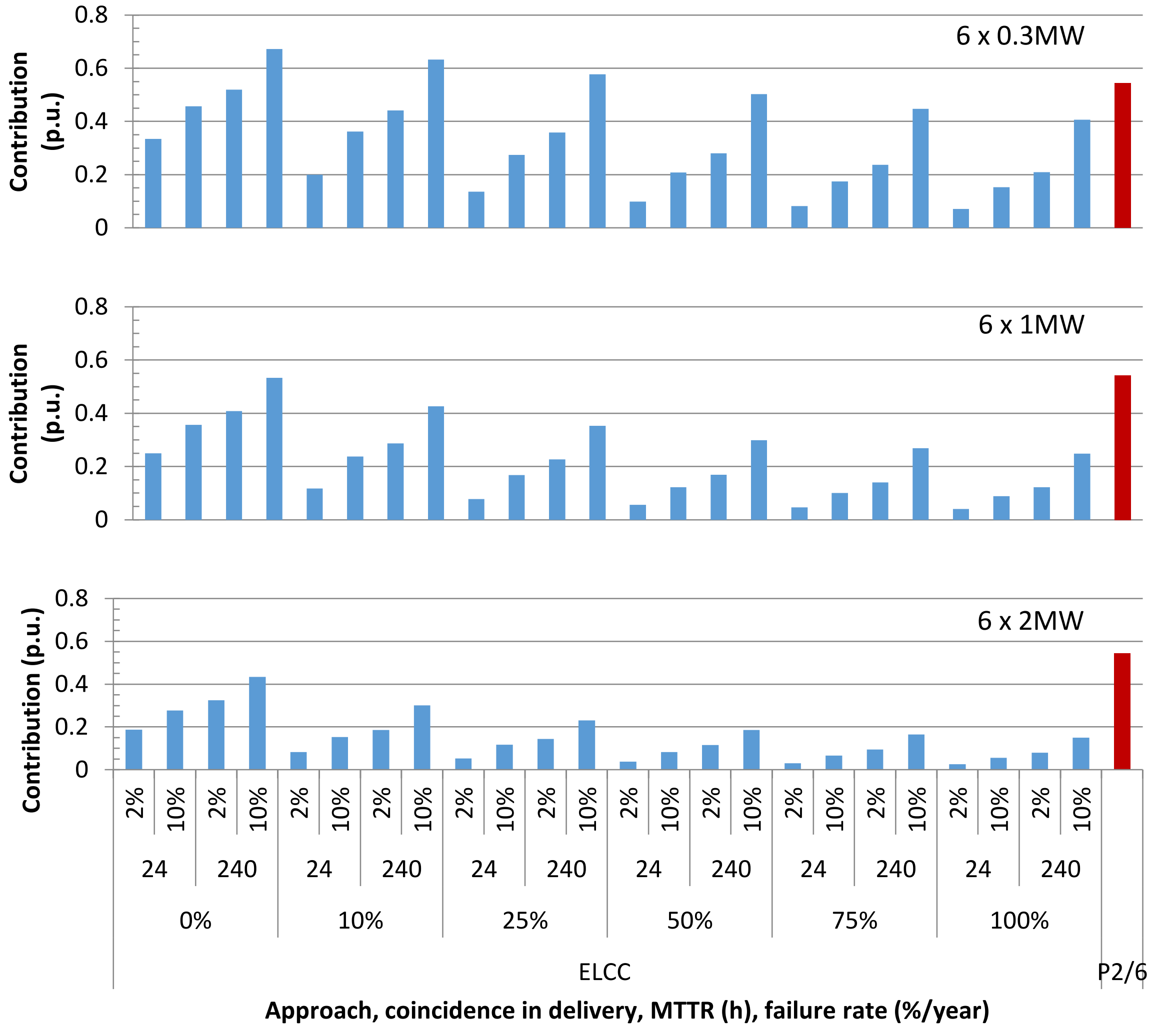


Figure 9.12: Capacity contribution of six DSR facilities for different scenarios regarding the DSR size, DSR coincidence in delivery as well as transformer circuit MTTR and failure rate

The security contribution calculated through the ELCC approach decreases as coincidence in delivery is increased. 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 are characterised by a smaller contribution. Finally, the security contribution calculated through the ELCC approach increases with an increasing failure rate and MTTR of the transformer circuits as well with a decreasing DSR size.

9.3.3 Impact of common-mode failure on a protection system

A more elaborate study builds on the model introduced in Section 5, which showcases a situation where DG-related reverse flows increase the risk of supply interruptions. In this section the model is extended with a corrective protection system in order to mitigate these risks, but this system is not infallible: the possibility of ICT-related failures is explicitly modelled.

As illustrated in Figure 9.13, the model is composed of a distribution system at 11 kV connected to the rest of the network via primary substation with two identical 33/11 kV transformers with a capacity of 17 MW each (only active power is considered). The distribution system has a significant amount of HV-connected photovoltaic power, composed of 4 farms with 28,125 panels of 320 W each for a total installed capacity of 36 MW.

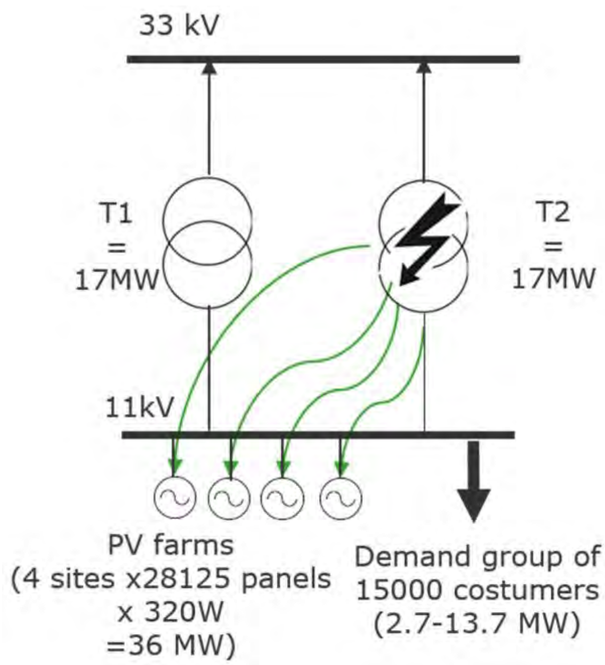


Figure 9.13: Test system including a protection system to reduce post-fault overloads

The protection scheme is intended to remotely disconnect distributed generation sites after a single transformer outage, in order to rapidly reduce the exporting power flow, thereby preventing overloads in the remaining transformer and thus the disconnection of the distribution system. The communication flows for a hypothetical fault in transformer T2 are visualised by green arrows. Such a system can be implemented at a much lower cost than an additional transformer, which may make it worthwhile from an expected benefit perspective. Moreover, by preventing infrequent very costly events it is able to reduce the long tail of high-impact events. However, a common concern for the use of corrective actions is its potential to fail to respond as desired: if the remote disconnection of PV farms fails due to ICT failures, load shedding may be unavoidable.

To investigate the risks associated with incorrect operation of the corrective protection system, a failure model is constructed using the approach in [82]-[83]. The failure modes of the protection system are illustrated in Figure 9.14.

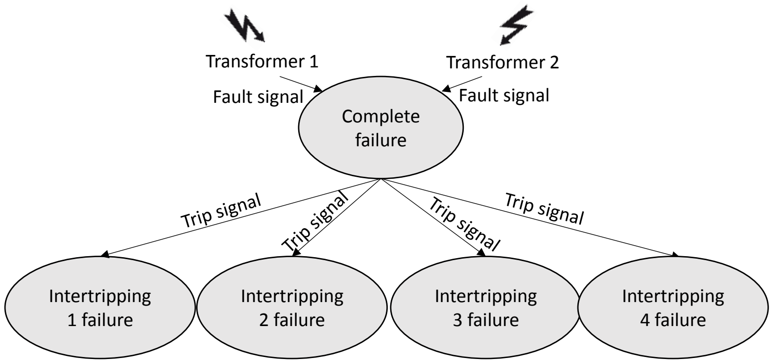


Figure 9.14: Failure model diagram of the protection scheme

As illustrated, a fault in either transformer activates the protection system. It may be inhibited by a complete failure of the corrective protection system, representing the failure of the sensing relays and the logic controller to identify the fault and initiate the trip signal. When this failure mode occurs, none of the PV farms connected to the scheme are successfully disconnected. Under normal operations, the logic controller sends trip signals to the remote PV farms connected to the scheme. Figure 9.14 assumes connections to all four PV farms of our test system, but this number will be varied to investigate designs with various levels of redundancy. The trip signals are transmitted through independent communication channels to each site, where remote circuit breakers disconnect the targeted DG unit(s) from the network. As represented in the figure, the communication channel and circuit breaker associated with each farm constitute an individual failure mode. A complete failure of the corrective protection system to respond to the initial trigger (transformer fault) is assumed to occur with a probability of 3.8% [83]. The communication of a trip signal to an individual PV farm and its successful execution is assumed to succeed with a probability of 80%. The method to compute expected outage costs is detailed in Appendix 13.11 and 13.12.

Case studies

Figure 9.15 shows the expected annual interruption costs for different transformer repair times and fault rates, considering a 1-day reconnection time for customers. Each sub-graph has four curves associated with different scenarios as follows: The VoLL is set to either £34,000/MWh (black and red) or £17,000/MWh (blue and green). The black and blue curves consider an unreliable protection system with the failure modes illustrated in Figure 9.14, whereas a hypothetical 100% reliable protection system is considered for comparison in the red and the green curves. The expected curtailment costs are shown for different numbers of PV farms connected to the protection system, thus investigating the effect of redundant PV intertripping configurations.

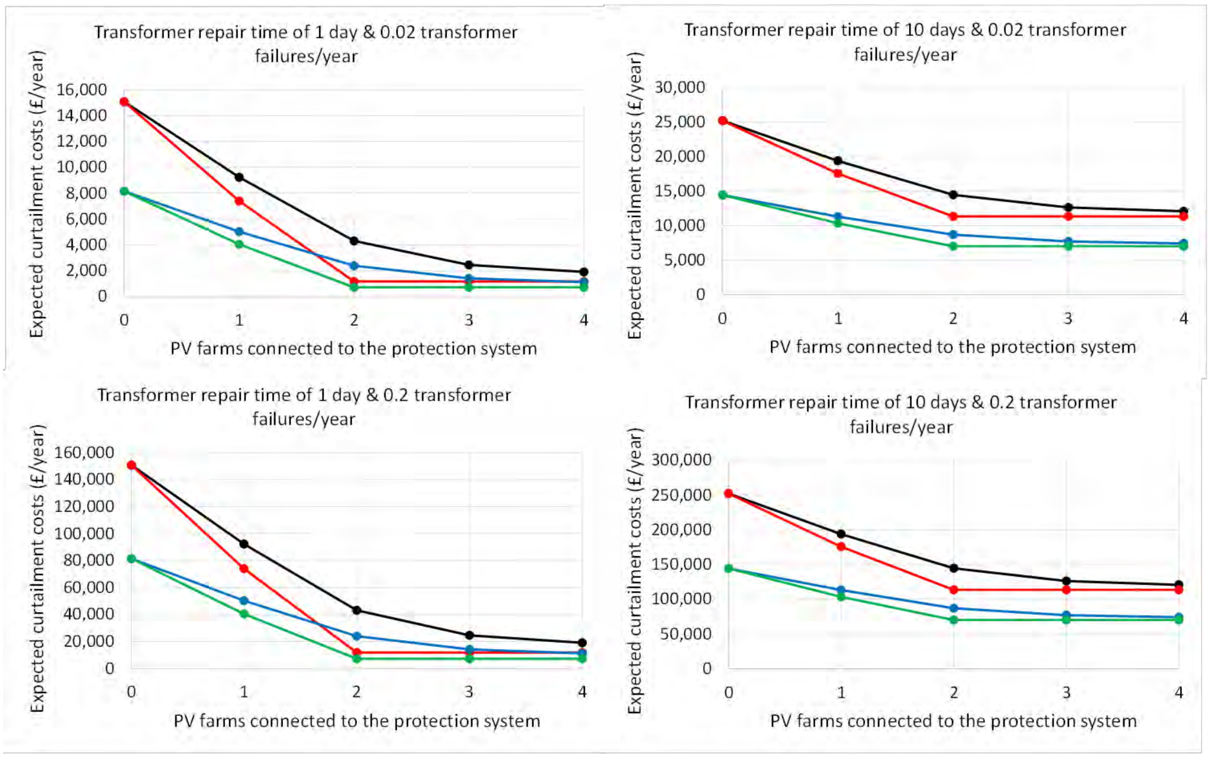


Figure 9.15: Expected curtailment costs considering 1 day of reconnection time

The annual risk exposure decreases with the number of PV farms connected to the protection scheme, as more protection connections may counteract eventual failures to activate one or more tripping systems. Note that a 100% dependable system (green and red curves) requires the use of *two* communication channels to neutralise all risk related to single transformer faults. Disconnecting a single PV farm is not sufficient to reduce the flows to within the transformer capacity for all operating conditions. It should be noted that even for an unreliable system (black and blue curves), the annual expected interruption costs are notably reduced, when compared to the base case without corrective protection system (0 PV farms). The system therefore permits the DNO to mitigate a substantial part of the risk related to single transformer faults. The residual risk is due to common mode transformer outages where corrective actions have no impact. The achievable benefits of intertripping schemes thus depend on the proportion of costs associated with common mode transformer failures: when common mode failures dominate the curtailment costs (e.g. in the 10 day repair case), intertripping schemes have lower benefits.

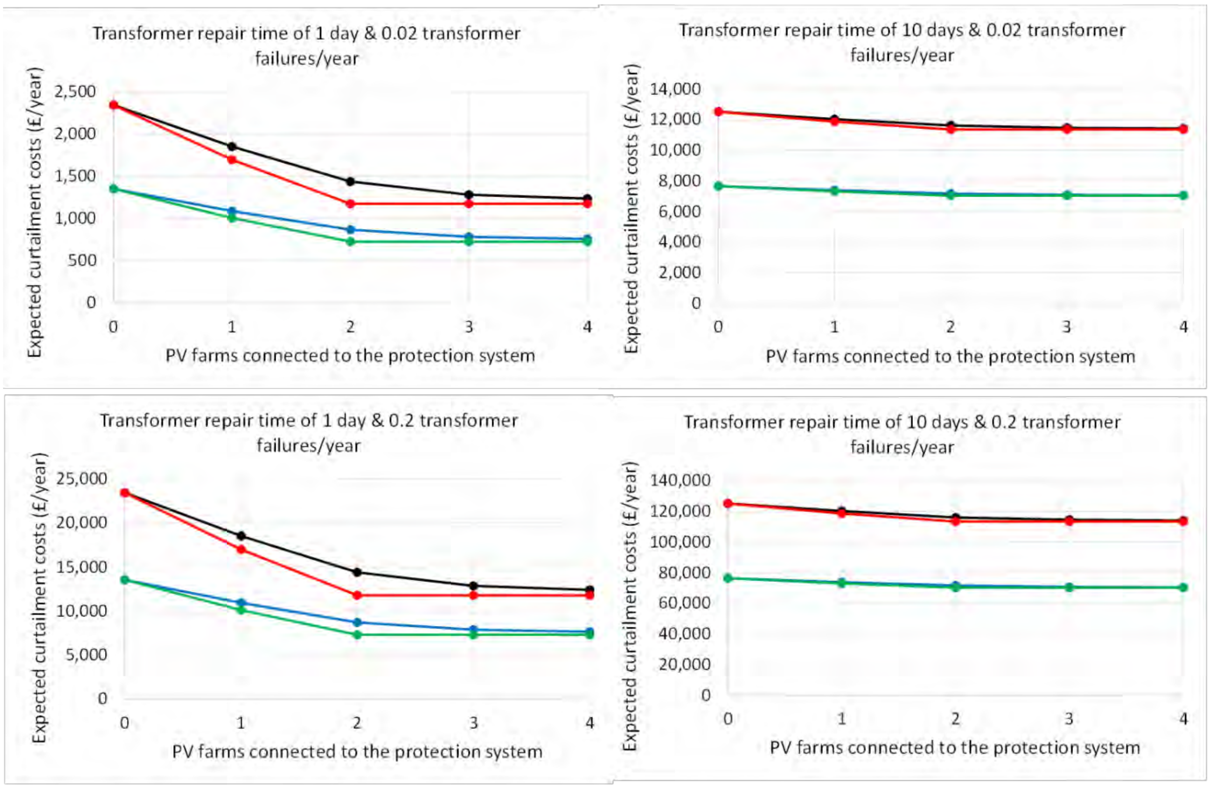


Figure 9.16: Expected curtailment costs considering 1 hour of reconnection time

Figure 9.16 has the same structure as Figure 9.15 but considering a reconnection time of 1 hour instead of 1 day. The results indicate that the benefits from the protection system are lower when the supply to the distribution system is rapidly reconnected. This is especially evident for the scenarios assuming 10 days of transformer repair time -two diagrams on the right- where the costs are clearly dominated by common mode transformer faults (where disconnections persist for the repair time).

The protection system not only reduces the expected costs but also the expected number of years between service interruptions. As shown in Figure 9.17, these are notably improved when compared to the base case, even for an unreliable protection system (black curve). When redundant communication channels are considered (e.g. 4 PV farms), disconnections are mostly related to the total failure of the protection system (see Figure 9.14). For a perfectly reliable protection system, the use of two PV sites ensures that only common mode transformer faults result in the disconnection of the distribution system.

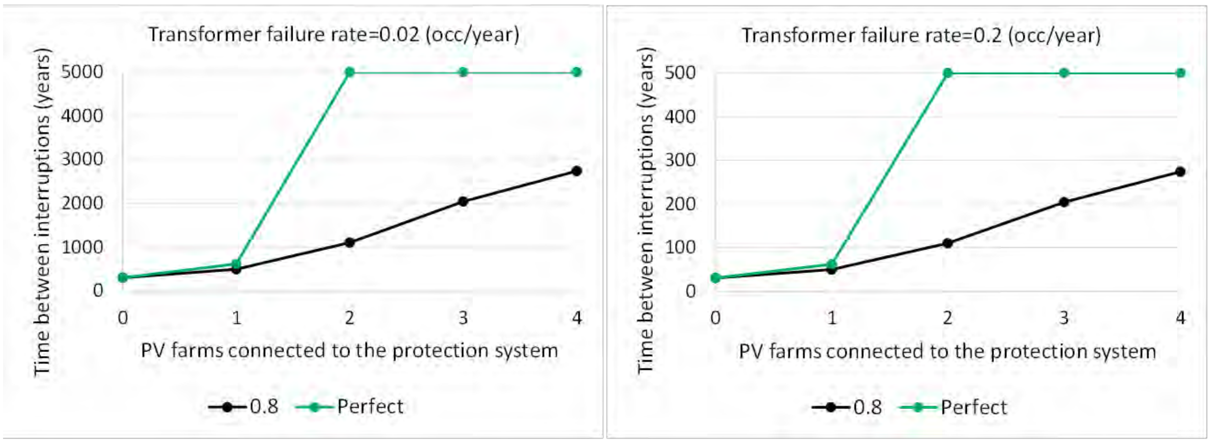


Figure 9.17 Mean time between costumer disconnections

9.3.4 Conclusions

The use of a fallible corrective protection system has been investigated as a strategy to reduce curtailment costs. The system consists of a remote tripping scheme that disconnects a preselected set of DG sites upon occurrence of a transformer fault. The impact of such a corrective system has been quantified for different reliability levels, reconnection and repair times, and VoLL levels. The analysis carried out demonstrated that intertripping schemes provided a cost effective solution for connecting increased amounts of DG whilst avoiding network reinforcement. Although traditional reinforcement would be more reliable the overall associated costs are significantly higher.

The results demonstrate that even a very unreliable protection system can reduce risk exposure, especially when combined with redundant features (in this case, disconnection of more than two PV sites). This suggests that in cases where reinforcement of the network is not economically justified, it is worthwhile investing in a low-cost corrective solution that results in significant savings even for moderate dependability levels. However, we note that fewer benefits are achieved in the scenarios where common mode failures dominate the curtailment costs as the protection system has no impact in these cases.

9.4 Reliability assessment for distribution networks considering High Impact Low Probability events

9.4.1 Introduction

Traditionally, the reliability parameters used for assessing the reliability performance of electricity networks are based on “average” values derived from historical data. This kind of assessment is typically employed for selecting a set of network designs that meet the reliability criteria. However, exceptional rare events, for example: extreme weather conditions leading to floods could increase the failure rates of network components affected by the events and also increase repair times. The impact of HILP events, if not anticipated, can lead to significant and prolonged interruptions of supply.

As this type of events is infrequent, its "weighted-average" probability cannot be calculated / estimated accurately due to the lack of data. However, a distribution of HILP events could be assumed and used to estimate the failure rates for various confidence levels and enables reliability assessments. The expected risk for a specified confidence level could then be estimated.

In this context, a set of studies has been carried out with the objective to:

- Assess the consequences of HILP events with different severity, focusing on the impact of extreme weather conditions on the increased failure rate of network components and reliability performance of the system,
- Consider how to include HILP explicitly in network design optimisation through considering robust network operation and design measures, taking into account emergency operation actions such as the provision of emergency supply (mobile generation) to improve the restoration process, and
- Identify the role and quantify the value of emergency operation actions and emergency network development.

9.4.2 Impact of HILP on reliability performance and the use of emergency generation as a mitigation measure

Description of the studies

In order to achieve the objectives, a set of case studies has been carried out investigating the impact of a HILP event with different severity on the reliability performance of the system. During a HILP event, the failure rate of line sections is increased and the repair time of component is accordingly prolonged. There are 2 HILP failure factors used in the studies: (i) 10 and (ii) 50 (the latter is 5 times more severe than the former). A HILP failure factor of 10 and 50 means that the asset failure rate is 10 times and 50 times higher than the average, respectively. As the HILP events may also prolong the restoration or repair time, the studies also investigate 3 different HILP factors that affect the MTTR: 2, 5 and 10. This means the MTTR during the HILP events will be 2x, 5x or 10x larger than the MTTR in normal operating conditions. It is assumed that Urgent Repair time is increased during HILP event and 24 hours is used as a reference value. The example is illustrative and should provide insights in the issues that would be important to consider in the context of future network design standards.

The studies also investigate the impact of availability of emergency supply schemes (mobile generation). Two parameters, i.e. the waiting time for deploying emergency (mobile) generation and the supply rate, are varied. For the waiting time, the values used in the studies are 3 h and 24 h. Typically, the deployment time for mobile emergency generation is about 4.5 h, on average which is within the range of the studies. In terms of the supply rate, the emergency power may not be able to fully supply the load interrupted, therefore two scenarios with supply rate of 25% and 100% of full demand are studied. Depending on the size of the network in outage the amount of mobile generation which could be deployed might be lower than 25%. In this illustrative example with total affected region of 5 MW during peak period assuming that 100% of the demand could be picked up by mobile generation is considered reasonable.

A set of parameters used in the studies is shown in Table 9.7.

Table 9.7: Case study parameters

Parameters	Values
Failure rate for overhead lines (%/km.year)	10
Switching time (minutes)	30
Restoration time (hours)	24
Section length (km)	2
Peak demand of each load point (kW)	500
Loading level	N-0
HILP failure factor	10, 50
HILP repair factor	2, 5, 10
Emergency generator preparing time (h)	3, 24
Emergency generator supply rate	25%, 100%
Value of Lost Load (£/MWh)	17,000
HILP event duration (h)	48

The *fragility* approach, which was originally invented to describe the probabilistic relationship between nuclear plant failure and ground acceleration in earthquake, can also be applied in the reliability analysis [104]-[105] to express the probability of distribution network line section failure with respect to the severity of HILP events.

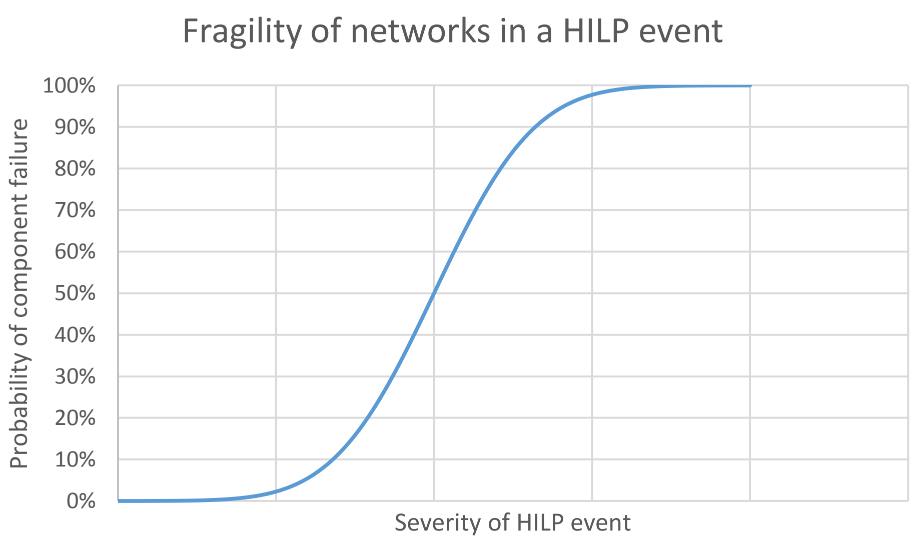


Figure 9.18: Fragility of networks in a HILP event

The generic shape of the fragility function is shown in Figure 9.18. The trend indicates that the probability of a network component failure increases as a HILP event, e.g. storm, becomes more profound.

The studies have been carried out on a HV distribution network shown in Figure 9.19. The studies assume that each HV section have installed disconnectors on both sides. This allows any single circuit fault to be isolated and supply restored in switching time which reduces the supply interruption. The 11 kV network is designed as a radial network with a normally open circuit breaker (NOP) that connects the two main feeders for back-feeding during contingencies. The part of the network affected by the fault(s) can be isolated by opening the corresponding switchgear and the affected load points can be resupplied by the adjacent branch. At each load point, a distribution transformer is connected.

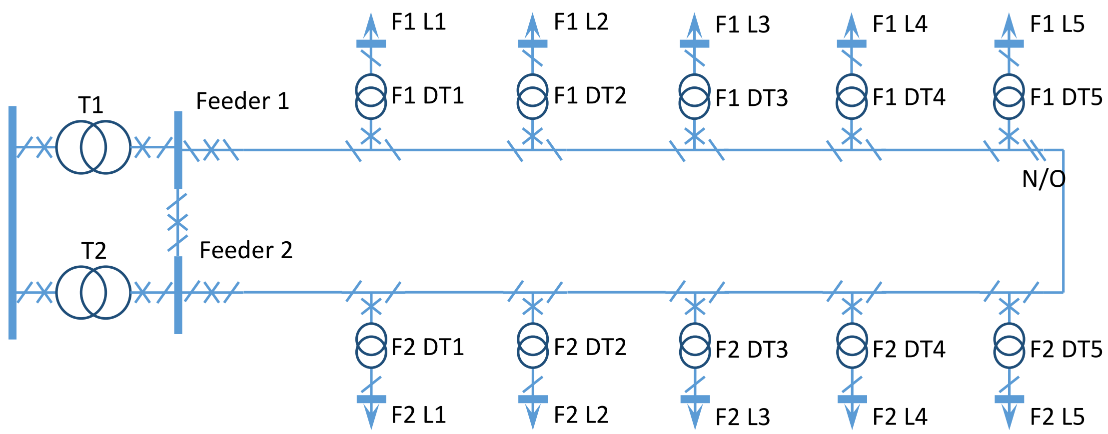


Figure 9.19: An example of radial HV distribution network

The studies have been carried out using the year-round load profile with 30-min time resolution.

Results

Time-sequential Monte Carlo method is conducted to model the impact of HILP events on network reliability performances. The results of the studies are presented in Table 9.8.

Table 9.8: System reliability and cost performances under various HILP and provision of emergency supply scenarios

Network Reliability	HILP MTTR	No emergency supply		25% emergency supply rate				100% emergency supply rate			
				3h		24h		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)	EENS (MWh/event)	Cost of EENS (k£/event)	EENS (MWh/event)	Cost of EENS (k£/event)
No HILP	x1	1.33	22.6	1.29	21.9	1.33	22.6	1.26	21.4	1.32	22.4
HILP FRx10	x2	3.2	54.4	2.5	42.5	2.9	49.3	1.6	27.2	2.6	44.2
	x5	5.1	86.7	3.3	56.1	4.3	73.1	1.8	30.6	3.0	51.0
	x10	11.6	197.2	7.4	125.8	9.2	156.4	1.8	30.6	4.2	71.4
HILP FRx50	x2	15.4	261.8	9.8	166.6	13.2	224.4	3.2	54.4	11.1	188.7
	x5	55.2	938.4	33.4	567.8	39.6	673.2	4.7	79.9	19.2	326.4
	x10	157.8	2,682.6	111.2	1,890.4	126.5	2,150.5	5.7	96.9	27.2	462.4

Table 9.8 shows the results of case studies for distribution network reliability with different HILP factors and emergency supply. Expected Energy Not Supplied (EENS) and cost of ENS are computed for analysing the network reliability and cost performance. It can be se that under normal weather condition, i.e. no HILP event, the EENS for each failure event is relatively low, in the range between 1.26 MWh (with emergency supply) and 1.33 MWh (without emergency supply). The improvement of EENS due to the emergency supply is relatively modest, i.e. 0.06 MWh or £1.2k cost savings. Marginal improvement of the EENS performance and the small benefit obtained indicate that the emergency supply may not be justified in normal conditions.

When a HILP situation happens, the failure rate of network components increases by 10 or 50 times of the original and repair time is prolonged to 2, 5, 10 times of the original as 2 days, 5 days, 10 days (as high impact may cause significant damage of OH that would require long repair times) . If no emergency supply is available, the system EENS can be as high as 157.8 MWh and the corresponding cost is £2.682m for a case with the HILP failure factor of 50 and the repair factor of 10. The system EENS increases when the failure rate goes up and repair time increases. If emergency supply is available in the HILP event, the system EENS can be significantly reduced. For example, for a case with the HILP failure factor of 10 and the repair factor of 2, the EENS in a case with no emergency supply is 3.2 MWh and with the emergency supply, it can be reduced down to 1.6 MWh, i.e. 50%. The improvement is considerably higher for a severe HILP event. For a case with the HILP failure factor of 50 and the repair factor of 10, the EENS with emergency supply is down to 5.7MWh which is merely 4% of the original 157.8 MWh, saving £2.5857m for reducing the duration of supply interruptions. Considerable improvement of the EENS performance and the savings obtained indicate that the emergency supply can be justified in dealing with HILP situations.

In order to show more clearly the impact of HILP with different severity, the reliability performances of the system for cases with HILP failure factor of 10 and 50 are compared in Figure 9.20.

The results demonstrate that higher EENS would be associated with more severe HILP situation, longer repair time, lower supply rate and longer deployment time of mobile generation. Improvement of the EENS can be made by shortening the deployment time of the emergency generation and increasing the supply rate.

Figure 9.21 shows the cost of EENS using VoLL of £17,000/MWh for cases with HILP failure factor of 10 and 50. When there is no emergency supply, the costs of EENS vary between £54.2k and £2683k in different conditions. If the emergency generation is available, the cost savings in the case with the HILP failure factor of 10, the repair factor of 2, 25% supply rate and 24h deployment time are relatively low, i.e. £4.3k (£54.2k-£49.9k). This savings increase to £2.586m (£2683k-£96.9k) in the case where the HILP failure factor is 50, the repair factor is 10, with 100% supply rate and 3h waiting time.

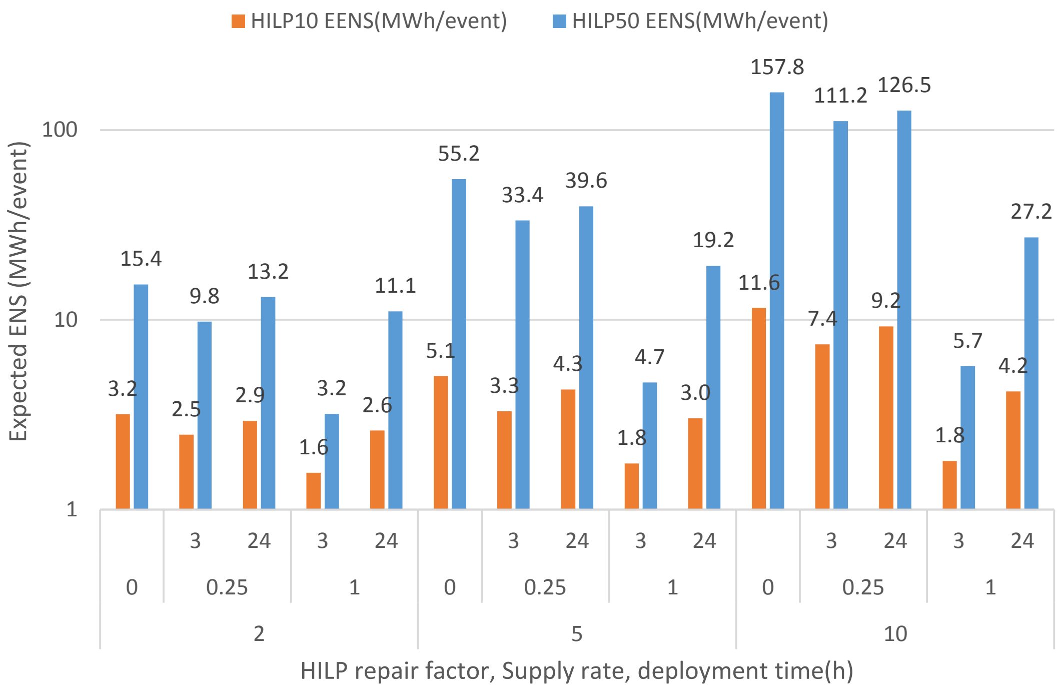


Figure 9.20: Reliability performances of the system for HILP cases considered in the studies

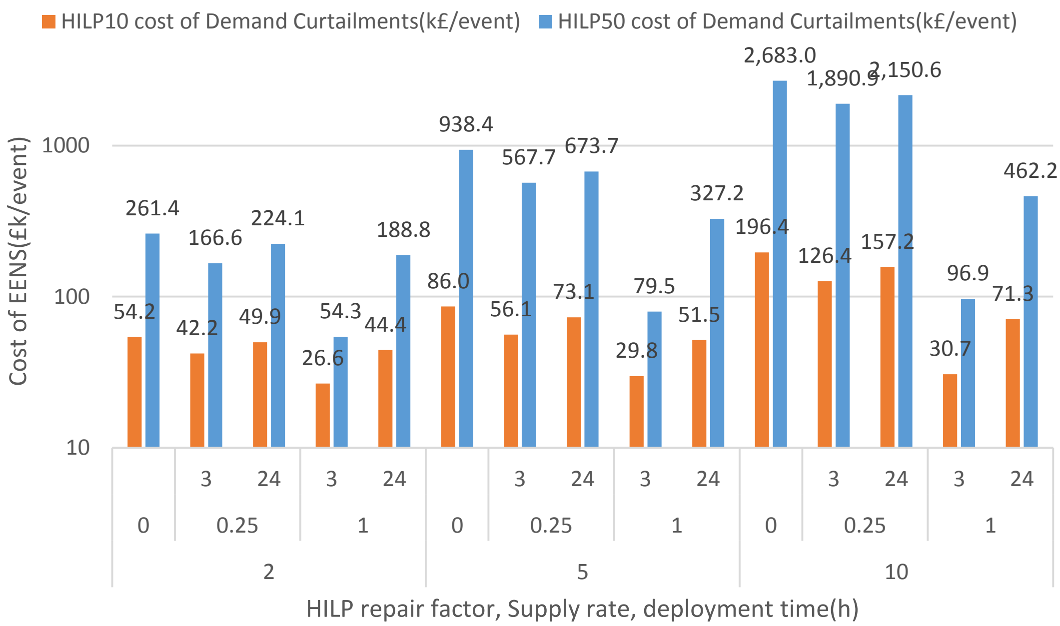


Figure 9.21: Cost of EENS for HILP cases considered in the studies

This kind of analysis can also be used to inform development of alternative actions for improving the resilience of the system, for example, by transforming the OH network which is prone to extreme weather conditions to an UG network. Considering the cost per km for replacing OHL with underground cables is £110k/km, the cost of transforming the test network is 22km*£110k/km=£2.42m. From the above study, during a HILP event (e.g. a storm), the cost of EENS can be as high as £2.682m. In that case, the loss incurred in a HILP event can justify the cost of transforming the network. As an alternative, the provision of emergency mobile generators, especially when these can be deployed fast, could improve considerably the reliability performance of the system affected by a HILP event and reduce the associated cost of EENS.

In order to get more insight on the impact of improving the deployment time of the Figure 9.22 shows the distribution function of EENS for different deployment times of emergency generation, i.e. 3, 6, 12 and 24 h in cases with HILP repair factor of 2 and HILP failure factor of 50.

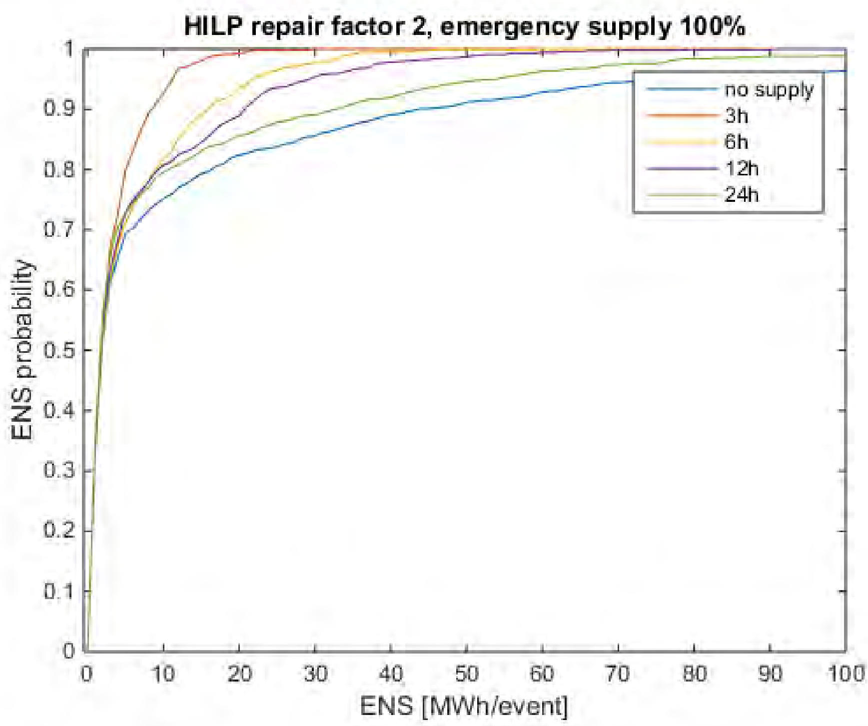


Figure 9.22: Cumulative probability distribution of ENS for HILP events

The analysis demonstrates that decreasing deployment time of emergency generation would significantly reduce the probability of high levels of ENS. For example, there is 90% chance that the ENS due to the HILP event is smaller than 10 MWh, 17 MWh, 19 MWh, 22 MWh, 35 MWh, 56 MWh for cases with emergency generation deployment time of 3h, 6h, 12h, 24h and no emergency generation, respectively.

9.4.3 Preventive vs. corrective mode of investment: which one is the optimal strategy for HILP?

After a natural hazard has occurred (e.g. flooding), power outages caused by affected electricity infrastructure (e.g. substation) can be minimised by the deployment of an array of post-contingency mitigation actions in the form of backup generation and transfer cables that can supply demand from neighbouring (unaffected) substations. Alternatively, preventive network investment can minimise both impact of natural hazards and cost associated with the deployment of post-contingency actions that can be potentially inefficient. Hence there is a clear opportunity to determine an effective portfolio of preventive and mitigation (post-contingency) actions that can be undertaken by system operators and planners in order to improve network resilience. We refer to resilience rather than security to distinguish from the problem associated with more frequent N-k events that may occur and thus the focus of this work is on pre- and post-contingency measures portfolios that can reduce risk exposure to HILP events (it is important to bear in mind that there would be many practical factors that would influence the speed at which new transfer capacity could be installed during a HILP events).

There is a number of fundamental questions associated with the portfolio of measures that may increase the network resilience against occurrence of natural hazards such as:

To what extent a portfolio of merely post-contingency mitigation actions (such as deployment of mobile backup generation and transfer cables) would be efficient to deal with outages caused by natural hazard? (historically, network infrastructure has been installed to deal with "credible" rather than rare events)

Can network resilience be efficiently improved through network reinforcements rather than through a portfolio of post-contingency mitigation actions?

How the set of post-contingency measures that may include deployment of provisional cables from neighbouring substations can affect the design of network infrastructure?

Overall: what is the right balance between preventive and mitigation (post-contingency) measures that can efficiently improve network resilience? We have developed a method that could be applied to different specific cases. A more comprehensive analysis can be undertaken but scenarios would need to be defined. An illustrative case study example is provided later in this section where four options are considered. However, this will be very case specific and hence requires precise definition of HILP.

Answering these questions would be important for developing appropriate strategies for dealing with rare conditions driven by natural hazards, which would include preventive actions in terms of network design and corrective actions needed to deal with natural catastrophes in a post-contingency, remedial mode.

The Optimal Portfolio Model

To tackle the aforementioned problem, we propose a novel optimisation model that can efficiently balance the set of preventive and corrective measures to deal with high impact low probability events originated by natural catastrophes (e.g. flooding). The optimisation model fully enumerates all N-1 and N-2 outages (so-called scenarios), recognising common mode failure probability caused by natural hazard.

The optimisation model minimises in total 6 cost components in its objective function as follows:

- Up-front network investment or annuity cost of (permanent) network infrastructure associated with the infrastructure that functions under normal operating conditions in the intact system. Part of this infrastructure is also available post-contingency (except for that affected by the hazard);
- Energy bought from main system which accounts for the cost related to main system operation and is calculated under each contingent state and the intact system. Under outages, this energy volumes are used to supply the part of demand that is not curtailed or supplied by backup generating units;
- Corrective network investment which corresponds to transfer cables deployed (in corrective mode) under a given outage state;
- Backup generation rental fee which corresponds to generating units deployed (in corrective mode) under a given outage state (rental fee paid under the emergency condition)
- Fuel cost of backup generation associated with the fuel cost of operation from backup units that function under the emergency condition; and
- Lost load associated with demand that cannot be covered through remaining network infrastructure, backup generation and transfer cables from neighbouring substations.

Although the model is stochastic, its solutions can full comply with N-1 criterion and use network redundancy (rather than post-contingency actions such as backup generation and corrective network deployment) to prevent demand curtailment under the occurrence of credible (N-1) outages. In contrast, non-credible (rare) events are treated in a probabilistic fashion and thus covered through an optimal portfolio of measures that include post-contingency actions. The stochastic model presents one decision stage in the beginning, before uncertainty is realised, and one (two-period) post-fault stage as follows (see Figure 9.23):

- Here and now, first stage: where decisions associated with up-front (permanent) network investment are taken
- Period 1, second stage: where decisions from first stage are implemented and demand is shed if not sufficient up-front network capacity was built to deal with outage states (albeit demand shedding can be minimised by using backup generation that can be rapidly deployed). Corrective network investment is decided in this period (right after uncertainty is revealed), but implemented at the beginning of period 2.
- Period 2, second stage: where demand is shed if not sufficient up-front network capacity was built to deal with outage states, albeit demand shedding can be minimised by using both backup generation (deployed in period 1) and corrective network investment that is implemented at the beginning of this period (but decided and built during period 1).

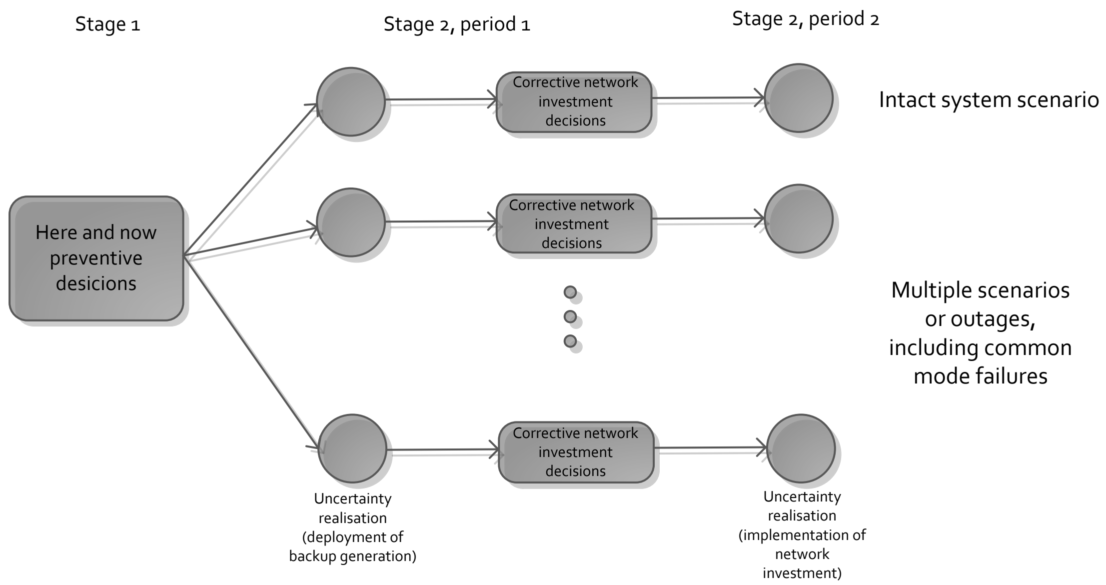


Figure 9.23: Scenario tree of optimal portfolio model

Case studies

We aim to determine optimal (greenfield) network design and optimal portfolio of pre- and post-contingency actions associated with network configuration shown in Figure 9.24, where each candidate line and backup generating unit has a capacity of 25 MW, and flooding event can affect substation in the right hand side network corridor, causing a double outage event every time that it occurs. The left hand side substation is located in a place where effect of natural hazard is harmless. Demand in both nodes is equal to 25 MW.

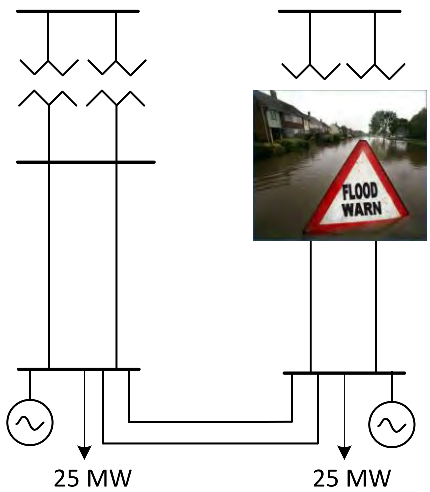


Figure 9.24: Location of demand and entry points together with configuration of candidate infrastructure (i.e. backup generation and candidate lines that can be built in preventive –upfront- or corrective mode)

Cost and reliability data of network infrastructure and further information are as follows:

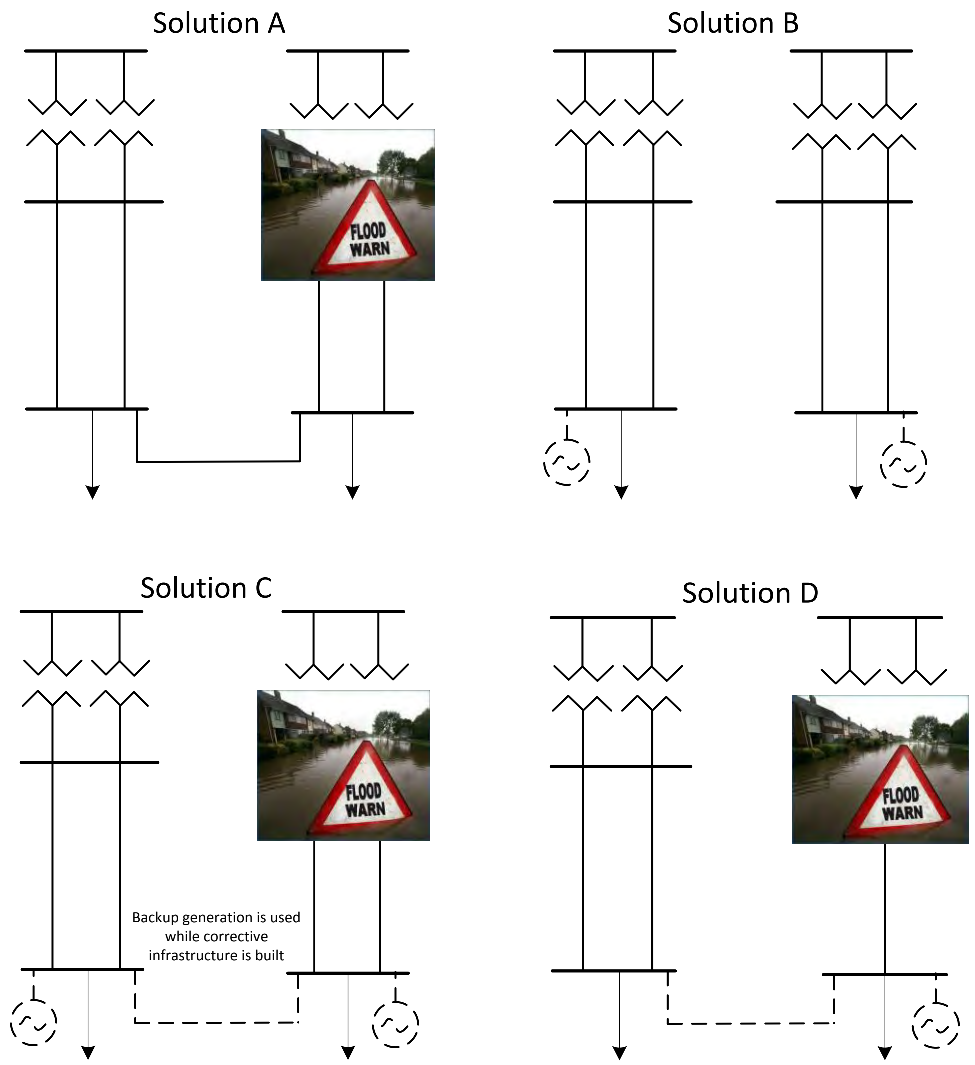
- Energy cost (bought from main system) under normal condition = £50/MWh
- Fuel cost of backup generators = £300/MWh
- Rental fee of backup generators = £5k/MW/event (based on an event of 3 days)
- VoLL = £17,000/MWh
- Investment cost of network = £3,750/yr (for 25 MW)
- Outage rate of lines = 1 occ/yr
- Mean time to repair (MTTR) of lines = 3 days
- Frequency of flooding = 0.1 occ/yr
- Duration of flooding = 30 days
- Construction/deployment time of corrective network investment = 3 days. It is important to stress that there would be many practical factors that would influence the speed at which new transfer capacity could be installed during different HILP events.

Results of the abovementioned base case and those of three more sensitivities are shown in Figure 9.25.

<u>Solution A</u> is that associated with the base case, where no post-contingency actions are needed under any N-1 and N-2 events. Permanent line built between both demand nodes is mainly driven by the need to cover risks of flooding that can affect infrastructure associated with the right-hand side network corridor.

<u>Solution B</u> presents less network infrastructure built (since its cost is increased) and, instead, two backup generating units (one in each demand location) are used as a mitigation measure to reduce risk exposure to double outage events, which are extremely rare since occurrence of flooding has been neglected in this case.

<u>Solution C</u> shows implementation of corrective network investment where flooding event has a lower probability of occurrence (1 occ in 100 years), leading to deployment of a provisional cable (which is less costly than permanent network infrastructure) and 2 backup generating units, which can effectively minimise demand curtailment while transfer cable is deployed.



Cost (k£/yr)	**A**	**B**	**C**	**D**
Network investment	19	15	15	75
Emergency generation (expected)	0	10	24	21
Energy bought (from system)	21,900	21,898	21,898	21,897
Lost load (expected under N-1 and N-2 events)	0	0	0	0

Figure 9.25: Base case solution [A] and sensitivities [B-D] (hard line indicates permanent network infrastructure, while dashed line indicates post-contingency corrective actions)

Finally, Solution D shows a network design associated with costly network investment (e.g. 5 times that of the base case), where although the number of overhead lines has been minimised, topology is such that is robust against all N-1 events (including that driven by floods) and can also deal with N-2 events through backup generation.

Solutions A-D demonstrate that optimum portfolios of pre- and post-fault measures will change accordingly to a number of assumptions and input data.

9.4.4 Conclusions

This study modelled the impact of HILP events. The reliability performance of a test distribution network has been evaluated through time-sequential Monte Carlo simulation. Impacts of HILP events with different severity levels have been studied considering the contribution of emergency generation with different supply rate and preparation time as mitigation measures. The results demonstrate that severe HILP events can lead to significant cost of lost load which may justify development of more resilience network (e.g. undergrounding the overhead network to reduce exposure to adverse weather), supported by provision of fast and high capacity emergency generation, especially during very severe HILP events.

9.5 Summary

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

- Portfolio of technologies, including traditional network and non-network solutions, will not only reduce the total system costs (cost of investments in network assets, availability and utilisation costs of DSR/DG and cost of expected energy not supplied), but could reduce exposure to CMF and HILP events.
- Concept of Conditional Value at Risk can be applied to limit the risk exposure to HILP events – this will result in increase in network investment and/or DSR costs, while reducing the consequences of high impact outages. Conditional Value at Risk (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 modelling developed can be applied).

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. 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.

In the context of developing the future security standards, 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 is particularly relevant for urban networks; related work have been carried out by ENA Urban Reliability

(HILP) working group indicating the importance of reducing the risks associated with HILP for Central Business Districts [106].

- 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 the electricity distribution network in the UK.
- Emergency operation and investment actions to deal with HILP. From the results of case studies, we have learnt that the use of emergency operation and investment actions such as provision of mobile generators, and transfer cables could lessen 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). We have demonstrated that the failure of ICT infrastructure may cause CMF which renders multiple sources (e.g. DSR, special protection scheme that requires communication) providing network services unavailable.

It has been demonstrated via a few illustrative cases that consideration of CMF and HILP will lead to a higher resilient network design with more robust construction, higher degree of network redundancy, and more provision of emergency generators. On the other hand, ignoring CMF and HILP will lead to potentially high exposure to CMF and HILP events which increases the risk of having supply interruptions.

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's parameters (e.g. frequency, the scale of impact) that can be used in the probabilistic approaches.
- The impact of a certain hazard is network specific. For example, the risk of having flood in plateau areas is much lower in comparison with that in lowland areas; impact on urban networks will be different in comparison with the impact on sparse rural networks. Different networks may be exposed to different types of hazards. So the justification of the investment via CBA will be case specific.

In any cases, it is important that all stake-holders have confidence in the process used to identify and assess risk, so that appropriate decisions can be made on its management.

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

10.1 Motivation

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.

The aim of this section is to illustrate concept. Methodology is developed to deal with different consumer choice driven supply continuity. In this case VoLL (as one of the indicators) would vary with time of day, temperature, etc. The key point is to demonstrate that future network design could reflect consumer choices. In this scenario, network charges will reflect the value consumers attribute to continuity of supply (e.g. consumers that value continuity of supply highly will pay larger network charges). In broad terms this is similar to the concept of “triad charges”, some consumers reduce their load during triad periods and this reduces their transmission network charges.

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.

The remainder of this section is organised as follows. Section 10.2 outlines a model of distribution network planning accounting for network failures. Section 10.3 details the developed models of consumers’ preferences and flexibility. Section 10.4 presents case studies demonstrating the benefits of integrating these preferences and flexibility in distribution network planning and operation.

10.2 Distribution network planning model

In the distribution network planning framework, the planner determines the network assets (transformers and lines) to be build or reinforced by minimising the total cost of the network within the planning horizon. This total cost is given by the summation of the annuitized investments costs associated with building / reinforcing assets and the expected annual costs of energy not supplied for the served consumers. This total cost minimisation problem is subject to power flow constraints ensuring that the network operates within its thermal and voltage limits.

Failures of network transformers and lines are modelled by employing Sequential Monte Carlo (SMC) simulation, see section 13.2. Given the Probability Distribution Functions (PDF) of failure occurrences and duration of restoration for these network components, SMC simulation provides the state of each network component (normal operation or failure) at each time step of the planning horizon. Exponential PDF are employed in this study for modelling failure occurrences and duration of restoration.

10.3 Modelling consumers' preferences and flexibility

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 while the second captures their ability to shift their energy requirements in time accounting for the relevant inconvenience costs. These two modelling approaches are detailed in the following sub-sections.

10.3.1 Price-demand functions

The valuation of electricity supply by the consumers is widely expressed in the relevant literature in the form of a "price-demand" function or equivalently "consumers' willingness to pay" function. In the context of this report, this function represents the demand D requested by the consumers for different levels of the scarcity price p (increment in energy price due to failures in the distribution network) or equivalently the scarcity price consumers are willing to pay for different levels of their electrical demand. The interception of the curve at the x-axis represents the consumers' baseline demand D_b, i.e. the demand consumers request when there is no failure in the network and the scarcity price is zero. The interception at the y-axis represents the value of lost load (VoLL), i.e. the maximum scarcity price consumers are willing to pay for a unit of served demand during a failure. The product of the scarcity price times the served demand determines the DUoS charges incurred by the consumers to secure supply during failures.

Under the traditional distribution network planning paradigm, this function is assumed constant and equal to the VoLL, as illustrated in Figure 10.1, implying that the scarcity price consumers are willing to pay for an additional unit of demand is equal to the VoLL irrespectively of their demand level. The shaded area represents the cost or disutility incurred by the consumers due to energy not supplied for a given level of demand D. This assumption neglects a well-known concept of microeconomics, namely the reduction of demand with an increasing price. This concept expresses the fact that consumers do not value identically every unit of energy. The first units of energy, serving critical loads such as lighting and heating, are valued more than additional units of energy serving non-critical loads the operation of which can be postponed such as washing machines and dishwashers.

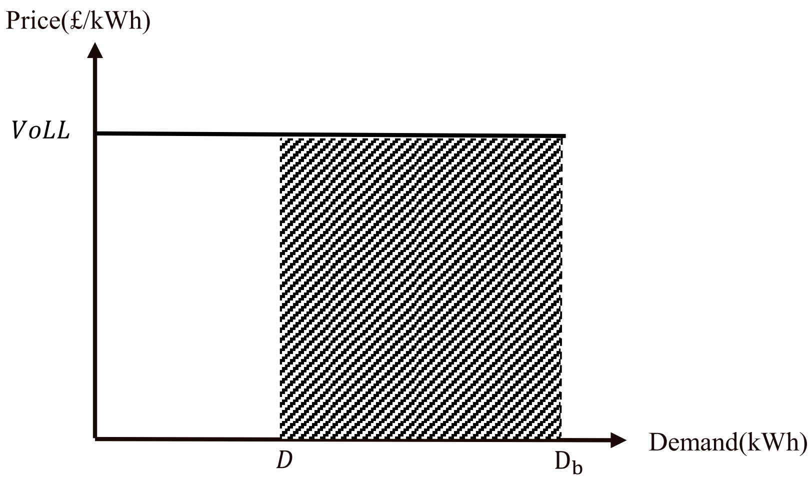


Figure 10.1: Constant price-demand function

This decreasing nature of energy valuation can be represented in the simplest form as a linear decreasing function, as illustrated in Figure 10.2. The shaded area represents again the cost of energy not supplied.

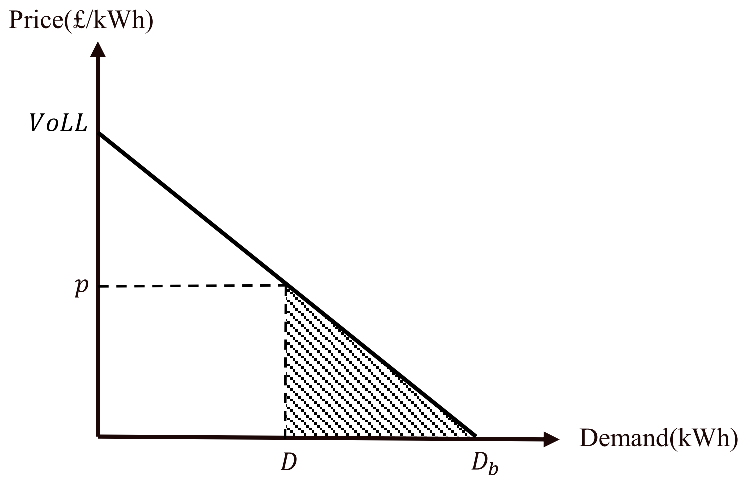


Figure 10.2: Linear decreasing price-demand function

A more representative model of consumers' behaviour needs to take into account the different price-demand relationship for different sets of consumers' loads. This property can be represented as a piecewise linear decreasing function, as illustrated in Figure 10.3. The first section of the function represents the price-demand relationship for critical loads, while the second section represents the price-demand relationship for non-critical loads.

Figure 10.3 illustrates two different price-demand functions, corresponding to two consumers with different flexibility levels. For the same level of the scarcity price p, the consumer with high flexibility requests lower demand and is rewarded for this lower security of supply through lower DUoS charges. The shaded area corresponds to the extra DUoS charges incurred by the consumer with lower flexibility.

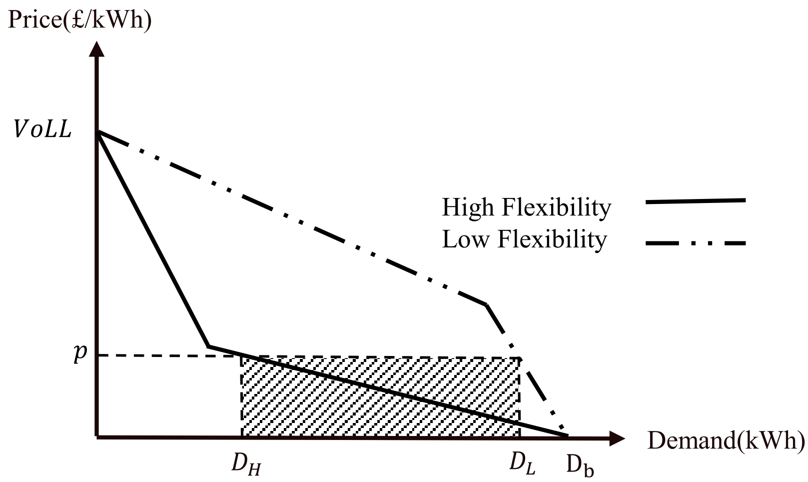


Figure 10.3: Piecewise linear decreasing price-demand functions

10.3.2 Modelling time shifting of demand

Although the above linear and piecewise linear price-demand functions constitute a more accurate representation of consumer's behaviour than the traditional assumption of a constant function, they still cannot capture the ability of some loads to shift their energy requirements in time. This characteristic is associated with either the consumers' flexibility to reschedule the operation of some appliances (such as washing machines and dishwashers) or the explicit storage elements of certain loads (such as hot water tanks of water heaters and battery of electric vehicles).

In order to capture this time shifting ability, a new model has been developed. In this model, the demand of a consumer with shifting capability at a time period t can be reduced (implying that demand is shifted from t to another period) or increased (implying that demand is shifted from another period to t). It is assumed that demand shifting is energy neutral (i.e. the total size of demand reductions is equal to the total size of demand increases) within the time window defined by the start of an outage and 24 hours after the end of it. The cost of consumers' inconvenience for each unit of energy shifted is denoted by VoSL (value of shifting load) and defines the level of time-shifting flexibility of each consumers (a high VoSL implies low time-shifting flexibility and vice-versa).

10.4 Case studies

10.4.1 Test system

A simple two-node network is examined, corresponding to the primary and secondary of a 33/11 kV substation, as illustrated in Figure 10.4. Demand at the substation secondary has a peak of 20 MW and a daily demand profile presented in Figure 10.5 and assumed constant throughout the planning horizon.

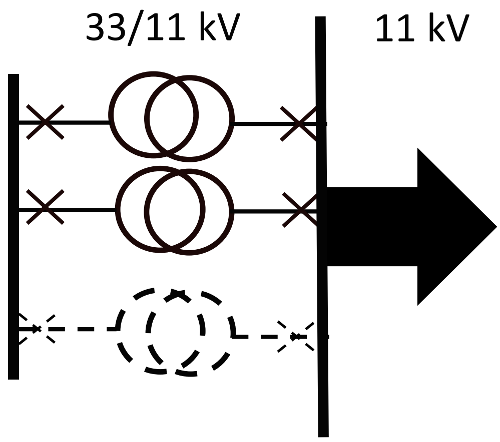


Figure 10.4: Test system

The relationship between the total transformers' capacity of the substation and the peak demand determines the level of security provided by the network. For example, a substation with two transformers of 10 MW each provides N-0 security, as failure of any part of the substation capacity results in demand not supplied; a substation with two transformers of 20 MW each provides N-1 security, as continuity of supply is guaranteed even in the event of failure in one of the transformers.

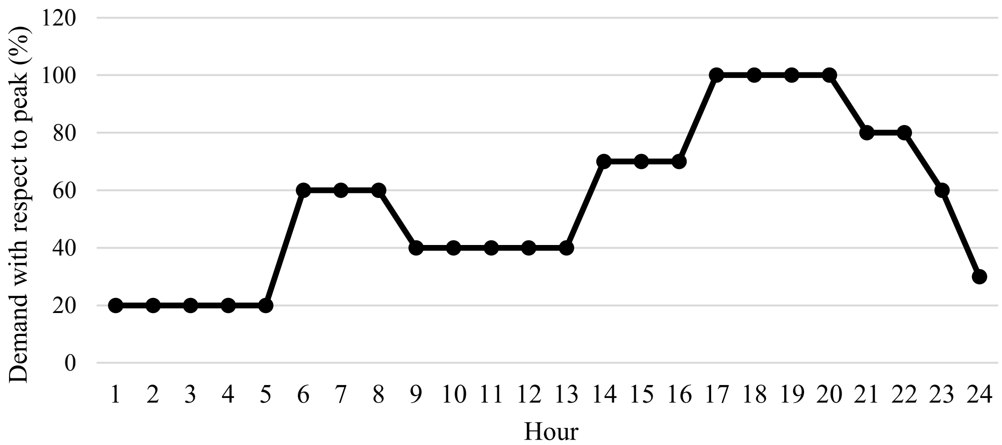


Figure 10.5: Normalised daily demand profile

Both demand flexibility models are investigated in the case studies. Regarding the price-demand function model, different shapes of this function are considered in the studies to model different consumers' flexibility levels, as illustrated in Figure 10.6. 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 VoSL are considered to represent different levels of time-shifting flexibility.

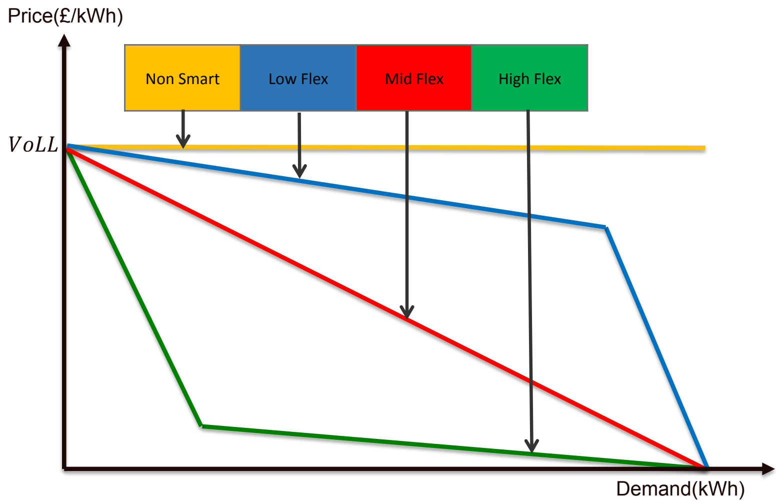


Figure 10.6: Price-demand functions investigated in the case studies

Finally, three different scenarios are considered regarding the reliability of the substation transformers, in terms of the average failure rate λ_1 and the average duration of restoration λ_2, presented in Table 10.1.

Table 10.1: Network reliability scenarios examined in the case studies

	Low reliability	Medium reliability	High reliability
Failure rate, λ_1	0.2 f/year	0.2 f/year	0.02 f/year
Restoration rate, λ_2	5 days	1 day	1 day

10.4.2 Impact of consumers' preferences on network reinforcement decisions

In this section we assume that the substation with two transformers is in place and explore whether the substation should be reinforced by adding a third transformer of the same size (Figure 10.4). Different scenarios are considered regarding the level of security (translated to the capacity of each of the substation's transformers) and it is assumed that the annuitized cost of the third transformer is *£100,000/year*. Two different case studies are examined: the first represents consumers' flexibility in the form of (non-constant) price-demand functions (Section 10.3.1), neglecting their ability to shift their energy requirements in time, while the second accounts for this ability (Section 10.3.2), assuming that their price-demand function is constant and equal to the VoLL.

Regarding the first case study, Table 10.2 presents the expected annual costs of energy not supplied without a third transformer in place for the different scenarios regarding network reliability, level of security and price-demand function of the served consumers, assuming that the VoLL is equal to £17,000/MWh (as discussed in section 2). Given that the costs of energy not supplied are negligible with a third transformer in place, the network planner will decide to build the latter if its investment cost is lower than the costs of energy not supplied without this third transformer in place. Scenarios where this transformer addition is justified are indicated in red colour in Table 10.2.

Table 10.2: Expected annual costs of energy not supplied without network reinforcement for different consumers' price-demand functions

Network Reliability	Security Level	Non-smart	Low Flex	Mid Flex	High Flex
Low	N-0.75	3.4E+05	8.1E+04	2.1E+04	3.4E+03
	N-0.5	7.5E+05	3.1E+05	8.8E+04	1.4E+04
	N-0.25	1.4E+06	6.9E+05	2.3E+05	3.6E+04
	N-0	2.4E+06	1.4E+06	5.0E+05	7.9E+04
Medium	N-0.75	6.7E+04	1.6E+04	4.1E+03	6.8E+02
	N-0.5	7.9E+04	4.5E+04	1.3E+04	2.0E+03
	N-0.25	2.8E+05	1.4E+05	4.4E+04	6.8E+03
	N-0	4.9E+05	2.8E+05	9.8E+04	1.5E+04
High	N-0.75	3.3E+04	7.7E+03	2.0E+03	3.2E+02
	N-0.5	7.2E+04	3.0E+04	8.4E+03	1.3E+03
	N-0.25	1.4E+05	6.5E+04	2.1E+04	3.4E+03
	N-0	2.3E+05	1.3E+05	4.8E+04	7.4E+03

For every network reliability and security level scenario, a higher consumers' flexibility (i.e. lower valuation of energy supply) 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 substation reinforcement. This value of consumers' flexibility is increased with lower network reliability and level of security, as the energy not supplied is increased. An alternative way to demonstrate this benefit of demand flexibility in avoiding / postponing network reinforcement is the quantification of the minimum VoLL at which the addition of the third transformer is justified (Table 10.3). This value is increased with higher consumers' flexibility, as well as higher network reliability and security level.

Table 10.3: 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

Table 10.4 and Table 10.5 present the same results in the second case study for different scenarios regarding the value of shifting load (VoSL). A lower VoSL (higher time-shifting flexibility) results in lower costs of energy not supplied as it enables the consumers to shift their demand requirements during failures towards periods of normal operation (Table 10.4). Therefore, a higher time-shifting flexibility results in a higher minimum VoLL for which addition of a third transformer is justified (Table 10.5).

Table 10.4: Expected annual inconvenience costs (including costs of energy not supplied and energy shifted) without network reinforcement for different values of VoSL

Network Reliability	Security Level	VoSL=100%VoLL	VoSL=10%VoLL	VoSL=1%VoLL	VoSL=0.1%VoLL
Low	N-0.75	3.4E+05	3.5E+04	3.5E+03	3.5E+02
	N-0.5	7.5E+05	7.6E+04	7.8E+03	1.0E+03
	N-0.25	1.4E+06	1.5E+05	1.8E+04	5.1E+03
	N-0	2.4E+06	1.1E+06	9.3E+05	9.1E+05
Medium	N-0.75	6.7E+04	8.4E+03	2.2E+03	1.6E+03
	N-0.5	7.9E+04	1.8E+04	4.4E+03	3.1E+03
	N-0.25	2.8E+05	3.8E+04	1.3E+04	1.1E+04
	N-0	4.9E+05	2.0E+05	1.7E+05	1.7E+05
High	N-0.75	3.3E+04	3.3E+03	3.3E+02	3.3E+01
	N-0.5	7.2E+04	7.5E+03	1.1E+03	4.5E+02
	N-0.25	1.4E+05	1.9E+04	7.1E+03	5.9E+03
	N-0	2.3E+05	1.0E+05	8.7E+04	8.6E+04

Table 10.5: Minimum VoLL (in £/MWh) justifying reinforcement for different values of VoSL

Network Reliability	Security Level	VoSL=100%VoLL	VoSL=10%VoLL	VoSL=1%VoLL	VoSL=0.1%VoLL
Low	N-0.75	8,800	85,000	850,000	8,500,000
	N-0.5	3,400	33,600	326,900	2,550,000
	N-0.25	1,500	14,200	118,100	416,700
	N-0	700	1,500	1,800	1,900
Medium	N-0.75	44,400	354,200	1,352,300	1,859,400
	N-0.5	32,300	141,700	579,500	822,600
	N-0.25	7,600	55,900	163,500	193,200
	N-0	3,500	8,500	10,000	10,000
High	N-0.75	90,200	901,500	9,015,200	90,151,500
	N-0.5	35,400	340,000	2,318,200	5,666,700
	N-0.25	15,200	111,800	299,300	360,200
	N-0	7,400	17,000	19,500	19,800

10.4.3 Impact of consumers' preferences on DUoS charges

In this section we assume that the substation is not yet built and the planner determines the optimal capacity of each of its two (identical) transformers. The customers do not exhibit time shifting flexibility and they are equally divided to three categories, according to the extent of their flexibility, represented by their price-demand function.

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Figure 10.7 presents the expected annual DUoS charges for a customer of each of the three categories, assuming that the charges for an average consumer are equal to £100.

These results demonstrate an equitable outcome; 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.

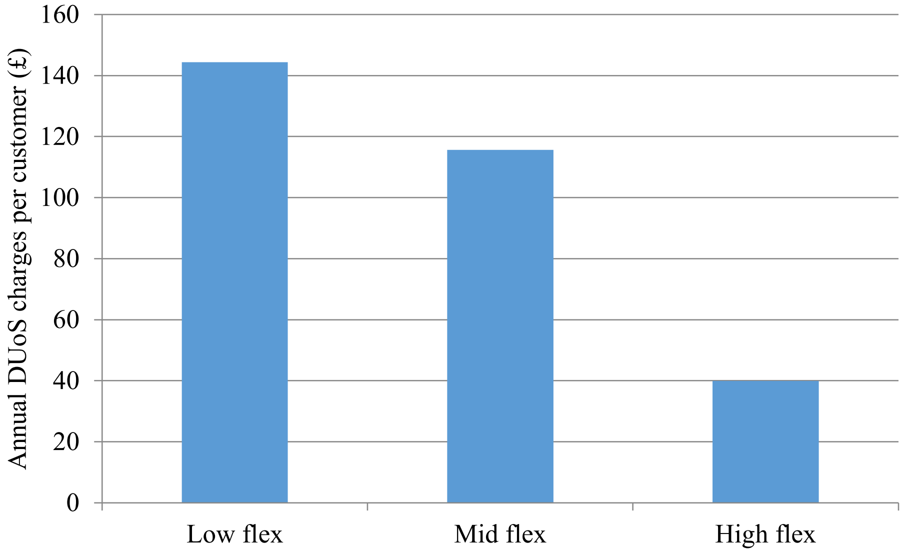

Figure 10.7: Annual DUoS charges for consumers with different price-demand functions

This is the network charges when we have the reliable network with N-0 security (transformers with capacity of 10,000). The calculation is based on annual expected payment of all consumers in each group. The payment calculation is based on the served demand times price, where price is obtained from the Lagrange multiplier associated to the constraint on available capacity of transformers. The ratio of between these consumer groups is used as the index of their network usage and the following DUoS are obtained:

- DUoS% of low flexible = its own charges/overall charge = 58.8k/122.1k=48%
- DUoS% of mid flexible = its own charges/overall charge = 47k/121k=38%
- DUoS% of high flexible = its own charges/overall charge = 16.2k/121k=13%.

Now let’s assume that the average charge per consumer is £100, then the total payment of three consumers, one per each group, is £300. Therefore:

- DUoS of low flexible = 48% X 300 = £144
- DUoS of mid flexible = 38% x 300 = £114
- DUoS of high flexible = 13% x 300 = £39.

10.5 Conclusions

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 significant opportunity for smarter load 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.

In this context, the current distribution operation and planning framework does not properly account for the preferences and flexibility of the consumers. The valuation of electricity supply is assumed identical for every unit of energy supplied, irrespectively of the specific service it provides to the consumer. The value of energy consumed for critical loads (e.g. lighting, computers etc.) is assumed equal to the valuation of energy consumed for non-critical loads, the operation of which can be shifted in time (e.g. wet appliances). Furthermore, during an outage, partial shedding of each consumer's demand is not possible; their whole demand is either served or shed, implying low reliability levels. In order to avoid network overloading during such conditions, a portion of the consumers is completely disconnected from the network, implying unfair treatment of different consumers. Finally, the ability of certain consumers to shift in time their energy requirements is not taken into account. As a result of the above paradigm, distribution use of system (DUoS) charges are based on long-term socialised impacts of consumers' demand on the network and do not recognise the differentiated impacts of individual consumers' choices.

Building on roll-out of smart metering, this section outlined a novel framework for 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 substation 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 non-critical loads during an outage, in contrast to the traditional framework leading to complete shedding of some consumers' demand.

11 LONG-TERM NETWORK PLANNING

Electricity demand is expected to increase in the long term due to the connection of new consumers and the envisaged electrification of transport and heat sectors. In addition, a lot of assets are approaching the end of their useful life, driving the need for replacements. These factors are expected to drive the reinforcement and development of the electricity networks in the future. Modelling is the same as in Section 2. Assumption is that the network would have sufficient capacity and just additional connections are needed to increase redundancy.

Network losses are an important factor to be considered in planning the capacity and design of future distribution networks. Previous work [157] demonstrated that the capacity of distribution network should be significantly larger that the peak demand requirements given that the savings in losses exceed the extra cost of oversizing the network.

For example, previous studies have shown that an optimally sized LV cable, considering the RIIO-ED1 capitalisation guidelines with 3.5% discount rate and up to 45-year lifetime, 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 8-14% of its thermal rating. 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 11.1. It should be pointed out that present P2/6 peak loading, other than for LV, is typically 50%.

Table 11.1: 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

As the loss-inclusive network design would provide significant spare capacity, this may be used to improve security of supply at low costs through increasing network connectivity. In the following sections, we describe the results of our studies looking at alternative design philosophies of distribution networks at various voltage levels, with the objective to determine the optimal design and level of redundancy (or security) taking into account the significantly increased capacity of future networks. The cost of improving the network design will be balanced against the associated benefits using the CBA framework described in Appendix A.

The objective of this section is to determine the optimum redundancy levels for distribution networks in the long term. In particular, it attempts to answer the question whether the future HV and LV networks should continue to be designed at N-1 and N-0 security levels, respectively, and whether there is a case for enhancing the security beyond N-1 for HV and beyond N-0 for LV, given that future network capacity should be significantly increased as mentioned above. The section also investigates the economically efficient EHV and 132 kV network design.

11.1 LV Network Design

A range of studies using Monte Carlo simulation and analytical approaches, see sections 13.2 and 13.5 respectively, have been carried out to determine the long-term economically efficient LV network design, looking at a range of deterministic security levels such as N-0, N-1 and 'N-1.5'. Degree of redundancy is denoted by N-x. In this case network topology is main factor while in Section 2 it is loading. A generic Low Voltage (LV) system shown in Figure 11.1 is used to evaluate the performance of various configurations with different levels of redundancy in order to determine the optimal configuration producing the least-cost solution. The network configuration coloured in blue represents the network without any redundancy (N-0). In this configuration, a loss of one circuit component will result in a loss of supply for the entire LV feeder. 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 as long as the fault is not the at distribution transformer. It is important to highlight that at LV there is only one distribution transformer per substation while there are two or more transformers per HV substation. This has been modelled accordingly in the studies.

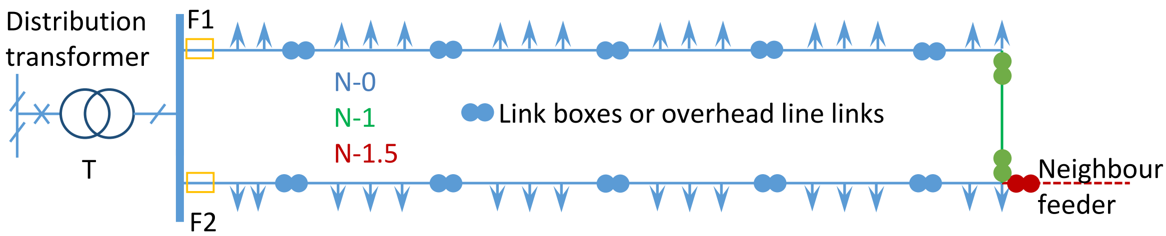

Figure 11.1: A generic LV network system with different configurations to provide certain levels of security of supply

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 as long as the outages occur at different feeders. The 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 11.2 shows the assumptions on reliability and cost parameters used in the studies. The key parameters that have been varied as part of the sensitivity studies are the failure rate, mean-time-to (MTT) Restore, MTT Repair, network loading, network cost (assumed proportional to section length), and VoLL. Different sets of parameters are used to develop high and low circuit availability scenarios for underground cables and overhead lines.

Table 11.2: Reliability parameters for LV studies

Parameter	Value
Type of network	Overhead and underground cables
Feeder peak demand (kW)	10, 50 and 100
Failure rate (%/km.year)	10 and 50
MTT Restore (h)	3, 4 and 8
MTT Repair (h)	4 and 8
Section length (km)	0.75
VoLL (£/MWh)	17,000 and 34,000
Cost	Link boxes: £1.5k Line links: £0.75k

Table 11.3 and Table 11.4 shows the results of the study for LV overhead and underground networks, respectively. The table contains the optimal long-term redundancy levels for different LV network constructions, failure rates, MTT restore and repair, and feeder peak loadings. The results from the table should be interpreted as follows: N-0/N-0:1 means that N-0 redundancy is the optimal redundancy level if the VoLL is £17,000/MWh while for the VoLL of £34,000/MWh the optimal redundancy level is between N-0 and N-1 depending on the cost of new link boxes or line links. The variation of the costs of link boxes and line links investigated in the study was ±20% of the values specified in Table 11.2.

The results demonstrate that the N-0 design is economically efficient for overhead networks with 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. 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 the greater VoLL.

Table 11.3. 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 11.3 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 11.4. 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 11.4demonstrate that for underground networks the economically efficient design is predominantly N-1, as it is expected to typically supply higher levels of load. LV network may continue to operate radially but may be reconfigured when needed (post-fault).

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.

11.2 HV Network Design

A generic High Voltage (HV) system shown in Figure 11.2 is used to evaluate the performance of various configurations with different levels of redundancy in order to determine the optimal configuration producing the least-cost solution. A range of studies have been carried out to determine the long-term economically efficient HV network design looking at a range of deterministic security levels such as N-0, N-1, 'N-1.5', 'N-1.75', and N-2 as shown in Figure 11.2.

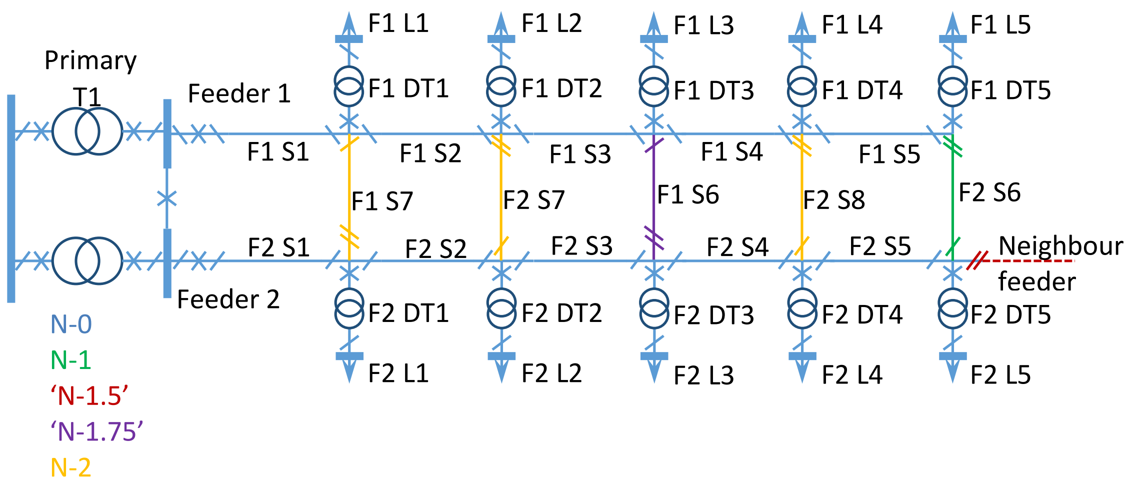

Figure 11.2: A generic HV network system with different configurations to provide certain levels of security of supply

The starting HV network topology is radial (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 source of supply is arranged. Connecting the feeders at their ends, as shown in green, and keeping one of the switchgears open allows supplying some of the load affected in the case of a fault at one feeder from the remaining feeder. 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 the whole 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 double 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 normally open connection, 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 last considered configuration, obtained by adding three normally open point (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.

Table 11.5 shows the assumed reliability and cost parameters for the HV network used in the study. Key parameters that have been varied in sensitivity studies are the failure rate, MTT Restore, MTT Repair, network loading, network cost (assumed proportional to section length) and VoLL. Different sets of parameters are used to represent high and low circuit availability scenarios for underground cables and overhead lines.

Table 11.5: Reliability parameters for HV studies

Parameter	Value
Type of network	Overhead and underground cables
Feeder peak demand (kW)	500, 2500 ,and 5000
Failure rate	OHL 1km: 5% and 20% UGC 1km: 2% and 10%
MTT Restore (h)	3 and 12
MTT Repair (h)	24 and 120
Section length (km)	0.25 and 1
VoLL (£/MWh)	17,000 and 34,000
Cost	OHL 1km: £19k UGC 1km: £101k PM switchgear: £2.9k GM switchgear: £8k

Table 11.6 to Table 11.10 show the *breakeven length* of NOP sections for overhead and underground feeders and for different loading conditions. The breakeven length of NOP sections is obtained by calculating the benefit of investing in NOP sections calculated as savings in EENS and then determining the length of the section that would result in an investment cost equal to the benefit of the section.

In order to illustrate this approach, we look at the breakeven lengths of NOP sections for overhead feeders with failure rate 20%/km.year, automated fault isolation, and mean time to restore and repair 12 and 120 hours respectively (Table 11.7). The incremental benefit is obtained from the incremental savings in EENS due to security improvement, multiplied by the VoLL. For instance, as shown in Table 11.7, for the case with a section length of 0.25 km, the potential benefit of improving the security level from N-0 to N-1 is £94,306/year if the VoLL is £17,000/MWh. Depending on the assumed cost of new overhead lines and switchgear, the length of the NOP section should be less than 18.3 km in case of high asset costs, or 27.5 km in case of low asset costs, in order for the N-1 configuration to be more cost-efficient than N-0.

Table 11.6: Breakeven length of NOP sections for which cost of upgrade is the same as potential benefit for HV overhead feeders for different failure rate and mean time to restore and repair and when each feeder peak demand is 500 kW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
5	3/24	0.25	N-1	£1,181	0.2	0.1	£2,362	0.6	0.3
		1	N-1	£4,715	1.2	0.8	£9,430	2.6	1.7
	12/120	0.25	N-1	£4,758	1.3	0.8	£9,517	2.7	1.7
		1	N-1	£18,861	5.4	3.6	£37,722	10.9	7.2
20	3/24	0.25	N-1	£4,715	1.2	0.8	£9,430	2.6	1.7
		1	N-1	£18,723	5.4	3.5	£37,446	10.9	7.2
	12/120	0.25	N-1	£18,861	5.4	3.6	£37,722	10.9	7.2
		1	N-1	£72,719	21.2	14.1	£145,437	42.5	28.3
			N-1.5	£2,062	0.5	0.3	£4,124	1.1	0.7

Given that distances between distribution transformers in this network are on average 0.25 km, similar length is assumed to be required for a new NOP section and hence the net benefit can be derived from moving to the N-1 configuration given that the required length is shorter than the breakeven length. In case of 1 km average distances between distribution transformers the assumption is that NOP section would be also 1 km. Increasing further the level of redundancy to N-1.5 is not economically justifiable considering that the potential benefit of the N-1.5 configuration over N-1 is smaller than the cost of the two additional switchgears required to implement the N-1.5 configuration. From this exercise, it can be concluded that the N-1 configuration is the optimal and economically efficient design for this case. This approach is then applied for other cases with different section lengths, failure rates, etc. It should be pointed out that switching duration does not impact the breakeven length of NOP sections significantly and therefore conclusions derived here apply for both automated fault isolation and manual switching. It is further observed that the time required for feeder reconfiguration does not impact the results significantly.

Table 11.7 shows the breakeven length of the NOP section for which the cost of upgrade is the same as the potential benefits, calculated for overhead feeders and for different failure rates and mean times to restore and repair, for a feeder peak demand of 500 kW. The configurations not relevant for the conclusion are omitted from the table. For example, for the failure rate of 5%/km.year, MTTR (restore/repair) of 3/24 hours and section length of 0.25 km, the incremental benefit of the N-1 configuration compared to N-0 is £1,181/year and £2,362/year for the VoLL of £17,000/MWh and £34,000/MWh, respectively. The cost of two switchgears is deducted from this benefit and the remaining benefit is divided by the unit cost of the conductor. The result is the length of the NOP section for which the total cost of N-0 and N-1 designs is the same, and is denoted as breakeven length. If the actual NOP section length is lower than the breakeven length, the economically efficient configuration is N-1, otherwise it is N-0. For sensitivity purposes it is assumed that the asset costs can vary ±20% from the values given in Table 11.2.

For the purpose of this exercise it is assumed that the actually required NOP section length would be the same as the length of the main feeder sections. Breakeven NOP section lengths printed in blue denote that the section length is shorter than the breakeven length, while red denotes the opposite. For the network with a failure rate of 5%, MTTR of 3/24 and section length of 0.25 km, assuming the VoLL is £17,000/MWh, the breakeven length of the NOP section, ranging between 0.1 and 0.2 km depending on the assumed asset costs, is always smaller than the feeder section length. It is therefore concluded that N-0 is the economically efficient design in this case. However, if the VoLL is £34,000/MWh, the breakeven length of NOP section is between 0.3 and 0.6 km, and both of these values are greater than the assumed main feeder section length, suggesting that N-1 is the economically efficient solution. In the case of 1 km section length but with the same failure rates and MTTR, the breakeven length is between 0.8 and 1.3 km if VoLL is £17,000/MWh. This means that for a higher level of new asset cost the economically efficient solution is N-0, while for a lower asset cost one should follow the N-1 design. For all other cases in Table 11.7 the economically efficient solution is N-1 design.

Table 11.7 shows the breakeven lengths of NOP sections for HV overhead feeders where feeder peak demand is 2,500 kW. For all considered combinations it is at least N-1 configuration that is the most efficient. For relatively unreliable HV overhead networks and with section lengths of 1 km the N-1.5 design is economically efficient if (i) VoLL is £34,000/MWh, or (ii) VoLL is £17,000/MWh and asset cost is low. The incremental benefit is linearly dependent on feeder loading, which can be verified by comparing these values with those from Table 11.6.

Table 11.7: Breakeven length of NOP sections for which cost of upgrade is the same as potential benefit for HV overhead feeders for different failure rate and mean time to restore and repair and when each feeder peak demand is 2,500kW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
5	3/24	0.25	N-1	£5,904	1.6	1.0	£11,808	3.3	2.2
		1	N-1	£23,574	6.8	4.5	£47,148	13.7	9.1
	12/120	0.25	N-1	£23,792	6.8	4.5	£47,583	13.8	9.2
		1	N-1	£94,306	27.5	18.3	£188,611	55.2	36.8
20	3/24	0.25	N-1	£23,574	6.8	4.5	£47,148	13.7	9.1
		1	N-1	£93,616	27.3	18.2	£187,231	54.8	36.5
	12/120	0.25	N-1	£94,306	27.5	18.3	£188,611	55.2	36.8
		1	N-1	£363,594	106.6	71.0	£727,187	213.2	142.1
		1	N-1.5	£10,310	2.9	1.9	£20,621	5.9	3.9
			N-1.75	£2,474	0.6	0.3	£4,947	1.3	0.8

Table 11.8 shows the breakeven length of NOP sections for HV underground feeders where the feeder peak demand is 2,500 kW. The key difference between underground and overhead networks in terms of the breakeven length of NOP sections arises from the fact that underground network is generally more expensive then overhead. From Table 11.5 the underground cable is about five times more expensive and the two switchgears are more than five times more expensive than for an overhead line. On the other hand, the underground network generally has greater availability. In underground networks with a failure rate of 2%/km.year, MTTR 3/24 hours and section length of 0.25 km, the economically efficient design is N-0 given that EENS savings (£2,363 and £4,725/year for VoLL of £17,000/MWh and £34,000/MWh, respectively) are not sufficient to even cover the cost of switchgears for VoLL of £17,000/MWh. For the same failure rate and section length, but assuming that the restoration time cannot be practically reduced to less than 12 hours, while assuming the VoLL is £34,000/MWh, the N-1 configuration emerges as the most efficient one for lower asset costs.

In summary, for relatively low failure rates the economically efficient design is N-0 if (i) VoLL is £17,000/MWh, or if (ii) VoLL is £34,000/MWh in short networks where the cost of new assets is towards the top of the considered range. For all other considered combinations the economically efficient design is N-1. The incremental benefit again increases proportionally to the increase of peak demand. Given that the highest considered failure rate of underground networks is half of that of overhead networks and that the underground network is more expensive to build, there are no economically efficient designs observed beyond N-1.

Table 11.8: Breakeven length of NOP sections for which cost of upgrade is the same as potential benefit for HV underground feeders for different failure rate and mean time to restore and repair when each feeder peak demand is 2,500 kW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	3/24	0.25	N-1	£2,363	0.1	0.0	£4,725	0.4	0.2
		1	N-1	£9,443	0.9	0.6	£18,886	2.0	1.3
	12/120	0.25	N-1	£9,534	0.9	0.6	£19,068	2.0	1.3
		1	N-1	£37,998	4.2	2.7	£75,995	8.5	5.6
10	3/24	0.25	N-1	£11,801	1.2	0.7	£23,602	2.5	1.6
		1	N-1	£47,034	5.2	3.4	£94,069	10.5	7.0
	12/120	0.25	N-1	£47,440	5.2	3.4	£94,879	10.6	7.0
		1	N-1	£186,327	21.0	14.0	£372,654	42.2	28.1

Table 11.9 shows breakeven lengths of NOP sections for HV overhead feeders when peak demand is 5,000 kW. As expected, it is at least N-1 configuration that is the most efficient. For relatively low network availability and if VoLL is £17,000/MWh, the economically efficient design is N-1.5 for longer networks. If VoLL is £34,000/MWh, the economically efficient design is N-1.75 for longer networks, while for shorter networks and lower cost of new assets it is the N-1.5 design.

Table 11.9: Breakeven length of NOP sections for which cost of upgrade is the same as potential benefit for HV overhead feeders for different failure rate and mean time to restore and repair and when each feeder peak demand is 5,000 kW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
5	3/24	0.25	N-1	£11,808	3.3	2.2	£23,617	6.8	4.5
		1	N-1	£47,148	13.7	9.1	£94,296	27.5	18.3
	12/120	0.25	N-1	£47,583	13.8	9.2	£95,166	27.8	18.5
		1	N-1	£188,611	55.2	36.8	£377,223	110.6	73.7
20	3/24	0.25	N-1	£47,148	13.7	9.1	£94,296	27.5	18.3
		1	N-1	£187,231	54.8	36.5	£374,462	109.7	73.1
	12/120	0.25	N-1	£188,611	55.2	36.8	£377,223	110.6	73.7
			N-1.5	£1,303	0.2	0.1	£2,606	0.6	0.4
		1	N-1	£727,187	213.2	142.1	£1,454,374	426.6	284.4
			N-1.5	£20,621	5.9	3.9	£41,241	12.0	7.9
			N-1.75	£4,947	1.3	0.8	£9,895	2.8	1.8

Table 11.10 shows the breakeven lengths of NOP sections for underground networks when the peak demand per feeder is 5,000 kW. In virtually all considered configurations the N-1 design is the most economically efficient. The only exception is for short feeders with failure rate of 2%/km.year, MTTR 3/24 hours and high asset cost, where N-0 is the preferred design.

Table 11.10: Breakeven length of NOP sections for which cost of upgrade is the same as potential benefit for HV underground feeders for different failure rate and mean time to restore and repair when each feeder peak demand is 5,000 kW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	3/24	0.25	N-1	£4,725	0.4	0.2	£9,450	0.9	0.6
		1	N-1	£18,886	2.0	1.3	£37,773	4.1	2.7
	12/120	0.25	N-1	£19,068	2.0	1.3	£38,136	4.2	2.7
		1	N-1	£75,995	8.5	5.6	£151,990	17.1	11.4
10	3/24	0.25	N-1	£23,602	2.5	1.6	£47,205	5.2	3.4
		1	N-1	£94,069	10.5	7.0	£188,138	21.2	14.1
	12/120	0.25	N-1	£94,879	10.6	7.0	£189,758	21.4	14.2
		1	N-1	£372,654	42.2	28.1	£745,309	84.5	56.3
			N-1.5	£5,193	0.4	0.2	£10,386	1.0	0.6

Table 11.11 and Table 11.12 show the long-term planning results for an economically efficient degree of redundancy of HV overhead and underground network designs, respectively, for different constructions, section lengths, failure rates, mean times to repair and restore, feeder loading levels and VoLL. For instance, N-1/N-1:1.5 means that the economically efficient degree of redundancy is N-1 if VoLL is £17,000/MWh irrespectively of the asset upgrade costs (range of ±20% is assumed) and if VoLL is £34,000/MWh the economically efficient degree of redundancy is between N-1 and N-1.5 depending on the asset upgrade costs.

Table 11.11: 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 where 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.

Table 11.12: 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 where 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.

Figure 11.3 shows the EENS for different circuit availabilities, degrees of redundancy and section lengths for underground cables when feeder peak demand is 2,500 kW. High circuit availability refers to a failure rate of 2%/km.year for underground cables and a MTT Restore/ Repair (MTTR) of 3/24 hours, respectively; low circuit availability assumes a failure rate of 10%/km.year and a MTTR of 12/120 hours, respectively.

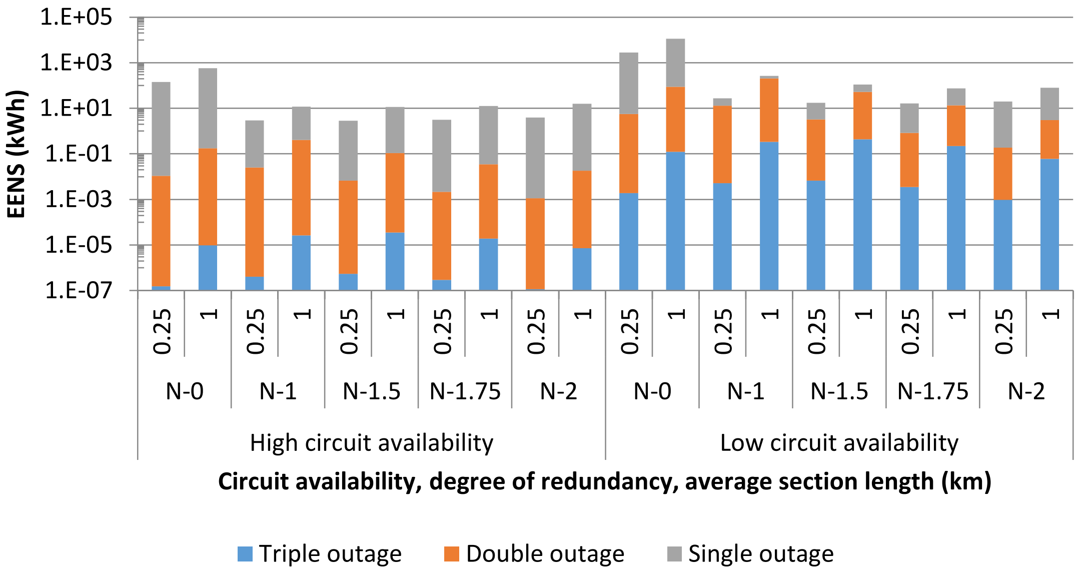

Figure 11.3: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 2,500 kW; logarithmic Y-axis

Figure 11.3 shows the breakdown of EENS resulting from single, double and triple outages of sections of the two-feeder HV network, assuming that automated fault isolation is installed. The vertical axis is plotted in logarithmic scale given that EENS originating from single outages is a strongly dominant component in the N-0 configuration, while the EENS levels originating from double and triple overlapping outages are far smaller. It is assumed that the time required for automated fault isolation is two minutes; therefore, following an outage of a single section, all customers' supply can be restored by reconfiguration within two minutes. There is hence a small EENS originating from single outages beyond an N-0 configuration.

In order to better illustrate the ratios between EENS components, the chart of Figure 11.3 is plotted with a linear vertical axis in Figure 11.4. It is now evident that for N-0 redundancy the EENS component originating from single outages is the dominant one. For low circuit availability level the EENS is about 11.1 and 2.8 MWh/year if average section lengths are 1 and 0.25 km, respectively. For high circuit availability the values are much smaller (e.g. for 1 km section length it is below 0.6 MWh/year). For comparison, 11.1 MWh/year represents about 0.04% of the total annual demand. EENS components originating from double and triple overlapping outages are significantly smaller and are barely visible in Figure 11.4.

Figure 11.5 shows only the components of EENS originating from double and triple overlapping outages. It is immediately obvious that the double outage component is the most significant one. The greatest EENS component value of about 205 kWh/year is observed for low circuit availability in the N-1 network configuration and for average section length of 1 km. This is still about 54 times smaller than the highest value observed in Figure 11.4 (11.1 MWh/year). The respective ratio in case of high circuit availability would be about 1,400 times.

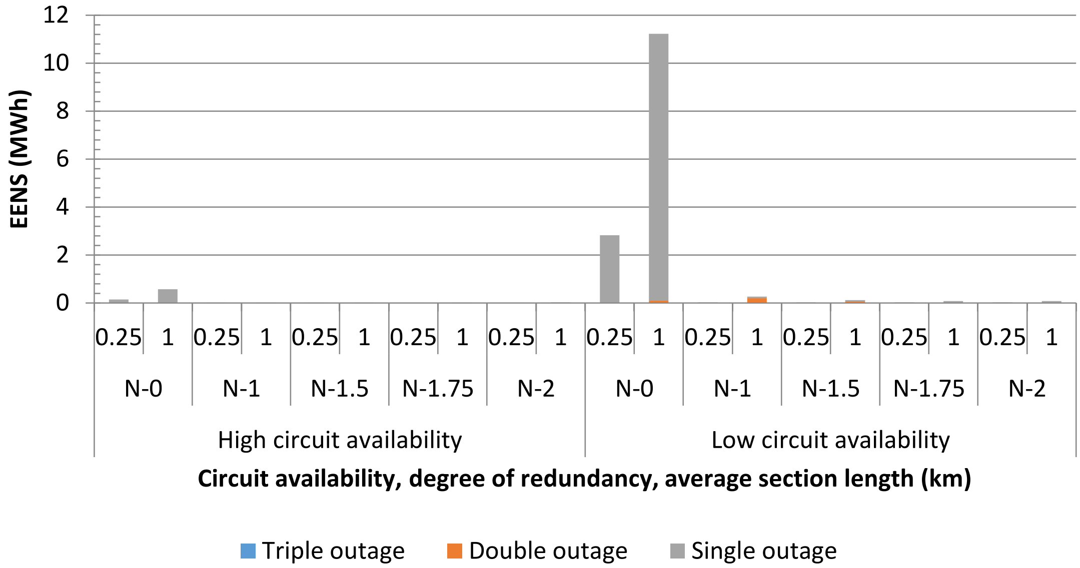

Figure 11.4: EENS per annum for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 2,500 kW; linear Y-axis

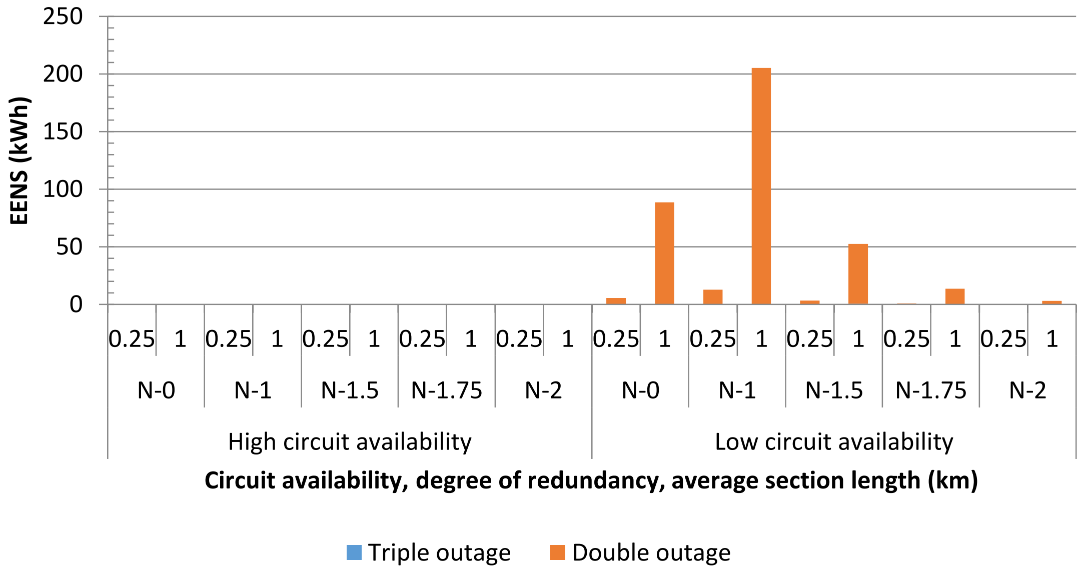

Figure 11.5: N-2 and N-3 components of EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 2,500 kW; linear Y-axis

The double outage component of EENS increases in the N-1 design compared to N-0 given that some double outages in the N-1 design correspond to two single non-overlapping outages in the N-0 design. In designs N-1.5 and beyond the EENS from double overlapping outages is reduced. For the N-2 design the double outage component is significantly lower than for the N-1 design although greater network length results in more overlapping double outages in the N-2 design.

Figure 11.6 shows the EENS when peak demand per HV feeder is 5,000 kW. Values are greater but the trend is the same as in Figure 11.3.

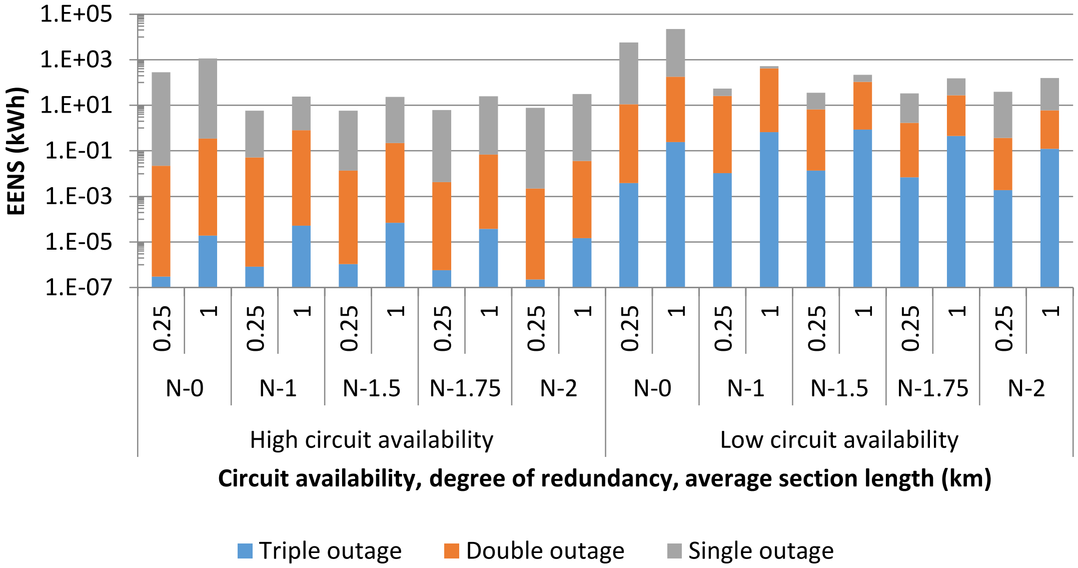

Figure 11.6: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 5,000 kW; logarithmic Y-axis

In order to better illustrate the ratios between EENS components the above chart is also shown with a linear vertical axis in Figure 11.7. It can be seen that the single outage component of EENS is a dominant one if the degree of redundancy is N-0 i.e. for the radial feeder configuration. As expected, the EENS values double compared to the values in Figure 11.4.

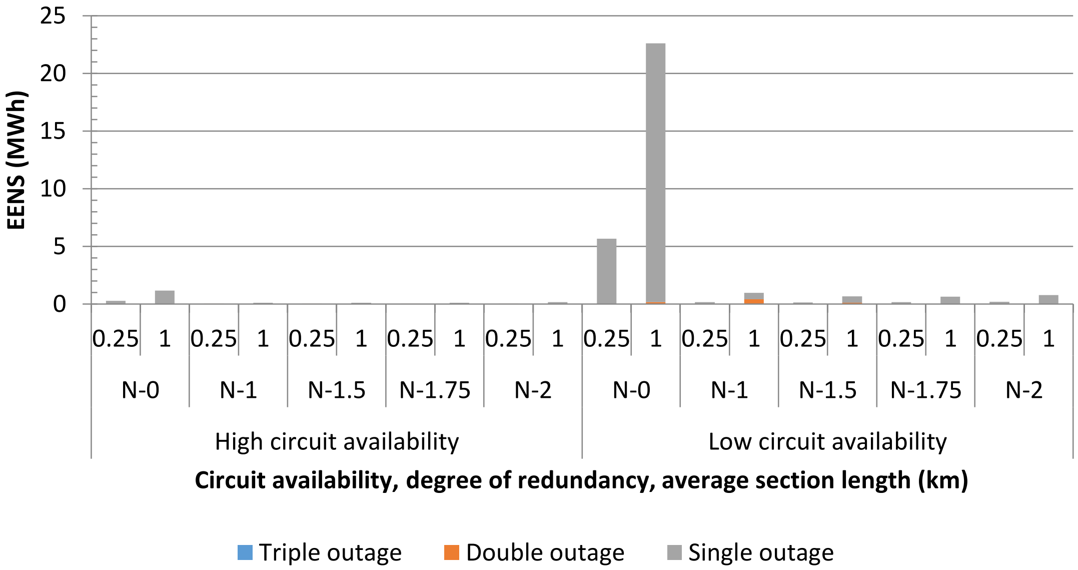

Figure 11.7: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 5,000 kW; linear Y-axis

Figure 11.8 shows only the double and triple overlapping outage components of the EENS.

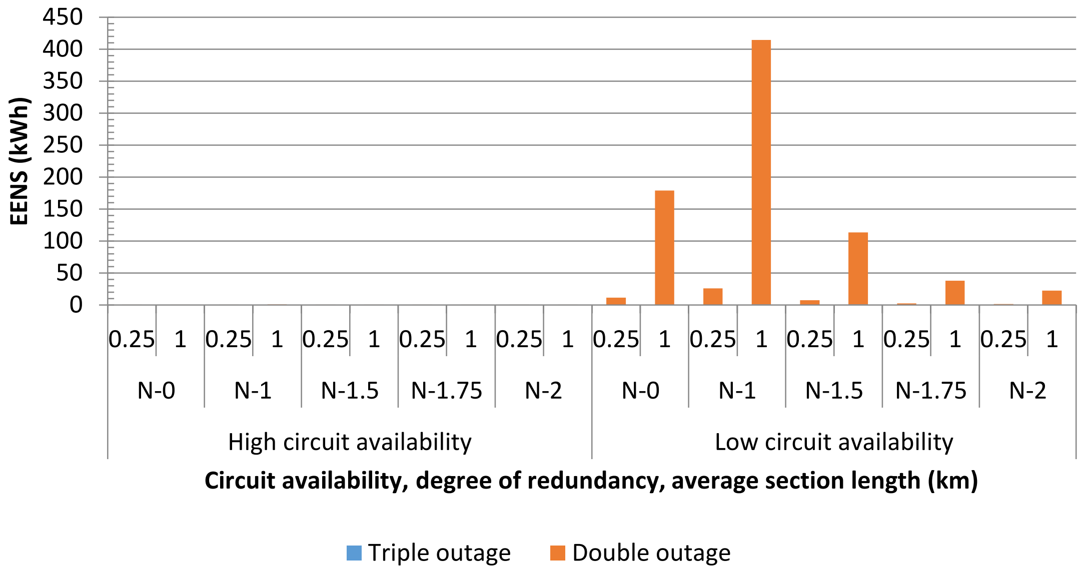

Figure 11.8: N-2 and N-3 components of EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 5,000 kW; linear Y-axis

It can be seen that the double outage component far exceed the triple outage contribution. EENS values are doubled with respect to the values presented in Figure 11.5.

Primary substations

The economically efficient number of transformers per primary substation is investigated by minimising the total cost, consisting of the cost of EENS, and the cost of the substation, including the cost of transformer feeder cables and the repair cost for different levels of redundancy. While methodology is the same, the analysis in Section 2 considers at which degree of redundancy to upgrade substation. Figure 11.9 illustrates a primary substation configuration. The blue part corresponds to a two-transformer substation. Adding the red part will form a three-transformer substation adding both red and green parts will form a four-transformer substation.

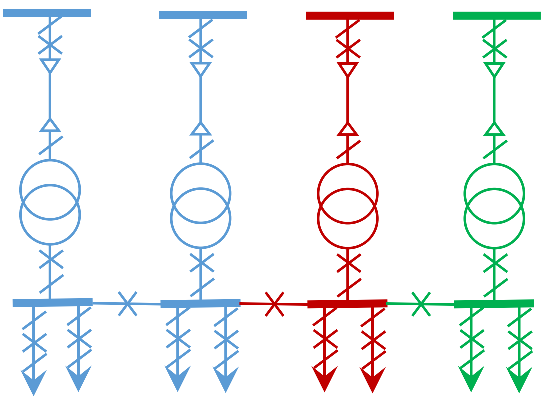

Figure 11.9: Illustration of primary two-transformer (blue), three-transformer (including red part) and four-transformer (including red and green part) primary substations

Ratings of two-, three- and four-transformer primary substations are 2x30MVA, 3x15MVA and 4x10MVA, respectively. Two failure rates of 1 and 10%/year are considered. Their average repair cost is £250k. Two values for the length of each transformer feeder cables (1 and 5 km) and for their failure rate (2 and 8%/km.year) are considered. Their average repair cost is £19.5k. Reliability parameters are summarised in Table 2.10. During an outage a load transfer of 20% is assumed that can be achieved within 10 minutes. It is assumed that mobile generators of 10MW total maximum capacity can be deployed within 4.5 hours on average and with a cost of £1-3.5/kW.day. Maintenance is done once every eight years with an outage duration of 5 days and urgent maintenance close down time of 9 hours.

Table 11.13: Reliability related parameters used in the analysis

Asset	Failure rate (%/unit.year)	Urgent repair time (hours)	Average normal repair time (hours)	**Repair cost (£k)**
EHV underground cable (km)	2-8	24-72	120	19.5
EHV/HV transformer	1-10	192	720	250
EHV circuit breaker	0.87	12	24	
HV circuit breaker	0.55	6	6	
Disconnector	0.1	1.5	12	

The substation cost with two, three and four transformers used in the analysis is given in Table 11.14 for two different lengths of transformer feeder cables. There is a significant difference in the cost of substations with the two transformer substation being the least expensive and the four transformer substation the most expensive.

Table 11.14: Substation cost including cost of cables and switchgears but excluding land cost

EHV/HV Substation	Cost (£k/year)	
	Cable 5 km	Cable 1 km
2x30 MVA	285.9	129.9
3x15 MVA	511.4	194.4
4x10 MVA	718.5	259

The considered peak demand is 30 MW (denoted as degree of redundancy N-1 using the two-transformer paradigm). Given that for all systems the N-1 total emergency rating is the same (30 MW), the sum of emergency ratings of two-, three- and four-transformer systems are 60, 45 and 40 MVA respectively.

Table 11.15 shows the breakeven VoLL comparing designs with two and three or four transformer EHV/HV substation. Breakeven VoLL is derived as ratio of savings in cost of substation, repair and losses by savings in EENS. The upper and lower cell values are the breakeven VoLL for load profile with low and high load factor, respectively.

Table 11.15: Breakeven VoLL comparing design with two and three or four transformer EHV/HV substation

Length of transformer feeder cable (km)	Failure rate	Two to three transformer substation	Two to four transformer substation
1	Min	552,745 416,831	2,837,191 2,109,598
	Max	95,834 70,823	204,462 150,740
5	Min	1,453,186 1,049,153	5,385,444 3,780,522
	Max	159,555 113,456	310,204 219,506

It can be seen that breakeven VoLL is greater for load profile with low load factor, for lower failure rate, and longer transformer feeder cable. In addition, breakeven VoLL between two and four-transformer EHV/HV substation is greater than between two and three-transformer substation. The smallest observed breakeven VoLL of £70,801/MWh is for case two to three-transformer substation with shorter transformer feeder cable, greater failure rate and load profile with high load factor. This means that the two-transformer substation design is the economically efficient design subject to input parameters.

In summary, the three- and four-transformer designs offer savings in cost of interruptions compared with the two-transformer design. The impact of the cost of renting mobile generation is insignificant. Savings in cost of interruptions are not enough to offset the difference in the cost of substations, transformer feeder cables and repair cost increase due to the greater number of components. Hence, the economically efficient solution is a two-transformer design.

11.3 EHV Network Design

11.3.1 Design A

A generic Extra High Voltage (EHV) system shown in Figure 11.10 is employed to evaluate the performance of various configurations with different levels of redundancy in order to determine the optimal configuration producing the least-cost solution. The approach is the same as the approach used in the previous studies. Circuits are added on top of the basic network (N-0) to improve the redundancy level to N-1,'N-1.5', 'N-1.75' and N-2 as described in the previous studies.

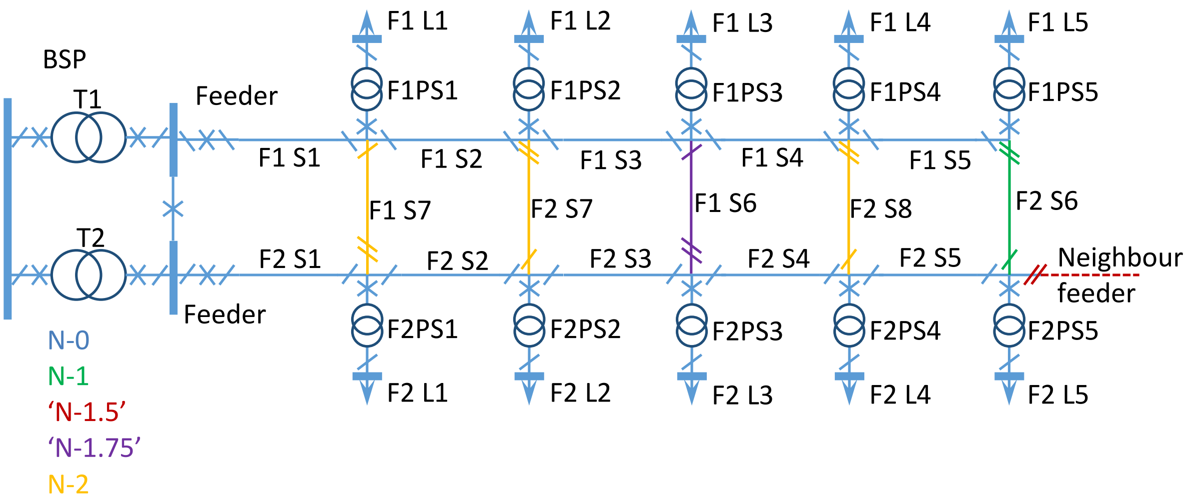

Figure 11.10: A generic EHV network system with different configurations to provide certain levels of security of supply

Table 11.16 shows the reliability parameters used in the studies. The key parameters that have been varied as part of the sensitivity studies are the failure rate, MTT Restore, and MTT Repair. Different sets of parameters are used to develop high and low circuit availability scenarios for both underground cables and overhead lines.

Table 11.16 Reliability parameters for EHV studies (design 1)

Parameter	Value
Type of network	Overhead and underground cables
Transformer peak demand (MW)	7.5 and 20
Failure rate	OHL:2% and 15% UGC: 2% and 8%
MTT Restore (h)	6 and 24
MTT Repair (h)	24 and
Section length (km)	2.4 and 12
VoLL (£/MWh)	17,000 and 34,000
Cost	OHL 1km: £39-46k UGC 1km: £290k Switchgear: £10k

Similarly to the approach used in the HV case study, Table 11.17 to Table 11.20 present the breakeven length of NOP sections for different network constructions and transformer peak demand loadings. These results are used to derive the optimal degree of redundancy.

Table 11.17 shows the breakeven length of NOP sections for which the cost of upgrade is the same with the potential benefits for overhead feeders of different failure rates and mean times to restore and repair and for a 7.5MW peak demand for each transformer. The configurations not relevant for conclusion are omitted from the table. For example, for a failure rate of 2%/km.year, MTTR 6/24 hours and section length of 2.4 km, the incremental benefit of configuration N-1 compared with configuration N-0 is £666k/year and £1,331k/year for a VoLL of £17,000/MWh and £34,000/MWh respectively. From this benefit, the cost of two switchgears is taken out and the remaining benefit divided by the unit cost of conductors results in the length of the NOP section for which the total costs of N-0 and N-1 designs are the same, denoted as breakeven length. If the actual NOP section length is lower that this breakeven length, the economically efficient configuration is N-1, otherwise it is N-0. For sensitivity purposes it is assumed that the range of costs vary within ±20% of the values quoted in Table 11.16.

For the purpose of this exercise, it is assumed that the actual NOP section length would be the same as main sections length. Breakeven NOP section length values in blue denote that the section length is smaller than the breakeven NOP section length, while values in red denote the opposite. For networks with a failure rate of 2%, MTTR of 6/24 hours, section lengths of 2.4 km and a VoLL of £17,000/MWh, the breakeven length of the NOP section, varying between 144 and 170, is much greater than the actual section length for the whole considered range of asset costs. It is concluded that N-1 is the economically efficient design. This also applies if the VoLL is £34,000/MWh. In the case of a 12 km section length with the same failure rate and MTTR, the breakeven length varies between 717 and 845 km if the VoLL is £17,000/MWh. This means that for the whole range of new asset costs the economically efficient solution is N-1. For lower network availability the economically efficient design is N-1.5 for smaller and N-1.75 for larger network lengths.

Table 11.17: EHV overhead networks with each transformer peak demand 7.5 MW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/24	2.4	N-1	666	170	144	1,331	341	289
		12	N-1	3,299	845	717	6,597	1,691	1,434
2	24/24	2.4	N-1	2,731	700	593	5,461	1,400	1,187
		12	N-1	13,551	3,474	2,945	27,101	6,949	5,891
15	6/24	2.4	N-1	4,920	1,261	1,069	9,840	2,523	2,139
			N-1.5	43	11	9	86	22	18
		12	N-1	22,957	5,886	4,990	45,914	11,772	9,981
			N-1.5	1,054	270	229	2,109	540	458
			N-1.75	152	39	33	304	77	66
15	24/24	2.4	N-1	20,231	5,187	4,397	40,461	10,374	8,795
			N-1.5	110	28	23	220	56	47
		12	N-1	95,518	24,491	20,764	191,036	48,983	41,529
			N-1.5	2,692	690	585	5,384	1,380	1,170
			N-1.75	581	149	126	1,162	297	252

Table 11.18 shows the breakeven length of NOP sections for EHV overhead feeders when each transformer's peak demand is 20 MW. For all considered combinations a configuration of at least N-1 is economically optimal. For relatively unreliable EHV overhead networks and with section lengths of 12 km, the N-1.75 design is economically optimal. The incremental benefit is linearly dependent on the feeder loading which can be observed when the presented values are compared with the corresponding values in Table 11.17.

Table 11.18: EHV overhead networks with each transformer peak demand 20 MW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/24	2.4	N-1	1,775	455	385	3,550	910	771
		12	N-1	8,796	2,255	1,912	17,592	4,510	3,824
			N-1.5	51	13	11	102	26	22
2	24/24	2.4	N-1	7,281	1,867	1,582	14,563	3,734	3,165
		12	N-1	36,135	9,265	7,855	72,270	18,530	15,710
			N-1.5	131	33	28	261	67	56
15	6/24	2.4	N-1	13,120	3,364	2,852	26,240	6,728	5,704
			N-1.5	115	29	24	230	59	49
		12	N-1	61,219	15,697	13,308	122,438	31,394	26,616
			N-1.5	2,812	721	611	5,624	1,442	1,222
			N-1.75	405	103	88	810	207	176
15	24/24	2.4	N-1	53,948	13,832	11,727	107,896	27,665	23,455
			N-1.5	294	75	63	587	150	127
			N-1.75	11	2	2	22	5	4
		12	N-1	254,715	65,311	55,372	509,429	130,623	110,745
			N-1.5	7,179	1,840	1,560	14,357	3,681	3,121
			N-1.75	1,549	397	336	3,098	794	673

Table 11.19 shows the breakeven length of NOP sections for EHV underground feeders when each transformer's peak demand is 7.5 MW. The difference between underground and overhead networks in terms of the breakeven length of NOP sections lies in the fact that the underground network is generally more expensive than the overhead network. From Table 11.16 it is observed that the underground cable is almost seven times more expensive. In addition, the underground network generally has greater availability. In the underground networks where the failure rate is 2%/km.year, the MTTR is 6/24 hours and the section length is 2.4 km, the economically efficient design is N-1 as EENS savings of £666 and £1,331/year for a VoLL of £17,000/MWh and £34,000/MWh, respectively, are sufficient to cover the cost of switchgears and the lengthy underground cable. In summary, a configuration of at least N-1 is economically efficient with N-1.5 being the economically efficient design in some instances where the underground cable failure rate is 8%/km.year. In general, a lower network availability and a greater VoLL drives a greater degree of redundancy.

Table 11.19: EHV underground network with each transformer peak demand 7.5 MW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/24	2.4	N-1	666	29	19	1,331	57	38
		12	N-1	3,299	142	95	6,597	284	190
2	24/24	2.4	N-1	2,731	118	78	5,461	235	157
		12	N-1	13,551	584	389	27,101	1,168	779
8	6/24	2.4	N-1	2,645	114	76	5,290	228	152
		12	N-1	12,751	550	366	25,503	1,099	733
			N-1.5	304	13	9	608	26	17
8	24/24	2.4	N-1	10,861	468	312	21,722	936	624
			N-1.5	31	1	1	63	3	2
		12	N-1	52,685	2,271	1,514	105,370	4,542	3,028
			N-1.5	776	33	22	1,551	67	45

Table 11.20 shows the breakeven length of the NOP sections for EHV underground feeders when each transformer's peak demand is 20 MW. The economically efficient design is at least N-1. For lower network availability, the economically efficient network design is N-1.5 or N-1.75. The incremental benefit is also increased proportionally to the peak demand.

Table 11.20: EHV underground network with each transformer peak demand 20MW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/24	2.4	N-1	1,775	76	51	3,550	153	102
		12	N-1	8,796	379	253	17,592	758	505
2	24/24	2.4	N-1	7,281	314	209	14,563	628	418
		12	N-1	36,135	1,557	1,038	72,270	3,115	2,077
8	6/24	2.4	N-1	7,053	304	203	14,105	608	405
			N-1.5	33	1	1	66	3	2
		12	N-1	34,004	1,466	977	68,008	2,931	1,954
			N-1.5	810	35	23	1,620	70	46
8	24/24	2.4	N-1	28,962	1,248	832	57,925	2,497	1,664
			N-1.5	84	4	2	167	7	5
		12	N-1	140,493	6,056	4,037	280,986	12,111	8,074
			N-1.5	2,068	89	59	4,137	178	119
			N-1.75	362	16	10	723	31	21

Table 11.21 shows the long-term economically efficient degree of redundancy of EHV network designs for different constructions, section lengths, failure rates, mean times to repair and restore, feeder loadings and VoLL. N-1.5:1.75/N-1.75 means that for a VoLL of £17,000/MWh, N-1.5 is the optimal level of redundancy for the upper limit of the considered asset cost range and N-1.75 is the optimal level of redundancy for the lower limit, 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 11.21: EHV Network optimal redundancy; 'N-' term is omitted for simplicity

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

The results demonstrate that in most cases the optimal level of redundancy for EHV networks is N-1.5. Higher redundancy up to N-1.75 for both overhead and underground constructions can be proposed for cases with higher failure rates, higher loadings and relatively longer restoration/repair times. For relatively low failure rates and shorter section lengths, N-1 is the economically efficient network design for both overhead and underground constructions. As observed in previous studies, underground networks tend to require less redundancy due to lower failures rate and higher asset costs.

Figure 11.11 shows the EENS for different circuit availabilities, degrees of redundancy and section lengths for an underground construction when each transformer's peak demand is 7.5 MW. High circuit availability denotes a failure rate of 2%/km.year and a MTTR of 6/24 hours, while low circuit availability denotes a failure rate of 8% and a MTTR of 24/24 hours. This figure presents the breakdown of EENS resulting from single, double and triple outages of sections of the two-feeder EHV network. The Y-axis is logarithmic given that the EENS originating from single outages is the dominant component in N-0 configurations and the EENS originating from double and triple overlapping outages are significantly smaller. It is assumed that automatic fault isolation is available.

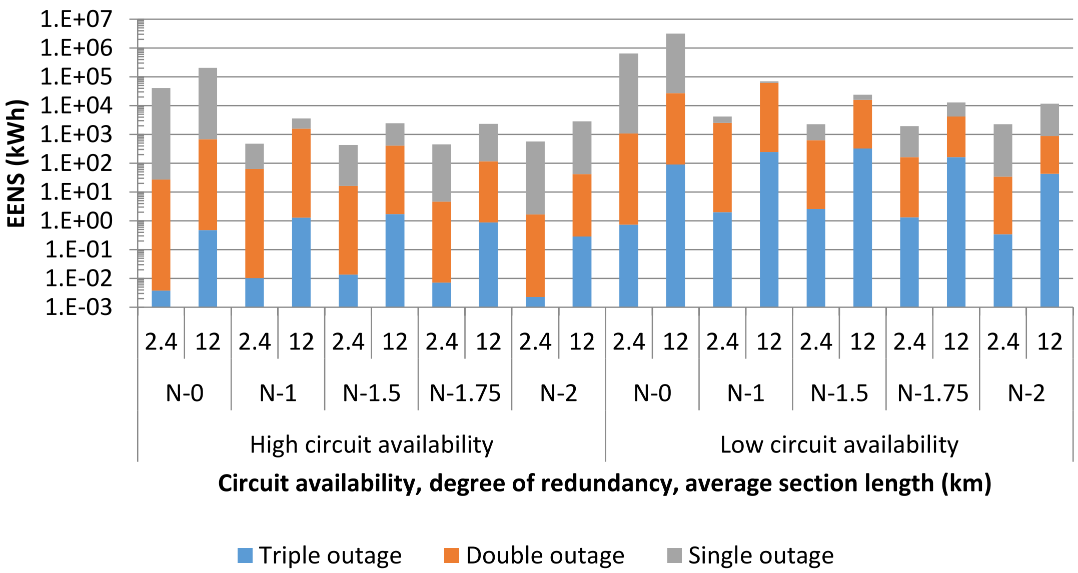

Figure 11.11: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 37.5 MW; logarithmic Y-axis

In order to better illustrate the ratios between EENS components the above chart is presented with a linear Y-axis in Figure 11.12. It can be seen that for N-0 degree of redundancy the EENS component originating from single outages is the most significant one and for low circuit availability it is about 646 and 3,163 MWh/year if average section lengths are 2.4 and 12 km, respectively. For high circuit availability the EENS values are much smaller and for 12 km average section length the EENS is about 202 MWh/year. For the sake of comparison, it is worth mentioning that 3,163 MWh is about 0.76% of the total annual demand. EENS components originating from double and triple overlapping outages are significantly smaller and almost cannot be seen in the Figure.

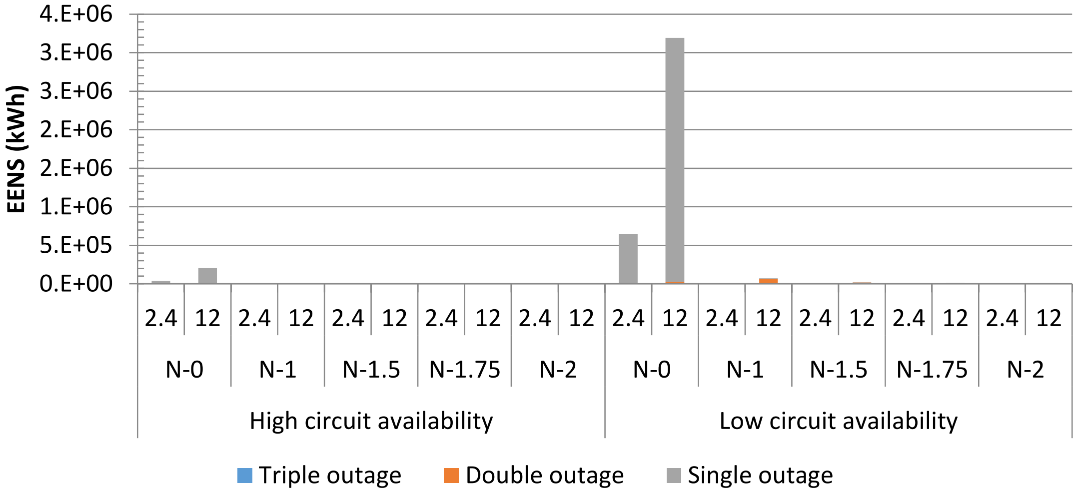

Figure 11.12: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 37.5 MW; linear Y-axis

Figure 11.13 shows only components of EENS originating from double and triple overlapping outages. It can be seen that the double outage component is the most significant one. The greatest value of about 62 MWh corresponds to low circuit availability, an N-1 redundancy level and an average feeder section length of 12 km. This is about 50 times smaller than the greatest value in Figure 11.12. The same ratio if high circuit availability is considered would be about 130 times. The double outage component of EENS increases in the N-1 design compared to the N-0 design given that some of the double outages in the N-1 design are two single non-overlapping outages in the N-0 design. In designs N-1.5 and beyond the EENS from double overlapping outage is reduced. It is significantly smaller for the N-2 design in comparison with the N-1 design even though longer networks result in more overlapping double outages in the N-2 design.

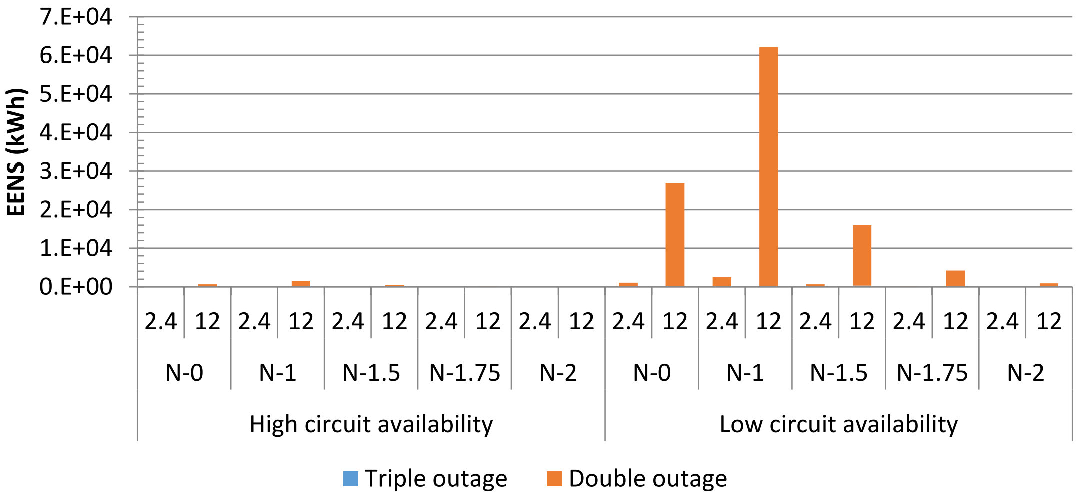

Figure 11.13: N-2 and N-3 components of EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 37.5 MW; linear Y-axis

Figure 11.14 shows the EENS when each transformer's peak demand is 20 MW. Values are greater but the trends are the same as in Figure 11.11.

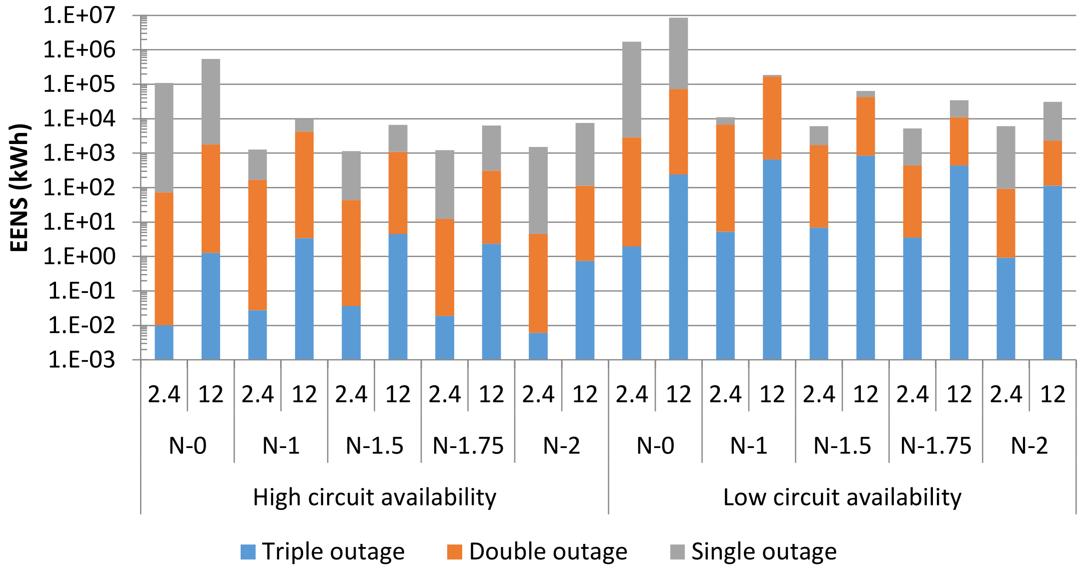

Figure 11.14: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 100 MW; logarithmic Y-axis

In order to better illustrate the ratios between EENS components the above chart is shown with a linear Y-axis in Figure 11.15. It can be seen that for an N-0 degree of redundancy the single outage component of EENS is the dominant one. The EENS is more than doubled with respect to Figure 11.12. As expected, its increase is equal to the increase of demand.

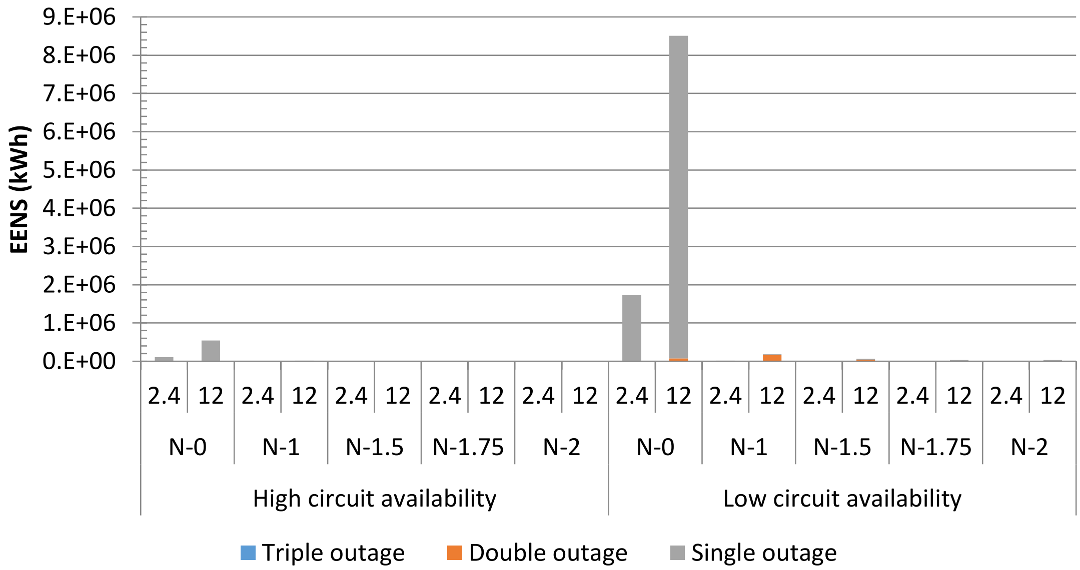

Figure 11.15: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 100 MW; linear Y-axis

Figure 11.16 shows only the double and triple overlapping outage components of the EENS. It can be seen that the double outage component is the most significant one. EENS values are increased compared to values in Figure 11.13 as demand increases.

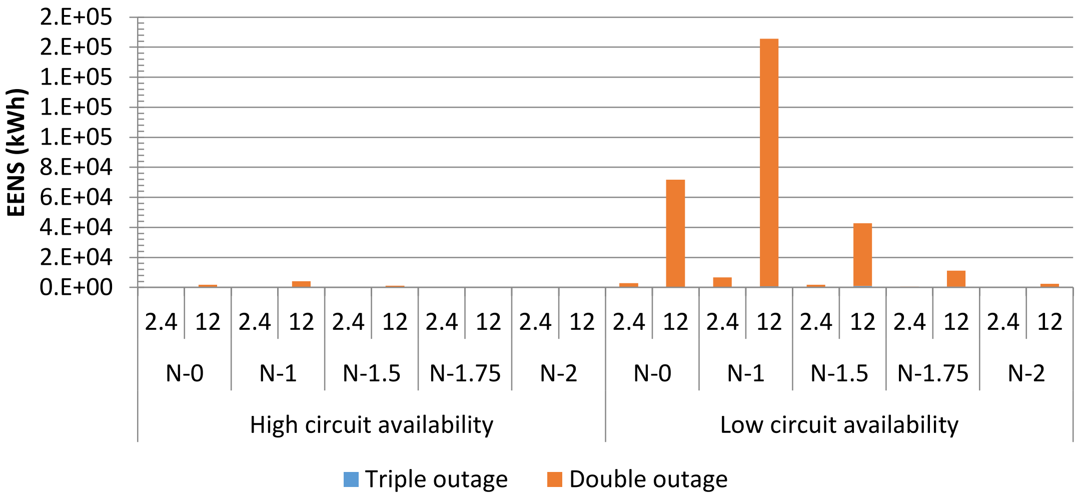

Figure 11.16: N-2 and N-3 components of EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 100 MW; linear Y-axis

Bulk supply substations

The economically efficient number of transformers per bulk supply substation is investigated by minimising the total cost, consisting of the cost of EENS and the cost of the substation, including the cost of the transformer feeder cables and the repair cost for different levels of redundancy. The substation topology is the same with the one shown in Figure 2.3 but with grid instead of primary transformers.

Ratings of two-, three- and four-transformer bulk supply substations are 2x90MVA, 3x45MVA and 4x30MVA, respectively. Two failure rates of 1 and 10%/year are considered. Their average repair cost is £1m. Two values for the length of the transformer feeder cables (1 and 5 km) and for their failure rate (2 and 8%/km.year) are considered. Their average repair cost is £50k. Reliability parameters are summarised in Table 2.33. During an outage a load transfer of 20% is assumed that can be achieved within 2 minutes. It is assumed that mobile generators of 10MW total maximum capacity can be deployed within 4.5 hours on average. Maintenance is done once every eight years with an outage duration of 10 days and an urgent maintenance close down time of 12 hours.

Table 11.22: Reliability related parameters used in the analysis

Asset	Failure rate (%/unit.year)	Urgent repair time (hours)	Average normal repair time (hours)	Repair cost (£k)
132 kV underground cable (km)	2-8	48-120	240	50
132kV/EHV transformer	1-10	240	720	1,000
132 kV circuit breaker	0.53	24	48	
EHV circuit breaker	0.87	12	24	
Disconnector	0.1	1.5	12	

The linearised typical cost of bulk supply substation including 5 km of cables per transformer is (£24.6k/MVA x N + £6k/MVA) x N x ER, where N is the number of transformers and ER is the emergency rating (MVA). The cost values used in the analysis are summarised in Table 2.34. In addition, the substation cost with one km of transformer feeder cable is estimated. The differences in costs between substation designs are lower compared with the primary substation case. The range is between 13% and 26% for a case with 1 and 5 km transformer feeder cable length, respectively.

Table 11.23: Substation cost

132kV/EHV Substation	Cost (£k/year)	
	Cable 5 km	Cable 1km
2x90 MVA	993.5	353.5
3x45 MVA	1,076.7	356.7
4x30 MVA	1,251.8	398.5

The considered peak demand is 90 MW (denoted as degree of redundancy N-1 using the two-transformer paradigm). Given that for all systems the N-1 total rating is the same, the total ratings of three-and four-transformer designs are 135 and 120 MVA respectively.

Table 11.24 shows breakeven VoLL comparing designs with two and three or four transformer 132kV/EHV substation. Breakeven VoLL is derived as ratio of savings in cost of substation, repair and losses by savings in EENS. The upper and lower cell values are the breakeven VoLL for load profile with low and high load factor, respectively.

Table 11.24: Breakeven VoLL comparing design with two and three or four transformer 132kV/EHV substation

Length of transformer feeder cable (km)	Failure rate	Two to three transformer substation	Two to four transformer substation
1	Min	33,660 30,056	227,049 160,407
	Max	19,928 16,161	47,658 34,071
5	Min	72,404 57,650	354,810 251,101
	Max	14,356 11,388	35,010 24,951

It can be seen that breakeven VoLL is greater for load profile with low load factor, for lower failure rate, and longer transformer feeder cable. In addition, breakeven VoLL between two and four-transformer EHV/HV substation is greater than between two and three-transformer substation. For the VoLL of £17,000/MWh the economically efficient design is three-transformer 132/EHV for higher failure rate and longer transformer feeder cable or for shorter transformer feeder cable and load profile with high load factor. In other cases two-transformer design is economically efficient. For the VoLL of £34,000/MWh the economically efficient design is two-transformer bulk supply substation in case of longer transformer feeder cable and low failure rate. In other cases three-transformer substation is economically efficient.

In summary, the three- and four-transformer designs offer savings in cost of interruptions compared with the two-transformer design. Savings in cost of interruptions for a higher failure rate and a longer cable repair time are not enough to offset the difference in cost of substation and repair cost, and the economically efficient solution is a three-transformer design. In case of a lower failure rate and a shorter cable repair time, the two-transformer design is economically efficient. Reducing the cost of interruption by avoiding the severity of common-mode failures of busbars sectionalisers could also favour the two-transformer substation design. The impact of the cost of renting mobile generation is insignificant.

11.3.2 Design B

Another generic topology of an Extra High Voltage (EHV) system, as shown in Figure 11.17, is employed to evaluate the performance of various configurations with different levels of redundancy in order to determine the optimal configuration producing the least-cost solution. In contrast to the previous section, the EHV topology used in this study consists of two feeders that feed into two 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.

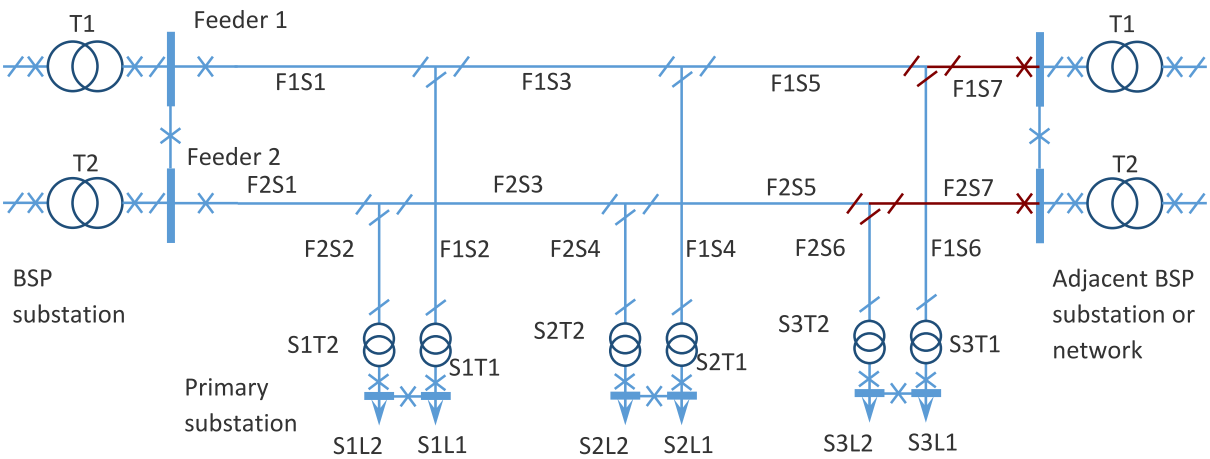

Figure 11.17: EHV Generic network configurations (Three Primary Substations Illustration)

Table 11.25 shows the reliability parameters used in the studies. The key parameters that have been varied as part of the sensitivity studies are the failure rate, MTT Restore, MTT Repair, network loading, network cost (assumed proportional to section length), and VoLL. Different sets of parameters are used to develop high and low circuit availability scenarios for both underground cables and overhead lines.

Table 11.25 Reliability parameters for EHV studies (design 2)

Parameter	**Value**
Type of network	Overhead and underground cables
Number of primary substations	1,2, and 3
Transformer peak demand (MW)	7.5 and 20
Failure rate	OHL 1km: 2% and 15%/year UGC 1km: 2% and 8%/year Transformer: 1% and 10%/year Transformer feeder maintenance: once in 8 years, 9 hours urgent close down time, 120 hours outage duration. Busbars sections: 0.1%/year
MTT Restore (h)	OHL: 12 UGC: 24 Transformer: 192 h Busbar section: 2 h
MTT Repair (h)	OHL: 120 UGC: 120 Transformer: 720 Busbar section: 12h
Section length (km)	Main: 4 and 20 km Spur: 0 and 10 km
VoLL (£/MWh)	17,000 and 34,000

Table 11.26 and Table 11.27 show the long-term economically efficient degree of redundancy for overhead and underground network designs respectively for different constructions, section lengths, failure rates, mean times to repair and restore, feeder loadings and the VoLL.

Table 11.26: Optimal Layout, EHV Overhead (no CMF), VoLL £17,000/MWh / £34,000/MWh; 'N-' term is omitted for simplicity

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	4/0, 4/10, 20/0, 20/10	Min	1	1	1	1	1	1	1	1
	4/0	Max	1	1	1	1	2	2	2	1/2
	4/10	Max	2	1/2	1/2	1/2	2	2	2	2
	20/0	Max	2	2	1/2	1/2	2	2	2	2
	20/10	Max	2	2	2	2	2	2	2	2
2	4/0, 4/10, 20/0, 20/10	Min	1	1	1	1	1	1	1	1
	4/0	Max	1/2	1/2	1	1	2	2	2	2
	4/10	Max	2	2	2	1/2	2	2	2	2
	20/0	Max	2	2	2	2	2	2	2	2
	20/10	Max	2	2	2	2	2	2	2	2
3	4/0, 4/10	Min	1	1	1	1	1	1	1	1
	20/0	Min	1	1	1	1	1/2	1	1	1
	20/10	Min	1	1	1	1	1/2	1/2	1	1
	4/0	Max	2	1/2	1/2	1/2	2	2	2	2
	4/10	Max	2	2	2	2	2	2	2	2
	20/0	Max	2	2	2	2	2	2	2	2
	20/10	Max	2	2	2	2	2	2	2	2

The results demonstrate that the optimal configuration for EHV overhead networks varies between N-1 and N-2 with the majority of cases exhibiting an optimal configuration N-2. As in previous sections, it is observed that the drivers to select a higher redundancy level are higher loadings, higher failure rates, higher the VoLL and lower network costs. For comparison, for existing EHV overhead networks presented in Section 2 the optimal degree of redundancy is between N-0.5 and N-1. Hence, loss inclusive network design justifies higher degree of redundancy.

Table 11.27: Optimal Layout, EHV Underground VoLL £17,000/MWh / £34,000/MWh; 'N-' term is omitted for simplicity; 'N-' term is omitted for simplicity

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	4/0, 4/10, 20/0, 20/10	Min	1	1	1	1	1	1	1	1
	4/0	Max	1	1	1	1	1	1	1	1
	4/10	Max	1	1	1	1	1/2	1	1	1
	20/0	Max	1	1	1	1	1	1	1	1
	20/10	Max	1	1	1	1	1/2	1/2	1	1
2	4/0, 4/10, 20/0, 20/10	Min	1	1	1	1	1	1	1	1
	4/0	Max	1	1	1	1	1	1	1	1
	4/10	Max	1	1	1	1	1/2	1/2	1	1
	20/0	Max	1	1	1	1	2	1/2	1/2	1
	20/10	Max	1	1	1	1	2	2	1/2	1/2
3	4/0, 4/10, 20/0, 20/10	Min	1	1	1	1	1	1	1	1
	4/0	Max	1	1	1	1	1/2	1	1	1
	4/10	Max	1	1	1	1	1/2	1/2	1	1
	20/0	Max	1	1	1	1	2	2	2	1/2
	20/10	Max	1	1	1	1	2	2	1/2	1/2

The results also show that in most cases, the optimal network redundancy for underground networks is N-1. Higher redundancy of up to N-2 is proposed for cases with higher failure rates, higher loadings, longer restoration/repair times, and higher the VoLL.

Both EHV network designs, A and B, results in N-1 or greater degree of redundancy.

11.4 132 kV network

11.4.1 Design A

A generic 132 kV test network similar to the one shown in Figure 11.10 but with 132 kV instead of EHV and with super grid and grid substations instead of grid and primary substations respectively, is used to evaluate the performance of various configurations with different levels of redundancy in order to determine the optimal configuration producing the least-cost solution, as shown in Figure 11.18. The approach is the same with the approach used in the previous studies. Circuits are added on top of the basic radial network (N-0) to improve the redundancy level to N-1,'N-1.5', 'N-1.75' and N-2 as described in the previous studies.

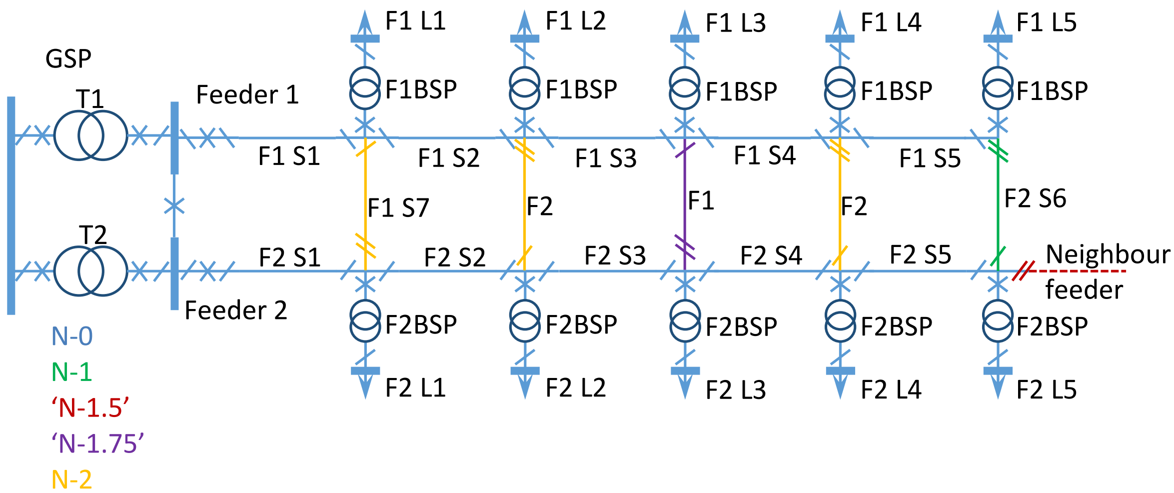

Figure 11.18: A generic 132 kV network system with different configurations to provide certain levels of security of supply

Table 11.28 shows the reliability parameters used in the studies. The key parameters that have been varied as part of the sensitivity studies are the failure rate and MTT Restore. Different sets of parameters are used to develop high and low circuit availability scenarios for both underground cables and overhead lines.

Table 11.28: Reliability parameters for 132 kV studies (design 1)

Parameter	Value
Type of network	Overhead and underground cables
Transformer peak demand (MW)	6, 30 and 60
Failure rate	OHL 1km: 2% and 15%/year UGC 1km: 2% and 8%/year
MTT Restore (h)	OHL: 6 and 24 UGC: 6, 48 and 120
MTT Repair (h)	OHL: 24 and 240 UGC: 48 and 240
Section length (km)	2.4 and 12
VoLL (£/MWh)	17,000 and 34,000
Cost	OHL 1km: £53-87k UGC 1km: £1,215k Switchgear: £45k

Table 11.29 shows the breakeven length of NOP sections for which the cost of upgrade is the same with the potential benefits for overhead feeders of different failure rates and mean times to restore and repair and for a peak demand of 6 MW for each transformer. The configurations not relevant for conclusion are omitted from the Table. For example for a failure rate of 2%/km.year, a MTTR of 6/24 hours and a section length of 4.8 km the incremental benefit of the N-1 configuration compared to the N-0 configuration is £1,091k/year and £2,182k/year for the VoLL of £17,000/MWh and £34,000/MWh respectively. From this benefit, the cost of the two switchgears is taken out and the remaining benefit divided by the unit cost of conductors results in the length of the NOP section for which the total costs of N-0 and N-1 designs are the same, denoted as breakeven length. If the actual NOP section length is lower that this breakeven length, the economically efficient configuration is N-1, otherwise it is N-0. For

sensitivity purposes it is assumed that the range of costs is ±20% of the values quoted in Table 11.28.

Assuming that the actual NOP section length would be the same as the main sections length, the economically efficient design is selected. Breakeven NOP section length values in blue denote that the actual section length is smaller than the breakeven NOP section length, while red values denote the opposite. For networks with a failure rate of 2%, a MTTR of 6/24 hours, a section length of 4.8 km and the VoLL of £17,000/MWh, the breakeven length of the NOP section, ranging between 103 and 256 km, is much greater than the section length for the whole considered range of asset costs. It is concluded that N-1 is the economically efficient design. This also applies if the VoLL is £34,000/MWh In the case of an 18 km section length and the same failure rate and MTTR, the breakeven length ranges between 386 and 952 km if the VoLL is £17,000/MWh. This means that for the whole considered range of asset costs, the economically efficient design is N-1. For other considered network configurations and reliability parameters the economically efficient design is N-1.5 and N-1.75. It can be seen from the Table that this greater redundancy is driven by lower network availability (larger failure rate, longer restore and repair times) and greater cost of interruptions. It can be seen that the increase of degree of redundancy reduces the breakeven length of the NOP section. An exception is observed for the case of a higher failure rate (15%), a MTTR of 24/240 hours and a longer network. In this instance EENS originating from double outages is significantly greater compared to single outages, so that it decreases the incremental benefit between N-0 and N-1 designs and increases the incremental benefit between N-1 and N-1.5 designs.

Reduced restoration times drive lower redundancy network designs. The restoration time is modelled as the average restoration time of different actions such as transfer capacity, mobile generation or other alternative supply deployment and urgent repair. For 132 kV overhead lines urgent repair time is 24 hours. Restoration time of 6 hours on average can be achieved for example with 20 % of demand resupplied by transfer in a relatively short period of time and by resupplying 80% of demand by mobile generation (up to 10-15 MW) deployed in 4.5 to 10 hours. Operational investment to reduce restoration time could reduce the need for asset redundancy such as in the case of networks with section lengths of 4.8 km and failure rate of 2% and MTTR 24/240 hours. For those networks, N-1.75 might be the economically efficient solution but if the restoration time is reduced from 24 to 6 hours the economically efficient design is N-1.5.

Normal repair time for overhead lines is about 240 hours but if an alternative supply such as mobile generation is deployed, priority will be given to repair the line and typically it will be repaired in about 24 hours. As long as single outages can be isolated without any customer interruptions, the feeder reconfiguration repair duration would not impact customers' quality of supply for a single fault. However, probability of overlapping outages increases with longer repair duration. Reducing repair duration could impact the economically efficient design. For example, for a failure rate of 2%/km.year, a MTTR of 6/240 hours and a longer network, the economically efficient design is likely to be N-1.75 (except for the case with the VoLL of £17,000/MWh and asset costs in the upper limit of the considered range where the N-1.5

design is economically efficient) while if the repair time is reduced from 240 to 24 hours, the economically efficient solution is N-1.5.

Table 11.29: Breakeven length of NOP section in 132 kV overhead networks where feeder peak demand is 30 MW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/24	4.8	N-1	1,091	256	103	2,182	513	208
		18	N-1	4,043	952	386	8,085	1,905	773
	24/24	4.8	N-1	4,389	1,034	419	8,779	2,069	840
		18	N-1	16,291	3,841	1,559	32,582	7,683	3,120
			N-1.5	89	19	7	178	40	16
	6/240	4.8	N-1	1,044	245	99	2,088	491	199
			N-1.5	31	6	2	61	13	5
		18	N-1	3,401	801	325	6,803	1,603	651
			N-1.5	413	96	38	825	193	78
			N-1.75	105	23	9	210	48	19
	24/240	4.8	N-1	4,204	990	402	8,408	1,981	804
			N-1.5	114	25	10	229	52	21
			N-1.75	28	5	2	57	12	4
		18	N-1	13,768	3,245	1,318	27,535	6,492	2,636
			N-1.5	1,545	363	147	3,089	727	295
			N-1.75	405	94	38	810	189	77
15	6/24	4.8	N-1	7,951	1,874	761	15,902	3,749	1,522
			N-1.5	141	32	12	282	65	26
			N-1.75	29	5	2	57	12	4
		18	N-1	27,121	6,395	2,597	54,242	12,791	5,195
			N-1.5	1,927	453	183	3,853	907	368
			N-1.75	476	111	45	953	223	90
	24/24	4.8	N-1	32,125	7,575	3,076	64,250	15,152	6,153
			N-1.5	354	82	33	708	165	67
			N-1.75	83	18	7	167	38	15
		18	N-1	111,271	26,242	10,657	222,542	52,485	21,315
			N-1.5	4,833	1,138	462	9,666	2,278	925
			N-1.75	1,248	293	119	2,497	587	238
			N-2	299	22	9	598	45	18
	6/240	4.8	N-1	5,503	1,296	526	11,005	2,594	1,053
			N-1.5	1,561	366	148	3,122	735	298
			N-1.75	420	97	39	839	196	79
			N-2	112	7	3	224	16	6
		18	N-1	1,492	350	142	2,985	702	285
			N-1.5	15,264	3,598	1,461	30,528	7,198	2,923
			N-1.75	5,119	1,206	489	10,237	2,413	980
			N-2	1,983	154	62	3,965	310	126
	24/240	4.8	N-1	22,479	5,300	2,152	44,958	10,602	4,305
			N-1.5	5,842	1,376	559	11,684	2,754	1,118
			N-1.75	1,599	375	152	3,197	752	305
			N-2	490	37	15	980	75	30
		18	N-1	9,424	2,221	902	18,848	4,444	1,804
			N-1.5	57,084	13,461	5,467	114,167	26,925	10,935
			N-1.75	19,447	4,585	1,862	38,894	9,171	3,724
			N-2	7,767	609	247	15,534	1,220	495

Table 11.30 shows the breakeven length of the NOP sections for 132 kV overhead feeders where feeder peak demand is 150 MW. For all considered combinations a design of at least N-1 redundancy level is economically efficient. For relatively unreliable 132 kV overhead networks with section lengths of 12 km, the N-1.75 design is economically efficient. The incremental benefit is linearly dependent on the feeder loading which can be observed if the values of this Table are compared with the corresponding values in Table 11.29. As in the previous studies, drivers for economically efficient designs with lower redundancy are higher

network availability in terms of lower failure rate and shorter restoration and repair times, as well as lower VoLL.

Table 11.30: Breakeven length of NOP section in 132 kV overhead networks where feeder peak demand is 150 MW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/24	4.8	N-1	5,456	1,285	522	10,912	2,572	1,044
		18	N-1	20,213	4,766	1,935	40,426	9,533	3,871
			N-1.5	177	40	16	355	82	33
	24/24	4.8	N-1	21,946	5,174	2,101	43,893	10,350	4,203
			N-1.5	32	6	2	64	13	5
		18	N-1	81,455	19,209	7,801	162,911	38,421	15,603
			N-1.5	445	103	42	890	208	84
			N-1.75	95	21	8	189	43	17
	6/240	4.8	N-1	5,221	1,230	499	10,441	2,461	999
			N-1.5	153	34	14	305	70	28
			N-1.75	34	6	2	68	14	5
		18	N-1	17,007	4,009	1,628	34,014	8,021	3,257
			N-1.5	2,063	485	197	4,127	972	394
			N-1.75	525	122	49	1,051	246	100
	24/240	4.8	N-1	21,020	4,956	2,012	42,040	9,913	4,026
			N-1.5	571	133	54	1,143	268	108
			N-1.75	142	32	13	284	65	26
		18	N-1	68,838	16,234	6,593	137,677	32,469	13,186
			N-1.5	7,723	1,820	739	15,446	3,641	1,478
			N-1.75	2,024	476	193	4,048	953	387
			N-2	561	42	17	1,122	86	35
15	6/24	4.8	N-1	39,756	9,375	3,807	79,511	18,751	7,615
			N-1.5	706	165	67	1,411	331	134
			N-1.75	143	32	13	285	66	26
		18	N-1	135,604	31,980	12,988	271,209	63,963	25,977
			N-1.5	9,633	2,270	922	19,265	4,542	1,844
			N-1.75	2,381	560	227	4,763	1,122	455
			N-2	317	23	9	633	48	19
	24/24	4.8	N-1	160,626	37,882	15,385	321,251	75,765	30,770
			N-1.5	1,771	416	169	3,542	834	338
			N-1.75	417	97	39	834	195	79
		18	N-1	556,356	131,214	53,290	1,112,712	262,430	106,581
			N-1.5	24,166	5,698	2,314	48,332	11,397	4,628
			N-1.75	6,242	1,471	597	12,484	2,943	1,195
			N-2	1,494	116	47	2,988	233	94
	6/240	4.8	N-1	27,513	6,487	2,634	55,026	12,976	5,270
			N-1.5	7,805	1,839	747	15,610	3,680	1,494
			N-1.75	2,099	493	200	4,197	988	401
			N-2	559	42	17	1,118	86	35
		18	N-1	7,462	1,758	714	14,924	3,518	1,428
			N-1.5	76,319	17,998	7,309	152,638	35,998	14,619
			N-1.75	25,593	6,034	2,450	51,185	12,070	4,902
			N-2	9,913	778	315	19,827	1,557	632
	24/240	4.8	N-1	112,395	26,507	10,765	224,791	53,015	21,531
			N-1.5	29,210	6,887	2,797	58,419	13,776	5,595
			N-1.75	7,994	1,884	765	15,987	3,769	1,530
			N-2	2,451	191	77	4,902	384	155
		18	N-1	47,120	11,112	4,512	94,240	22,225	9,026
			N-1.5	285,418	67,314	27,338	570,837	134,630	54,677
			N-1.75	97,234	22,931	9,313	194,468	45,863	18,626
			N-2	38,836	3,051	1,239	77,671	6,105	2,479

Table 11.31 shows the breakeven length of the NOP sections for EHV overhead feeders when feeder peak demand is 300 MW. For all considered combinations, a redundancy level of at least N-1 is economically efficient. For relatively unreliable 132 kV overhead networks with section lengths of 12 km, the N-1.75 design is economically efficient. The incremental benefit

is linearly dependent on the feeder loading which can be observed if the values of this Table are compared with the corresponding values in Table 11.29. As in the previous studies, drivers for economically efficient designs with lower redundancy are higher network availability in terms of lower failure rate and shorter restoration and repair times, as well as lower the VoLL.

Table 11.31: Breakeven length of NOP section in 132 kV overhead networks where feeder peak demand is 300 MW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/24	4.8	N-1	10,912	2,572	1,044	21,825	5,146	2,089
			N-1.5	25	4	1	51	10	4
		18	N-1	40,426	9,533	3,871	80,852	19,067	7,743
			N-1.5	355	82	33	709	166	67
			N-1.75	52	11	4	104	23	9
	24/24	4.8	N-1	43,893	10,350	4,203	87,785	20,702	8,408
			N-1.5	64	13	5	127	28	11
		18	N-1	162,911	38,421	15,603	325,822	76,843	31,208
			N-1.5	890	208	84	1,781	418	170
			N-1.75	189	43	17	379	88	35
	6/240	4.8	N-1	10,441	2,461	999	20,882	4,923	1,999
			N-1.5	305	70	28	611	142	57
			N-1.75	68	14	5	136	30	12
		18	N-1	34,014	8,021	3,257	68,029	16,043	6,515
			N-1.5	4,127	972	394	8,254	1,945	790
			N-1.75	1,051	246	100	2,101	494	200
			N-2	211	15	6	422	31	12
	24/240	4.8	N-1	42,040	9,913	4,026	84,079	19,828	8,053
			N-1.5	1,143	268	108	2,285	537	218
			N-1.75	284	65	26	567	132	53
			N-2	55	3	1	109	7	2
		18	N-1	137,677	32,469	13,186	275,354	64,940	26,374
			N-1.5	15,446	3,641	1,478	30,892	7,284	2,958
			N-1.75	4,048	953	387	8,096	1,908	774
			N-2	1,122	86	35	2,243	175	71
15	6/24	4.8	N-1	79,511	18,751	7,615	159,022	37,504	15,231
			N-1.5	1,411	331	134	2,823	664	269
			N-1.75	285	66	26	570	133	54
		18	N-1	271,209	63,963	25,977	542,418	127,927	51,955
			N-1.5	19,265	4,542	1,844	38,531	9,086	3,690
			N-1.75	4,763	1,122	455	9,525	2,245	911
			N-2	633	48	19	1,267	98	39
	24/24	4.8	N-1	321,251	75,765	30,770	642,503	151,532	61,541
			N-1.5	3,542	834	338	7,085	1,669	678
			N-1.75	834	195	79	1,667	392	159
		18	N-1	1,112,712	262,430	106,581	2,225,425	524,863	213,162
			N-1.5	48,332	11,397	4,628	96,665	22,797	9,258
			N-1.75	12,484	2,943	1,195	24,969	5,887	2,391
			N-2	2,988	233	94	5,977	468	190
	6/240	4.8	N-1	55,026	12,976	5,270	110,052	25,954	10,540
			N-1.5	15,610	3,680	1,494	31,220	7,362	2,989
			N-1.75	4,197	988	401	8,394	1,978	803
			N-2	1,118	86	35	2,236	174	70
		18	N-1	14,924	3,518	1,428	29,847	7,038	2,858
			N-1.5	152,638	35,998	14,619	305,275	71,997	29,240
			N-1.75	51,185	12,070	4,902	102,370	24,142	9,805
			N-2	19,827	1,557	632	39,653	3,116	1,265
	24/240	4.8	N-1	224,791	53,015	21,531	449,581	106,032	43,062
			N-1.5	58,419	13,776	5,595	116,839	27,555	11,190
			N-1.75	15,987	3,769	1,530	31,974	7,539	3,062
			N-2	4,902	384	155	9,804	769	312
		18	N-1	94,240	22,225	9,026	188,481	44,451	18,053
			N-1.5	570,837	134,630	54,677	1,141,673	269,261	109,355
			N-1.75	194,468	45,863	18,626	388,936	91,728	37,253
			N-2	77,671	6,105	2,479	155,342	12,211	4,959

The typical normal repair time in 132 kV underground networks is 240 hours which is the same as in overhead networks. The typical urgent repair time is longer than in overhead networks and can be between 48 and 120 hours.

Table 11.32 shows the breakeven length of the NOP section for 132 kV underground networks with each feeder's peak demand being 30 MW. For networks with a failure rate of 2%, a MTTR of 6/48 hours, a sections length of 4.8 km and the VoLL of £17,000/MWh, the breakeven length of the NOP section, ranging between 7 and 11 km, is greater than the actual section length for the whole considered range of asset costs. It is concluded that N-1 is the economically efficient design. This also applies if the VoLL is £34,000/MWh. In the case of an 18 km sections length and the same failure rate and MTTR, the breakeven length ranges between 27 and 41 km if the VoLL is £17,000/MWh. This means that for the whole considered range of asset costs the economically efficient solution is N-1. For a lower network failure rate the economically efficient design in case of a 4.8 km sections length is up to N-1.5 while in case of an 18 km sections length it is up to N-1.75. For a higher network failure rate, the only case where the economically efficient design is N-1 corresponds to a network with an average section length of 4.8 km and where relatively fast resupply can be achieved and repair is always done as a priority. For a higher network failure rate and shorter section lengths, the greatest observed degree of redundancy is N-1.75 while for networks with longer section lengths it is N-2. It can be seen from the Table that greater redundancy is driven by lower network availability (higher failure rate, longer restore and repair times) and greater cost of interruptions. For all considered cases, the increase of the degree of redundancy reduces the breakeven length of the NOP section. The exception to this trend observed in overhead networks does not apply to underground networks as they are generally more reliable and the upper considered failure rate is about half of that for overhead networks. Therefore, the double outage component of EENS is not significant enough to drive this effect.

Table 11.32: Breakeven length of NOP section in 132 kV underground networks where feeder peak demand is 30 MW

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/48	4.8	N-1	1,086	11	7	2,172	22	15
		18	N-1	3,970	41	27	7,939	82	54
	48/48	4.8	N-1	8,753	90	60	17,506	180	120
		18	N-1	32,152	331	220	64,303	661	441
	6/240	4.8	N-1	1,044	11	7	2,088	21	14
		18	N-1	3,401	35	23	6,803	70	47
	48/240	4.8	N-1	8,429	87	58	16,859	173	116
		18	N-1	27,756	285	190	55,512	571	381
			N-1.5	2,833	29	19	5,666	58	39
	120/240	4.8	N-1	21,164	218	145	42,327	435	290
			N-1.5	419	4	3	839	9	6
		18	N-1	70,503	725	483	141,006	1,451	967
			N-1.5	5,666	58	39	11,332	117	78
			N-1.75	1,505	15	10	3,010	31	21
8	6/48	4.8	N-1	4,224	43	29	8,449	87	58
		18	N-1	14,244	146	98	28,489	293	195
			N-1.5	1,216	12	8	2,431	25	17
	48/48	4.8	N-1	34,230	352	235	68,461	704	469
			N-1.5	403	4	3	807	8	5
		18	N-1	117,920	1,213	809	235,841	2,426	1,617

Failure rate (%/km.year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
			N-1.5	5,492	56	38	10,983	113	75
			N-1.75	1,440	15	10	2,880	30	20
	6/240	4.8	N-1	3,580	37	24	7,160	74	49
			N-1.5	468	5	3	936	10	6
		18	N-1	6,499	67	45	12,998	134	89
			N-1.5	5,538	57	38	11,076	114	76
			N-1.75	1,618	17	11	3,236	33	22
	48/240	4.8	N-1	29,245	301	201	58,490	602	401
			N-1.5	3,212	33	22	6,424	66	44
			N-1.75	850	9	6	1,699	17	12
		18	N-1	57,482	591	394	114,964	1,183	788
			N-1.5	37,989	391	260	75,979	782	521
			N-1.75	11,352	117	78	22,704	234	156
			N-2	3,983	14	9	7,965	27	18
	120/240	4.8	N-1	74,371	765	510	148,743	1,530	1,020
			N-1.5	6,423	66	44	12,846	132	88
			N-1.75	1,711	18	12	3,423	35	23
		18	N-1	158,173	1,627	1,085	316,346	3,255	2,170
			N-1.5	75,868	780	520	151,736	1,561	1,041
			N-1.75	23,086	237	158	46,172	475	317
			N-2	8,295	28	19	16,590	57	38

Table 11.33 shows the breakeven length of the NOP sections for 132 kV underground networks where each feeder's peak demand is 150 MW. For all considered combinations, a redundancy level of at least N-1 is the economically efficient. For relatively unreliable 132 kV underground networks with sections length of 12 km, the N-1.75 design is economically efficient. The incremental benefit is linearly dependent on the feeder loading which can be observed if the values in this Table are compared with the corresponding values in Table 11.32. As in the previous studies, drivers for economically efficient designs with lower redundancy are higher network availability in terms of lower failure rate and shorter restoration and repair times, as well as the lower VoLL.

Table 11.33: Breakeven length of NOP section in 132 kV underground networks where feeder peak demand is 150 MW

Failure rate (%/km. year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/48	4.8	N-1	5,430	56	37	10,860	112	74
		18	N-1	19,848	204	136	39,696	408	272
	48/48	4.8	N-1	43,764	450	300	87,529	900	600
		18	N-1	160,758	1,654	1,103	321,517	3,308	2,205
			N-1.5	1,774	18	12	3,547	36	24
	6/240	4.8	N-1	5,221	54	36	10,441	107	72
		18	N-1	17,007	175	117	34,014	350	233
			N-1.5	2,063	21	14	4,127	42	28
	48/240	4.8	N-1	42,147	434	289	84,294	867	578
			N-1.5	1,048	11	7	2,096	21	14
			N-1.75	265	3	2	529	5	4
		18	N-1	138,780	1,428	952	277,560	2,855	1,904
			N-1.5	14,166	146	97	28,332	291	194
			N-1.75	3,736	38	26	7,472	77	51
	120/240	4.8	N-1	105,818	1,089	726	211,636	2,177	1,451
			N-1.5	2,097	21	14	4,194	43	29
			N-1.75	535	5	4	1,070	11	7
		18	N-1	352,515	3,627	2,418	705,030	7,253	4,836

Failure rate (%/km. year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
			N-1.5	28,330	291	194	56,660	583	389
			N-1.75	7,525	77	52	15,050	155	103
8	6/48	4.8	N-1	21,121	217	145	42,243	435	290
			N-1.5	446	5	3	892	9	6
		18	N-1	71,221	733	488	142,443	1,465	977
			N-1.5	6,078	62	42	12,155	125	83
			N-1.75	1,517	16	10	3,034	31	21
	48/48	4.8	N-1	171,152	1,761	1,174	342,304	3,522	2,348
			N-1.5	2,017	21	14	4,033	41	28
			N-1.75	498	5	3	997	10	7
		18	N-1	589,602	6,066	4,044	1,179,205	12,132	8,088
			N-1.5	27,458	282	188	54,917	565	377
			N-1.75	7,200	74	49	14,400	148	99
	6/240	4.8	N-1	17,900	184	123	35,800	368	245
			N-1.5	2,339	24	16	4,678	48	32
			N-1.75	598	6	4	1,197	12	8
		18	N-1	32,495	334	223	64,991	669	446
			N-1.5	27,690	285	190	55,380	570	380
			N-1.75	8,090	83	55	16,179	166	111
	48/240	4.8	N-1	146,225	1,504	1,003	292,449	3,009	2,006
			N-1.5	16,059	165	110	32,118	330	220
			N-1.75	4,248	44	29	8,496	87	58
			N-2	1,241	4	3	2,481	8	6
		18	N-1	287,411	2,957	1,971	574,822	5,914	3,942
			N-1.5	189,947	1,954	1,303	379,894	3,908	2,606
			N-1.75	56,761	584	389	113,522	1,168	779
			N-2	19,913	68	45	39,827	137	91
	120/240	4.8	N-1	371,856	3,826	2,550	743,713	7,651	5,101
			N-1.5	32,114	330	220	64,229	661	440
			N-1.75	8,557	88	59	17,115	176	117
			N-2	2,575	9	6	5,149	18	12
		18	N-1	790,865	8,136	5,424	1,581,731	16,273	10,849
			N-1.5	379,340	3,903	2,602	758,681	7,805	5,203
			N-1.75	115,431	1,187	792	230,862	2,375	1,583
			N-2	41,475	142	95	82,949	284	190

Table 11.34 shows the breakeven length of the NOP sections for 132kV underground networks when each feeder's peak demand is 300 MW. For all considered combinations, a redundancy level of at least N-1 is the economically efficient. For relatively unreliable 132 kV underground networks with section lengths of 12 km, the N-1.75 design is economically efficient. The incremental benefit is linearly dependent on the feeder loading which can be observed if the values in this Table are compared with the corresponding values in Table 11.32.

Table 11.34: Breakeven length of NOP section in 132 kV underground networks where feeder peak demand is 300 MW

Failure rate (%/km. year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
2	6/48	4.8	N-1	10,860	112	74	21,720	223	149
		18	N-1	39,696	408	272	79,391	817	544
	48/48	4.8	N-1	87,529	900	600	175,058	1,801	1,201
			N-1.5	254	3	2	509	5	3
		18	N-1	321,517	3,308	2,205	643,033	6,615	4,410
			N-1.5	3,547	36	24	7,094	73	49
	6/240	4.8	N-1	10,441	107	72	20,882	215	143

Failure rate (%/km. year)	MTTR (hours)	Section length (km)	Configuration	Incremental benefit @ £17,000/MWh (£k/year)	Breakeven length of NOP section (km)		Incremental benefit @ £34,000/MWh (£k/year)	Breakeven length of NOP section (km)	
					Min assets cost	Max assets cost		Min assets cost	Max assets cost
			N-1.5	305	3	2	611	6	4
		18	N-1	34,014	350	233	68,029	700	467
			N-1.5	4,127	42	28	8,254	85	57
			N-1.75	1,051	11	7	2,101	22	14
	48/240	4.8	N-1	84,294	867	578	168,588	1,734	1,156
			N-1.5	2,096	21	14	4,192	43	29
			N-1.75	529	5	4	1,058	11	7
		18	N-1	277,560	2,855	1,904	555,121	5,711	3,807
			N-1.5	28,332	291	194	56,664	583	389
			N-1.75	7,472	77	51	14,943	154	102
	120/240	4.8	N-1	211,636	2,177	1,451	423,271	4,355	2,903
			N-1.5	4,194	43	29	8,387	86	57
			N-1.75	1,070	11	7	2,140	22	15
		18	N-1	705,030	7,253	4,836	1,410,060	14,507	9,671
			N-1.5	56,660	583	389	113,321	1,166	777
			N-1.75	15,050	155	103	30,101	310	206
				4,502	15	10	9,004	31	21
8	6/48	4.8	N-1	42,243	435	290	84,486	869	579
			N-1.5	892	9	6	1,784	18	12
		18	N-1	142,443	1,465	977	284,885	2,931	1,954
			N-1.5	12,155	125	83	24,311	250	167
			N-1.75	3,034	31	21	6,069	62	42
	48/48	4.8	N-1	342,304	3,522	2,348	684,607	7,043	4,695
			N-1.5	4,033	41	28	8,066	83	55
			N-1.75	997	10	7	1,993	20	14
		18	N-1	1,179,205	12,132	8,088	2,358,410	24,263	16,176
			N-1.5	54,917	565	377	109,833	1,130	753
			N-1.75	14,400	148	99	28,801	296	197
			N-2	3,955	13	9	7,910	27	18
	6/240	4.8	N-1	35,800	368	245	71,600	737	491
			N-1.5	4,678	48	32	9,357	96	64
			N-1.75	1,197	12	8	2,393	25	16
		18	N-1	64,991	669	446	129,981	1,337	891
			N-1.5	55,380	570	380	110,761	1,139	760
			N-1.75	16,179	166	111	32,359	333	222
			N-2	5,201	18	12	10,402	36	24
	48/240	4.8	N-1	292,449	3,009	2,006	584,898	6,017	4,012
			N-1.5	32,118	330	220	64,235	661	440
			N-1.75	8,496	87	58	16,991	175	116
			N-2	2,481	8	6	4,962	17	11
		18	N-1	574,822	5,914	3,942	1,149,644	11,828	7,885
			N-1.5	379,894	3,908	2,606	759,788	7,817	5,211
			N-1.75	113,522	1,168	779	227,043	2,336	1,557
			N-2	39,827	137	91	79,654	273	182
	120/240	4.8	N-1	743,713	7,651	5,101	1,487,426	15,303	10,202
			N-1.5	64,229	661	440	128,458	1,322	881
			N-1.75	17,115	176	117	34,230	352	235
			N-2	5,149	18	12	10,299	35	23
		18	N-1	1,581,731	16,273	10,849	3,163,461	32,546	21,697
			N-1.5	758,681	7,805	5,203	1,517,362	15,611	10,407
			N-1.75	230,862	2,375	1,583	461,724	4,750	3,167
			N-2	82,949	284	190	165,898	569	379

In summary, drivers for economically efficient designs with lower redundancy are higher network availability in terms of lower failure rate and shorter restoration and repair times, as well as the lower VoLL. Table 11.35 shows the long-term economically efficient degree of redundancy for 132 kV networks, for different constructions, section lengths, failure rates, mean times to repair and restore, feeder loadings and the VoLL.

Table 11.35: 132 kV Network Optimal Redundancy; 'N-' term is omitted for simplicity

Construction	Section length (km)	Failure rate (%/km.year)	MTTR (hours)	Feeder Peak Demand (MW)		
				30	150	300
Overhead	4.8	2	6/24	1	1	1/1:1.5
			24/24	1	1:1.5/1.5	1.5
			6/240	1:1.5/1.5	1.5:1.75/1.75	1.75
			24/240	1.5:1.75	1.75	1.75/1.75:2
		15	6/24	1.5:1.75	1.75	1.75
			24/24	1.75	1.75	1.75
			6/240	1.75:2/2	2	2
			24/240	2	2	2
	18	2	6/24	1	1:1.5/1.5	1.5/1.5:1.75
			24/24	1:1.5	1.5:1.75	1.5:1.75/1.75
			6/240	1.5:1.75/1.75	1.75	1.75/1.75:2
			24/240	1.75	1.75:2/2	2
		15	6/24	1.75	1.75:2/2	2
			24/24	1.75:2/2	2	2
			6/240	2	2	2
			24/240	2	2	2
Underground	4.8	2	6/48	1	1	1
			48/48	1	1	1/1:1.5
			6/240	1	1	1/1:1.5
			48/240	1	1.5	1.5:1.75/1.75
			120/240	1/1.5	1.5:1.75/1.75	1.75
		8	6/48	1	1/1.5	1.5
			48/48	1/1.5	1.5:1.75/1.75	1.75
			6/240	1/1.5	1.5:1.75/1.75	1.75
			48/240	1.75	1.75/2	2
			120/240	1.75	2	2
	18	2	6/48	1	1	1
			48/48	1	1:1.5/1.5	1.5
			6/240	1	1:1.5/1.5	1.5/1.5:1.75
			48/240	1.5	1.75	1.75
			120/240	1.5/1.75	1.75	1.75
		8	6/48	1/1:1.5	1.5/1.75	1.75
			48/48	1.5/1.75	1.75	1.75/2
			6/240	1.5/1.75	1.75	1.75/2
			48/240	1.75/2	2	2
			120/240	2	2	2

The results demonstrate that in most cases the optimal level of redundancy for 132 kV networks is N-1.5 or N-1.75. In networks with higher availability the maximum observed economically efficient degree of redundancy is N-1.75. Higher redundancy levels up to N-2 for both overhead and underground networks can be proposed for cases with higher failure rates, higher loadings and relatively longer restoration/repair times. N-1 degree of redundancy is economically efficient for shorter networks with relatively higher availability. As observed in previous studies, underground networks tend to require less redundancy due to lower failure rates and higher network costs.

Figure 11.19 shows the EENS for different circuit availabilities, degrees of redundancy and section lengths for underground networks when each feeder's peak demand is 150 MW. High circuit availability denotes a failure rate of 2%/km.year and a MTTR of 6/48 hours, while low circuit availability denotes a failure rate of 8% and a MTTR of 48/240 hours. The Figure illustrates the breakdown of EENS resulting from single, double and triple outages of sections of the two-feeder EHV network. The Y-axis is logarithmic given that the EENS originating from single outages is the dominant component in N-0 configurations and EENS originating from double and triple overlapping outages are comparably smaller. It is assumed that time for fault isolation is two minutes.

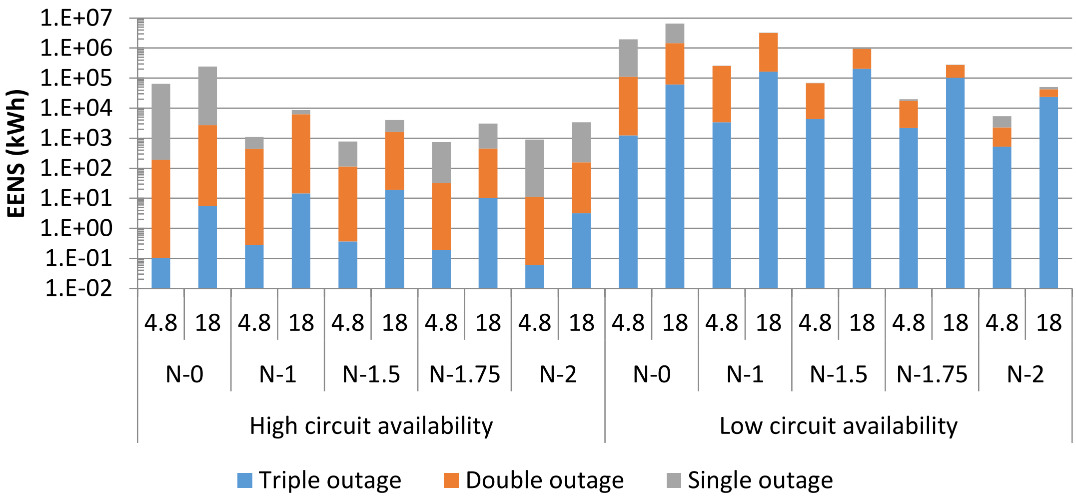

Figure 11.19: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 150 MW; logarithmic Y-axis

In order to better illustrate the ratios between EENS components the above chart is shown with a linear Y-axis in Figure 11.20. It can be seen that for an N-0 degree of redundancy the EENS component originating from single outages is the most significant one and for low circuit availability it is about 9 and 26 GWh/year if the average sections length is 4.8 and 18 km respectively. For high circuit availability the values are much smaller and for an 18 km average section length the EENS is about 1.2 GWh/year. For comparison purposes, it should be mentioned that 26 GWh is about 1.6% of the total annual demand. EENS components originating from double outages are the greatest in N-1 designs given that some of those would be counted as two single outages in N-0 designs and for low circuit availability the EENS is about 15 GWh/year. EENS originating from triple overlapping outages is significantly smaller.

Figure 11.21 shows only components of EENS originating from double and triple overlapping outages. It can be seen that the double outage component is the most significant one. The greatest value of about 15 GWh corresponds to low circuit availability, N-1 network redundancy, and average section length of 18 km. This is about 1.7 times smaller than the greatest single outage EENS component corresponding to N-0 redundancy in Figure 11.20. The same ratio if high circuit availability is considered is about 39 times. The double outage component of EENS increases in N-1 design compared to N-0 given that some of the double outages in N-1 are two single non-overlapping outages in N-0. In designs of redundancy N-1.5 and beyond, the EENS from double overlapping outage reduces. It is significantly smaller for N-2 design in comparison with N-1 design, given the short reconfiguration duration even though a longer network results in more overlapping double outages in N-2 design.

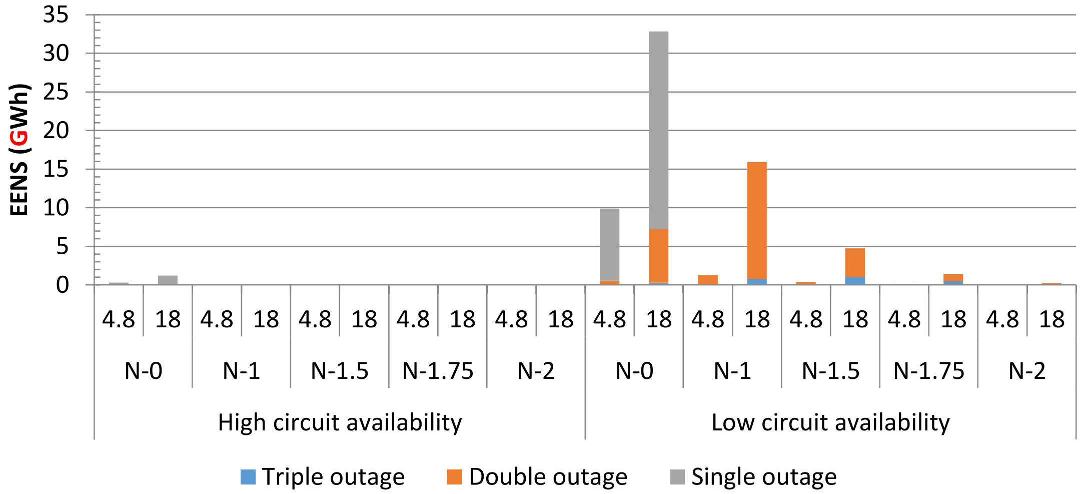

Figure 11.20: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 150 MW; linear Y-axis

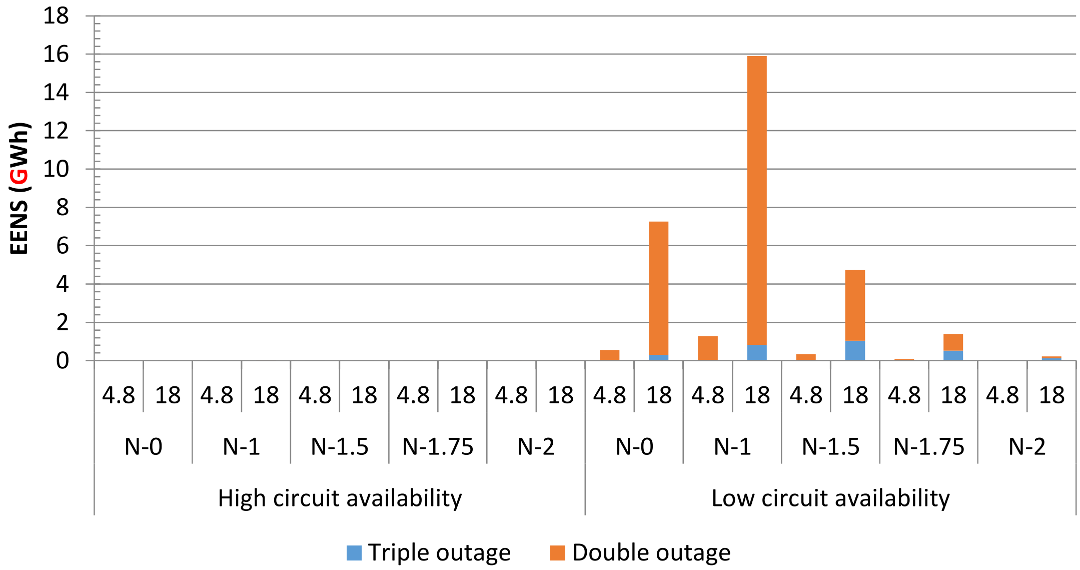

Figure 11.21: N-2 and N-3 components of EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 150 MW; linear Y-axis

Figure 11.22 shows the EENS when each feeder's peak demand is 300 MW. EENS values are greater but the trends are the same as in Figure 11.19.

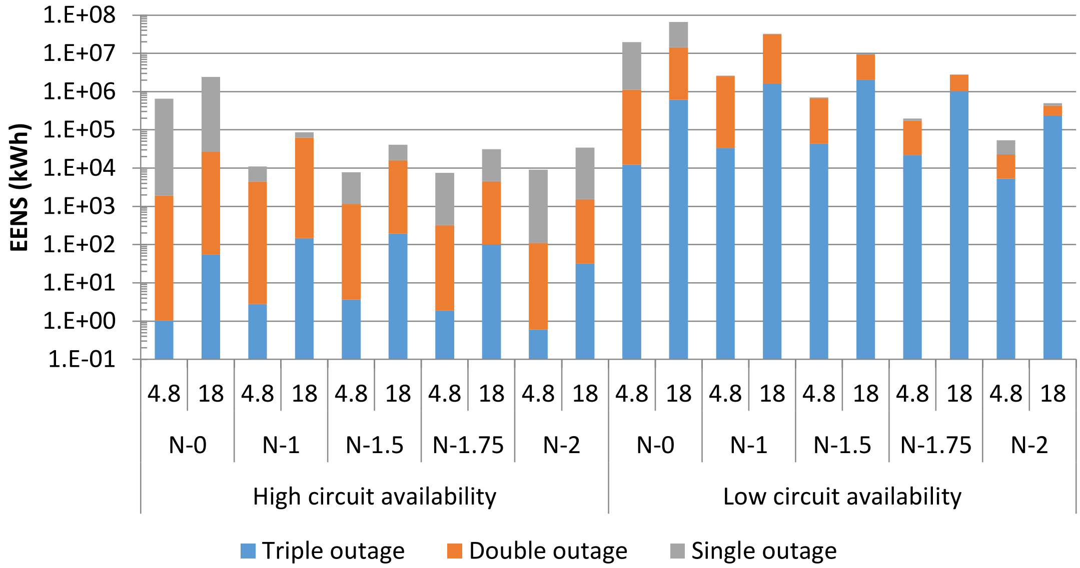

Figure 11.22: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 300 MW; logarithmic Y-axis

In order to better illustrate the ratios between EENS components the above chart is drawn with a linear Y-axis in Figure 11.23. It can be seen that for an N-0 degree of redundancy the single outage component of EENS is the dominant one. The EENS is increased two times with respect to the values in Figure 11.20 which is the same as the increase of demand.

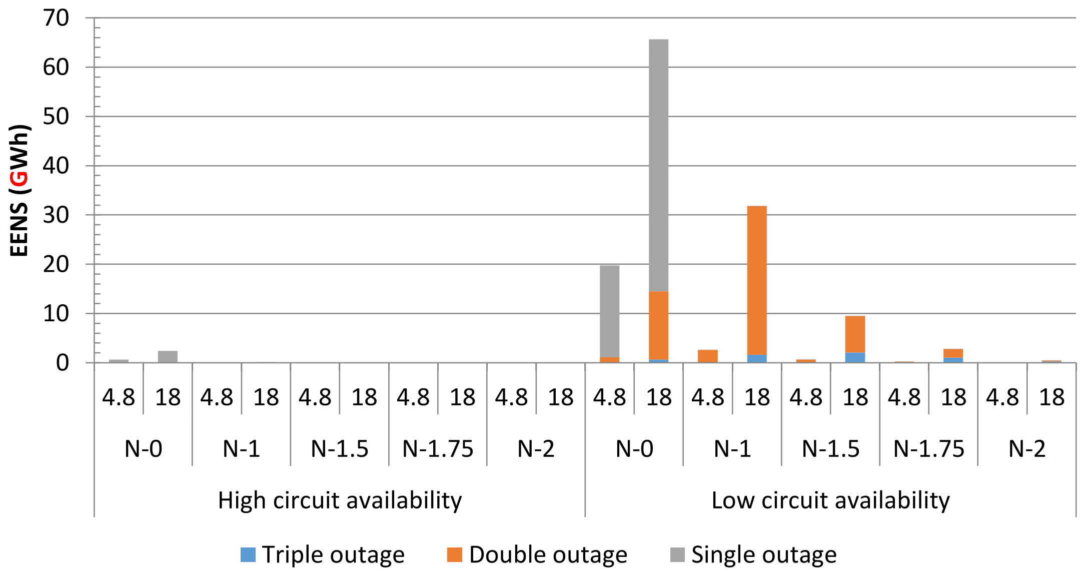

Figure 11.23: EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 300 MW; linear Y-axis

Figure 11.24 shows only the double and triple overlapping outage components of the EENS. It can be seen that the double outage component is the most significant one. EENS values are two times higher than the ones is Figure 11.21.

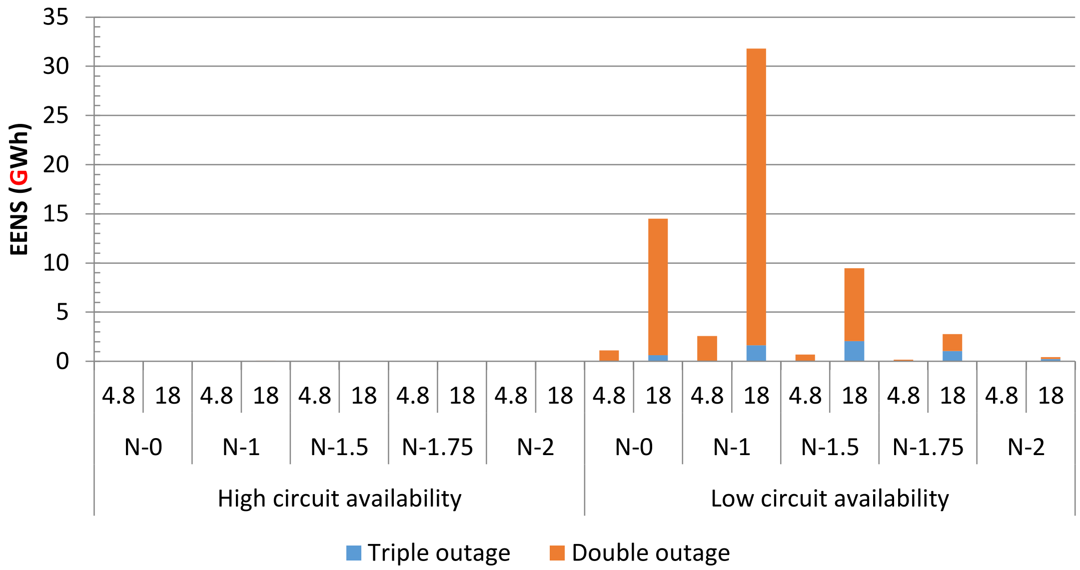

Figure 11.24: N-2 and N-3 components of EENS for different circuit availabilities, degrees of redundancy and section lengths for underground feeders with total feeder peak demand of 300 MW; linear Y-axis

11.4.2 Design B

Another generic topology of a 132 kV system, as shown in Figure 11.25, is used to evaluate the performance of various configurations with different levels of redundancy in order to determine the optimal configuration producing the least-cost solution. In contrast to the previous section, the EHV topology used in this study consists of two feeders that feed into two primary substations. The main EHV feeders have the option to interconnect with the neighbour grid substation to improve security.

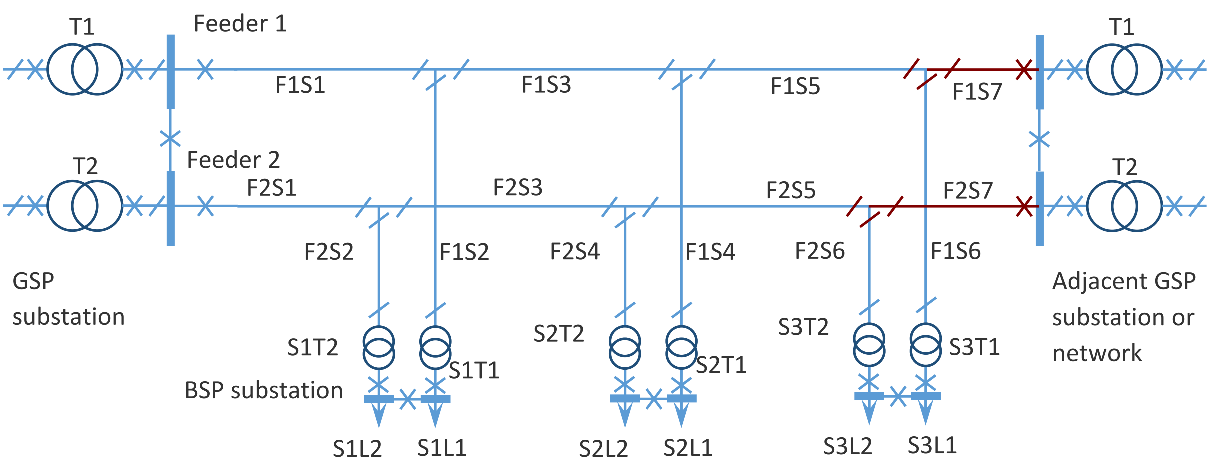

Figure 11.25: 132 kV generic network configurations

Table 11.36 shows the reliability parameters used in the studies. The key parameters that have been varied as part of the sensitivity studies are failure rate, MTT Restore, and MTT Repair. Different sets of parameters are used to develop high and low circuit availability scenarios for both underground cables and overhead lines.

Table 11.36: Reliability parameters for 132 kV studies

Parameter	Value
Type of network	Overhead and underground cables
Number of BSP substations	1,2, and 3
Transformer peak demand (MW)	22.5 and 45
Failure rate	OHL 1km: 2% and 15% UGC 1km: 2% and 8% Transformer: 1% and 10% Transformer feeder maintenance: once in 8 years, 18 hours urgent close down time, 240 hours outage duration. Busbars sections: 0.1%
MTT Restore (h)	OHL: 24 UGC: 48 Transformer: 240 h Busbar section: 2 h
MTT Repair (h)	OHL: 120 UGC 120 Transformer:720 Busbar section: 12h
Section length (km)	Main: 4 and 20 km Spur: 0 and 10 km
VoLL (£/MWh)	17,000 and 34,000

It is assumed that the time required to complete reconfiguration (of the network shown) is 10 min, and the load transfer of 0, 10, 20 and 30% via the HV network is within 10 min. Mobile generation is also available to restore the supply with a maximum capacity of 10 MW and it is available within, on average, 4.5 hours. We also assume that a temporary cable can be laid to restore the supply after a transformer outage within 36 hours.

In this study, the optimal level of redundancy is calculated by comparing the cost of upgrading the network and its associated benefit computed as the saving in EENS times the VoLL. The cost of upgrade includes the cost of network components involved, the cost of load transfer, the cost of mobile generation and the cost of laying the temporary cable.

Table 11.37 and Table 11.38 show the long-term economically efficient degree of redundancy for HV overhead and underground network designs respectively for different numbers of primary substations, section lengths, failure rates, mean times to repair and restore, feeder loadings and VoLL.

Table 11.37: Optimal Layout, 132 kV Overhead (without Common-mode failures), VoLL £17,000/MWh / £34,000/MWh; 'N-' term is omitted for simplicity

Number of BSPs	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	1	1	1	1	1	1	1	1
	8/0	Max	1/2	1/2	1	1	2	2	1/2	1/2
	8/10	Max	2	2	2	2	2	2	2	2
	30/0	Max	2	2	2	2	2	2	2	2

Number of BSPs	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%
	30/10	Max	2	2	2	2	2	2	2	2
2	8/0, 8/10	Min	1	1	1	1	1	1	1	1
	30/0	Min	1	1	1	1	1/2	1/2	1	1
	30/10	Min	1	1	1	1	1/2	1/2	1/2	1
	8/0, 8/10, 30/0, 30/10	Max	2	2	2	2	2	2	2	2
3	8/0, 8/10	Min	1	1	1	1	1	1	1	1
	30/0	Min	1/2	1	1	1	2	1/2	1/2	1/2
	30/10	Min	1/2	1	1	1	2	2	1/2	1/2
	8/0, 8/10, 30/0, 30/10	Max	2	2	2	2	2	2	2	2

Table 11.38: Optimal Layout, 132 kV Underground VoLL £17,000/MWh / £34,000/MWh; 'N-' term is omitted for simplicity

Number of BSPs	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	1	1	1	1	1	1	1	1
	8/0	Max	1	1	1	1	1	1	1	1
	8/10	Max	1	1	1	1	1	1	1	1
	30/0	Max	1	1	1	1	1/2	1	1	1
	30/10	Max	1	1	1	1	1/2	1/2	1/2	1/2
2	8/0, 8/10, 30/0, 30/10	Min	1	1	1	1	1	1	1	1
	8/0	Max	1	1	1	1	1	1	1	1
	8/10	Max	1	1	1	1	1/2	1/2	1	1
	30/0	Max	1/2	1/2	1/2	1	2	2	2	1/2
	30/10	Max	1/2	1/2	1/2	1/2	2	2	2	2
3	8/0, 8/10, 30/0, 30/10	Min	1	1	1	1	1	1	1	1
	8/0	Max	1	1	1	1	1/2	1/2	1/2	1
	8/10	Max	1	1	1	1	2	1/2	1/2	1/2
	30/0	Max	2	2	2	1/2	2	2	2	2
	30/10	Max	2	2	2	1/2	2	2	2	2

The results show that in most cases the optimal level of redundancy is N-1. Higher redundancy up to N-2 is proposed for cases with higher failure rates, higher loadings and longer restoration/repair times. For comparison, for existing 132 kV networks, presented in Section 2, the optimal degree of redundancy is between N-0.5 and N-1. Hence, loss inclusive network design justifies higher degree of redundancy.

11.5 Comparison with the present P2 standards

Table 11.39 shows the range of optimal long-term degree of redundancy needed at 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 improve the level of redundancy as shown in Table 11.39, considering the capacity of the networks that is already oversized due to loss considerations.

Table 11.39 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

For the LV networks, the results show that in the majority of cases considered, N-1 might be appropriate especially in the case of higher loadings, higher failure rates and the higher VoLL.

Analysing the results of the studies across different voltage levels, we observe consistent trends that align with intuitive reasoning, postulating that a higher degree of redundancy is generally required in a system which serves larger demand groups (i.e. higher peak demand) with lower network reliability (higher failure rates and higher MTTR), with less flexibility (e.g. low load transfer capability and no mobile units to enable quick restoration), and higher value of security (VoLL). Another observation is that the underground network tends to require less redundancy due to its higher network reliability and higher network cost. This is also observed in the incremental planning studies.

For the HV networks, the results indicate that the N-1 redundancy level is generally adequate although in cases with low failure rates, low group demands and shorter times of supply restoration, the network could be planned with N-0 redundancy level.

EHV networks could be generally planned according to N-1 up to N-1.5 designs. In instances of relatively low reliability and when use of mobile generation is constrained, the economically efficient design may be N-1.75.

For the 132 kV network, the results show an interesting finding according to which the N-2 design is proposed in the majority of cases for overhead networks, and in some cases for underground networks. The results indicate that in higher voltage networks that supply larger group demands the cost-efficient level of redundancy tends to increase. This is an expected outcome and is also in line with the principles of the current security standard.

It can be seen that the optimal degree of redundancy are greater than for existing networks, see Section 2. For existing HV networks typical optimal degree range is between N-0 and N-0.5. For existing EHV and 132kV networks it is between N-0.5 and N-1.

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

The analysis of the optimal network design in the long term clearly indicates a significant network capacity and redundancy at the LV and HV levels, driven by efficient loss-inclusive network design. This capacity and redundancy, possibly in the form of interconnected LV feeders, will provide opportunities for enhancing the coordination of local generation, DSR and energy storage technologies across larger regions, further enhancing the controllability of local distribution networks supplying urban or rural districts.

There is already a significant amount of distributed generation serving as a backup source of electricity supply in the event of a disconnection from the main grid. This generation could be used to facilitate a 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 distribution and transmission infrastructure assets. At the moment however distributed generation is not able to operate in island mode.

As a result of the above factors, a paradigm shift in the network design philosophy may be expected, as illustrated in Figure 11.26. Traditionally, the level of redundancy reduces and the time to restore energy supply increases as voltage level reduces. 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 and their ability to operate in islanding modes may reduce the need for redundancy at the transmission network level[19].

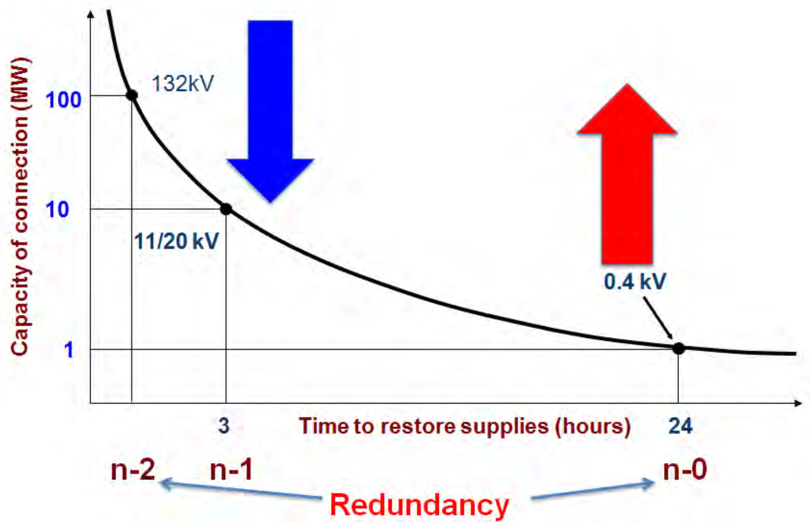

Figure 11.26 Paradigm shift in network design philosophy enabled by smart district networks (microgrids)

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

[19] 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

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 district networks is in line with the concepts focused on the planning, construction, operation, and management of smart cities' energy infrastructure, systems, and services that have recently emerged as a distinctive and potent domain. 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 (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 networks would significantly enhance the security of supply delivered to local communities.

11.7 Conclusions

In the context of long-term network planning, the consideration of network losses is likely to require the replacement of currently used network components with those having ratings that are several times higher than their expected peak loading. At the same time, a large number of distribution network assets are near the end of their useful lifetime, requiring a rather comprehensive renewal programme over the coming years. These circumstances open up opportunities to explore new approaches to ensuring supply redundancy in LV and HV networks.

The cost-optimal level of redundancy depends on several key drivers and network parameters:

- Network reliability parameters – failure rates, restoration times (automation), repair / replacement times
- Costs of network reinforcement
- Costs of operational measures (back-up generation, emergency supply / repair etc.)
- Costs of interruptions (VoLL)

The results of the case studies presented in this section suggest that a higher degree of redundancy is generally required in a system which serves a higher demand, is characterised by lower network reliability (i.e. higher failure rates and higher MTTR) and lower flexibility (e.g. low load transfer capability and no mobile units to enable quick restoration), and when the value of security (VoLL) is higher. Another observation is that the underground network tends to require less redundancy due to its higher network reliability and higher network cost.

The results, see Table 11.40, indicate that the N-1 redundancy level is generally adequate for HV networks, although in some cases the network can be planned with an N-0 redundancy level (e.g. in cases with low failure rates, low demands, and fast supply restoration times). The optimal redundancy level for EHV networks is found to generally be between N-1 and N-1.5. For the 132 kV network, the N-2 design appears to be cost-efficient in the majority of cases for overhead networks, and in some cases for underground networks. The results also indicate that, in line with present security standards, higher voltage networks that supply larger demand groups would require a higher level of redundancy. It can be concluded that the existing security provisions in P2/6 are about right in the longer term.

Table 11.40 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

The results indicate that the two-transformer substation design is generally economically efficient at primary substations and the two- and three-transformer designs are generally economically efficient at bulk supply substations. The optimal degree of redundancy is also driven by the customer perception of the value of security (VoLL) and therefore a higher VoLL tends to yield a higher degree of redundancy.

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