RELIABILITY AND RISK ANALYSIS OF POST FAULT CAPACITY SERVICES IN SMART DISTRIBUTION NETWORKS

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LIST OF TABLES

List of Figures

ABSTRACT

Title: Reliability and Risk Analysis of Post Fault Capacity Services in Smart Distribution Networks

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A thesis submitted for the degree of Doctor of Philosophy (PhD)

Recent technological developments are bringing about substantial changes that are converting traditional distribution networks into “smart” distribution networks. In particular, it is possible to observe seamless integration of Information and Communication Technologies (ICTs), including the widespread installation of automatic equipment, smart meters, etc. The increased automation facilitates active network management, interaction between market actors and demand side participation. If we also consider the increasing penetration of distributed generation, renewables and various emerging technologies such as storage and dynamic rating, it can be argued that the capacity of distribution networks should not only depend on conventional asset.

In this context, taking into account uncertain load growth and ageing infrastructure, which trigger network investments, the above-mentioned advancements could alter and be used to improve the network design philosophy adopted so far. Hitherto, in fact, networks have been planned according to deterministic and conservative standards, being typically underutilised, in order for capacity to be available during emergencies. This practice could be replaced by a corrective philosophy, where existing infrastructure could be fully unlocked for normal conditions and distributed energy resources could be used for post fault capacity services. Nonetheless, to thoroughly evaluate the contribution of the resources and also to properly model emergency conditions, a probabilistic analysis should be carried out, which captures the stochasticity of some technologies, the randomness of faults and, thus, the risk profile of smart distribution networks.

The research work in this thesis proposes a variety of post fault capacity services to increase distribution network utilisation but also to provide reliability support during emergency conditions. In particular, a demand response (DR) scheme is proposed where DR customers are optimally disconnected during contingencies from the operator depending on their cost of interruption. Additionally, time-limited thermal ratings have been used to increase network utilisation and support higher loading levels. Besides that, a collaborative operation of wind farms and electrical energy storage is proposed and evaluated, and their capacity contribution is calculated through the effective load carrying capability. Furthermore, the microgrid concept is examined, where multi-generation technologies collaborate to provide capacity services to internal customers but also to the remaining network. Finally, a distributed software infrastructure is examined which could be effectively used to support services in smart grids. The underlying framework for the reliability analysis is based on Sequential Monte Carlo Simulations, capturing inter-temporal constraints of the resources (payback effects, dynamic rating, DR profile, storage remaining available capacity) and the stochasticity of electrical and ICT equipment. The comprehensive distribution network reliability analysis includes network reconfiguration, restoration process, and ac power flow calculations, supporting a full risk analysis and building the risk profile for the arising smart distribution networks. Real case studies from ongoing project in Electricity North West demonstrate the concepts and tools developed and provide noteworthy conclusions to network planners, including to inform design of DR contracts.

DECLARATION

No portion of the work referred to in the thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

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To those who never stop fighting for what they dream of.

To those who try to make the ideal real.

To my loved ones.

Happiness is only real when shared

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Love you all! I guess this is it!

ACRONYMS

ADN Active Distribution Network

AMI Advanced Metering Infrastructure

API Application Programming Interfaces

CCDF Composite Customer Damage Function

CDF Customer Damage Function

CHP Combined Heat and Power

CIC Customer Interruption Costs

CI Customer Interruptions

CML Customer Minutes Lost

DER Distributed Energy Resources

DMG Distributed Multi-Generation

DMS Distribution Management System

DG Distributed Generation

DNO Distribution Network Operators

DR Demand Response

ECC Equivalent Conventional Capacity

ECOST Expected Customer Interruption Cost

EENS Expected Energy Not Supplied

EFC Equivalent Firm Capacity

EHP Electric Heat Pump

EIC Expected Interruption Costs

ELCC Effective Load Carrying Capability

EM Event Manager

ENWL Electricity North West Limited

FOR Forced Outage Rate

IED Intelligent Electronic Devices

IIS Interruption Incentive Scheme

IoT Internet of Things

LI Load Indices

LV Low Voltage

MG MicroGrid

MV Medium Voltage

MES Multi-energy Systems

OL Overhead Lines

QoS Quality of Service

RES Renewable Energy Sources

RPS Renewable Portfolio Standard

RTTR Real Time Thermal Rating

SCADA Supervisory Control And Data Acquisition

SOA Service-oriented architectures

TLTR Time Limited Thermal Rating

TTF Time to Failure

TTR Time to Repair

TTS Time to Switch

TTI Time to Isolate

UGC Underground Cables

UoM University of Manchester

WTA Willingness to Accept

WTP Willingness to Pay

1 INTRODUCTION

Distribution networks have traditionally been passive networks, distributing power from bulk-supply points to consumers. Yet, due to the increase of distributed energy resources (DER), the emergence of new loads (increase of demand, electrification of transport and heating), active participation of consumers and Information and Communication Technologies (ICT) developments, distribution networks are evolving towards active and "smart" networks. Future distribution networks, embedded between transmission networks and end-consumers, will take advantage of new techniques of monitoring, control, communication infrastructure and small-scale generation in order to support distribution network operation and planning in an efficient and economical way. This chapter will provide some initial discussions around current regulations for UK distribution networks and secondly will give the general picture of a smart distribution network and current challenges around it. Finally, research aims, objectives and contributions will be given.

1.1 Regulation of the Electricity Distribution in the UK

Distribution Network Operators (DNOs) are obliged to plan and develop their systems in accordance with a standard agreed by Ofgem, the UK regulator for gas and electricity markets. The standard currently in force is Engineering Recommendation (ER) P2/6 [1]. It has provided clear guidance to DNOs in the majority of design situations, as to the network capacity required and prerequisites to comply with the security levels agreed.

The level of security in distribution networks is defined in terms of the time taken to restore power supplies succeeding a predefined set of outages. Subsequently, security levels on distribution systems are graded according to the total amount of peak power that can be lost. This network design philosophy is depicted in Table 1-1 , which reproduces Table 1 of ER P2/6.

However, the prospect of continued growth in the deployment of Distributed Generation (DG) and other resources and the emergence of active networks and increased automation may require new approaches to network design. More specifically, the lack of an established framework by which DNOs can reward generators for the provision of security contributions has been identified as a barrier and also the current regulatory arrangements do not incentivise DNOs to make payments to generators. Apart from that, demand side capabilities (through Demand Response (DR) schemes for example) have been recognized to offer considerable capacity relief via the decrease of load demand. Nonetheless, DR contribution is not reflected through ER P2/6. Subsequently, ER PR/6 is currently under review. DNOs are trying to create a new updated framework so the security provided by network assets together with systems and infrastructure provided by others can be properly assessed.

Table 1-1: Recommended Security Level in P2/6[2]

		Minimum demand to be met after	
Class of Supply	**Range of Group Demand**	**First Circuit Outage ('N-1' outage)**	**Second Circuit Outage ('N-1-1' outage)**
A	Up to 1 MW	In repair time: Group Demand	Nil
B	Over 1 to 12 MW	(a)Within 3 hours: Group Demand Minus 1MW (b)In repair time: Group Demand	Nil
C	Over 12 to 60 MW	(a)Within 15 minutes: Smaller of (Group Demand-12MW) and 2/3 Group Demand	Nil

		(b)Within 3 hours: Group Demand	
D	Over 60 to 300 MW	(a)Immediately: Group Demand Minus Up to 20 MW(Automatically Disconnected) (b)Within 3 hours: Group Demand	(c)Within 3 hours: For Group Demand Greater than 100 MW, Smaller of(Group Demand Minus 100 MW) And 1/3 Group Demand (d)Within time to restore arranged outage: Group Demand
E	Over 300 to 1500 MW	(a)Immediately: Group Demand	(b)Immediately: 2/3 Group Demand (c)Within time to restore arranged outage: Group Demand
F	OVER 1500MW	In Accordance With CEGB Planning Memorandum PLM-SP2 or Scottish Board Security Standard NSP 366	

1.2 Ofgem targets

Apart from ER P2/6, Ofgem' Interruption Incentive Scheme[1] (IIS) [3] and Guaranteed Standards of Performance [4] have also impacted distribution network design. The former sets output performance targets for network operators and the latter sets service levels, through regulatory initiatives that must be met on an individual customer basis.

[1] The interruption incentive scheme has symmetric annual rewards and penalties depending on each DNO's performance against their targets for the number of customers interrupted per 100 customers (CI) and the number of customer minutes lost (CML).

Where a DNO fails to provide the prescribed level of service, the customer affected is entitled to receive financial compensation subject to certain exemptions.

IIS targets are set taking into account DNOs' historical performance and other network factors which vary for each DNO. DNO networks have inherited differences, including network design, configuration, and topographical factors such as length of network, customer location and customer density.

Guaranteed Standards of Performance are set for the purpose of protecting customers in relation to quality service provided by DNOs. In the context of the regulation of DNOs in the UK, quality of supply, sometimes referred to as continuity of supply, is measured in terms of the number of interruptions and the length of time for which a customer is off supply. In particular, DNOs are obliged to report annually to Ofgem Customer Interruptions (CI) and Customer Minutes Lost (CML) and are subject to penalties or rewards according to their performance. Under the quality of service performance measures[5], quality of supply indices CI and CML are defined as:

- **Number of customers interrupted per year (CI):** The number of customers whose supplies have been interrupted, per 100 customers per year over all incidents, where an interruption of supply lasts for three minutes or longer, calculated as:

$$\boldsymbol{CI = \frac{total\ number\ of\ customers\ interrupted\ for\ all\ incidents}{total\ number\ of\ customers} \times 100} \tag{1-1}$$

- **Duration of interruptions to supply per year (CML):** Average customer minutes lost per customer per year, where an interruption of supply to customer(s) lasts for three minutes or longer, calculated as:

$$\boldsymbol{CML = \frac{sum\ of\ customers\ minutes\ lost\ for\ all\ incidents}{total\ number\ of\ customers}} \tag{1-2}$$

Ultimately, DNOs provide Ofgem with information each year to help the latter monitor performance against their price control incentives and obligations. For illustration purposes, Figure 1-1 and Figure 1-2 show the DNOs' 2010-11 performance relative to their IIS targets for the year [6]. Figure 1-1 shows that in 2010-11, 13 of the 14 DNOs outperformed their CI targets and will receive a financial reward under the incentive scheme while the remaining DNO (EPN) incurred a financial penalty. Figure 1-2 shows that 11 DNOs beat their CML targets over the same period and will receive a financial reward. The remaining three DNOs (LPN, EPN and SSEH) incurred a financial penalty.

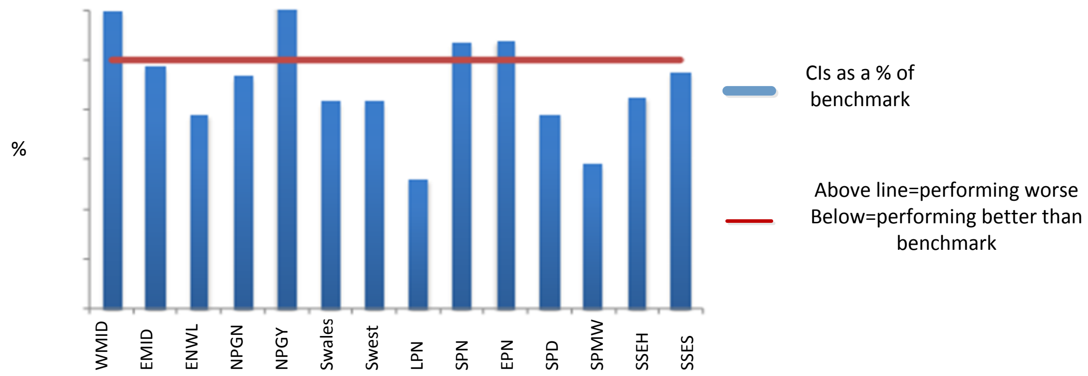


Figure 1-1: CI – 2010-11 performance relative to IIS targets [6]

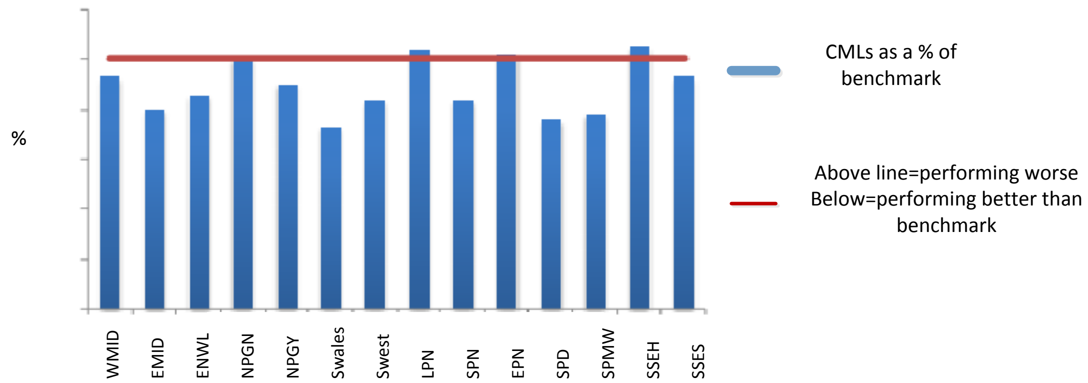


Figure 1-2: CML – 2010-11 performance relative to IIS targets [6]

Typically, DNOs would set an overall business objective to improve continuity of supply in their licence areas so that their CI and CML performance are eliminated. Delivering this objective would reduce fault costs, improve customer service and increase rewards under the regulatory incentive scheme.

Generally, the factors that would affect performance and would play a key role to reduce CI and CML are the following according to [7]:

- Improvements to network design
- Reduce the duration and frequency of planned work reducing pre-arranged shut-downs
- Investing in automation systems to restore customers in under 3 minutes
- Increase through investment the ability to restore supply by remote control

- Increase through investment the availability and number of sectionalizing points and interconnections
- Quicker dispatch and first field response to restore customers not connected to a faulty section
- Provision of alternative supplies
- Quicker fault repair and final restoration

1.3 Smart Distribution Networks

Future electricity networks shall encounter technological advances and forthcoming social, environmental and economical requirements [8][9]. Therefore, following the transformation of the electricity market from a vertically integrated environment into a liberalized one, system security, cost of supply and energy efficiency need to be examined under a new perspective.

The concept of smart grids describes the evolution of electricity networks. According to the European Technology Platform of Smart Grids [10], 'a smart grid is an electricity network that can intelligently integrate the actions of all users connected to it in order to efficiently deliver sustainable, economic and secure electricity supply'. A smart grid exploits state-of-the-art equipment and services, merging them with monitoring, control, communication and self-healing technologies.

Power systems at the transmission level have always been somehow "smart", nonetheless, at the distribution level they are now been transformed from passive to active networks where intelligent control can play a key role. Representative aspects appear to be the bidirectional power flows and the distribution of decision-making and control in comparison with the centralized traditional approach. The concept of an active network has been described as[11]:

'A network where real-time management of voltage, power flows and even fault levels is achieved through a control system either on site or through a communication system between the network operator and the control device.'

According to [9] the evolution towards smart grids would:

- Facilitate an increased integration of DG based on renewable energy sources (RESs)[12], either dispatched in an autonomous fashion or managed by local distribution system operators;

- Enable local energy demand management, interacting with end-users through smart metering systems;
- Benefit from information and communication technology (ICT) developments, so as to offer an increased level of security, quality and reliability;

In summary, the evolution to smart distribution networks assists the integration of DG, RES, demand response (DR) and energy storage technologies, and creates opportunities for novel types of equipment, services and interactions, all of which would need to conform to common protocols and standards. The main objective of a smart distribution network would be to balance efficiently generation with demand, allowing both sides to decide how to operate optimally in real-time.

1.3.1 Reliable Planning and Operation of Smart Distribution Networks

Conventionally, in vertically integrated markets electricity companies were responsible for long-term and operational planning with the aim to manage the power system, and balance generation and consumption[13]. Therefore, they were supervising the whole system and were focusing on supplying their own consumers. Power installations, transmission and distribution networks were designed and sized to meet this objective.

Nonetheless, in a free electricity market, although producers act in a competitive manner, the grid has become a shared infrastructure facilitating all stakeholders of the electricity market. This paradigm change [14] permits to all producers who sell energy and all consumers who extract energy to be connected, resulting to an increased global social welfare. The daily operation of such infrastructure is managed by system operators who comply with arranged regulations.

In this context, the DNOs intrinsically guarantee the distribution network reliability, by maintaining the power quality and by ensuring the security of supply at distribution level in order to deliver energy to each consumer within their own area of operation.

Regarding the distribution network operation, distribution networks are operated radially, with a unique path available from the end users towards the source of supply. Subsequently, if a disturbance occurs, the supply to the customers will only be restored after the repair time of the faulty component. However, in order to comply with the security and reliability targets posed by Ofgem, DNOs design distribution networks as meshed. Hence, following contingencies, by closing a normally open point (NOP) a path for an alternative supply may be established for customers in a circuit not directly affected by the fault. In order to allow this network reconfiguration, distribution circuits are typically loaded at less than their maximum capability, which leads to lower capacity utilisation. Nonetheless, in a 'smart grid' context, the integration of more ICT could enable changing this conventional approach to network operation, particularly through deployment of distributed energy resources (DER) such as Demand Response (DR).

1.3.2 Active participation of consumers through Demand Response

The reliable operation of a power system necessitates a perfect balance between supply and demand in real time. Considering though that both supply and demand levels could change rapidly and unexpectedly due to many reasons, such as generation units forced outages, transmission and distribution lines outages and sudden load change, it is quite challenging at times to maintain that balance. As long as power system infrastructure is quite capital-intensive, DR is expected to be one of the cheaper and rather promising resources available to support the system operation [15].

The US Department of Energy defines DR as 'a tariff or program established to motivate changes in electricity use by consumers in response to electricity prices or to give incentive payments to reduce consumption when grid reliability is jeopardized'. From the utility perspective, DR could provide a flexible load shape to better match the load and operating efficiencies. From the costumer perspective, it could reduce electricity costs and could increase the awareness and control for individual consumers. In particular, costumers might decide to modify their consumption if they get exposed to a more volatile electricity price or get attracted from economic incentives posed from the DNOs.

As far as the impact of DR programs to network planning is concerned, the implementation of such programs can result in a radical change in the planning philosophy adopted so far. In order to meet the prescribed security criteria, system operators would typically rely on the available transmission capacities and ancillary services provided by the generators, assuming that demand is inelastic to prices and inflexible to respond to sudden utility signals mainly due to the lack of essential technology. The failure to incorporate demand flexibility has imposed unnecessary generating plants, production costs and environmental harm. Currently reserve requirements are established based on forecasts of system peak demands that do not take into account DR to price changes. In the future power system, however, which follows the notion of the smart grid, consumers shall play a crucial role in improving the security and reliability of the system. They shall be equipped with smart home energy management systems thus becoming more alert to the energy price and system status[16]. As a consequence, we would observe reduced reliance on generation capacity, reduced investment costs, increased efficiency and environmental benefits.

Apart from the above mentioned DR benefits related to network planning approaches, in summary DR could bring several benefits from an electricity network owner and system operator perspective, as indicated from ENA in [17]:

- Balance power flows and assist in emergency situations on the network.
- Defer and/or avoid network investment by suppressing demand on the network from peak times or at times of network stress.
- Facilitate earlier connection of low carbon technologies as a short term alternative to reinforcing the existing network infrastructure.
- Address network constraint issues at a local level if designed and managed in an appropriate manner to avoid additional network constraints.

To sum up with the DR applications, according again to [17], the value of DR is specific to the various parties (such as suppliers and operators) utilising DR, as depicted in Figure 1-3.

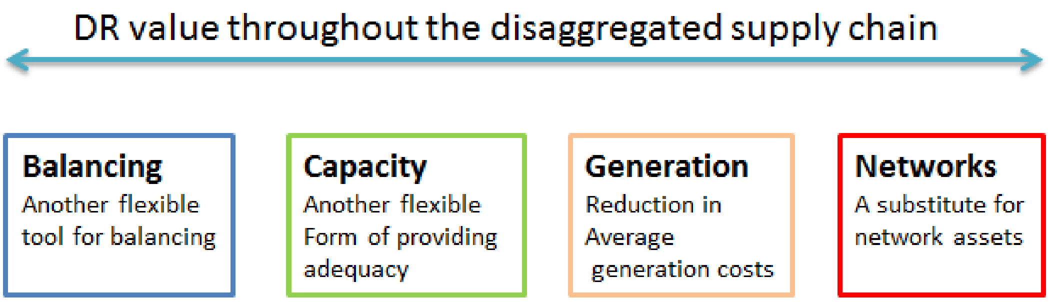


Figure 1-3: DR value chain [17]

Regarding now the different DR programs available, DR has been categorized into price-based DR programs and incentive based DR programs [15]. The classification can be illustrated in Figure 1-4:

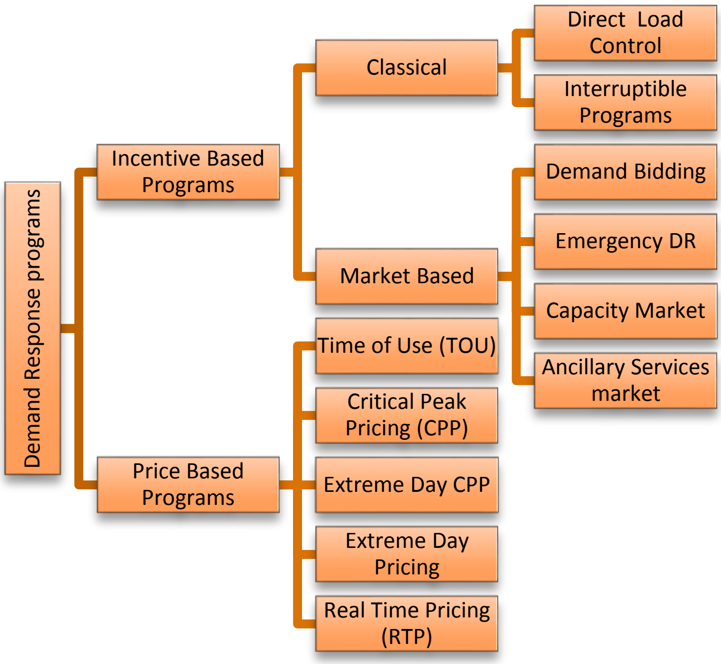


Figure 1-4: Classification of DR programs [15]

In this thesis, incentive based DR programs have been analysed and more specifically Direct Load Control and Emergency DR , where normally contracted customers receive credit benefits or discount rates for their participation in the program, in order to reduce or cease their consumption after a system operator signal. In particular, in direct load control programs, utilities have the ability to remotely shut down participant equipment on a short notice. The most typical remotely controlled equipment are, air conditioners and water heaters, because there is intrinsic storage available in those applications. Direct load control programs usually are addressed to residential or small commercial customers. In a similar perspective, in Emergency DR programs, costumers (usually industrial costumers) are paid incentives if occasionally, they reduce their electricity demand during power shortages or other emergencies. Those programs would facilitate the network operator to receive extra capacity capabilities in case of network disturbance for example, thus avoiding other more costly investments which have to be done before hand.

1.3.3 Integration of Distributed Energy Resources

Current environmental targets in the UK, specify that 15% of energy consumption should come from renewable resources by 2020 and greenhouse gas emissions should be reduced at least by 80% below the 1990 baseline by 2050 [18]. Following this policy and the aforementioned technological developments, it is observed a significant rise of

DG installations, mainly based on renewable energies such as wind turbines and photovoltaic panels. These DG units are planned to be directly integrated into the network at LV and MV level as they are intended to be close to the end consumers. This integration represents a dramatic change in the electricity generation and distribution. In particular, it challenges the operational planning at distribution level, particularly when considering the variability of renewable energy sources and their distributed nature.

However, integration of DG into the system creates the opportunity for DG to substitute distribution network capacity investments. The contribution of DG technologies (and DER in general) to the generation capacity margin is calculated by the extent to which that technology can displace existing conventional generating plant without compromising system reliability. Some DG technologies have a positive capacity margin and provide positive benefits to system capacity costs. Such an example could be the micro-CHP, since its output is typically coincident with the winter peak demand condition, as this is also the time of peak heating demands[19]. In contrast, wind generation has a capacity value of less than 1, and produces disproportionately more energy than it displaces in capacity.

To this end, to enable higher integration of fluctuating electricity generated by wind, storage technologies could be utilised[20]. For instance, bulk energy storage systems such as large-scale pumped storage appear to be an obvious solution to deal with the intermittency of renewable sources and the unpredictability of their output. During the periods when intermittent generation exceeds the demand, the surplus could be stored and then used to cover periods when the load is greater than the generation. Reference [21] presents a whole-systems approach to valuing the contribution of grid-scale electricity storage in future low-carbon energy systems. Authors in [22], continuing their study in [21] claim that the value of storage as a standing reserve is driven by the amount of installed wind and by generation system flexibility. The results of their study show that benefits are more significant in systems with low generation flexibility and with large installed wind capacity. In addition, storage is uniquely able to stock up generated excesses during high wind and low demand periods, and subsequently discharge this energy as needed.

Regarding the capacity contribution of storage, the contribution that storage can make to capacity is assessed by its ability to replace the last generating units in the merit order

[23]. In order to do so there must be sufficient energy available for discharge at times of supply shortage and a high enough power rating to cover the whole of the deficit. The available energy depends on previous storage operation. Finally, storage can only help with a future shortage if it can be subsequently charged from a supply surplus.

In the same context, the emergence of microgeneration technologies along with the rest of DER mentioned previously, have facilitated the development of the microgrid (MG) concept; in turn, MGs can be a key tool to integrate large volumes of DER in distribution networks. In a few words, MGs comprise distribution systems with DER (including demand management, storage, and generation) and loads capable of operating in parallel with, or independently from, the main power grid. Typically, MG components are distributed and located in close proximity to the energy users. The generators, and possibly also loads, are controlled to achieve a local energy and power balance. Such systems can be operated in an autonomous way, if disconnected from the main grid or in a non-autonomous way, if interconnected to the grid [9]. The operation of MGs in the network can provide distinct benefits to the overall system performance, if managed and coordinated efficiently. Indicative MG benefits include the provision of power quality, reliability, and security for end users and operators of the grid, the improvement of distribution system reliability performance and their capability to enable smart grid technology integration. In this context, according to [24] MGs can contribute an appreciable part of the UK energy demand if the appropriate support mechanisms for the generation technologies involved are maintained.

Ultimately, real time thermal rating (RTTR), as part of a larger suite of smart grid technologies is coming out to be a very promising technology that could eliminate or reduce the requirements for reinforcements and investments for conductors and could also very successfully inform network operators for the actual state of the system when needed. In particular, with RTTR (which could be applied both in overhead lines and underground cables), network lines could be loaded at enhanced rating levels (and not in fixed deterministic values), taking advantage of conductors specifications and actual network, environmental and conductor conditions.

1.3.4 Interactions between Distribution Network Actors through ICT

ICT developments and their significant embracement in power systems for the sake of future smarter networks, facilitate interaction between thousands of DG units, system operators, consumers, other actors such as aggregators and energy suppliers.

Information can be bidirectional between the actors involved and transmitted in real time, as well as new decision support tools can exist, to interpret and act upon the new information presented. This would bring an increase in complexity of system operation. However, with the correct frameworks and innovation, this new paradigm of distributed control should facilitate the development of more reliable, cost effective and sustainable systems that achieve maximum utilisation of all the resources connected within them.

In the context of DER integration and ICT advancements, various DER services could prosper in the notion of smart distribution networks, as described in the previous sections. DR programs, energy storage, renewables and DGs could be put forward to offer capacity services, ancillary services, network support services. The DER entities could be managed by energy suppliers, network operators or aggregators. [17] depicts the common interactions that would exist in a smart distribution network through the illustration in Figure 1-5.

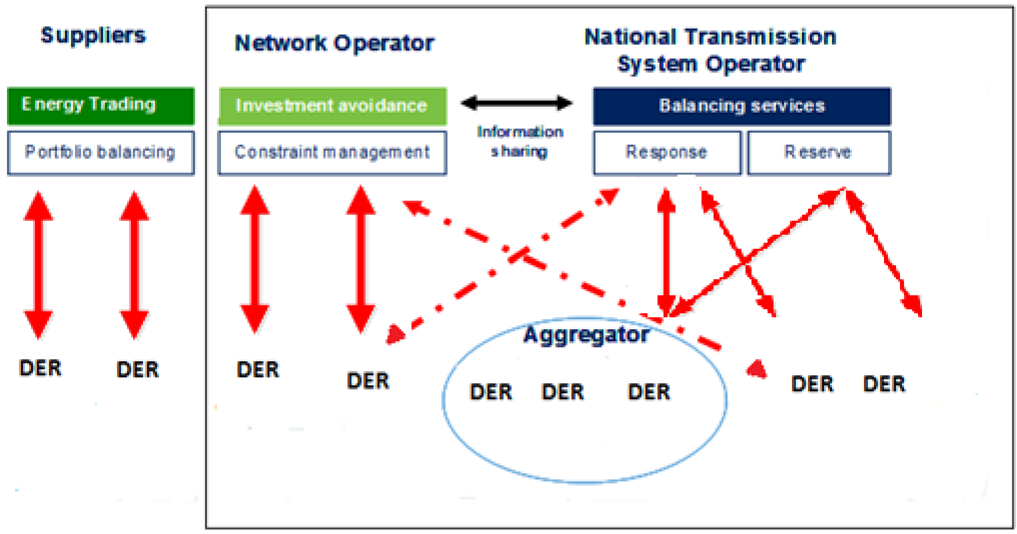


Figure 1-5: Interactions between actors involved in smart distribution networks[17]

1.3.5 ICT technologies for DER integration

In order to reduce the effect of disturbances during emergencies, a reliable and cost effective communication system which complies with Quality of Service (QoS) requirements is of paramount importance[25]. The ICT infrastructure supporting the active network operation is developed following similar framework for SCADA systems[2], creating an active system called Distribution Management System (DMS). DMS supervises the operation of the distribution network. Its main functionalities are to collect electrical measurements and perform the state estimation[25]. Also, it communicates with the Intelligent Electronic Devices (IEDs) which are distributed around the distribution network to support protection and operation activities.

According to [25], Power Line communication, wired and wireless communication are potential ICT technologies that can generally be applied in the power system infrastructure. Additionally, depending on the circumstances and taking into account the pros and cons of each technology, an evaluation should be carried out to determine the best selection for the power system case. Internet is considered a quite appropriate communication network to control economically the distribution system. Nonetheless, it doesn’t ensure the QoS requirements that smart distribution systems would demand nor disputes all the security concerns related to its function [26]. Under those circumstances and based on [25], for urban networks where communication infrastructure is widely built, Internet based Virtual Private Network (VPN) which is a shared communication network architecture is a potential secure solution, while for rural areas WiMAX is an alternative applicable option. In particular, VPN entails the advantages of a dedicated private network while its functional costs are distributed to its users. Moreover, WiMAX has a low cost and large bandwidth, however, as other wireless technologies it is threatened by propagation impairments[27]. Based on the above considerations, in the context of smart distribution networks, [25]propose two configurations of active network management systems, one for urban and one for rural area. The general configuration is formed by a server, which performs the role of DMS, connected via an optical fibre link to the communication infrastructure, and several routers (one for each DER) used to interface the controllable resources with the communication system. The

[2] SCADA (Supervisory Control and Data Acquisition) is a management system which consists of deploying a network of local controllers across a distribution network with the aim of properly managing the distribution network in a range of operational conditions in an autonomous as well as collaborative manner[78][39]

proposed active management model is depicted in Figure 1-6. To this end, the above mentioned configurations and ICT frameworks will be selected in the next chapter where smart distribution networks will be modelled.

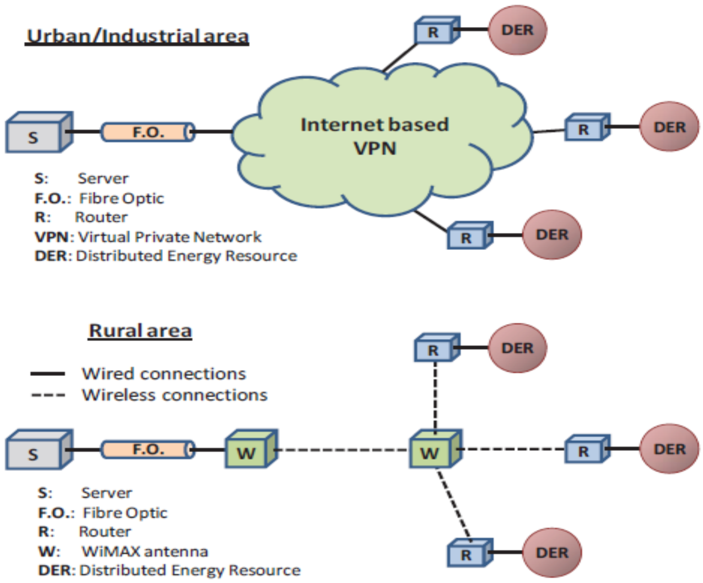


Figure 1-6: Models of an active management system [25]

1.3.6 Power and ICT network reliability interdependence

Uncertainty and unreliability of ICT networks could negatively affect future power networks. Examples of ICT failures that could threaten the reliable operation of the power network are failure in digital devices, loss of communication, intrusion attempts, software failures, untypical changes in the status of switching devices or setting of digital relays. Consequently, when a reliability assessment is carried out, these failures need to be detected and included in the reliability evaluation model.

The impact of ICT failures on power networks has been examined in [28] by introducing the cyber-power interdependencies. More specifically, interdependency means that the correct and appropriate operation of one element depends on the existence and proper function of some other elements. Direct interdependencies are those that failures in the ICT network cause a failure or a change in the power network. In contrast, indirect interdependencies are those failures that do not directly cause a failure in the power network, but indirectly they increase the risk of a failure or impact negatively the performance of the power network.

In another study, authors [29] examine the coincidence of the ICT failure with respect to the electrical failure. According to the study, if the ICT failure occurs before an electrical failure, the system operator may not be warned about the degradation of their system, so corrective actions may not be implemented in time to restore the system to the normal state, or their ability to deal effectively with the electrical disturbance may be significantly compromised because of the ICT failure. Respectively, in a case that the ICT failure occurs after the electrical failure, again the restoration of the electrical disturbance will be delayed either due to lack of provision of real-time data, or inaccurate representation of the system state, or a delay in the implementation of the corrective action. The results of the study indicate that an increase in the failure rate of the ICT infrastructure results in an increase in load shedding. On the contrary, an increase in their repair rate contributes to decreasing the load disconnection and to increasing reliability of the entire system.

Regarding the ICT infrastructure topology proposed in [25], the following studies of the same authors in [30][31], take into account the impact of ICT on the reliability of an active distribution network. In case that the technology used is Internet, the entire Internet based VPN has been modelled as a unique element, due to the extremely high meshed structure of the Internet network and its self-healing characteristic. On the contrary, when WiMAX communication infrastructure is considered, each antenna is modelled separately, representing the true communication network scheme adopted. The results of their study indicate that performance highly depends on the communication signal and that the position and number of WiMAX antennas plays a key role for the active operation success.

1.4 Need for quantifying the reliability performance of smart distribution networks

Reliability modelling and evaluation of distribution systems has been subjected to lower attention comparing to transmission and generation systems and this is mainly justified from its low capital cost and the localized effect of its outages. However, analysis of customer failure statistics of most utilities shows that the distribution system makes the greatest individual contribution to the unavailability of supply to a customer [32].

Additionally, previous sections demonstrated the radical change of the operation philosophy of distribution networks from passive to active. The introduction of DER technologies, such as DR, energy storage and other renewables, along with relevant ICT infrastructure, when accompanied by appropriate control strategies would reduce the requirements for network investments. DNO investments would include building new capacity and refurbishing and replacing existing assets as they reach the end of their technical lifetime. Investments though are highly driven from the changes happening in distribution networks.

To this end, those serious changes, along with the respective regulation for a continuous and high quality of service create the significant need to understand the impact that various DER technologies and accompanying control strategies would have on network reliability and what would be eventually the risk profile of a smart distribution network. The reliability and risk assessment of smart distribution networks, and also the assessment of the capacity contribution of integrated resources would provide network operators with important information and guidance for future investments and planning scenarios.

More specifically, the stochastic nature of the resources involved in the electricity value chain, the capacity services and corrective control actions that could be made in real time, after disturbances or after utility signals necessitate the introduction of novel techniques to assess the level of risk in power networks. Traditional concepts of system security and deterministic ways of risk calculation and planning strategies such as ER P2/6 will not be entirely appropriate in the context of smart grids and smart distribution networks considering that with the emergence of new technologies, it is possible to release capacity and utilise network in a more efficient way. Therefore, in this thesis, probabilistic measures and techniques will be used, that take into account the stochastic nature of active consumers, renewables, ICT infrastructure and corrective actions taken from the network operators after random network faults and disturbances.

To this end, the reliability performance of those smart distribution networks will be evaluated, and DNOs would provide Ofgem with CI and CML indicators, as well as additional information for DER performance and contribution. A proper assessment of networks reliability performance is of paramount importance since it is the formal indication of presenting the level of quality of service and continuity of supply. Typically, most European countries would ensure a high quality energy supply and it has been observed that DNOs make efforts for improvement and increased satisfaction for the quality of service. The number and duration of interruptions in European networks is generally low, ranging from about 15 minutes to 400 minutes a year, as depicted in Figure 1-7. Consequently, to maintain this positive trend, it is quite important to fully understand and properly model the novel entities and mechanisms integrated in distribution networks.

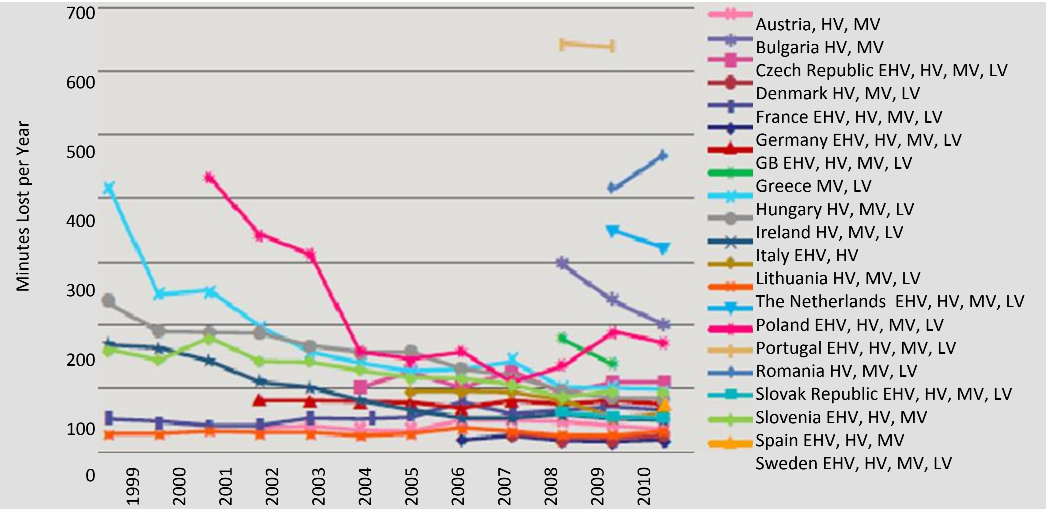


Figure 1-7: Unplanned long interruptions-minutes lost per year (1999-2010)[33]

1.5 Distribution Network Planning with Differentiated Reliability

If we exclude a small number of special cases, electricity networks are planned on the basis that all consumers place the same value on a continuous supply of electricity and should thus be treated equally. In contrast, one of the assumptions underlying future networks is that consumers can submit a real-time demand curve. High prices associated with emergencies will thus automatically reduce the load and thus significantly decrease the need for involuntary load shedding.

In this context, in the envisaged smart distribution network, it is assumed that network users will not place the same value on a continuous supply of electricity. Essentially, such a system would deliver different levels of reliability to different consumers depending on their willingness to pay. This crucial change of consumer behaviour, already defined as DR should be taken into account in current network planning practices. The novelty of this idea lies in moving from a preventive and deterministic security approach to network planning to a corrective one that takes into account individual users' reliability level requirements.

In a corrective approach to network planning, network planners would practically have to evaluate how much network capacity is needed beyond what is needed to satisfy the peak demand when there are no unscheduled outages. From an individual consumer's perspective, this involves balancing the cost or inconvenience of having to curtail or reschedule energy usage against the cost of operational security measures and the cost of additional network investments. The framework developed would eventually contribute to informing investment strategies and improving reliability of active networks.

The inconvenience of unwilling load shedding or the cost of interruption is typically reflected by the Value of Lost Load (VOLL). VOLL represents the value that electricity users attribute to security of electricity supply and the estimates could be used to provide a price signal about the adequate level of security of supply. Typically, those types of values accrue from the impact that electricity outages could bring to electricity users. Therefore, information such as the one depicted in Figure 1-8 are essential to determine the value that electricity users yield to a continuous supply.

According to [34] two approaches could be used to calculate the VOLL through the terms of willingness-to-accept (WTA) payment for an outage and willingness-to-pay (WTP) to avoid an outage for domestic and small and medium sized businesses electricity users. Those approaches include the choice experiment and the contingent valuation questions. In essence, a choice experiment involves asking a consumer to choose between alternatives about electricity outage scenarios and prices to pay or receive to avoid or experience the outage. The choice experiment approach allows the examination of the WTA and WTP of electricity outages of different lengths, seasons, days of the week and times of the day. Econometric estimation and standard statistical techniques are then used to convert the choice experiment results into £/MWh VoLL figures and confidence intervals. In contrast, the contingent valuation method, asks consumers directly what they would be willing to pay/accept to avoid/experience the outage.

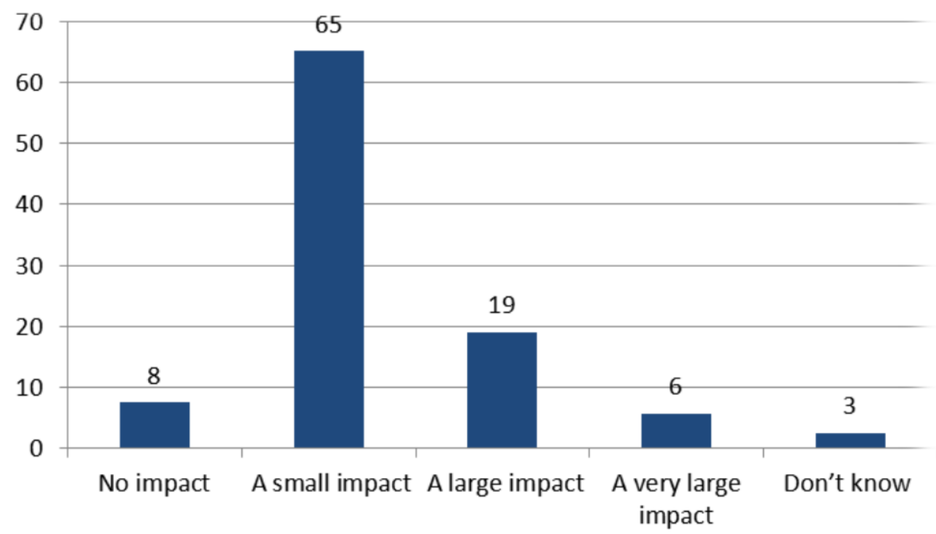


Figure 1-8: Impact would an electricity outage of one hour have on your household (% of total number of households having participated in the survey)[34]

1.6 Research Aims and Objectives

As elaborated above, future electricity networks would face the high degree of uncertainty because of spread penetration of renewable resources and ambiguous increase in load demand, and high complexity due to the integration of large number of heterogeneous devices, ubiquitous ICT, as well as the interaction of many actors such as generators, aggregators, regulators and consumers [35].

Furthermore, traditional concepts to maintain system security such as through preventive N-1 deterministic criteria have been challenged, with the argument that information and control available in real time through ICT could allow deployment of relevant corrective actions following contingencies.

In order to identify easier the aims and objectives of this thesis, research gaps could be summarized in the following points (detailed critical literature review can be found in every chapter):

- Reliability impacts of novel technologies such as DR and storage have been already addressed by researchers. However, reliability assessment of smart distribution networks, including also the stochasticity of ICT and also examining the reliability implications of the involved technologies to increase the capacity utilisation of the existing assets has not been sufficiently addressed. Although for example, researchers have proposed DR as an option to enhance the utilisation of current distribution networks, an extensive reliability analysis of such a scheme which evaluates the potential DR capacity requirements associated with this objective has not been done.

- Additionally, regarding the technologies integrated into the distribution network, a systematic reliability analysis framework to assess potential services that could be introduced has not been widely seen in the literature. Typically, in the literature a particular technology is used and examined, such as either only DR or storage, or even a combination of resources. However, in this thesis, the proposed framework based on sequential Monte Carlo simulations (SMCS) while also includes a realistic distribution network analysis, is ecumenically implemented for various DER technologies (making obviously the appropriate modelling arrangements for each particular technology).
- Apart from that, MGs, wind farms and storage have been already proposed as potential resources and valid solutions mainly for network reliability improvement. Nonetheless, their reliability support is not commonly linked with the smart distribution network concepts and the accompanying interactions between consumers and operators/aggregators. Thus, their support and accruing benefits are frequently considered as impacts and not as services. On the other hand, the resources involved and presented in this thesis are examined in the light of capacity services offered to the DNOs to better establish capacity contribution from non-conventional assets and as a means to postpone network investments.
- It has been observed that regardless the reliability assessment tools regularly proposed for distribution networks in the existing literature, network analysis is not commonly incorporated in the assessment. Thus, although the reliability assessment might seem coherent by utilising widely accepted reliability evaluation techniques, when the analysis includes variable and uncertain generation and load profiles (as such from wind generation, DR profile, variable load demand and sudden peaks or imbalances between load and generation) and also random faults, it is of paramount importance to be in the position to identify the potential network thermal and voltage violations happening in the distribution network (this typically happens by performing the power flow calculations). To this end, especially for distribution networks, when reliability

implications are addressed by researchers without a simultaneous network analysis, conclusions cannot be considered as extremely realistic.

- Furthermore, although researchers have already proposed and examined various DR programs (such as incentive or price-based programs) and also, network operators have indeed applied DR programs (such as emergency DR with large customers [36] or residential DR for reducing demand in exchange of compensation [37]), it not at all common that such real life implementations have been replicated by researchers. In this thesis a DR scheme proposed by a UK DNO (the C_2C scheme proposed by Electricity North West Limited) has been examined in terms of reliability and also with the aim to identify the actual needs for DR and to inform potential DR contracts.
- Moreover, regarding the implementation dynamic thermal ratings of underground cables in distribution networks, there is little work that has been done, especially in terms of reliability analysis, capacity unlock and also when the certain technology is combined with other DER technologies such as DR. In this thesis, DR has been combined with dynamic thermal ratings to further utilize network lines and assess reliability and network capacity impacts and mainly inform DNOs as to how much more demand could be accommodated without proceeding to new investments.
- Finally and most importantly, it is identified that a comprehensive and unified framework to identify the reliability and capacity contribution of novel technologies supporting active network support and DNO corrective control, as well as risk implications related to them, has not yet been sufficiently examined. Furthermore, although most of the technologies introduced, have been evaluated from the perspective of reliability impacts, they have not been sufficiently addressed from the perspective of the DNO operating and planning philosophy and tactics. In this thesis, it will be shown that a probabilistic reliability assessment, combined also with various sensitivity studies for different levels of load growth and different DER capacities or contracted DR customers could extremely affect the DNO decisions for investments and reinforcements.

In this respect, this work, while constituting a part of the smart grid vision, aims to provide a general framework to quantify the reliability and risk profile of new, smart distribution networks. Reliability assessment methodologies will be used, and relevant reliability and risk metrics will be proposed to determine the reliability and risk profile of the key components within a smart distribution network. The proposed metrics will be measured via the application of Monte Carlo Simulation techniques. The ultimate aim is to estimate the risk that the novel technologies and the complex corrective services introduced in the system would bring and then to inform planning and operation decisions.

The analysis involves increased customer participation in system operation through DR; an extensive use of ICT to allow the effective implementation of any DR scheme; network reconfiguration strategies which contradict with the distribution planning and design strategies adopted so far; integration of storage and other DER into the distribution networks for provision of network support services; the formation of MGs and thereinafter their interconnection into the distribution network to provide again post-contingency services and allow the connection of new customers beyond security limits and the application of time-limited thermal ratings to stress the network lines' utilisation. In this context, objective of this thesis is to present qualitative and quantitative studies showing the impact of novel technologies on network planning and operation.

To this end, in this thesis, DR, time-limited thermal ratings, energy storage, wind farms and MGs would offer post-contingency network support, allowing the DNOs to increase capacity utilisation, supply greater load demand and improve reliability. The specific analysis has been done by consistently evaluating the reliability performance of a distribution network when those services are introduced. It is interesting also to note that, distribution network restoration process after a fault has been consistently modelled and also an extensive network analysis has been done through power flow analysis throughout the reliability assessment process.

On the above premises and to achieve the general aim of this research, this thesis will carry out studies to meet the following objectives:

- Evaluate the reliability performance of different distribution network configurations (ring and radial) and different levels of automation (manual or automatic operation of NOP and switches)
- Develop a comprehensive and realistic DR direct load control scheme for post-fault network support and to examine the potential contribution of the DR

scheme on distribution network capacity through an extensive sensitivity analysis

- Present an ICT infrastructure to support a DR scheme and evaluate the impact of ICT failures on distribution network reliability and on the implementation of post-fault emergency services
- Evaluate the reliability implications related to a time-limited thermal rating model for underground cables in order to further utilise them above their sustained rating up to the maximum allowed temperature
- Propose a MG framework for post-fault services and evaluate the MG impacts on distribution network reliability and on external and internal MG customers
- Propose collaborative wind farm and energy storage operation strategies to provide post-fault capacity services and evaluate the capacity contribution (through the concept of capacity credit) of the proposed schemes
- Present a distribution software infrastructure for services in smart grids and to evaluate the reliability implications related to that
- Carry out comprehensive case studies on real networks to demonstrate the concepts developed and their practical applicability and value

1.7 Main Contributions

The drivers that will shape the future electricity networks are various including the increased variability in the availability of generation, the increased utilisation of existing assets due to load growth, increased integration of distributed generation and renewables, increased participation of consumers, ageing of infrastructure and needs for new investments and engagement to reduce carbon emissions and increase the integration of low carbon technologies.

These changes indicate that future electricity and energy networks in general will be difficult to manage and design. Real time decision-making techniques will be implemented to coordinate storage operation, demand response actions, real time thermal rating systems, distributed generation, network power flow management and supply restoration. The risk and implications associated with these concepts and their functionality and role inside the electricity networks need to be identified and properly modelled and captured.

This thesis, in essence, investigates the risks and implications of the above mentioned challenges inside a smart distribution network, through an extensive reliability and risk assessment framework. In particular, technologies and operational strategies are integrated into the distribution network with the main aim to provide post fault capacity services. Reliability and risk indicators, along with important information about the accompanying capacity contribution of the resources involved, are evaluated and provide interesting feedback for the DNOs, to help them make planning decisions.

Consequently, driven by the objectives mentioned in the previous paragraph, the contributions of this thesis are summarized below:

1. **Development and assessment of a comprehensive and realistic direct load control DR scheme for post-fault capacity services.**

A direct load control DR scheme is proposed, where during a contingency event DR customers are disconnected according to a predetermined priority list which is based on customers' costs of interruption. The reliability assessment studies of the DR scheme have taken into account asset emergency ratings, realistic load profiles, power network constraints, payback effects and the cost of interrupted load. The risk of contracting varying levels of DR has been assessed and in particular the risk of contracting fewer DR customers than required when applying deterministic security standards. Finally, a techno-economic analysis has been performed to estimate the ''unreliability costs'', borne by the DNO, for normal and DR customers with differentiated reliability levels in different scenarios.

2. **Assessment of the reliability and capacity implications related with the application of time-limited thermal ratings in combination with DR.**

The well-known CRATER tool, adopted from [38] has been utilised to calculate the time-limited thermal ratings (TLTRs) in underground cables and thus utilise harder the network lines, based on the actual loading, network conditions and most importantly the cable temperature which determined the realistic loading limits of the cable. TLTRs are combined with the DR scheme already proposed and a reliability assessment based on SMCS is executed to determine the additional load demand that can be supplied by the existing network and also to evaluate the network reliability impacts.

3. **Development of a MG framework for post-fault services and evaluation of MG impacts on distribution network reliability.**

A framework to implement MG services into the reliability assessment has been presented with the aim to evaluate the impact of those services on the distribution network as a whole and on the expected reliability of customers located internal and external to the MG. The technologies combined to build the MG have been based on [40] and [41]. In particular, the potential of a MG to use its energy surplus to supply external customers in the area, should the area become isolated from the grid after a contingency occurs has been quantified. Finally, reliability metrics related to the operation of a MG as an island have been also presented and calculated.

4. **Development of collaborative wind farm and energy storage operation model for provision of post-fault capacity services and evaluation of their capacity contribution.**

An analysis of coordinating the operation of wind farm and electrical energy storage in the context of smart grids with significant ICT enabled automated infrastructure has been proposed. Different operational strategies (collaborative and non-collaborative) for those two technologies have been assessed with the aim to maximize network capacity support during post-fault operations. The reliability implications associated with these strategies have been studied. Finally, the classic concept of Effective Load Carrying Capability has been used to calculate their capacity contribution.

In order for the above mentioned contributions to be accomplished, additional work was carried out, either with the purpose to support the ongoing research or to provide further insights. The following bullets contain the supplementary work:

- **Development of a reliability assessment framework and relevant modelling based on SMCS. The developed framework is easily modifiable to model the specific post fault services suggested.**

The reliability assessment tool built for the analysis of distribution network reliability has been based on SMCS and time series analysis, while properly modelling the operation of each particular entity introduced. Distribution network reconfiguration following restoration process has also been included in the study in order to realistically reflect the reliability profile of the network. Isolation, switching and repair actions of network components have been properly modelled. The built framework takes into account the stochastic failure nature of both the electrical network lines and the remote or manual schemes that are used to support the proposed active operation and the rest of ICT equipment failures. Finally, traditional reliability indicators such as CI, CML, EENS and load point indices have been evaluated, but also specific risk indicators related with the performance of the integrated technologies have been proposed. The built tool is characterized in the thesis as the “SMCS reliability modelling tool”.

- **A critical literature review of reliability assessment of power systems with the consideration of DER resources such as DR, energy storage, wind generation and MGs.**

  Reliability assessment techniques have been studied, placing greater focus on simulation techniques and most specifically Monte Carlo simulations. Reliability methods and reliability impacts from the above mentioned technologies are critically discussed in each specific chapter, from chapter 3 to chapter 7. Furthermore, in Chapter 2, the Sequential Monte Carlo Simulations (SMCS) framework philosophy has been extensively described.

- **Assessment of the reliability implications of different distribution network configurations.**

  Different network configurations along with DR have been studied as an alternative solution to network investments to increase the utilisation of the existing infrastructure. More specifically, ring and radial distribution network operation have been evaluated. The capability of the different configurations has been compared on capacity utilisation, network capacity expansion, reliability performance and network losses. Additionally, different levels of automation have been considered, including manual and automatic operation of distribution network switches. At the same time the impact of DR on network reliability and its overall contribution to the system reliability performance under different configurations has been studied.

- **Discussion and evaluation of an ICT infrastructure to support the DR scheme and assessment of the impact of ICT failures on distribution network reliability and on the implementation of post-fault emergency services.**

A decentralized ICT infrastructure topology and specific communication technology combinations have been adopted from existing literature on smart distribution networks [39] and [31]. The impact of ICT failures on reliability, happening either due to bad weather conditions (when wireless technologies are used) or happening due to random equipment failures, has been assessed and captured from the reliability analysis framework developed.

- **Discussion of a distribution software infrastructure for services in smart grids and development of case study application to evaluate the reliability implications related to the proposed framework.**

  A comprehensive framework for the development of a distributed real-time event-based software infrastructure that could involve different actors in a smart grid context has been extensively described as presented and proposed from existing literature[42]. The proposed middleware platform has been used as the ICT support to provide real time DR services. A representative case study has been presented and thoroughly evaluated while utilising the platform and subsequently the feasibility of the proposed platform and the prerequisites for an extensive deployment of similar practices throughout the UK has been studied.

1.8 Publications

The above contributions in this thesis lead to peer-reviewed journal and conference publications:

1) L. A. Syrri and P. Mancarella, "Reliability and risk assessment of post-contingency demand response in smart distribution networks," *Sustain. Energy, Grids Networks*, vol. 7, pp. 1–12, 2016

2) E. Patti, A. L. A. Syrri, M. Jahn, P. Mancarella, A. Acquaviva, and E. Macii, "Distributed Software Infrastructure for General Purpose Services in Smart Grid," *IEEE Trans. Smart Grid*, 2015

3) L. A. Syrri and P. Mancarella, "Reliability evaluation of demand response to increase distribution network utilisation," *2014 Int. Conf. Probabilistic Methods Appl. to Power Syst.*, pp. 1–6, 2014.

4) L. A. Syrri and P. Mancarella, “Evaluation of Reliability Performance of Distribution Networks Implementing Demand Response Schemes,” *9th Mediterr. Conf. Power Gener. Transm. Distrib. Energy Conversion.*, 2014.

5) L. A. Syrri, E. A. M. Ceseña, and P. Mancarella, “Contribution of Microgrids to Distribution Network Reliability,” in *PowerTech*, 2015.

6) L. A. Syrri, Y. Zhou, E. . Martínez Ceseña, J. Mutale, and P. Mancarella, “Reliability and economic implications of collaborative distributed resources,” in *CIRED Workshop - Helsinki*, 2016, no. 260, pp. 1–5.

1.9 Thesis structure

In accordance with the aforementioned objectives and contributions, the thesis is structured as eight chapters, which are summarised as follows:

Chapter 1 gives a general overview of the background of the research work in this thesis, including current planning regulations in the UK and discussions around the transit of the distribution network from passive to active into the context of smart grid. The need to quantify the reliability performance of smart distribution networks is discussed along with the capacity considerations of the integrated DER technologies and DR. Finally, the objectives and main contributions of this project are discussed.

Chapter 2 describes the probabilistic framework for the reliability evaluation of smart distribution networks. More specifically, the selected computational approach, namely the sequential Monte Carlo simulation is reviewed and presented, providing all the necessary background information to build the tool for the probabilistic reliability assessment. The selected distribution network reliability indices are also presented and described and also an approach to deal with the computational time burden is proposed. Finally, distribution network operation under normal and emergency conditions is described and the distribution network restoration process is also described thoroughly.

Chapter 3 provides a set of DR studies which are based on a realistic DR scheme, named ‘Capacity to Customers’, implemented by Electricity North West in trials in the North West of England, which is basically an inter-trip scheme where DR customers are disconnected by the DNO in case of emergency. The test networks provided by Electricity North West are presented. Reliability assessment is performed for ring and radial configurations, for different levels of automation. Ring and radial configurations are also compared in terms of capacity utilisation and losses. The ICT infrastructure which supports the DR scheme is presented and a sensitivity analysis for the impacts of ICT failures is performed.

Chapter 4 introduces a priority DR direct load control scheme. The philosophy that underpins the DR scheme is described which is mainly based on the evaluated cost of interruption. The priority list for the disconnection of DR customers is developed and also the OPF algorithm that is included in the DR scheme is defined. The payback effects concept is introduced and integrated into the algorithm. A techno-economic analysis evaluates reliability and risk indicators related with network reliability performance and DR operation and also unreliability costs are also evaluated. A sensitivity analysis to evaluate the risk associated with the DR capacity level is performed and implications are discussed.

Chapter 5 introduces the concept of time-limited thermal ratings (TLTRs), where intense utilisation of underground cables until their temperature rating has been reached is allowed. TLTRs values for the cables are calculated from the CRATER tool previously developed by EA Technology; therefore, the CRATER tool and also the rating calculation model are described in summary. Additionally, cable elements are described and also the concepts of deterministic ratings are discussed. The TLTRs are combined with the priority DR scheme introduced in chapter 4 and a reliability assessment for various scenarios of loading levels is executed to evaluate to what extent networks can be overloaded.

Chapter 6 introduces the idea of MG services for post contingency network support. An overview of MGs and interactions between the actors which support MG services is given. The algorithm to integrate the post contingency MG support into the reliability assessment is presented. Additionally, the MG multi-generation components are described. Finally, MG related reliability and risk metrics are introduced and an extensive reliability analysis in a real case study is performed.

Chapter 7 presents a framework for collaborative DER operation for post-fault capacity services. Initially, the reliability implications of power systems when integrating DER are discussed and reviewed. Then, the proposed model for the operation of wind farm and electrical energy storage is properly described. The effective load carrying capability concept is introduced and then the capacity credit of different operational strategies for the DER selected is calculated, while performing reliability assessment studies into a distribution network case study.

Chapter 8 presents the main conclusions of this thesis. The key results and findings of this project are also summarized. Finally, suggestions for future work are discussed.

Finally, regarding the appendices contents:

Appendix 1 discusses the application of a middleware platform for general purpose services in smart grid. At first all the layers forming the middleware platform are introduced and defined. Afterwards, an example of peer to peer communication paradigm in distribution networks is demonstrated, discussing the implications of peer to peer communication reliability of the proposed middleware solution. A case study application based on DR services for corrective control demonstrates the capabilities and challenges of the proposed middleware framework.

Appendix 2 provides the ac power flow and ac optimal power flow equations as formulated within the Matpower software.

2 Probabilistic Framework For The Reliability Evaluation Of Smart Distribution Networks

An assessment method is necessary to quantify the performance of the smart distribution network under investigation. The complexity characterizing each of the technologies involved, such as the intertemporal constraints of demand response and energy storage, the fluctuations of the wind profile and the stochastic faults happening in random times indicate that a time series analysis is of paramount importance to properly capture the behaviour and impacts of the above mentioned facts. Therefore, in this thesis, the Sequential Monte Carlo Simulation (SMCS) technique has been selected as the reliability assessment method. In this chapter, SMCS methods are extensively described. Furthermore, distribution system operation under normal and emergency conditions is described and the network restoration process is also illustrated and later inserted into the SMCS process along with the network analysis. Ultimately, the chapter gathers all the above-mentioned described fundamentals in one framework, thereinafter referred as the "SMCS reliability modelling tool" which will be used for the reliability assessment deployed in the rest of the thesis.

2.1 Power System Reliability

The primary objective of electric power systems is to provide electrical energy to their consumers in the most economical manner and with an acceptable level of continuity and quality[43], in other words reliability. The North American Electric Reliability Council (NERC) defines power system reliability as follows [44]:

"Reliability, in an electric power system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service."

Reliability can be addressed by considering two basic functional aspects of the power systems, adequacy and security [43]:

5. **Adequacy** relates to the existence of sufficient facilities within the system to satisfy the consumer load demand. These include the facilities necessary to generate sufficient energy and the associated transmission and distribution facilities required to transport the energy to the actual consumer load points. Adequacy is therefore associated with static conditions which do not include system disturbances.
6. **Security** relates to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to whatever perturbations it is subject. These include the conditions associated with both local and widespread disturbances and the loss of major generation and transmission facilities.

Nonetheless, a continuous supply of electrical energy cannot be guaranteed at all times due to either forced outages of plant or removal of facilities for scheduled maintenance or most importantly due to failures of equipment or the system which could happen stochastically and unexpectedly [32]. These undesirable events could provoke interruption for a small number of customers or could lead to a widespread disruption of supply. In this context, the probability of customers being disconnected can be reduced by increased investment during the planning and/or the operating phase. However, overinvestment could lead to increased costs and it is evident therefore that the economic and reliability constraints can conflict, and this can lead to difficult managerial decisions at both the planning and operating phases.

Regarding distribution network planning in the UK, a cost-benefit analysis approach has been used to determine the optimum economic and technical design of the distribution network. Figure 2-1 shows the concept of cost-benefit approach that underpins the ER P2/6. This approach balances the cost of outages, which is affected by the stochastic behaviour of the system, against investment and maintenance costs. Cost of outages reduces when redundancy is increased, because typically this reduces the number of interruptions. Increased redundancy apparently increases investment costs and also improves the reliability performance of the network. The optimal compromise regarding the network capacity and redundancy is found where the incremental cost of investment and maintenance is equal to the benefit of reducing cost of interruptions.

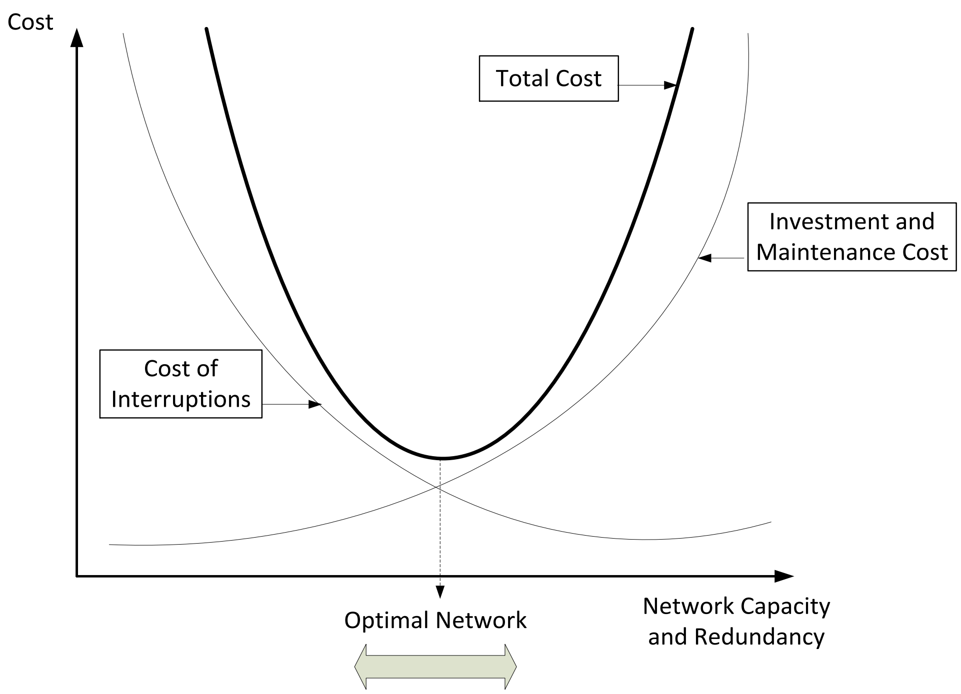


Figure 2-1: Concept of Cost-Benefit Analysis [45]

2.1.1 Probabilistic Reliability Criteria

Design, planning and operating criteria and techniques have been gradually developed in an attempt to drive decision making when economic and reliability constraints coexist. Initially, the criteria and techniques used in practical applications were only deterministic (such as the "N-1" criterion in transmission planning), especially due to limitations of computational resources and lack of realistic reliability techniques[43].

However, the main drawback of deterministic criteria is that they do not reflect the stochastic nature of system behaviour, of customer demands or of component failures and as a result the need for probabilistic evaluation of system behaviour has been acknowledged from early times [46].

Probabilistic evaluation acknowledges not only the severity of an event, but also its likelihood of occurrence. Appropriate combination of severity and likelihood yields indices that accurately reflect system risk. For that reason, probabilistic techniques are considered suitable for assessments related with power systems. Additionally, high impact-low probability events are taken into consideration by probabilistic models. Therefore, probabilistic power system evaluation provides an accurate measure of the risk level, which is vitally important in supporting the real-time operational decision-making process and the integration of ICT, DG and active network management into the reliability assessment process.

2.1.2 Reliability Evaluation Techniques

The two main approaches for power systems reliability assessment are analytical and simulation techniques[47]. Analytical techniques represent the system by a mathematical model and evaluate the reliability indices from this model using direct numerical solutions. Simulation techniques estimate the reliability indices by simulating the actual process and random behaviour of the system. Those techniques can take into account random events such as outages and repairs of elements represented by general probability distributions, components' behaviour, load and generation variation. Expected values of reliability indices together with their probability distributions could be evaluated. This information gives a very detailed description, and hence understanding of the system reliability. Nonetheless, the most typical barrier for the simulation approach is the large amounts of computing time.

The simulation process mainly refers to Monte Carlo Simulations, which can be performed in two ways. The first one called non-sequential examines basic intervals of time of the simulated period after choosing these intervals in a random manner. The second approach, called sequential examines each basic interval of time of the simulated period in chronological order.

Analytical and simulations approaches could be used for distribution network reliability assessment [48][31]. In [49] a multi-state availability model has been proposed, whereby all possible combinations of component failures are enumerated and associated to a probability. However, analytical techniques [47]-[50] can be cumbersome and infeasible for large scale networks and very complex schemes including ICT and DR actions, automation schemes, inter-temporal mechanisms such as emergency rating implementation and payback effects, network reconfiguration and DR schemes, as in this work. In contrast, the simulation approach simulates the actual system and components' behaviour in a chronological manner, allowing a high degree of complexity in system modelling and capturing the physical significance of the calculated reliability indices. In the literature, there are already several applications of MC simulations that take into account the presence of DG and the reliability of ICT components involved in active network management schemes [51]–[54][31].

In summary, for systems involving novel technologies such as DR and energy storage, payback effects and ICT interactions, as mentioned intertemporal constraints exist and chronological effects are of paramount importance. Therefore and most commonly, in the majority of studies involving such simulation, Sequential Monte Carlo Simulations (SMCS) have been selected as the appropriate technique. It should be mentioned though, that apart from SMCS there are also other techniques such as Pseudo-Sequential Monte Carlo simulation, as used by researchers in [31], which combines non-sequential selection of the system state with the sequential analysis of the neighbouring states only when the extracted initial state is a failure state. This method though can only provide expected values and not the whole probability density function of the reliability indices. Although probability density functions of the calculated indices are not presented in this thesis, their calculation is quite important for understanding and estimating network conditions and post fault capacity services potentials. Thus, it is not preferred for the reliability evaluation performed in this context. SMCS technique fundamentals will be discussed next.

2.2 Sequential Monte Carlo Simulation Framework

The simulation of a real system entails the use of models and probability distributions which represent the components and variables contained in the system. In this way, the occurrence of the events follows the random behaviour of the components. In SMCS, this is achieved by generating random numbers and converting them into density functions. More specifically, the probabilistic system states of the components are modelled using the notion of Time To Failure (TTF), Time To Repair (TTR), Time To

Switch (TTS) and Time To Isolate (TTI), where the last two represent distribution system behaviour during the restoration process and will be explained in a later subsection.

2.2.1 Random Number Generation

The inverse transform method [47] is used for the generation of uniform random numbers in the range 0 to 1. The numbers are converted into the desired non-uniform probability distribution using the cumulative distribution function $F(t)$ of the latter. Components' distribution functions for reliability analysis are typically exponential because such distribution is considered an appropriate model for the long, relatively constant period of low failure risk that characterizes the middle portion of the Bathtub Curve[3]. Additionally exponential distribution is memoryless thus indicating that the remaining life of a component is independent of its current age. However, a function like Weibull distribution can be used if component ageing is considered. Inverse transform method can be illustrated in Figure 2-2 for a component with exponential distribution.

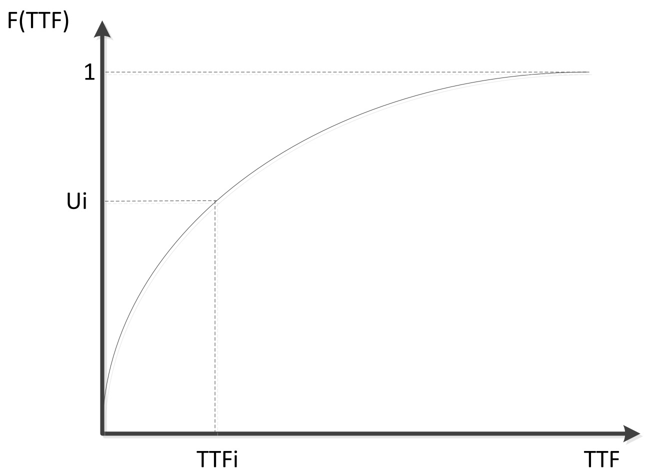


Figure 2-2: Explanation of the inverse transform method

[3] The bathtub curve is widely used in reliability and comprises three parts: The first part is a decreasing failure rate (early failures). The second part is a constant failure rate (random failures). The third part is an increasing failure rate (wear-out failures).

In order to demonstrate this procedure, the calculation of a random number U, which follows an exponential distribution, is presented. The probability density function of a random TTF is given in (2-1), where λ is the mean value of the exponential probability distribution. The cumulative probability distribution function is given in (2-2).

$$f(x) = \lambda e^{-\lambda x} \tag{2-1}$$

$$F(x) = 1 - e^{-\lambda x} \tag{2-2}$$

Using the inverse transform method, the random TTF is given by

$$TTF = -\frac{1}{\lambda} ln(1 - U) \tag{2-3}$$

U is the random number sampled from its uniformly distributed probability distribution function. Since $1-U$ is an inverse of U, it is also distributed uniformly in the same manner as U. Hence, (2-3) can be simplified as in (2-4):

$$TTF = -\frac{1}{\lambda} ln(U) \tag{2-4}$$

2.2.2 Component unavailability

The majority of power system components can be represented by a two state model (up and down). The up state indicates that the component is in the operating state and the down state indicates that the component is out of order due to failure. The probability of finding the component in the down state is known as the component unavailability (for generation units it is typically called forced outage rate *FOR*). Unavailability is described by (2-5).

$$U = \frac{\lambda}{\lambda + \mu} = \frac{MTTR}{MTTR + MTTF} \tag{2-5}$$

Where λ and μ are the expected failure and repair rate respectively, $MTTF$ is the mean time to failure and the reciprocal of λ and $MTTR$ is the mean time to repair and the reciprocal of r. How the concept of unavailability is associated with the two state model is shown in the state space diagram in Figure 2-3.

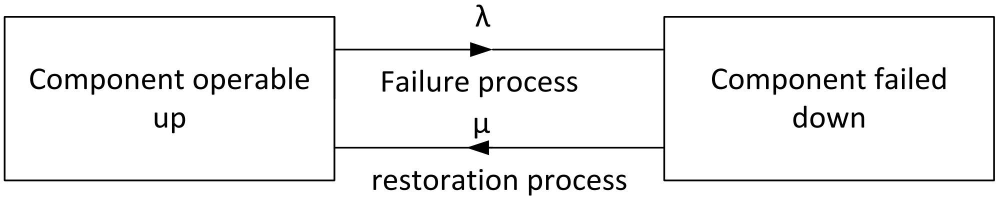


Figure 2-3: Two state model for a single component

2.2.3 Description of SMCS sampling process

The sampling process for the system components can be summarized in the following steps:

Step 1: A typical sequence of up-down cycles can be deduced by sequentially sampling a value of TTF, then TTR, then TTF, etc as explained in 2.2.1. This produces a sequence, which basically gives the chronological component state transition processes and is illustrated in Figure 2-4.

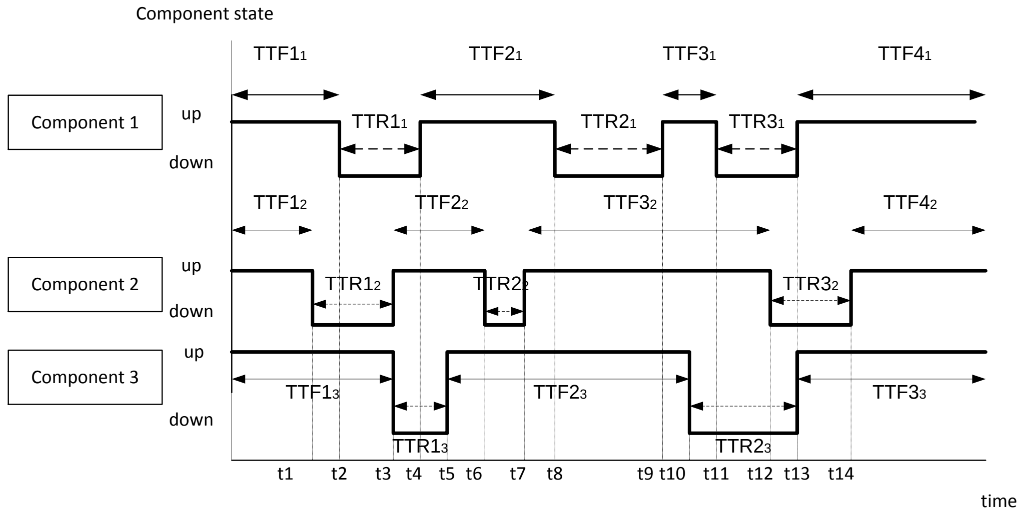


Figure 2-4: Chronological State Transition Process

For illustrative purposes, the calculations for the transition states of component 1 (parameters are with subscript '1') for the given time span will be described thoroughly:

- ✓ $TTF1_1$ and $TTR1_1$ are calculated. $TTF1_1$ represents the time when the first failure occurs. When the simulation time becomes equal to $TTF1_1$, component 1 will transit to the failure state. $TTF1_1$ lasts until t_2 according to Figure 2-4. Component 1 will remain to the down state for $TTR1_1$ interval until t_4;

- ✓ A new time to failure $TTF2_1$ will be calculated and therefore, the time of the next failure can be derived as follows: $t_8 = TTF1_1 + TTR1_1 + TTF2_1$. $TTF2_1$ does not correspond to a real simulation time because it only counts the period after which the component will fail again after having been repaired. On the contrary, t_8 includes the time needed for the first failure and repair to take place and hence, identifies the total simulation time needed for the second failure of the corresponding component;
- ✓ Respectively a new time to repair $TTR2_1$ will be calculated and defines the time that the component will transit from the failure state to the operational state again. This time is t_9 and is calculated as: $t_9 = t_8 + TTR2_1$;
- ✓ The procedure will be continued at the same fashion hence new times to failure and repair are calculated;

Step 2: The chronological system state transition process can be obtained by combining the chronological component state transition processes of all components (shown in Figure 2-5).

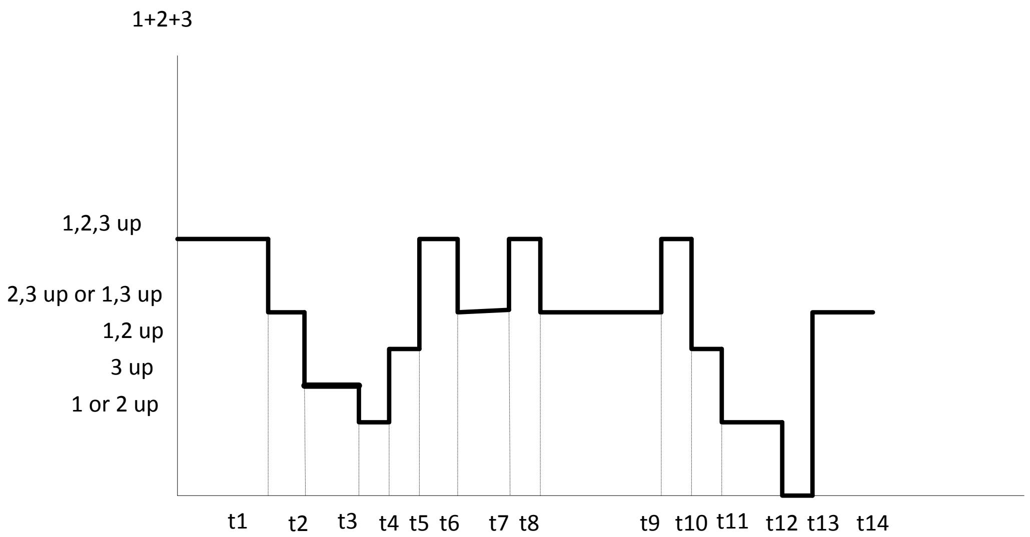


Figure 2-5: Chronological system state transition process

When sorting the events in a chronological order we could know the system state at every time t:

Table 2-1: Timeline of the system state

Simulation time	Events

t_1	Component 2 fails
t_2	Component 1 fails
t_3	Component 2 restores- component 3 fails
t_4	Component 1 restores
t_5	Component 3 restores
...	...

Step 3: A system analysis to obtain the desirable reliability indices is conducted. Steps 1-2 are performed for a sequence of system states (typically a year). The yearly indices are accumulated as $F(X_y)$: X_y is the sequence of system states in year y and $F(X)$ is the reliability index function over the year y. The estimated expectation of a reliability index X for a period of N_{SY} simulated years is calculated as in (2-6).

$$\boldsymbol{E(X) = \frac{\sum_{y=1}^{N_{SY}} F(X_y)}{N_{SY}}} \tag{2-6}$$

Step 4: Steps 1-4 are repeated until the stopping criteria have been met;

Thenceforward, the system available capacity curve is superimposed on the chronological hourly load curve to obtain the system available margin model. A positive margin denotes that the system generation is sufficient to meet the system load, while a negative margin implies that the system load has to be curtailed. The superimposition is shown in Figure 2-6:

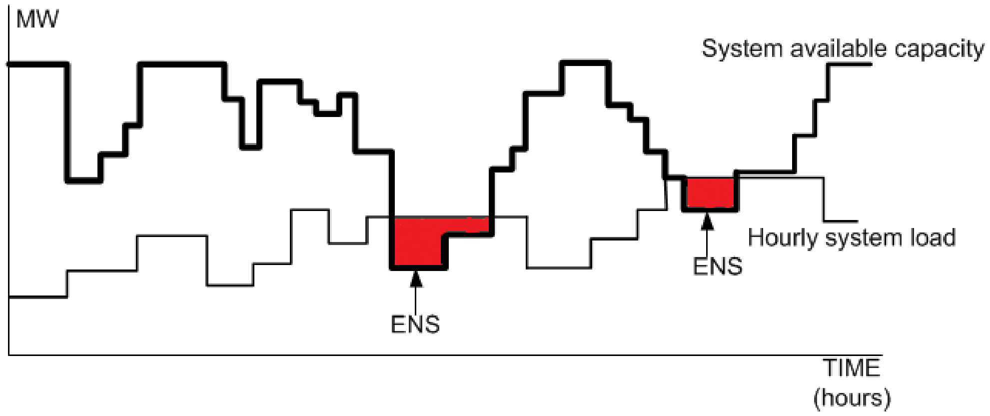


Figure 2-6: Superimposition of the system available capacity model on the load model

2.2.4 Stopping Criteria

Monte Carlo simulation is a fluctuation convergence process. As the simulation proceeds and the number of samples increases, the estimated indices will be a better approximation of their real values. The simulation should be terminated when the estimated reliability indices reach an acceptable level of confidence which is determined by the coefficient of variation:

$$\boldsymbol{b} = \frac{\boldsymbol{\sigma}}{\boldsymbol{E}(\boldsymbol{X})} \tag{2-7}$$

In (2-7) σ is the standard deviation of the estimated expectation and is obtained by (2-8) [55]:

$$\boldsymbol{\sigma} = \sqrt{\frac{\mathbf{1}}{\boldsymbol{N_{SY}}(\boldsymbol{N_{SY}} - \mathbf{1})} \sum_{\boldsymbol{y}=\mathbf{1}}^{\boldsymbol{N_{SY}}} \left[\boldsymbol{X_y} - \boldsymbol{E}(\boldsymbol{X})\right]^2} \tag{2-8}$$

Different reliability indices have different convergence speeds and related to that it has been established that the coefficient of variation of EENS index has the lowest rate of convergence[55]. Therefore, in this thesis, as elsewhere [56][57], EENS has been selected for the convergence identification and the convergence point has been considered arrived for a tolerance error lower than 5%.

2.2.5 MTTF, MTTI, MTTS, MTTR for overhead lines and underground cables

The developed SMCS framework simulates the system behaviour by capturing the sequence of post-fault events, known as restoration process, in chronological order, following the framework presented in [58].

More specifically, the reliability behaviour of overhead lines (OL) and underground cables (UGC) is modelled by their Mean Time To Isolate (MTTI), Mean Time To Switch (MTTS) and Mean Time To Repair (MTTR), which represent the expected values of their correspondent underlying probability distributions. MTTI represents the average time it will take for an upstream isolation switch to be found and operated after a fault occurs on a system component. For manual switches, this is the time it takes for a repair team to identify the fault, drive to the upstream isolation switch location and operate the switch. For an automated or remote controlled switch, MTTI will be considerably shorter (a few minutes or a couple of seconds). MTTS represents the average time of the downstream switching actions. It includes the location and operation of switching switches and Normally Open Points (NOPs). Similarly, the level of automation and remote controlled switches will have an impact on MTTS. Finally, as already mentioned, MTTR is the average time it will take for a failure to be repaired. It includes the travel time between fault response teams and fault locations and the actual repair of the faulty component. The type of component, the number and the initial location of the repair team will also have an impact on MTTR. It is assumed that all probability distribution functions are exponential. Therefore, for every action Y (isolation/switch/failure/repair), $TTYs$ are expressed by $TTY = -MTTY ln(U)$ where $MTTY$ is the mean time to that action and U is a random number in the range (0, 1), as from (2-3).

The sequence of the events following a failure of a network line, as replicated in the SMCS process is illustrated in Figure 2-7. It can be seen that protection actions are negligible and isolation actions start immediately after the fault.

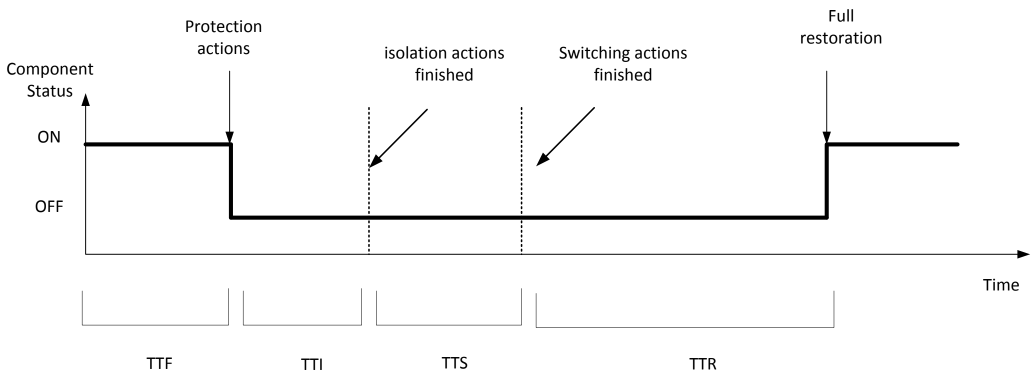


Figure 2-7: Restoration process as simulated by the SMCS

In summary, the characteristic sequential events presented in Figure 2-7, are described briefly below [52] and thoroughly in section 2.3:

- Protection actions: System protection clears the fault. This may leave some load disconnected. The duration of this action is negligible.

- Isolation actions: Identification and isolation of the faulted line. This activity could be manual, automatic or a combination.
- Switching actions: Switching actions will be initiated to restore supply to as many disconnected customers as possible. The duration of switching depends on the level of automation. The amount of load left disconnected depends on the reserves on the neighbouring feeders.
- Repair Actions: Repair of the faulty component. The duration of the repair depends on the severity of the fault and the availability of repair teams.

2.3 Distribution system operation under normal and emergency operation

As already described in Chapter 1, distribution networks have been designed to comply with prescriptive deterministic standards on the level of operational redundancy (ER P2/6 [1]). In this context, in the UK at 6.6 and 11kV voltage level, networks are designed in a 'ring' configuration but operated radially, with radial feeders that can be interconnected by closing Normally Open Points (NOPs). This configuration guarantees that if a disturbance were to occur, alternative paths exist to supply customers not directly connected to the fault. However, in order to allow this network reconfiguration and reliable customer supply following a fault, distribution feeders are typically underutilised. This also means that in the case of load growth additional asset is needed, even if faults are a relatively rare event, sometimes happening once every few years [59].

2.3.1 Customers classification after a network fault

Under the current network configuration, if a fault were to occur in one of the feeders, all customers in that feeder would be initially disconnected while the fault and some customers are isolated from the rest of the network by the protections system. At this point, the location of the customers can be classified in four areas: 1) isolated from the fault and connected to their original feeder, 2) isolated along with the fault, 3) isolated from the fault, NOP and feeder, and 4) isolated from the fault and connected to the NOP. For the exact location of customers depending on their classification see Figure 2-8.

If repairs were needed to clear the fault, in the meantime energy supply would be restored to some customers (area 4) via a neighbouring feeder by closing the NOP. In case the closure of the NOP is manual, this would normally take 1 hour, otherwise if the NOP is automated, NOP closure actions would be concluded in a short period. Afterwards, if repairs were to take longer than a few hours, a service crew would be sent to manually disconnect customers (area 2) from the fault and reconnect them to the grid or to the remainder customers that were still islanded from the network (area 3). Finally any customers connected in area 3 would be supplied via the connection of a mobile generator.

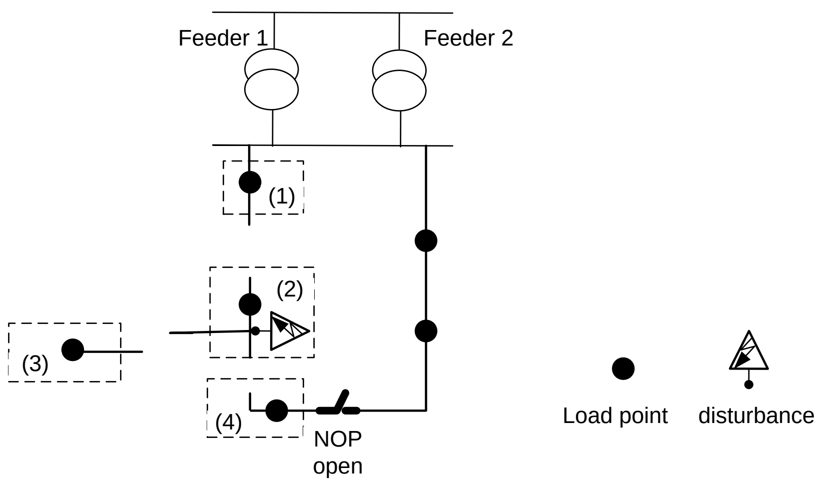


Figure 2-8: Customer classification based on their location after a fault

2.4 Distribution Network Restoration Process

Components that could fail and then lead to a contingency event are the typical equipment that an electricity network consists of, such as transformers, circuit breakers, isolation switches, overhead lines and underground cables.

The state of the distribution network when the isolation switches position is in their usual position, no protection devices have tripped, all components are operating properly and load levels are within the design limits is commonly referred to as the Normal Operating State (NOS)[60]. The NOS is the preferred state of a distribution network since demand can be adequately supplied. A contingency event would cause the system to leave the NOS and enter the contingency operating state. How the system behaves in a contingency is crucial to identify how the continuous supply of demand is affected.

Therefore, regarding the switching actions performed after a network fault, typically DNOs would follow certain steps to deal with the disturbance situation. It should be noted that the whole activity of identifying and isolating the faulty section and resetting the upstream protection device can be manual (either local or remote controlled) or automatic. This adjustment would determine the duration of this activity. In particular, following a fault at fist the relevant protections at the beginning of the feeder (primary circuit breakers) open to prevent further damage and clear the fault. Protection reclosing actions are then performed with the aim to isolate the faulty circuit. As a result, some customers in a circuit not directly affected by the fault may be disconnected from the rest of the network for a relatively small period. Subsequently, switching actions are taken to restore the supply to as many disconnected loads as possible. Finally, the faulty component should be repaired, a process which might take several hours.

The switching actions typically performed by the DNO are illustrated in steps through Figure 2-9 and detailed below:

Step 1: For this illustration the network is operated radially during normal conditions.

Step 2: Let’s assume that a network line fails between load points B and C in feeder 1. The protection system response is initiated after the fault occurs. The primary circuit breaker (PCB_1) from the side of the fault trips to clear the fault and to prevent further damage, leaving all the customers of feeder 1 interrupted. However, this interruption lasts less than 3 minutes, thus considered as *short interruption.* This time is sufficient for the DNO to initiate the rest of the actions: switching actions to identify the fault location, isolation of the fault from the rest of the network and then repair of the fault.

Step 3: The first isolation switch (Is) upstream to the fault opens and the Intermediate Point Switch (IPS_1) opens as well to band the fault. The tripped protection device PCB_1 is reset restoring supply to costumers at load point A and the NOP closes to restore supply to customers at load point D. Customers between B and C remain interrupted.

Step 4: The IPS_1 closes with the aim to start restoring supply to as many customers as possible. This would particularly mean that the NOP would commence to move from the IPS_1 to a substation closer to the fault restoring supply to each substation from the IPS_1 to the faulty section, starting from customers located in load point C.

Step 5: The same process is carried forward until all the load points apart from the fault affected one have been restored back to supply. Customers in load point B will remain interrupted until either the fault has been repaired or a mobile generator has alternatively been sent to supply the customers until the fault is fixed.

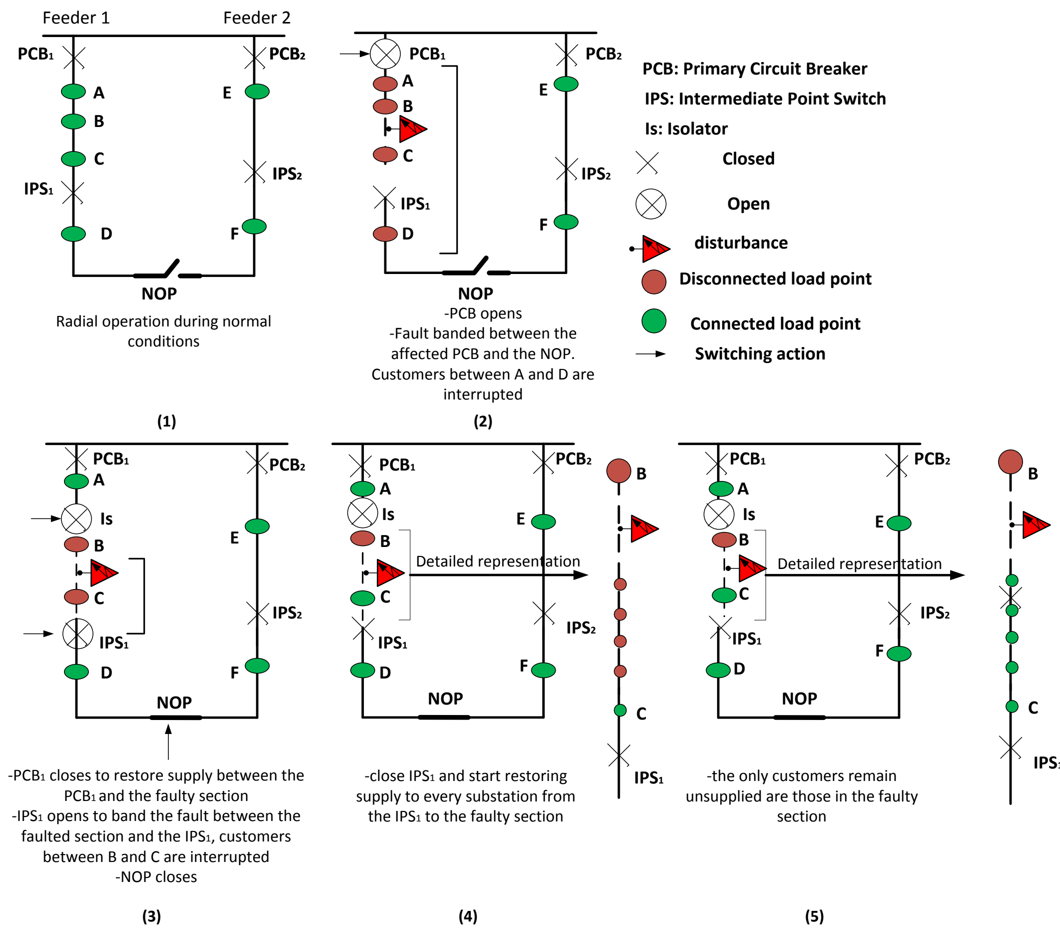


Figure 2-9 : Fault restoration process

The restoration process happens in a chronological order and the time to perform each of the activities described in the previous steps (protection, isolation and switching actions) depends on the level of automation that has been implemented in the distribution system, in other words, it depends on if the actions are operated manually or automatically. Therefore, Figure 2-10 indicates in a summarizing manner the times that the above mentioned restoring actions would be performed in order for the disconnected customers to come back to continuous supply.

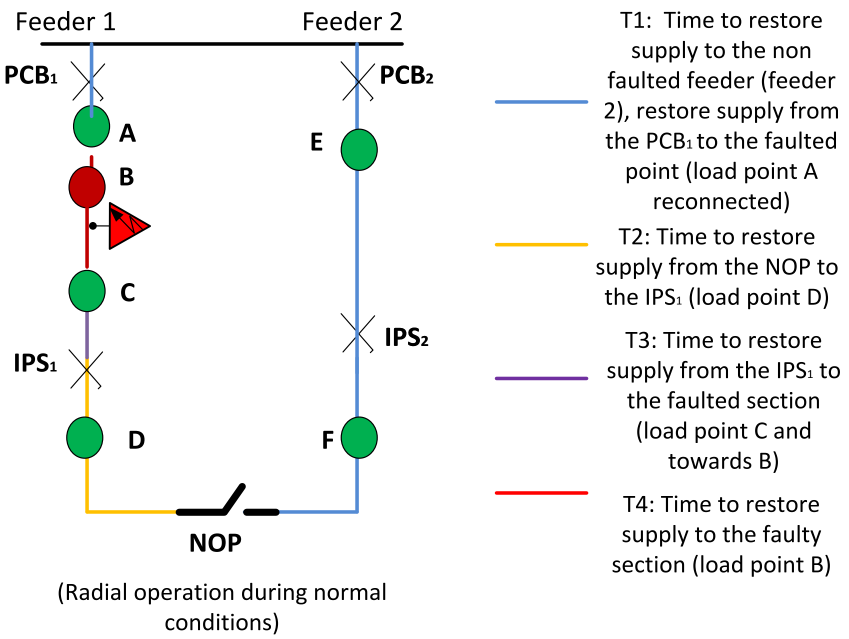


Figure 2-10: Times to restore supply to disconnected customers

Finally, it should be mentioned that the whole activity of the restauration process which is thoroughly described in this section has been implemented in the reliability assessment tool which is based on SMCS. For every random fault happening during the SMCS, the whole restoration process is initiated, identifying the fault location and the switching actions to happen inside the network. Furthermore, the network analysis is performed through an AC power flow tool which is modelled with the aid of Matpower 4.1[61] simulator. In this way, voltage and thermal violations, load shedding and network conditions are properly calculated throughout the whole restauration process and the network disturbance, providing in the end realistic results. Matpower includes four different algorithms for solving the AC power flow problem. The default solver is based on a standard Newton's method and this is the solver that has been used for most of the studies in the thesis[62] . More details for the power flow algorithm are given in Appendix 2. Additionally, the process of identifying the isolated load points and branches after a network fault is facilitated by a set of Matpower functions (called 'finding_islands') which locate and return the islanded buses and branches.

2.5 Reliability Cost-Reliability Worth

The underlying trend in the continuous debate between economics and reliability is the need to determine the worth of reliability in a power system and who is responsible to contribute to this worth. The economic impact of a power system outage includes losses of revenue by the utility, loss of energy utilisation by the customer, but also loss of comfort for the service lost and other social and environmental costs.

Establishing the worth of service reliability can be realized through evaluating the impacts and monetary losses incurred by customers due to service interruption. This evaluation is typically done with Customer Interruption Costs (CIC) [63]. [64] and [65] have shown that in the event of supply interruptions, customers are only concerned with the inability to use their equipment and the likely damage to this equipment.

In particular, the cost of an interruption from the customer's perspective depends on the customer characteristics (type and nature of activities of customer, energy requirements and energy-time dependency) and the interruption characteristics (duration, frequency and time of occurrence of interruptions) [32]. The most preferable methodological approach to calculate the CIC has been recognized to be the cost of interruption surveys [66] due to the argument that the customer is the most suitable to value his loss of supply. Afterwards, the standard way to display CIC is through the Customer Damage Function (CDF). The CDF determines the relationship between interruption duration and the customer economic losses. CDF is calculated for a given customer type and if aggregated, sector CDFs for the various classes of customers in the system can be produced. The sector CDFs can be aggregated at any particular load point in the system to produce a composite CDF (CCDF) at that load point.

For each contingency j that leads to load curtailment at the load bus k, the variables generated in the contingency evaluation are the magnitude L_{kj} (MW) of load curtailment, the frequency f_j (occurrence/year), and the duration d_j (hours) of the contingency j. The cost $c_j(d_j)$ for load curtailment of contingency j can be obtained from the duration d_j and the CCDF for the given service area.

The expected customer interruption cost (ECOST) of power interruptions to customers at bus k for all contingencies NC is given by (2-9) [32].

$$\boldsymbol{ECOST_k = \sum_{j=1}^{NC} L_{kj} f_j \, c_j(d_j)} \tag{2-9}$$

2.6 Distribution Network Reliability Indices

A radial distribution system comprises series components such as lines, cables, isolators, bus-bars. For a customer connected to a load point of such a system all components between himself and the supply point should be functional. The three basic reliability parameters of average failure rate λ_s, average outage time r_s and average annual unavailability U_s are given by (2-10), (2-11) and (2-12) respectively[32].

$$\boldsymbol{\lambda_s = \sum_i \lambda_i} \tag{2-10}$$

$$U_s = \sum_i \lambda_i r_i \tag{2-11}$$

$$r_s == \frac{U_s}{\lambda_s} \tag{2-12}$$

The three primary distribution network indices are important however they do not reflect the severity of a system outage since they are independent of the number of customers connected to each load point and on the volume of the load demand in each load point. Therefore, apart from those indices, CI and CML which are customer orientated indices are used and also EENS which is energy-orientated index.

In this thesis the reliability assessment is carried out with the SMCS framework, therefore, all the indices are quantified based on the chronological events happening in each simulated year and average values can afterwards be extracted as well as probability distributions. The load point and system indices are given below, where y denotes a particular sampling year (SY) and NSY is the total number of sampling year.

Annual Frequency of Interruptions counts the total number of interruptions in a load point k, in a sampling year and its expected value is EAFI (occ/year):

$$\boldsymbol{EAFI_k = \frac{\sum_{y=1}^{N_{SY}} AFI_{k_y}}{N_{SY}}} \tag{2-13}$$

Annual Duration of Interruptions is the total duration of interruptions in a load point k that are sampled in a sampling year and its expected value is EADI (hours/year):

$$\boldsymbol{EADI_k = \frac{\sum_{y=1}^{N_{SY}} ADI_{k_y}}{N_{SY}}} \quad (2\text{-}14)$$

Energy not supplied is the total energy not supplied during all interruptions in a load point k in a sampling year and its expected value is EENS (MWh/year):

$$\boldsymbol{EADI_k = \frac{\sum_{y=1}^{N_{SY}} ENS_{k_y}}{N_{SY}}} \quad (2\text{-}15)$$

Using the frequency and duration indices calculated above through the SMCS, system customer orientated indices CI and CML can also be extracted for each sampling year and then accordingly its expected value (interruptions/100customers/year for the CI and minutes lost/customer/year for the CML):

$$\boldsymbol{CI_y = \frac{\sum_k AFI_{k_y} \cdot Ncust_k}{\sum_k Ncust_k} \cdot 100} \quad (2\text{-}16)$$

$$CML_y = \frac{\sum_k ADI_{k_y} \cdot Ncust_k}{\sum_k Ncust_k} \cdot 60 \quad (2\text{-}17)$$

It can be observed that two sets of indices are used to measure the reliability of power systems. These are the load point indices which reflect the behaviour of individual load points, and system performance indices which reflect the overall behaviour of service areas or systems. Load point indices represent the average behaviour of individual load points. Therefore the relevant frequency and duration indices represent the impact of system behaviour on the individual customers attached to that load point. System indices are aggregated indices that represent the average behaviour of that part of the system that has been aggregated. They are evaluated from the indices of the load points included in the aggregation. Therefore the relevant frequency and duration indices represent the impact of system behaviour on the "average" customer of that part of the system – a customer who does not really exist[45].

2.7 Probabilistic Framework for post fault capacity services (SMCS reliability modelling tool)

The previous paragraphs of Chapter 2 provided the necessary fundamental literature regarding the SMCS reliability assessment and the related indices, as well as the current local DNO's practices regarding restoration process. As already explained, the SMCS has been decided to be the most suitable method for this thesis to assess post-fault capacity services in smart distribution networks. Therefore, the probabilistic framework proposed for this thesis is based on SMCS while 1) modelling the specific network and electronic components capturing their stochasticity, 2) modelling the distribution network restoration process, 3)performing the ac power flow calculations of distribution network under study to capture the voltage and thermal violations and thus 4)recognizing the need for post fault services which could be coming as said, from DR, MGs, wind farms and EES or dynamic thermal ratings. For each of the technology or combination of technologies selected, appropriate modifications are adapted, to model for instance the payback effects for DR customers or the MG disconnection to work in islanded mode. In this section, the SMCS reliability modelling tool will be shown in Figure 2-11 for illustration purposes for the case that the post fault actions performed are DR combined with TLTR. Green parts of the flowchart would remain unchanged for different post fault capacity services, while orange parts of the flowchart contain actions related with DR and TLTR. Figure 2-11 shows that simulation is done in a chronological order, typically in half-hourly steps, for a certain amount of iterations (typically thousands) until the stopping criteria have been satisfied. Time series load profiles are inserted in the analysis, and random faults are located throughout the network through random number generation. When a fault or a contingency is happening, distribution network reconfiguration is executed and isolated points are identified. AC power flow calculations are executed to determine the level of severity and the related network violations and thus proceed to corrective actions. For the particular example of DR and TLTR depicted in Figure 2-11, during electrical normal state, DR customers would be also paid back. Additional details and explanations will be given in the relevant Chapters (Chapters 4 and 5).

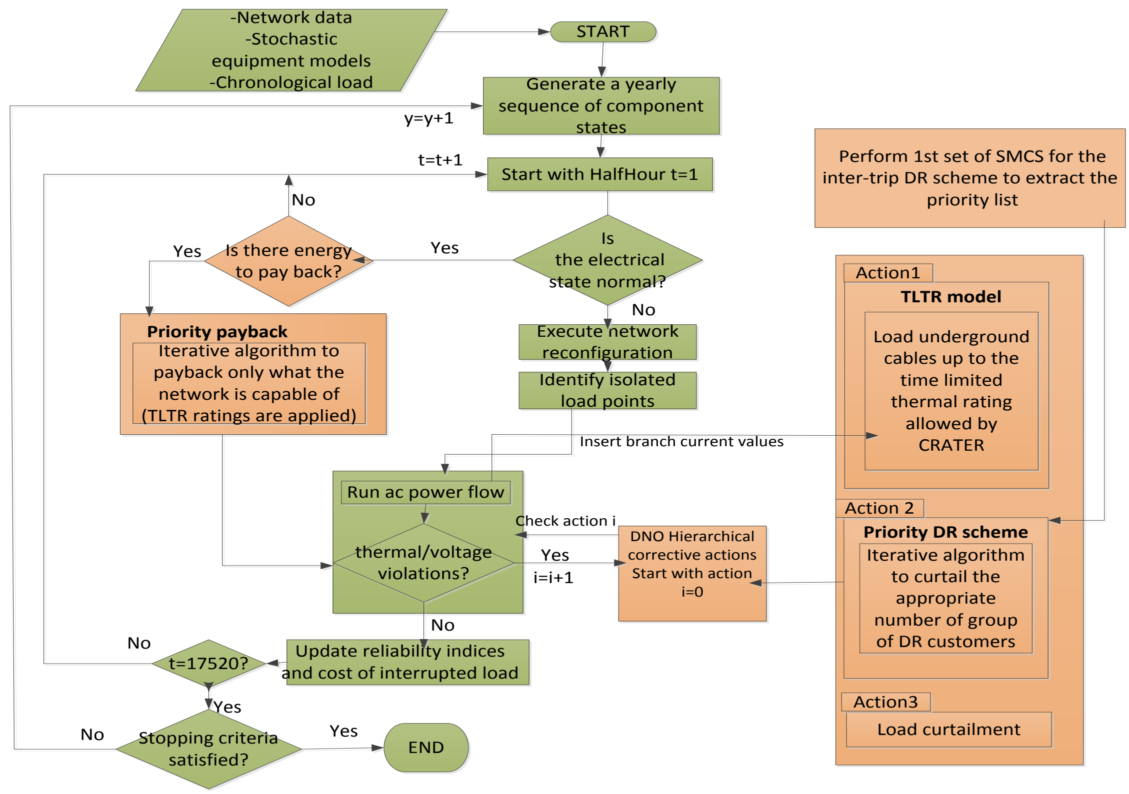


Figure 2-11: Example flowchart for the SMCS reliability modelling tool when DR and TLTR are implemented

2.8 Dealing with the Computational Time Burden

The most significant burden of choosing SMCS for reliability assessment is the high computational effort that is needed, due to the simulations happening in a chronological order and also the high number of iterations for convergence.To deal with this burden in this thesis, three alternative solutions have been tested and implemented, all of them falling into the same philosophy strategy which is the parallel computing.

- **Spmd function:** The first alternative examined is the parallel computing toolbox of Matlab® [67] (more specifically the *spmd* function). The particular tool allows the use of multicore processors with the aim to run in parallel the application.
- **RedQueen:** Similar philosophy but with more powerful capabilities has been also accomplished through the combined utilisation of RedQueen[68] which is a high performance computing cluster at the University of Manchester. Redqueen is suitable for parallel jobs, and intensive long running applications such as SMCS.

- **Condor Pool:** The third alternative utilised for the simulation purposes is the high-throughput computational facility of the University of Manchester (UoM) EPS Condor pool [69] . The UoM Condor Pool utilised HTCondor which is a High Throughput Computing software for distributed parallelization of computationally intensive tasks. HTCondor can seamlessly integrate both dedicated resources and non-dedicated desktop machines into one computing environment. HTCondor can run both sequential and parallel jobs.

Depending on the prerequisites of the simulation (in terms of input data inserted, parameters modelled, requirements for convergence, length of a single iteration, and specifications of the case study) one of the three solution methods is selected. After deciding the parallel computing tool to use, then the simulation (or alternatively called 'job') is decomposed into smaller sub-jobs with the aim to execute each sub-job in a parallel process. In the end, the result data of each sub-job are merged back together, to calculate the reliability indices and the final results. The parallel computing framework that has been used for the reliability assessment in smart distribution networks with SMCS can be summarized in Figure 2-12**Error! Reference source not found.**.

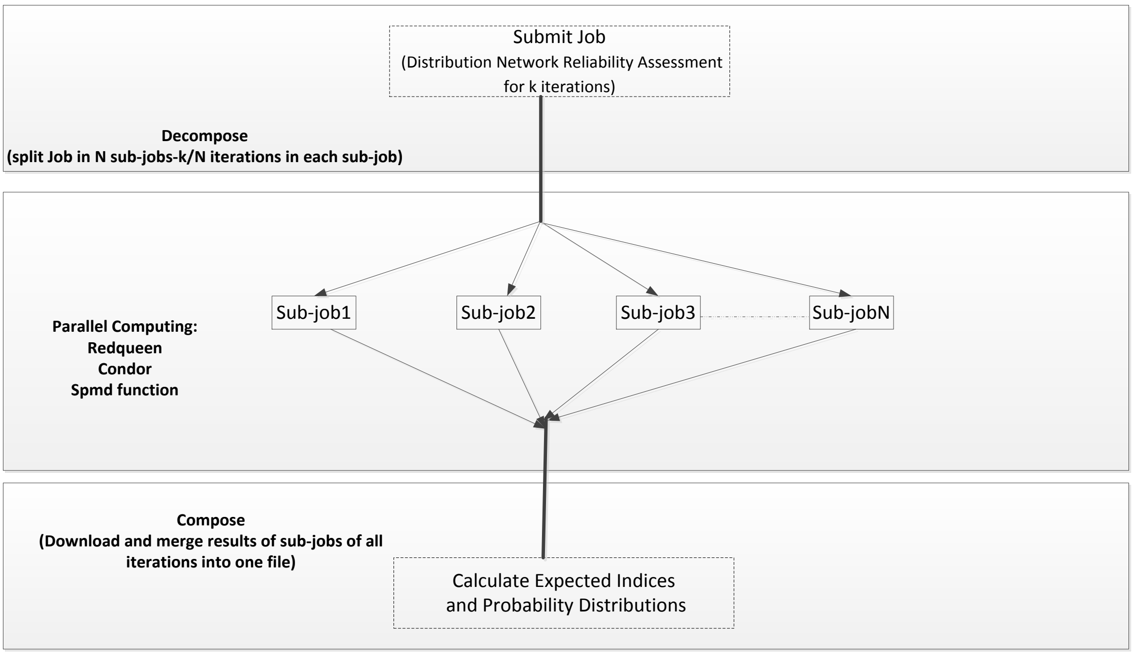


Figure 2-12: Parallel Computing Framework

2.9 Summary

This chapter presented the probabilistic framework for the reliability evaluation of smart distribution networks. Firstly, an overview of power system reliability including probabilistic reliability criteria and reliability evaluation techniques has been given. Thereinafter, the Sequential Monte Carlo Simulation (SMCS) technique has been extensively described, providing the necessary theoretical background of the traditional methodology. Reliability worth is also discussed in order to provide the adequate information for the calculation of cost of interruption. Furthermore, the distribution network reliability indices calculated from the SMCS process are introduced. Afterwards, the basic concepts for distribution network operation in normal and emergency situations are introduced. More specifically, customer classification after a network and also the distribution network restoration process are thoroughly reported. Finally, a solution to deal with the high computational effort of SMCS is found through the utilisation of parallel computing. All of this information together builds the framework for the reliability analysis of smart distribution networks. This framework includes a probabilistic tool (SMCS) in order to cater for the uncertainty and the stochasticity of the equipment and the entities involved, a network restoration process mechanism in order to realistically reflect the distribution network operations and a practical solution based on parallel computing to surmount the time burden of SMCS. It is also important to mention, that the whole process inside this framework, also includes a realistic analysis of the distribution network since power flow calculations are properly considered, evaluating any resulting thermal or voltage violations during the distribution network outages. For the sake of consistency, the whole framework presented, including all the above-mentioned mechanisms and characteristics, for the rest of the thesis will be defined as "**the SMCS reliability modelling tool**". The SMCS reliability modelling tool will be used in the rest of the chapters when reliability and risk assessment procedure has to be executed.

3 DISTRIBUTION NETWORK UTILISATION ASSESSMENT WITH INTER-TRIP DR POST FAULT SERVICES

In response to distribution network challenges such as increasing demand, infrastructure ageing and integration of distributed generation, alternative approaches are being sought to release existing network capacity before proceeding to new investments. Considering that most distribution networks in the UK are typically designed as a ring but operated radially, this chapter discusses the effect of a ring operation (or radial operation with automated control schemes) aimed at maximizing the capacity utilisation of the existing asset. In this context, DR schemes are then proposed as a corrective action following a contingency with the aim of maintaining the system within its limits. The proposed DR scheme, named inter-trip DR scheme, basically reproduces and evaluates the DR scheme suggested by the local DNO (the so called C_2C solution), where all contracted DR customers are disconnected during the contingency situation. With the support of the corrective DR scheme, the connection of new load shall be permitted without proceeding to new investments. This could happen by utilising the existing unused capacity during normal conditions and disconnecting DR customers as network support during emergencies. The ICT infrastructure supporting the DR scheme is also assessed in case ICT faults occur. The *reliability assessment of the proposed model is executed with the use of the SMCS reliability assessment tool.*

3.1 Capacity to Customers

Given the new control capabilities enabled by advances on ICT, more effective network assets' use could be put forward, changing the conventional approach to network operation. In particular, Demand Response (DR) schemes could be enabled for network capacity release and deploying increased automation to create self-healing capability. In this respect, a practical scheme has recently been proposed by Electricity North West Limited (ENWL), one of the DNOs in the UK, within the '*Capacity To Customers'* (C_2C) project [59], as illustrated in [70] whereby post-fault DR is used along with network automation, with the aim to provide network capacity release. More specifically, DR would be implemented during emergency conditions whereas the previously untapped network capacity would be used for normal operation. The C_2C method is also meant to reduce social costs (i.e., power losses, emissions, and number and duration of customer interruptions, amongst others) via the increased network automation and reconfiguration, while moving from radial to ring feeder operation. The C_2C method is eventually expected to defer (or even avoid) the need of costly network reinforcements, particularly in the presence of uncertainties (e.g., demand growth uncertainty).

3.1.1 Description of the C_2C method

According to [59], the C_2C method releases capacity by utilising innovative management technologies in conjunction with customer commercial arrangements.

Current Extra High Voltage (EHV) and High Voltage (HV) networks use redundancy and network interconnection to comply with security of supply standards. As said previously, network feeders are interconnected by a NOP, however this is only utilised in the event of a network fault or planned outage, since in normal operations they are operated radially. In ENWL networks, historical information show that approximately half of circuits do not suffer any faults, and one third experience faults lasting 1 – 2 hours in any five-year period [59]. Under such circumstances, closing the NOP allows all customers affected by a fault to be re-supplied from the alternative circuit. The C_2C method aims to release this unused capacity for the connection of new demand and generation. Specifically the network is redesigned to allow the NOP to be run closed, allowing the whole capacity of the ring to be used by joining the two circuits.

Apart from the ring operation proposed by C_2C, to ensure that security of customer supply is maintained and supplies can be restored during fault outages, the C_2C method has developed and trialled new post-fault DR contracts which would allow ENWL to either reduce consumption or reduce generation depending upon the nature of the post fault constraint being addressed. More specifically, under the C_2C paradigm when a new customer connects to the network they would be offered the option to sign up to a managed contract in exchange for a reduced connection charge which would be equivalent to the saving of reinforcement costs. These contracts would allow ENWL to manage their consumption or generation during a disturbance and ensure supplies can be restored to all other customers in the event of a fault.

After applying the C_2C method with a number of participants, the C_2C trial has now been completed .In light of the above, this chapter would assess the effectiveness of the C_2C method with respect to the reliability performance and other network characteristics such as losses.

3.1.1.1 Drawbacks of the C_2C ring configuration

As explained in Section 2.4 , after a network fault the first action to be taken is the tripping of the primary circuit breaker in the circuit from the side of the fault for protection purposes. However in the ring configuration, in case of a fault, protective actions interrupt both feeders to clear the fault. This type of protective action though, is due to last less than 3 minutes due to the higher automation that has been implemented in the system to support the C_2C scheme and thus does not greatly affects the customers. The concept is illustrated in Figure 3-1.

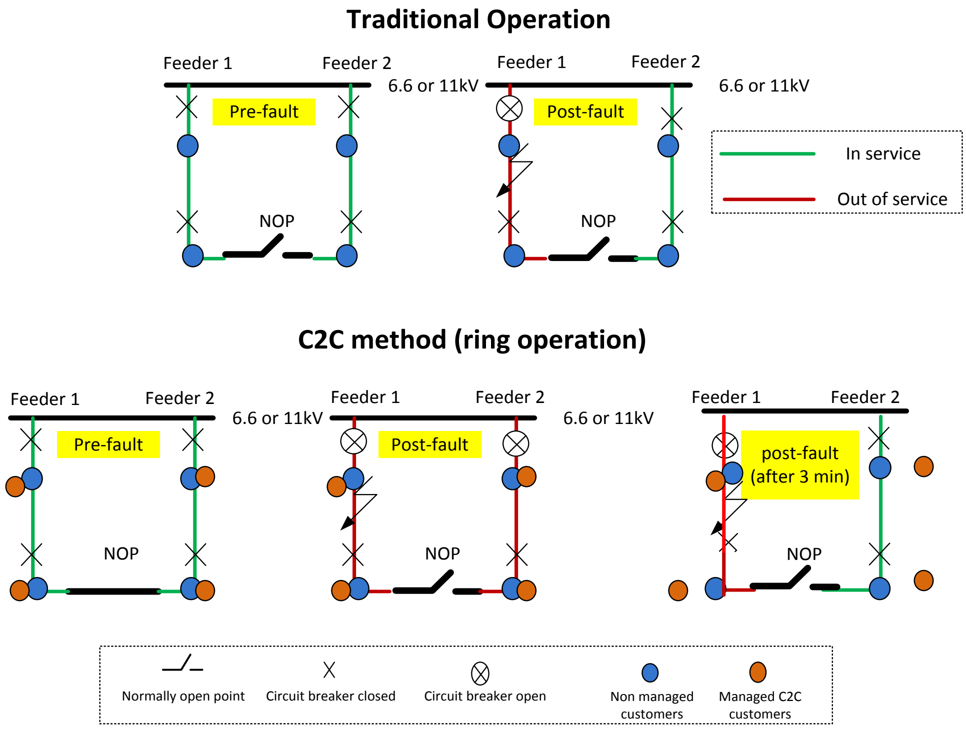


Figure 3-1: Traditional versus C$_2$C operation in terms of feeder interruption due to protection actions

3.2 DR for post-fault network support

DR is used to indicate a variety of mechanisms which aim to control or motivate end users to alter their normal consumption pattern in order to shift demand from peak to off-peak (less expensive hours), or balance demand through load shedding at times of capacity deficit[15][71]. In fact, DR could be utility driven, for instance contributing to distribution network capacity support, reducing operational costs, and improving system reliability[72], or customer/ market driven [73] , where customers may adapt their load level in response to real time pricing . Altogether, DR could be a useful controllable product for transmission/distribution system operators [74], including for minimization of spinning reserve from partially loaded generators [75], real time balancing [76] and corrective control [77]. In this section, the DR scheme used is purely focused in a system led DR scheme, and more specifically a Direct Load Control (DLC) scheme, since the DNO takes decisions to activate DR depending on the network conditions, as suggested from C$_2$C. The DLC-DR scheme is supported by an appropriate ICT infrastructure to perform post fault actions.

The concept suggested in C$_2$C method is adopted to develop the DR scheme for post-contingency network support and described in Figure 3-2. For illustrative purposes it has been assumed that each feeder has a maximum rating of 10MW and no reactive power is considered. The pre-fault configuration could be either radial (which is the typical configuration) or ring and the total demand connected to both feeders is not allowed to exceed 10MW. Accordingly, during a contingency, the NOP can be closed after isolating the fault, so that all customers are supplied with the unaffected 10 MW feeder (worst case scenario).

In contrast, in the proposed approach, additional customers are allowed to be connected to either feeder so that total demand increases beyond 10MW and could in case reach the maximum capacity limitation of 20MW in total in normal conditions. In case though of a network fault, during the post fault operation, the DR customers contracted by the DNO would get disconnected and also the network would be operated as ring in order to provide an alternative supply path.

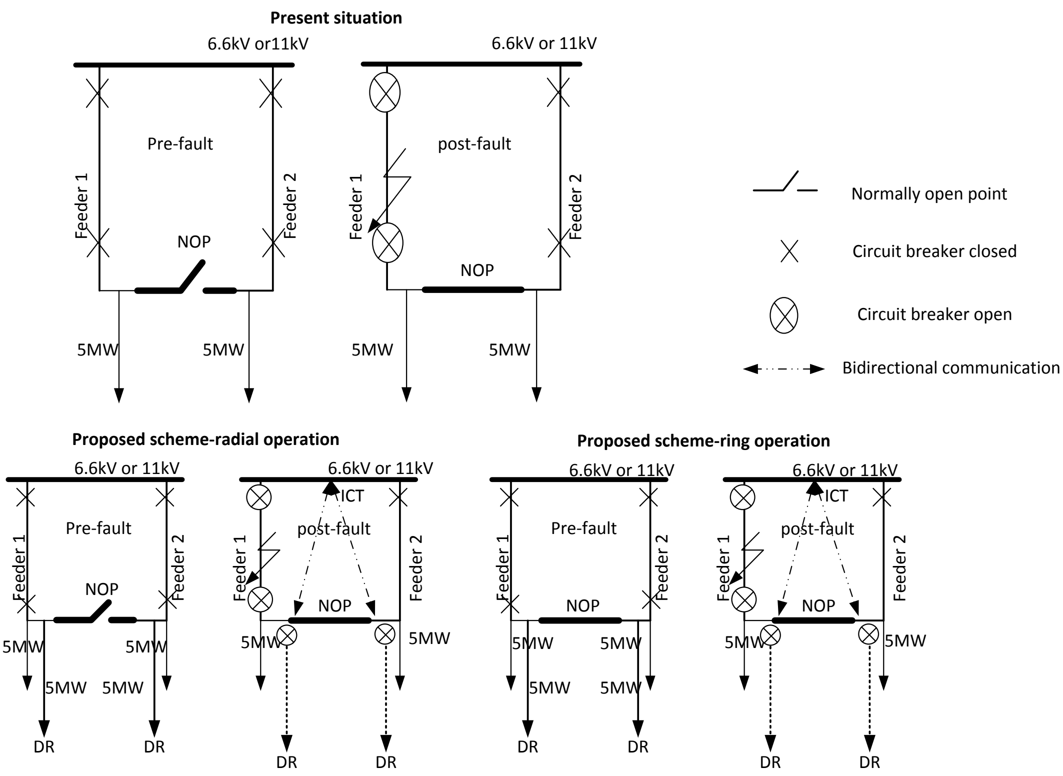


Figure 3-2: Present situation versus proposed scheme to unlock network capacity

3.3 ICT platform for the smart distribution network

In this section, some introduction of the current DNO's communication systems will be given and then based on the available literature a specific ICT topology will be selected and then described to support the active DR scheme.

3.3.1 Current DNO's communication systems

Traditionally, DNOs perform the monitoring and control of their networks through SCADA systems. These systems spread local controllers across a distribution network with the aim of properly managing operational tactics in an autonomous and collaborative manner [78] [39].

According to [39], SCADA systems consist of a master terminal located at a DNO's control centre and a large number of Remote Telemetry Units (RTUs) located at widespread sites. RTUs gather network measurements from field sensors and then send commands to control devices. Additionally, they communicate with the control centre via heterogeneous communication channels utilising a variety of physical links such as fibres optics, private pilot cables, Public Switched Telephone network (PSTN) lines, satellite and mobile cellular networks and certain link capacities, from a few hundred bits per second to a few thousands bits per second.

Conventionally, SCADA systems are designed in a centralised architecture[78]. In such a way, all RTUs send timely information through the DNO's communication system to the control centre every few seconds acknowledging the network operation state. In the control centre, these data are analysed by software programs to detect the requirement of corrective actions such as operating an on load tap changer, or sending control signals to other remote equipment. Currently, most SCADA systems at low voltage levels depend on manual operation.

3.3.2 ICT platform to support the proposed DR scheme

In order for the relevant real-time post contingency actions to be taken, ICT is deployed in the context of the smart grid. The appropriate combination of an ideal architecture and communication technologies plays a crucial role for a reliable, scalable and cost effective communication system. The ICT topology adopted in this work is based on [39] and the mix of technologies selected is based on [25][31]. In [39] a decentralized architecture for regional active network management is proposed. This assumes the existence of autonomous regional controllers which manage their geographical sub-networks, but at the same time communicate with other regional controllers and the DNO control centre. Hence, it could be said that there are two levels of communication. The first level is from the DR connection point to the distribution primary substation (where the regional controller is located). The second level is from the primary substation to the DNO control centre. For both the communication levels, a selection of

Wide Area Network (WAN) wired or wireless technologies could be used such as optical fibres, narrowband Power Line Carrier , Satellites, WiMAX or 3G/4G cellular networks [79][31][26][80][81]. ENWL for instance, deploys the available digital communication network (GSM in case). However, in this work, WiMAX technology has been used (proposed by [31][26]) for both communication levels, as it offers a standardized point-to-multipoint high-speed communication with a large geographical coverage which greatly improves the communication performance. Moreover, the regional controller located in the primary substation is connected via an optical fibre link to the communication infrastructure, and controls all the DR points interfaced with the communication system through local routers. The regional controller executes the state estimation to estimate the state of the monitored distribution network, communicating both with the DNO control centre and the DR points and as a result is responsible for the immediate disconnection of the DR customers in case of an emergency. The ICT scheme used is represented in Figure 3-3.

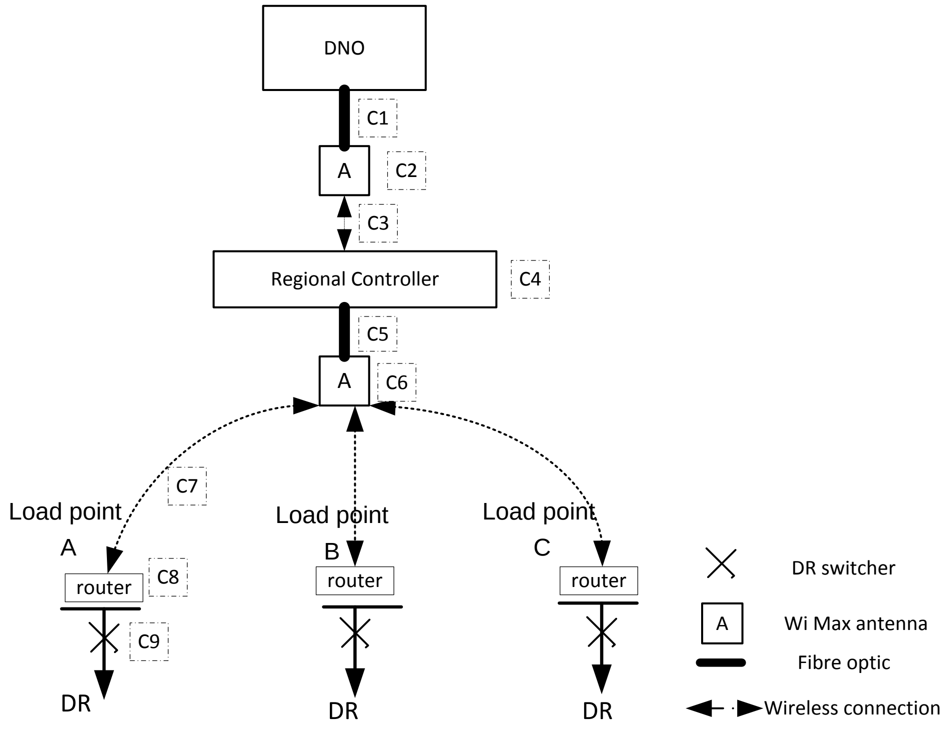


Figure 3-3: Distributed ICT platform supporting the DR scheme

3.3.3 Impact of ICT failures on Smart Distribution Networks

It has become clear that there is a strong interdependency between the ICT and power infrastructures. Many control strategies have been designed based on ICT equipment and communication networks. For this reason, ICT is fundamental to the reliability of smart distribution networks, since the effectiveness of the remedial actions used to cope with different contingencies depends on the capability to communicate with the DER in the network. As a result, for a correct performance evaluation , the modelling of the active management system is essential, in order to understand how its reliability can affect the adequacy of the whole distribution system.

For the ICT platform described in Section 3.3.2 , if one of the ICT and electronic components fails to operate, the DR actions cannot be taken. To be more specific, if there is a fault somewhere in between the communication path from the DNO to the DR remote controller, the emergency corrective action might not be taken and as a result the remaining circuit would be overloaded, likely ending up with more customers being disconnected due to protection actions. Observing Figure 3-3, if one of the ICT and electronic components linking each DR point with the regional controller fails to operate, or the communication signal between the Wi-MAX antenna and the DR router is lost due for instance to bad weather conditions, then the emergency DR actions of that particular point either cannot be taken or are delayed. Additionally, if the Wi-MAX antenna, fibre optic or the whole regional scheme is out of operation, the DR scheme for every node is unsuccessful. In this work, the communication signal is modelled based on weather distributions elaborated from statistical data [15], whereas the rest of the components adopt two possible up and down states based on probability distributions of typical mean time to failure and mean time to repair. The above mentioned information can be summarised in the following fault tree in Figure 3-4 depicting the case where DR actions in load point A cannot be taken due to ICT failure. C_i represents component *i* of the ICT platform (as illustrated in Figure 3-3). For instance, if due to bad weather conditions the communication signal was lost, the DNO would not be able to get informed for the disturbance, or the DR customers would not be able to receive the signal for their contracted disconnection. Similarly, if a DR switch is out of service then DR customers in that particular load point would not be able to provide the service.

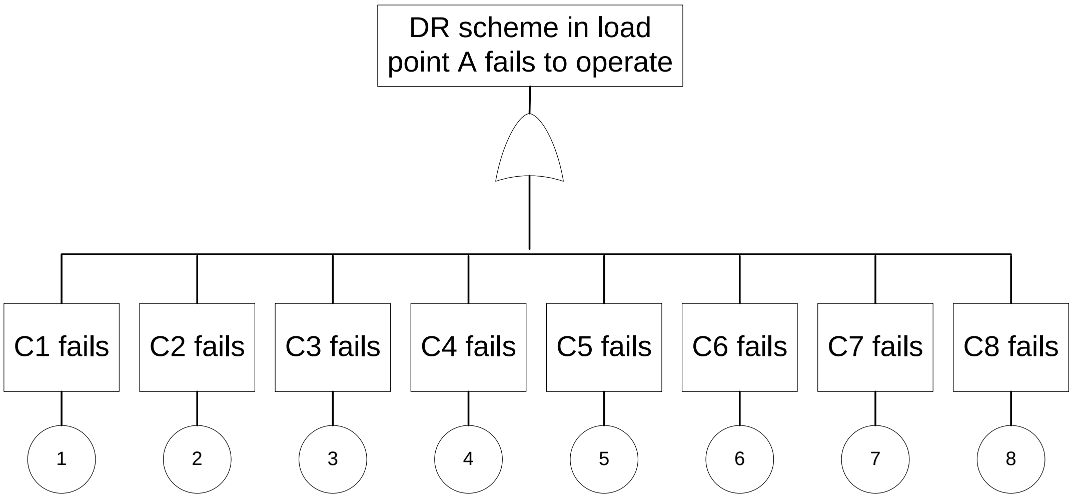


Figure 3-4: Fault tree depicting the case where the DR scheme in load point A would fail to operate due to ICT failure

3.4 DR formulation

As already mentioned, distribution networks are now planned in compliance with the ER P2/6 [1]. Therefore, the baseline load demand that a network can accommodate is evaluated according to the ER P2/6 security limits. When DR is used as a corrective action (with the aim to release unused network capacity) compliance with the security considerations is not compulsory under normal operation and only constraints are voltage and thermal limits. What basically happens is that the network is operated beyond its security limits and it is assumed that if a contingency occurs, a relevant amount of load is disconnected to bring the network within acceptable voltage or thermal limits.

In consequence, in this case the load demand is higher than the ER P2/6 baseline and the DNO has contracted this surplus of load as responsive, for post-contingency capacity support. This load is managed and controlled by the DNO through the ICT equipment and after a disturbance and in case there are network violations, automated actions open the DR switches. This DR scheme, as adopted by the C2C method, could be named as **inter-trip DR scheme,** because should a disturbance occurs and the network enters in a contingency situation, all DR load is disconnected to prevent further system damage, through automatic control arrangements.

Summarizing the DR model characteristics, DR could be formulated assuming that it is dispatched to supply load in the form of load reduction. For contingency time *t*, (3.1) illustrates the responsive load demand $L\_DR_{b,t}$ at bus *b* and time point *t*. Basically let *L* denote load consumption, while the superscripts 'new' and 'P2/6' represent the new load after the capacity release and the baseline ER P2/6 load respectively.

$$\boldsymbol{L\_DR_{b,t} = \varphi_{b,t}{}^{DR} \cdot \xi_{b,t}{}^{ICT\_DR} \cdot (L^{new}{}_{b,t} - L^{P2/6}{}_{b,t})} \tag{3-1}$$

Where $\varphi_{b,t}{}^{DR}$ is a binary indicator denoting if DR action has to be initiated, $\xi_{b,t}{}^{ICT\_DR}$ is a binary indicator denoting if ICT platform is available to support the DR scheme. If the ICT platform is not available, the DR actions cannot be taken in that bus.

3.5 Overall DR scheme methodology description

The analysis focuses on evaluating the reliability performance of the proposed scheme, taking into account the stochastic failure nature of both the electrical network and the ICT schemes that are used to support the proposed active operation. The analysis framework built for this purpose is based on SMCS that enable the quantification of risk for any critical event and the ability of the system to respond to disturbances arising within the system. Therefore, the SMCS reliability modelling tool described in Chapter 2 is implemented. Specific numerical applications to real UK distribution networks are used to illustrate outputs of the studies with regard to the reliability performance of radial and ring configuration, the reliability performance of the proposed DR scheme as well as network operation information such as losses and headroom for capacity increase for both configurations.

3.5.1 Simulation Procedure

A specific algorithm has been developed to simulate the actual distribution system restoration process, as described in Chapter 2. In line with implementations in C2C, remote controlled switches exist in the quarterly points of the two radial feeders, and an automatic NOP in the midpoint which interconnects the two radials. Additionally isolators exist between load buses to isolate potential faulted sections, consistently with real networks.

Following a fault, the relevant protections open to clear the fault. Protection reclosing actions are then performed with the aim of isolating the faulty circuit. After every switching action is taken, the status of the rest of the switching devices is checked in order for the next switching action to be performed. DR loads are disconnected according to inter-trip scheme. Apart from that, the DNO may take other post contingency actions such as to curtail normal load.

In the case the ring configuration is chosen, the NOP is closed from the beginning of the studies. In contrast, in the radial configuration, the NOP remains open, until a switching action has to be taken following a contingency. It should be mentioned that protection re-closing actions would last a few minutes (typically less than 3 minutes). This duration is currently considered by Ofgem as little enough in order for interruptions to be accounted as "short-term" and not to be penalized from a regulatory perspective. Subsequently, switching actions are taken to close the NOP (if the system is operated radially) in order to restore the supply to as many disconnected loads as possible, using an existent and available electrical path from neighbouring feeders. The NOP could be manually or remotely operated. The last action to be performed is the repair of the faulted component, which might take in the region of several hours. The algorithm is illustrated in Figure 3-5.

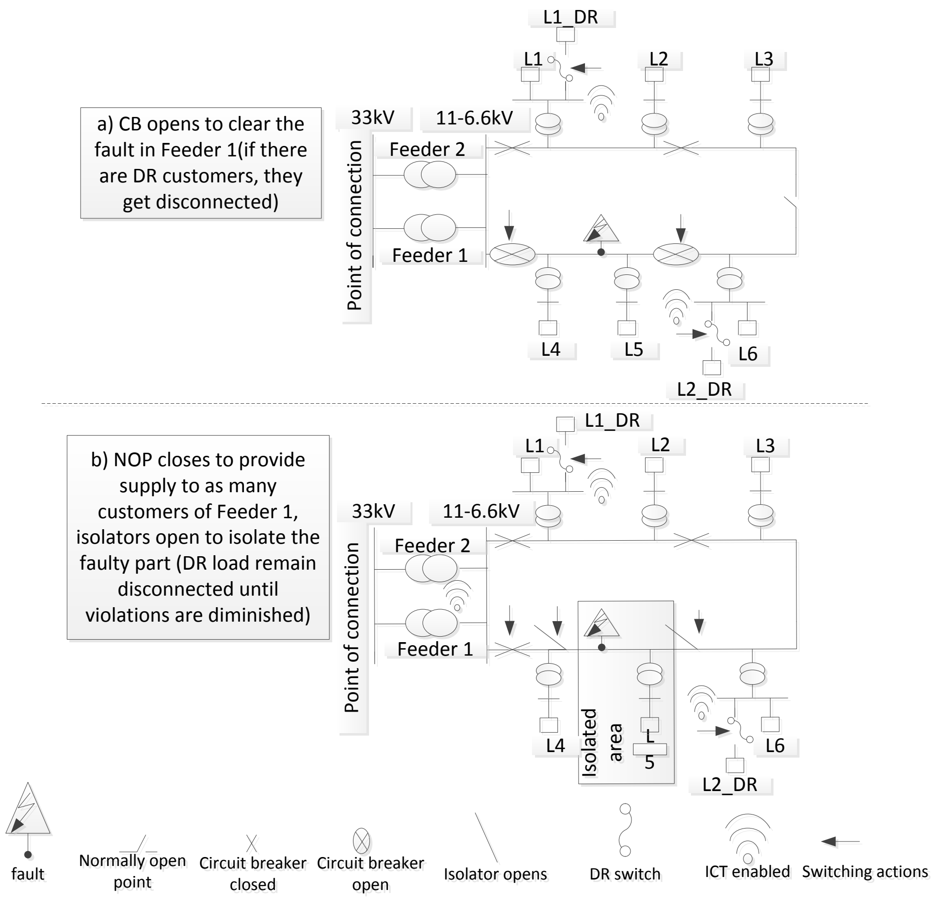


Figure 3-5: Distribution System Operation with the DR scheme under contingency situation

The methodology adopted, including the active management scheme and the reliability considerations of the ICT infrastructure, is summarised and illustrated in the flowchart of Figure 3-6. The procedure is repeated for every hour of the year, skipping the hours where the distribution system state is normal. For the contingency hours, the DR scheme is applied, taking also into account the probability of communication signal loss, or any other electronic failure. The system state is simulated through an AC power flow analysis with the aid of Matpower 4.1[61]and the whole modelling procedure is based on Matlab®.

The reliability assessment utilises the SMCS reliability modelling tool presented in Chapter 2 as already mentioned. The SMCS simulates the system behaviour in a sequential order analysing the system performance throughout a year. For every sample year, random TTF and TTR are generated for the components, using the component state duration distribution function. Additionally, after a network line fault, TTI and TTS are generated. The former represents the time to identify the fault, drive to the upstream isolation switch location, and operate the switch; the latter represents the duration of downstream switching actions. If the NOP is manually operated, it is assumed here that the mean time to switch is one hour. Additionally, it is assumed that the probability distribution of the switching time is exponential. After having known the chronological component state transition process, the system analysis is conducted for every time step and annual reliability indices are calculated. After the stopping criteria have been satisfied, expected values and probability distributions are obtained for each index. Additional theoretical background can be found in [55].

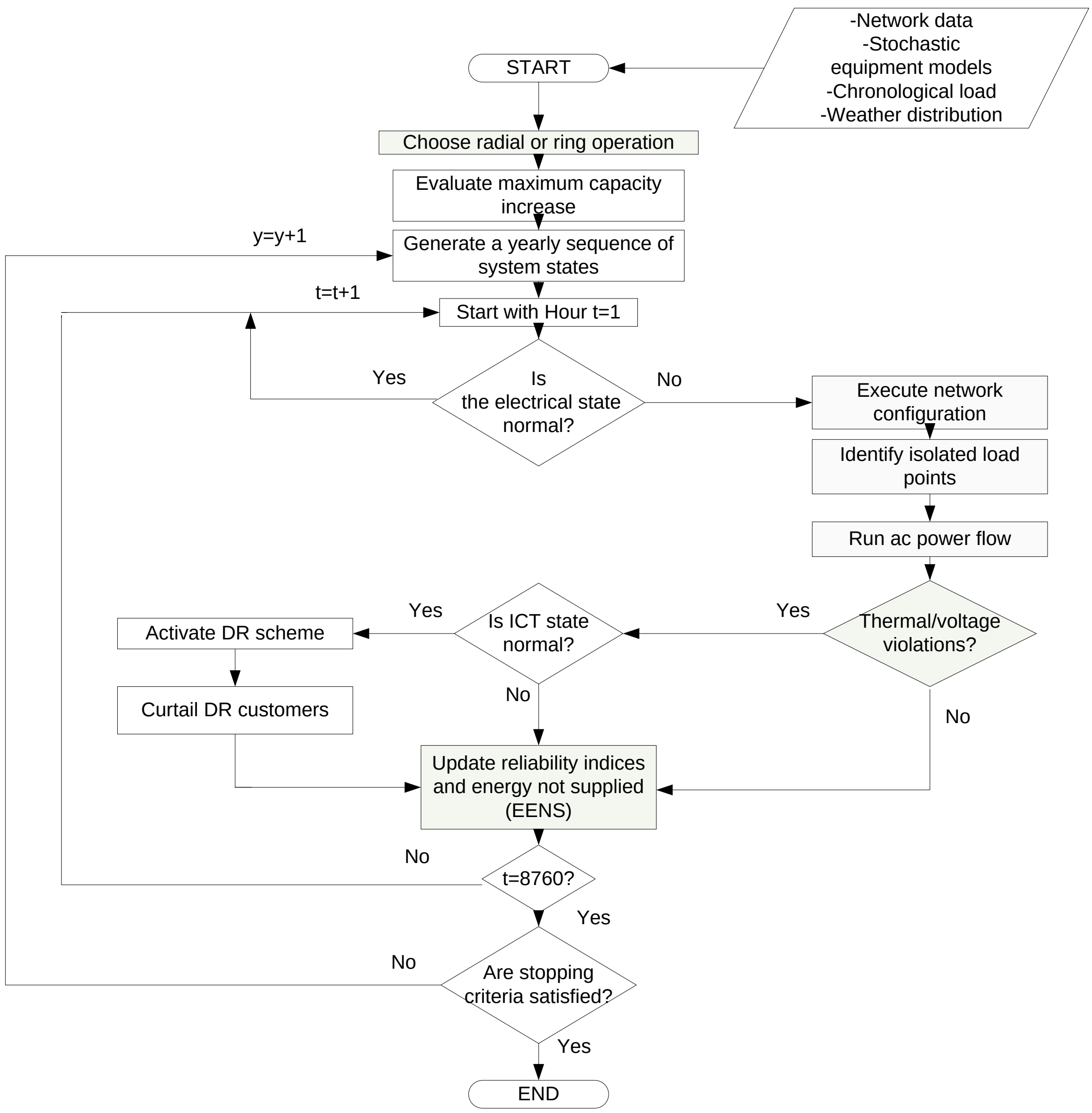


Figure 3-6: Flowchart of the SMCS for the DR inter-trip scheme

3.5.2 Configuration scenarios

Summarizing the above considerations, three configuration scenarios are examined in the next sections:

7. Ring configuration (symbolized as '*ring*')
8. Radial configuration with automatic operation of the NOP (symbolized as '*radial automatic'*)
9. Radial configuration with manual operation of the NOP (symbolized as '*radial manual'*)

Regarding the case that the NOP is automatic and the network is radially operated (*radial automatic*), it should be mentioned that when modelling for the reliability assessment the operation of the automatic closure of the NOP and the probability of its failure, the *ring* configuration and the *radial automatic* configuration are almost identical. More specifically, the SMCS is not capturing the few minutes that the automatic NOP needs to operate. Typically, the failure rate of the NOP is quite low, additionally as the coincidence of the NOP failure and the line loss is a rare event it is wise to use the concept of expectation [32] to accurately evaluate the effect of NOP failure. Hence, for all the reliability indices extracted during the *radial automatic* operation equation (3-2) has been implemented:

$$\begin{aligned} \boldsymbol{Reliability\ index}_{\boldsymbol{radial\ automatic}} &= (\boldsymbol{Reliability\ index} | \boldsymbol{NOP\ operates}) \\ &\cdot \boldsymbol{P}(\boldsymbol{NOP\ operates}) + (\boldsymbol{Reliability\ index} | \boldsymbol{NOP\ fails}) \\ &\cdot \boldsymbol{P}(\boldsymbol{NOP\ fails}) \end{aligned} \tag{3-2}$$

Where $P(NOP\ operates)$ is the NOP availability and comes from $A_{NOP} = \frac{\mu_{NOP}}{\mu_{NOP}+\lambda_{NOP}}$.

3.6 Test Networks Description

Case studies conducted during this research project were performed on real UK distribution networks which belong to Electricity North West Limited (ENWL). ENWL is one of the 14 DNOs in Great Britain and it owns and operates the regional electricity distribution network in North West of England. ENWL connects 2.4 million properties, and more than 5 million people in the region to the National Grid. ENWL delivers this power through its network of around 13,000 km of overhead lines, over 44,000 km of underground cables, almost 86,000 items of switchgear and more than 34,000 transformers [82].

ENWL has provided for this research 36 high voltage (6.6kV or 11kV) distribution networks characterized as 'mainly urban' or 'very urban' networks and for those networks load classification is 'mainly domestic' customers or 'mixed' (including also industrial and commercial) customers.

For each of those networks, all the technical data are provided in order to perform load flow analysis including bus data such as active and reactive power demand, number of customers, voltage magnitude and angle, generators' data including real and reactive power output, and branch data including resistance, reactance, susceptance and MVA rating. The majority of the test networks comprises two feeders as shown in Figure 3-7.

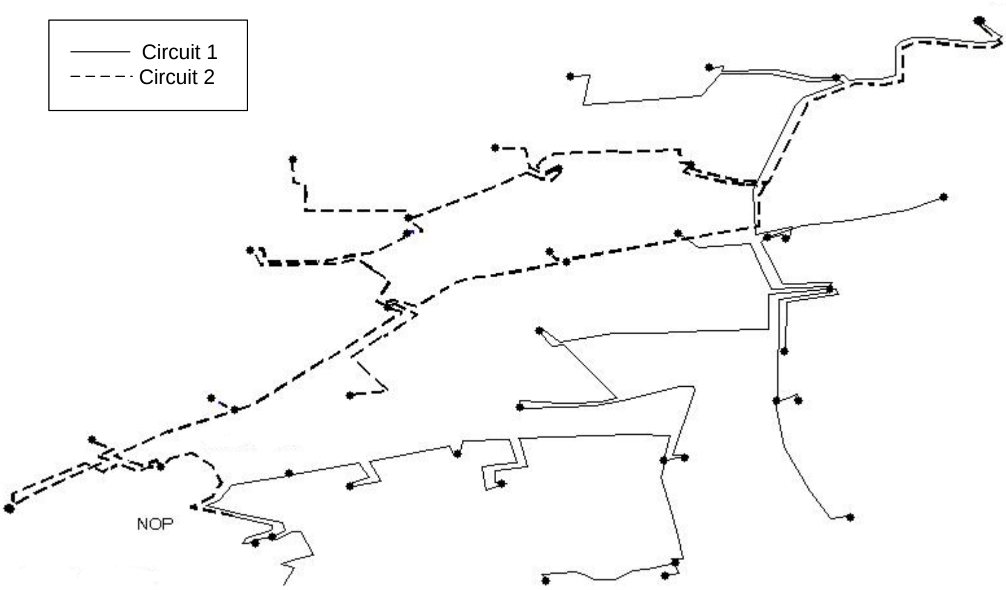


Figure 3-7: Example Test Network

In this chapter, ring and radial configurations are compared in terms of losses, capacity release and reliability performance. After analysing the 36 networks, it was concluded that the most efficient configuration (in terms of capacity release) is system dependent and not ring configuration brings always the best results, as may one would expect [77]. This depends on the presence of a bottleneck (thermal or voltage) on one of the radial circuits which could constraint the ring operation. For that reason, in the first instance, ring and radial configuration are compared based on the capacity increase and losses performance. This would be illustrated by using two different test distribution networks.

3.7 Radial vs Ring Configuration: Comparing Network Utilisation and Losses

According to ER P2/6, the prescribed maximum duration of interruptions for bulk-supplied groups of customers is based on their aggregated or “group” peak demands. Typically for the distribution networks under study, the “group demand” is in the range [1MW, 12MW]. Therefore a load equivalent to the group demand minus 1MW should be restored within 3 hours, with the rest to be reconnected within repair time. The baseline capacity is therefore evaluated according to the ER P2/6 limits and any capacity release gained through DR shall be determined compared to this baseline.

As already mentioned, analysis of many typical ENWL networks indicates that the results could be network specific and therefore deserve to be discussed further. Two distribution networks have been examined: the test networks ‘Ashton on Mersey’ and

'Farnworth'. Aston on Mersey is a 6.6kV very urban network, serving 2863 customers (mainly domestic), comprising 32 nodes and 32 lines. Its peak demand is 3.90+j 1.28MVA. Farnworth is an 11kV very urban network, serving 2870 customers (mainly domestic), comprising again 32 nodes and 32 lines. Its peak demand is 4.43 + j 1.46 MVA. Test network characteristics are summarized in Table 3-1.

For the time series analysis, which will be conducted in the next sections, hourly load profiles for typical representative days have been retrieved from Elexon databases [83], where average hourly profiling data for different days and seasons are provided for eight Profile Classes. It has been assumed that the load profiles for residential commercial and industrial customers are represented by Profile Classes 1, 4 and 8 respectively. A typical winter daily profile for the three customer types is illustrated in Figure 3-8.

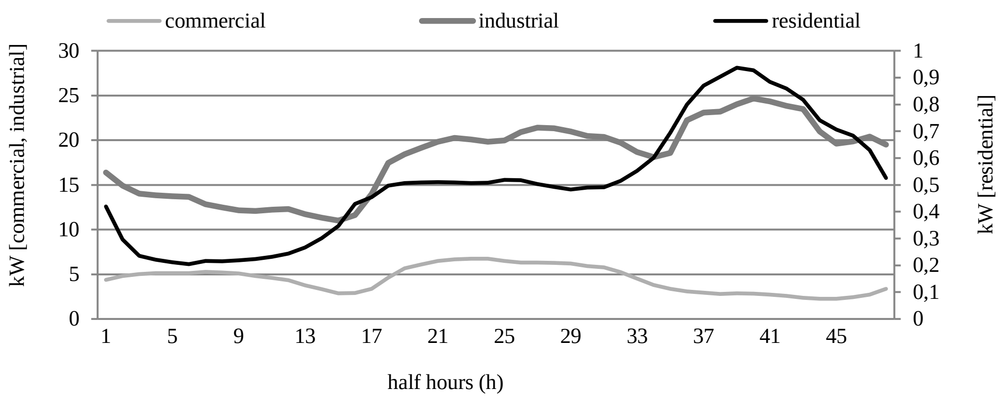


Figure 3-8: Typical winter daily profile for the three customer types

3.7.1 Capacity utilisation

The maximum load increase that the network can withstand is calculated through iterative power flows, where load demand is increased in steps, up to the point that an additional increase would provoke thermal or voltage violations. The methodology is illustrated in Figure 3-9. This calculated load demand increase basically corresponds to the network capacity utilisation increase.

With the present loading of the test networks, there was still headroom for load increase (23% for Ashton on Mersey and 20% for Farnworth) up to the point that ER P2/6 standards allow, which implies that the networks are currently underutilised with respect to the ER P2/6 allowance. The maximum capacity increase through DR for both networks is illustrated in Table 3-2. For both networks thermal constraints are the bottleneck for additional increase. Furthermore, it can be observed that results are not consistent between networks: for Ashton on Mersey the radial configuration permits the highest increase, while for Farnworth it is the ring one. This depends on the presence of a bottleneck on one of the radial circuits which constraints the whole loop operation.

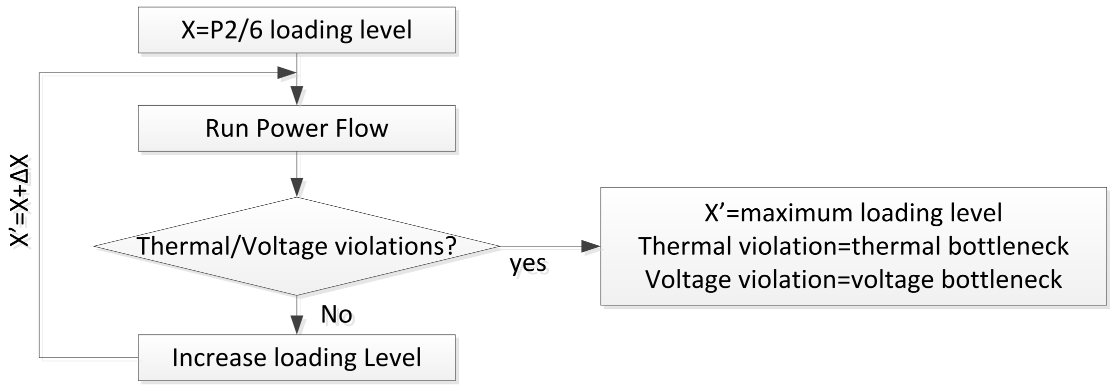


Figure 3-9: Iterative power flows to calculate the maximum network loading level

Table 3-1: Test Networks characteristics

	Voltage	**Peak Demand**	**Customers**	**Topology**
Aston on Mersey	6.6kV	3.90+j1.28MVA	2863	32 buses, 32 lines
Farnworth	11kV	4.43+j1.46MVA	2870	32 buses, 32 lines

Table 3-2 : Capacity increase above the ER P2/6 baseline gained with DR

Capacity Increase (%)	**Ring**	**Radial**
Ashton on Mersey	59	76
Farnworth	65	61

3.7.2 Load indices

Load Indices (LI) represent demand versus capacity. This set of indices is introduced by Ofgem for the RIIO-ED1[4] price control framework [84] and are associated with the conditions and the loading of the assets.

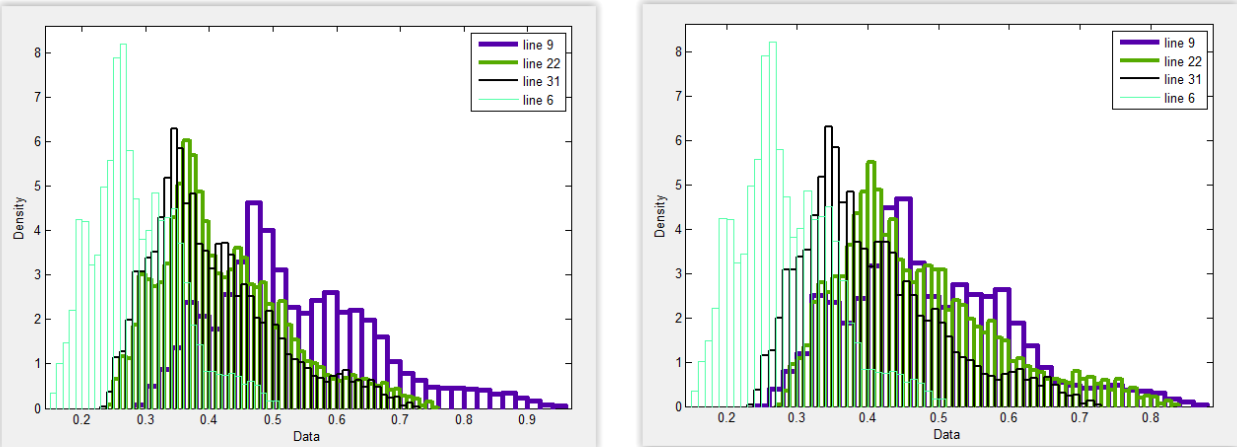
One of the key factors in the overall reliability of a network is how often assets are loaded above their rated capacity. Networks that are overloaded will experience increased interruptions to customer supplies. This is because the physical condition of their individual assets will deteriorate at a faster rate than otherwise anticipated, leading to an increase in outages.

Therefore, LI would give information on the utilisation of the assets and for tracking changes in their utilisation over time. The LI can be used to inform an assessment of the efficacy of the DNOs' general reinforcement decisions over the price control period. Under the LI framework, each demand group is assigned a ranking based on the loading and firm capacity at the site, and for the forecast period based on the DNO's views about future load growth, the options for investments and their impacts.

For the purpose of this analysis, LI have been calculated for the network lines giving the utilisation of each network line throughout a yearly load demand profile. LI for each line is calculated as the ratio of the power flowing through a line to the firm capacity of that line. Since LI are calculated throughout a yearly profile, probability density functions of the most highly utilised lines are illustrated in Figure 3-10 and Figure 3-11 for both configurations and networks under study. It can be observed that even for the four most highly utilised lines, it is only a few times during the year that the utilisation is increased, whereas typically the range of values for utilisation does not exceed the 70% of the line's capability. Furthermore, only for line 9 and line 32 in Figure 3-10 and Figure 3-11 respectively, line capacity utilisation reaches its maximum limit, indicating that those lines would be the thermal bottleneck for an additional load growth.

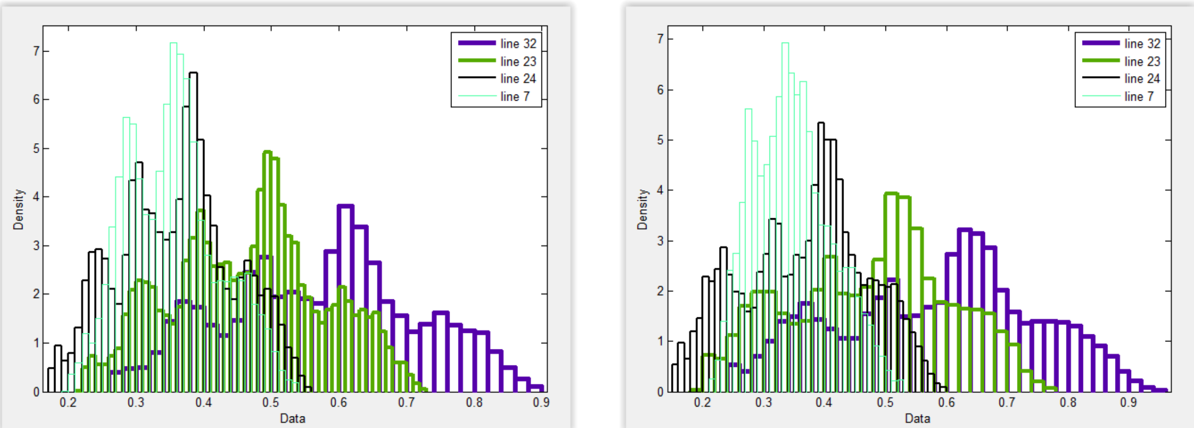
[4] The RIIO-ED1 price control set the outputs that the 14 electricity DNOs need to deliver for their consumers and the associated revenues they are allowed to collect for the period from 1 April 2015 to 31 March 2023. RIIO-ED1 is the first electricity distribution price control to reflect the new RIIO (Revenue=Incentives+Innovation+Outputs) model for network regulation.

However, it is clearly seen that this event would happen extremely rarely. It is also demonstrated that radial configuration results in higher line utilisation comparing to ring configuration. In summary, for both configurations, it is observed that the majority of network lines are typically half utilised throughout the yearly demand profile, a fact which endorses the remark that current distribution networks are underutilised.



(a) (b)

Figure 3-10: Probability density function for the LI of the 4 most highly utilised network lines Aston on Mersey, (a) ring, (b) radial



(a) (b)

Figure 3-11: Probability density function for the LI of the 4 most highly utilised network lines Farnworth, (a) ring, (b) radial

3.7.3 Losses

Additionally, the annual power losses for the two configurations are compared. The formula used to calculate the losses from Matpower is given in equation (3-3).

$$\textit{\textbf{Annual power losses}}\ (\%)$$

$$= \frac{\textit{\textbf{annual power losses in all the network lines}}}{\textit{\textbf{annual consumption}}}$$

$$= \frac{\sum_t \sum_{l_{a\_c}} I_{l_{a\_c,t}}{}^2 \cdot R_{l_{a\_c}}}{\sum_t \sum_b L_{b,t}} = \frac{\sum_t \sum_{l_{a\_c}} |P_a - P_c|}{\sum_t \sum_b L_{b,t}} \qquad (3\text{-}3)$$

Where l_{a_c} is a network line from bus *a* to bus *c*, P_a is the real power injected at bus *a*, $L_{b,t}$ is the load consumption at bus *b* at time step *t*, $I_{l_{a\_c,t}}$ is the current flowing through line l_{a_c} at time *t*, $R_{l_{a_c}}$is the line's resistance.

The calculated values are summarized in Table 3-3, where annual power losses are expressed as a percentage of annual consumption. As expected, radial operation results in a higher percentage of losses.

Table 3-3 : Annual power losses as a percentage of annual consumption for different configurations before and after the capacity increase

Losses	Before Increase		After Increase	
	Ring	Radial	Ring	Radial
Ashton on Mersey(59% increase)	0.699	0.7	1.293	1.313
Farnworth (61% increase)	0.237	0.238	0.441	0.443

3.8 Case study: Reliability assessment of the Inter-trip DR scheme

The reliability assessment methodology presented in the previous sections, which includes the DR post-contingency scheme, the inclusion of the ICT infrastructure supporting the scheme and the network restoration process is implemented in the test distribution networks under study.

The analysis focuses on comparing the outcomes for different configurations with the introduction or not of the DR scheme. For the rest of the chapter, the P2/6 scheme (corresponding to the current system without the introduction of active management with DR) is considered as the baseline scheme.

The case studies are summarized in Table 3-4. As already mentioned, the rationale for studying two distribution networks is that, analysis of many typical UK networks indicates that the results could be network specific and therefore deserve to be discussed further.

The input failure and repair rates for the network components that were assumed to fail are provided in Table 3-5 and are based on available UK statistics taken from [85]. The failure and repair rates for the ICT components are retrieved from [31]. In addition, the weather data for the communication signal are based on typical weather performance for the UK. A three-state weather distribution has been considered, including sunny, cloudy, and rainy conditions. A different likelihood of occurrence was assigned to each weather condition, with higher signal availability associated to sunny conditions and a lower one to rainy conditions.

Table 3-4: Characteristics of the case studies

Scenarios	-Network 1 *(Aston on Mersey)* -Network 2*(Farnworth)*
Load Increase Schemes	-Demand Response-compliance with network constraints *(DR)* -Compliance with P2/6 standards *(noDR)*
Configurations	-Ring -Radial automatic -Radial manual

Table 3-5: Failure and Repair Times for the network components

Component	Failure Rate (failures/year) (lambda)	Mean Repair Time (hours) (r)
Overhead lines	0.155	10.5
Cables	0.05	10.5
NOP	0.05	10
DR switchers	0.5	10
Router	0.1429	4
Antenna	0.0667	12
Fibre Optic	0.004	24
Server	0.0013	8

Table 3-6: Weather distribution and wireless signal availability for three- state model of weather conditions[86]

Weather condition	Percentage of hours with particular weather condition	Wi-MAX signal availability
Sunny	16%	100%
Cloudy	46%	99.6%
Rainy	39%	98%

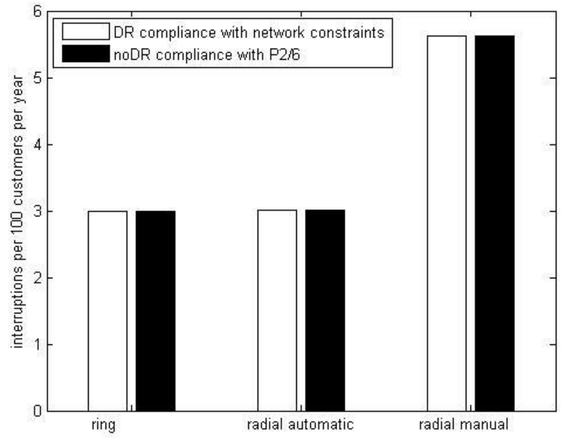
3.8.1 Illustration of reliability results for the different schemes

The implementation of different operational schemes (DR-compliance with network constraints versus noDR-compliance with P2/6) is compared based on the customer-related reliability performance (CI and CML).

For the case where the DR scheme is not incorporated it is assumed that there is a load increase up to the point that security constraints (ER P2/6 standards)[1] are still satisfied (at this voltage level are slightly less conservative than an N-1 criterion). That is 23% load increase for Ashton on Mersey and 20% for Farnworth above the current loading. This amount is equal to the maximum capacity utilisation complying with the security standards.

For the case where the DR scheme is incorporated, the load increase complies with the calculations depicted in Table 3-2. Furthermore, in this particular case, the amount of DR required is equal to the load increase, also corresponding to the capacity increase assessed, equally distributed throughout each load point of the network.

Considering that the contracted amount of DR is equal to the load increase, one would expect that reliability performance of the network would not deteriorate following a load increase above the baseline conditions. It is clearly demonstrated in Figure 3-12 that although the network capacity has been stressed, normal customers experience similar reliability levels as before (differences in the results lie in the range of the 3rd decimal point). Therefore, it can be concluded that the introduction of the DR scheme allows the connection of new load without the need for new network reinforcements and without compromising the reliability levels of the network.



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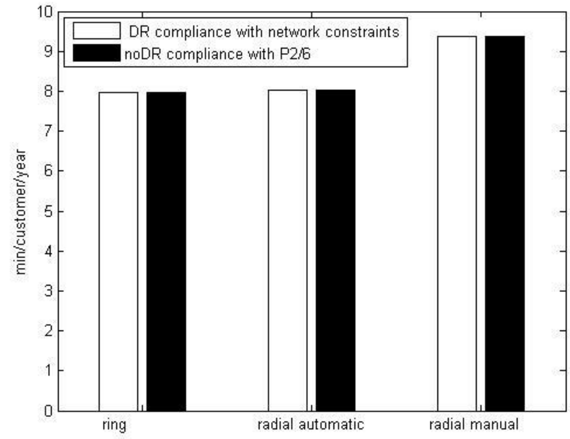


(b)

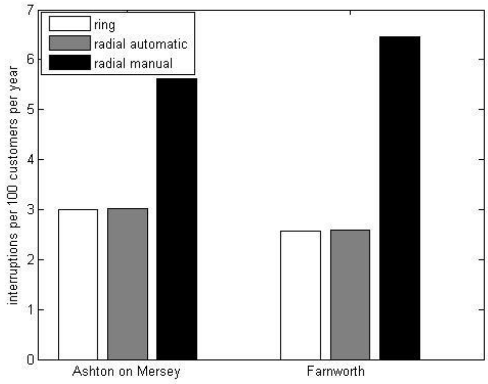
Figure 3-12: Aston on Mersey reliability performance, (a) CI, (b) CML

3.8.2 Illustration of reliability results for different configurations

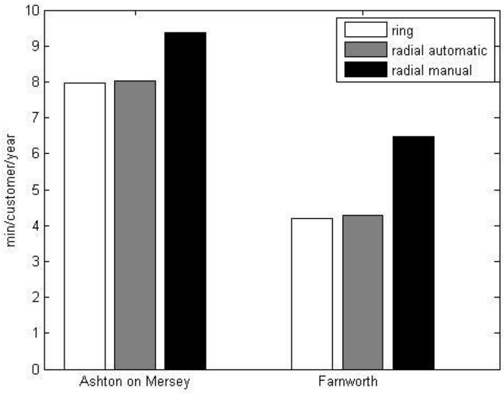
In the UK DNOs are obliged to report annually to Ofgem their CI and CML and are subject to penalties or rewards according to their performance based on each DNO's targets. At the moment DNOs are not required to report the short-term interruptions (SI), that is interruptions under 3 minutes. However, indices relevant to these SI are also presented below, with the aim to highlight potential deviations between ring and radial configurations.

Although each configuration could support different amount of load increase (as seen in Table 3-2, the same load demand has been applied for both ring and radial configurations (equal to the minimum load increase of both configurations) for consistency in the comparison process. Analysing the resulting CML and CI for different configurations (Figure 3-13a and Figure 3-13b) there are some common trends that arise for both networks. Radial operation with a manual NOP exhibits the worst CML and CI values, as it can be expected since part of the customers remain disconnected while the NOP is manually switched. Then, for the ring and radial automatic NOP operation, the reliability indices are quite similar. However, *radial automatic* has slightly worse performance because the automatic closure of the NOP is also subject to failure. Similar conclusions could arise for the three configurations for the EENS index depicted in Figure 3-13c.

On the other hand, the ring configuration suffers from the highest number of SI (Figure 3-13d), calculated by counting the total number of annual circuit interruptions. This is because when the two circuits are operated in a ring, in case of a fault the supply to the whole ring is interrupted by the protections on both heads of the feeder in order to clear the fault. In contrast, in the radial configurations, only the faulty circuit is temporarily completely out of service.



(a)



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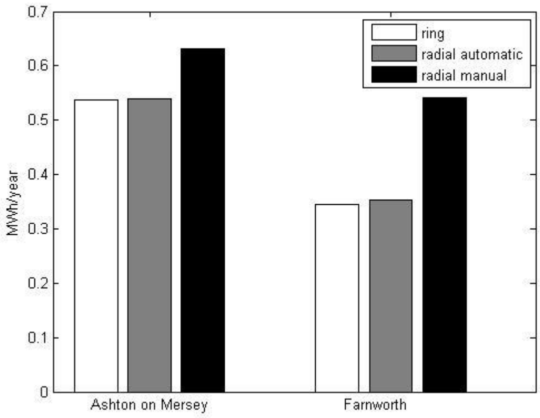
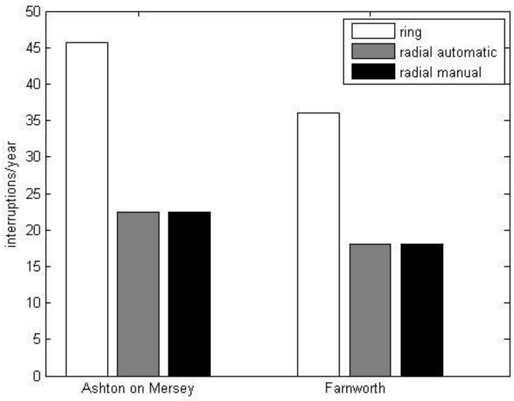


(c)



(d)

Figure 3-13: Comparing different configurations, (a) CI, (b) CML, (c) EENS, (d) SI

3.8.3 Reliability levels of the DR contracted customers

The reliability performance for the DR contracted customers is discussed here in order to better understand their contribution and also the reliability level that they experience. Table 3-7 and Table 3-8 depict the percentage increase in the reliability indices for the DR contracted customers for both networks. From Table 3-7 and Table 3-8 it can be observed that the level of discomfort for DR customers is much greater compared to the normal customers, since the DR customers remain disconnected until the faulted component has been again into service. However, this was indeed to be expected as they are receiving contractual economic incentives in exchange.

Table 3-7: Percentage increase in the reliability indices for the DR contracted customers, Aston on Mersey

Configuration	CI	CML	EENS
Ring	+22.9%	+11%	+59.4%
Radial automatic	+23.8%	+12%	+56.7%
Radial manual	+9.7%	+7.7%	+57.2%

Table 3-8: Percentage increase in the reliability indices for the DR contracted customers, Farnworth

Configuration	CI	CML	EENS
Ring	+83.9%	+91.9%	+101%
Radial automatic	+89.3%	+96%	+99%
Radial manual	+25.7%	+46.4%	+74.5%

3.8.4 Incorporation of ICT failure

The significance of analysing also the probability of ICT components failure could be evaluated by repeating the same studies assuming that the ICT components are always available. In such a case, the DR scheme should be always successfully activated. Table 3-9 and Table 3-10 present the percentage decrease in CI, CML and EENS for each configuration for 100% ICT availability. The values for the indices are always lower compared to the results of Figure 3-13. This implies that there might be an erroneous perception of the network performance if ICT failure rates are neglected.

Table 3-9: Percentage decrease for 100% ICT availability, Aston on Mersey

Configuration	CI	CML	EENS
Ring	-3.24%	-0.42%	-0.25%
Radial automatic	-3.2%	-0.41%	-0.246%
Radial manual	-0.68%	-0.12%	-0.75%

Table 3-10: Percentage decrease for 100% ICT availability, Farnworth

Configuration	CI	CML	EENS
Ring	-5.52%	-0.11%	-0.63%
Radial automatic	-5.44%	-0.10%	-0.619%
Radial manual	-1.69%	-0.51%	-0.29%

3.8.5 Sensitivity analysis for the ICT faults

Due to the high uncertainty related to the reliability data for the area of ICT components failure and repair rates in the numerical illustration of the method, sensitivity analysis is carried out to determine the impact of the assumed data on the reliability evaluation results. In particular, the wide range method is used, where the reliability data are varied over a wide range to examine the impact on unreliability and unavailability.

Aston on Mersey network is used and the studies are performed for the scenario 'DR – compliance with network constraints' and demonstrated only for the ring configuration.

The reliability analysis has been performed for increased values of the failure rate (lambda) and repair rate (r) of all the components related to the ICT infrastructure supporting the DR scheme. An increased failure rate reflects a decrease in the ICT equipment availability and reliability, since the probability of an ICT outage is augmenting. An increased repair rate reflects an additional delay in the repair of the faulty component. Figure 3-14 presents the CML and EENS respectively, resulting after the reliability assessment.

In general it is observed that when the ICT equipment failure rate is increased, CML and EENS increase for normal customers. In other words, the reliability performance of normal customers is deteriorating. An ICT failure would hinder the successful activation of a DR scheme or would cause the early termination the service due to the ICT failure. Therefore, it is expected that system reliability is degrading (interruptions of normal customers are increasing since the DR scheme fails to respond).

Nonetheless, it is observed that although the impact of ICT failures increase is linear, it is not as significant as the size of the failure rate increase. For instance, for ICT failure rates 16 times higher than the baseline values, it is observed that CML index is increased approximately by 23% and the EENS index is increased by 14%. This happens mainly because an ICT failure entails a negative impact on the indices only when DR activation is required, hence those two prerequisites need to coincide. It can be concluded from the results that ICT failure does not coincide extremely frequently with DR activation requirements.

Figure 3-15 shows the reliability results for a sensitivity study of the repair rate value, where similar conclusions can be made.

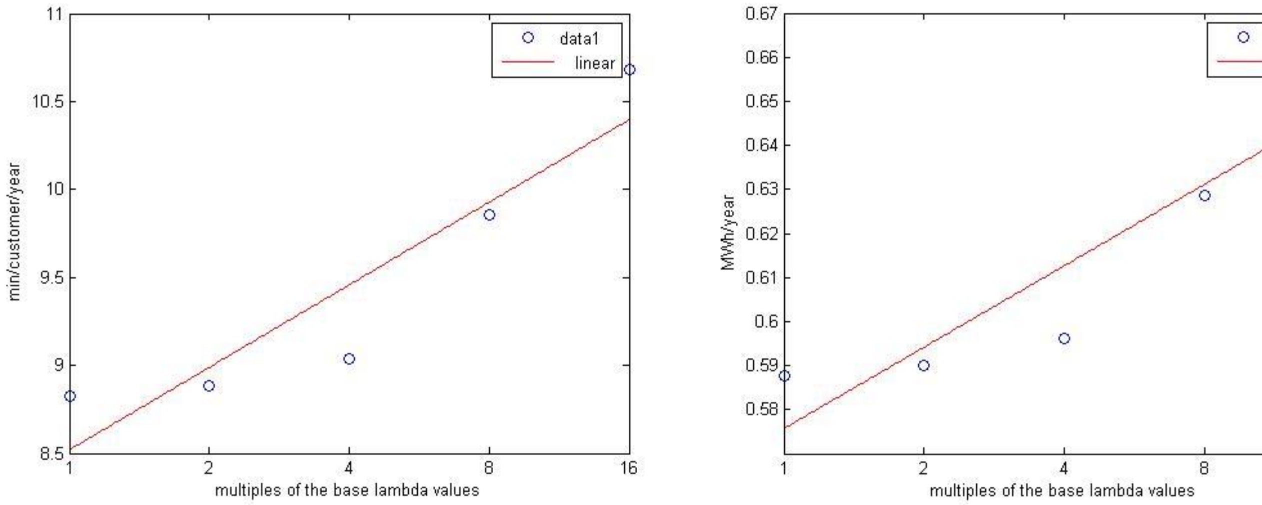


Figure 3-14: CML (left) and EENS (right) for multiples of the base lambda values

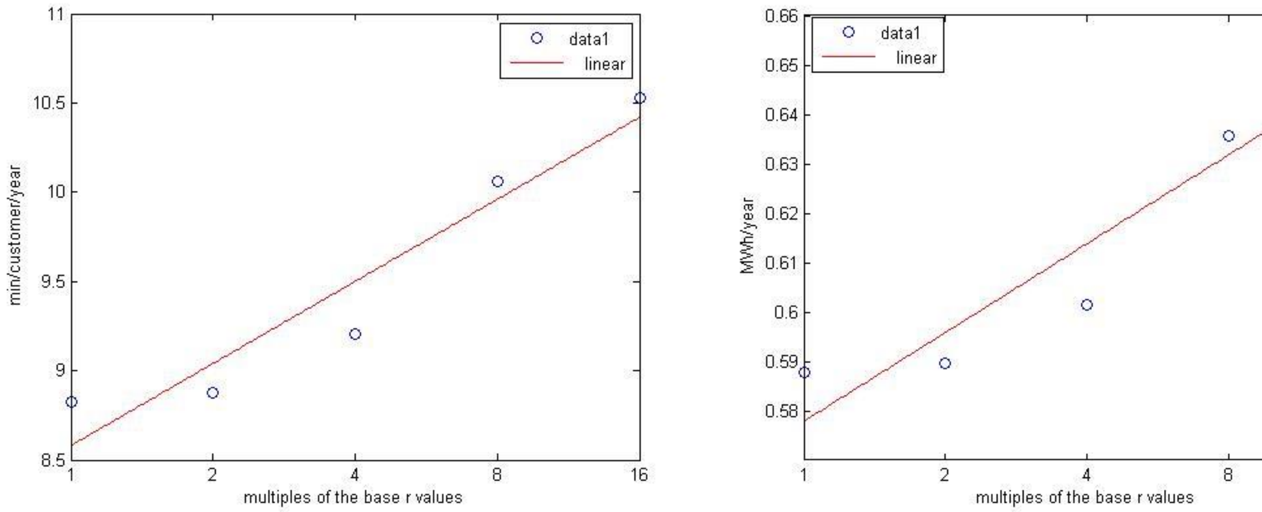


Figure 3-15: CML (left) and EENS (right) for multiples of the base r values

3.8.6 Concentrated DR

In the previous sections, it was assumed that the amount of available DR was distributed equally along the network load points. In this section however, the case where the amount of the available DR is concentrated in whole in a specific load point is examined.

In case there is the flexibility of controlling the location and the amount of a new load, this kind of sensitivity study could provide network planners significant information in terms of identifying the optimal location to accommodate that new load, taking into account also the reliability worth of the non-contracted customers, whose reliability level has to be regulated. The comparison between the load points focuses on which location can bring about the best reliability performance for the network.

For illustrative purposes, only the ring configuration is discussed, again for the scenario 'DR –compliance with network constraints', applied in Farnworth. Farnworth has 32 buses of which the 17 accommodate demand. Therefore, the study has been repeated 17 times, assuming each time that the whole of contracted DR amount is located only in a particular load point.

As taken from section 3.8.2, when DR is distributed along the load points CI equals 2.72 interruptions /100 customers/year and CML equals 4.24 min/customer/year for the selected scenario in Farnworth. Figure 3-16 shows CI and CML results when connected DR concentrated only in one single load point. In Figure 3-16 axis x, indicates the load point and axis y indicates the result of the reliability assessment for each case. It is observed that CI values oscillate from 3 to 4.2 interruptions/100 customers/ year and CML oscillate from 4.5 to 8 min/customer/year.

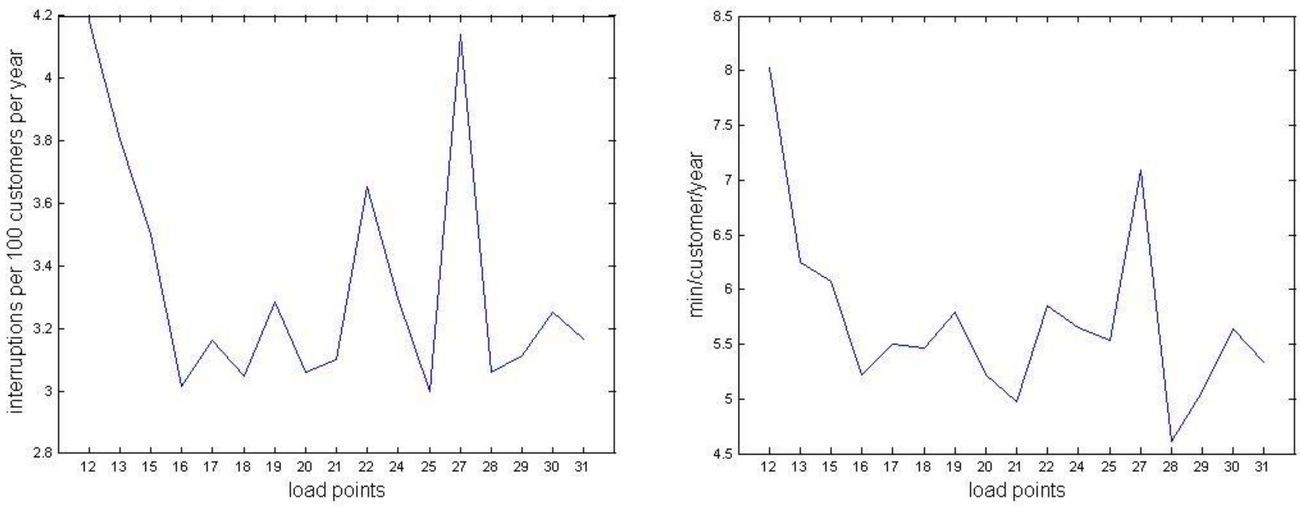


Figure 3-16: CI and CML values for concentrated DR only in a load point, ring configuration, Farnworth

Furthermore, Figure 3-17 and Figure 3-18 depict the load point indices expected annual duration and frequency of interruptions (EADI and EAFI) respectively, again for the 17 cases. In the figures, x axis indicates the location of the additional responsive demand, whereas z axis shows the reliability performance for all the load points due to that responsive load. Those figures present more detailed information with respect to the impacts that connection of DR in particular load points would bring. For instance, when connecting DR exclusively in load point 12 and 27 (dark blue and dark orange respectively) then EAFI and EADI perform higher values (thus worst reliability performance) with respect to connection in other load points such as load point 22.

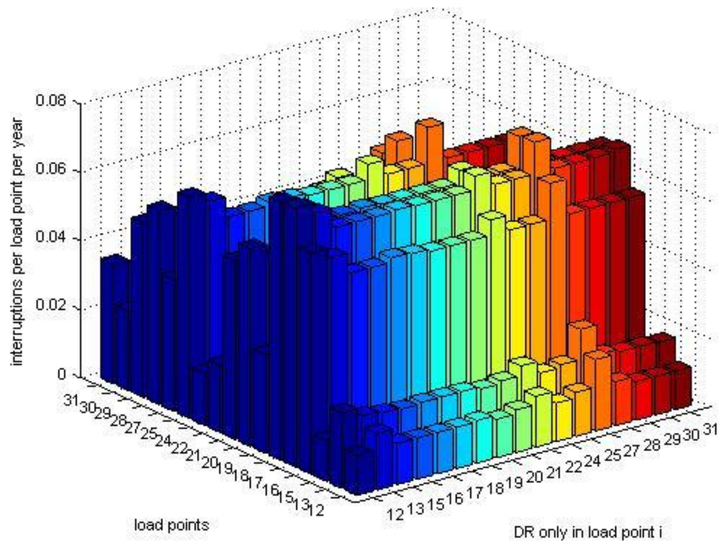


Figure 3-17: EAFI in each load point for concentrated DR only in one load point, ring configuration, Farnworth

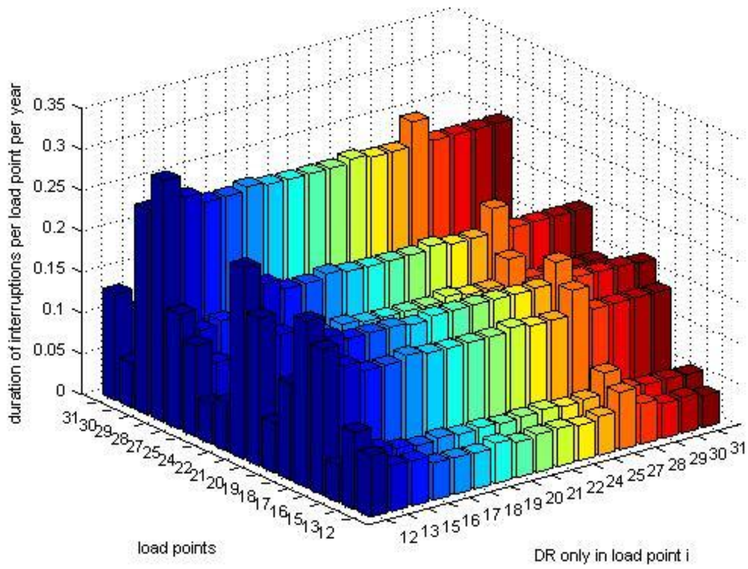


Figure 3-18: EADI in each load point for concentrated DR only in one load point, ring configuration, Farnworth

3.8.7 Different levels of automation

To allow services between the DNO and other interesting actors and also to ameliorate the quality of service, manual switches could be replaced by autonomic switches and in addition to that, increased automation could be spread around the network to allow fast reconfiguration and corrective control. Therefore, the current distribution network operation would transform to accommodate any network support schemes.

In the previous subsections of 3.8, the introduction of the DR scheme, as suggested and described in the C_2C project, requires increased levels of automation, that is, automatic switches to replace manual switches so that switching actions during the restoration process are complete in less than 3 minutes (so as to count as short interruptions which are not regulated).

This section presents a sensitivity study on the level of automation for the switching actions to be performed during the restoration process, which was extensively described in section 2.4.

For simplicity, only the Intermediate Point Switches (IPS) and Normally Open Point (NOP) have been modelled, assuming that the switching time selected for each IPS and NOP also includes (in an additive manner) the time to switch all the manual or remote switchers located in between.

Another detail which is also included in the study refers to the number of teams a DNO has available to respond to a fault, for example in order to repair the faulty sections, isolate the fault, check the status of the switching devices or perform the manual switching. Two simple scenarios have been studied and modelled in this section, with the aim to illustrate the impact of this particular parameter: *single repair team* and *multiple repair teams*:

- When only one repair team exists, actions should happen only one at a time and consecutively. In particular, this would mean that switching of the IPS could happen only after the NOP has closed, connecting every part of the network back to supply in a chronological order starting from the healthy feeder and performing switching and repair actions towards the faulty component.
- In the case that multiple repair teams exist, switching actions in different locations could happen simultaneously. Reconnecting back to supply a section of the network that is not related with the fault would not have to wait for prior

switching and repair actions to happen. This would practically mean that IPS would be able to close before the moving of the NOP.

This case study would analyse four different levels of automation, assuming that *level 4* refers to the case of fully automated distribution network. Thereinafter three other levels of automations, assuming different values for mean time to switch (MTTS) are considered and the SMCS reliability analysis is performed. Automation scenarios are summarized in Table 3-11 and reliability results are illustrated in Figure 3-19.

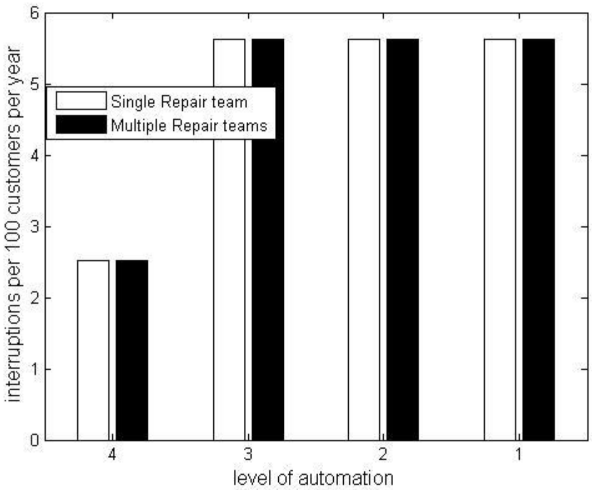
It is interesting to observe that when the network is not fully automated, (where switching actions happen in less than 3 minutes and interruptions are not penalized thus not included in the calculation of CI) the level of automation does not have any impact on CI (Figure 3-19a). The reason behind that is that customers indeed would have to remain disconnected until the switching action is performed. And since the interruption of a section lasts more than 3 minutes, it is of similar consequence how fast the reconnection would be in order to count as an interruption.

Nonetheless, the level of automation plays a crucial role in CML and consequently in EENS. The highest the level of automation, the fastest the customers would be reconnected, thus the duration of interruption would be lower. Figure 3-19b demonstrates that as the level of automation is increased CML are decreasing. Similar conclusions can be made for EENS in Figure 3-19c.

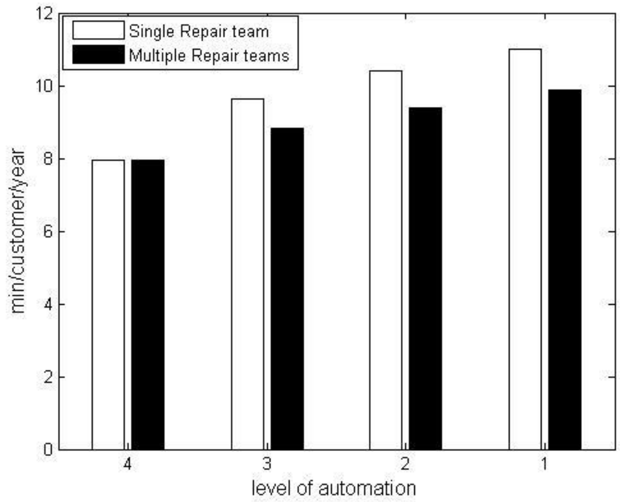
It is also interesting to note that as expected, CML and EENS reliability results are better for the case that multiple repair teams are considered. Again, for the case of CI, the number of repair teams does not have any impact on the results, since repair teams would only affect the time of customers' reconnection. Furthermore, for the case that the network is fully automated (level 4), multiple repair teams instead of a single one for the switching processes would not provide any benefit, since all the processes happen automatically.

Table 3-11: Scenarios for 4 levels of automation

Automation level	MTTS_NOP	MTTS_IPS (single repair team)	MTTS_IPS (multiple repair teams)	MTTR faulty section
4 (full automation)	<3 min	<3 min	<3 min	5 hours
3	30 min	30 min after the NOP is closed	30 min	5 hours
2	1 hour	1 hour after the NOP is closed	1 hour	5 hours
1 (no automation)	1h 30 min	1 hour and 30 min after the NOP is closed	1 hour and 30 min	5 hours



(a)



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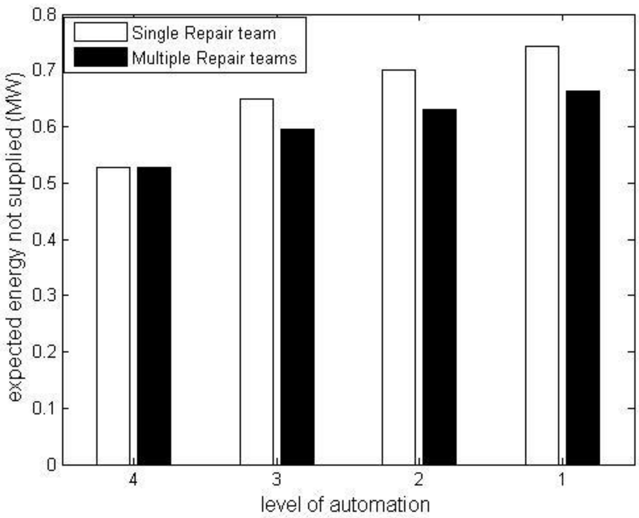

(c)

Figure 3-19: CI (a), CML (b) and EENS (c) for 4 scenarios of automation level

3.9 Conclusion

This chapter described a DR scheme to increase the distribution network capacity utilisation which is based in a realistic project named C_2C. The proposed scheme was implemented in both radial and ring configurations in order for the best configuration to be chosen. The configurations were compared in terms of losses, capacity increase, and reliability performance. The reliability assessment was carried out with SMCS taking into account the fact that failures can occur not only in the electrical network but also in the electronic components that serve the realisation of the DR scheme.

The reliability performance was assessed through the currently regulated reliability indices but also through the short interruptions that are not currently considered. The results show that the implementation of DR could potentially increase the network utilisation without the need to change the present configuration, provided that automatic schemes to close the NOP are in place. In fact, ring operation might not always be the best option. Although losses are inevitably lower in the ring relative to radial operation, radial operation could sometimes bring higher capacity utilisation and also a better reliability performance. Additionally, ring operation undoubtedly brings about higher short interruptions which are currently non-regulated, but this could be subject to changes in the future. Finally, inclusion of the communication signal availability and the availability of electronic components brings more accurate insights on the network performance when DR and active network management schemes are incorporated.

To better understand the above mentioned ideas and concepts the chapter is concluded by providing a sensitivity analysis of the ICT failure and repair rate, in order to illustrate the impact of those faults and also a sensitivity analysis on the level of automation and also the location of DR. Results again indicate that the higher the level of automation, the lower the duration of interruptions for customers. Furthermore, when failure and repair rates of ICT components increase, reliability performance deteriorates, however deterioration is not substantially high due to the low probability of coincidence of the ICT failure with the electrical network failure and also the need to activate DR which is driven by the level of emergency (size of load demand and remaining network capacity during fault conditions).

4 Reliability And Risk Assessment Of Post-Fault Priority DR

Following from the previous chapter where post fault DR was proposed to provide capacity release in smart distribution networks, this chapter extends the DR model, by proposing priority disconnection of the contracted customers. A comprehensive framework for the assessment of related reliability and risk implications is presented. The priority DR scheme is a direct load control (DLC) scheme where DR customers are now efficiently disconnected and are characterized by differentiated reliability levels. The cost of interrupted load is used as a proxy for the value of the differentiated reliability contract for different customers to prioritize the disconnections. The framework tackles current DNO's corrective actions such as network reconfiguration, emergency ratings and load shedding, also considering the physical payback effects from the DR customers' reconnection. SMCS is used to quantify the risk borne by the DNO if contracting fewer DR customers than required by deterministic security standards. Numerical results demonstrate the benefits of the proposed DR scheme, when compared to the C_2C solution. In addition, as a key point to boost the commercial implementation of such DR schemes, the results show how the required DR volume could be much lower than initially estimated when properly accounting for the actual risk of interruptions and for the possibility of deploying the asset emergency ratings. The findings [87] *support the rationale of moving from the* *current prescriptive deterministic security standards to a probabilistic reliability assessment and planning approach applied to smart distribution networks, which also involves distributed energy resources such as post-contingency DR for network support.*

4.1 Demand Response through a Direct Load Control Program

A Direct Load Control (DLC) Program is modelled in this chapter to provide post-contingency network support similar to the one proposed in the C_2C solution. In a DLC program, customers sign up for a contract giving the utility the option to remotely shut down appliances and non-vital loads during high demand periods or power supply emergencies. In return, they receive credit via economic benefits for this participation. A similar project has been implemented by the utility Wisconsin Public Service [88].

In the literature several DLC algorithms have been developed. In [89] the DLC algorithm determines the optimal control schedules that an aggregator should apply to the controllable devices of a large number of customers in order to optimize load reduction over a specified control period. A building energy simulation tool is employed to model the average behaviour of the thermal loads of each customer type. The controllable customers are operated as a virtual power plant taking part in the electricity market by offering load reduction bids to the system operator. In [90] a DLC scheme of air conditioning loads (ACL) is proposed, aiming to reduce the peak load, scheduling the cycling on/off times of the loads based on their interruption costs. The objective of this DLC is to minimize the overall system operating cost comprising the energy cost, the spinning reserve cost and the compensation to the ACL customers. A novel adaptive control strategy for integrating DLC with interruptible load management to provide instantaneous reserves for ancillary services is presented in [91]. There, a fuzzy dynamic programming is firstly used to pre-schedule the DLC and satisfy the customers' requirements and then the adaptive control strategy further operates the interruptible load to adjust the DLC scheduling in real time.

In the context of this work, a DLC scheme similar to [36] is adopted. In the proposed approach the network is operated beyond its security limits, thus serving a higher volume of load demand; then if a contingency occurs a relevant amount of load is disconnected to bring the network within acceptable voltage and thermal limits.

Effectively, through DLC, DR customers accept a level of '*differentiated reliability*', where the system delivers different levels of reliability to different customers depending on their preferences, which are driven by the willingness to accept lower service quality for economic benefits. A similar concept of differentiated reliability has recently been presented in [92], proposing optimal switch configuration algorithm for customers who pay additional fees for higher reliability. The problem is formulated as an optimization, which is performed off-line (storing optimal switch combinations in a database to be used in real time) with the objective of minimizing utility liability while assuring the supply of power to priority customers. From the above-mentioned DLC references only [90] [91] have included the power network constraints into the problem formulation and only [90] has examined the reliability performance of the network including the DLC scheme applying the analytical technique of state enumeration into a transmission network. However, quantifying the reliability and risk profile arising from application of differentiated reliability DR or DLC using probabilistic techniques such as Monte Carlo simulations in current and future distribution networks is a topic broadly unexplored.

Furthermore, the reliability impacts on power networks when implementing demand side management techniques has been already addressed by researchers. DR impacts on bulk system reliability have been researched in [93]. The paper also considers the load forecast uncertainty, while applying load shifting as a demand side management measure. DR impacts on distribution network operation have been discussed in [94] where for the reliability evaluation a limited set of contingency states have been considered. Load profiles for major residential appliances are extracted from meter consumption and also the flexibility of the responsive loads is also taken into account. Impacts of DR programs on short-term reliability assessment of wind integrated power systems is studied in [95] applying Monte Carlo method. The outlined literature aims at quantifying the reliability benefits when DR is activated. However, none of those articles discusses the reliability implications of DR to increase the utilisation of the existing network and the potential DR capacity requirements associated with this objective. On the other hand, [96] proposes DR as an option to enhance the utilisation of the current distribution network capacity, but without doing any reliability analysis. Therefore, it can be appreciated how little work has been carried out in terms of reliability and risk considerations of DR resources that would accept differentiated reliability contracts, whilst this solution could bring substantial capacity support (and network reinforcement postponement or even avoidance [70]) benefits and is in fact already being trialled, for instance in the aforementioned C_2C project.

On top of that, any load reduction due to the DR scheme would probably need to be recovered at a later time. This process is characterized as energy payback [97] and is a potential side-effect of intentionally reducing consumption. Although this effect has been studied from an operational and a market perspective [91][98] , payback effects have been included in [90] [99], but to none of the above articles which are more related to distribution network reliability with DR services.

Finally, related to the reliability technique, analytical and simulations approaches could be used for distribution network reliability assessment [48][31]. In [49] a multi-state availability model has been proposed, whereby all possible combinations of component failures are enumerated and associated to a probability. However, this practice might result cumbersome for large scale networks, complex automation schemes, intertemporal mechanisms such as emergency rating implementation and payback effects, network reconfiguration and DR schemes, as in this work. In contrast, the simulation approach simulates the actual system and components' behaviour in a chronological manner, allowing a high degree of complexity in system modelling and capturing the physical significance of the calculated reliability indices. Therefore, SMCS have been preferred in this work.

4.2 Chapter objectives

Based on the above and following preliminary work carried out in [77], this chapter discusses the modelling of DR in the form of direct load control (DLC) as post fault corrective actions to release untapped emergency network capacity during normal operations.

The SMCS reliability modelling tool presented in Chapter 2 has been utilised for the reliability assessment, making use of time series profiles, which are a key input to effectively assess the DR requirements. The cost of interrupted load has been used as a proxy of DR contract values and to determine a disconnection priority list. Numerical applications to UK distribution networks from the C_2C project are used to demonstrate the framework, quantifying how the distribution network risk profile changes when moving from an N-1 preventive security to a corrective DR-based security context, and assessing the technical risk and economic implication borne by the DNO when contracting different volumes of DR.

Specific objectives of this work which also represent key contributions with respect to the current research are:

- Assessing the reliability performance of two DR schemes, namely, the currently trialled C_2C scheme (hereinafter indicated as *inter-trip*) and the proposed *priority* DLC scheme where during a contingency event DR customers are disconnected according to the determined priority list. Selection of DR customers according to their interruption costs has also been seen in [90] , however in that study DLC is implemented in the peak load periods of every day, whereas in our study DLC is applied only as corrective action after a random fault has been placed in the network in a random hour of the year.
- Performing the reliability studies taking into account asset emergency ratings, realistic load profiles, power network constraints, payback effects and the cost of interrupted load. In case of residential DR, detailed major appliance modelling has been conducted which is necessary for residential DR , a process only seen in [100] (though not including reliability analysis) and in [94](however the reliability analysis is performed with state enumeration and not through simulation and time series analysis which will be proven crucial). Furthermore, distribution network reconfiguration following restoration process has also been included in the study in order to realistically reflect the reliability profile of the network. To the authors' best knowledge service restoration along with DR has been presented only in [101], where again reliability assessment has not been considered.
- Assessing the risk associated with contracting varying levels of DR, and in particular fewer DR customers than required if applying deterministic security standards. DLC DR is used to provide capacity release after network demand has been increased above the ER P2/6 limits and DR requirements are also identified from the reliability and risk analysis.
- Performing a techno-economic analysis to estimate the "unreliability costs", borne by the DNO, for normal and DR customers with differentiated reliability levels in different scenarios.

- Realising that detailed load profiles simulation, time series analysis and application of emergency rating effectively capture the actual network capacity requirements in a contingency period, concluding that DR capacity requirements are much lower than what the deterministic standards initially indicated.

4.3 General description of the DR scheme and modelling assumptions

In the context of this work, a DLC scheme similar to [36] is adopted. In the proposed approach the network is operated beyond its security limits, thus serving a higher volume of load demand; then if a contingency occurs a relevant amount of load is disconnected to bring the network within acceptable voltage and thermal limits. That load comes from DR customers[5] contracted by the DNO for emergency conditions. In this paper, the same assumptions made for the C2C project have been considered with the aim to assess quantitatively the proposed solution from a reliability perspective:

- In the event that load demand is higher than the ER P2/6 baseline, the DNO has contracted the surplus of load as 'responsive' for capacity support. This load is controlled by the DNO through ICT and after a disturbance automated actions open the DR switches.
- DR actions are limited to *two* corrective interruptions per contracted customer per year, of maximum *eight* hours per interruption, thereinafter referred as *DR activation constraints*.

Those DR activation constraints apply to commercial and industrial *(C&I)* customers. Although the C2C scheme has not been implemented to residential *(R)* customers so far, necessity of DR from *R* customers has been highly acknowledged [102] and decision models for managing residential DR has been examined [103] showing that realizing effective DR in smart networks is evolving. Hence, in this work *R* customers are also involved. The above DR activation constraints apply for those customers as well.

[5] Smart switches may be used so that only curtailable load is contracted and in case disconnected out of the total customer's demand.

4.3.1 Inter-trip Scheme for DR Disconnection

Based on the C_2C case, in the inter-trip scheme all DR load is disconnected to prevent further system damage should a disturbance occur, regardless of their location and current demand (restricted by the DR activation constraints). This approach leaves significant room for improvement as illustrated below.

4.3.2 Priority Scheme for DR Disconnection

To alleviate unnecessary DR interruptions, in the priority scheme DR load is optimally disconnected by the DNO according to a predefined priority list when the fault occurs. This implies that there might be the possibility that only a percentage of DR load is disconnected depending on the circumstances (whereas in inter-trip DR all DR load is disconnected). The scheme is built on the assumption that the existence of higher automation and control schemes could allow the DNO to individually control each DR load. In practice, this could for instance be realised by automation between circuit breakers and DR points, supported by different measurements.

4.4 Priority list for the Priority scheme

The cost of interrupted load is used by the DNO as a proxy to estimate the value that DR customers put on supply and then prioritize the customers' disconnections according to those criteria. It is calculated as a function of Value of Lost Load (VOLL), the latter representing the value an average consumer puts on an unsupplied kWh, thus capturing the customer welfare and their willingness to accept the interruption. The use of VOLL to determine unreliability costs has been seen again in the literature [104]. In addition, such an approach makes the DR interruption costs comparable with costs that the DNO might have to bear for disconnecting non-DR customers.

The *VOLL* is expressed in £/kWh and calculated through the Customer Damage Function [32] which for a specific customer category maps the cost of an interruption against the duration of an interruption. It is calculated according to the methodology presented in [64] as a function of the duration of interruption and is evaluated for different customer types for a set of interruption durations. Since it is customer mix and system dependent, it is calculated case by case. The *VOLL* is calculated through equations (4-1) to (4-3) [64].

(4-1) illustrates the calculation of the normalized customer interruption cost for a load point occupied by users of sector type *s*. The cost is normalized with respect to the load point's peak demand. (4-2) calculates the normalized values of cost for all the load points of sector *s*. Finally, (4-3) gives the VOLL as a function of interruption duration again, for a sector *s*. In the relations below, r^i is the interruption duration in the range of [30 min, 1h, 4h, 8h], Customer Interruption Costs (*CIC*) are expressed in £ and represent the anytime average customer interruption cost of a specific duration for customers of different sectors. *CIC* are system independent, are retrieved from [105] for interruption durations of [30 min, 1h, 4h, 8h] and presented in Table 4-1. $L_{s,lp}$ is the peak demand of load point *lp* of sector *s*, $n_{s,lp}$ is the number of load points of sector *s*, LF_s is the load factor of sector *s*.

$$C_{s,lp}(r^i) = \frac{CIC_s(r^i)}{L_{s,lp}}$$

(4-1) :normalized customer interruption cost per load point for sector s (£/kW)

$$VOLL_s(r^i) = \frac{C_s(r^i)}{LF_s \cdot r^i}$$

(4-2): normalized customer interruption total cost for sector s (£/kW)

$$C_s(r^i) = \frac{\sum_{n_{s,lp}}\left[C_{s,lp}(r^i)\right]}{n_{s,lp}}$$

(4-3) : VOLL for sector s (£/kWh)

Table 4-1: Customer Interruption Costs as a function of the duration of interruption

	Customer Interruption Costs in £ for duration of interruption of			
Sector	30 minutes	1 hour	4 hours	8 hours
Residential	1.26	1.62	1.98	4.44
Commercial	114.27	169.65	241.41	1022.97
Industrial	175.8	261	371.4	1573.8

The total cost of interrupted load $IC_{j^{n,r}}$ of a customer *j* for a set of interruptions is calculated as in (4-4).

$$\boldsymbol{IC_{j^{n,r}}} = \sum_{i}^{total\ interruptions} \boldsymbol{VOLL_j^i\left(d_{j^{n,r}}{}^{i}\right) \cdot d_{j^{n,r}}{}^{i} \cdot P_{DL_{j^{n,r}}}{}^{i}} \tag{4-4}$$

where d is the duration of interruption(hours), P_{DL} is the disconnected load (kW). Superscript ‘n’ is for normal customers and ‘r’ for responsive. Equation (4-4) which is based on [32],gives the total cost of interrupted load per customer for all the interruption events experienced due to random faults generated in a sampling year, calculated for each interruption as the value this type of customer puts on the interruption times the duration of the interruption times the amount of disconnected load during the interruption. The expected total cost of interrupted load per DR customer $E[IC_{j^r}]$ obtained from the SMCS process is used for the construction of the differentiated reliability priority list and is essentially the relation between equation (4-4) and the parameters of the contracts with differentiated reliability levels. In fact, the value of $E[IC_{j^r}]$ is used in our model as a proxy by the DNO to estimate the value that DR customers put on supply, and the DNO uses that information for the priority DLC scheme to prioritize the DR customer’s disconnection. The priority list is created containing the DR customers sorted in an ascending order depending on their $E[IC_{j^r}]$ values, either individually or clustered in groups. In the case that customers are clustered in groups, the available DR capacity of each cluster is the aggregated responsive demand of the cluster’s customers. The expected total cost of interrupted load for each cluster c is calculated as $E[IC_c] = \sum_j^{c\ customers} E[IC_{j^r}]$. $E[IC_c]$ values accordingly are sorted in an ascending order to form the priority list.

4.5 OPF Algorithm for the priority scheme

Objective of the OPF algorithm is to meet the network voltage and thermal constraints with the minimum utilisation of DR capacity and DR interruption costs. Therefore, an iterative function is implemented whereby an AC power flow is used to assess the total DR level needed after a fault at a given time so there are no network violations following successive disconnections of DR customers according to the priority list. The cluster with the lowest interruption cost should be interrupted first. The function is repeated until either all DR customers are disconnected or sufficient amount of DR has been deployed so as objectives are met. However, following the DR activation constraints, when a customer is already called twice in a year, he becomes unavailable for any future call; when a customer is already disconnected for consecutive 8 hours he is automatically reconnected and becomes unavailable for the rest of that particular call. Hence, customers who are on the top of the list are called always first comparing to those who are further down on the list, but their interruptions are limited to a maximum of twice a year and 8 hours per interruption. Further, these customers are selected first as they bring a lower interruption cost to the DNO (objective of the OPF): this should be completely acceptable by the customers since they have been specifically contracted for this response and they are compensated accordingly. The OPF algorithm is presented in Figure 4-1.

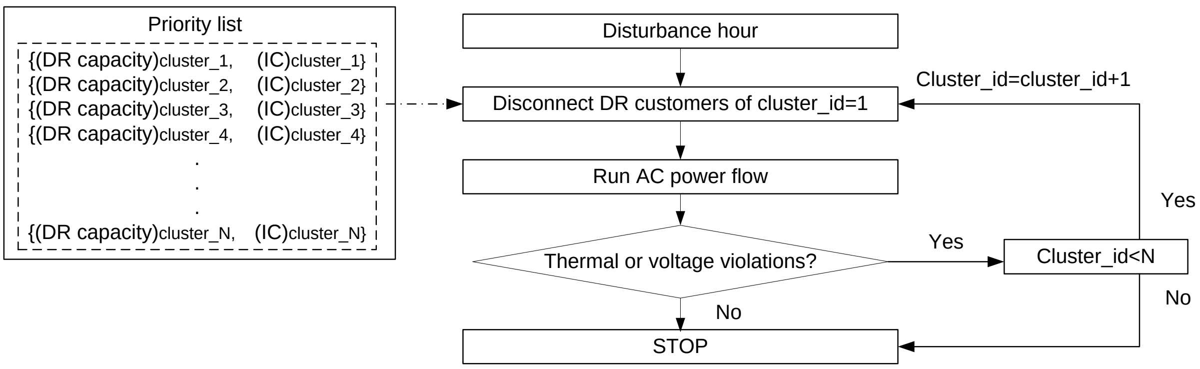

Figure 4-1: OPF Algorithm for the optimal DR disconnections

4.6 DR Capacity Levels

Initially the maximum load demand that the network could accommodate if DR was used as corrective control needs to be evaluated. Hence, load flow studies are executed to determine the amount of additional X MW supplied when DR is introduced, while network constraints and DR activation constraints are satisfied and at the same time reliability of normal customers is not jeopardized. The load X thus also corresponds to the maximum amount of DR required at peak time.

The case that the 100% of that load X is responsive and is contracted as DR is the base DR scenario. However, various DR capacity levels (CL^{DR}), representing the ratio of contracted MW to the value X (in percentages of X) of the required DR capacity have been examined. In particular, DR capacity levels from 0% to 100% are considered, where 0% denotes that no DR capacity is contracted and 100% that the contracted DR capacity is equal to X. This study thus brings insights into the implications that DNO could face if deciding to contract less DR than nominally required, given the rareness of faults happening at load peak times. This analysis may also be useful to assess the risk for DNO due to uncertainty 1) in contracting the *X* amount of DR , 2) that part of DR is unavailable when called upon to respond (for instance due to automation failure) and 3) around the actual responsive load profile.

4.7 DR formulation

Summarizing the model characteristics of the previous subsections, DR could be formulated assuming that it is dispatched to supply load in the form of load reduction. For the contingency hour *t*, (4-5) illustrates the active responsive demand at bus *b* and time *t*.

$$\boldsymbol{P\_DR_{b,t} = \varphi_{b,t}{}^{DR} \cdot \left(\left(\sum_{j_R} \xi_{j_R} \cdot \psi_{j_R} \cdot \sum_{a} PR^{a}_{j_R,b,t} \right) + \sum_{j_{C\&I}} \xi_{j_{C\&I}} \cdot \psi_{j_{C\&I}} \cdot PR_{j_{C\&I},b,t} \right)} \qquad (4\text{-}5)$$

Where $\varphi_{b,t}{}^{DR}$ is a binary indicator denoting if DR action has to be initiated, ξ_j and ψ_j are binary indicators denoting if customer *j* has been called no more than twice per year and eight hours per interruption respectively. $PR^{a}_{j_R}$ is the responsive demand of appliance *α* of a residential customer and $PR_{j_{C\&I}}$ the responsive demand of a commercial or industrial customer.

For each time step *t*, the amount of responsive load is capped by the associated limit:

$$\mathbf{0 \leq \sum_{b}^{buses} P\_DR_{b,t} \leq CL^{DR}} \cdot \mathrm{X} \qquad (4\text{-}6)$$

4.8 Incorporating Payback Effects into the analysis

Demand side resources like DR can be deployed to supply the load in the form of load reduction. Therefore, a load recovery process is needed to re–establish the demand services affected, unless the curtailed consumption is forgone by the corresponding electricity consumers. This aspect is more appropriately referred to as the “payback” of these resources.

Payback effects are analysed to realistically reflect the changes in individual customers’ behaviour. For *R* customers, it could be the turning on of an interrupted appliance and for *C&I* customers the restart of an industrial machine or the rebooting of an air-conditioning system to succeed the comfort room temperature.

In this work payback effects are modelled as an increase in the total demand. DR load that was curtailed during the disturbance period is recovered in the period starting after the customer's reconnection.

Following [98], an energy payback of 100% is assumed for *R* customers and a 50% energy payback for *C&I* customers. Additionally, the recovery period is assumed to last maximum 4 hours, during which scheduled recovery is completed. For each time step of the recovery period the amount of DR load recovered is decided based on the amount of load curtailed during the disturbance period and the duration of the recovery period. It should be emphasized, that the payback characteristics chosen are for exemplificative purposes, discussing a general formulation for load recovery, with the aim to fit in the wider implications of the reliability assessment. To illustrate the concept, an example case is presented in Figure 4-2 , after generating a random fault during a random day of the year. A fault is happening on the 11th hour of the day, lasting for 14 hours. For this particular case, post fault DR is only needed for hour 24 and thus is accordingly initiated. The curtailed demand is paid back after the disturbance period from hour 26 to hour 29.

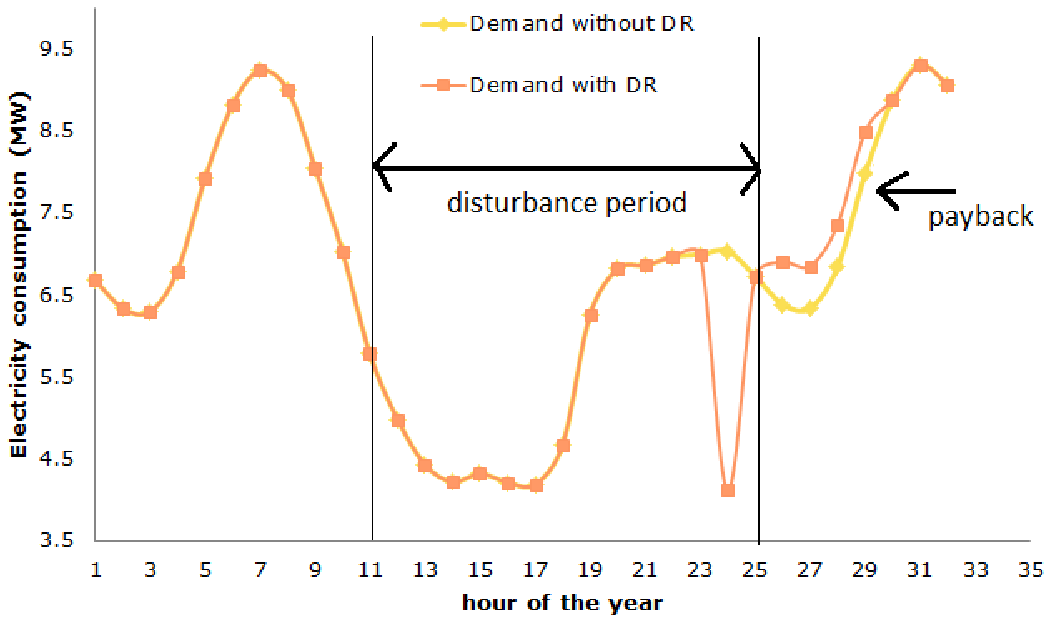

Figure 4-2: Illustrating the payback effect after the corrective disconnection.

Nevertheless, either due to the recovery period coinciding with high demand period or due to the payback value itself, congestion could be introduced, jeopardizing the network's reliable operation when the system is intact. Therefore, to alleviate the payback effects, the following strategies are implemented:

- Inter-trip scheme: If network capacity is not sufficient in a time slot of the recovery period, new corrective DR disconnection could be triggered or even worse, normal customers could be curtailed. Negative reliability implications for normal customers are a side effect of payback and that bears constraints in the load increase (X value) that DR implementation could allow.
- Priority scheme: Based on the flexibility that higher automation allows, for each time slot of the recovery period that congestion is created, an OPF similar to the one described in 4.5 is applied, preventing normal customers' curtailment. Specifically, the priority list is now searched from the opposite direction giving priority on reconnecting DR load from customers with the highest IC. In every time step of the recovery period, the maximum number of DR load that network conditions allow is paid back. The residue of the DR load is recovered in the next available time step. Consequently, the recovery period might be prolonged depending on the network conditions.

  The flowcharts for each strategy are presented in Figure 4-3 and Figure 4-4.

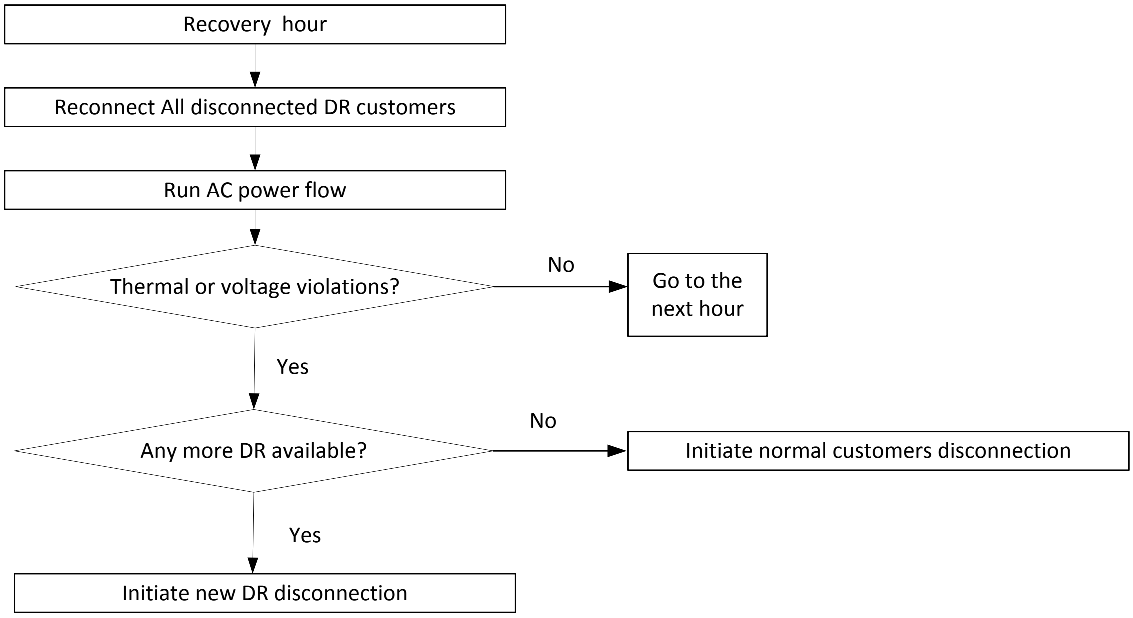

Figure 4-3: Payback alleviation strategy for the inter-trip scheme

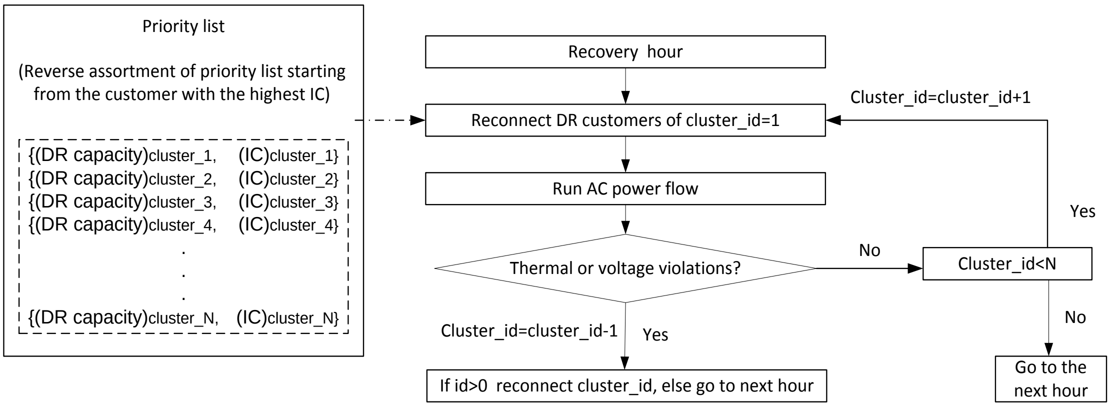

Figure 4-4: Payback alleviation strategy for the priority scheme

4.9 DR related Reliability and Risk Metrics

In this analysis, CI and CML, EENS and EIC (Expected Interruption Costs) are the set of reliability indices calculated. Mathematical expressions of the above indices can be found in Chapter 2. These indices are presented both for the normal and the DR customers in order to quantitatively assess their unreliability discomfort from the service quality and reliability cost perspective.

Following from Section 4.4, $EIC^{n,r}$ are calculated as in (4-7) for normal and responsive customers.

$$\boldsymbol{EIC^{n,r}}=\left(\sum_{N=1}^{samples\ N}\sum_{j^{n,r}}\boldsymbol{IC}_{j^{n,r}}\right)/\boldsymbol{N} \tag{4-7}$$

(4-7) gives the expected total cost of interrupted load for all customers, known as unreliability costs for the DNO. Consequently, EIC^{n} represent the *DNO unreliability costs for normal customers* and EIC^{r} represent the *DNO unreliability costs for DR customers*, reflecting the costs due to load interruption events. Interruptions could happen because of an unexpected disturbance (if for example customers are located in the fault-affected area) or because of a corrective disconnection initiated from the DNO (intentional load curtailment). It should be noted that $EIC^{n,r}$contain the costs for both types of interruption for the customers. DNO unreliability costs for DR customers exclusively related to corrective disconnections could be considered as possible compensation payments to the DR customers (in reality it is impossible to predict when a fault will occur), since they reflect the worth of their interruption. The sum of EIC^{n}

and EIC^r gives the total incurring unreliability costs for the DNO (EIC^{n+r}). These costs provide possible reliability cost trade-off information to DNOs[6].

Further *risk indicators*, illustrating the actual DR capacity requirements and utilisation are also introduced. These indicators are particularly relevant to assessing the risk potentially incurred by the DNO when contracting less DR capacity than the value X nominally required. These risk indicators are the probability of DR utilisation ($P(util_{DR})$) and the probability of DR requirements exceeding DR capacity ($P\left(DR_{req} > X\right)$), both measured based on number of hours. Those indicators are calculated through the SMCS process according to the formulas (4-8) and (4-9) respectively.

$$\boldsymbol{P(util_{DR})} = \frac{\boldsymbol{total\ hours\ of\ DR\ disconnections}}{\boldsymbol{total\ hours\ of\ disturbance}} \tag{4-8}$$

$$P\left(DR_{req} > X\right) = \frac{total\ hours\ of\ normal\ customers'\ \ curtailment}{total\ hours\ of\ disturbance} \tag{4-9}$$

4.10 Overall methodology description of the DLC Scheme

The proposed reliability and risk assessment framework is the integration of the DLC DR scheme, the OPF disconnection algorithm, the model of system operation during emergency conditions, and the SMCS reliability modelling tool presented in Chapter 2.

Two scenarios are further considered, depending on whether post fault emergency thermal rating is applied (TR_{emerg}) or not (TR_{norm}). In particular, as from DNO's practical implementations [106], typical consideration for post fault emergency rating would allow additional loading of 20% above normal rating to distribution lines for 2 hours.

The system state is simulated through an AC power flow analysis with the aid of Matpower 4.1[61]and the whole modelling procedure is based on Matlab®. Finally, to

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[6] Besides these unreliability costs DNOs should also pay other (mostly fixed) costs for DR contracts and automation. These costs should be weighed against the savings from avoided infrastructure investment ([70]) and are not included in this study with reliability focus.

deal with the computational burden of SMCS, simulations are executed with the Matlab's parallel computing toolbox (spmd function) and the high performance computing cluster Redqueen [68]. The steps of the methodology are detailed in Table 4-2 and illustrated in Figure 4-5.

Table 4-2: Steps of the methodology

A) INTER-TRIP SCHEME (1^{ST} SET OF SMCS):
Step A1: Calculate VOLL functions. Initiate the SMCS process.
Step A2: Insert VOLL functions. Insert load point profiles for all customer types, customer and system data. Generate yearly sequence of system components.
Step A3: (Start with half hourly time step *t*=1). If the system is in abnormal state, identify isolated points. Execute network reconfiguration, perform AC power flow. If the system is in contingency, three hierarchical actions are taken until thermal and voltage violations are eliminated. If we are in the TR_{emerg} scenario, lines are overloaded for two consecutive hours after the corrective actions are initiated. If this is not successful, DR corrective actions are taken (inter-trip strategy) and if violations still persist, load curtailment of normal customers is also applied. (Proceed to the next half-hour).
Step A4: If the system is in normal condition no corrective actions are taken. If *t* is the time step after a DR reconnection, energy payback is initiated and takes place every time step of the recovery period. (Proceed to the next half-hour).
Step A5: Repeat steps 3-4 until the studied period (year) has finished. Load interruptions are recorded for every time step to calculate reliability and risk indicators of every sample year. Repeat steps 2-5 for the next sampling year until SMCS stops.
PRIORITY SCHEME(2^{ND} SET OF SMCS)
Step B1: Define the differentiated reliability priority list through steps A1-A5.

Step B2: Repeat steps A1-A5 inserting also the priority list in step A3. If DR actions need to be taken, or energy to be recovered the priority strategy is followed.

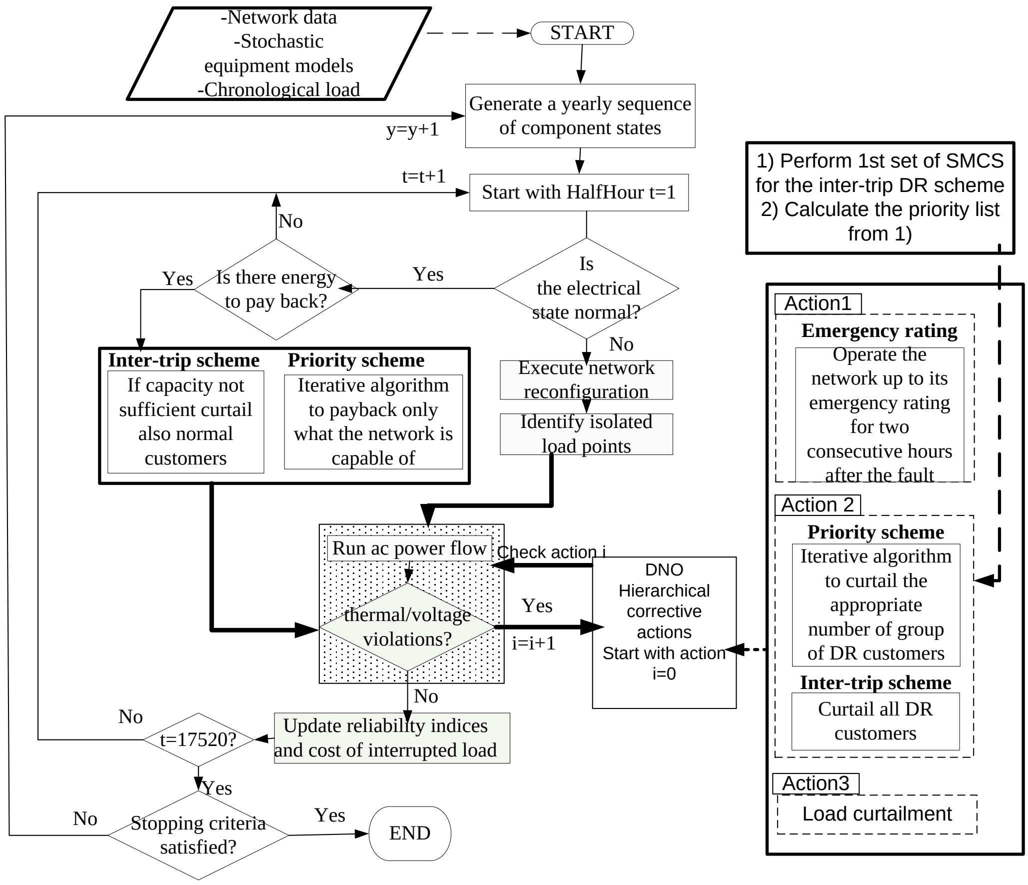


Figure 4-5: Flowchart describing the overall methodology

4.11 Case Study Applications

4.11.1 Test Network Description, Load Profiles and other Input Data

To demonstrate the proposed methodology, a real distribution network, named Holme Road Network and located in England North West has been used. Current demand, which respects ER P2/6 standards, corresponds to 6.51MW and 2.14MVar and is considered for this case study as the "base case". The network is illustrated in Figure 4-6. Network data for this "base case" are illustrated in Table 4-3. Demand data have been retrieved from the local DNO. It has to be noted that the specific network is mainly domestic, however for the purposes of the study, the assumption that there are also exist industrial and commercial customers has been made. To this end, each network load point has been assumed to serve either residential, industrial or commercial customers and depending on the load point peak demand and typical customers' characteristics in the UK [83], the number of customers have been calculated for Table 4-3.

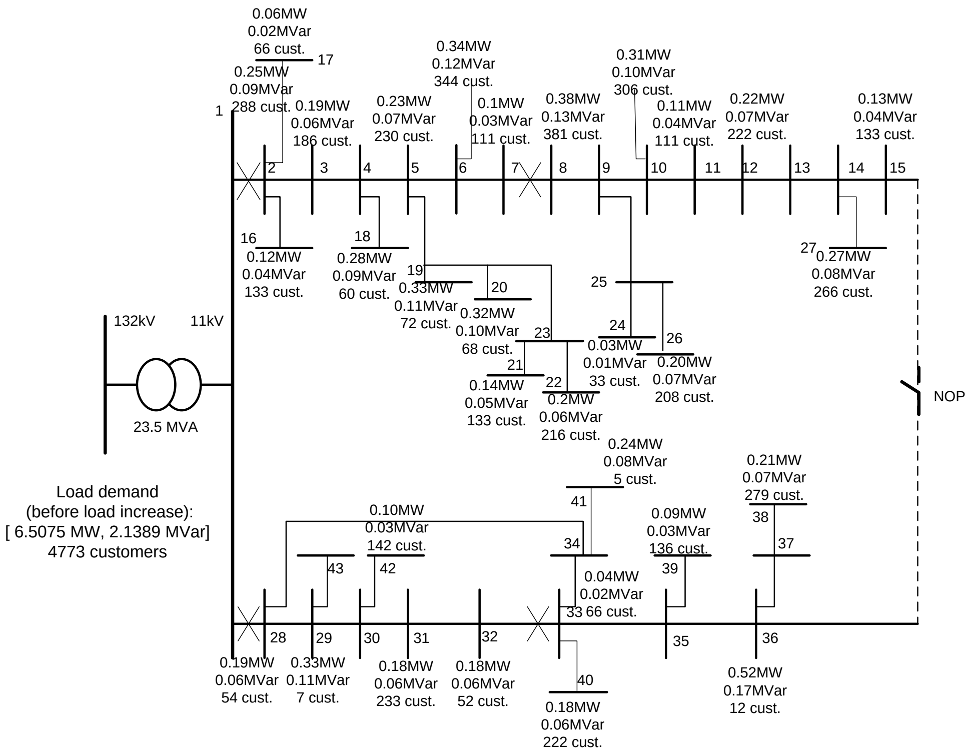


Figure 4-6: Test distribution network-data taken from the local DNO

Table 4-3: Network data for the base case

Customer Type (CT)	Number of Customers	% of Peak Demand (PD)	Aggregated PD[MW, MVar]
Residential	4443	63	[4.09, 1.35]
Industrial	24	11	[0.70, 0.23]
Commercial	306	26	[1.72, 0.56]
Total	4773	100	[6.51, 2.14]

As a consequence, in this paper, half-hourly consumption of *C&I* customer types have been retrieved again from Elexon databases [83]. It has been assumed that the load profiles for *C&I* customers are represented by Profile Classes 4 and 8 respectively. Figure 4-7 depicts winter and summer weekday profiles. For *C&I* customers, responsive load could be the whole load or a curtailable non critical part of each customer load. It is defined as a proportion of the customer load and follows a yearly load profile analogous to the customer type.

For the *R* customers, realistic profiles have been generated by the CREST tool [107] for each individual customer, for the different seasons weekdays and weekends. The tool generates random number of people per household and random allocation of appliances indicating operation and consumption of each appliance. For the heat appliances, the model presented in [108] has been used to extract heat demand, using for less complexity the same technology for all *R* customers, in this case electric heat pumps. Load profiles for all customers are normalised according to the load point peak demand. Figure 4-8 demonstrates the share of the major appliance groups in the total demand for a winter weekday in a typical house. For *R* customers responsive load comes exclusively from responsive appliances, whose operation time and energy consumption could be modified without affecting the comfort level of their users[94]. For this study, for each *R* customer involved, responsive appliances are the 'cold' appliances (such as freezer, refrigerator), 'wet' appliances (such as dish washer and washing machine) and 'heat' appliances. Consequently, to identify available *R* DR in each load bus, the responsive appliances' demand for all the *R* customers of every bus is aggregated in each time step.

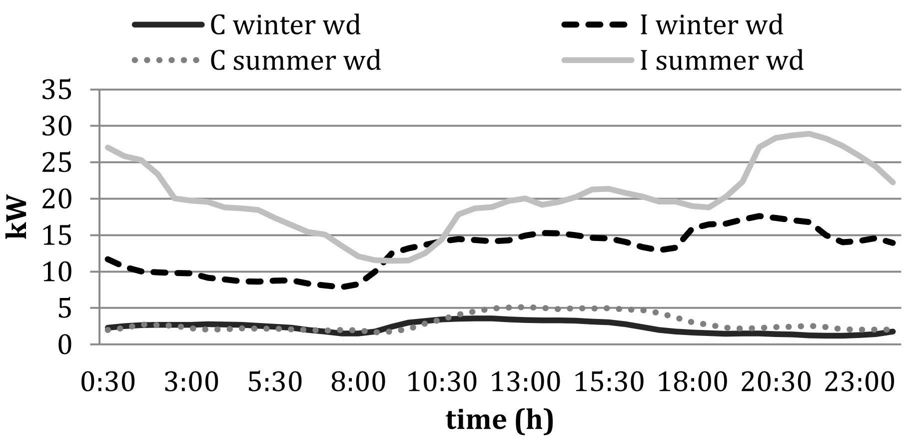


Figure 4-7: Typical winter and summer profiles for C&I customers

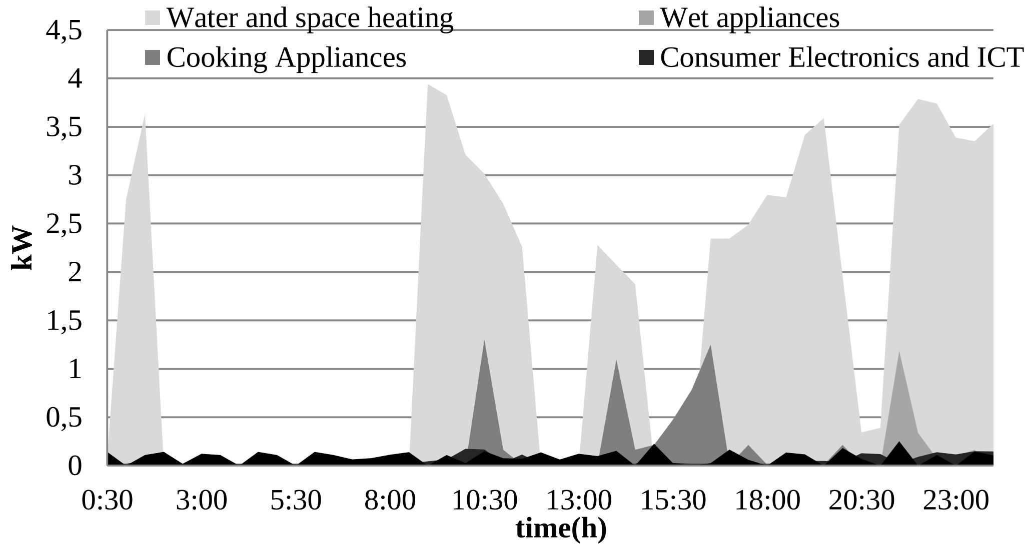


Figure 4-8: Appliance level demand in a typical house (winter weekday)

The reliability data used for the study are retrieved from available UK statistics [85] and are depicted in Table 4-4. The VOLL function for the different types of customers, after taking into account the customers' composition, allocation and demand is calculated according to the methodology presented in Section 4.4 and depicted in Table 4-5 .Table 4-6 presents the maximum calculated additional demand that network can supply in different scenarios, assuming that there is corrective DR (thus it is not necessary to comply with ER P2/6) and normal customers maintain the same reliability levels as before the increase. In the next section, only Scenario 5 will be illustrated in the case study. Therefore, this 25% additional demand (1.6269 MW and 0.535MVar), which also corresponds to a maximum contracted DR capacity *X*=100%, has been assigned proportionally to the different load buses.

Table 4-4: Reliability Data used in the case study[7]

	MTTF (hours)	MTTR (hours)	MTTI(minutes)	MTTS (minutes)

[7] ICT infrastructure supporting the DR scheme is assumed perfectly reliable. For ICT reliability impact on the proposed DR scheme, preliminary work has been done in [77].

Underground Cables	56.516	5	-	-
Switches (circuit breakers, NOP)	56.516	5	3	3
-Mean Time to Identify the Status (MTTIS) of switching devices =3 minutes				

Table 4-5: VOLL as a function of the duration of interruption

	VOLL in £/kWh for duration of interruption of			
Sector	30 minutes	1 hour	4 hours	8 hours
Residential	8.56	5.23	2.93	2.1
Commercial	128.17	91.19	96.60	95.66
Industrial	520.17	352.78	300.22	244.68

Table 4-6: Maximum load increase for different scenarios

	Load Increase (%)
Scenario 1:No payback effects, no DR activation constraints	+50
Scenario 2:Payback effects, no DR activation constraints	+45
Scenario 3:No payback effects, maximum 2 interruptions of 8 hours for all customer types	+30
Scenario 4:Payback effects, maximum 2 interruptions of 8 hours for C&I customers, 2 interruptions of 4 hours for R customers	+20
Scenario 5:Payback effects, maximum 2 interruptions of 8 hours for all customer types	**+25**

4.11.2 Inter-trip case (100% DR Capacity Level)

This section illustrates the "inter-trip case". The reliability performance of the test network is examined for the higher loading condition (25% higher of P2/6 levels) but also for the current loading without DR for comparison purposes ("base case"). From Table 4-7, it can be observed that although the network capacity has been stressed, *normal customers* experience the same reliability levels as before. However, *DR customers'* reliability quality is worse comparing to normal customers. In particular, DR customers may be interrupted along with normal customers when they are located in the fault-affected area that becomes isolated or get intentionally disconnected by the DNO as a corrective action. Reliability indicators of DR customers are illustrated as 'total' representing their total discomfort, which contain both types of interruptions and as 'corrective' which are only due to the corrective DR scheme to quantify its share.

Furthermore, Table 4-7 shows how post fault rating extremely affects and improves DR indices. For this network, the bottleneck in emergency conditions is thermal constraints, therefore the 120% lines overloading for 2 hours after the fault plays a catalytic role to alleviate them. It can be observed that DR corrective actions are eliminated. This is an important finding since it shows that if emergency rating is a viable option under those circumstances, it could replace or support DR corrective actions.

Table 4-7: Reliability Indicators-Inter-trip scheme

Base case [CI:6.61 CML:21.76 EENS:1.28]	**Inter-trip DR Case**			
	TR_{norm}		TR_{emerg}	
	Normal customers	DR customers total/corrective	Normal customers	DR customers total/corrective
CI*	6.61	9.42/2.85	6.61	6.61/0
CML**	21.76	25.20/3.54	21.76	21.76/0
EENS***	1.28	0.34/0.0869	1.28	0.23/0

**CI (interruptions/100 customers-year), **CML (minutes/customers-year), ***EENS (MWh/year)*

4.11.3 Priority case (100% DR Capacity Level)

The studies of the previous subsection are repeated for the priority scheme. Cost of interrupted load for responsive customers is calculated from the inter-trip case to build the differentiated reliability priority list. Given the much higher value of VOLL, industrial and commercial customers bring the highest cost for the DNO if interrupted. Hence after a disturbance residential customers are interrupted first, then commercial and finally industrial customers.

To illustrate the methodology, customers are categorized into five clusters which contain aggregated contracted capacity for differentiated reliability DR of the following levels [20%, 40%, 60%, 80%, 100%] with respect to the maximum level X. For this loading scenario, again there is no impact on the normal customers' indices. For higher loading, normal customers are affected. In the inter-trip scheme if due to payback, capacity limits are reached, they would have to be curtailed. The same happens when DR activation restrictions have been outreached but contingency remains. In the priority scheme, normal customers are slightly affected due to the flexibility to disconnect different DR customers depending on the situation, hence reaching later the maximum frequency and duration of a customer's intervention. In contrast, for the inter-trip scheme, indiscriminate disconnections would lead to reaching the restriction limits faster, thus needing additional curtailment.

Nonetheless, it can be observed that reliability indices for DR customers improve for this scheme. Comparing Table 4-7 and Table 4-8, CI reduce by 43.2%, CML by 45.5% and EENS by 51% (DR indices due to corrective actions, TR_{norm} scenario), thus improving the total DR indices too. In particular, the breakdown of DR utilisation ($P(util_{DR})$) depicted in Table 4-9 for each DR cluster shows that the probability to utilise large clusters of DR capacity is quite low. For instance, the probability to utilise the 100% contracted DR capacity is only 0.0021%. Likewise, it is extremely interesting to observe that DR corrective actions in conjunction with TR_{emerg} scenario become an even rarer event (0% DR utilisation for this loading level).

These findings highlight how the inter-trip scheme may result in unnecessary DR disconnections. In fact, the amount of DR capacity to disconnect as a corrective action crucially depends on the location of the fault and the system loading level at the time when the fault occurs. For instance, if a system disturbance coincides with a period of low demand, DR needs are much lower (or even null) relative to high demand time, as the healthy feeder may have sufficient capacity on its own to support all the customers after NOP closure. Considering time series profiles is therefore critically important to highlight this aspect and truly assess DR requirements. The only case when the 100% of contracted DR capacity is interrupted is during a fault at the beginning of each feeder and coinciding with the peak demand. Finally, emergency rating implementation totally compensates and could effectively replace the need for any DR scheme for this loading scenario.

Table 4-8: Reliability Indicators-Priority Scheme

Base Case [CI:6.61 CML:21.76 EENS:1.28]	Priority DR Case			
	TR_{norm}		TR_{emerg}	
	Normal customers	DR customers total/corrective	Normal customers	DR customers total/corrective
CI*	6.61	8.25 /1.62	6.61	6.61/0
CML**	21.76	23.58/1.93	21.76	21.76/0
EENS***	1.28	0.299/0.0426	1.28	0.23/0

**CI (interruptions/100 customers-year), **CML (minutes/customers-year), ***EENS (MWh/year)*

Table 4-9: $P(util_{DR})$ for the Priority Scheme

Cluster id	Aggregated DR Capacity (MW)	(%) of Contracted DR capacity utilised	TR_{norm} (%)	TR_{emerg} (%)
0	0	0	99.505	100
1	0.3253	20	0.1301	0
2	0.6508	40	0.1553	0
3	0.9761	60	0.1553	0
4	1.3015	80	0.0525	0
5	1.6269	100	0.0021	0

4.11.4 Risk associated with DR capacity Level: Sensitivity Study

As seen above it is very rare that the capacity X is actually called upon. Therefore, in this section, a sensitivity analysis is performed for a range of DR capacity levels.

For lower DR capacity levels, fewer DR customers are contracted thus resulting in lower DR volume that can be disconnected following a fault. In particular, for 0% DR capacity level only normal customers exist in the network and no responsive load. Reliability indices for normal and DR customers, for both types of disconnection schemes and the TR_{norm} scenario are presented in Figure 4-9 and Figure 4-10. All the indices follow similar trends, and for illustration purposes only CI are presented. TR_{emerg} scenario is omitted, since for this loading level, the 20% emergency thermal rating fully compensates DR corrective actions. The sensitivity study shows that reliability indices for normal customers are worsening for lower DR levels because instead of implementing DR disconnections as a corrective control, normal customers would be curtailed to maintain the network within thermal and voltage constraints (Figure 4-9 and Figure 4-10). To quantify this risk, presents the probability of DR requirements exceeding DR capacity $P(DR_{req} > X)$. When no DR has been contracted, there is $P(DR_{req} > X)$ of 0.258% that the DNO will proceed to load curtailment for normal customers. It should be mentioned that for load increase higher than +25%, which is the scenario under study (scenario 5, Table 4-6), $P(DR_{req} > X)$ for 100% DR capacity level is higher than zero (whereas now is equal to zero confirming that normal customers' reliability is not jeopardized). Furthermore, it can be observed that for DR levels higher than 30% (priority) and 50% (inter-trip) (see Figure 4-9), reliability indicators for normal customers are slightly changed and this can be justified through the very low $P(DR_{req} > X)$ at those DR capacity levels. This can be also identified in Figure 4-11, where it is seen that for higher DR capacity levels (higher than 30% for the priority case), normal customers experience almost the same levels of reliability in terms of EENS as in the base case (before the load increase). This is also supported by the low values of the probability of DR requirements exceeding DR capacity, which diminish while DR capacity levels increase.

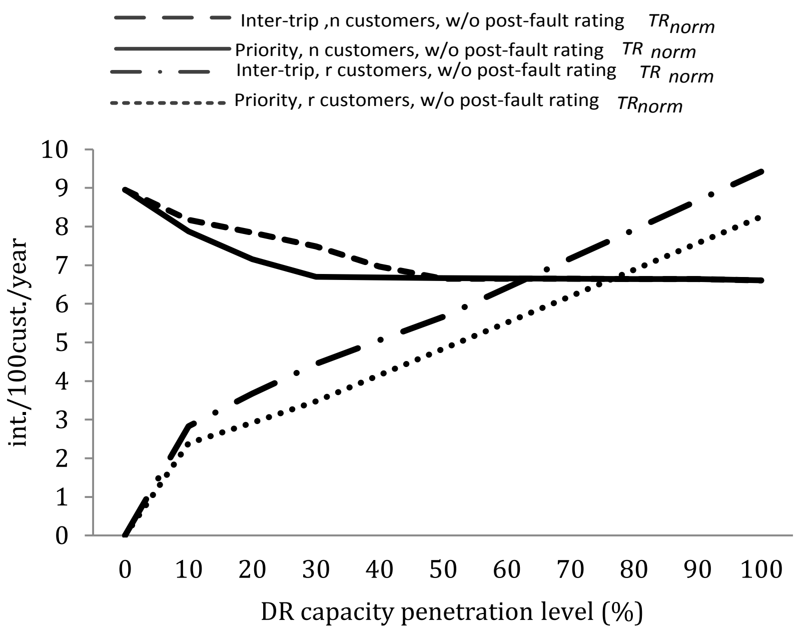


Figure 4-9: CI as a function of DR Capacity Level

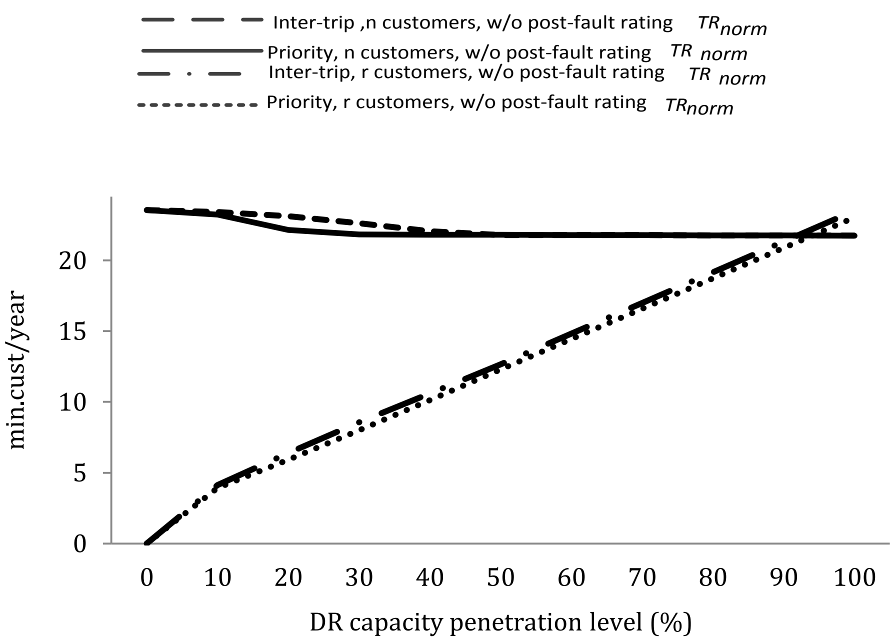


Figure 4-10: CML as a function of DR Capacity Level

Table 4-10: $P((DR_{req} > X))$

DR capacity level (%)	DR contracted capacity (MW)	Inter-trip TR_{norm} probability (%)	Priority TR_{norm} probability (%)
0	0.0000	0.258	0.258
10	0.1627	0.238	0.211
20	0.3254	0.195	0.164
30	0.4881	0.124	0.118
40	0.6508	0.044	0.084
50	0.8134	0.019	0.061
60	0.9761	0.016	0.041
70	1.1388	0.011	0.024
80	1.3015	0.007	0.017
90	1.4642	0.004	0.006
100	1.6269	0	0

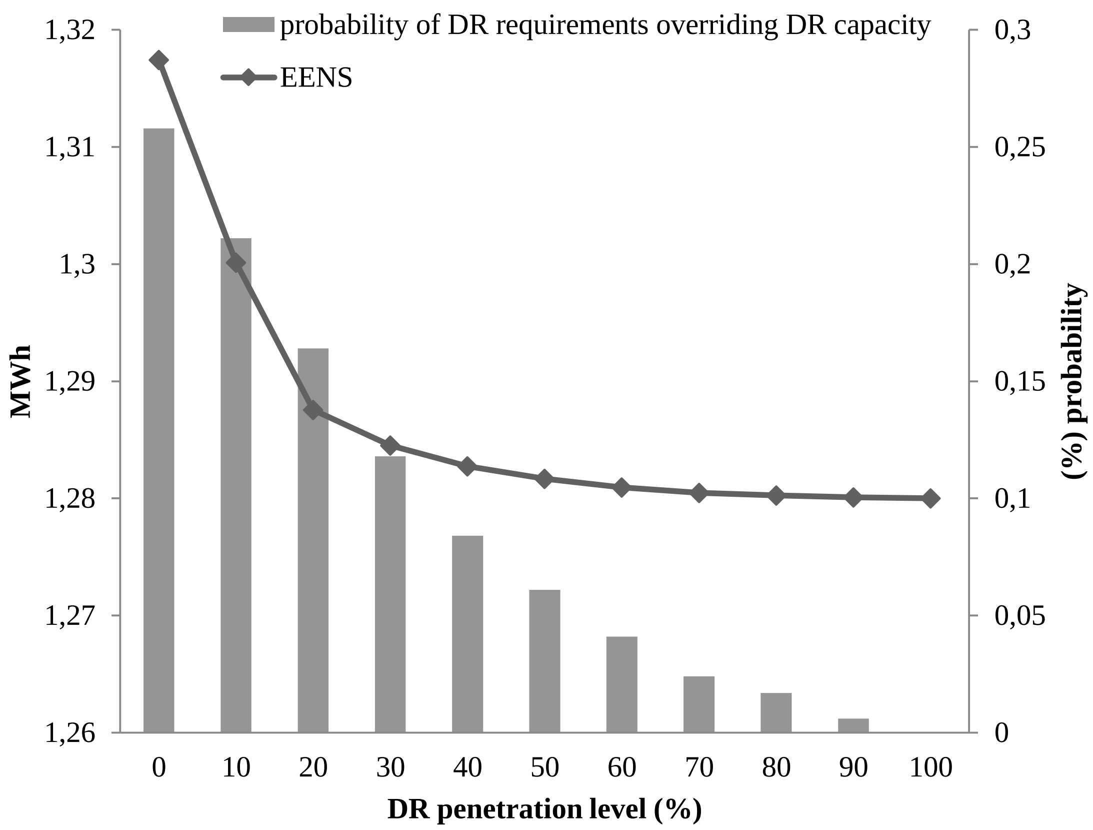


Figure 4-11: EENS and $P(DR_{req} > X)$ as a function of the DR capacity level- priority scheme (TR_{norm})

Similarly, the DNO unreliability related costs are illustrated in Figure 4-12. For comparison purposes, the DNO unreliability costs for the base case are also depicted in the figure. Results for the inter-trip scheme are not included since they follow a similar pattern with the priority but in a larger scale. It can be appreciated that EIC^{n+r} are decreasing for higher DR capacity levels. In general, the cost parameters follow the trends of their associated reliability indices: when reliability performance is improving, unreliability costs are decreasing alongside. Interestingly, it is observed that although EIC^{r} are increasing for higher DR, the savings from reducing EIC^{n} are more substantial thus EIC^{n+r}follows the pattern of the latter. The priority scheme is a more profitable solution since it results in 0.11% lower EIC^{n+r} comparing to the inter-trip (DR corrective disconnections are fewer). Comparing now with the baseline unreliability costs, by increasing EIC^{n+r} by 20% the network could feed successfully 25% more demand, without compromising the reliability level of the existing customers and without any reinforcements (TR_{norm} scenario, 100% DR capacity level. Another interesting observation is that the share of DNO unreliability costs related to DR compensation payments (referring only to unreliability costs due to corrective disconnections of DR customers) are quite low due to the rareness of the corrective events (0.12% of EIC^{n+r} for 100% DR capacity level). The remainder share of EIC^{n+r} corresponds to the cost of interrupted load in the isolated area waiting for alternative provision of supply (following equation (4-4) interruption costs are higher for higher levels of disconnected load).

Based on the above findings, it could be concluded that the priority scheme is a cheaper solution than the inter-trip scheme, while yielding to the lowest EIC^{n+r} for 100% DR levels. The overall outcome is that increasing levels of DR capacity reduce total DNO costs thus demonstrating the combined contribution of automation and DR to reliability.

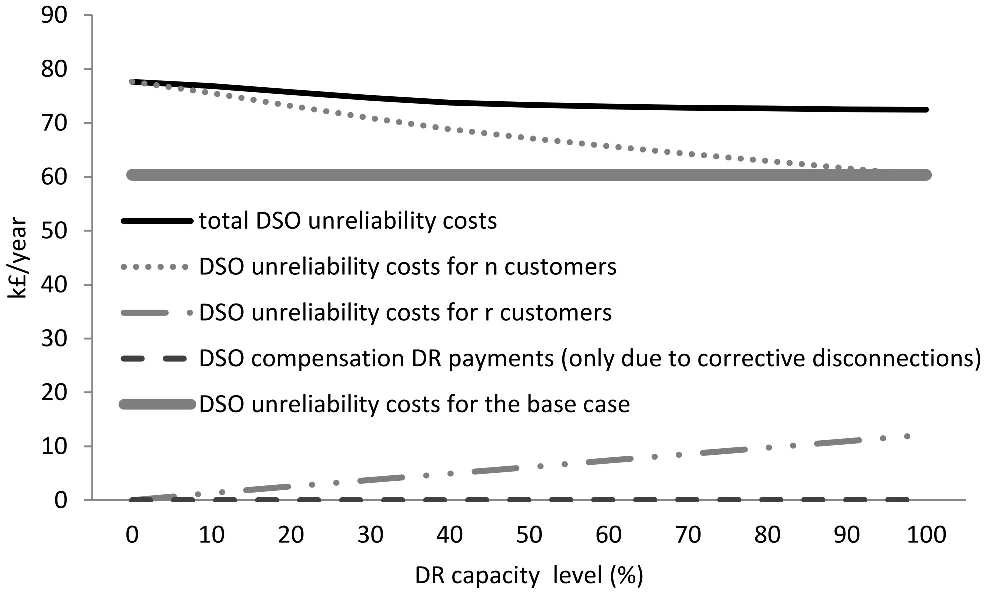


Figure 4-12: DNO unreliability related costs as a function of DR capacity levels, priority scheme (TR_{norm})

4.12 Conclusions

This chapter has presented a comprehensive techno-economic assessment of the reliability implications and associated risk of using post fault DR to release existing untapped capacity in distribution networks. The solution relies on DR customers accepting contracts for differentiated reliability and the inclusion of fast network reconfiguration through high automation and post fault emergency rating. Energy payback as a side effect of DR has been included in the modelling. DR activation restrictions have been also considered reflecting the realistic assumptions posed by the local DNO. The studies have been developed within a SMCS framework, allowing the full use of time series analysis. An OPF algorithm has been proposed for selective disconnection of DR customers according to a priority list which reflects the reliability worth that DR customers value their interruption.

An extensive quantitative analysis indicates that DR requirements might be (much) lower than estimated on the basis of peak demand. From another perspective, if post fault rating is implemented, there is a zero probability of utilizing the contracted DR capacity. Those results are in contrast with the conservative expectation for DR needs and the reason behind that is that network disturbance rarely coincides with a period of high demand. With DR the network could be stressed up to its maximum limits without compromising the reliability comfort of normal customers and without proceeding to network reinforcements, with a small increase in the unreliability costs. Alternative, a full reliability worth assessment shows the reliability implications, costs and their associated probabilities when the DNO decides to contract less capacity than indicated by the security standards.

Although the numerical results cannot be generalized, the findings from this work support the rationale of moving towards increased automation and control in priority distribution networks and from an N-1 preventive security to a corrective DR-based security context. Work in progress aims to extend the operational model presented here to network planning in the presence of DR.

5 Time-Limited Thermal Ratings With DR For Post-Fault Network Support

This chapter utilises the priority DLC DR model proposed in the previous chapter, introducing the concept of time-limited thermal ratings (TLTRs) to replace the deterministic emergency ratings. More specifically, TLTRs are applied to underground cables during contingencies, allowing a much higher utilisation of the cable comparing to the predetermined static rating value. In this context, network lines are utilised beyond the firm capacity levels, improving network reliability and providing extra capacity release. A time series analysis is implemented through a SMCS process, allowing an accurate cable temperature and rating calculation along a variable load profile and random allocated faults. TLTRs for network cables are calculated through the CRATER tool (which is adopted form [38]) for each contingency hour, which is properly inserted inside the SMCS process. CRATER would help to quantify to what extent existing networks can absorb additional fluctuating power injection without exceeding thermal limits. The TLTRs are combined with the post-fault DLC DR and reliability assessment of case study distribution networks is executed.

5.1 Underground Cables in Power Systems

Current distribution network challenges draw attention to techniques which allow more efficient asset utilisation and delay reinforcement projects. Real time thermal ratings (RTTRs) in underground cables (UGC), is one potential implementation. The RTTR concept is based on the observation that the current carrying capacity (ampacity) of a circuit must be such that its temperature rating is not exceeded. This parameter is influenced by the ability of the component to dissipate to the environment the heat produced by the joule effect, and by external conditions such as ambient temperature, or wind speed. Therefore, one of the most primary parameters to design an underground power system is the cable ampacity. The proper determination of UGC ampacity, especially in emergency conditions, requires a thorough analysis and attention to application considerations and technical parameters. Relevant considerations for low and medium voltage electrical systems can be found in [109]. In the next sub-sections, fundamental details related to the UGC characteristics and current rating calculation will be given.

5.1.1 Cable elements

UGC applications include direct buried cables and cables installed in a duct bank or concrete foundation. A medium voltage insulated cable circuit consists of three single core cables or one three core cable with terminations at each end to connect it to the transformer or switchgear in the network. Typically, an electric cable is made up of a conductor, which channels the electricity flow and an insulation that contains this electricity flow in the conductor. Other auxiliary elements that constitute a cable exist, summarized all together as follows [110]:

- **Conductor:** The main purpose of the conductor is to carry current under normal/overload/short-circuit operating conditions.
- **Internal semi-conductor:** Its functionality contains the prevention of concentration of electric field at the interface between the insulation and the internal semi-conductor. It also ensures the close contact with the insulation and the mitigation of electric field at the conductor.
- **Insulation:** It is placed to withstand voltage field stresses such as switching overvoltage during the cable service life.

- **External semi-conductor:** It ensures close contact between the insulation and the screen. It also prevents concentration of electric field at the interface between the insulation and the external semi-conductor.
- **Metallic screen:** It provides an electric screen, radial waterproofing, active conductor for the capacitive and zero sequence short-circuit current. Finally it contributes to mechanical protection.
- **Outer protective sheath:** It insulates the metallic screen from the surrounding medium. It protects the metallic screen from corrosion. It also contributes to mechanical protection and reduces the contribution of cables to fire propagation.
- **Armour:** Steel wire armour provides mechanical protection, which means the cable can withstand higher stresses, be buried directly and used in external or underground projects. The armouring is normally connected to earth and can sometimes be used as the circuit protective conductor for the equipment supplied by cable.
- **Oil duct:** For the oil filled cables the main insulation is oil-impregnated insulation papers. The conductor is wrapped in several layers of the paper in a continuous process and is dried in a vacuum chamber to remove humidity, and then is impregnated with insulating oils.

Cable components are illustrated in the following figure:

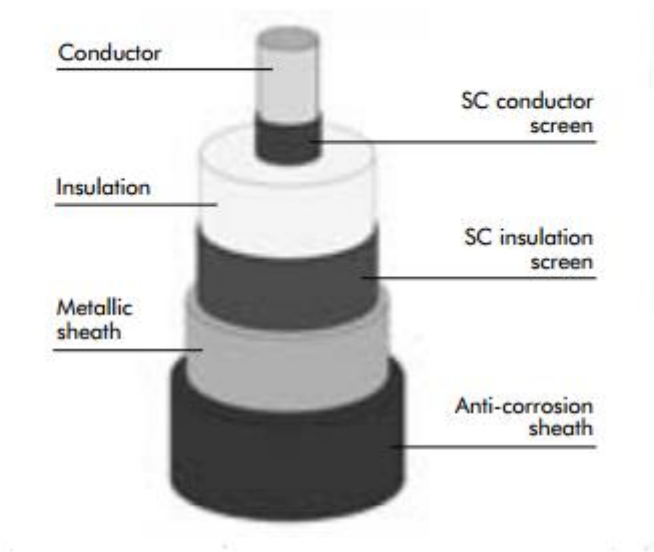


Figure 5-1: Cable components [110]

5.1.2 Deterministic Ratings for UGCs

Engineering Recommendation P17[111] provides a basis for estimating the ratings of cables for particular environmental and operational conditions, and gives tables of ratings for a stated set of conditions that have been selected as typical for distribution cables. Also, a set of correction factors are provided to allow adjustment where environmental conditions differ from those assumed in the guide.

There are three types of ratings for UGCs in the UK. These are namely the Sustained rating, the Cyclic rating and the Distribution rating [112]:

- **Sustained Rating:** It is the steady-state rating of the conductor. In other words it is the current rating, that is, the maximum load that can be applied continuously in order not to exceed the pre-determined maximum conductor temperature and not to suffer detrimental effects.
- **Cyclic Rating:** In this rating type, the capacity of the conductor raises or decreases depending on the shape of the cycle. For instance, if we consider season cycles, in winter when the weather is colder the conductor is rated higher, because soil temperature is lower during the winter. In contrast, in summer the conductor is de-rated due to the increased temperatures. Furthermore, if we consider the variability of network loading, which can often be expressed as a time-repeating cycle, the sustained rating values could afford particular change and this could mainly happen because the because the cable takes time to heat up and never exceeds its design temperature. In P17 cyclic ratings are typically calculated after the sustained rating calculation, utilizing a 24 hour profile of normalized hourly load values (the industry standard Load Curve G).
- **Distribution Rating:** In P17 [111] distribution ratings are defined as ratings calculated for stated conditions commonly occurring on distribution systems. The distribution rating is determined from a similar approach with the cyclic rating. However, it is higher in order to cope with short-time peak loads. For instance, in a typical operation a cyclic scenario occurs. Let’s assume that an emergency occurs at the peak of the cycle. Load demand increases while maintaining the shape of the cycling load. At the end of the emergency period the conductor temperature has reached its maximum value. Typically distribution ratings are calculated for an utilisation of 50%, i.e. the pre-emergency peak is 50% of the emergency peak.

5.2 Rating calculation model for Underground Cables

Current carrying capacity of the cable is given by the appropriate standards based on the permissible temperature rise. The standards provide a margin for current carrying capacity based on different installation techniques. Typically, the current rating of UGCs could be theoretically computed using the conventional IEC60287 recommended methods [113] and IEC60853 [114] and for the UK, the British Standard [115].

Thermal resistivity is the heat transfer capability through a substance by conduction. Current passing through a conductor produces losses in the form of heat, which appears as a temperature rise in the conductor. Unless the heat is dissipated, the temperature in the conductor will exceed the rating of the conductor insulation and damage the cable. The conductor's ampacity is based on the ability to dissipate heat through the thermal resistances surrounding the conductor[109].

To begin with, the first step of the rating calculation process is to calculate the thermal resistivity of each major component in the cable and surrounding soil. This includes the cable insulation, sheath, over sheath, armour, armour bedding, duct, duct filling, and soil. The resistivity is a function of the thermal resistivity per unit length of each material and the thickness of each material. Secondly, the thermal capacitance of each layer must be calculated. This is a function of the volume and thermal inertia per unit volume of each part of the cable. The rating is then a function of the electrical losses in the conductor as well as dielectric losses and circulating currents in the sheath and armour.

All types of cable insulation have a specified maximum operating temperature therefore the temperature of the environment determines the available temperature rise between that of the non-loaded cable and that of the fully loaded cable. The higher the ambient temperature is, the less the current capacity of the cable[116]. Furthermore, the thermal resistivity of the ground *g* controls the rate at which the heat generated by the cable loss is dissipated. The higher the value of *g*, the lower is the rate of heat transfer through the ground and the lower is the current rating of the cable[116].

The next equations taken from [117] represent the basic formulas required to calculate the permissible current rating in an AC buried cable where drying out of the soil does not occur.

- The permissible current rating of an AC cable can be derived from the expression for the temperature rise above ambient temperature:

$$\begin{aligned}\boldsymbol{\Delta\theta} = (\boldsymbol{I^2R} + \mathbf{1/2}\boldsymbol{W_d}) \cdot \boldsymbol{T_1} + [\boldsymbol{I^2R}(\mathbf{1} + \boldsymbol{\lambda_1}) + \boldsymbol{W_d}] \cdot \boldsymbol{n} \cdot \boldsymbol{T_2} \\ + [\boldsymbol{I^2R}(\mathbf{1} + \boldsymbol{\lambda_1} + \boldsymbol{\lambda_2}) + \boldsymbol{W_d}] \cdot \boldsymbol{n} \cdot (\boldsymbol{T_3} + \boldsymbol{T_4})\end{aligned} \tag{5-1}$$

Where I is the current flowing in one conductor (A), $\Delta\theta$ is the conductor temperature rise above the ambient temperature (K), R is the alternating current resistance per unit length of the conductor at maximum operating temperature (Ω/m), W_d is the dielectric loss per unit length for the insulation surrounding the conductor (W/m), T_1 is the thermal resistance per unit length between one conductor and the sheath (K.m/W), T_2 is the thermal resistance per unit length of the bedding between sheath and armour (K.m/W), T_3 is the thermal resistance per unit length of the external serving of the cable (K.m/W), T_4 is the thermal resistance per unit length between the cable surface and the surrounding medium, (K.m/W), n is the number of load-carrying conductors in the cable (conductors of equal size and carrying the same load), λ_1 is the ratio of losses in the metal sheath to total losses in all conductors in that cable, λ_2 is the ratio of losses in the armouring to total losses in all conductors in that cable.

Equation (5-1) converts to:

$$\boldsymbol{I} = \left[\frac{\boldsymbol{\Delta\theta} - \boldsymbol{W_d}[\mathbf{0.5} \cdot \boldsymbol{T_1} + \boldsymbol{n} \cdot (\boldsymbol{T_2} + \boldsymbol{T_3} + \boldsymbol{T_4})]}{\boldsymbol{RT_1} + \boldsymbol{nR}(\mathbf{1} + \boldsymbol{\lambda_1}) \cdot \boldsymbol{T_2} + \boldsymbol{nR}(\mathbf{1} + \boldsymbol{\lambda_1} + \boldsymbol{\lambda_2}) \cdot (\boldsymbol{T_3} + \boldsymbol{T_4})}\right]^{\mathbf{0.5}} \tag{5-2}$$

- The AC resistance per unit length of the conductor at its maximum operating temperature is given by the following formula:

$$\boldsymbol{R} = \boldsymbol{R}' \left(\mathbf{1} + \boldsymbol{y_s} + \boldsymbol{y_p}\right) \tag{5-3}$$

Where R is the current resistance of conductor at maximum operating temperature (Ω/m), R' is the DC resistance of conductor at maximum operating temperature (Ω/m), y_s is the skin effect factor, y_p is the proximity effect factor.

- The skin effect factor y_s is given by the following equations:

$$\boldsymbol{y_s = \frac{x_s^4}{192 + 0.8 \cdot x_s^4}} \qquad \boldsymbol{for\ 0 < x_s \leq 2.8}$$
$$\boldsymbol{y_s = -0.136 = 0.0177x_s + 0.0563x_s^2} \quad \boldsymbol{for\ 2.8 < x_s \leq 3.8}$$
$$\boldsymbol{ys = -0.354x_s - 0.733} \qquad \boldsymbol{x_s > 3.8} \tag{5-4}$$

Where

$$\boldsymbol{x_s^2 = \frac{8\pi f}{R'}\ 10^{-7} k_s} \tag{5-5}$$

Where f is the supply frequency in hertz and values for k_s can be found in [117].

- The proximity effect factor y_p for three-core cables and for three single-core cables is given by:

$$\boldsymbol{y_p = \frac{x_p^4}{192 + 0.8\, x_p^4} \left(\frac{d_c}{s}\right)^2 \left[0.312 \left(\frac{d_c}{s}\right)^2 + \frac{1.18}{\frac{x_p^4}{192 + 0.8\, x_p^4} + 0.27}\right]} \tag{5-6}$$

d_c is the diameter of conductor (mm), s is the distance between conductor axes (mm) and values for x_p are given in [117].

- The dielectric loss per unit length in each phase is given by:

$$\boldsymbol{W_d = \omega C U_o^2 \tan\delta}\ \text{(W/m)} \tag{5-7}$$

Where $\omega = 2\pi f$, C is the capacitance per unit length (F/m), U_o is the voltage to earth (V). Values of $\tan\delta$ and of the loss factor are found in [117]. The dielectric loss depends on the voltage level and it only becomes important at levels related to the insulation material being used. The value of U_o at which the dielectric loss should be taken into account where three-core screened or single-core cables are used can be found in [117].

- The capacitance for circular conductors is given by:

$$\boldsymbol{C = \frac{\varepsilon}{18 \ln\left(\frac{D_i}{d_c}\right)} 10^{-9}}\ \text{(F/m)} \tag{5-8}$$

Where ε is the relative permittivity of the insulation, D_i is the external diameter of the insulation (excluding screen) (mm), d_c is the diameter of conductor, including screen, if any (mm).

- The loss factor for a three core wire armour cable is given by:

$$\boldsymbol{\lambda_2 = 1.23 \cdot \frac{R_A}{R} \cdot \left(\frac{2c}{d_A}\right)^2 \cdot \frac{1}{\left(\frac{2.77 \cdot R_A \cdot 10^6}{\omega}\right)^2 + 1}} \tag{5-9}$$

Where R_A is the AC resistance of armour at maximum armour temperature (Ω/m), d_A is the mean diameter of armour (mm), c is the distance between the axis of a conductor and the cable centre (mm).

5.3 The CRATER Tool

The concept of the distribution rating has been introduced in ER P17. However, to evaluate the distribution rating for a circuit requires typically the cross examination of look up tables, a non-practical and lengthy process [118]. Further, the tables can only be applied to particular predetermined conditions, for instance when applied to groups of equally loaded circuits and certain soil conditions. P17 doesn't cover all cable types and is generally conservative and the British Standard which covers everything is much more complex. Apart from that, as explained in [38], distribution ratings allow cables load to increase for a fixed period of time, assuming the cable has been operated at half-utilisation for a long time beforehand. However, distribution ratings are a deterministic measure and provide no means of calculating the potential impact of load increase on the distribution rating. In contrast, when actual network, loading and environmental conditions are taken into account to calculate the relevant thermal rating, then the latter are closer to their actual ampacity and higher utilisation of the network is achieved. This calls upon the need to more accurately quantify the actual loading current of an UGC. In this context, RTTR system is part of a larger suite of smart grid technologies that allows electrical conductors to operate at higher capacities based on their local weather or internal parameters and network and loading conditions. This could happen by increasing the conductors' thermal ratings while adhering to the maximum operating design temperatures.

To this end, the most important drivers to develop a software tool like CRATER were the need to create an easily operated electronic version of P17, but also the need to cope with smart grid developments and automate the process of thermal rating calculations. CRATER is an advanced Cable Ratings tool utilised for the calculation of current ratings of a wide range of thermally interdependent circuits [119]. It is developed by EA Technology with the support of the GB DNOs. It is used commercially by many network operators in the UK [118] both for steady state studies and real time applications [120] . CRATER has lately been extended to a much wider range of cables types, configurations and topology conditions and is still under further development to consider all possible parameters and equipment conditions.

The CRATER tool is based on the extensive rating calculation methodology presented in the UK adaptation of IEC60287 in [117] and briefly given in section 5.2. As explained, the heat flow can be modelled by analogy to an electrical circuit where heat flow is represented by current, temperatures are represented by voltages, heat sources are represented by constant current sources, absolute thermal resistances are represented by resistors and thermal capacitances by capacitors. Figure 5-2 represents a basic cable thermal resistance circuit model that is drawn similar to an electrical resistance circuit. Heat is generated within the cable and flows through a series of thermal resistances to the ambient temperature. In the depicted circuit, current is effectively injected at the circular point in the top left of the diagram, causing a voltage rise. T_A and Q_A represent the thermal resistance and capacitance of the cable insulation respectively. $T_B$and Q_B are the thermal resistance and capacitance of the remaining layers. Models exist which split $T_B$and $Q_B$into more parts but IEC 60853-2 [114] views the two part model as being sufficient. Using this two part model, it is possible to calculate the temperature of the cable after an arbitrary sequence of loads. In a few words, the methodology can be summarized in the following points:

- $I = (I_1, I_2, I_3, I_4, I_5 \ldots I_n)$ is a set of the half hourly currents experienced by a cable. The set is calculated typically through power flow equations, thus taking into account the network loading conditions.
- Necessary parameters describing the cable including conductor size, conductor shape, insulation material, armour type, armour material, bonding design, sheath material, laying conditions and energising voltage, etc, are summarized in a set P. A full list of parameters can be found in IEC 60853-2[114].

- Then, $F(P, I)$ is a function requiring the parameters of the cable and the currents the cable has been exposed to previously, to calculate the current temperature T of the cable. The calculation of the current temperature and afterwards the comparison of this value to the highest tolerable temperature would eventually give the actual allowable thermal rating of the cable, defined here as time-limited thermal rating.

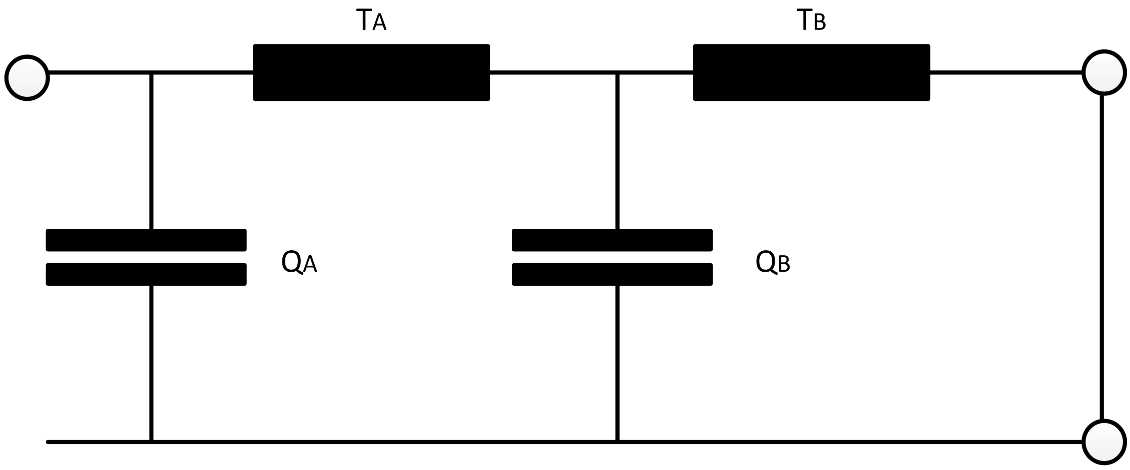


Figure 5-2: Equivalent electrical circuit

5.4 Reliability assessment of the Time-Limited Thermal Ratings (TLTR) with DR

A systematic approach should be proposed in order to identify the extra headroom capacity and overall contribution that could be available after the calculation of the RTTRs. When using the RTTRs instead of constant values, cables are operated beyond their firm capacity providing important benefits to the networks which need to be properly evaluated. In consequence, it is of great interest to properly quantify the reliability impact that those practices would bring on smart distribution networks and consequently on network planning practices.

5.4.1 Related works

The implementation of RTTRs has been recently proposed in the literature as a smart grid technology to enhance network utilisation and existing capabilities before proceeding to new reinforcements. RTTRs are defined as a time-variant rating that can be practically exploited without damaging components or reducing their life expectancy. Actual measurements of environmental and weather conditions (wind speed, wind direction, ambient temperature and solar radiation) are used as the input to steady-state thermal models[121]. In this sense, RTTRs provide thermal visibility of the network, making system operators aware of the actual rating with respect to the sustained, cyclic and distribution ratings suggested in 5.1.2.

There is a recent interest on understanding the impact of these enhanced variable ratings on network reliability performance [38], [122]–[129]. Authors in [122] implement three thermal rating models for overhead lines, static, seasonal, and time varying, into a sequential modelling with SMCS, to validate the methodological enhancements on reliability transmission networks. In [123] a probabilistic modelling and simulation methodology for estimating the occurrence of critical line temperatures in the presence of fluctuating power flows is presented. Dynamic thermal equations for overhead lines are inserted in a Monte Carlo simulations framework which makes use of a variance reduction technique. The method is tested in a transmission system application. In [124], SMCS was performed to investigate the reliability of an electrical network incorporating dynamic thermal rating in overhead lines and wind farm. The modelling of the time-series data was performed with ARMA models.[125] investigates the impact or real time thermal ratings for overhead lines on distribution network reliability. Critical spans are identified, and the dependence or ratings on conductor distance is included. For the reliability analysis state sampling and SMSCs are used. Same authors present an extended analysis in [126] where real RTTRS are combined with energy storage systems, for a demand peak shaving application to enhance distribution network security of supply. Authors in [127] assess the reliability impact of dynamic thermal rating of overhead lines, underground cables and transformers in distribution networks, SMCS approach is used to identify the amount of DG penetration that dynamic thermal rating allows. [128] investigates the adequacy impacts of RTTRs of different underground distribution network cabling systems, accounting for line losses and the risk of aging, however without accounting for the thermal inertia in UGCs. In the paper the SMCS computational reliability assessment tool has been utilised.

It can be observed that, a research trend towards time varying thermal ratings has risen. Studies have been performed both on overhead lines and transmission networks and UGCs and distribution networks. All of the studies have selected SMCS reliability method, in order to cater for the time dependencies between the network loading, the consecutive actions after the fault and the weather conditions. However, as seen only in [126], time varying thermal ratings have been combined with another smart grid technology (e.g storage), whereas no study so far has investigated the impact of time varying thermal ratings when co-operating with DR. A relevant study has been performed by [129], where time varying thermal ratings are combined with a DR scheme, nonetheless the study is applied in a transmission networks and it only deals with overhead lines and their rating models, which is fundamentally different. Additionally, authors in [130] develop an optimal residential DR approach integrated with real time thermal ratings to balance the hourly wind power production in smart distribution networks. However, no reliability assessment is executed.

Subsequently, it is clear that more research is needed in the area in order for the full potential of time varying thermal system to be unlocked effectively. In this work, time-limited thermal ratings have been applied to UGC during contingencies along with the implementation of a DLC DR scheme and the effect of those two mechanisms on distribution network reliability have been evaluated and discussed. The definition time limited thermal rating (TLTR) is given because the real time rating that cable temperatures and network conditions allow, has been only applied for post-contingency network support. This type of corrective control commonly would last for a few hours, for example until the fault repair has been completed, or the alternative supply and reconfiguration has been executed and the network comes back to its normal state. The actual thermal capacity of UGCs is calculated accurately through the well-recognized CRATER tool which embeds all the important technical aspects of the cable rating. A similar study was performed in [38], where the authors utilised again the CRATER tool, implementing a reliability evaluation in distribution networks which also included degrading performance due to ageing equipment and increasing loading. However, the study does not include the potential of DR and it analysed a flat load curve instead of a time varying load profile. The CRATER tool utilised for this work, is a subset of the complete tool, since in this work we only care for the dynamic rating calculation. It should be mentioned that the tool is not developed in this thesis, but it is adopted from [38] and inserted into our model. The model developed in [38] is a suite of modelling tools based on CRATER for the cable rating calculations.

To this end, the methodology of this work is based on the SMCS reliability modelling tool, analysing a time series load demand. The study also combines a network analysis, in order to properly calculate the cable currents and then inserts those values in the CRATER tool. Thereinafter, the cable temperatures are evaluated and then compared with the maximum acceptable temperature. Details of the algorithm are given in the next section.

5.4.2 Time-limited thermal rating (TLTR) model

The model computes cables temperature based on the dynamic past. More specifically, for a half-hourly analysis, branch currents are calculated in each time step (and for a certain amount of past time steps) through AC power flow for a variant load profile. The calculated values are saved in a historical sequence which is updated for each time step the process is executed. The historical sequence of branch currents is inserted in the CRATER tool in order to calculate the actual temperature of the branches at the time step and then depending on the network conditions the permissible cable rating of this time step is evaluated. For every time step, the half-hourly rating capacity of the cables must be calculated such that their temperature remains less than their associated limit (predefined maximum allowed temperature for the cables). The whole process is illustrated in Figure 5-3:

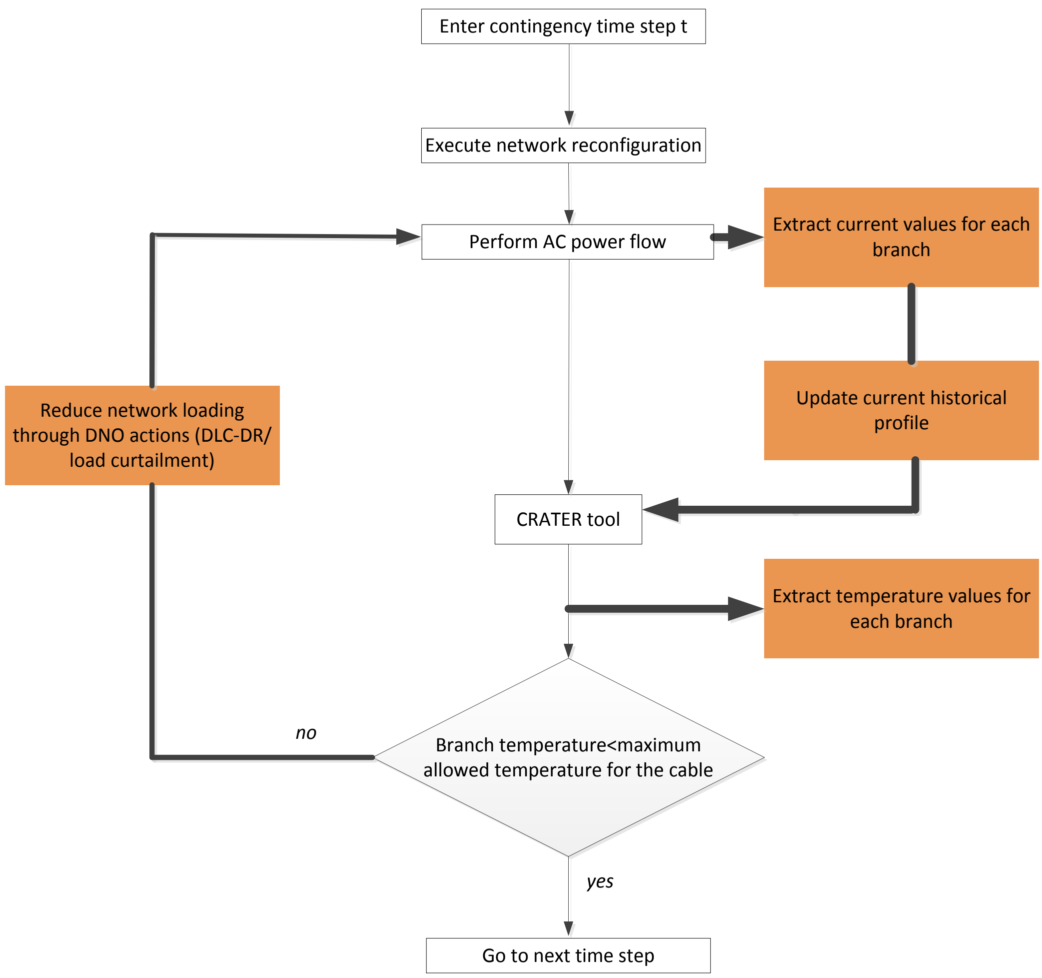


Figure 5-3: Time-limited thermal rating (TLTR) model

5.4.3 Overall methodology description

The TLTR described in section 5.4.2 would replace the emergency rating introduced in Chapter 4. It is reminded that the emergency rating is rather deterministic representation of an intervention, abiding by the instructions of the local DNO for a 20% increase above the sustained rating, for two-hours during the contingency regardless the specific network conditions and support requirements.

The same extensive methodology of the priority DR scheme introduced in Chapter 4 has been applied in this section, including network configuration, the OPF algorithm for the priority disconnection of DR customers and payback effects. The available DNO hierarchical actions would be the application of TLTR, the DR priority scheme and finally load curtailment of normal customers, actions taken in the given sequence.

The reliability assessment is performed with SMCS, allowing for the time dependencies between the modelled parameters to be captured perfectly. As always, the SMCS reliability modelling tool presented in Chapter 2 has been used. The simulation period is a year, and the chosen time step is half-hour. The system state is simulated through an AC power flow analysis with the aid of Matpower 4.1[61]and the whole modelling procedure is based on Matlab®. The inclusion of the CRATER analysis, presupposes the update of the historical branch current profile in each time step. For this analysis the historical profile would contain 8760 half-hours, which is also updated in each contingency time step due to the random faults and the resulting network conditions. This process increases the computational complexity of the analysis however this is not a burden for this thesis since again the parallel computing framework introduced in **Error! Reference source not found.** has been used. More specifically, for this study ondor pool has been utilised[69].

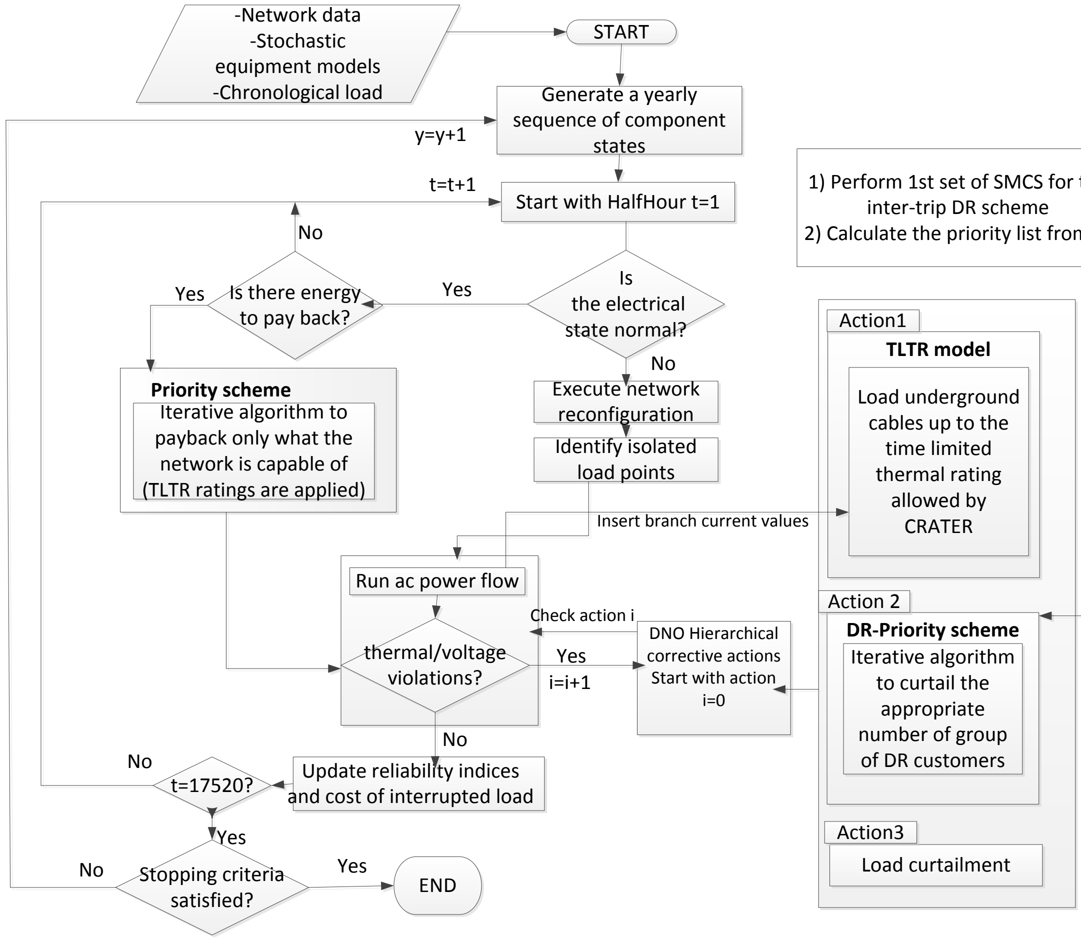


Figure 5-4: Flowchart for the overall methodology

5.5 Case study

This section assesses the reliability implications related with applying TLTRs on smart distribution networks along with the coincident implementation of DR schemes for reinforced results.

The methodology and the TLTR capabilities are demonstrated in a real distribution network, where current demand, which respects ER P2/6 standards, corresponds to 6.51MW and 2.14MVar. For the “base case”, the loading and customer date presented in 4.11 have been used. For the reliability analysis, reliability data taken from the local DNO [106] have been used (depicted in Table 5-1).

Regarding the TLTR parameters, in this work, three core solid paper insulated power cables are utilised and the size of the cables is 95 mm^2, 185 mm^2 and 300 mm^2, values based on [106] and [116]. This model has assumed a maximum allowed temperature of up to 65°C and soil ambient allowed temperature of up to 15°C.

Table 5-1: Reliability data used for the case study

	MTTF (hours)	MTTR (hours)
UGCs of Feeder A	49269	5
UGCs of Feeder B	56772	5

Three scenarios are studied depending on what type of post fault rating has been applied:

- **Normal Rating:** Network lines' rating is static and their limits should not be violated. Values of Normal Rating are equal to the 'Sustained Rating'.
- **Emergency Rating:** According to the DNO's intervention, network lines are allowed to be loaded 20% higher than the normal rating for two consecutive hours
- **Time Limited Thermal Rating:** Network lines could be loaded as much the CRATER calculations allow taking into account the cable temperature and the loading conditions. The only restriction is not to overheat the cables above the maximum allowed temperature.

5.5.1 Sensitivity analysis on the loading level

The contribution of TLTR to distribution network reliability is quantified through a sensitivity analysis of the network loading level. More specifically, it is assessed how the reliability indices change as we move above the loading firm capacity. Therefore, it has been assumed that current rating refers to the firm capacity and is depicted as 100% loading level. Every increase is determined with respect to the current loading level. Results for the different rating scenarios are illustrated and compared in order to highlight the benefit of TLTR with respect to the emergency rating examined in the previous chapter.

For this section, contracted DR capacity has been assumed to be equal to the load increase above the firm capacity. For instance, for loading level 125%, contracted DR is equal to 25% and so forth.

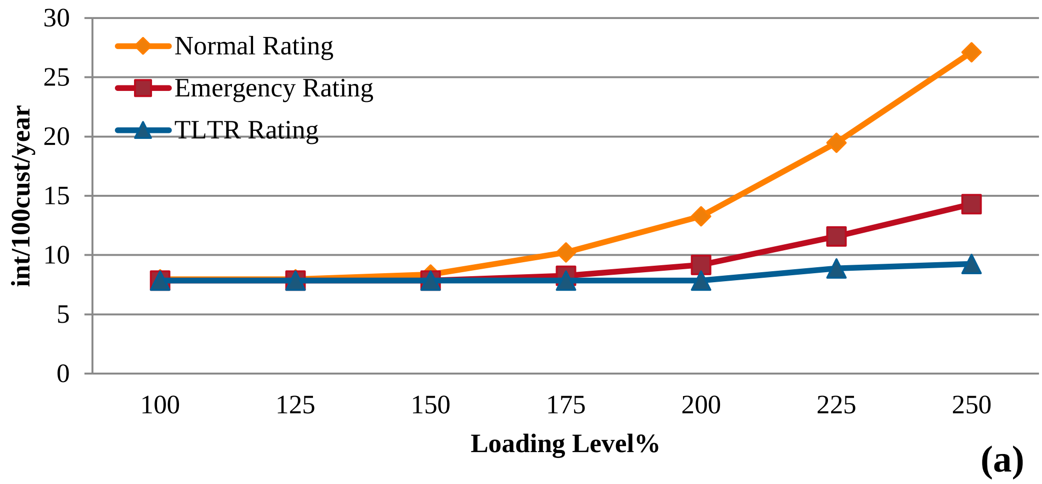
Figure 5-5 presents CI, CML and EENS for the three scenarios of post fault rating, for a range of loading levels above the firm capacity. It can be easily observed that TLTR rating outperforms the other two types of rating. As demand increases, reliability indices are much lower for this rating scenario, especially when compared with the normal rating scenario. However, it is interesting to note that up to 150% loading level, all ratings have similar reliability performance for normal customers. This observation comes in line with the current practices for network loading where networks are typically underutilised. Furthermore, up to 175% emergency and TLTR rating have similar performance for normal customers. Afterwards, for loading levels above 175%, differences become more noticeable and finally for 250% loading level, the three ratings have a significantly distinctive performance, with the normal rating presenting clearly the worst values in the reliability indices tested. In general, it can be observed that even for 250% loading level, when the TLTR is implemented, reliability indices are increasing in a relatively slow pace, allowing extremely high network utilisation.

Although for normal customers, emergency and TLTR rating have similar performance for loading levels up to 175%, for DR customers there is difference on the reliability indices from the first level of load increase (125%) for the two rating scenarios. As explained in section 5.4.3, the first corrective action implemented by the DNO is the application of thermal ratings, then the DR corrective control is applied, and as a final action the DNO performs normal customers' curtailment. For the scenario of TLTR rating, it is observed that the DNO has a lower probability to go to the second step of corrective control, since TLTR utilises harder the existing network, comparing to the emergency rating which can be applied only for two hours and allows a constant overload of 120%. Table 5-2 contains CI and CML for DR customers. Results refer only to corrective interruptions[8] to better illustrate the lower amount of corrective actions of TLTR rating comparing to emergency rating. It is demonstrated that DR requirements are much lower for TLTR rating, since interruptions and duration of interruptions are lower for TLTR when compared with the other two rating types.

[8] It is reminded that DR customers may be interrupted along with normal customers when they are located in the fault-affected area or get intentionally disconnected by the DNO as a corrective action. Reliability indicators of DR customers are illustrated as 'total' representing their total discomfort, which contain both types of interruptions and as 'corrective' which are only due to the corrective DR scheme to quantify its share.

In the same context, Figure 5-6 demonstrates the risk indicator $P(DR_{req} > X)$ which reflects the probability that DR requirements exceed DR capacity, thus triggering normal customer curtailment. $P(DR_{req} > X)$ is presented for selected loading levels and it can be observed that up to 200% loading level, for emergency and TLTR the probability of corrective load curtailment is very low, with emergency rating presenting slightly higher values.

Another important parameter to note is that both for emergency and TLTR rating, the distribution network given can withstand up to 175% load increase above the firm capacity without any significant implications for normal customers. This is mainly explained from the low capacity utilisation that current networks exhibit. This fact drives the interest for an additional set of sensitivity studies regarding the DR capacity penetration level, given in the next section.



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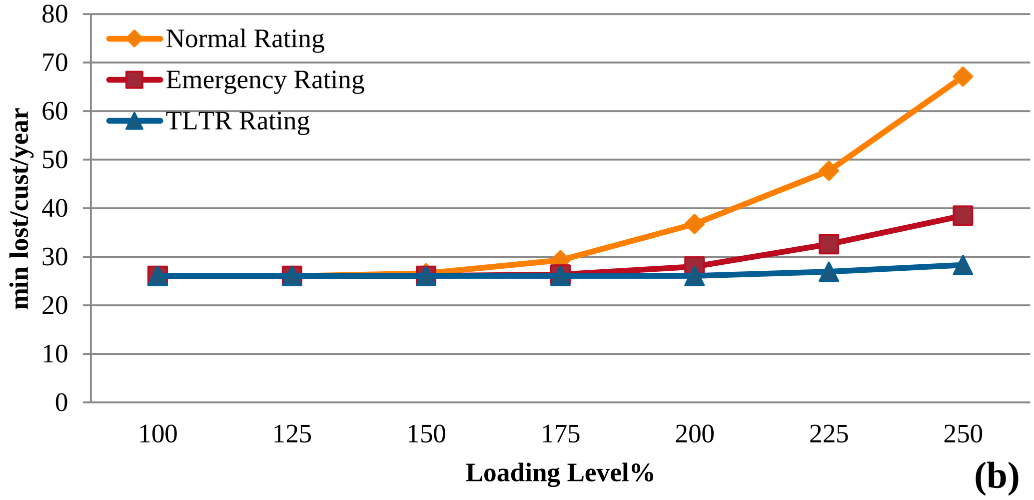

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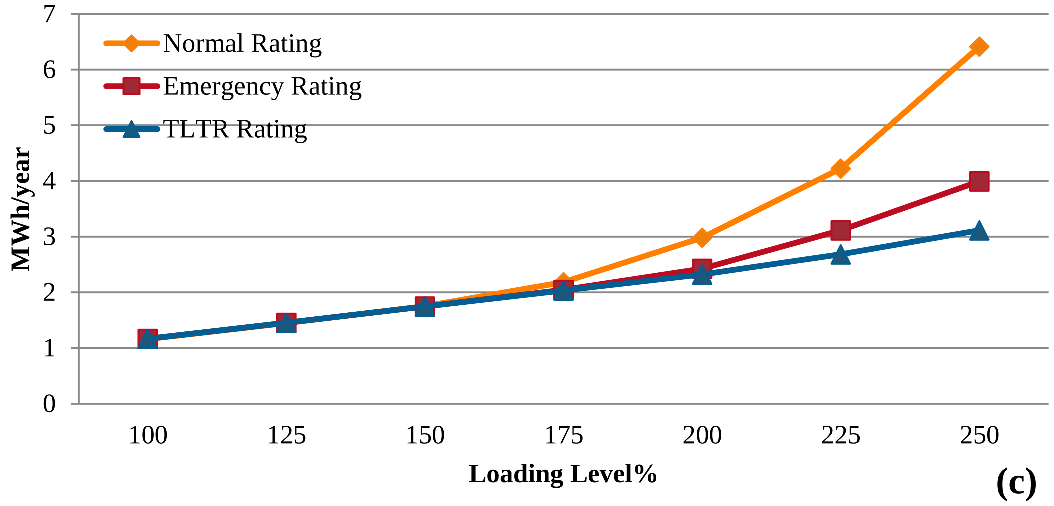


(c)

Figure 5-5: Reliability indices for normal customers for various loading levels, (a) CI, (b) CML, (c) EENS

Table 5-2: Reliability indices for DR customers-corrective interruptions only

	CI (int./100 customers-year)			CML (min./customers-year)		
Loading Level (%)	normal	emergency	TLTR	normal	emergency	TLTR
100	0.000	0.000	0.000	0.000	0.000	0.000
125	1.996	0.079	0.000	1.913	0.041	0.000
150	7.099	1.447	0.034	7.481	1.519	0.010
175	16.252	5.228	0.789	20.044	5.438	0.776
200	27.257	12.234	3.416	34.645	14.715	3.423
225	37.718	20.496	7.530	50.822	25.980	8.410
250	48.821	28.914	12.488	65.886	37.439	14.509

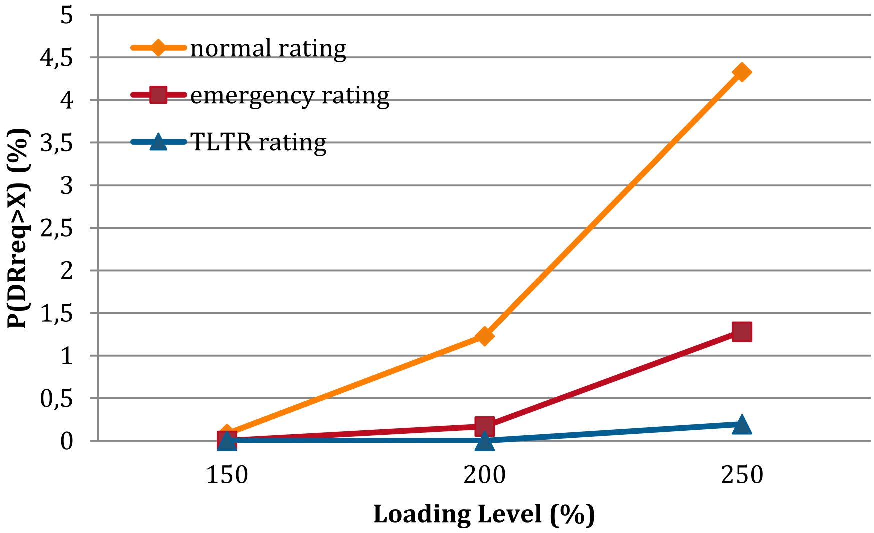


Figure 5-6: ($P(DR_{req} > X)$)

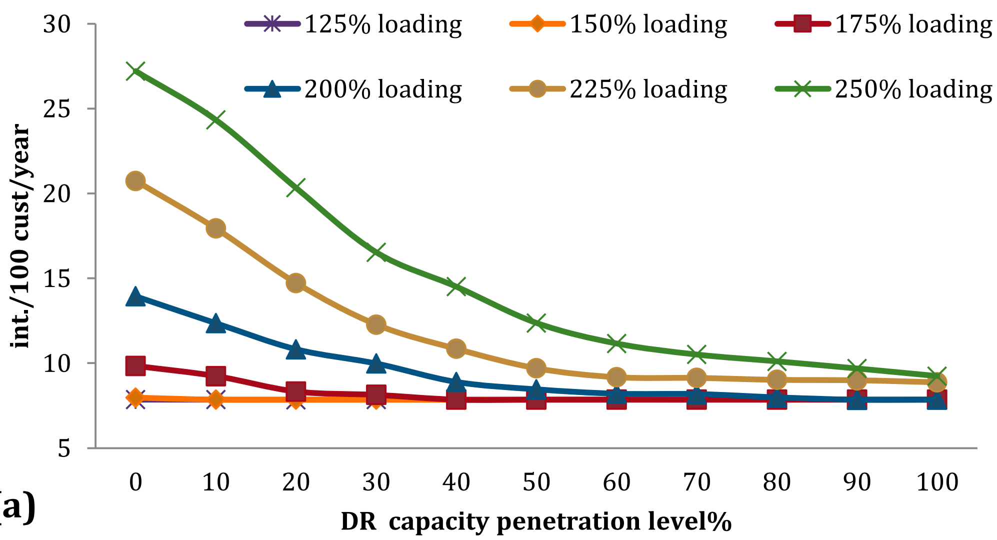
5.5.2 Sensitivity analysis on the DR capacity penetration level

In the previous section the studies were executed under the assumption that DR capacity is equal to the load increase above the firm capacity (100% DR penetration level). Additionally, since the DR scheme selected is the priority one, it is reminded that for each random contingency event only the required amount of DR customers gets disconnected (the OPF algorithm selects the number of clusters that will become disconnected based on the network conditions and also on the cost of interrupted load for the DR customers).

Results of section 5.5.1 indicate that DR capacity utilisation is low (due to the low values of the reliability indices for DR customers in Table 5-2). Therefore in this section, a sensitivity study on the DR capacity penetration level is executed. 100% DR capacity penetration level implies that the contracted DR capacity is equal to the 100% of additional demand connected to the network. 0% DR capacity penetration level implies that there are no DR customers contracted. Reliability indicators for normal and DR customers are presented in Figure 5-7. Results are shown only for the TLTR rating. Results for the other types of ratings are omitted but they present a similar trend, however in a larger scale. However, it should be mentioned that as shown previously, when TLTR rating scenario is applied, reliability indices are lower comparing to the emergency rating scenario and when normal rating is applied, reliability indices present the worst results.

As it was expected, for loading levels up to 200%, lower DR capacity penetration level do not provoke a significant negative impact on the reliability indices. In particular, for loading levels up to 175%, CI (Figure 5-7a) and CML (Figure 5-7b) show an almost constant performance for DR capacity penetration levels above 30%. In other words, even if only the 30% of the additional load demand was contracted for DR corrective disconnections, reliability of normal customers wouldn't be jeopardized. For higher loading levels, the crucial DR penetration level (above which reliability indicators do not change much) is higher than 30% but again considerably low.

Consequently, it can be concluded that contracting for corrective DR the exact same amount of load that was added above the firm capacity is not necessary. Lower DR penetration levels could result to acceptable reliability levels for normal customers as well.



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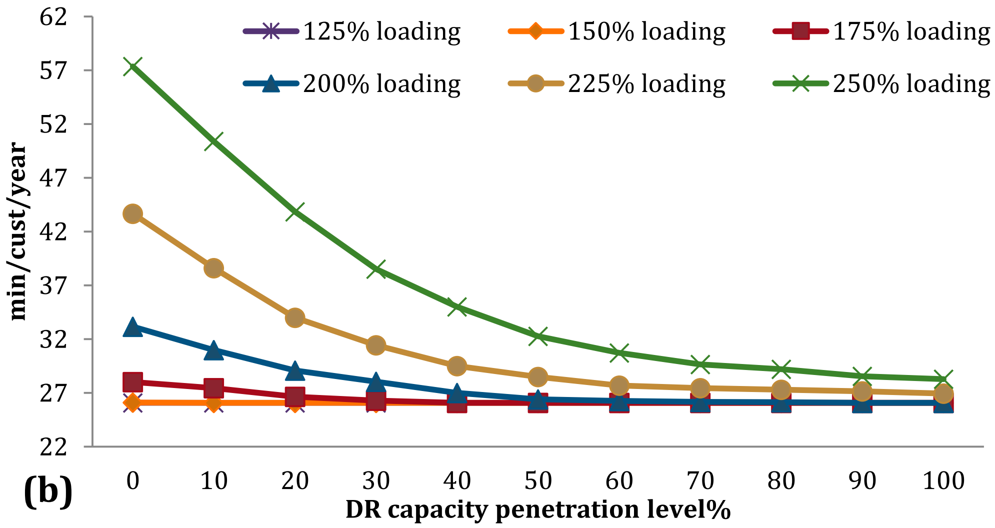

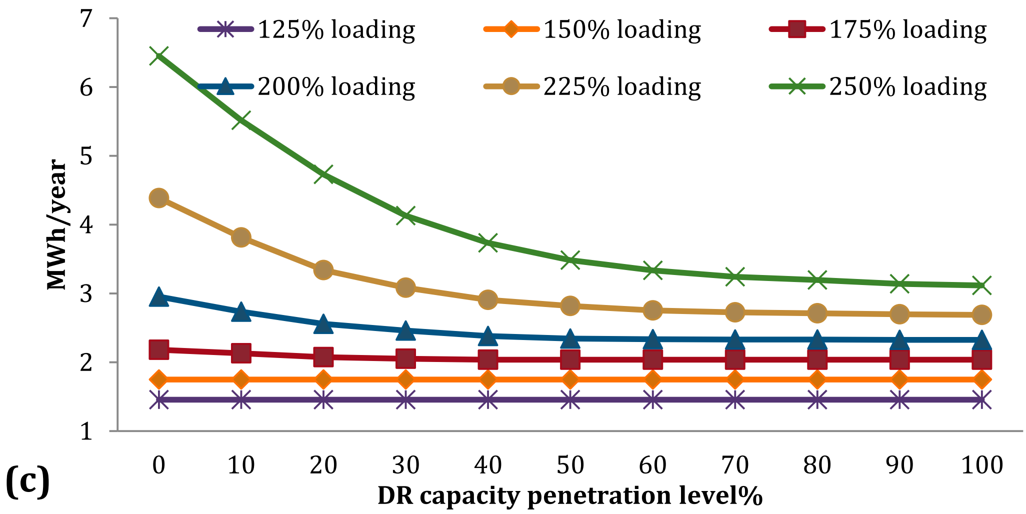

Figure 5-7: Reliability indices for normal customers (a) CI, (b) CML, (c) EENS

5.6 Conclusions

This chapter has presented a comprehensive framework for reliability assessment in distribution networks that successfully combines time limited thermal ratings (TLTR) and demand response applied as a post fault service. The reliability assessment has been built on the SMCS reliability modelling tool presented in Chapter 2 and the DR scheme has been adopted from the priority DR scheme presented in Chapter 4. TLTRs have been calculated from the broadly known CRATER tool, which calculates UGC's temperatures based on the dynamic past of the current flows. According to TLTR philosophy, UGC could be loaded above their sustained rating, with the only limitation not to exceed the maximum allowed temperature. Taking into account that reaching the maximum allowed temperature takes quite a lot of time, the reliability assessment and the sensitivity analysis on various loading levels has shown that distribution network utilisation can been significantly increased.

The SMCS framework uses a time series analysis thus allowing the calculation of the historical current profile of network cables. Apart from that, DR requirements are properly captured since the intertemporal dependencies between the network faults, available DR, and loading profile are modelled extensively from the time series analysis.

Results indicate that TLTRs surpass the performance of deterministic emergency ratings presented in the previous chapter, mainly because they permit flexible cable overload, which responds to specific network conditions. Reliability indices for normal customers are lower for application of TLTRs when compared with application of emergency ratings. Furthermore, the study shows that even for a loading level much higher than the firm capacity, CI and CML for normal customers do not deteriorate significantly when TLTRs are applied. Regarding reliability results for DR customers, again TLTRs demonstrate higher benefits compared to emergency ratings. When the TLTR scenario is applied, reliability indices for DR customers are lower comparing to the other two rating scenarios, indicating that TLTR could reduce or even eliminate the requirements for DR corrective interventions. In the same context, sensitivity analysis on the DR capacity penetration level shows that DR utilisation can be quite light and demonstrates that DR requirements are lower than initially estimated and especially lower than the equivalent load increase above the firm capacity.

In summary, TLTRs improve significantly network reliability performance and have a significant potential to increase network utilisation, allowing the connection of new demand without the need for subsequent reinforcements.

6 MGs For Distribution Network Post Fault Services

In the previous three chapters DR and TLTRs were examined as potential resources providing post fault capacity services and improving network reliability. In a similar context, this chapter aims at shedding light on the impacts that the use of Microgrids (MGs) for post-contingency distribution network management can have on reliability. MGs are expected to bring about significant economic benefits for distribution networks in the form of network reinforcement deferral and increased reliability levels. The SMCS reliability modelling tool is used for the evaluation of a real distribution network while a framework to implement the MG services is also proposed. The results show that reliability improvements for MG users can be remarkable, while external network users and the network operator also perceive benefits [131]. *The former experience higher reliability levels and the latter experience lower network reinforcement needs when connecting additional customers due to the services provided by MGs.*

6.1 MG services for Post-Contingency Network Support

Significant progress in DERs such as various DG technologies, energy storage, and DR, in coordination with developments in ICT, can potentially reduce the need for traditional system expansion practices and increase the reliability of electricity supply for customers. One promising new concept that has emerged in recent years due to the aforementioned developments in the energy sector is the MG.

MGs are entities that coordinate different DERs to supply customers either while connected to the energy grid or islanded from it should a contingency occur and grid supply be interrupted [132].

6.1.1 Overview of MGs

There is research worldwide towards establishing functional MGs within utility systems. The increased participation of small generation sources and loads in electricity markets and in the provision of ancillary services is some of the most important advantages of MGs. Furthermore, MGs can also facilitate a high penetration of DG, particularly renewable energy sources; facilitate cogeneration in combined heat and power systems; increase the quality and reliability of the electricity supply; defer or avoid network investments; contribute to network adequacy; and provide cost efficient electricity infrastructure replacement strategies (see [133] for further details). Both stakeholders internal and external to the MGs could thus profit from these economic, technical, environmental and social benefits [134].

With regard to the internal economic values created by a MG, according to [135], an energy market within the MG may exist, where the MG units could sell at prices higher than wholesale level and customers could buy at prices lower than retail level. To fully achieve more economical benefits, the application of real time pricing schemes and dispatch decisions could be used (see for instance [136]).

Different tools are available in the literature to model and assess MG reliability services. In general, according to [137], two different modes of operation can be envisaged, namely, normal interconnected mode and emergency mode. In the former, the MG is connected to the grid, being either partially supplied from it or exporting power to the grid. In the latter, the MG operates autonomously when the disconnection from the upstream network occurs. More specifically, as stated in [138] if a blackout occurs, MG capabilities can be exploited to reduce customer interruption times by providing a fast black start recovery in the LV grid; allowing MG islanded operation to feed local consumers until the MV network becomes available.

Apart from the two operational modes, the MG can be found in two transition modes known as island forming and grid synchronisation[139], as seen in Figure 6-1. When the

MG is operated in grid connected mode, the DERs forming it are controlled as active and reactive power sources so that they inject into the network a controllable amount of power while using the grid voltage and frequency as a reference. In islanded mode, the DERs are controlled in order to maintain the voltage and frequency within acceptable limits.

The transition between grid-connected and islanded mode (island forming) can be planned in advance or caused due to an unexpected event. A scheduled transition could be planned for maintenance reasons or due to economic motivations. Unplanned transition is usually the result of a major fault in the grid or another sudden event. During the island forming transition, the MG control has to be designed to support the system frequency and voltage. Any transients produced by this transition should be sufficiently mitigated in order to allow the recently formed islanded MG to reach a stable operation. The transition between islanded and grid-connected mode (grid synchronisation) is controlled so that the MG can be safely re-connected to the grid.

For the successful realization of the MG reliability services, it is assumed that proper control systems and an approved MG architecture are in place. More specifically, a MG connects to the grid at a point of common coupling that maintains voltage at the same level as the main grid during normal grid connected mode. For the islanded mode a switch can separate the MG from the main grid automatically or manually.

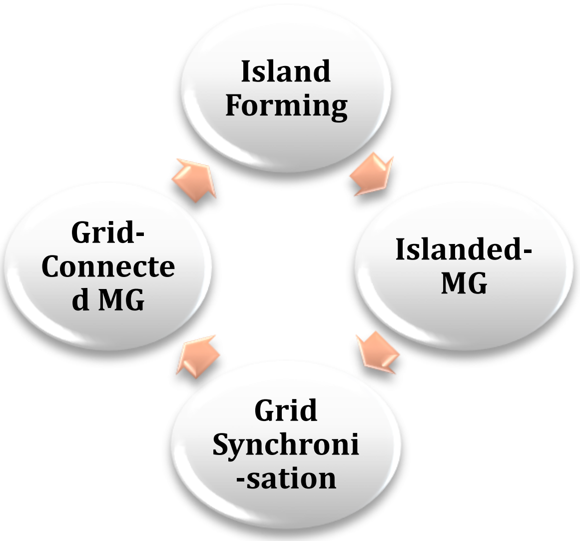

Figure 6-1: MG operating and transition modes[139]

6.1.2 Interactions between actors to support MG services

A MG as an entity should perform a number of functions such as supply of electrical and/or thermal energy, participation in the energy market, ancillary services and black start. Those functions are ensured through the MG control system, which could be centralized or decentralized and includes three hierarchical levels [140]: The DNO, the market operator (MO), the MG Central Controller (MCC) and local controllers (LCs) associated with each DER unit and/or load, as seen in Figure 6-2.

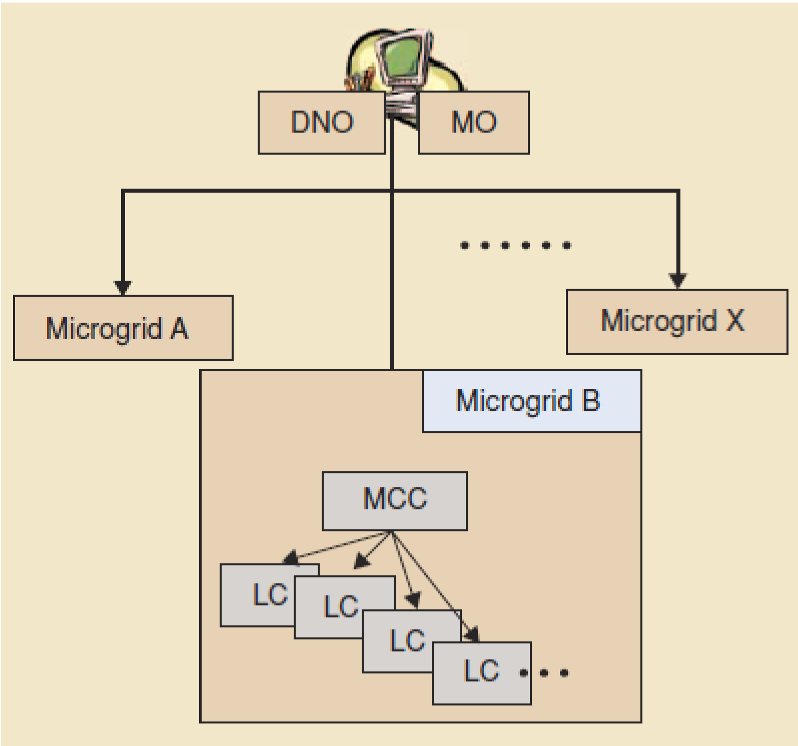

Figure 6-2: A MG supervisory control architecture [140]

The main interface between the DNO/MO and the MG is the MCC. The MCC is also responsible for coordinating the LCs. The LC controls the DER units and the controllable loads within a MG, ensuring smooth operation for the loads they control. In a centralized operation, each LC receives set points from the corresponding MCC and have the autonomy to perform local optimization for power exchange of the DER units. In a decentralized operation each LC makes decisions locally in order to meet the load demand and maximize exports to the main grid based on the market prices.

6.1.3 Prospective Distribution MG services

- **Distribution Network Capacity Services from MG:** The MG can reduce capacity requirements and defer investments in network reinforcements by supporting the grid during emergency conditions. This would allow demand to grow beyond traditional security limits (e.g. UK P2/6 engineering recommendations [1]) by having the MG operate as an island during emergency conditions.

- **Distribution Network Reliability Services from MG:** The installation of the MG is expected to increase the reliability for the customers within the MG, as well as for those external to the MG. More specifically, depending on the capacity requirements during a disturbance and the location of a fault with respect to the MG, the MG could fulfil the following operational services:
  - ✓ *The MG is located in an area not directly affected by the fault.* As a result, it could provide capacity support. In case a fault happens, MGs would normally island themselves from the grid using an inter-strip scheme, and would supply their customers using internal resources. If the contingency occurs during a peak demand period and the DNO faces capacity limitations or risks to exceed thermal or voltage limits, the MG is notified to remain islanded. In such a way, the net network demand would decrease during contingencies, thus releasing network capacity that can be used to supply the rest of the customers.
  - ✓ *The MG is located in the fault affected area along with other customers.* As a result, it could provide reliability support. As in the previous case, one solution would be that the MG would island itself immediately through an inter-trip scheme. However, because of the sustained fault, the DNO would not be able to restore supply to the MG and nearby customers and a section of the network remains disconnected. Under such conditions, the DNO would normally connect a mobile generator to supply the disconnected area. However, if the MG has enough spare electricity generation capacity, it could supply some or all customers in the area (internal and external to the MG) until the fault has been cleared.

6.1.4 Related works

The previous section indicates that MGs have the potential to bring significant reliability benefits.

Reliability evaluation of distribution networks with islanded operation of DGs or MGs has been examined in [141]–[151]. An analytical technique based on connection matrices of DGs and impact factor has been used in [141] to evaluate the reliability of customers in a MG. In [142] a non-sequential MCS method is adopted, considering different operation modes under single or multiple contingencies. In [143], the authors present an analytical assessment method to consider the combined effect of islanding and the simultaneous presence of switches subject to tele-control or on-site demand. In [144], a two-step SMCS is performed to assess accurately the grid-connected and islanded modes of a MG, proposing also reliability and economic metrics for the assessment of the MG. In [151] a novel method is presented for assessing the reliability of MG, considering the probabilistic behaviour of solar and wind power. The study period is divided into different timeframes, and for each timeframe, the timeframe capacity factor is considered for each renewable DG. To assess the MG reliability, the loss of load expectation and expected energy not supplied are calculated which result in a reduction in the required data and running time for reliability assessment. The main advantage of the proposed model is that it does not depend on detailed data that is hard to obtain, and does not deal with convergence, error limit, or runtime issues that exist in Monte Carlo simulation. The study in [149] uses Markov process to model generation to load ratio when analysing the impact of RES on the islanded MG reliability. In [147] stochastic linear programming is introduced to obtain optimal operating schedules for a given MG under local economic and environmental conditions. The paper indicates that adopting a stochastic approach can both increase the reliability of MG operations and improve its economic performance, which also illustrates the advantages of using integrated modelling approaches. In [146] a simulation model on unit commitment and economic dispatch of DERs is presented showing that a MG with DERs offers much better distribution network reliability indices compared to a MG and a system without DERs due to its ability of transiting to islanded mode operation when the utility grid fails. In [148] a procedure of supply reliability evaluation for MGs is presented which includes renewable energy sources such as wind power and solar PVs. Finally, [145] presents a model for the assessment of the reliability of a CHP-based MG. Probabilistic methods such as loss-of-load probability, loss-of-energy probability, and frequency and duration are used in the context of tracking electric demand profiles. Worth of reserve capacity and demand for reserve are evaluated from capacity outage probability distribution and demand curve.

However, there are various services that MGs could provide in addition to the reliability benefits to customers internal to the MG in the case of loss of mains, which have not been explored in the literature and which are objectives of the present study. These services include distribution network support which would benefit the DNO and customers (external to the MGs) connected to the same distribution network. More specifically, in this work it is discussed that MGs can support the distribution networks by (i) providing post-contingency DR to manage network issues that may arise and allow the DNO to connect new customers beyond traditional security limits and (ii) providing its electricity generation surplus to customers that may be taken offline ("islanded") alongside the MG after a sustained contingency. In terms of methodology, as done in [144] and [152], reliability evaluation is carried out via a SMCS method, adapted from the model in [77]. SMCS allow realistic reliability assessment via the use of hourly demand time series to address the operation sequence of protections and switchers, in contrast with other analytical techniques or non-sequential MCS [141]–[143]. Furthermore, as a major contribution, a framework to implement the MG services described in the previous paragraph into the reliability assessment is also presented with the aim to evaluate the impact of those services on the distribution network as a whole and on the expected reliability of customers internal and external to the MG. More specifically, the potential of a MG to use its energy surplus to supply external customers in the area, should the area become isolated from the grid after a contingency occurs, has not been discussed or quantified before. Finally, reliability metrics related to the operation of a MG as an island are also presented and calculated.

6.2 Distribution Network Post-Contingency MG Support

Distribution network reconfiguration after a disturbance has already been discussed in previous chapters, now the role of the MG in relation to post-contingency support is demonstrated. Let us consider a fault occurring in Feeder 2 between L1 and L2 in the network depicted in Figure 6-3. After the system is reconfigured due to the fault, the MG provides reliability and capacity support. More specifically, the circuit breaker at the beginning of the feeder immediately opens leaving L1, L2 and L3 disconnected. At the same time, the MG switch opens, as the MG starts operating in islanded mode (see Figure 6-3a). In the sequence, the DNO tries to restrict the fault within a smaller area (isolated area in Figure 6-3b), leaving L2 customers without supply. Then, L1 is resupplied through the main feeder. Until the NOP is manually switched, L3 and the MG customers remain isolated from the main supply. In this case, if the MG has spare capacity, it can be reconnected to supply to L3. After the NOP is closed, L3 can be resupplied through Feeder 1 (MG could provide additional capacity if needed).

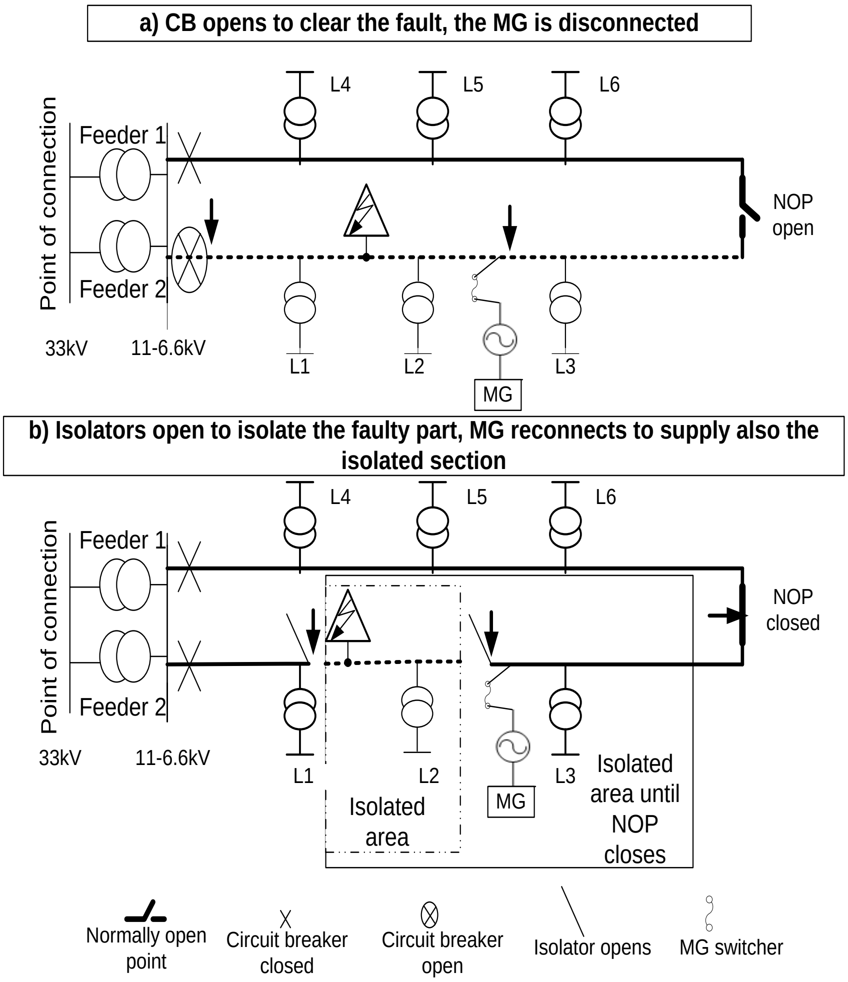

Figure 6-3: Reconfiguration with MG support

The above mentioned operations are fully modelled by the algorithm developed for this work. In particular, depending on the MG location with respect to the fault and also the network loading conditions at that time, MG services would be initiated. Either the MG would become intentionally islanded and remain islanded until the repair of the fault, or after the switching and isolating actions it would be reconnected to provide network support. Apart from those post fault operations, an additional corrective DNO action is also assessed, based on the local DNO current practices: the application of post fault emergency thermal rating after a disturbance and for the next 2 hours after the fault.

A high level description of the operational strategy of the MG during post fault operation and the reliability assessment framework of the distribution network that the MG is embedded is given in Figure 6-4.

It can be observed that great attention is given on the location of the MG with respect to the network fault, since the MG location would determine the type of the service that the MG would be called to offer (capacity or reliability support) depending also on the fault severity.

As part of the reliability assessment procedure, in order to facilitate the modelling of MG services, the MG is considered to be a single virtual power plant that integrates the capabilities of the available resources that have been selected to form it. This assumption simplifies the reliability calculations, while treating the MG as a single entity during islanded or interconnected mode.

- When the MG is in islanded mode, there are no electricity flows from and to the grid. The reliability for customers within the MG can be determined based on the probability of a successful transition into an island after a contingency occurs, and the probability of having enough generation capacity to meet the needs of the customers within the MG [49] during the period of islanding, as illustrated in equation (6-1). The reliability of customers outside the MG is estimated based on the typical SMCS process.

$$\boldsymbol{P_{MG\ internal\ customers}\{success\}}$$
$$= \boldsymbol{P\{successful\ island\ transition\}} \times \boldsymbol{P\{enough\ MG\ generation\}} \tag{6-1}$$

- When the MG is in interconnected mode, there are positive or negative flows from and to the rest of the grid, depending on the generation capacity of the MG and the energy needs of the MG at that time.

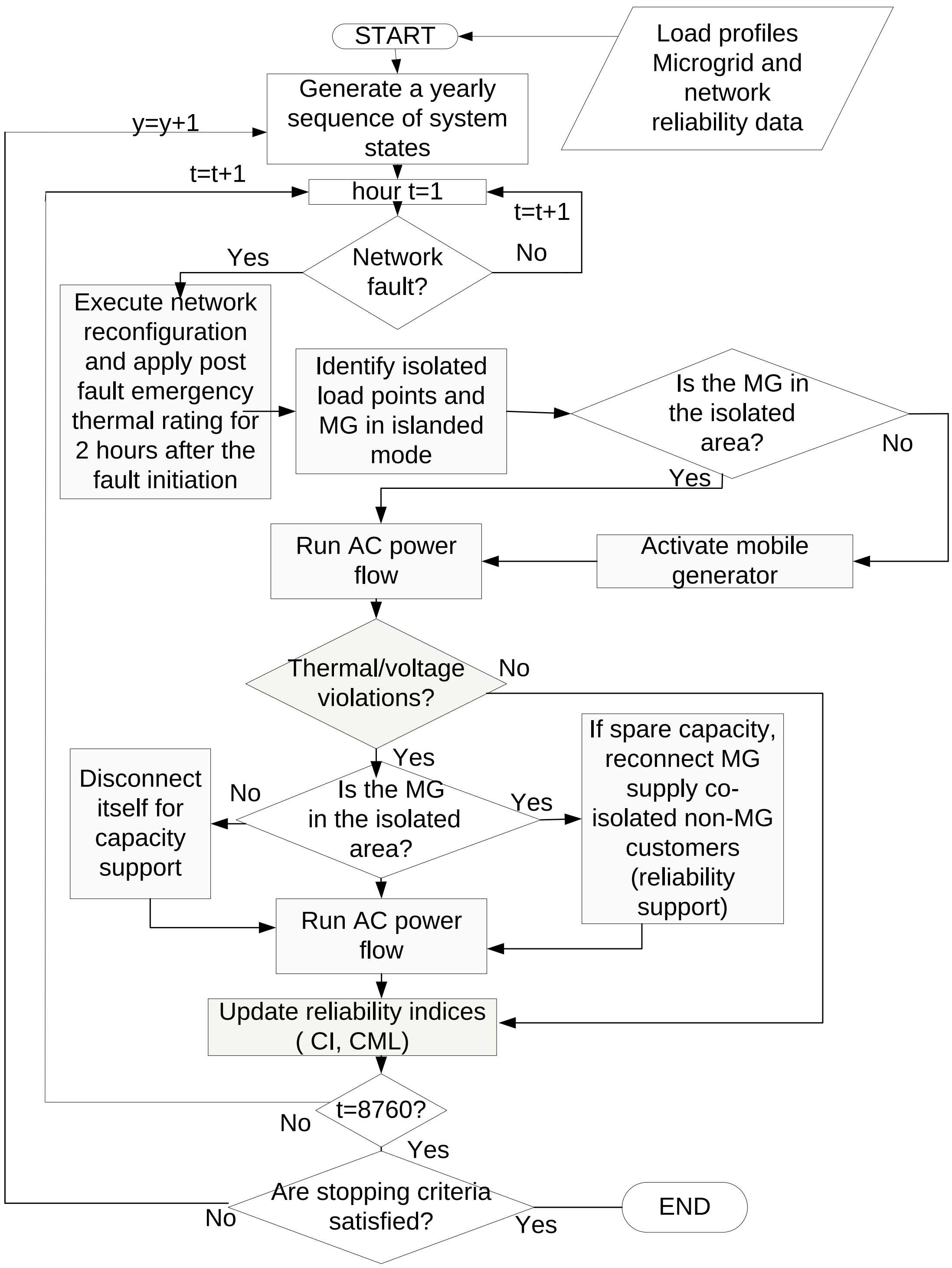

Figure 6-4: Flowchart of the simulation algorithm

6.3 MG related Reliability and Risk Metrics

In order to assess the impact that MG post-contingency support has on distribution network reliability, a set of MG-related metrics are proposed. Those metrics reflect the suggested MG reliability and capacity services and are calculated during the SMCS process. MG reliability indices for the MG reliability evaluation have been also proposed in [144] and include operation reliability indices in islanded mode, indices reflecting DG and load characteristics, MG economic indices and customer-based reliability indices, measuring specific aspects that would affect the performance of a MG.

For this study, the MG reliability indices are: the probability of MG to provide reliability support ($P_{MG}\{RS\}$), the probability of MG to provide capacity support ($P_{MG}\{CS\}$), the frequency of islanded operations (λMG_{island}) and the duration of islanded operations ($r_{MGisland}$). Their expressions are calculated from the number of hours that each behaviour is identified during the simulation period and their accompanying formulas are given to (6-2) to (6-5), where N is the number of sampling years.

$$\boldsymbol{P_{MG}\{RS\} = \frac{total\ hours\ of\ MG\ reliability\ support\ operation}{total\ hours\ of\ disturbance}} \tag{6-2}$$

$$P_{MG}\{CS\} = \frac{total\ hours\ of\ MG\ capacity\ support\ operation}{total\ hours\ of\ disturbance} \tag{6-3}$$

$$\lambda MG_{island} = \frac{\sum_{y=1}^{N_{SY}} total\ number\ of\ islanded\ operations_n}{N_{SY}} \tag{6-4}$$

$$r_{MGisland} = \frac{\sum_{y=1}^{N_{SY}} total\ hours\ of\ islanded\ operations_n}{N_{SY}} \tag{6-5}$$

6.4 Distributed multi-generation MG components

In multi-energy systems (MES), electricity, heat, cooling, fuels and transport optimally interact with each other, within a district, a city or a region [153]. Due to the technical, economic and environmental benefits of those systems with respect to the classical ones (where energy vectors act independently) there is an increased interest to model and assess their performance. In this outlook, the most important components of those systems are the distributed multi-generation (DMG) technologies involved, such as combined heat and power (CHP), electric heat pumps (EHPs), air conditioning devices, tri-generation of electricity heat and cooling, thermal storage and so on.

CHP produce usable heat and electricity from a certain input fuel and are widely acknowledged for their high potential in terms of energy saving with respect to the separate production [154]. Additionally, CHP can be combined with thermal storage which allows the CHP to generate electricity when prices are high, and go offline when prices are low. Thermal storage allows CHP plant to store heat when it is not needed, and they allow CHP plant to go offline because heat load can still be met from the stores[155].

Furthermore, EHPs are considered an efficient and economical alternative to existing boilers, having the capability to decarbonise the heating sector. However, since they consume electricity to produce heat, they are dependent on the decarbonisation of electricity generation.

In a MG context, DMG could be utilised to extend the concept of electricity only MG to MES, satisfying both electricity and heat demand and capturing environmental benefits that a multi-energy focus might bring. Authors in [156] study the optimal design of multi-node MGs integrating heat pumps and cogeneration units considering optimal predictive control strategies. In [157], an optimization approach is presented with the aim to deploy small scale MGs in commercial buildings consisting of generation, heat and electrical storage, and CHP applications. In [158], authors present an original idea to incorporate in the optimization technique by which owners could make a schedule to cater electric and heat demand using a DER-mix in a CHP-based MG, weighting between emission and fuel costs, without the utility's participation.

It can be observed that the utilisation of DMG to form a MG has been addressed by several researchers in the literature and one of the most important topics for research is to understand and identify the most optimal way to integrate the multiple energy vectors, maximizing economic, environmental benefits and fully utilizing the inherent flexibility and efficiency of the components involved.

For instance, researchers in [159] [160] propose optimal DMG configurations and planning practices to maximize the benefits of simultaneous power and heat demand dispatch for energy needs. However it is out of the scope of this work to identify optimal operational strategies for DMG, since we would only focus to examine the reliability impacts that MG services could have on network operation and planning. Therefore, in this work, the framework proposed in [40] has been adopted and implemented for the purposes of the MG case study. More specifically, in [40] a comprehensive techno-economic and environmental modelling and optimization framework for operational and planning evaluation of different DMG options has been developed. In addition, the different DMG options are assessed from an investment, environmental perspective in order to provide pros and cons of different DMG options.

From a variety of different DMG combinations proposed, eventually for this study *DMG type 7*[40] has been selected as also proposed in [41] . In this DMG combination, CHP units along with an auxiliary boiler, EHP units and thermal energy storage are combined and operated together, to gain flexibility and support the electricity and heat demands. The auxiliary boiler is utilised only for covering peak heat demand or for back up purposes. The EHP is cascaded to the CHP, using electricity from the electricity grid. The inherent flexibility of supplying electricity and heat from different inputs significantly increases responsiveness to price or utility signals and sudden changes in demand. Furthermore, the thermal energy storage is bringing additional flexibility to the heating side, enabling the CHP to decouple its operation from heat demand following. In particular, when coupling thermal energy storage to CHP and the auxiliary boiler, the CHP is not solely driven by the consumers' heat demand and it is able to store excess heat during high electricity prices and thus sell electricity at favourable market prices. In contrast, during periods that electricity prices are low, the CHP could be offline and the heat demand could be covered by the rest of the heat resources. In addition, when also cascading CHP and EHP, this would create virtual competition between these two units based on the hourly spark spread (which is the difference between the electricity price and the gas price adjusted by the electrical efficiency). Also the EHP can be supplied either from the CHP or from the grid. Both the CHP and the EHP optimize their operation based on the electricity prices but also based on the state of charge of the TES. Summarizing, the CHP and the electricity grid are electricity producers and the EHP is electricity consumer.

The schematic diagram of the MG DMG components is illustrated in Figure 6-5.

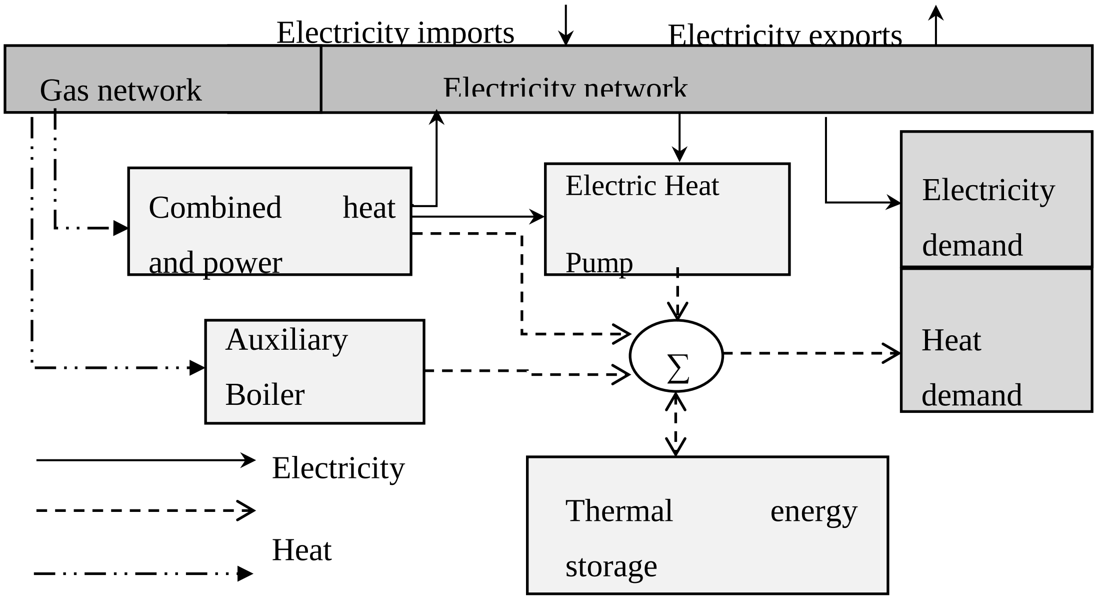

Figure 6-5: High level diagram of MG[9]

6.5 Case study

The case study aims at quantifying the impacts in terms of reliability associated with the deployment of a MG for post-contingency distribution network support.

6.5.1 Case study input data and modelling assumptions

The network under study is the Holme Road 11kV network in Preston, UK, where current demand, which respects ER P2/6 standards, corresponds to 6.51MW and 2.14MVar. For this study, the DNO customer, demand and reliability data have been used.

The network comprises two feeders supplying 3700 domestic customers. The MG is interconnected at the Holme Road network as well and it serves a small residential community comprising 231 domestic customers. A simplified illustration of the network is given in Figure 6-6.

[9] Illustration is prepared by Dr. Eduardo Martínez Ceseña.

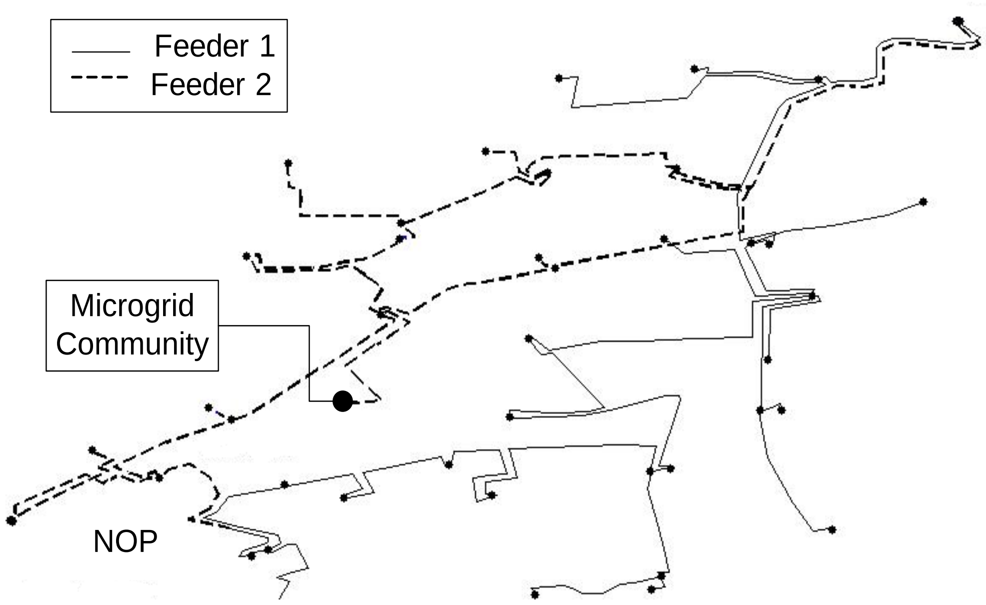

Figure 6-6: MG community connected in Home Road network

As discussed in Section 6.4, the MG adopts a combination of multi-generation technologies that supply both the electricity and heat needs of the community. The MG comprises (1) four 500 kW combined heat and power units with an electrical and thermal efficiencies of 35% and 45%, respectively; (2) two 1000 kW electric heat pumps with a coefficient of performance of 3; (3) a 200m^3 thermal energy storage unit; and (4) a 6000 kW gas boiler with an efficiency of 85% [40]. The configuration of the MG and the capacity of the different devises were optimised for the minimisation of energy costs for the community as detailed in [40]. As a result, the MG is oversized with respect to the electricity needs of the community, and it can use its spare electricity capacity to supply neighbouring customers that might become isolated following a fault, as described in Section 6.2.

At this point it should be also mentioned, that for the reliability analysis, exclusively the electricity needs of the customers are considered, thus analysing through the AC power flow only the electricity flows from and to the MG, and load demand profiles, while omitting the consumers' heat demand inside the MG.

Using reliability data from the local DNO, a failure rate of 0.1778/km has been used for feeder 1 and 0.1543/km for feeder 2. It is assumed that it would take the DNO 5 hours in average to connect a mobile generator to an area that has become isolated due to a contingency. Additionally, it is considered that manual operations of the NOP take 1 hour in average (also exponentially distributed for the SMCS). The reliability of the MG is assessed considering that the probability of the multi-generation equipment to meet the internal customers' needs is 99.04% and the probability that a fault in the distribution network will not affect the MG is 95%. Hence, the MG has a 94.08% probability of successfully transitioning to the islanding mode after a fault occurs in the distribution network. Finally, the emergency thermal rating of the distribution network is modelled by assuming that the lines could be overloaded by 20% beyond their normal rating for up to two consecutive hours (in accordance with current DNO recommendations).

The SMCS reliability modelling tool presented in Chapter 2 has been utilised for this work. It is already established that SMCS which is based on time series, is critical for a realistic assessment of reliability, as it facilitates consideration of the sequence restoration actions and dynamic ratings in the face of randomly located disturbances that may occur at period of high demand. The algorithm simulates the actual distribution system behaviour in detail; placing particular focus on properly reflecting the full restoration process, including isolation, switching, repair and corrective actions taken by the DNO and described the previous chapters. It is assumed that the operation and repair times of the components are exponentially distributed and sampling values of their failure and repair rates are randomly generated in each simulation. An hourly time series yearly demand is simulated, with a full AC power flow analysis, allocating random failures around the network. The system state is simulated through an AC power flow analysis with the aid of Matpower 4.1[61]and the modelling procedure described in the previous sections is based on Matlab®. The procedure is repeated for every hour of the year, skipping the cases where the distribution system state is normal. Finally, all reliability indices are calculated considering the characteristics of the network. The simulations are performed for a few thousand of iterations (at least 3.000), until the SMCS stopping rules have been satisfied (e.g., when the coefficient of variation is less than 5%). The spmd function has been used for the parallel computation of the study. The reliability levels are estimated for both the network and all customers (i.e., customers internal and external to the MG). Therefore, customer related indices (CI, CML), EENS, load point indices (frequency and duration of interruption) and MG related reliability metrics are evaluated and discussed for this case study.

Two demand scenarios are studied: one representing the current network conditions where demand is below P2/6 levels and another where demand is further increased by

50% exceeding P2/6 limits. After the increase, the aggregated active and reactive peak demand is equal to 9.77MW and 3.22MVAR respectively. Eventually, four cases are assessed based on the framework proposed in Section 6.2 and summarized in Table 6-1, comparing reliability indices when either introducing the MG, or not, the latter case accompanied by network reinforcement (to support the potential load growth).

Table 6-1: Case study scenarios

Case	Loading level	MG	Lines reinforcement
Base case-Below P2/6	Respecting P2/6	Without MG	No
MG case-Below P2/6	Respecting P2/6	With MG	No
Reinforced Base Case-Above P2/6	50% above P2/6	Without MG	Yes (50% above current capacity)
MG Case (no reinforc.)-Above P2/6	50% above P2/6	With MG	No

In this work, in both normal and emergency conditions, the distribution network capacity is estimated through iterative load flows, as discussed in [161], and is reached whenever voltage or thermal issues may prevent the network from supplying all customers (in the timeframe specified in P2/6) during emergency conditions.

6.5.2 Case study results and discussions

At first, load point indices EAFI and EADI are illustrated in Figure 6-7 and Figure 6-8, respectively. The indices are depicted for the four case studies. The location of the load points plays a crucial role to their reliability performance. That is, load points close to the primary substations, the NOP or close to very robust (in terms of availability) lines have low EAFI and EADI, whereas load points close to the end of the circuit or easily isolated in case of a fault experience the highest EAFI and EADI.

Note that the MG is connected in "load point 19", which belongs to Feeder 2 and, as a result, the associated EAFI and EADI for this load point are negligible. Furthermore, it is observed that many load point are extremely affected by the MG connection and present negligible EAFI and EADI in comparison with *Base case-Below P2/6* and

Reinforced Base Case-Above P2/6. Those load point are located also in Feeder 2, relatively close to the MG and hence their reliability improvement is attributed to the reliability and capacity support of MG in case of disturbance. It should be noted that reliability results are highly affected by the location of the MG. A sensitivity study on potential MG locations could help to identify the optimal MG location for the best reliability improvements or capacity contribution however this study is outside the scope of this work.

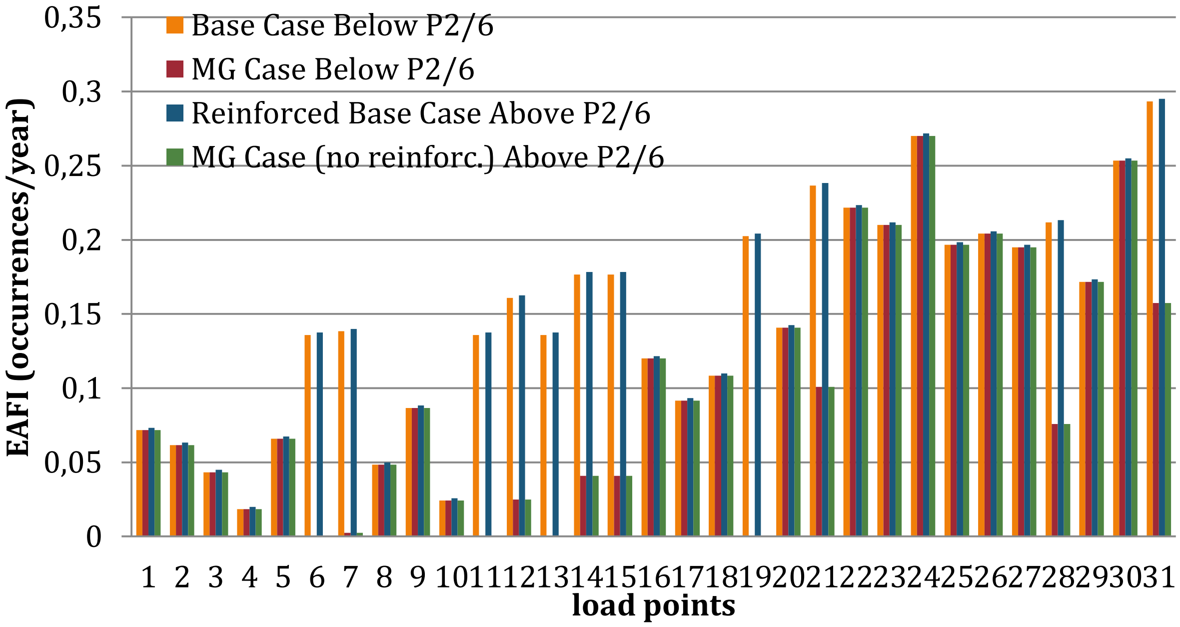

Figure 6-7: Expected annual frequency of interruptions for all scenarios

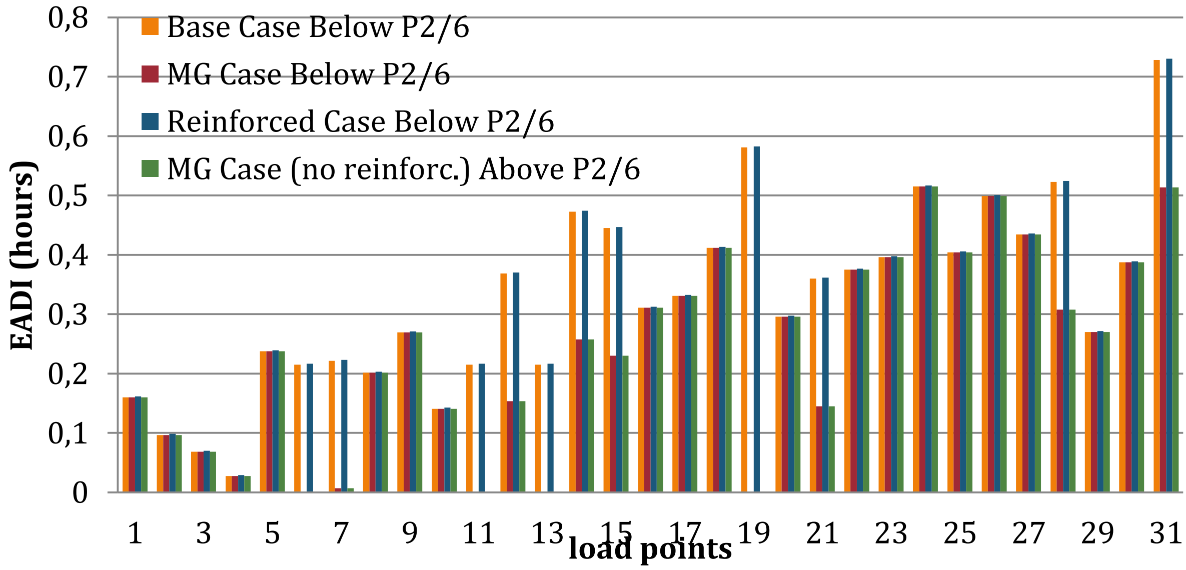

Figure 6-8: Expected annual duration of interruptions for all scenarios

Table 6-2 shows CI, CML and EENS for the different cases considered and the different types of customers for network loading below P2/6 levels. Equivalently, Table 6-3 presents the same indices for load demand above P2/6 levels. It can be observed, that the *MG case* always performs better than the alternative case. Even when comparing the reinforced network (‘*Reinforced Base Case-Above P2/6’)* with the current network without reinforcements when the MG is installed (‘*MG Case (no reinforc.)-Above P2/6’),* the latter shows better reliability performance, that is indices are lower. In addition, the MG community customers experience a high quality of supply, with almost negligible CI and CML as long as the MG is capable of supplying its own customers, with a high probability of a successful transition to the islanding mode. Finally, it is seen that the high quality of supply in the MG area improves the average reliability performance of the network without any network reinforcement by the DNO. Nevertheless, this effect could result in false impression about the actual reliability levels for system customers. For instance, the DNO should report to the regulator the CI and CML of ‘All customers’, although it can be observed that in reality, ‘external MG customers’ present worse indices than the reported ones. When load demand is increased by 50%, Table 6-3 shows that reliability indices follow similar pattern as in Table 6-2, with CI and CML ranging in similar values, and EENS being increased due to the increased demand.

Furthermore, Table 6-4 demonstrates further reliability indicators related with the MG reliability and operational performance. Those probabilities depend on the severity of the disturbance situation, which is a combination of the location of the fault and the network loading during that fault. It can be indicated that after a fault occurs there is a probability of 10.9% that the MG will provide reliability support to the DNO. Regarding the capacity support service, the MG is not required to provide this service when demand is below P2/6 levels, whereas, in this study, there is only a probability of 0.032% that the DNO would require this service even if the network is overloaded by 50% above P2/6 limits. This emphasizes the low probability of occurrence of a fault during a period of high demand, which is properly captured by the SMCS approach. The average frequency and duration of the islanded operations are also calculated. Those reliability indices give a clear insight of the actual utilisation of MG islanded operation services.

Table 6-2: CI (int./100 cust.) , CML(min./cust.) and EENS (MWh) for each case for all types of customers

Load demand Below P2/6 levels			
Base Case	**MG Case**		
All customers (network)	**All customers (network)**	**External MG customers**	**MG Community customers**
CI: 15.38 CML:20.26 ENS:1.07	CI: 12.22 CML:16.78 EENS:0.78	CI: 12.94 CML:17.76 EENS:0.83	CI: 0.72 CML:0.99 EENS:0.046

Table 6-3: CI (int./100 cust.) , CML(min./cust.) AND EENS (MWh) for each case for all types of customers

Load demand Above P2/6 levels (50% increase)			
Reinforced Base Case	MG case (no reinforc.)		
All customers (network)	All customers (network)	External MG customers	MG Community customers
CI: 15.54 CML:20.36 ENS:1.61	CI: 12.21 CML:16.77 EENS:1.17	CI: 12.91 CML:17.74 EENS:1.24	CI: 0.92 CML:1.21 EENS:0.095

Table 6-4: Reliability Metrics Related To MG Operation

	Below P2/6 levels	**Above P2/6 levels**
$\boldsymbol{P_{MG}}\{\boldsymbol{RS}\}$ (%)	10.9	10.9
$\boldsymbol{P_{MG}}\{\boldsymbol{CS}\}$ (%)	0	0.032
$\boldsymbol{\lambda MG_{island}}$ (occurrences)	0.202	0.204
$\boldsymbol{rMG_{island}}$ (hours)	0.58	0.58

6.6 Summary

This chapter has presented a framework for technical assessment of the reliability impacts of MGs on distribution networks when MGs could be used to provide network capacity support and reliability services. A specific sequential Monte Carlo based methodology has been introduced for such an assessment. A community based MG that supply both electricity and heat to its district energy systems and which is connected to a UK 11kV network has been used as case study example to illustrate the proposed concepts. The results have been expressed in terms of regulated reliability indices (CI and CML), classical load point reliability indices, EENS and another set of indices related to the MG islanded operation. The main outcome is that MGs can offer considerable reliability benefits showing a significant impact to customers internal and also external to the MG, when network support mechanisms are in place. Furthermore, the DNO could host significant load growth without the need of costly network reinforcements and without compromising the reliability of the distribution network.

7 Collaborative DER For Distribution Network Post Fault Services

Apart from the emergence of multi-generation technologies which could be inserted for various services in distribution networks, as introduced in the previous chapter, it is widely known that a large scale penetration of distributed energy resources such as Wind Farms (WF) and Electrical Energy Storage (EES) will be key attributes of future distribution networks. In this light, it is essential to develop a comprehensive understanding of how these resources actively affect reliability levels and distribution network reinforcement needs. In this chapter, it is discussed and assessed how WF and EES could contribute to network reliability by providing capacity during post fault operations, thus potentially deferring reinforcement needs that are triggered by load growth. A reliability assessment framework based on SMCS is used to quantify the reliability improvements owing to WF and EES. To this end, the classic concept of Effective Load Carrying Capability (ELCC) is used to calculate their capacity contribution. Different operational strategies for WF and EES are proposed and it is shown that collaborative resources could provide higher reliability improvements and consequently higher ELCC comparing to a stand-alone resource of non-collaborative ones[162].

7.1 Reliability Implications of power systems with DER

The electricity network is increasingly being characterized by a massive penetration of renewables [163] and novel Information and Communication Technologies (ICT) [164]. On the one hand, the large volume of variable renewables (e.g., wind) is challenging, and will continue to challenge, the operation and reliability of electricity distribution networks [165]-[12]. On the other hand, ICT can facilitate the commercial and operational interaction between different actors including, for example, Distribution Network Operators (DNOs), renewable energy resources such as Wind Farms (WF) and Electrical Energy Storage (EES) [166].

Utilisation of renewable energy resources such as wind and solar energy for electric power supply has received considerable attention in recent years due to global environmental concerns associated with conventional generation. Many countries have implemented or are in the process of implementing policies to promote renewable energy, such as a Renewable Portfolio Standard (RPS)[167]. Acceptance of the RPS is a commitment to produce a specified percentage of the total power generation from renewable sources within a certain date. Nonetheless, the available energy from wind and solar energy is intermittent and variable. To this end, large wind integration can produce large power fluctuations which risk the provision of a continuous power supply. Additionally, the amount of wind energy that can be absorbed by a power system at a particular time can be greatly limited as the available conventional units may not be able to respond to changes due to wind fluctuations. In order to use these energy sources as viable power generation, and also maintain the system stability, EES is incorporated to match the power supply with the instantaneous power demand.

Subsequently, EES could coordinate with WF to tackle the intermittency of wind power output [22] and is required to provide generating capacity. As far as the integration of EES in active distribution networks, it appears to improve their efficient operation and development. Through its potential of balancing fluctuations in the supply and demand of electricity, EES can introduce important benefits to the whole electric system. It has a significant impact on both ends of the network: to the generator side, storage has the potential to improve the generator's efficiency and to the end-user of the network, storage will enhance power quality and reduce peak loads.

In fact EES devices, located where utility distribution systems are approaching a capacity limit, can provide significant economic assessment. These benefits are associated with deferred or avoided distribution equipment upgrades that often involve a large increment in capacity such as the addition of a second transformer in a substation or refurbishment in a long line segment. Celli *et al*.[168]insist that if storage is located at critical points in the distribution system enhanced service reliability can be achieved.

In general, both EES and wind are proved to have significant positive impacts on the system reliability performance[169]–[171]. The impacts on system reliability and economics from WF and EES have been evaluated by many researchers in the literature [172]–[174]. In [172], SMCS is applied considering different operational strategies for WF and EES and calculating reliability through generation adequacy studies; thus, not analysing network conditions. In [173], composite energy storage and wind generation are operated in a transmission system and the reliability assessment is carried out based on a state-enumeration approach. In [174], an SMCS based adequacy and economy analysis of distribution systems integrated with EES and renewables is carried considering islanding operation; however, again network conditions are not taken into account. It can be seen that existing literature on reliability assessment of WF and EES requires the use of probabilistic approaches (e.g., state-enumeration [173]), among which SMCS is preferred when managing multiple sources of uncertainty, particularly when modelling the sequence of events (e.g., for post fault restoration sequence modelling). However, existing work tends to focus on generation adequacy, economic implications and/or smart operation (e.g., islanding) without explicitly modelling the network conditions, thus neglecting network voltage and thermal limits which are critical for distribution network analysis.

7.2 Proposed model for WF and EES post-contingency network support

On the above premises, a methodology based SMCS is proposed for the assessment of reliability of distribution networks with DER, while explicitly quantifying network impacts associated with different operational strategies of the resources involved. More specifically, full post fault restoration processes are simulated while capturing the significant variability of wind and load profiles and randomly located network faults. The classic concept of Effective Load Carrying Capability (ELCC) [175] is used to indicate the resources' capacity credit, within the context of potential load growth. The capacity credit is used to quantify increased distribution network capacity to be gained from different post fault operational strategies for WF and EES. Also, the economic benefits associated with this additional network capacity are given, as calculated in [162] based on the cost benefit analysis framework used by UK DNOs and relevant network reinforcement planning practices[176][177]. In particular, this work provides a techno-economic analysis of coordinating the operation of WF and EES in the context of future smart grids with significant ICT enabled automated infrastructure.

7.2.1 Proposed operation of WF-EES

It is firstly assumed that WF and EES operate independently, which limits the flexibility of EES to cope with WF fluctuations. This case of WF-EES operation would be hereinafter defined as *non-collaborative* operation. WF and EES provide capacity support as autonomous entities without interaction. This could happen for instance due to the lack of communication between the assets' owners. In this case, the EES would not use its flexibility to dispatch according to the wind variations. The overall available capacity is the sum of the individual ones.

Thereafter, assuming the aforementioned ICT infrastructure is in place, WF and EES collaborate to maximize network capacity support during post fault operations. This case of operation hereinafter is defined as *collaborative* operation. More specifically, it is considered that EES owners would have access to load consumption and wind power output forecasts during the post fault event. This operation could be offered to DNOs which, after paying a fee, could benefit from increased network reliability levels and/or postponed (even withdrawn) investments in distribution network upgrades. A high level diagram of the interactions between the considered actors is depicted in Figure 7-1.

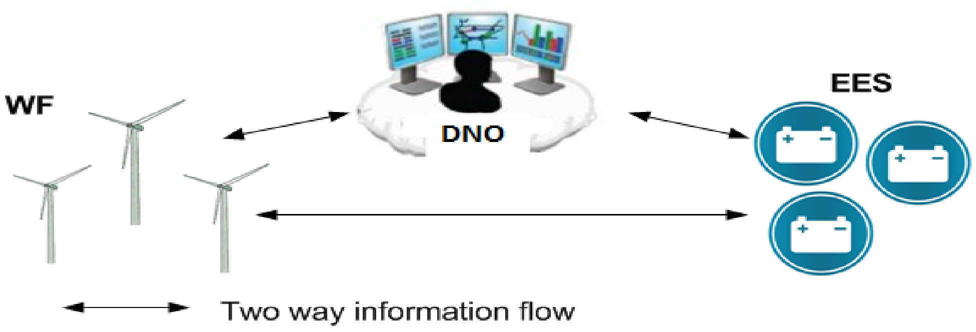

Figure 7-1: Interactions between actors for the collaborative operation of WF-EES

7.2.2 Modelling the WF

The power output of a wind turbine generator can be determined from its power curve, which is a plot of output power against wind speed. A typical power curve of a wind turbine generator is illustrated in Figure 7-2 . In general, a wind turbine generator is designed to start generating at the cut-in speed V_c and is shut down for safety reasons at the cut-out speed V_{co}. Rated power P_r is generated when the wind speed is between the rated speed V_r and the cut-out speed V_{co}. When the wind speed lies within the cut-in speed V_c and the rated speed V_{co}, the power output and the wind speed have a nonlinear relationship as shown in Figure 7-2.

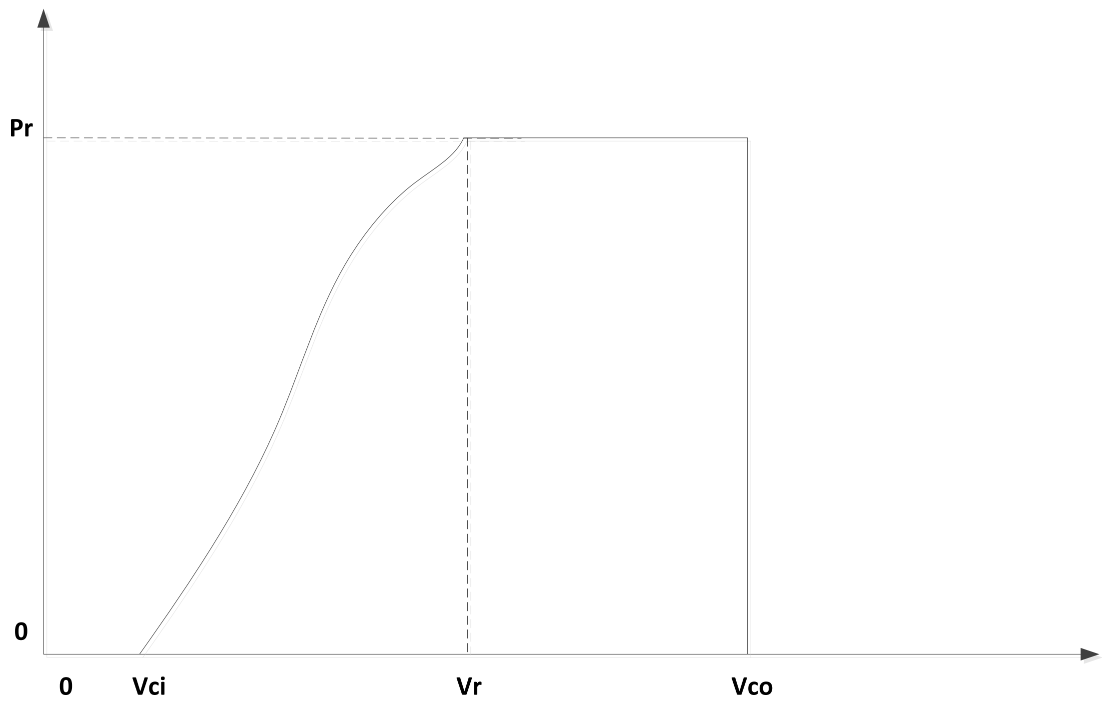

Figure 7-2: Power curve of a wind turbine generator

The power output of a wind turbine generator varies with the wind speed and is calculated using the following equations [178][171]:

$$\boldsymbol{P(V)} = \begin{Bmatrix} (\boldsymbol{A} + \boldsymbol{B} + \boldsymbol{C} \cdot \boldsymbol{V}^2) \cdot \boldsymbol{P_r} & \boldsymbol{V_{ci}} \le \boldsymbol{V} \le \boldsymbol{V_r} \\ \boldsymbol{P_r} & \boldsymbol{V_r} \le \boldsymbol{V} \le \boldsymbol{V_{co}} \\ \boldsymbol{0} & \boldsymbol{otherwise} \end{Bmatrix} \tag{7-1}$$

$$A = \frac{1}{(V_{ci} - V_r)^2} \cdot \left[V_{ci}(V_{ci} + V_r) - 4(V_{ci} \cdot V_r) \left[\frac{V_{ci} + V_r}{2 \cdot V_r} \right]^3 \right] \tag{7-2}$$

$$B = \frac{1}{(V_{ci} - V_r)^2} \cdot \left[4 \cdot (V_{ci} + V_r) \cdot \left[\frac{V_{ci} + V_r}{2 \cdot V_r} \right]^3 - (3 \cdot V_{ci} + V_r) \right] \tag{7-3}$$

$$C = \frac{1}{(V_{ci} - V_r)^2} \cdot \left[2 - 4 \cdot \left[\frac{V_{ci} + V_r}{2 \cdot V_r} \right]^3 \right] \tag{7-4}$$

As far as the reliability model of the WF is concerned, since the WF consists of many identical wind turbine generators, in order to find the probability of each state (where a unit or more are on forced outage rate), the bionomial distribution is used in which the probability $P\{r\}$ of a specific state $\{r\}$ is given by equation (7-5), where n is the number of units, r is the number of available units, p is the availability of each unit and q is the unavailability of each unit.

$$\boldsymbol{P}\{\boldsymbol{r}\} = \frac{\boldsymbol{n}!}{\boldsymbol{r}!\,(\boldsymbol{n}-\boldsymbol{r})!} \cdot \boldsymbol{p}^{\boldsymbol{r}} \cdot \boldsymbol{q}^{\boldsymbol{n}-\boldsymbol{r}} \tag{7-5}$$

7.2.3 Modelling the EES

Regarding the EES modelling, the fundamental parameters of EES that have to be considered are the energy capacity, charging and discharging power ratings and finally charging and discharging efficiencies. More specifically, the maximum demand reduction that can be provided by EES is equal to its discharging power rating.

During the charging process, EES behaves as an additional load in the system, and it could use electricity from the grid or surplus wind generation to get charged. During the discharging process EES behaves as generation since it dispatches to supply load.

For this study, EES is used for post fault operation where in order to provide additional network support, it dispatches to supply load either in collaboration with the wind generation or independently. Therefore, we focus only on the discharging process of EES. More specifically, it is assumed that a specific amount of EES energy is reserved for post fault operation. Regarding the discharging power rating of the storage, this is not explicitly predefined, but it is constrained by the levels of energy stored and discharging duration as it will be explained below. Additionally the discharging efficiency is assumed to be 100%.

For the case that EES operates independently either because there is no communication with the WF (non-collaborative operation) or because it acts autonomously, the discharging power rating $R_{d,b,t}^{max}$ of an EES located at bus b for each contingency hour t, of a contingency period T_{con} starting at hour $t_{start}$is given by (7-6). Thereinafter, the discharging power output $R_{d,b,t}$ for each contingency hour t is determined during the network power flow analysis and depends on demand needs and network conditions at each time $t.$ At the end of each contingency period the levels of energy stored in the EES are updated, as observed in (7-7).

$$\boldsymbol{R_{d,b,t}^{max}} = \frac{\boldsymbol{E_{t_{start},b}}}{\boldsymbol{T_{con}}} \tag{7-6}$$

$$E_{t_{start}+T_{con},b}=E_{t_{start},b} - \sum_{t=t_{start}}^{t_{start}+T_{con}-1} R_{d,b,t} \tag{7-7}$$

Where $E_{t_{start},b}$is the energy capacity stored at the EES located at bus b at the time slot we enter the contingency and $E_{t_{start}+T_{con},b}$ is the remaining energy capacity at the end of the contingency period.

Additionally, regardless the EES operation, the following restrictions need to be respected:

$$\boldsymbol{E_{min,b} \leq E_{b,t} \leq E_{max,b}} \tag{7-8}$$

$$0 \leq R_{d,b,t} \leq R_{d,b,t}^{max} \tag{7-9}$$

$$0 \leq R_{d,b,t}^{max} \leq R_{max,d,b} \tag{7-10}$$

In (7-8) $E_{min,\boldsymbol{b}}$ is the bottom energy level that has to be held and is defined from the depth of discharge of the specific device and $E_{max,b}$ is basically the energy capacity of the EES located at bus b. In (7-10) $R_{max,d,\boldsymbol{b}}$ is the device nominal discharging power rating.

7.2.4 Modelling the collaborative operation of WF-EES

In the collaborative operation of WF-EES, EES is discharged to compensate for wind power variations. More specifically, EES targets to maximise the overall capacity support to the network by filling the gaps between the expected wind power outputs and load consumption during the contingency period. Therefore, in contrast with the non-collaborative operation, where the EES output could be a constant value for a certain period, in the collaborative operation, EES output varies throughout the contingency period, depending on the wind variation with respect to the load profile.

The algorithm for the collaborative WF-EES operation, which has been developed in [162][10], aims to maximize the capacity that can be constantly provided by these two resources during the whole post fault event and is described in Table 7-1.

Table 7-1: Collaborative operation of WF-EES, steps of the algorithm

Step 1: Identify contingency period $\boldsymbol{T_{con}}$

Step 2: Identify the minimum wind capacity level C_{wind} (lowest value of wind power output throughout T_{con})

Step 3: Superimpose the load time series on the wind time series to identify the time slots $[X_{EES}]$ where load demand is higher than wind power output. The positive margin indicates the amount of energy required to be dispatched from the EES.

Step 4: Discharge EES during time slots $[X_{EES}]$, by starting from the slot with the lowest wind power output.

Step 5: The scheduled amount of discharging power output of the EES per slot is the minimum between 1) the energy required during the time slot and 2) the difference of wind power output of the next and the current time slot-aiming to reach the next wind capacity level which is higher than C_{wind}

[10] Modelling of the collaborative algorithm done by Dr. Eduardo Martínez Ceseña.

7.3 Evaluation of Capacity Credit for the WF and EES

The concept of capacity credit is used to quantify the contribution of different generation technologies to supporting demand. The concept was initially developed in the context of only conventional generation systems [175] but with the integration of different variable renewable technologies such as wind, there has been an increased interest on quantifying the contribution of those technologies [179]. The main difference with the conventional units lies on the fact that renewables depend on uncertain natural resources thus not generating at a rated constant capacity.

Traditionally for generation resources, Effective Load Carrying Capability (ELCC) [175], Equivalent Firm Capacity (EFC)[179] and Equivalent Conventional Capacity (ECC) [180] are the common and well-established metrics to use for capacity credit evaluation. Recently, the capacity credit for demand side resources such as EES and DR has been investigated, since they can potentially displace generation plants. ELCC metric is applied for DR in [181][182] and ECC metric for EES [183]. Finally, authors in [184] have carried out a systematic analysis of the impact on capacity credit of the parameters that characterise EES and DR and developing a comprehensive framework to evaluate the capacity credit of those demand side resources.

In this study, the concept of ELCC is selected for the evaluation of wind and storage capacity credit. Therefore, this capacity credit evaluation method is described subsequently in more detail. The ELCC measures the capacity credit of a new generation source (WF only, EES only, or both) by also adding a new virtual load to the system along with the new generation. Accordingly, the capacity contribution of a resource is defined to be the additional load that could be supplied by the network on the condition that the original reliability level is preserved. It should be noted that at this point, original system is the system before the addition of the new generation and the new virtual load. The reliability level here is represented by the *EENS*. The concept of ELCC is illustrated in Figure 7-3 and the steps for the ELCC calculation are summarized in Table 7-2.

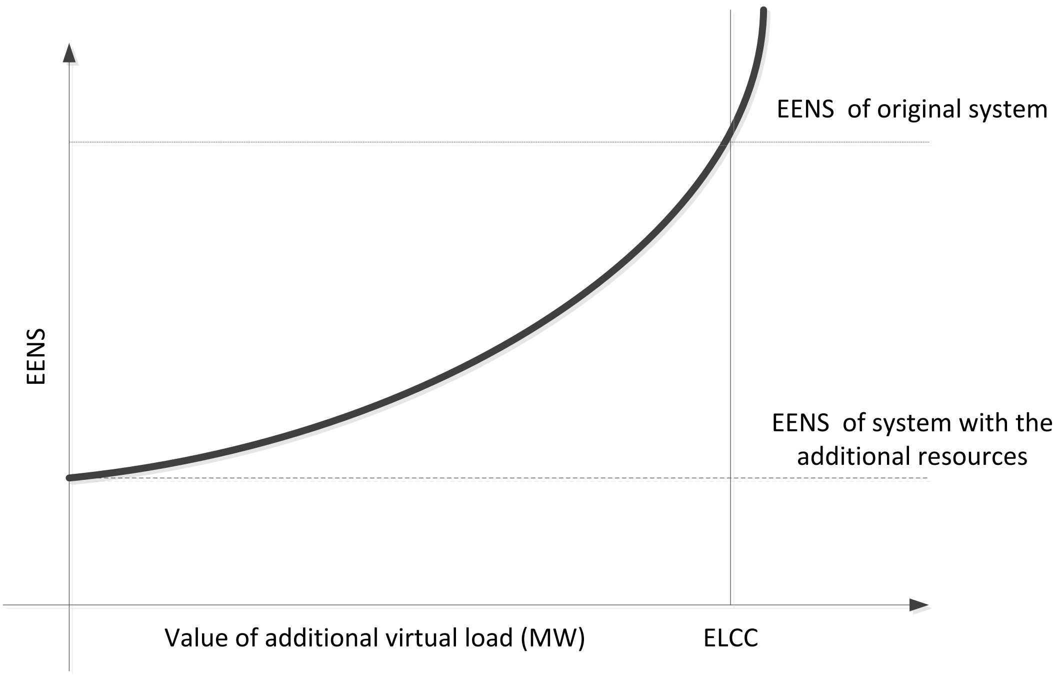

Figure 7-3: Illustration of ELCC definition

Table 7-2: Steps of the methodology to calculate ELCC

Step 1: Calculate reliability level $\boldsymbol{EENS_{orig}}$ in the original system (no WF or EES installed/original load profile)
Step 2: Add the new DER generation (WF only/EES only/both) , calculate reliability level $EENS_{modif}$
Step 3: In the new DER system, start increasing the load demand until $EENS_{modif}$ reaches $EENS_{orig}$. The ELCC is the value of this additional load.

Note: Reliability calculations are performed through SMCS

7.4 Case study

In this section, the proposed approach is demonstrated on a real UK distribution network. A WF and EES are inserted in the network under various operational strategies, examining at first the reliability impacts that they would infer and then the capacity contribution through the concept of ELCC.

7.4.1 Description of cases for the different WF-EES operation

Five cases for the operation of WF and EES are considered, as discussed in detail below:

- **Case 1 (C1): Baseline**: In this case, there are no resources integrated in the network. Thus, the amount of load that is above the maximum load that the network can supply during post fault operations is curtailed. This would be represented by the reliability level of the original network ($\boldsymbol{EENS_{orig}}$).
- **Case 2 (C2): WF**: Only a WF is connected to the network in this case. The WF's capacity contribution is determined by the maximum wind output power that constantly lasts throughout the fault period. In other words, this is a capacity that WF guarantees to provide continuously. For instance, if the wind output power was expected to be zero at any time during the fault period, the WF's capacity contribution would be zero as it failed to provide a capacity constantly. Regarding the WF post fault operation, the wind power output above the certain
- **Case 3 (C3): EES**: Only EES is connected to the network in this case, whereby the capacity contribution from EES is the maximum discharging power that, similar to WF, lasts throughout the fault period. More specifically, this discharging power is determined by the energy reserved for the fault and the duration of the fault.
- **Case 4 (C4): Non-collaborative WF-EES**: WF and EES provide capacity support independently (for instance due to the lack of communication between the assets' owners). In this case, the EES would not use its flexibility to dispatch according to the wind fluctuations. The overall available capacity is the sum of the individual ones.
- **Case 5 (C5): Collaborative WF-EES**: In this case EES is discharged to compensate for wind power variations. More specifically, EES targets to maximise the overall capacity support to the network by filling the gaps between the expected wind power outputs and load consumption during the fault period.

With the assumption that any load in C1 would trigger the need for network reinforcement, the integration of WF and EES enables the network to withstand a certain level of load growth without demanding network reinforcement. This level of load growth would be quantified as the capacity credit of WF and/or EES in line with the concept of ELCC, as mentioned earlier.

The impact of each case on the network capacity needs is depicted in Figure 7-4.

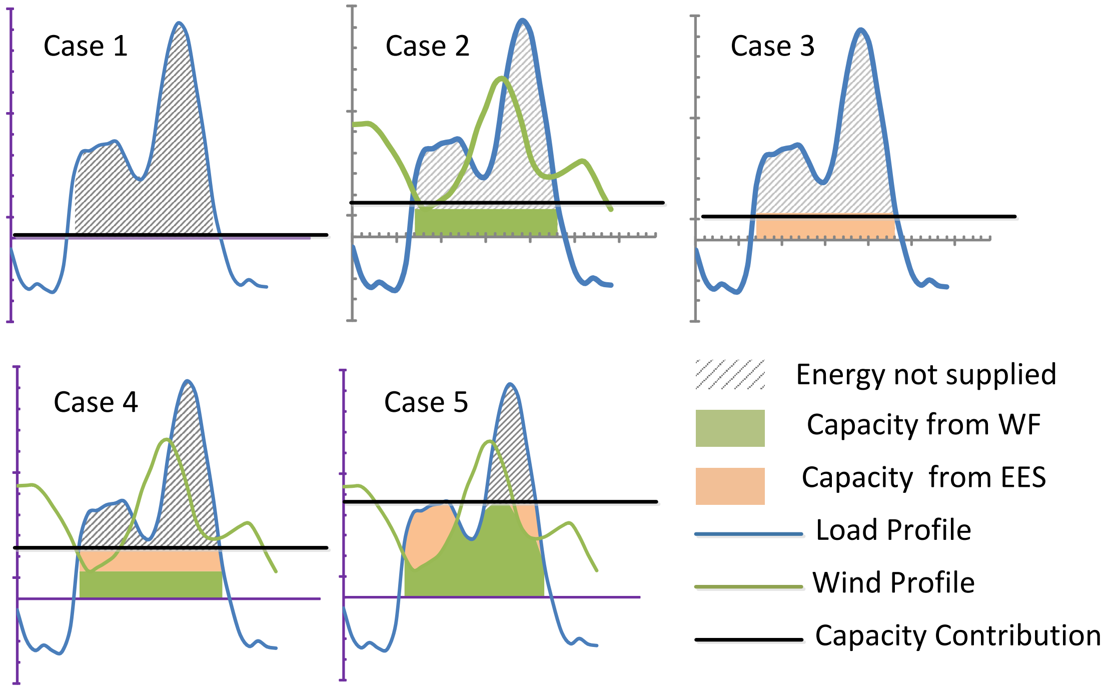

Figure 7-4: Cases for the different WF-EES operational strategies [11]

7.4.2 Overall methodology description

SMCS is again used for this set of studies since it allows proper modelling of the sequence of restoration actions, auto-correlated wind profiles and EES charging and discharging process. This is critical for a realistic assessment of reliability in the face of inter-temporal constraints of the aforementioned resources [99].

The full restoration process includes isolation, switching, and repair and corrective actions taken by the DNO (the SMCS reliability modelling has been applied). For every sample year, random time to failure/repair and switch are generated for the components using exponential distribution functions. The simulation platform uses Matlab® and Matpower 4.1[61] for a full yearly AC optimal power flow[12] (OPF) of hourly resolution, making the rational assumption that the DER resources are cheaper comparing to the

[11] Illustration are prepared by Dr. Yutian Zhou.

[12] Generation cost data of the DER resources and conventional generation are expressed through polynomial cost functions in Matpower formulations.

distribution network conventional generation injected from the distribution substation. In order to deal with the computational complexity of the simulations, including also the long repetitive process to calculate the ELCC, the Condor Pool [69] has been utilised.

Regarding now the specific network modelling operations it is considered that WF and EES are called to provide capacity support during post fault operations. However, load curtailment would also be initiated by the DNO if the additional capacity provided by WF and EES is not enough to maintain voltages and currents within limits. Hence, loss of supply could be attributed directly to either a failure or a corrective curtailment, and consequently deteriorates the reliability level (reliability indicators increase). Besides load curtailment, another corrective action considered is to update the tap ratio of the 11kV/400V transformers in case of voltage violations. The overall methodology for the network operations during the simulation period is summarized in Figure 7-5.

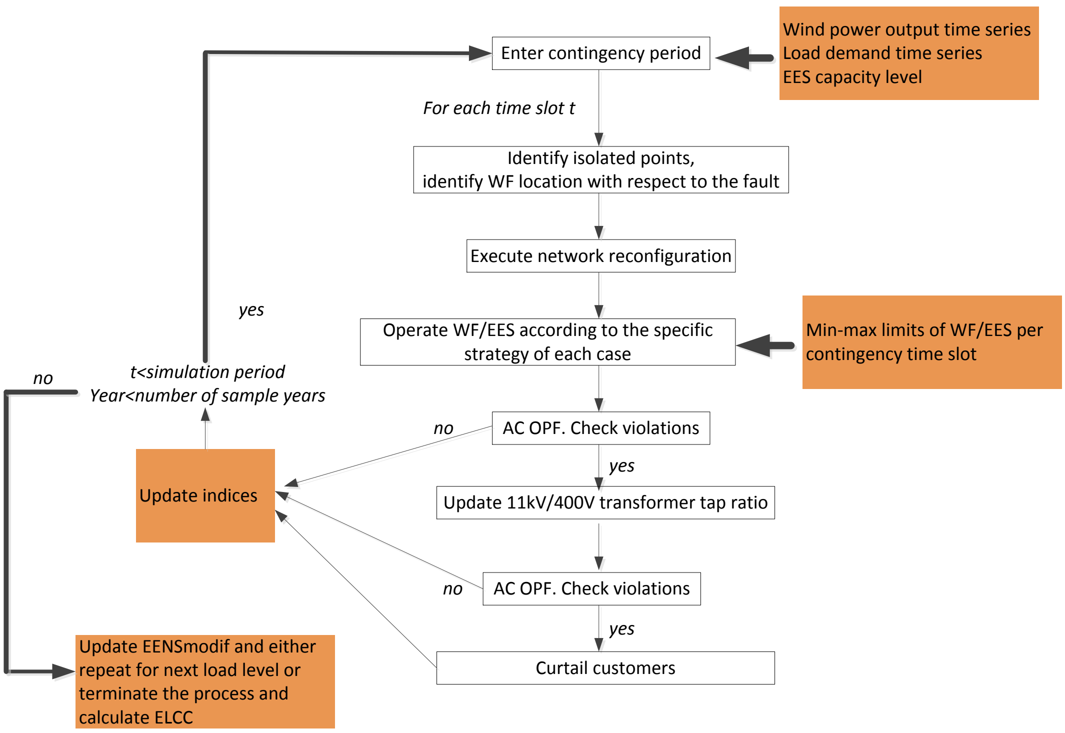

Figure 7-5: Operations during contingency period

7.4.3 Input data

One of the test networks provided by the local DNO has been selected for the purposes of the study. The network comprises two radial feeders, interconnected through a normally open point, which supplies mostly residential and commercial customers (modelled as Profile Class 1 and 4 [185]). Currently, the network is oversized and there is no need for network capacity. Therefore, for the sake of illustrating the proposed approach under realistic conditions, demand has been scaled up (i.e., 9.51 MW peak) without compromising the reliability targets of the UK regulator (i.e., Ofgem) [186]. For the cases that DER are introduced in the network, the WF is located in load bus 13 and EES devices have been connected in every load bus. The network illustration can be visualized in Figure 7-6.

As suggested by the relevant DNO [106], a failure rate of 0.1778/km has been used for feeder 1 and 0.1543/km for feeder 2, and fast automatic switching operations (i.e., within three minutes) are considered. However, it is important to note that the approach is flexible enough to consider other alternatives (see e.g. [131]).

Wind speed yearly data for a period of 33 years have been extracted from a freely available model of University of Reading, which uses MERRA re-analysis wind speed data[187]. For each sampling year the SMCS randomly selects an hourly wind profile for a full year (from the 33-year database). The power output of the WF is then estimated using the power curve model presented in [178] and assuming a capacity of 4.6MW (see ‘Lowca’ WF [188], which can be a representative case for WF at the distribution level).

In order to explore the impacts of EES, three different energy capacity levels are considered in the case study, including 1 MWh, 3 MWh and 5 MWh (denoted by subscripts a, b and c respectively). It is assumed that the specific amount of energy is reserved for post fault operation and it reflects the total energy capacity which is the sum of each specific device. Regarding the charging and discharging rate of the storage, as explained explicitly in 7.2.3, this is not predefined, but it is constrained by the levels of energy stored and discharging duration.

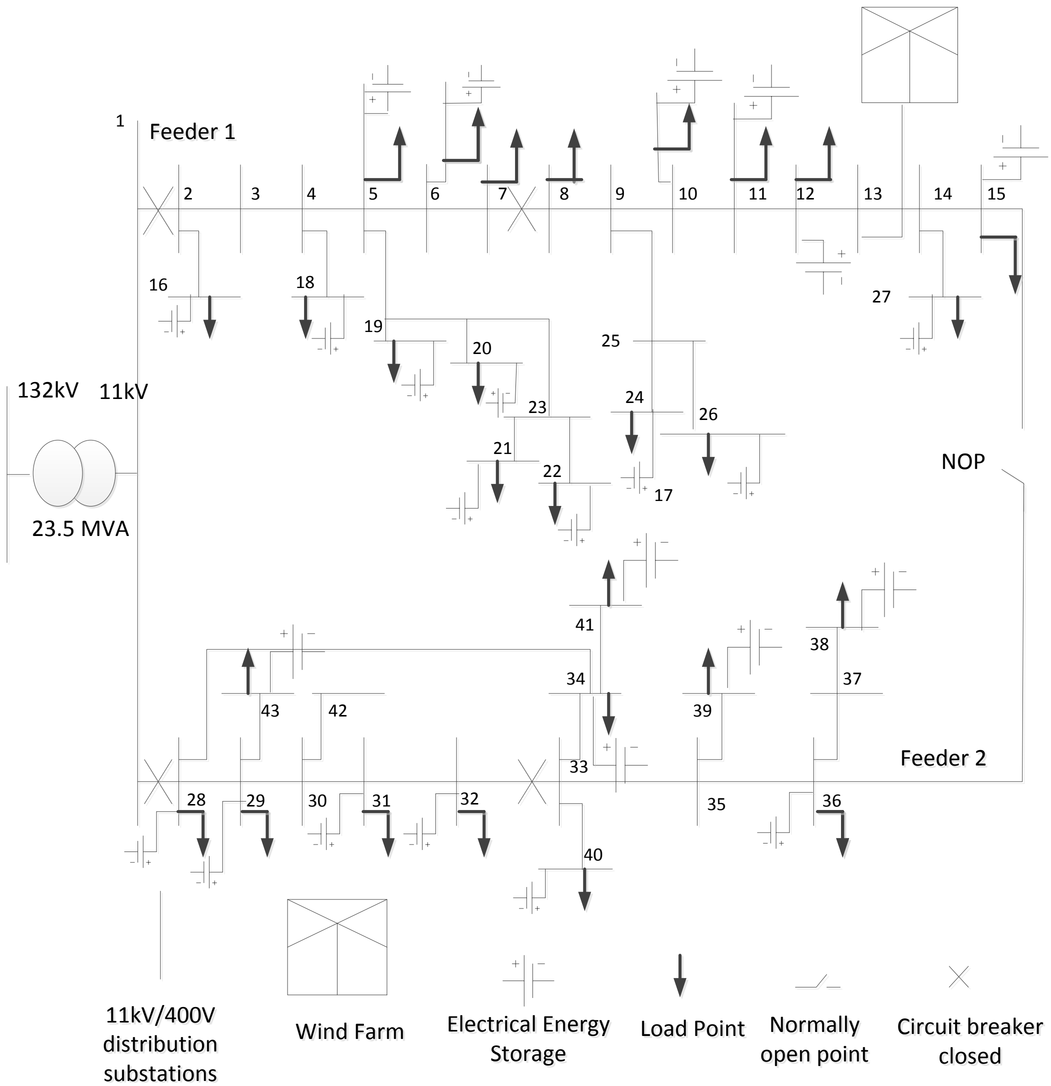

Figure 7-6: Case study distribution network

7.4.4 Results and discussions

The results of the study (for C1 to C5 with selected levels of EES) for a range of load growth are presented in Figure 7-7 to Figure 7-9. Note that the original reliability level is represented with the subscript *orig*.

The baseline case C1 is shown for comparison purposes. It can be seen that the introduction of WF (C2) provides a mild reliability improvement (similar performance to $C3_b$). Reliability is further improved when both devices are operated (C4 and C5). However, it can be noted that the collaborative operation performs much better than the non-collaborative one ($C5_c$ better than $C4_c$). Interestingly, it can be seen that when the resources collaborate, a smaller level of storage is required for a similar reliability performance with non-collaborative resources ($C4_c$ performs similarly to $C5_b$). Finally collaborative resources with small storage level perform better than a stand-alone EES of a higher level ($C5_a$ better than $C3_b$)

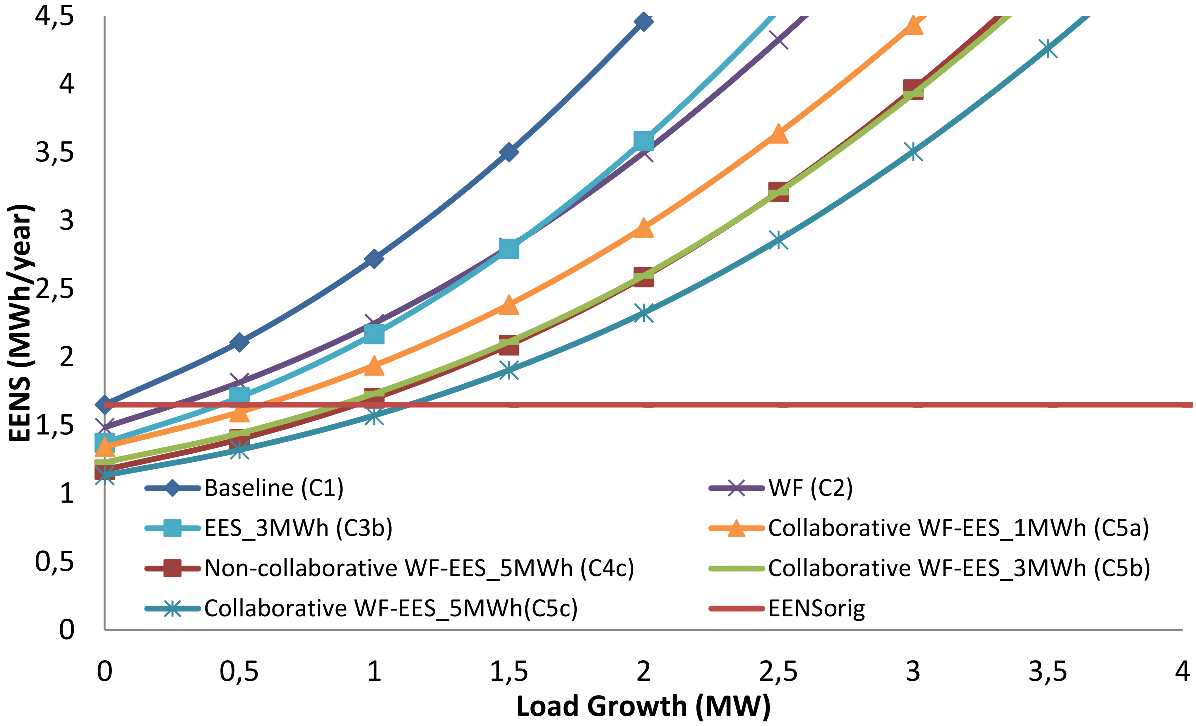

Figure 7-7: Impact of load growth on EENS for various scenarios

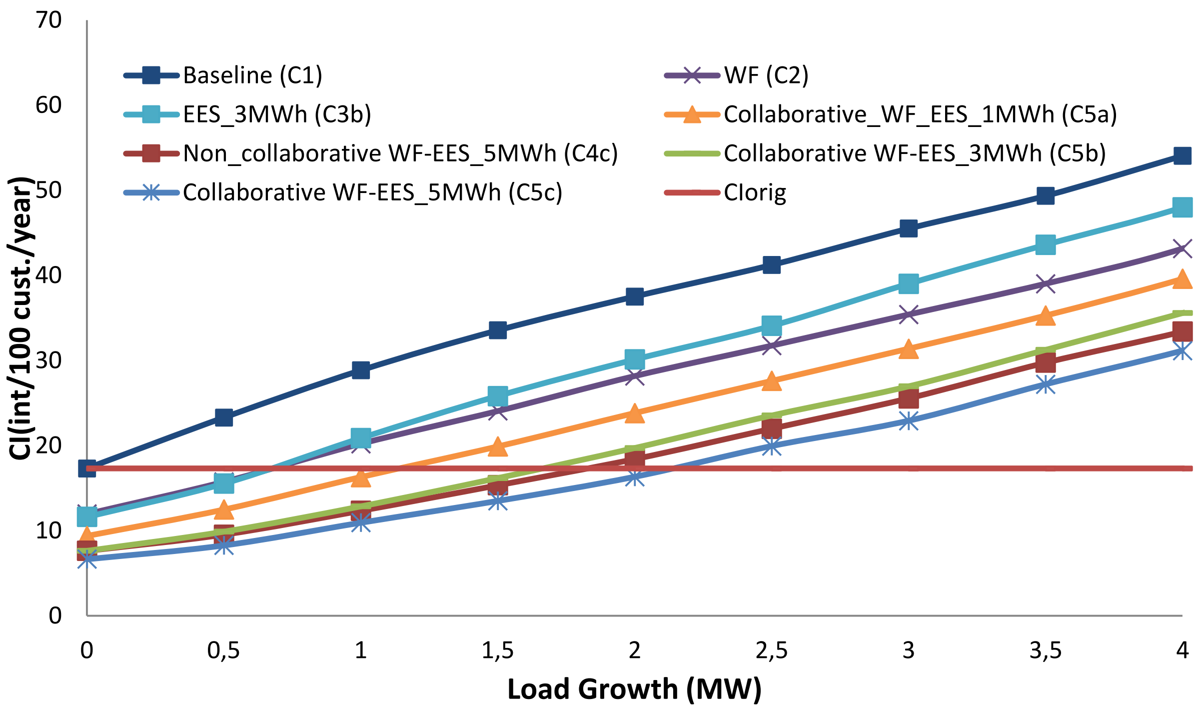

Figure 7-8: Impact of load growth on CI for various scenarios

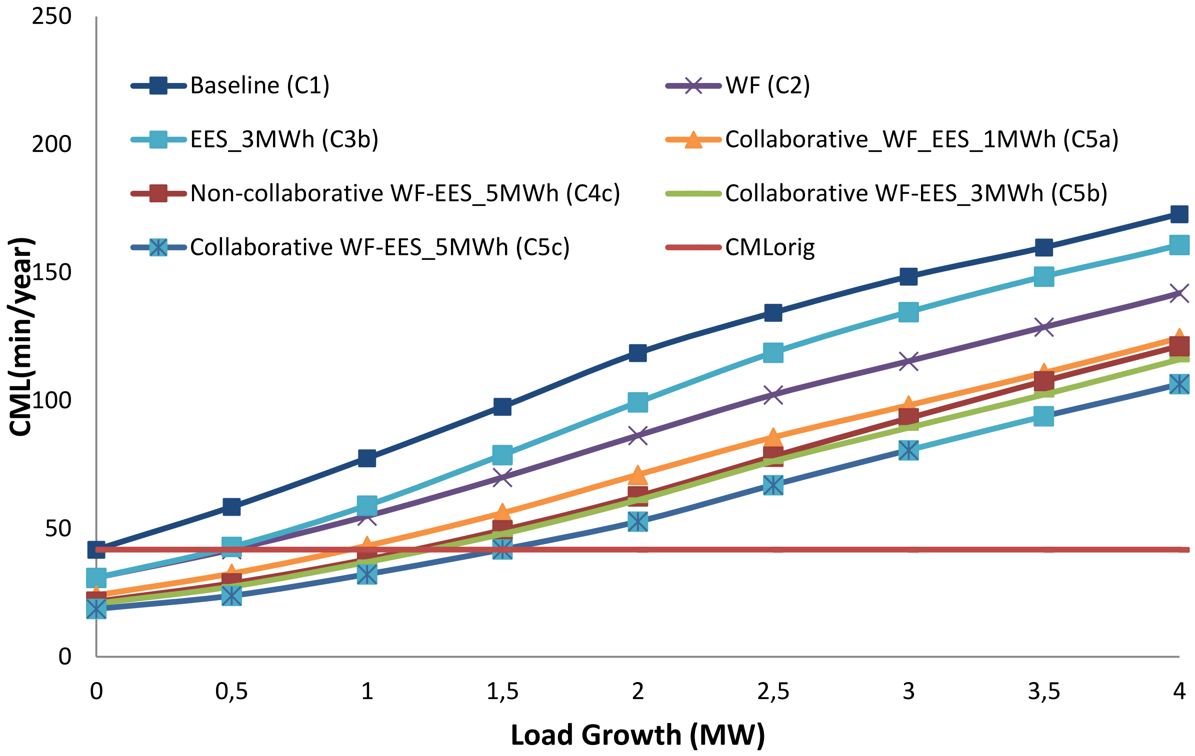

Figure 7-9: Impact of load growth on CML for various scenarios

The impact of different operational strategies on the reliability indices can be justified in a more straightforward manner from the probability of occurrence of a corrective load curtailment. In case the network capacity and the contribution provided by the DER resources are not sufficient, then the curtailment of network customers is initiated (as explained in 7.4.2). Subsequently, reliability indices deteriorate.

In particular, how a specific operational strategy (case) performs is related to the uncertainty around 1) the location of the fault, 2) the load demand during a fault and 3) the wind power output during the fault. The network capacity requirements highly depend from the above-mentioned factors and could greatly vary subject to them. This is properly captured by the probabilistic analysis carried out. The probability of corrective load curtailment for the different scenarios is depicted in Figure 7-10.

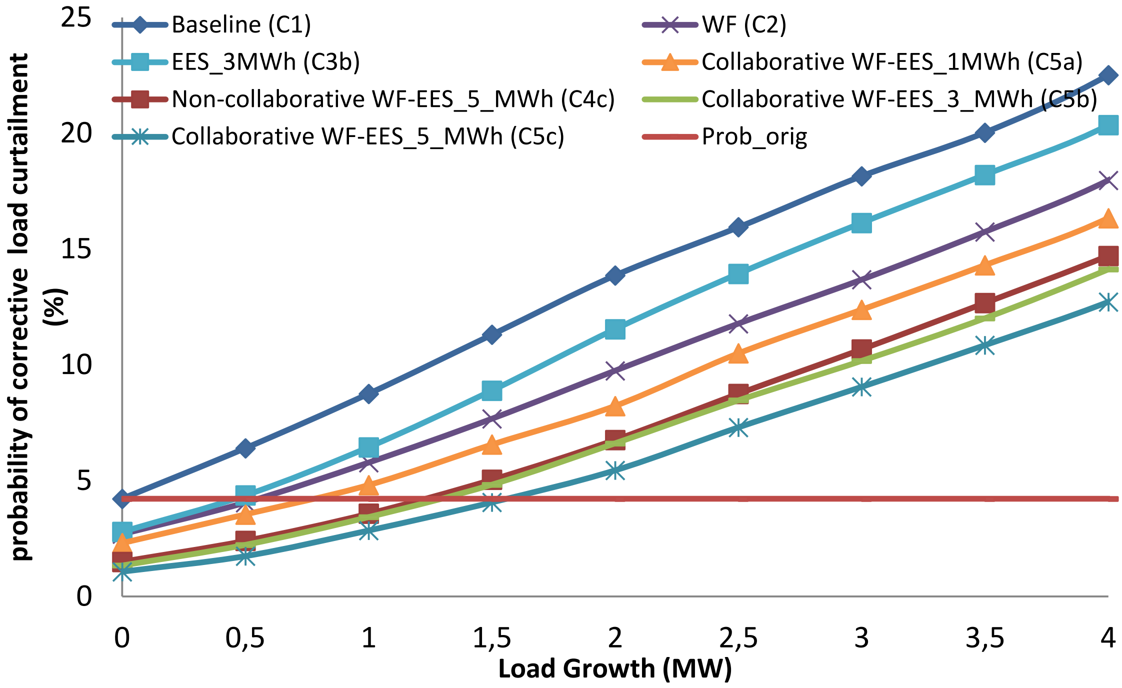

Figure 7-10: Probability of corrective load curtailment for the different scenarios

The premise that collaborative behaviour (C5) outperforms other alternatives is corroborated in terms of *EENS*, *CI* and *CML*, also with the results presented in Table 7-3. For the sake of simplicity, only a specific load growth (2MW) and storage capacity (5 MWh) levels are presented.

It is also worth mentioning that $C5_c$ is the only scenario that complies with the Ofgem reliability targets after the corresponding load growth. This implies that the need for network reinforcement can only be withdrawn on condition that the integrated WF and EES operate collaboratively; otherwise, network reinforcement is inevitable though the same amount of WF and EES are in the network.

Table 7-3: Reliability indices for the different cases

[Ofgem *CML*=55.6] [Ofgem *CI* =55.2]	EENS (MWh/year)	CML min./year)	CI (int.100cust/year)
C1 (Baseline)	4.46	118.58	37.50
C2 (WF)	3.5	86.37	28.16
$C3_c$ (EES_5MWh)	3.14	86.8	25.35

$C4_c$ (non-collaborative WF-EES_5MWh)	2.59	62.68	18.40
$C5_c$ (collaborative WF-EES_5MWh)	2.32	52.78	16.32

The capacity credit for the different scenarios in Figure 7-7 to Figure 7-9 is presented in Table 7-4. It can be observed that $C5_c$ has the highest ELCC value. Additionally it can be seen that when the resources collaborate they could perform similar to non-collaborative resources with a smaller size of EES ($C5_b$ similar to $C4_c$). The capacity credit of collaborative WF-EES is always higher compared to non-collaborative resources of the same level of EES ($C5_c$ higher than $C4_c$). Additionally it is interesting to observe that collaborative resources of a small level of EES could give a higher capacity credit of a stand-alone EES of a higher size ($C5_a$ higher than $C3_b$).

As shown in [162] in order to estimate the economic benefits for DNOs from the additional network capacity provided in each case, the quantified capacity credit is used to calculate DNO revenues in terms of the Net Present Value (NPV). The NPV is taken as the discounted savings between optimal network reinforcements with and without the additional capacity associated with each case and is subject to several realistic load growth scenarios detailed in [177].

For this work, the scenario based CBA framework created in [161] [72] has been used, which is in line with emerging UK regulations based on the new Revenues = Incentives + Innovations + Outputs (RIIO) price control scheme [189]. The new RIIO price control is expected to incentivise DNOs that develop or implement novel distribution level solutions that may lead to reduced investment costs or provide other benefits. In this regard, Ofgem introduced a deterministic CBA framework for DNOs to assess new asset investments based on “RIIO”. According to Ofgem’s CBA framework, DNO investment costs associated with the implementation of a distribution network solution should be assessed based on the Net Present Costs (NPC) criterion as denoted by equations (7-11) – (7-17) which are taken from[190].

$$\boldsymbol{Capitalized\_Inv_y = 0.85 \times \sum_{n=1} Inv_{n(y),y}} \tag{7-11}$$

$$Expensed\_Inv_y = 0.15 \times \sum_{n(y)=1} Inv_{n(y),y} \tag{7-12}$$

$$Dep_y = \sum_{y1=1}^{y} \frac{Capitalized\_Inv_y}{Dep\_Lifetime} \tag{7-13}$$

$$RAV_y = Capitalized\_Inv_y - Dep_y - RAV_{y-1} \tag{7-14}$$

$$CC_y = RAV_y \times WACC \tag{7-15}$$

$$DNO\_Inv_y = Expensed\_Inv_y + Dep_y + CC_y \tag{7-16}$$

$$NPC = \sum_{y=1}^{45} \frac{DNO\_Inv_y}{(1+d)^y} \tag{7-17}$$

Where $Capitalized\_Inv_y$ and $Expensed\_Inv_y$ are shares of the investment costs ($Inv_{n,y}$) that can be recovered over time and immediately, respectively; Dep_y is the depreciation of all capitalized investments over the depreciation lifetime $Dep\_Lifetime$, RAV_y is the regulated asset value. CC_y is the cost of capital, $WACC$ is the pre-tax weighted average cost of capital (which is 4.2% for ENWL). DNO_Inv_y are the investment costs incurred by DNOs in a given year. Finally, the subscript $n(y)$ denotes the n-th intervention's investment associated to a network solution in year y, and the subscripts y and $y1$ denote time periods (years).

DNO revenues in terms of the NPV are presented in Table 7-4 as calculated from [190] and retrieved from [162]. Results in Table 7-4 provide further evidence that collaboration between WF and EES can provide attractive capacity and economic contributions compared with other alternatives (including non-collaborative behaviour).

Table 7-4: ELCC and DNO NPV for different scenarios[13]

Cases		ELCC (MW)	DNO NPV ($£x10^3$)
C2	**only WF**	0.25	115
$C3_b$	**EES_3MWh**	0.42	192
$C5_a$	**Collaborative WF-EES _1MWh**	0.58	260
$C4_c$	**Non collaborative WF-EES_5MWh**	0.94	404
$C5_b$	**Collaborative WF-EES_3MWh**	0.86	390
$C5_c$	**Collaborative WF-EES_5MWh**	1.12	428

7.5 Conclusion

This chapter has presented a probabilistic assessment associated with the reliability implications of using distributed energy resources such as WF and EES for post fault services. The capacity credit associated with those resources has also been evaluated using the well-known ELCC concept. A collaborative operation of those resources has been proposed, and more specifically the optimal scheduling of the EES during the post fault operation so as to maximize the wind power utilisation.

The studies have been developed and performed within a SMCS framework allowing the full use of time series analysis. This approach enables the actual capacity requirements of the considered resources to be properly captured during a random contingency. This information could be important for the DNO in case they would like to evaluate the network capacity needs due to load growth. Furthermore, the capacity credit calculated for WF and EES could be a representative value to encourage services and interactions between DNOs and other actors against DNO infrastructure interventions. Regarding the different operational strategies, it is shown that

[13] DNO NPV calculations are performed by Dr. Eduardo Martínez Ceseña.

collaborative resources could provide higher reliability improvements and consequently higher ELCC comparing to a stand-alone resource of non-collaborative ones.

8 CONCLUSIONS AND FUTURE WORK

The final chapter summarizes the research performed in this thesis and the main conclusions that can be drawn from the results and case studies. Proposed areas of further research are also outlined.

8.1 Discussions and Summary

The significant penetration of DG, the development of DER such as DR and storage and the technological advances, challenge the traditional regulation, operation and planning of power systems.

In particular, ICT evolution in the form of automated equipment, sensors, actuators, smart switches, but also Ubiquitous Computing and Internet of Things facilitate active network management, the active participation of consumers and real-time decision making. For this thesis, the afore-mentioned ICT advances have been implemented to assist corrective network actions initiated by DNOs or other actors who benefit from providing services to the DNOs. In addition, the services provided are exclusively post fault capacity services in order to provide network support after a system disturbance either to avoid additional congestion, either to reduce load curtailment and improve the continuity of supply for network customers, or in a broader sense to avoid network reinforcements. This corrective philosophy would change the traditional concepts of system security which are based on conservative methods such as the N-1 security.

As a consequence, deterministic ways of assessing the level of risk would no longer reflect the requirements for evaluation of risk in a smart distribution network and should be replaced by probabilistic measures. In this sense, stochastic nature of the resources involved, uncertainty around the failure of the equipment, weather uncertainty, uncertain load growth and, complex interdependencies between the power system components, etc., could be accurately captured and modelled by probabilistic assessment.

To this end, the research work in this thesis has established a comprehensive probabilistic framework for reliability and risk analysis of smart distribution networks. In this context, numerous technologies have been studied including DR, MGs, electrical energy storage, wind farms, time-limited thermal rating, ICT infrastructure for active management and various smart grid services. Considering that the proposed service is post fault network support, the stochasticity around the parameters and distribution network constraints, the modelling framework is based on a SMCS analysis which also includes the network analysis through power flow simulations and the detailed modelling of the operations and the components.

The work conducted in this thesis can be summarized below:

- **A probabilistic framework based on SMCS has been developed (the SMCS reliability modelling tool).** The built framework takes into account the stochastic failure nature of the electrical components such as lines and switches, but also the ICT components of a management system such as routers, antennas and wireless signal. Typically, the simulation period is a year, and the resolution half hours. Realistic load profiles are used for three types of customers, including the detailed representation of home appliances for residential customers. Random failures are placed throughout the network during random time steps and the distribution network restoration process is executed, including isolation-switching and repair actions and also network analysis through ac power flow calculations. Relevant details can be found in Chapter 2.

- **Different distribution network configurations have been studied.** Traditionally, distribution networks are operated radially, although NOP exist in principal locations in order to permit the provision of alternative supplies. As proposed by the C_2C project, higher automation is introduced in the distribution networks and also networks are operated also in a ring. Assessment studies are carried out to examine losses, capacity release and reliability indices comparing radial and ring configurations, for different levels of automation. Relevant details can be found in Chapter 3.

- **A direct load control post-contingency DR scheme has been developed.** In the proposed DR scheme (priority DR scheme), DR customers are specifically contracted from the DNO to provide post fault services. The cost of interrupted load has been used as a proxy of DR contract values and to determine a disconnection priority list. Physical payback effects are also included while modelling the impacts on the load demand profile after the customer reconnection. The proposed priority DR scheme is tested against the C_2C model (C_2C replication in the thesis called as inter-trip DR, is extensively studied in Chapter 3) proposed by the local DNO and aims to release untapped network capacity. Relevant details can be found in Chapter 4.

- **Time-Limited Thermal Ratings have also been introduced for network support during contingencies.** Typically, network lines' loading should not exceed pre-determined ratings, a set of deterministic values which are calculated based on the cable characteristics. TLTRs are based on the hypothesis that for the majority of the yearly demand profile network lines are half-utilised and also on the fact that a line could be loaded up to a certain, relatively high temperature until it gets damaged. However, rising from the starting temperature to the highest permissible temperature is a long lasting process. While this occurs the cable could exceed its rating to provide network support. The CRATER tool has been utilised to calculate the cables' temperature during different conditions and the impact of those to distribution network reliability and on various levels of load growth has been studied. Relevant details can be found in Chapter 5.

- **DER and MG post fault services have been proposed and their capacity contribution calculated based on effective load carrying capability.** The introduction of wind farms and electrical energy storage systems is also assessed. A collaborative operation of EES and WF is proposed, where EES is used to fill the capacity gaps during low or variant wind generation. The collaborative operation is established on the premises of smart grid environment which allows the interaction between wind farm operators, EES owners and network operators. To identify the capacity contribution of the resources, the classic concept of ELCC has been utilised. Apart from the aforesaid resources, the concept of MG is also described and assessed, proposing a combination of technologies for heat and electricity community needs. Reliability indices related to MG operation have been proposed and reliability is assessed for customers internal and external the MG. Relevant details can be found in Chapters 6 and 7.

8.2 Conclusions

The main conclusion drawn from this research is that remarkable capacity contribution can be delivered from DER both for normal and emergency conditions. Those resources could allow the connection of new customers and thus the supply of additional load demand, without the need for equivalent network reinforcements and new investments. This significant benefit relies on the fact that most distribution networks in the UK are half-utilised due to the conservative security standards that are in place. According to the security standards, it is suggested that part of network capacity should be reserved for emergency conditions.

In this thesis, it has been shown how untapped network capacity can be unlocked for normal conditions, along with generation capabilities from DER, while during emergency conditions DER could provide post fault services. It has been also demonstrated that DER needs can be lower than initially estimated (when compared with deterministic values). This is mainly justified from the variability around the load demand profile and the uncertainty and rareness of fault-events. Networks are designed based on peak demand conditions however the coincidence of a severe fault with a peak load demand is not a common event. The thesis explores the capacity requirements for DER if they were to replace network reinforcements with the rise of demand. At this point it should be reminded that, in order to capture successfully the interdependencies between demand profile, random faults throughout the year, complex storage operation, payback effects and wind variability etc., time series analysis is executed.

Apart from the capacity contribution, system reliability improvement such as for CI and CML (which are the regulated indices) are clearly identified. The quality of supply is ameliorated due to network support provided by resources, when for example active customers or MGs are voluntarily disconnected reducing the demand that the DNO has to supply (thus reporting less interruptions), when resources provide generation support in isolated or faulted network sections, without the need to wait for alternative supplies or lengthy repairs.

According to the results obtained from numerical studies and analysis in each chapter, the key conclusions that can be inferred from the research work in this thesis are presented at the following bullet points. At this point, it should be also reminded that conclusions and studies are carried out following the certain assumptions suggested throughout the thesis such as the particular suggested reconfiguration and automation strategies, post fault services, as well as the particular input network parameters, including components' failure rates and load consumption. Additionally, OPF algorithms used in the thesis would give local optimal solutions, thus suggested solutions would be affected by inserting different input parameters. Consequently, the results and conclusions are obtained from analysing real distribution networks and specific assumptions, therefore although one could claim that conclusions are case and network specific, the flexibility and amplitude of the framework, to include probabilistic implications, realistic parameters, technical network and equipment operational characteristics, give us the assent to generalize the conclusions and extrapolate them beyond the scenarios and cases applied in the numerical studies. Besides, the value stemming from this research is triggering network operators to rethink the way they operate and design their systems and showing the significance of DER inclusion and probabilistic analysis. To this end conclusions are summarized as follows:

Ring/Radial configuration:

- Radial operation with automatic switching equipment has similar reliability performance (in terms of CI and CML) with ring operation. Therefore, in a reliability perspective, for a radially operated network, the need to change the present configuration from radial to ring is not a necessary action, provided that remote operation schemes are in place.
- Active losses are inevitably lower in a ring operation and this should be taken into account when network planners are taking design decisions. However, regarding network capacity utilisation, whichever configuration brings about better results is network specific.

- In a ring operation, after a fault the supply to the whole ring is interrupted by the protections on both heads of the feeder in order to clear the fault. This results in higher short interruptions (SI) for the ring configurations. SI are currently not regulated, however this might change in the future.

Inclusion of ICT failure-level of network automation:

- Inclusion of the communication signal availability and electronic components availability brings more accurate insights on network performance.
- Sensitivity analysis on the failure and repair rate of ICT components shows that as mean time to failure and mean time to repair increase, reliability indices also increase, therefore reliability performance deteriorates. However, degradation is not dramatically high, because even if an ICT failure occurs this does not imply straightforward interruption of supply, but it needs to coincide with a requirement for post-contingency action. For instance, ICT failure needs to coincide with electrical failure but also with the case that load demand is higher than the residual network capacity.
- Higher levels of automation reduce the duration of restoration actions by replacing manual switches with automated switches or in general shortening the duration of switching actions. This improves the CML and EENS indices because customers remain disconnected for shorter time. However, CI don't change with respect to the level of automation since, the amount of customers being interrupted depends on network topology and the location of the fault. Only in a fully automated network CI would reduce because switching actions taken automatically would hamper the isolation of network parts or would link immediately a specific network part with an alternative supply.

Priority DR for post fault services:

- As a general viewpoint, the implementation of DR could potentially increase network utilisation.
- Priority DR scheme brings better reliability performance for DR contracted customers comparing with the inter-trip scheme (C_2C model), reducing the amount of DR customer disconnections. This principally happens because the amount DR disconnections is determined based on the specific conditions during the disturbance and the identification of the actual requirements is based on the

OPF algorithm, thus disconnecting only the DR load needed for the particular event (whereas in the inter-trip scheme DR customers are disconnected all together.

- The introduction of payback effects limits the allowance for additional load increase without the need for reinforcements thus constraining DR capability to unlock network utilisation. It can also deteriorate the reliability indices because the load demand increases after the customer reconnection to recover the energy lost during the contingency. For higher loading levels, payback effects are more noticeable, since capacity limits are reached faster and thus new disconnections are initiated, or performed disconnections that need to be recovered later.
- A full sensitivity analysis on the DR penetration level provides information on the actual DR requirements and a proposed set of risk indices shows the risk of contracting less DR than initially estimated according to the traditional security standards. The study shows that DR requirements could be much lower than estimated on the basis of peak demand and the main reason is that network disturbance rarely coincides with a period of high demand.
- Reliability indices for normal customers are worsening for lower DR levels because instead of implementing DR disconnections as a corrective control, normal customers would be curtailed to maintain the network within thermal and voltage constraints
- The calculation of cost of interrupted load and its inclusion in the OPF algorithm for the sequence of DR customers' corrective disconnection reflects realistically the customer preferences. This is because the cost of interrupted load is calculated as a function of VOLL, thus capturing the customer welfare and their willingness to accept the interruption.

DR with TLTR for post fault services:

- Typically, for the studied networks, the bottleneck during emergency conditions is thermal (violation of thermal constraints is more frequent than of voltage constraints) therefore the application of emergency/TLTR rating has positive impacts on network operation and performance. It is reminded that emergency rating in this thesis is defined as the DNO's practical implementation of 120% overloading for two consecutive hours.

- Additionally, the application of emergency/TLTR rating amplifies utilisation of the existing network and triggers the possibility to continue to use cable systems beyond 100% firm capacity while maintaining acceptable network performance.
- According to local DNO's practical implementations during contingencies, chronologically, application of emergency/TLTR ratings comes first and DR actions are initiated afterwards. It has been demonstrated that for a certain limit of loading level, emergency ratings can fully compensate DR corrective actions. For higher loading levels, emergency/TLTR ratings can reduce the DR needs and calls for DR disconnection.
- TLTR perform remarkably better than emergency ratings. Sensitivity studies on various levels of load demand above the firm loading capacity, show the reliability indices are lower (better performance) for TLTR rating. Similarly, TLTR rating could allow the accommodation of higher load demand (when compared with emergency rating) without compromising the reliability of existing customers and network security.

MG for post fault services:

- The DNO could host significant load growth without the need of costly network reinforcements and without compromising the reliability of the distribution network.
- MGs offer considerable reliability benefits both for customers internal and external the MG. Especially for internal customers, continuity of supply is extremely high, if we assume that MG components generation output can supply successfully its internal demand (it has been shown that MGs are typically oversized for economic reasons). In consequence, the high reliability performance inside the MG improves the average reliability performance for the whole network.
- Load point reliability indices are highly affected from the location of the MG. Load points close to the MG, in a case of a fault, have a higher possibility to become isolated along with the MG, thus taking advantage of MG capacity and reliability support.
- The proposed MG reliability indicators are calculated based on the number of hours disturbance events could last and capture the severity of the disturbance situation (combination of the location of the fault and the network loading

during the fault. Even for a loading level quite higher above the firm loading capacity contribution of the MG has a low probability of provision, emphasizing the low probability of a fault occurrence during a period of high demand.

Collaborative EES &WF for post fault services:

- It has been shown that by intelligently collaborating, distributed energy resources can increase the capacity support to distribution networks and, thus, improve reliability levels and reduce costs. This is attributed to the increased wind utilisation when flexible EES fills the gaps between the intermittent wind power and demand.
- However, for low loading levels, when network capacity utilisation is not stressed enough during contingencies, collaborative DER operation does not outperform substantially the non-collaborative DER operation. Contribution of the resources and differences or benefits of each operation can be identified more distinctly for distressing conditions (typically for high loading levels) when probability of corrective load curtailment increases. In this case, DER could be used to provide capacity support and avoid the load curtailment.
- Another interesting conclusion is that when the resources collaborate, a smaller level of EES is required for a similar reliability performance with non-collaborative resources. Finally collaborative resources with low EES level perform better than a stand-alone EES of a higher level.

8.3 Future Work

Potential ideas for further research based on the knowledge gained through the literature review, the techniques and concepts presented in this thesis will be discussed in this section.

- Primarily, as seen throughout the chapters of this thesis, the post-fault services suggested (DR, TLTR, MGs, EES and WF) have been described mostly on an individual basis (with the exemption of DR and dynamic thermal rating which have been examined in a combined mode in Chapters 4 and 5). The reason behind that is, that it is important to understand the capabilities and the potentials of each technology and the impacts that each one could have on distribution network reliability and utilization. Since the framework for the reliability analysis and the modelling of each technology have already been built, an interesting future work would be to combine all the technologies in one ecumenical framework and perform the relevant studies.

- The extensive reliability and risk analysis of smart distribution network provided us with significant information regarding distribution network reliability performance through regulated and non-regulated reliability and risk indicators. As a consequence, it would be especially interesting to insert the thesis results into a substantial network planning analysis which includes various objectives apart from reliability considerations, (which could be also conflicting) such as energy losses, total costs, CO_2 emissions etc.
- As demonstrated in the thesis, there is a methodological trend of moving from a deterministic preventive security to a probabilistic corrective security philosophy. Potential contribution of various resources such as DR, EES, wind farms, MGs and TLTRs, has been examined and has provided network planners with substantial food for thought for future planning methodologies and frameworks. It would be very interesting to include in a more systematic manner the economical factor in order to end up with more comprehensive conclusions. So far only the cost of unreliability has been added in the study, however, it is essential to include the cost of alternative investments, such as lines reinforcements, substation upgrades, network expansion, etc. Additionally, the cost of other operational security measures shall be included, such as the cost of reserve and security margins. In the end, the ideal distribution network planning analysis would balance the costs of unreliability, costs of smart schemes, and costs of operational security measures against the costs of additional network investments.
- The thesis has examined comprehensively potential solutions and methods to increase distribution network utilisation, however mainly referring to network lines and their capability, and generally distribution network after the point of the distribution substation. Nonetheless, it is equally important to examine the utilisation of substation transformers, which are quite expensive and important assets in a distribution network. For instance, how utilisation of substation transformers is affected from novel technologies, introduction of new demand and network reconfiguration should be also examined.
- The reliability and risk analysis framework developed for this thesis has attempted to capture and evaluate the stochasticity of smart distribution

networks, including modelling of random electrical and ICT faults, random DR behaviour, weather uncertainty, and uncertain network operation during post-contingency operation. For this thesis, time series analysis has been executed using realistic demand profiles for three types of customers, and specifically for residential customers, the specific appliances have been also modelled through CREST tool. Additionally, impacts of different technologies and reliability of network has been studied through sensitivity analysis of various loading levels. However, the uncertain load growth has not been included into the simulation tool, only various scenarios have been independently studied. Therefore, it would be very interesting to execute reliability assessment either using forecasted demand profiles or systematic stochastic scenario based demand profiles. The reliability assessment framework would be exactly the same, however if we consider this more realistic input demand data, results could be more attractive to network planners.

- Electrical energy storage (EES) has been included in the thesis through the provision of post fault services. For the analysis, it has been assumed that specific amount of EES capacity was deliberately kept to be used for post fault operation, however, no analysis has been demonstrated for operations related with the rest of the EES capacity (which as mentioned could be used for various purposes, such as to facilitate active network operation and smooth voltage violations caused from generation fluctuations, to ease the integration of renewables). Preliminary studies have been executed in this context however, it would be very interesting to include potential EES operations and carry out reliability analysis utilising the actual remaining EES capacity after normal and emergency EES operations.
- The thesis has attempted to assess realistically the electricity network of the future and has demonstrated a comprehensive reliability and risk assessment including the analysis of example features (DR, EES, TLTR, ICT infrastructure, MGs). The study has omitted the integration of electric vehicles, although they constitute a paramount part of smart distribution networks (electrification of transport shall be accomplished through the widespread replacement of regular cars). The introduction of electric vehicles has a great impact on load demand due to the charging requirements of electric cars, but also could provoke capacity contribution and network services through the vehicle to grid concept.

Therefore, it would be very appealing to include in the framework analysis electric vehicles.

- Finally, the reliability assessment has only included the unexpected fault of network equipment, such as network lines or switches, and also electronic faults, all modelled through their mean time to failure and their probability distribution. Nonetheless, the ageing of the equipment has not been included in the study. Taking into account, that the building of UK electricity infrastructure reached its peak between the 1950s and 1960s, the ageing of power system equipment is an important factor which would be interesting to be included. This could be done by including in the analysis apart from the repairable failure, the end-of-life failure. This inclusion would affect the results, most probably showing an increased contribution of the DER's applications.

APPENDIX 1: DISTRIBUTED SOFTWARE INFRASTRUCTURE FOR GENERAL PURPOSE SERVICES IN A SMART GRID CONTEXT

In the thesis' chapters, various DER were used for post-fault capacity services in smart grids. Additionally, in Chapter 3, a particular ICT infrastructure was adopted to facilitate the implementation of DR active management. In a similar manner, significant developments coming from ICT research propose sophisticated middleware platforms which are able to manage large-scale data exchange and numerous interactions between actors. Those platforms utilise mainly the Internet backbone and in a secondary phase any ICT technology as the physical link and at the same time allow interoperability between different technologies, scalability and cyber security. Therefore, in this section, the implementation of this practical solution will be examined for smart grids applications. In particular, the event-driven middleware developed in [42] is adopted in this chapter as a potential solution platform for general purpose services in smart grid, as also proposed in *[191]*. After providing the related background for the middleware platform, the aim of this section is to demonstrate a practical deployment and identify potential bottlenecks of the platform in power system applications. In particular, a numerical case study, where the middleware is utilised as a platform for corrective DR services is presented and evaluated. The case study examines the implementation implications for the whole U.K. distribution network, and the capabilities of the selected infrastructure are discussed.

Current challenges for optimal ICT infrastructures

Smart grids are transforming all levels of the power system chain with the aim of facilitating the pathway towards more sustainable, economical, and reliable networks by deploying low carbon technologies and advanced ICT options. However, if we consider the major changes that are likely to happen and the huge integration of renewables, storage, and so forth, as also seen in the previous chapters, power systems' control philosophy has to be updated. Also, new commercial structures will be needed to enable the interaction of actors such as aggregators, energy suppliers, in a distributed energy market. In this context, research is needed to develop optimal ICT infrastructures that could facilitate interactions among all the relevant actors and different controllable network devices and technologies for provision of different services. In particular, ubiquitous computing[192], Internet of Things[193] and relevant technologies could help address this challenge by providing means to seamlessly interact with distributed sensors and actuators, and facilitate access to data and control actions to multiple parties.

However, the main concern related to interactions between actors, devices and technologies in smart grids is the level of interoperability. To cope with these issues and to be open to future developments, middleware approach is employed. Although there are several works in the existing literature using middleware for developing smart grid solutions [194]–[198], the middleware platform developed in [42] and then proposed in [191] is adopted here as the platform for general purpose services in smart grid. The selected middleware enables true interoperability between heterogeneous protocols and devices, both wireless and wired, providing real-hardware abstraction. Moreover, exploiting the existing IP networks, it enables a peer-to-peer (P2P) [199] software infrastructure and guarantees scalability thanks to a publish/subscribe approach [200] so that different actors can access the same information coming from the middleware for different purposes without affecting others. Additionally, it uses Service-Oriented Architectures (SOA) [201] to achieve true interoperability across heterogeneous devices and between different applications. Furthermore, it provides features to enable secure and trusted communication between the peers. Finally, it provides a rule framework to easily develop control policies.

Exploiting this paradigm, and to illustrate an application of the relevant concepts, DR could be put forward as an example of interaction between end-users, system operators, retailers, and so forth. In this context, different DR providers in different or similar geographical areas may interact with different market actors for provision of different services. On the other hand, different parties may need access to data from the same DR provider for different applications (for instance, aggregation of reserve services and consumption measurements). Additionally, DR dispatch notices could vary from minutes (balancing services) to day ahead (preventive constraint management), depending on the service it is called to provide [202], and these notice times need to be properly considered in the design of the supporting ICT infrastructure. It is in the attempt to manage all this complexity of multiple parties and services that the benefits of the adopted middleware platform [191] can fully emerge.

Middleware for General Purpose Services in Smart Grid

On these premises, the aim of this section is to describe the comprehensive framework for distributed real-time event-based software infrastructure introduced in [191] for general purpose services in smart grid. For the sake of simplicity, for the rest of the chapter when we refer to the event-based software infrastructure, we would use the definition “middleware”, referring to the platform introduced in [191].

As shown in Figure Appendix 1- 1, the selected middleware consists of a three-layered architecture with: an application layer, a services layer, and an integration layer. The middleware provides developers with a set of components, called managers. They are designed exploiting a SOA approach and each manager exposes its functionalities as web services. The rest of this section describes each layer of the proposed infrastructure in more detail[191].

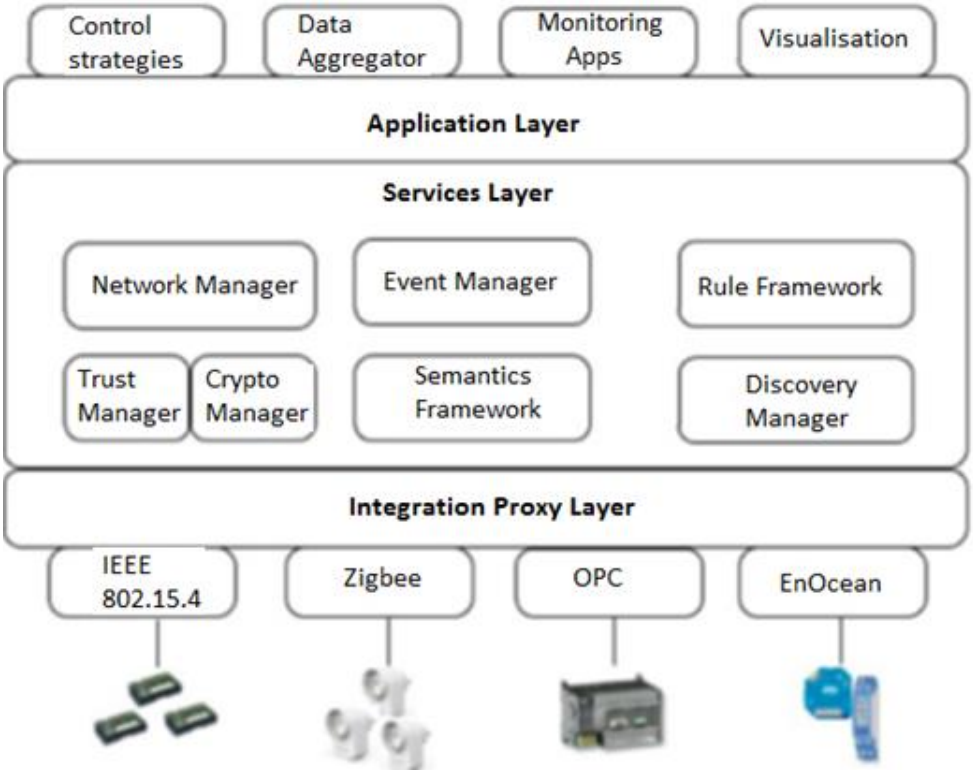

Figure Appendix 1- 1: Architectural scheme for the selected middleware[14] [191]

Application Layer: The application layer represents the highest layer of the proposed infrastructure. It provides a set of Application Programming Interfaces (API) to develop distributed event-based applications in order to manage the grid and post process data coming from the lower layers. At that level, interoperability is enabled between different devices as well as, thanks to the web Service approach, between third party software. Hence, different applications for several actors can be developed to provide general purpose services down to the single appliance in a house. Furthermore, in order to avoid huge ICT network overheads due to transmission of such fine grained information, data aggregation applications can also be developed to aggregate information about some subsystems [75]. Finally, each component of the proposed solution can be duplicated in the middleware network providing reliability from the software side.

[14] Illustrations in Figures Appendix 1-1 to -4 are prepared by Dr. Edoardo Patti.

Services Layer: The services layer provides components specifically designed for general purpose services in smart grid, which should support the management of reoccurring tasks.

1) Network Manager: The middleware allows direct communication between all the applications inside its network, even if they are behind a firewall or network address translator.

2) *Trust and Crypto Managers:* The proposed middleware already comes with features to enable a secure and trusted communication between different actors [203]. The trust manager controls whether a device or service in the P2P network can be trusted or not. Therefore, it enables mutual authentication between actors by providing the means to create a public key infrastructure. Hence, malicious peers cannot call services in the middleware network and cannot receive any kind of data. The crypto manager allows cryptographic operations used for message protection exploiting symmetric and asymmetric encryption in order to guarantee the confidentiality between the parties. In addition, it can sign each message with digital certificates providing integrity of data.

3) Event Manager: In an event-based communication approach, the event manager provides a data centric model based on the publish/subscribe service [200] for the middleware web services. This approach decouples the production and consumption of the information by removing all the explicit dependencies between the interacting entities, which increases scalability. In smart grids, where we deal a lot with events coming from both devices and distributed software, this mechanism is a key requirement to develop systems and applications. Each event contains both measurement and timestamp and it is published under a certain topic. The event topic has a hierarchical format, which also provides some basic semantic information about the type of event. Following this format, also other middleware software components, and not only sensors, can publish events just by changing the event topic and software components interested in certain events can subscribe for them.

4) Semantics Framework: It enables semantic interoperability across heterogeneous devices and technologies. The middleware provides managers to store, access, and update semantic knowledge about an application domain and the implemented system. In this particular case, knowledge and meta-data about sensors and actuators are modelled as well as their relation to domain model objects such as appliances, grid substations or buildings. These data are modelled and managed by well-known semantic web technologies, adhering to existing standards, namely web ontology language (OWL). Knowledge is made available to application developers, allowing them to query any kind of information from a rich domain model. This could be the location or capabilities of a sensor but also, for instance, a list of all sensors in a specific grid substation, or an actuator with a certain control capability.

5) Discovery Manager: It is responsible for discovering locally available devices that are connected via an integration proxy. Once an integration proxy is discovered, semantic information is extracted and used by the discovery manager to update its knowledge base, which contains the global knowledge about devices in the network. When several discovery managers are available in the P2P middleware network they synchronize their knowledge about devices so that all of them have the same knowledge about the available devices connected to the same middleware network.

6) Rule Framework: Typical power system management functions can be expressed in rules: the system listens to certain events, processes them based on given knowledge and algorithms and performs a resulting action. Hence, a specific control strategy can be developed by putting together different basic rules. The rule framework allows a fully flexible implementation of any kind of rule-based system. The framework provides standard interfaces as a basis for specific rule implementations. These rule implementations can be combined in a rule engine that executes the rules on incoming events. Rule logic and contextual information needed to execute a rule are kept separately, following the principle of the separation of concerns. This allows designers to reuse rule implementations in different contexts, e.g., to apply the same energy control policy in different subsystem, but with different settings, depending on the peculiarities of the subsystem itself.

Integration Layer: The proposed infrastructure leverages upon an ICT infrastructure made of heterogeneous monitoring and actuation devices, both wireless and wired, which exploit different communication protocols and standards. The integration layer exploits the concept of integration proxy to enable interoperability across heterogeneous technologies. More specifically, the integration proxy is a middleware-based software component that acts as a bridge between the middleware network and the underlying technologies, devices, or subsystems. Each technology needs its own integration proxy to export its functionalities as web services. Hence, the integration proxy is the key to ensure communication between heterogeneous devices and allows us to use each low-level technology transparently inside the middleware network. Specifically, the integration proxy is a software component that runs on a PC and communicates directly with the heterogeneous networks receiving real-time information from various devices, regardless of the adopted communication protocols, hardware, or network topology. Once the information is received and interpreted by the integration proxy, this is immediately sent to the middleware network exploiting the publish/subscribe approach provided by the event manager. In a nutshell, the integration layer of the proposed middleware consists of several Integration Proxies, one for each technology.

P2P communication paradigm in distribution networks

In order to exchange information across the smart grid, a P2P [204] communication network topology shall be available where each peer acts simultaneously as supplier and consumer of resources enabling the communication directly with another peer. Figure Appendix 1- 2 shows an exploitable distributed approach for moving towards a fully operated smart grid, where a two-way communication is enabled between various entities and actors from the DNO level down to the customer’s meters at building or home level.

The Proxy and the Event Manager become the two main middleware components respectively to ensure the interoperability across heterogeneous devices and to enable a data centric communication between different actors. In addition, two P2P middleware-enabled applications can be developed and deployed to manage each subsystem:

1) The *Data Aggregator*: It provides an aggregation of real time consumption’s information coming from heterogeneous sources both hardware, thanks to the Proxy, and software (e.g. other Data Aggregators in the infrastructure).
2) The *Control Policy Manager*: It implements the control strategies to manage its subsystem. It receives and process real time information from heterogeneous devices, Data Aggregators and/or other applications before taking decisions and sending the corresponding actuation commands. It is worth noting that it can also receive or send action commands from/to other Control Policy Managers, again exploiting the Event Manager.

As shown in Figure Appendix 1- 2, these new components are proposed to be introduced at each level of the distribution network including also buildings and homes. At DNO, Substation and Transformer level, a Data Aggregator and a Control Policy Manager are deployed in addition to a Proxy and an Event Manager. Thanks to them, the distribution network can be divided in various P2P inter-connected subsystems, which will be able to exchange information with other distributed services or entities managed by different actors (see Figure Appendix 1- 3). It is worth noting that the proposed infrastructure provides a system to enable the communication also between different actors, without caring who owns a certain subsystem or a certain application. By exploiting this middleware, the information can be easily sent to the cloud and can be easily consumed by other actors, if authorized, to provide services.

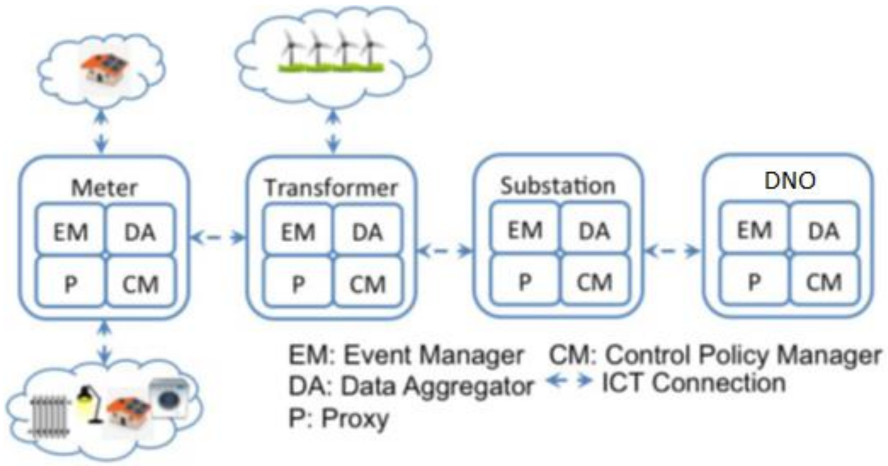

Figure Appendix 1- 2: Distribution network under middleware deployment [191]

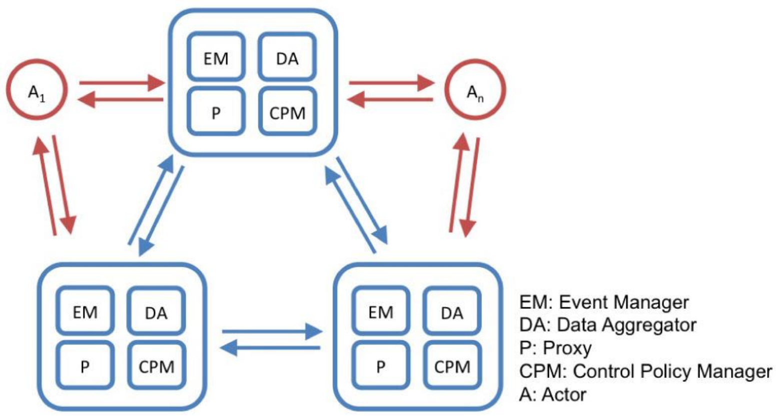

Figure Appendix 1- 3: Example of P2P communication[191]

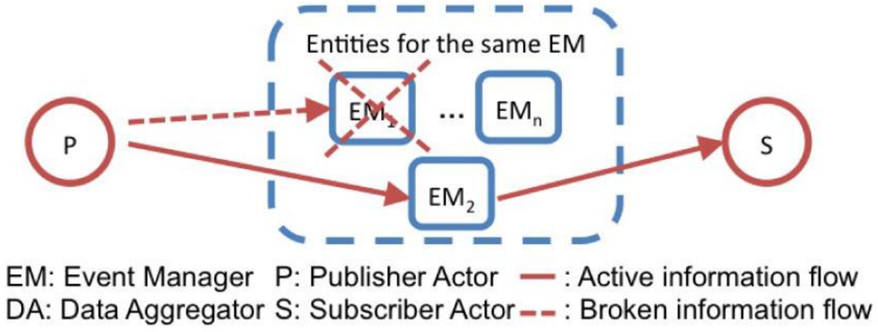

Figure Appendix 1- 4: Example of P2P communication flow reliability[191]

P2P Communication Reliability in the Proposed Middleware Solution

The proposed middleware enables a P2P network, where each peer is an actor and/or an entity of the smart grid. In this scenario, the Event Manager (EM) can be considered as a bottleneck for the whole information flow, indeed it is in charge to forward the data from publishers to subscribers. Hence, if the EM crashes for any reason the information flow is interrupted. However, in this middleware network, more EM can coexist together and each of them can handle different information flows. Moreover, the Network Manager ([205]) also provides features to make each middleware component reliable; so it can be duplicated and deployed in different servers. Therefore, multiple entities of the same EM, that manages a specific information flow, can be deployed in the network. Thus as shown in Figure Appendix 1- 4 , if an EM fails for any reason, another duplicated entity will be automatically and transparently selected to ensure the communication without breaking the information flow between the actors.

Another possible bottleneck could be the physical link to connect the EM to the Internet backbone. Indeed depending on the bandwidth of the adopted technology the number of data, in terms of bytes, that it can manage, changes. As shown in Table Appendix 1- 1, for each link technology the number of theoretical peers is calculated by dividing its bandwidth for our middleware event message size, which is almost 800 bytes (6400 bits). It is also assumed that each peer can send/receive a message per second. Moreover, each technology exploits two different channels for download and upload. So, publishers (pubs) exploit the download channel and subscribers (subs) the upload. On the contrary WiFi and satellite technologies use a single channel for both download and upload.

In the Wide Area Network (WAN) the prevailing wired technologies are fiber optic and DSL, while the wireless ones are WiMAX, 3G/4G and satellite. So, if the EM is connected to the Internet backbone via Fiber optics, theoretically the link can manage from about 1.5k to 156k peers in download and from about 1.5k to 156k peers in upload. With DSL, it handles from almost 1.2k up to 31.2k publishers and from almost 203 to 31.2k subscribers. The WiMAX link manages from about 20k to 156k peers in download and from about 4.3k to 156k in upload. With a 3G/4G link, the EM can handle from almost 2.2k to 156k pubs and from almost 868 up to 78k subs. Finally, exploiting the communication based on satellite technologies, the EM can manage from almost 4 to 70 peers both publishers and subscribers. Moreover, it should be noted that for wireless WAN technologies the number of sent/received events can decrease due to weather conditions that influence the performance of the link itself [206] [27].

If publishers and subscribers are in the same Local Area Network, the prevailing technologies are Ethernet and WiFi. Ethernet can manage from almost 1.5k up to 156k peers in download and from almost 1.5k up to 156k peers in upload. Finally, WiFi can handle in the same channel from almost 8.5k to 93.5k peers both pubs and subs.

Table Appendix 1- 1: Number of peers per bandwidth

Tech.	**Bandwidth**		**Max number of peers**		**Max coverage**
	Download	Upload	Pubs	Subs	
Local Area Network					
Ethernet	10Mbps	10Mbps	1.5k	1.5k	100m
	100Mbps	100Mbps	15.6k	15.6k	100m
	1Gbs	1Gbs	156k	156k	100m
WiFi	54Mbps		8.5k		300m
	600Mbps		93.5k		1km
Wide Area Network					
Fiber Optic	100Mbps	100Mbps	15.6k	15.6k	10km

	662Mbps	662Mbps	103.4k	103.4k	60km
	2448Mbps	2448Mbps	382.5k	382.5k	60km
	1Gbps	1Gbps	156k	156k	20km
	8Mbps	1.3Mbps	1.2k	203	4km
	12Mbps	3.5Mbps	1.8k	546	7km
DSL	24Mbps	3.3Mbps	3.7k	515	7km
	85Mbps	85Mbps	13.2k	13.2k	1.2km
	200Mbps	200Mbps	31.2k	31.2k	1km
WiMAX	128Mbps	28Mbps	20k	4.3k	10km
	1Gbps	1Gbps	156k	156k	100km
3G/4G	14.4Mbps	5.75Mbps	2.2k	898	5km
	82Mbps	22Mbps	13k	3.4k	
	326Mbps	86Mbps	50.9k	13.4k	100km
	1Gbps	500Mbps	156k	78k	
Satellite	28kbps		4		Depend on number of satellites
	128kbps		20		
	450kbps		70		

Case study application: The Middleware as a platform for DR Services

In order to illustrate the above concepts with a case study example, the middleware platform described coherently in the previous sections has been used as the ICT support to provide real time DR services. Initially the case study is presented and subsequently the feasibility of the proposed platform and the prerequisites for an extensive deployment throughout the UK are studied. More specifically, this is done by quantifying the capability of the ICT support, which as already mentioned, could affect negatively the P2P communication reliability. However, it is worth noting that the proposed solution exploits the already existing Internet backbone and its deployment does not affect the correct functioning. In addition, it does not require major improvements to the distribution network, except for the deployment of the middleware software components.

Description of the case study: DR for corrective control

In the following UK based case study, DR provides corrective control actions to Distribution System Operators when a DNO would need to manage the network constraints following a fault. Depending on the type of DR program contracted and the size of the responsive load, DR could be activated directly by the DNO, or via a DR aggregator (upon receipt of a load control request). In this context, for efficient DR services we assume that all UK customers are equipped with a smart meter, providing information about the load consumption and the available amount of DR, or a building management system, controlling a group of responsive appliances through its interface. Without loss of generality, in the sequel we will assume that for residential and commercial customers the service is provided through DR aggregators, whereas for industrial customers, the service is provided directly to the DNO, depending on the type of DR service the customer is contracted. Moreover, DR aggregators activate DR within three minutes upon request of the DNO, in order to contribute to corrective control in case of a system disturbance. For the residential customers participating in the scheme, the smart meter and the smart appliances are integrated in the middleware thanks to specific proxies, allowing in that way the aggregation of measurements of all the controlled appliances, as well as an independent control of specific appliances, at the home level. For the case study, for each participating building a unique message is sent through the smart meter to the interested actor. This message includes the total load consumption of the customer, as well as available DR, which is the actual flexible load. The information flow is bidirectional between smart meters and DR aggregators that send the control commands, as well as between DR aggregators and a DNO that requests the service. The nature of the DR service provided implies that the information exchange between smart meters and DR aggregators should have per-minute frequency in order to respond efficiently to the system operators instructions, having an accurate perception of the actual DR. All these interactions are depicted in Figure Appendix 1- 5.

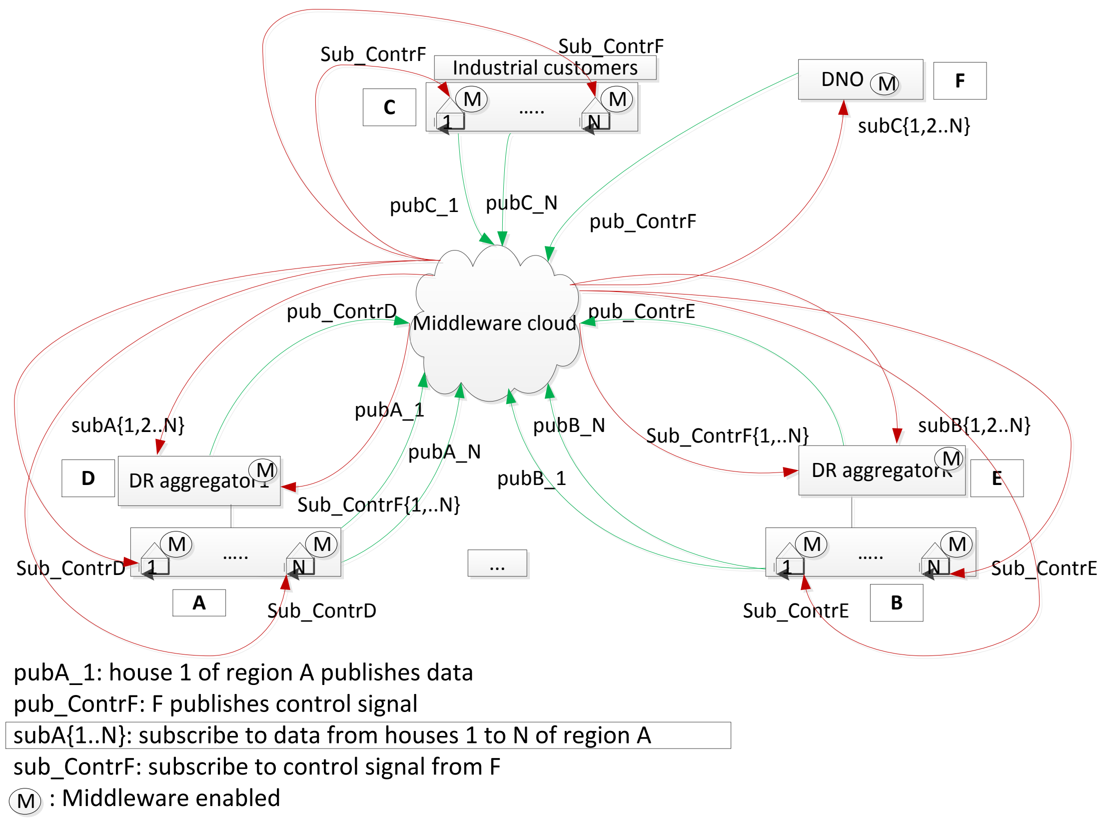

Figure Appendix 1- 5: Interactions between actors for a DR corrective control service

Dealing with the bottleneck of the physical link

The key factor that affects the middleware's efficiency is the capability of the physical link to send/receive data to/from the Internet backbone. Under the above assumptions, a DR aggregator may have to manage thousands of customers belonging to a DNO area. The same may also apply to a DNO, which may have to interact with various aggregators as well as industrial customers. As a consequence, the bottleneck would appear when a DR aggregator or a DNO would like to receive data coming from the smart meters. For that reason in the rest of the section the maximum number of customers an actor can manage without violating the download bandwidth of the physical link, as well as the number of subsystems an actor should build when it has to manage a big number of either customers or information are identified. Since the corrective control DR service is provided to each DNO, UK is divided in 14 regions corresponding to the 14 UK DNO areas. Thereafter, the appropriate number of actors operating in a specific region is calculated. These actors could be the DR aggregators, but also any other actor performing a different service in the region. In any case, the information exchange between the customers and any actor managing them would require the exploitation of WAN technologies, hence only the WAN technologies of Table Appendix 1- 1 are discussed excluding satellites because their small bandwidth is not appropriate for the case study.

8.3.1.1 Calculating the number of customers per actor:

To estimate the number of customers in each region, it is assumed that the house density in UK is 109 houses per km^2. Furthermore, the data packet sent from each house is about 800 bytes per minute, as mentioned previously. The maximum number of customers that an actor can subscribe to receive data from depends also on the technology the actor deploys to connect to the Internet backbone and it can be calculated as the ratio of the technology bandwidth to the data packet size sent by each customer. The results are shown in Table Appendix 1- 2.

Table Appendix 1- 2: Maximum number of customers per actor for different technologies

Technology	download bandwidth (Mbps)	Max. Number of Customers
Fiber Optic	100	983040
	662	6507725
	2448	24064819
	1000	9830400
DSL	8	78643
	12	117965
	24	235930
	85	835584
	200	1966080
WiMAX	128	1258291

	1000	9830400
3G/4G	14.4	141558
	84	825754
	326	3204710
	1000	9830400

Table Appendix 1- 2 shows the amount of contracted industrial customers that the DNOs can control directly through the Event Manager, in case of a need for direct load control. The same applies for any other actor who would like to deploy P2P communication with customers, which could be either distributed around UK or located in a specific region.

8.3.1.2 Calculating the number of subsystems, as the intermediate layer between the customers and an actor

In the circumstances that an actor would like to interconnect with a number of customers higher than the one depicted in Table Appendix 1- 2, or DR aggregators may need to manage a large amount of information coming from millions of smart meters, an appropriate number of P2P interconnected subsystems to support the information exchange and service provision on behalf of the DR aggregators. These subsystems act as an intermediate layer between the customer and the actor. Therefore, the so called subsystems are also actors/customers of the DR services under study. They could be subsystems owned by the DR aggregators, but they could be also owned by other companies playing in the market and providing again a service to the DR aggregators. Each subsystem manages its specific area, receiving signals from the DR aggregators and controlling buildings under its supervision.

The above can be facilitated by the middleware-based application as follows:

1) The data aggregator application is used to aggregate data coming from the area, and then send the aggregated packet to the DR aggregator;
2) The control policy manager facilitates each subsystem to act independently by sending control commands to the customers it manages. Assuming that all UK customers participate in the services presented, the appropriate number of subsystems is calculated for each DNO region (for the case that local

independent services need to be provided), and for the whole UK area. The number of subsystems is calculated as the ratio of the data packet size of the area to the bandwidth of the technology. All the above are depicted in Table Appendix 1- 3 providing the number of subsystems as the average number calculated for the bandwidth of each different WAN technology.

Table Appendix 1- 3: Number of Subsystems for each DNO region and the whole UK for an average combination of WAN technologies

DNO region	Number of customers	Mbytes per minute	Number of Subsystems (for a combination of technologies)
East England	2084080	1590.03	6
East Midlands	1703343	1299.55	5
London	1274319	972.23	4
North Wales, Merseyside and Cheshire	325692	248.48	1
West Midlands	547180	417.47	2
North East England	936528	714.51	3
North West England	1543985	1177.97	4
North Scotland	4272092	3259.35	11
South Scotland	4272092	3259.35	11
South East England	2081355	1587.95	6
Southern England	6762578	5159.44	17
South Wales	2264911	1727.99	6
South West England	2597361	1981.63	7
Yorkshire	1297427	989.86	4

TOTAL	31962942	24385.79	80

Table Appendix 1- 3 indicates the necessary number of subsystems an actor should deploy in order to manage and receive the data coming from a specific region. Scoping down the observations to our DR services, in case a local DNO would like to contract DR aggregators to manage the residential and commercial customers of the region, using North West England as an example, a number of 4 DR aggregators should be contracted, or equivalently, a DR aggregator should deploy 4 subsystems, which will be in charge of controlling the loads under their supervisory area, reporting to the DR aggregator, who also receives load request signals from the DNO. Needless to say, assuming a different number of houses/customers involved, the number of subsystems changes since it depends from the data size sent by the area.

Further discussions

Apart from the presented services provided by the existing actors (DNO, DR aggregators), in any time a new actor could appear, and subscribe to the information sent by the smart meters. Each new actor receives the events through the EM, utilizing his own physical link, without any conflict with the other actors, without even knowing their existence. For instance, energy suppliers of every region could exploit their own subsystems, using the data aggregator application, to aggregate electricity meter readings for billing purposes. As a second example, the DNOs could subscribe in receiving load consumption data from the DR aggregators throughout the year for quality of supply and safety demand reads. Meanwhile, for actors interested in the home level services, they could subscribe to receiving the original data published by the smart meters and also controlling heterogeneous home devices thanks to the middleware interoperability characteristics.

Conclusions

In this chapter, the distributed software infrastructure (middleware) for developing general purpose services in smart grid, developed in [42] and [191] has been described. The middleware aims to enable hardware-independent interoperability across heterogeneous devices and exploits a P2P communication paradigm to facilitate the access of multiple actors to the smart grid, thus allowing provision of services and information exchange between them. Most importantly, an example of deployment in distribution networks has been presented and evaluated where it was shown that different buildings could be associated to different aggregators that provide different services to different actors, which is indeed the main strength of the proposed middleware concept. The actors could receive data directly from specific customers or aggregated data coming from subsystems, exploited throughout the network, interacting independently. In addition, the capabilities of the proposed distributed infrastructure in terms of maximum number of customers an actor can manage and relevant number of subsystems that are required were calculated for the DR service presented. The same method could be applied to any other service provided by another actor, ensuring scalability and reliability for all the reoccurring services and therefore truly enabling the development of a distributed market place in a smart grid context.

APPENDIX 2: AC POWER FLOW AND AC OPTIMAL POWER FLOW IN MATPOWER

Network equations, ac power flow and ac optimal power flow equations, as calculated and formulated in the Matpower tool[207] are given in this section.

NETWORK EQUATIONS

The complex nodal current injections I_{bus} are given from (1) where V are the complex node voltages and Y_{bus} is the complex $n_b \times n_b$ bus admittance matrix in a network with n_b buses. Similar equations relate the branch currents I_f and I_t at the 'from' and 'to' ends of all branches respectively.

$$\boldsymbol{I_{bus}} = \boldsymbol{Y_{bus}} \cdot \boldsymbol{V} \tag{1}$$

System admittance matrices can be formed as:

$$\boldsymbol{Y_f} = [\boldsymbol{Y_{ff}}]\boldsymbol{C_f} + [\boldsymbol{Y_{ft}}]\boldsymbol{C_t} \tag{2}$$

$$Y_t = [Y_{tf}]C_f + [Y_{tt}]C_t \tag{3}$$

$$Y_{bus} = {C_f}^T Y_f + {C_t}^T Y_t + [Y_{sh}] \qquad (4)$$

where $[\cdot]$ denotes an operator that takes a $n \times 1$ vector and creates a $n \times n$ diagonal matrix with the vector elements on the diagonal. C_f and C_t are the connection matrices , where the $(i, j)^{th}$ and the $(i, k)^{th}$are equal to 1 for each branch i connecting bus j to bus k. The rest of the elements have zero values.

The current injection of (1) is used to calculate the complex power injections as functions of the complex bus voltages V[207], as given in (5). (6) and (7) give the complex power injections for branch currents at 'from' and 'to' of all branches.

$$\boldsymbol{S_{bus}}(\boldsymbol{V}) = [\boldsymbol{V}]\boldsymbol{I}^*_{\boldsymbol{bus}} = [\boldsymbol{V}]\boldsymbol{Y}^*_{\boldsymbol{bus}}\boldsymbol{V}^* \qquad (5)$$

$$S_f(V) = [C_f V] I_f^* = [C_f V] Y_f^* V^* \qquad (6)$$

$$S_t(V) = [C_t V] I_t^* = [C_t V] Y_t^* V^* \qquad (7)$$

The nodal bus injections are matched to the injections from loads and generators to form the AC power balance equations, as a function of the complex bus voltages and generator injections[207]:

$$\boldsymbol{g_s}(\boldsymbol{V}, \boldsymbol{S_g}) = \boldsymbol{S_{bus}}(\boldsymbol{V}) + \boldsymbol{S_d} - \boldsymbol{C_g}\boldsymbol{S_g} = \boldsymbol{0} \qquad (8)$$

AC POWER FLOW

The power flow problem solves the set of voltages and current flows inside a network for certain values of load and generation. Solvers in Matpower generally solve a set of equations in a form of (9), expressing nodal power balance equations as functions of unknown voltage quantities.

$$\boldsymbol{g}(\boldsymbol{x}) = \boldsymbol{0} \qquad (9)$$

In Matpower [207], a generator bus is selected as the reference bus, specifying a voltage angle reference and a real power slack. The voltage angle at the reference bus is a known value, but the real power generation at the slack bus is unknown in order to avoid overspecifying the problem. The remaining generator buses are considered to be PV buses, with the values of voltage magnitude and generator real power injection given. All non-generator buses are PQ buses, with the loads P_d and Q_d also given and the real and reactive injections fully specified.

The power balance equation of (8) is separated into its real and reactive parts, expressed as functions of the voltage angles Θ, magnitudes V_m and generator injections P_g and Q_g .The load injections are considered constant and given. The updated form of equations is given in two parts in (10) and (11) [207]:

$$\boldsymbol{g_P(\Theta, V_m, P_g) = P_{bus}(\Theta, V_m) + P_d - C_g P_g = 0} \quad (10)$$

$$g_Q(\Theta, V_m, Q_g) = Q_{bus}(\Theta, V_m) + Q_d - C_g P_g = 0 \quad (11)$$

For the AC power flow problem, the function $g(x)$ from (9) is formed by taking the left part of the real power balance equations (10) for all non-slack buses and the reactive power balance equations (11) for all PQ buses and inserting the reference angle, the loads and the known generator injections and voltage magnitudes[207] :

$$\boldsymbol{g(x) = \begin{bmatrix} g_P^{\{i\}}(\Theta, V_m, P_g) \\ g_Q^{\{i\}}(\Theta, V_m, Q_g) \end{bmatrix} \begin{matrix} \forall i \in \mathcal{L}_{PV} \cup \mathcal{L}_{PQ} \\ \forall j \in \mathcal{L}_{PQ} \end{matrix}} \quad (12)$$

The vector x as given in (13) consists of the voltage angles at all non-reference buses and the voltage magnitudes at PQ buses [207]:

$$\boldsymbol{x = \begin{bmatrix} \theta_{\{\iota\}} \\ u_m^{\{j\}} \end{bmatrix} \begin{matrix} \forall i \notin \mathcal{L}_{ref} \\ \forall j \in \mathcal{L}_{PQ} \end{matrix}} \quad (13)$$

$\mathcal{L}_{ref}$, $\mathcal{L}_{PV}$ and $\mathcal{L}_{PQ}$ represent the sets of bus indices of the reference bus, PV buses and PQ buses, respectively. This ends to a set of nonlinear equations with $n_{pu} + 2n_{pq}$equations and unknowns, where n_{pu} and n_{pq} are the number of PV and PQ buses, respectively. After solving for x the remaining real power balance equation can be used to compute the generator real power injection at the slack bus. In a similar manner, the remaining $n_{pu} + 1$ reactive power balance equations return the generator reactive power injections.

AC OPTIMAL POWER FLOW

The standard AC OPF problem is characterized by an optimization vector x, as represented in (14), comprising the vectors of voltage angles Θ , magnitudes V_m and the generator real and reactive injections P_g and Q_g[207]:

$$\boldsymbol{x} = \begin{bmatrix} \boldsymbol{\Theta} \\ \boldsymbol{V_m} \\ \boldsymbol{P_g} \\ \boldsymbol{Q_g} \end{bmatrix} \tag{14}$$

The objective function of the AC OPF is given in (15) and as illustrated it is the addition of individual polynomial cost functions f_P^i and f_Q^i of real and reactive power injections for each generator. The equality constraints are the same as in the standard power flow and given from (10) and (11) and the inequality constraints which refer to the branch flow limits are given in (16)-(17) [207]:

$$\boldsymbol{min_{\Theta,V_m,P_g,Q_g} \sum_{i=1}^{n_g} f_P^i(p_g^i) + f_Q^i(q_g^i)} \tag{15}$$

$$h_f(\Theta, V_m) = \left|F_f(\Theta, V_m)\right| - F_{max} \leq 0 \tag{16}$$

$$h_t(\Theta, V_m) = |F_t(\Theta, V_m)| - F_{max} \leq 0 \tag{17}$$

Finally, the variable limits for the constraints are given in (18) to (21) [207] referring to the reference bus angle and the upper and lower limits on bus voltage magnitudes and real and reactive generator injections :

$$\boldsymbol{\theta_i^{ref} \leq \theta_i \leq \theta_i^{ref},\ i \in \mathcal{L}_{ref}} \tag{18}$$

$$u_m^{i,min} \leq u_m^i \leq u_m^{i,max},\ i = 1 \ldots n_b \tag{19}$$

$$p_g^{i,min} \leq p_g^i \leq p_g^{i,max},\ i = 1 \ldots n_g \tag{20}$$

$$q_g^{i,min} \leq q_g^i \leq q_g^{i,max},\ i = 1 \ldots n_g \tag{21}$$

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