

Smart Metering Infrastructure for Distribution Network Operation

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Table of Contents

Table of Contents	ii
Abstract	v
Declaration	vi
Dedication.....	vii
Acknowledgement	viii
List of Figures	ix
List of Tables	xii
List of Acronyms	xiv
Publications	xvi
1 Introduction.....	1
1.1 Motivation	1
1.2 Research Objectives.....	4
1.3 Thesis Structure	5
2 Previous Research and Background.....	6
2.1 Smart Grids	6
2.1.1 The Smart Grid Vision.....	8
2.1.2 Evolution of Electric Utility Communication Requirements	10
2.1.3 Role of Communications in the Smart Grids	11
2.1.4 Requirements on Communications Infrastructure of Smart Grids.....	12
2.2 Communications Technogloeis	14
2.2.1 Overview of Different Communications	14
2.2.2 A Wide-Area Aggregation Network for Smart Grids	20
2.3 Smart Grid Applications and Analysis of Their Communications Infrastructure	22
2.3.1 Smart Grid Applications	22
2.3.2 Analysis of Communications Infrastructure	29
2.4 Development of Smart Metering Infrastructure.....	31
2.4.1 Options for the Smart Metering Development	31
2.4.2 Initiatives in the UK to Deploy Smart Meters	33
2.4.3 Smart Metering for Distribution Network Operation	35

2.5	Summary	37
3	Modelling of Smart Metering Communications	38
3.1	Introduction	38
3.2	Assumptions for the Simulation	39
3.3	Modelling of Smart Metering Communications using OPNET	40
3.3.1	Modelling of Physical Components	40
3.3.2	Modelling of Applications	43
3.3.3	OPNET Model Validation	63
3.4	Case Study	63
3.4.1	Simulation Results	65
3.4.2	Constrained Channel	67
3.5	Summary	68
4	Evaluation Method of Smart Metering Infrastructure for Smart Grid Operation... ..	70
4.1	Introduction	70
4.2	Smart Meters and PLC based ICT Infrastructure	71
4.3	Framework of the Evaluation Method	73
4.4	Communication System Modelling	73
4.5	Information Platform for Smart Grid Operation	75
4.5.1	Measurement Errors Induced by Communication Latency	75
4.5.2	State Estimator	78
4.5.3	Optimal Power Flow	79
4.6	Test Results	80
4.7	Summary	87
5	Integration of Smart Metering with Outage Management System	88
5.1	Introduction	88
5.2	Outage Management Systems (OMS)	88
5.3	Integration of Smart Metering and OMS	92
5.4	Outage Area Identification Using Smart Meter Information	92
5.4.1	Topology Analysis	93
5.4.2	Outage Area Identification Algorithm	96
5.5	Simplified Modelling of Smart Metering Infrastructure	100
5.5.1	Physical and MAC Layer Modelling	100

5.5.2 Network Layer Modelling	101
5.5.3 Package Definition.....	103
5.6 Case Study.....	104
5.7 Summary.....	114
6 Conclusions and Further Work.....	115
6.1 Conclusions.....	115
6.2 Further Work	118
References	120

Abstract

With the increasing demand for energy throughout the world and the associated environmental problems, the development of a highly efficient and environmentally friendly Smart Grid has become an important objective worldwide. In Great Britain, the Smart Grid has been primarily focused on the distribution networks and smart metering is widely considered as a critical step towards the Smart Grid future. Conventionally, the communications infrastructure at the distribution level is very limited in terms of functionality and availability. There was very limited work to evaluate the impact of the communications performance of smart metering infrastructure on distribution network operation.

This research investigated the impact of smart metering applications on communications requirements and the impact of the communications performance of smart metering infrastructure on distribution network operation.

A smart metering communications infrastructure was modelled and simulated using OPNET. The impact of smart metering applications on smart metering communications requirements has been investigated. It is shown that individual communications requirements for smart meters are not particularly communications intensive and that infrequent large transactions posed the most significant challenges on the communications infrastructure. As the link speed decreased, large time delays were observed which have direct impact on the functions related to distribution network operations.

An evaluation method was then developed to quantify the impact of smart metering communications infrastructure on distribution network operation. The main characteristics of the smart metering communications infrastructure were modelled. The characteristics of load variation were analysed and used to quantify the relationship between the time delay and the measurement error of the power system. The measured data from smart meters was refined to be used by the distribution network operational functions using state estimation and the impact was quantified using optimal power flow. Results show that fast data access is necessary for smart meter data to be used by the voltage control and the power control functions of a distribution network.

The potential of using smart metering for outage management was investigated. A topology analysis method was developed which maps the physical plant model of a distribution network to a simplified analytical model. An outage area identification algorithm was developed which uses the information from smart meters and is based on the simplified network model. The outage area identification can act as one of the main functions of an outage management system providing possible outage extent information. The impact of smart meter communications on the outage area identification algorithm was investigated based on the OPNET communications model. Test results showed that smart metering has a potential to support outage management of a power distribution network. Test results showed that the arrival criterion and the smart metering communications infrastructure have a large impact on the performance of the outage area identification.

Declaration

This work has not previously been accepted in substance for any degree and is not concurrently submitted in candidature for any degree.

Signed..... (Candidate) Date.....

This thesis is being submitted in partial fulfilment of the requirements for the degree of PhD.

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This thesis is the result of my own independent work/investigation, except where otherwise stated. Other sources are acknowledged by explicit references.

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Dedication

For my family

Acknowledgement

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List of Figures

Figure 2.1 - Smart Grid vision	9
Figure 2.2 - Evolution of utility communications requirements.....	11
Figure 2.3 - Structure of a PLC system.	14
Figure 2.4 – Increasing the PLC capacity	15
Figure 2.5 - Communication technologies and hierarchical organisation of a Smart Grid network	20
Figure 2.6 - Smart Grid applications at distribution level.	23
Figure 2.7 - The “Telegestore” system architecture (Enel)	32
Figure 3.1 - General structure of the simulation.	39
Figure 3.2 - A network with low speed links.	41
Figure 3.3 - Equivalent network with mixed high and low speed links.	41
Figure 3.4 - Smart meter communications models in OPNET	43
Figure 3.5 - IP channel utilisation - traffic from controller based on the baseline network.....	65
Figure 3.6 - IP channel utilisation - traffic to controller based on the baseline network.	66
Figure 3.7- Physical channel utilisation - traffic from Controller	66
Figure 3.8 - Constrained - IP traffic - from Controller.....	67
Figure 4.1 - The proposed ICT infrastructure for smart distribution networks	71
Figure 4.2 - Framework of the evaluation method.....	73
Figure 4.3 - Sources of time delay	74

Figure 4.4- Simulation model of the proposed communication infrastructure that is used in this chapter.....	75
Figure 4.5 - Load data of a MV/LV transformer	77
Figure 4.6 - Influence of the one-hour communication delay.....	78
Figure 4.7 - Test system	80
Figure 4.8 - Time delay with different meter number under Scenario 1	82
Figure 4.9 - Time delay with 100-meter configuration under Scenario 1 (units: second)	82
Figure 4.10 - Nodal voltage estimates provided by the state estimator under Scenario 1	83
Figure 4.11 - Time delay with different meter number under Scenario 2	83
Figure 4.12 - Nodal voltage estimates provided by the state estimator under Scenario 2	84
Figure 4.13 - Time delay with different meter number under Scenario 3.	84
Figure 4.14 - Nodal voltage estimates provided by the state estimator under Scenario 3	85
Figure 4.15 - Operating points based on different input errors.	86
Figure 5.1 - Outage Management System	89
Figure 5.2 - System Interfaces proposed by IEC TC57 WG14	91
Figure 5.3 - Integration of smart metering and OMS.	92
Figure 5.4 - Key components of outage area identification using smart meter information.....	93
Figure 5.5 - Example of topology analysis	96
Figure 5.6 - Network information needed by the outage area identification algorithm.	97

Figure 5.7 - Flowchart of the Outage Area Identification algorithm.....	99
Figure 5.8 - Time slots and channels.	101
Figure 5.9 - Example of a round trip time.	102
Figure 5.10 - Possibilities of the polling procedure.	103
Figure 5.11 - 146-node physical plant model of a MV distribution network.	104
Figure 5.12 – 33-node simplified model.	104
Figure 5.13 - The 33-node network under fault condition.	105
Figure 5.14 - Results from the Ireland Trial on NPLC.....	106
Figure 5.15 - Results from simulation of the Irish NPLC communication network using OPNET	107
Figure 5.16 - Correlation between the number of smart meters and information arrival time.....	108
Figure 5.17 - 10 % arrival criterion and 8 out-of-service MV nodes using NPLC.	109
Figure 5.18 - 10 % arrival criterion and 33 MV nodes using NPLC.....	109
Figure 5.19 - 3-meter arrival criterion and 8 out-of-service MV nodes using NPLC .	110
Figure 5.20 - 3-meter arrival criterion and 33 MV nodes using NPLC.....	110
Figure 5.21 -10 % arrival criterion and 8 out-of-service MV nodes using BPLC	111
Figure 5.22 - 10 % arrival criterion and 33 MV nodes using BPLC.....	112
Figure 5.23 - 3-meter arrival criterion and 8 out-of-service MV nodes using BPLC .	112
Figure 5.24 - 3-meter arrival criterion and 33 MV nodes using BPLC.....	113

List of Tables

Table 2.1 - Comparison of functions of different smart meter technology (Samarakoon, 2009).	36
Table 2.2 - Comparison of benefits of different smart meter technology (Samarakoon, 2009).	37
Table 3.1 - The key application characteristics of AMR.....	46
Table 3.2 - The application transaction structure of AMR.....	46
Table 3.3 - The objectives exchanged and their sizes of AMR	47
Table 3.4 - The details of packet exchanges of AMR	47
Table 3.5 - The key application characteristics of collection of log files.	48
Table 3.6 - The application transaction structure of collection of log files	48
Table 3.7 - The objectives exchanged and their sizes of collection of log files	49
Table 3.8 - The details of packet exchanges of collection of log files	49
Table 3.9 - The key application characteristics of meter software update.	50
Table 3.10 - The application transaction structure of meter software update.....	50
Table 3.11 - The objectives exchanged and their sizes of meter software update.....	51
Table 3.12 - The details of packet exchanges of meter software update.....	51
Table 3.13 - The key application characteristics of communication of tariffs.	52
Table 3.14 - The application transaction structure of communication of tariffs	53
Table 3.15 - The objectives exchanged and their sizes of communication of tariffs...53	
Table 3.16 - The details of packet exchanges of communication of tariffs.....	54
Table 3.17 - The key application characteristics of system alarms.....	54
Table 3.18 - The application transaction structure of system alarms.....	55

Table 3.19 - The objectives exchanged and their sizes of system alarms	55
Table 3.20 - The details of packet exchanges of system alarms	56
Table 3.21 - The key application characteristics of Application 6.	56
Table 3.22 - The application transaction structure of Application 6	57
Table 3.23 - The objectives exchanged and their sizes of Application 6.....	57
Table 3.24 - The details of packet exchanges of Application 6.....	58
Table 3.25 - The key application characteristics of Application 7.	58
Table 3.26 - The application transaction structure of Application 7	59
Table 3.27 - The objectives exchanged and their sizes of Application 7.....	59
Table 3.28 - The details of packet exchanges of Application 7.....	60
Table 3.29 - The key application characteristics of Application 8.	60
Table 3.30 - The application transaction structure of Application 8	61
Table 3.31 - The objectives exchanged and their sizes of Application 8.....	61
Table 3.32 - The details of packet exchanges of Application 8.....	62
Table 3.33 - Baseline smart meter application timings	62
Table 3.34 - Trials.....	65
Table 4.1- Key parameters.	81
Table 4.2 - Input/output error of the state estimator	85
Table 5.1 - Glossary of terms used in topology analysis	94
Table 5.2 - The performance of the n -meter arrival criterion	113

List of Acronyms

Acronym	Meaning
3G	Third Generation of Mobile Phone Technology Services
AARE	Application Association Response
AARQ	Application Association ReQuest
AES	Advanced Encryption Standard
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
AMM	Automated Meter Management
AMR	Automated Meter Reading
ANN	Artificial Neural Network
APDU	Application Layer Protocol Data Unit
A-XDR	Abstract External Data Representation
BER	Basic Encoding Rules
BPLC	Broad Band PLC
COSEM	Companion Specification for Energy Metering
CRC	Cyclic Redundancy Check
DA	Distribution Automation
DCC	The Data Communications Company
DER	Distributed Energy Resource
DES	Data Encryption Standard
DG	Distributed Generation
DLMS	Device Language Message Specification
DMS	Distribution Management System
DNO	Distribution Network Operator
DSL	Digital Subscriber Lines
DSP	Data Service Suppliers
EC	European Commission
ENA	The Energy Network Association
ES	Expert System
FEC	Forward Error Correction
GA	Genetic Algorithm
GGSN	Gateway GPRS Support Node
GIS	Geographical Information System
GPRS	General Packet Radio Service
GSM	Global System for Mobile Communications
HANs	Home-Area Networks
HV	High Voltage
ICT	Information and Communication Technologies
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
JADE	Java Agent Development Framework
LMU	Line Matching Unit
LV	Low Voltage
MAC	Medium Access Control
MAS	Multi-Agent System
MTU	Maximum Transmission Unit
MV	Medium Voltage
NAN	The Neighbourhood Area Network
NPLC	Narrow Band PLC
OBIS	Object Identification System

OCR	Optical Character Recognition
OFDM	Orthogonal Frequency Division Multiplexing
OLTC	On Load Tap Changer
OMS	Outage Management System
OPF	Optimal Power Flow
OPNET	Optimized Network Engineering Tools
PDN	Public Packet Data Network
PDU	Protocol Data Units
PMR	Private Mobile Radio
PPM	Prepayment Meters
PPP	Point to Point Protocol
QoS	Quality of Service
RTU	Remote Telemetry Units
SA	Simulated Annealing
SCADA	Supervisory Control and Data Acquisition
SEC	The Smart Energy Code
S-FSK	Spread/Spaced Frequency Shift Key
SGSN	Serving GPRS Support Node
TCP	Transmission Control Protocol
TDMA	Time Division Multiple Access
TETRA	Terrestrial Trunk Radio
TSO	Transmission System Operator
UDP	User Datagram Protocol
UK	The United Kingdom
WAN	Wide Area Network
WPDU	Wrapper Protocol Data Units

Publications

1. Wu J, He Y, Jenkins N, A robust state estimator for medium voltage distribution networks, *IEEE Trans on Power Systems*, 28(2), (2013), 1008-1016
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Chapter 1

Introduction

1.1 Motivation

The conventional communications infrastructure of an electric power system consists of SCADA (Supervisory Control and Data Acquisition) systems with dedicated communication channels and Wide Area Networks (WAN). The SCADA systems connect all the major power system facilities: large central power plants, transmission networks, grid substations and primary distribution substations to the system control centre. The WAN is typically used for corporate business and market operations (Ekanayake, 2012). These form the core communications infrastructure of a traditional power system at the transmission level.

Compared to such central generation and transmission oriented communication systems, the communications infrastructure at the distribution level is very limited in terms of functionality and availability. Conventionally, the distribution network operation mostly relies on a simplified version of the transmission SCADA system. The distribution SCADA system is usually designed with a centralised architecture interconnecting a master terminal located at the distribution control centre with many Remote Telemetry Units (RTUs) located at geographically dispersed sites. The key feature of such communications infrastructure is its heterogeneity in terms of communication medium (e.g. fibre, private wire, telephone lines, satellite and mobile radio) and channel capacity (from a few hundred to a few thousand bits per second) (Ekanayake, 2012).

Over the last few decades, electric power distribution networks have been facing a continuity of significant modifications due to an increasing amount of Distribution Energy Resources (DERs, in the form of distributed generation, energy storage and flexible demand) being connected to the distribution networks. This trend has mainly been driven by advances in

DER technology and the pressures to achieve a low-carbon future. With DER, the distribution network is no longer passive, but an active system which allows coexistence of bi-directional power flows (Jenkins, 2010). Moreover, the energy supplied/absorbed by these DERs is usually intermittent and hence difficult to predict and control. This brings about new operational challenges to distribution network operators (DNOs), e.g. voltage rise effect, increased fault level and fault management. DNOs need to actively manage these challenges. In addition, the distribution networks have the greatest opportunity for smart interventions, therefore mass investment is required to ensure that distribution networks can cope with this. The distribution network will need to become smarter, so more efficient and effective operation and communications solutions are urgently needed for a better management of the distribution networks.

As a result, Smart Grid has been proposed which is widely recognised as the future of modern electrical power systems. It involves modernising existing networks, changing the way they operate, facilitating changes in the behavior of energy consumers, providing new services, and supporting the transition to a sustainable low-carbon economy (Sun, 2010).

In Great Britain, the Smart Grid has been primarily focused on the distribution networks and smart metering is widely considered as a critical step towards the Smart Grid future. The UK government has committed to the rollout of smart meters for both electricity and gas in all homes and most small businesses by the end of 2020. A sum of £8.6 billion will be spent in replacing some 47 million gas and electricity meters, which are expected to deliver total benefits of £14.6 billion over the next 20 years (DECC, 2010B).

Although the purpose of the smart metering development is not primarily to benefit electric power networks, it does offer significant potential benefits for the power network planning, operation and management. The analysis of load and voltage profiles obtained from smart meters will allow improved asset utilisation of distribution networks. At present, the DNOs use generic profiles of domestic loads when assessing requirements for new connections and network reinforcement. These load profiles are likely to change in future due to the increasing connection of heat pumps and electric vehicles along with more prevalent demand response schemes. Using recorded smart meter data will provide a more accurate basis for the prediction of likely future voltage and demand operating ranges. This will enable network designers to specify equipment more accurately, reduce overspending on new equipment, and defer investment in asset replacement (Thomas, 2012). The use of smart

meters can help distribution network operation. The real-time, close to real-time or off-line energy consumption and power quality information are able to be used by a number of distribution network operational functions, e.g. load allocation, load forecasting, state estimation, voltage control and fault management. As a detailed example, smart meter information can be used to locate outages and reduce the supply restoration time (Thomas, 2012). Smart metering systems are also seen as a precursor to the widespread implementation of demand response. Smart meters in GB will support demand response through the communication of pricing levels to users, along with provision for incentive-based schemes such as direct load control.

A strong smart metering communications infrastructure, which meets the requirements of low latency, high bandwidth and high quality of service (QoS), is a key to deliver the aforementioned network benefits. The smart metering communications infrastructure and the dedicated DNO communication networks would tie together the meter end-points, the utility mobile workforce, advanced sensors and control centres into a single integrated network to support the smart distribution network operation.

Smart Grid applications require a specific level of assurance from the communications networks. Such requirements mainly focus on the quality of information provided by the ICT (Information and Communication Technologies) infrastructure. Regarding power system operation, the main requirements for Smart Grid applications are on the accuracy and latency of real-time measurements. Currently there is a lack of methods to quantify the impact of smart metering on distribution network operation. Various methods and tools have been developed to simulate the communications infrastructure of smart metering. However, these methods and tools cover either detailed communications network simulation ignoring the distribution network operation, or detailed analysis of distribution network operation without sufficient representation of communications in their modelling.

The overall aim of this work was to quantify the impact of smart metering applications on communications requirements, develop an evaluation method to quantify the impact of smart metering communications infrastructure on distribution network operation, and achieve a better understanding on the potential of using smart metering for outage management, which is one of the most critical distribution network operational functions.

1.2 Research Objectives

In order to fulfil the overall aim, three specific research objectives were defined.

- The first objective was to develop a method to model and simulate a realistic smart metering communications infrastructure and investigate the impact of smart metering applications on communications requirements. Representative smart metering applications used for the analysis need to be chosen and implemented in IEC 62056 (which is a set of standards for electricity metering data exchange by the International Electrotechnical Commission). New modelling and simulation methods need to be built which include physical and application components. The “last mile” channel size required to support smart metering communications using the Internet Protocol (IP) needs to be quantified.
- The second objective was to develop an evaluation method to quantify the impact of smart metering communications infrastructure on distribution network operation. The main characteristics of the smart metering communications infrastructure need to be modelled, e.g. response time of a smart meter. The characteristics of the distribution network, mainly the load variation behaviour, need to be analysed and used to quantify the relationship between the time delay and the measurement error of the power system. The measured data from smart meters needs to be refined to be used by the distribution network operational functions. An evaluation method which integrates the communications infrastructure modelling with distribution network operation needs to be developed.
- The third objective was to investigate the potential of using smart metering for outage management. The outage management system (OMS) plays an important role in the operation of distribution networks and is one of the key applications in the distribution network control centre. Outage management has been identified as a very promising power system application which can receive benefits immediately from the large-scale roll-out of smart meters. An outage area identification method based on topology analysis and smart meter information needs to be developed. The smart metering communication models need to be used to quantify the impact of the communications performance of smart metering on outage management.

1.3 Thesis Structure

The remaining chapters are organised as follows.

Chapter 2 gives background information and reviews previous literature. The chapter addresses all areas of the research, which are Smart Grids, the role of communications in the Smart Grid development, communications technologies, communications network modelling and smart metering.

Chapter 3 investigates the impact of smart metering applications on communications requirements. Modelling and simulation of smart metering communications infrastructure was carried out using the network simulation tool OPNET (Optimized Network Engineering Tools). Ethernet over power line was used as the physical layer medium. Representative smart metering applications used for the analysis were chosen and implemented in IEC 62056. The OPNET simulation was built including physical and application components and the model was validated before use. Several selected applications were simulated on a test network to examine the bandwidth impacts of last mile links under several scenarios.

Chapter 4 introduces a method to evaluate the performance of smart metering infrastructure in supporting the Smart Grid operation. The smart meters and Power Line Carrier (PLC) based ICT infrastructure was modelled in OPNET. The model is integrated with a state estimator (Wu, 2013) and an Optimal Power Flow (OPF) tool (Zimmerman, 2007) to set up a platform for analysing the feasibility and performance of smart metering infrastructure in supporting the Smart Grid operation.

Chapter 5 presents an outage area identification method based on topology analysis and smart meter information. This method was combined with the smart metering communications models to evaluate the impact of the communications performance of smart metering infrastructure on outage management.

Finally, Chapter 6 summarises this work and highlights its contributions. It also presents ideas for future work.

Chapter 2

Previous Research and Background

This chapter provides an overview of principles, methods and state of the art that are relevant to this work. First, the Smart Grid vision is introduced. The role and requirements of communications in the Smart Grid are discussed. This is followed by a literature survey of suggested communications technologies that the operational functions of distribution networks are likely to utilise. This leads to the discussion of previous research on analysis of Smart Grids applications and their communications infrastructure. Finally, this chapter concludes by reviewing the smart metering development and its potential roles to support distribution network operation, which serve as a basis for this work.

2.1 Smart Grids

There are two key drivers for the Smart Grid development: the policy driver and the technology driver, which push the modernisation of current power systems.

- Policy Driver

In 2009, the European Commission (EC) passed legislation to ensure that the European Union (EU) meets its ambitious climate and energy targets for 2020. These targets are known as the “20-20-20” Renewable Energy Directive, in which three key objectives were set (European Commission, 2009b): a 20% reduction in EU greenhouse gas emissions from 1990 levels; raising the share of EU energy consumption produced from renewable resources to 20%; and a 20% improvement in the EU’s energy efficiency. Within these overall targets, individual member states have been given different specific targets suited to their climates and circumstances; the target for the United Kingdom (UK) is to produce 15% of primary energy from renewable energy sources by 2020. Since the adoption of this directive, most

member states in the EU have experienced significant growth in renewable energy consumption.

The 2030 climate and energy framework was adopted by EU leaders in October 2014 which sets three key targets for the year 2030: at least 40% cuts in greenhouse gas emissions (from 1990 levels); at least 27% share for renewable energy; and at least 27% improvement in energy efficiency (European Commission, 2014).

The Climate Change Act 2008 (HM's Stationery Office and Queen's Printer of Acts of Parliament, 2008) established a legally binding target to reduce the UK's greenhouse gas emissions to at least 80% lower than the 1990 level by 2050. There was also a target set that emissions should be a third lower than the 1990 level by 2020.

Obviously electricity lies at the heart of these changes. Currently, GB has around 78 GW of generation capacity, leaving around 34% surplus capacity (known as gross capacity margin) over electricity demand at peak times (considered to be 58 GW) (Royal Academy of Engineering, 2013). With the potential electrification of heating, transport, and industrial processes, average electricity demand may rise by between 30% and 60% (HM Government, 2011).

In order to host a large penetration of low carbon technologies, power systems, especially electricity distribution networks, must be modernised for a better visibility, controllability and hosting capacity.

- Technology Driver

The technology driver mainly includes three aspects: aging assets, operational constraints, and reliability of supply.

In many countries, the transmission and distribution infrastructure is now beyond its design life and in need of replacement. The capital costs of like-for-like replacement will be high. The need to refurbish the transmission and distribution circuits is an obvious opportunity to innovate with new designs and operating practices. Some of the existing equipment is operating near their capacity, which limits the connection of renewable generation (Ofgem, 2009). This replacement requests more intelligent methods to dynamically increase the power transfer capacity of circuits and rerouting the power flows through less loaded circuits.

A large penetration of distributed energy resources may cause power system operation problems, e.g. violation of frequency limits, over-voltage, protection malfunction due to reverse power flow, thermal limit violation, excess fault level, etc (Jenkins, 2010).

More and more intermittent energy sources and demands are being connected to the power system, which is lowering the overall predictability and controllability of the power system. In the meantime, the electricity capacity margin is decreasing, which increases the risks to the security of the supply (Ekanayake, 2012).

Therefore, the grid will need a smarter operation in order to reflect the quantity, geography, and intermittency of power generation and to cope with the new forms of demand. Otherwise, conventional and expensive network reinforcement must be carried out.

2.1.1 The Smart Grid Vision

A growing recognition of the need to modernise the electric power grid to meet tomorrow's challenges has found articulation in the vision of a Smart Grid. Multiple industry and research groups have created architectural blueprints for the evolution of today's power grid into a Smart Grid that share several common features. The Smart Grids will offer several benefits to utilities and consumers (US Department of Energy, 2004):

- provide utilities the ability to monitor and manage their power delivery down to the home or business in real time;
- enable utilities to offer multiple rate structures to manage demand peaks and offer demand management services to encourage efficiency;
- allow utilities to manage outages more effectively by reducing their occurrence through better monitoring and control of the grid and by reducing the impact of outages through more efficient and early problem isolation;
- allow utilities to delay the construction of new plants and transmission lines and better manage their carbon output through implementing measure such as demand response;
- allow utilities to provide real-time information to their customers and to utility workers in the field, resulting in operational efficiencies and more reliable services;

- allow utilities to more proactively manage the integration of clean energy technologies into the grid to maximise their environmental benefits and operational values.

The Smart Grid is envisioned to offer these benefits by enabling and enhancing a broad range of utility applications, including smart metering, outage management, demand management, distribution automation, etc, as shown in Fig. 2.1.

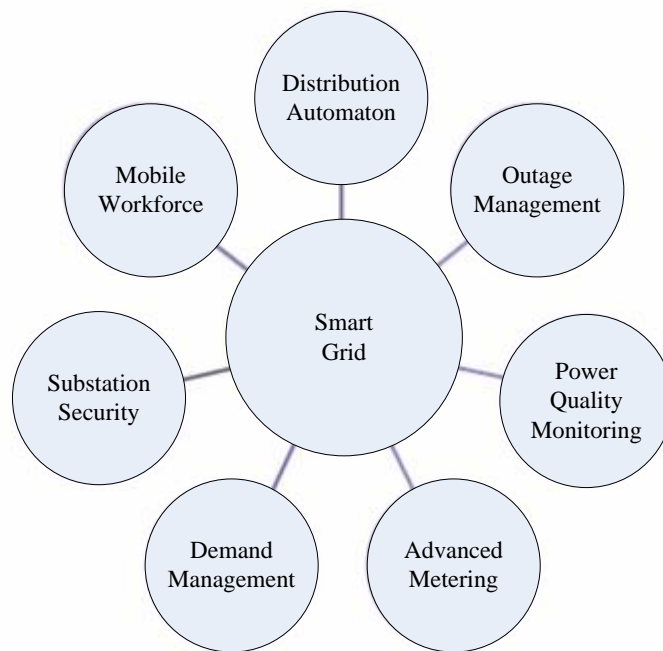


Fig. 2.1 Smart Grid vision (US Department of Energy, 2004)

Smart Grids are expected to make extensive use of modern information and communication technologies (ICT) to support a flexible, secure, and cost-effective decarbonised electrical power system. A Smart Grid is capable of controlling active networks intelligently to facilitate the integration of renewable energy into the power system (Jenkins, 2010).

Various definitions of the smart grid have been used by different countries and no single universal concept has been agreed on. This section presents two definitions that are often used in the UK.

- The concept of the Smart Grid, developed in 2006 by the European Technology Platform, is that “A Smart Grid is an electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those

that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies”.

- The definition provided by the Energy Networks Association (ENA) is that “The Smart Grid is everything from generation through to home automation with a smart meter being an important element, with every piece of network equipment, communications technology and processes in between contributing to an efficient and smart grid” (Energy Network Association, 2014)”.

A Smart Grid employs innovative products and services together with intelligent monitoring, control, communication and self-healing technologies in order to (Ekanayake, 2012; Jenkins, 2010; European Commission, 2006):

- better facilitate the connection and operation of generators of all sizes and technologies;
- allow electricity consumers to play a part in optimising the operation of the system;
- provide consumers with more information and better options choosing their energy supplier;
- significantly reduce the environmental impact of the total electricity supply system;
- deliver enhanced levels of reliability, quality and security of supply; and
- make the best use of electricity network infrastructures by proper asset management.

A Smart Grid of the future will enable appliances in the home to communicate with the smart meter and enable the networks to ensure efficient use of infrastructure, demand response and energy management. These are all critical to making the most of intermittent renewables and keeping the lights on in an affordable low-carbon energy future.

2.1.2 Evolution of Electric Utility Communication Requirements

In the last decades there has been a steady progression in communications requirements for utility applications as the applications themselves have evolved. One-way communications networks for reading meter data gave way to more advanced two-way communications down to the meters, supporting applications such as demand response (Tropos GridCom, 2009). Many utilities are in the process of implementing outage notification and remote

connect/disconnect using smart metering infrastructure. Figure 2.2 shows this evolution. The Smart Grids vision includes the need of a logical extension to encompass two-way broadband communications supporting a broader range of operational applications of distribution networks, e.g. distribution automation and control, power quality monitoring and substation automation, etc.

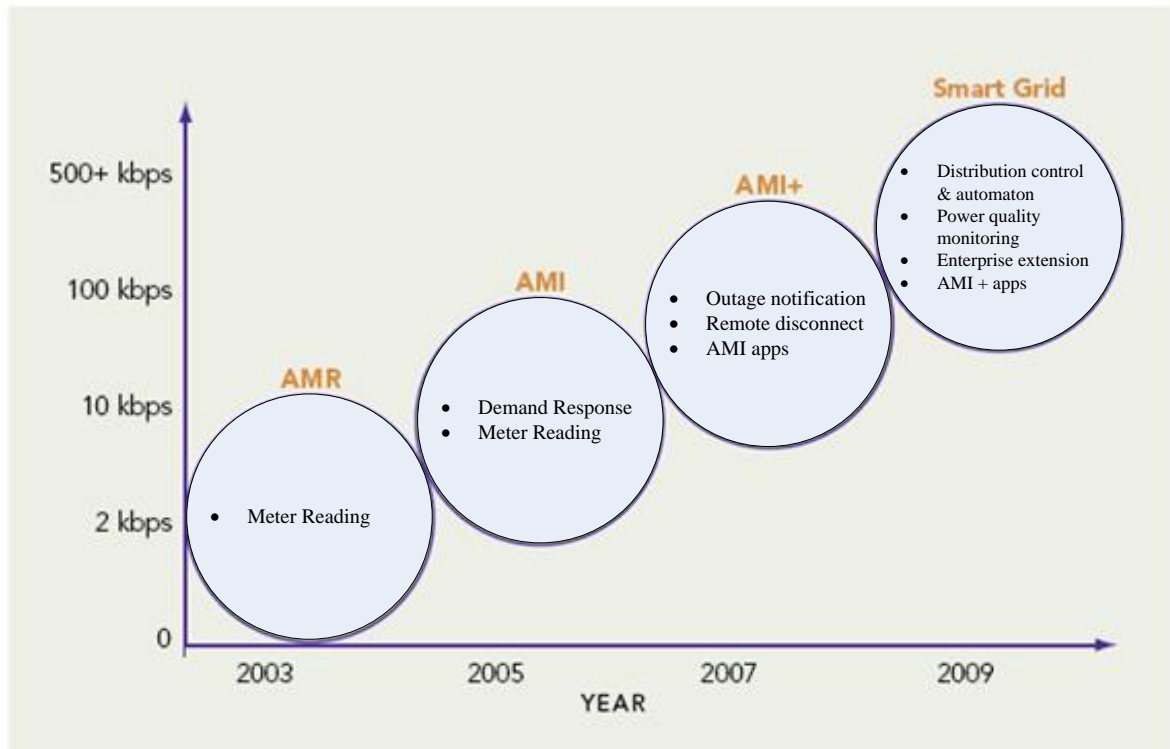


Fig. 2.2 Evolution of utility communications requirements (Tropos GridCom, 2009)

AMR - Automatic Meter Reading; AMI – Advanced Metering Infrastructure

2.1.3 Role of Communications in the Smart Grids

Conventionally, the communications infrastructure for monitoring and control of the power grid consists of many protocols and systems (Tropos GridCom, 2009). They are often proprietary and mutually-incompatible, including leased lines, fixed Radio Frequency (RF) networks, microwave links and optical fibre. Purpose-built communications networks are usually used for different application systems (Ekanayake, 2012). For example, it is typical today for a utility to use separate communications networks for SCADA, automated meter reading and mobile workforce access. Conventional automated meter reading systems for collecting meter data are still predominantly based on one-way low-bandwidth communications technologies. These one-way communications technologies need to be updated to support the low-latency bidirectional traffic flows needed to enable applications

such as demand response and outage management. The poor communications infrastructure underlying the monitoring of distribution networks leads to inadequate situational awareness for distribution network operators who are often blind to network constraints violations. There is no unified broadband communications infrastructure in place today that can simultaneously serve the needs of distribution automation, mobile workforce automation, smart metering, SCADA and other applications (US Department of Energy, 2004).

Broadband communications underpins the Smart Grids: many of the newer capabilities, such as DG (Distributed Generation) control, demand response and remote disconnects, require real-time two-way communications capabilities down to the meter end-points. Distribution automation applications require as close to sub-cycle latencies as possible. Advanced sensors that generate larger volumes of data require real-time high-speed communications links back to control centres. Utility field workforces employing bandwidth-intensive productivity applications such as mobile GIS (Geographical Information Systems) need a communications network that is high capacity and supports seamless mobility for standards-based wireless devices (US Department of Energy, 2004; Ekanayake, 2012). Therefore a strong communications infrastructure plays a critical role in the Smart Grid development.

2.1.4 Requirements on Communications Infrastructure of Smart Grids

Requirements on the communications infrastructure are usually different for different Smart Grid applications. The general requirements are listed below (US Department of Energy, 2004; National Energy Technology Laboratory, 2007; Ekanayake, 2012).

- **Standards-based:** The communications infrastructure needs to be based on standards to ensure support for the diverse set of utility applications and to provide investment protection. Applicable standards pertain to radio communication protocols, networking interfaces (TCP/IP) and industry standard security specifications.
- **IP (Internet Protocol) network:** A network that is based on IP provides the broadest possible platform for the delivery of a wide range of applications.
- **Real-time:** The network needs to provide the real-time low latency communications capabilities that are needed by applications such as distribution automation and outage detection and management.

- Scalable: The network and its network management system need to be capable of scaling to various utilities.
- Resilient and high availability: to meet the reliability requirements imposed on utilities, the network architecture must be resilient and capable of continuing to operate even in the presence of localised faults.
- Secure: since the grid and its components comprise critical infrastructure, the communications infrastructure for the Smart Grids needs to provide a secure foundation for information flow and conform to industry-standard security specifications.
- Supports traffic prioritisation: The communications network must be capable of prioritised delivery of latency-sensitive critical applications such as distribution automation, and over latency-insensitive traffic types such as metering data.
- Mobile: The network must support mobility to enable mobile workforce connectivity applications.
- Future-proof: in view of the long network lifetimes, the underlying network architecture and network elements must be selected so as to provide broad investment protection.
- Cost competitive: The communications infrastructure must be cost-competitive (Capital expenditure, CAPEX, as well as operational expenditure, OPEX).
- Broad coverage: The communications network should be capable of delivering broad coverage.

2.2 Communications Technologies

2.2.1 Overview of Different Communications

This section introduces some basic current communications and analyses the technical performance of each technology, its advantages and disadvantages.

2.2.1.1 Power Line Carrier (IEC 60495, 1993)

Power Line Carrier (PLC) uses the high voltage power line as a physical communication media. It offers the possibility of sending data simultaneously with electricity over the same medium. Therefore, the only cost incurred by PLC is the cost of additional terminal equipment, as well as repeaters, since the physical connection already exists.

PLC uses a Line Matching Unit (LMU) to provide the connection to the high voltage transmission or distribution line and prevents the injected signal from spreading to other parts of the power network (usually using a line trap). LMUs are usually implemented using capacitors. However, if the voltage transformer has a capacitive structure, it can also be utilised for line connection. The structure of a PLC system is shown in Fig. 2.3.

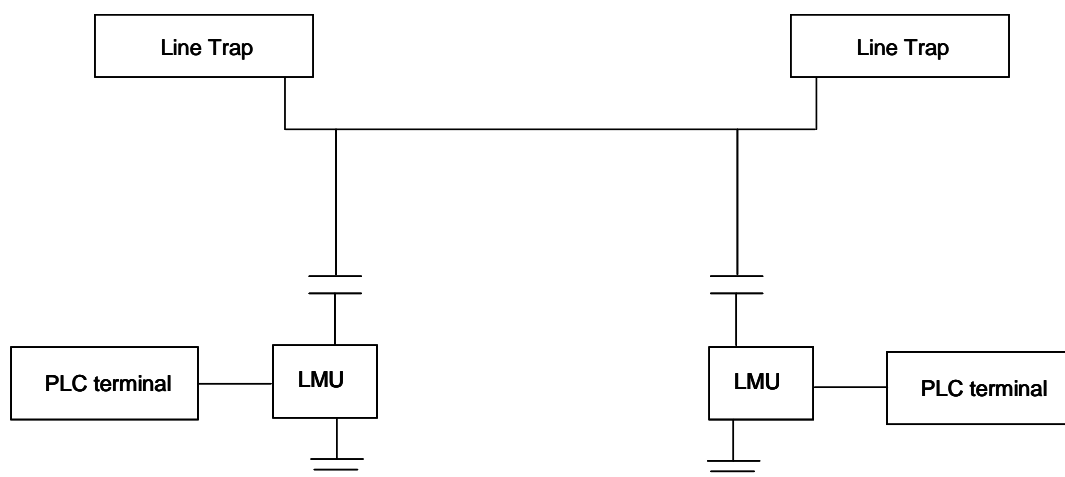


Fig. 2.3 Structure of a PLC system (IEC 60495, 1993)

The standard IEC 60495 (IEC 60495, 1993) defines the frequency band allocated for PLC as between 24 kHz and 500 kHz, and the width of a PLC communication channel as 4 kHz, with typically 64 kb/s per channel. By using a higher frequency, the PLC communication

will require a smaller line trap inductance; hence the communication cost will be reduced. However, this higher frequency will induce higher attenuation limiting the communication span. In practice the maximum distances are a few hundred kilometres. If longer distance communication is required, PLC terminals can be used to amplify the transmission signal as illustrated in Fig. 2.4.

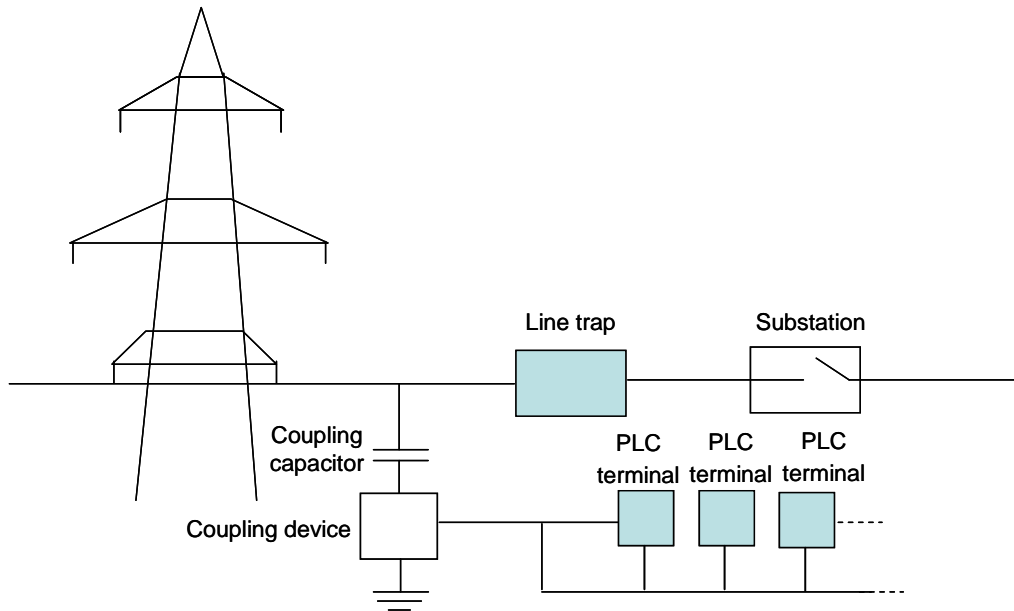


Fig. 2.4 Increasing the PLC capacity (IEC 60495, 1993)

The main technical drawback with using PLC over distribution networks is the impedance mismatch resulting from the transition from an over-ground line to an underground line or the opposite. In case of more than one transition, the quality of the communication will be affected by reflections created by the mismatches resulting from the transitions. To overcome this problem, additional equipment needs to be installed at every transition in order to reduce the effect of the mismatch. Therefore, before PLC is implemented, a full analysis of the distribution power network must be performed in order to determine the power line transitions.

2.2.1.2 Radio (Barry, 2003)

In power networks, control substations are often sparsely distributed and are far away from the control centre. For such long distances, the use of copper wire or optical fibre requires a lot of effort for digging and laying cables as well as high costs.

Although radio communication cannot replace the bandwidth offered by wired technology, the reliability, performance and running costs of radio networks have matured considerably over the past few years. Radio links, represent an alternative for communication between the control centre and primary substations, and even between different power network control entities (grid substations, primary substations, secondary substations, etc).

Microwave Radio

Microwave radio refers to radio systems operating at frequencies above 1 GHz, offering high channel capacities and transmission data rates. Microwave radio is widely used in long distance communications systems as an alternative to coaxial cable and fibre optics. Parabolic antennas can be mounted on masts and towers to send a beam to another antenna tens of kilometres away. Microwave radio offers bandwidth which ranges from few Mb/s to 155 Mb/s. However, the capacity of transmission over a microwave radio is proportional to the radio frequency used. The higher the frequency, the bigger the transmission capacity is, but the shorter the transmission distance. In addition, microwave radio requires line of sight between the two ends of the connection; hence, high masts are required. In case of long distance communications, the installation of high radio masts will be the major cost of microwave radio.

Ultra High Frequency (UHF)

Another alternative for wireless communication is the UHF-radio. UHF radio designates a range of electromagnetic waves whose frequency is between 300 MHz and 1 GHz. Unlike Microwave radio, UHF does not require the line of sight, and therefore, the installation cost is decreased as high masts are not needed.

UHF radio requires only a radio modem and an antenna and depending on the size of the antenna size, it can span over 10-30 km offering a bandwidth that can reach 192 kb/s. Moreover, the UHF radio can also be used as a relay radio station, hence, expending the

possible communication span. However, the number of hops may affect the capacity of the radio channel, i.e. more hops may decrease the effective transmission bandwidth.

UHF radio represents an excellent choice for applications where the required bandwidth is relatively low and where the communication end-points (control substations) are widespread over harsh terrain with many high obstacles where it is difficult to establish a line of sight.

2.2.1.3 Mobile Radio

During the last decades, mobile radio networks have witnessed an important expansion with the development of the cellular phone and mobile access to data. The standard that has enabled this development is GSM (Global System for Mobile Communications). Since the development of this standard mobile systems and infrastructures have been built in most countries worldwide. Initially designed to carry voice only, public mobile radio systems have evolved to support data traffic. In recent years, it has been recognised that public mobile radio has a potential that makes it a suitable communication solution for remote control and monitoring applications (Wilson, 2005; Ozdemir, 2006).

Global System for Mobile Communications: GSM (Barry, 2003)

GSM is an ETSI (the European Telecommunications Standards Institute) standard developed for the European public mobile telephony networks. GSM offers both voice and short message service (SMS) data communication. The SMS data service allows message lengths of up to 160 characters, with up to four separate messages concatenated together. However, SMS messages are given low priority by the network and there are no guarantees of delivery.

General Packet Radio Service (GPRS) (Barry, 2003)

GPRS can be considered as an extension of GSM mobile communication technology, for applications that go further than just voice. GPRS uses the existing GSM network and adds two new packet-switching network elements: the GGSN (Gateway GPRS Support Node) and the SGSN (Serving GPRS Support Node). The GGSN acts as a logical interface toward the external PDN (Public Packet Data Network) or other GPRS networks. The SGSN controls the connection between the network and the mobile stations.

Although GPRS operates on the same radio bands as GSM (900 MHz and 1800 MHz) and shares the base stations with it, a different terminal is required to connect to a GPRS

network. GPRS can be considered as an add-on data service to existing GSM technology with the difference that this service is always on. This makes GPRS much more suitable for wireless data communication than GSM. GPRS data rates can reach up to 170 kbps.

Third Generation of Mobile Phone Technology Services (3G) (Barry, 2003)

Third generation or 3G phone services takes the packet switched network a step further by providing a handset permanently connected to the network, hence removing the need for the connection initialization that is usually required in GPRS before transferring data. 3G communication services are built around data communication rather than voice as is the case with GSM and GPRS systems. Unlike GSM and GPRS, 3G operates at higher frequencies (around 2GHz), hence higher bandwidths are available giving a theoretical maximum data capacity of 2 mbps. In reality, reaching the 2 mbps is very difficult as a 3G terminal needs to acquire most of the spread sequences in the cell. However, 3G is better than GSM and GPRS technologies in the sense that it increases the users/bandwidth ratio and offers a higher data packet transmission capacity.

Private Mobile Radio (PMR) (Barry, 2003)

Unlike public mobile radio communication systems, PMR systems have been specifically designed for reliable professional use, which make them more suitable for power control systems. Similar to the progress made in public mobile radio networks, a standard for PMR has been developed by ETSI, called Terrestrial Trunk Radio (TETRA). Unlike GSM, TETRA targets only public safety and security applications as well as private companies' control systems such as utilities. Although being an open standard, TETRA network services are designed to be used in a closed environment which represents an advantage over public mobile radio GSM based networks.

2.2.1.3 Other Communications Technologies

There are several other communications technologies which have been or could be used for applications of distribution network operation.

Satellite communication technology has been used for many years in the domains of telecommunications and networking, and has been also adopted in SCADA applications.

This technology provides an extensive geographic coverage which makes it a good alternative for substation automation in order to reach remote substations (Barry, 2003).

Digital Subscriber Lines (DSL) allows the transmission of data over ordinary copper twisted-pair telephone lines at high frequencies which can go up to several MHz, providing broadband digital services. DSL collectively refers to group technologies that utilise the unused bandwidth in the existing copper access network to deliver high-speed data communication.

An optical fibre (or optical fibre) is a flexible, transparent fibre made by drawing glass (silica) or plastic to a diameter slightly thicker than that of a human hair (Senior, 2009). Optical fibres are used most often as a means to transmit light between the two ends of the fibre and find wide usage in fibre-optic communications, where they permit transmission over longer distances and at higher bandwidths (data rates) than wire cables. Fibres are used instead of metal wires because signals travel along them with lesser amounts of loss; in addition, fibres are also immune to electromagnetic interference, a problem from which metal wires suffer excessively. Fibres are also used for illumination, and are wrapped in bundles so that they may be used to carry images, thus allowing viewing in confined spaces, as in the case of a fiberscope. Specially designed fibres are also used for a variety of other applications, some of them being fibre optic sensors and fibre lasers. Optical networks play a key role in Smart Grid systems. Fibre to Ethernet converters are critical in Smart Grid applications. Most local Smart Grid systems need to be built on Ethernet for a variety of reasons, so making fibre work depends on media converters that enable Ethernet interoperability (Perle, 2016). Optical fibre is usually used as the core communication infrastructure and is not often used at the distribution level due to its high cost.

The ZigBee and Z-Wave short-range wireless technologies are widely used for remote monitoring and control. However, their specifications and applications are different. Both technologies are ideal for home-area networks (HANs), with a range around 10-30 meters. Because this thesis focuses on network applications, ZigBee and Z-Wave will not be considered in detail.

4G is the 4th generation of wireless mobile telecommunications technology, succeeding 3G. 5G is the 5th generation mobile networks, which is the proposed next telecommunications standards beyond the current 4G standards. Rather than faster peak Internet connection

speeds, 5G planning aims at higher capacity than current 4G, allowing higher number of mobile broadband users per area unit, and allowing consumption of higher or unlimited data quantities in gigabyte per month and user. Both 4G and 5G have a big potential for the future Smart Grid applications.

2.2.2 A Wide-Area Aggregation Network for Smart Grids

2.2.2.1 The Hierarchical Organisation of a Smart Grid Network

The expansion in the range of power system networked applications is driving the evolution of communications system requirements. It is helpful to consider the overall network hierarchy extending from the utility core network out to the endpoints and evaluate the requirements at each layer of the network to understand where and how each of these technologies best fits. The communications technologies and hierarchical organisation of a Smart Grid network are shown in Fig. 2.5 (Tropos GridComTM, 2009).

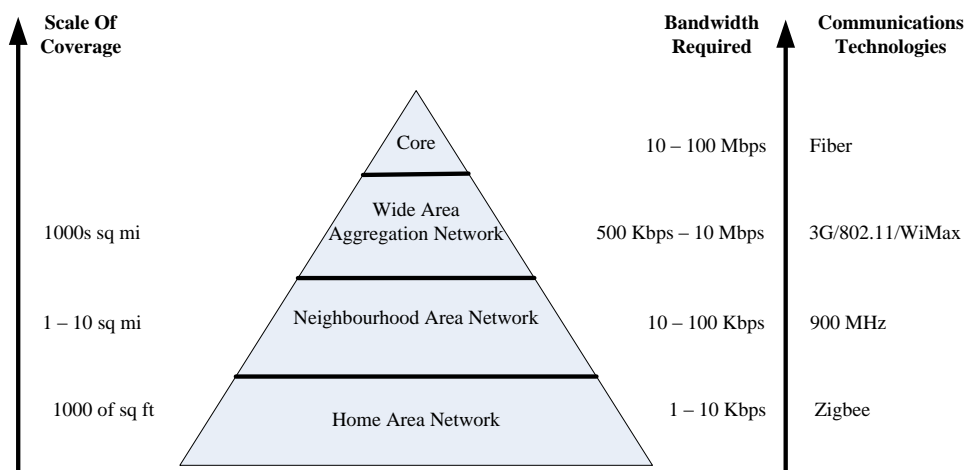


Fig. 2.5 Communication technologies and hierarchical organisation of a Smart Grid network (Tropos GridCom, 2009)

There is, typically, a hierarchy of networks extending from the Home Area Network through the Neighbourhood Area Network and the Wide-area Wireless Aggregation Network back to the Core. At each of these network layers there are distinct networking requirements and, correspondingly, different networking technologies that are most appropriate to meet those requirements.

- The Home Area Network (HAN) is inherently a multi-vendor environment composed of appliances and devices that need to network together seamlessly using

open standards. Bandwidth requirements are low (1-10 kbps) but ease-of-configuration, plug-and-play and low power consumption are essential. Home Area Networks cover areas of 1000's of square feet. Zigbee and HomePlug are examples of standards that meet these requirements (Tropos GridCom, 2009).

- The Neighbourhood Area Network (NAN) requires higher bandwidths (10-100 kbps) and two-way communication capability (for meter reading, demand response, remote disconnect, etc.). The network needs to cover thousands of homes and businesses, typically offering coverage over a few square miles. The architecture needs to be resilient and the protocols need to support meshing between meters. Radio technology used at this layer needs to offer low latencies (<10s) and excellent propagation in challenging RF environments. 900 MHz mesh networks have emerged as a common way to meet these requirements at the metering network layer, and key alternatives include PLC and licensed fixed RF systems.
- The Wide-area Aggregation Network, since it is increasingly used to aggregate traffic from multiple applications including metering, distribution automation & control and SCADA, needs to support even higher bandwidths (500 kbps - 10 mbps) and lower latencies (<milliseconds) and cover much larger areas, from the tens of square miles to thousands of square miles. It needs to extend the utility's fibre out from the substations into the broader territory to provide wide coverage at reasonable cost. It needs to offer standards-based interconnections to the diversity of applications and endpoints. It also needs to support Quality of Service guarantees for delay-sensitive applications and multi-layer security. 802.11, WiMAX and 3G data networks are mature proven technologies capable of meeting these requirements at the wide areas network layer.
- The Core Network connects back to the utility enterprise network and is frequently backhauled today through utility-owned fibre or high-speed microwave point-to-point links at substation locations that offers 100+ Mbps of capacity.

2.3 Smart Grid Applications and Analysis of Their Communications Infrastructure

2.3.1 Smart Grid Applications

2.3.1.1 Distribution Management Systems

This section focuses on Smart Grid applications at distribution level. Distribution systems are extensive and complex and so they are difficult to monitor, control, analyse and manage. Real-time monitoring and remote control is very limited in today's electricity distribution systems and so there is a need for intervention by the system operators particularly during wide-spread faults and system emergencies. However it is difficult to deal with such a complex system through manual procedures.

There are a number of applications used by the Distribution Network Operators (DNO) to monitor, control and optimise the performance of the distribution system. These applications are usually implemented into Distribution Management Systems (DMS). A DMS includes a number of applications that use modelling and analysis tools together with data sources and interfaces to external systems, as shown in Fig. 2.6. The modelling and analysis tools are pieces of software which support one or more applications. Data are usually collected by the SCADA system; a number of modelling and analysis tools, e.g. power flow and state estimation, are used to model the physical system and analyse the system states; and a number of advanced functions, e.g. outage management, are used to monitor, operate and manage the distribution network. The users usually interact with the DMS through the graphical user interface.

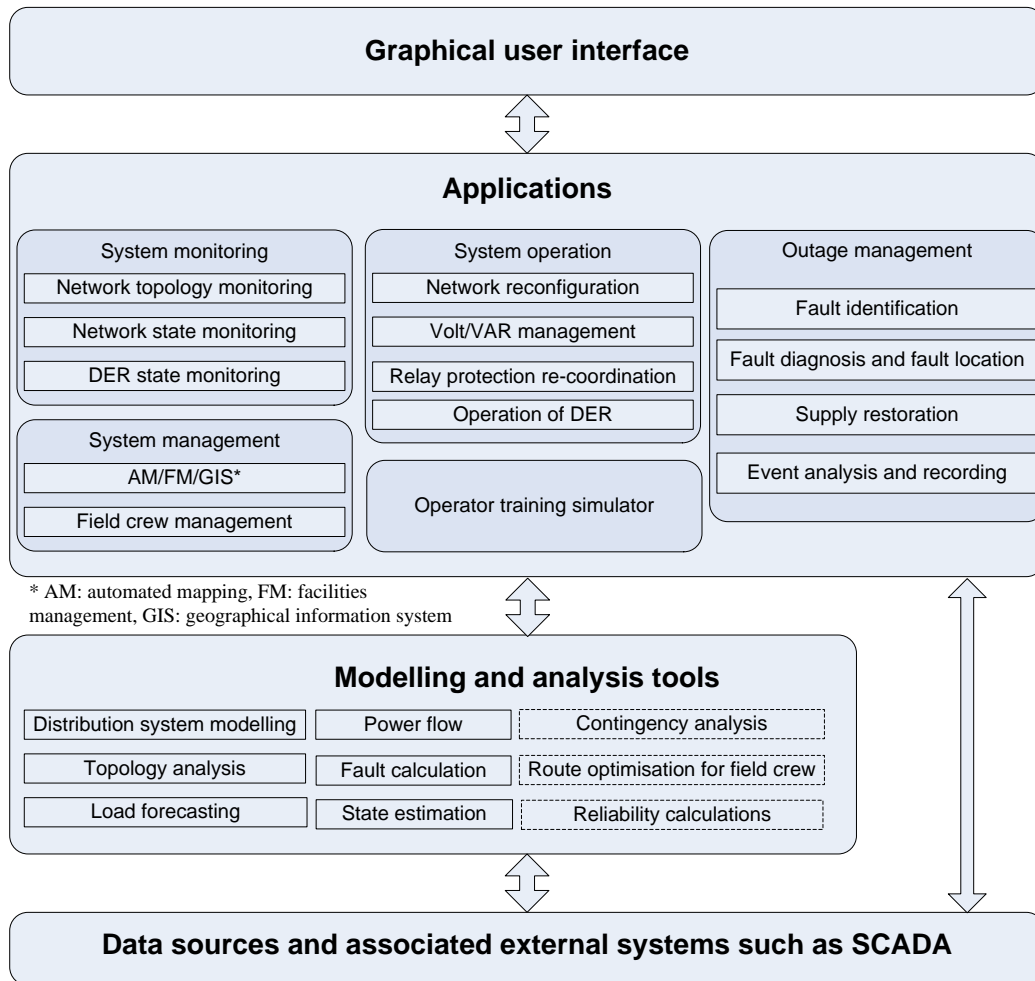


Fig. 2.6 Smart Grid applications at distribution level (Ekanayake, 2012)

2.3.1.2 Outage Management (Ekanayake, 2012)

As can be seen from Fig. 2.6, the Outage Management System plays a critical role in the Smart Grid applications.

The OMS is a system which combines the trouble call centre and DMS tools to identify, diagnose and locate faults, then isolate the faults and restore supply. It provides feedback to customers that are affected. It also, analyses the event and maintains historical records of the outage as well as calculating statistical indices of interruptions.

After a fault occurs, the remedial action depends on the severity of the problem. If the fault is a simple problem, the field crew can make the repair and restore supplies in a short time. If the fault causes a major outage, after the isolation of the faulted area, the un-faulted portions

will be restored using normally open points. The OMS tracks partial restorations. Automated fault detection, isolation, restoration schemes with feeder automation is widely used.

There were three main drivers for the research of outage management, which were the developments of computer technologies, artificial intelligence (AI) technologies and distribution automation.

- Generally, the computers built during the World War II era are known as the first generation computers, which were extremely difficult to program and were designed for a specific task. In 1970s, Intel 8080 was put into general market, and after that computer could be used to do a lot of things which included outage management. With the evolvement of personal computers and operating systems (from DOS to Windows) from 1980s, people could do much more work than ever before, and a lot of literature on outage management have been published from then on, especially after the Pentium CPU was put into market in middle 1990s.
- The innovation of artificial intelligence technologies was another driver for outage management. The field of artificial intelligence truly dawned in the 1950s, since then there have been many achievements in the history of artificial intelligence which facilitated the outage management. Expert system (ES) was first developed by researchers during the 1960s and 1970s and applied commercially throughout the 1980s, but after that ES development experienced a winter due to encountered several formidable difficulties, e.g. knowledge acquisition. After that there were many kinds of intelligent computation technologies have been developed, e.g. artificial neural network (ANN), genetic algorithm (GA), tabu search, simulated annealing (SA), ant colony, swarm optimisation, multi-agent, etc. As a result more and more papers on outage management employing these technologies were published.
- The third driver for supply restoration was the application of distribution automation (DA) technologies. The concept of DA originated in the 1970s using computer and communications technologies to improve operating performance. There were only a few small pilot projects to implement fault isolation during this period. There were several major pilot projects in the 1980s, and some large and many small projects in

the 1990s for implementing fault identification, location, isolation and restoration automatically.

Much literature treated outage manage as 0-1 integer programming problem and utilised varied approaches to solve it, e.g. Aoki (1988), Lee (1988), Aoki (1989), etc.

The prime objectives of the outage management problem can be formulated as follows basing on the review of the published literature (Ekanayake, 2012).

- (1) The number of customers with a restored supply should be the largest possible and in accordance with their importance.
- (2) Supply restoration should be accomplished as quickly as possible.
- (3) The restoration solution should be feasible.
- (4) It will not cause further outages during implementation.

2.3.1.2.1 Network Model

Network models and load models were fundamental and necessary for solving the outage management problem utilising computers. One-line diagram representations of balanced network models were employed by most literature using the concept of graph theory. By comparison, only a few papers work on unbalanced systems, e.g. Miu (1999) and Lei (2000).

There were two main types of one-line diagram representations. Both types utilised the concept of root, node and branch to represent the network model basing on graph theory. However, their meanings are different. For one network model, root denotes HV/MV transformer, node denotes branching point, and branch denotes distribution line section including load, e.g. Aoki (1988), Lee (1988), Aoki (1989), Codiasse (1989), Shirmohammadi (1992), Hsu (1992), etc. For the other network model, root denotes HV/MV transformer, node denotes branching point and load point (MV/LV transformer), and branch denotes distribution line section, e.g. Teo (1992), Devi (1995), Miu (1998, 2000), etc. The literature using these two network models is similar.

2.3.1.2.2 Load Model

For the outage management of MV networks, the information about the load of MV/LV substations is essential for the success of the restoration. The supply restoration in effect reallocates these loads temporarily to the other available source points. If a restoration is to be successful, the supporting network elements must not be overloaded. To observe this constraint the load of MV/LV substations has to be known. The problem is that at present the real-time measurements in MV distribution networks are still very limited, and even utilities that operate their systems using SCADA have very little knowledge of the real time status of the distribution system beyond the substation feeder breakers.

There were attempts to solve this problem by equipping the MV/LV substations with devices that would provide information regarding these loads in a real-time operation environment. Unfortunately, this appeared to be such an expensive and long-term process before the Smart Grid development. Therefore the problem was solved in some alternative and effective way in the past.

Kuo (1993) combined supply restoration with a load estimation algorithm which could provide the necessary load information. The restoration regime could last for hours and during that time the loads were changing. Therefore, it was important to make a reasonable prediction of how long the restoration regime will last and to observe the load constraints in the restored network configuration during that time. Huang (2005) combined supply restoration with a short-term MV load forecasting algorithm to solve this problem, which also provided a vision of proactive control.

Most literature on outage management (especially supply restoration) is based on the assumption that load information is known. Some references supposed the load for each line section is known, e.g. Aoki (1988), Lee (1988), Aoki (1989), etc. Some references assumed the load of each MV/LV substations is known. Most references of this kind assumed that active power and reactive power (or MVA or current) are known, e.g. Ahmed (1993), Lin (1998), etc. Some assumed that the peak load and load factor are known, e.g. Dialynas (1989). Some assumed that only the peak load is known, e.g. Devi (1991), which is equivalent to work basing on the worst case. Shirmohammadi (1992) assumed the load is voltage dependant current injection.

2.3.1.2.3 Constraints Considered

There were several constraints considered during the outage management process. Most references considered current capacity constraints and voltage drop constraints. Several references considered minimum number of switching operations, e.g. Sarma (1994). Some considered the constraint of minimum losses, e.g. Sarma (1994) and Sudhakar (2005), but this constraint was usually not important for outage management problem.

2.3.1.2.4 Types of Fault Treated

Lim (2009) considered multiple faults for supply restoration problem, and the other literature in the reference usually only considered single fault. Three general types of network element faults can be recognised in distribution networks, which are line faults, bus bar faults and transformer faults. There are other network elements that could be faulted, however in principle they can be associated with one of these three types.

The number of out-of-service network elements depends on the fault type and fault location, and also depends on the complexity and characteristics of a particular distribution network, such as topological features of the network, operational capabilities and applied operational devices, etc. It is necessary to consider these factors when we try to carry out outage management.

2.3.1.2.5 Restoration Area

Most literature only investigated outage management of MV networks. Several literature considered restoration of HV/MV substations, e.g. Dialynas (1991) and Mora (2003). Ref Dialynas (1989) investigated restoration of HV/MV substations as well as MV networks. Some literature studied the support from distributed generation, e.g. Hirotaka (2006) and Moreira (2007); hence the research area is MV network and LV network.

2.3.1.2.6 Hardware Requirements

Most literature considered both remotely-controlled and manually-controlled switchgear during the restoration process, and their work focused on solving the encountered

combinatorial problems. Remotely-controlled switchgear often considered in the restoration process are circuit breakers, switches, reclosers, auto-sectionalizers, etc. Manually-controlled switchgear often considered are switches, switchfuses, disconnectors, switch disconnectors, etc. Some literature only considered remotely-controlled switchgear, e.g. Aoki (1988), Lee (1988), and Aoki (1989). Poston (1989) and Scott (1990) tried to implement fault identification, location and supply restoration basing on the trouble call system.

2.3.1.2.7 Smart Meters for Outage Management

The ICT infrastructure of a Smart Grid provides the opportunity for a better outage management.

Jiang et al (2015) proposed a new multiple-hypothesis method for identification of the faulted section on a feeder or lateral. Credibility of the multiple hypotheses is determined using the available evidence from these devices. The proposed methodology is able to handle i) multiple faults, ii) protection mis-coordination, and iii) missing outage reports from smart meters and fault indicators. For each hypothesis, an optimisation method based on integer programming was proposed to determine the most credible actuated protective device(s) and faulted line section(s). Simulation results based on the distribution feeders of Avista Utilities serving Pullman, WA, validated the effectiveness of the proposed approach.

Tram (2008) discussed the technical and operational considerations necessary to make the Advanced Metering Infrastructure - OMS integration successful. Choi (2011) introduced a project “Development of MDMS (Meter Data Management System) and SUN (Smart energy Utility Network)” which implemented the OMS using smart meter information. Kuroda (2014) proposed an approach of outage location prediction utilising smart metering data for rapid detection and restoration of power outages.

There was very limited work to evaluate the impact of the communications performance of smart metering infrastructure on outage management. Chapter 5 considers this problem in detail.

2.3.2 Analysis of Communications Infrastructure

Analysis and simulation are two traditional approaches used in modelling for communications Networks (Banks, 2010). The basis of the analytical approach is to describe the system mathematically and create a mathematical model. This approach is usually preferred over simulation because it is less computationally intense. However, it is only feasible to describe small and simple systems mathematically. For large and complex systems, the mathematical models are often simplified by making assumptions, which as a result might not accurately represent the system in question. Although more computationally intense, the simulation approach does not have this limitation and even complex systems such as communications networks can be modelled in every detail. It is important to note that the question of the required level of detail needs to be carefully considered for both modelling approaches.

Smart Grid applications with communications infrastructure often form a computer network. Event-driven simulation, also called discrete-event simulation, is widely used in computer networks (Issariyakul, 2009). The majority of events are based on randomness. For example, communications protocols wait for a random period of time before retransmitting data in case of a data collision on the medium. Similarly, queuing strategies and generated data are usually based on probability distributions in order to consider the stochastic nature of computer networks.

Computer network simulators are utilised to build models for experimentation and analysis which provide extensive modelling APIs (Application Program Interfaces), simulation engines, data analysis capabilities, and model libraries, which includes a broad suite of standard protocols and technologies to support rapid model development. Examples of the most widely used simulators are the Network Simulator 2 (NS2), Network Simulator 3 (NS3), QualNet (QualNet), OMNeT++ (OMNeT), and the OPNET Modeler (Riverbed).

Garlapati et al. (2010) proposed an agent-based protection scheme for zone 3 relays considering the communications infrastructure. The power simulations were done with the help of Positive Sequence Load Flow (PSLF) software. Statistical values for relay failures were firstly calculated with PSLF. These values were used to create a traffic profile of the communications system which represents the behaviour of the agent-based protection scheme. This profile included information about agent communication such as

communication time and the size of messages. This was then implemented in the second step in the network simulator NS2 in order to obtain the average communication delays of the system through simulations.

Coury et al. (2002) proposed an agent-based current differential relay protection scheme. The communication delays and dropped messages were first simulated in NS2. They were then considered when developing and subsequently evaluating the performance of the agent-based system. This approach was only feasible because the communications behaviour of the agent-based application was simple and the traffic profile easy to predict and describe without experimentation.

Tahboub (2007) investigated the functionality of a multi-agent system (MAS) and communication traffic separately. They presented work on modelling and simulation of secure automatic energy meter reading. The authors used mobile agents that toured from one meter to the next to carry out the meter readings. The communications network and meters were simulated with OPNET Modeler while the mobile agents were implemented in JADE (Java Agent Development Framework), which served as a separate simulation to verify the functionality of the MAS. This verification didn't consider the communications infrastructure but the separate network simulations were used to get an indication of the impact of the agents on the infrastructure such as link utilisation and queuing delays. Although the network simulation provided additional information, the agent-based application was not accurately simulated. Only a simulation that accounts for both aspects, applications and communications network, could provide this.

The majority of researchers have used either NS2 or OPNET Modeler to develop and simulate their agent application models. For example, Lin et al (2011, 2012) presented work on a co-simulation framework of PSLF and NS2 for power applications. The agent-based applications were developed in NS2. He et al. (2010) utilised OPNET to model and simulate smart-meter applications and power line communication (PLC) infrastructure.

Research that neither used NS2 nor OPNET Modeler was presented by Song et al. (Song, 2011). The authors built a discrete-event network simulator in Erlang based on the Sim-Diasca simulation engine. The smart-meter agent applications were modelled in the simulator and most other models, such as link and computer node models, were implemented

from scratch. The simulator was built for the purpose of the presented application, which according to the authors allows for large-scale simulations.

To build an integrated simulation platform which considers both smart grid applications and communications, which behaves as the simulated system, is still a major challenge. The work in this thesis suggests a new method and the details can be found in Chapters 3 and 4.

2.4 Development of Smart Metering Infrastructure

2.4.1 Options for Smart Metering Development

Smart meters are available with different functionalities and use different technologies. The following examples are selected as representative cases.

Retrofitting existing meters

Conventional electro-mechanical meters and digital meters without pulse output cannot be used to provide any feedback to the consumer or to the supplier. Some technologies facilitate retrofitting such analogue and digital meters through non-invasive equipment such that those meters are converted to AMR. The techniques such as introducing optical position sensors (Melexis) or optical character recognition (OCR) based readers (Plexus) are commercially available. But most of the smart meter initiatives do not consider retrofitting as a feasible solution due to the cost and the limited capability for future expansions and opt for digital smart meters.

AMR with energy usage information through the Internet

This option does not give full flexibility as in the case of interval metering, but collect meter readings remotely and provide information to the customer through the Internet.

As an example, the “*Energy Controls*” (Econtrols) has smart meters that can be fitted in standalone installations or as part of a comprehensive metering system that comes with a module slot for simple ‘Plug & Play’ connection of a communications unit. It has direct connection or CT operated installation. The ‘Plug & Play’ communications module offers universal connection for high-speed reliable data transmission including RS232/485, PSTN, GSM/GPRS and Ethernet. It reads meters automatically through these communication lines. Collected consumption data are stored on their secure server which is backed up daily.

Customer can access their meter readings using a standard internet browser. The data can be manipulated to produce reports in a graphical format to identify consumption trends.

Use of AMR interval meters with AMI (Advanced Metering Infrastructure) expansion capabilities

Use of AMR interval meters is the most common approach in smart meter deployment and some of the implementation expected to expand to AMI. As an example “Telegestore”™ smart meter system used by “Enel” from Italy (Enel) is given below.

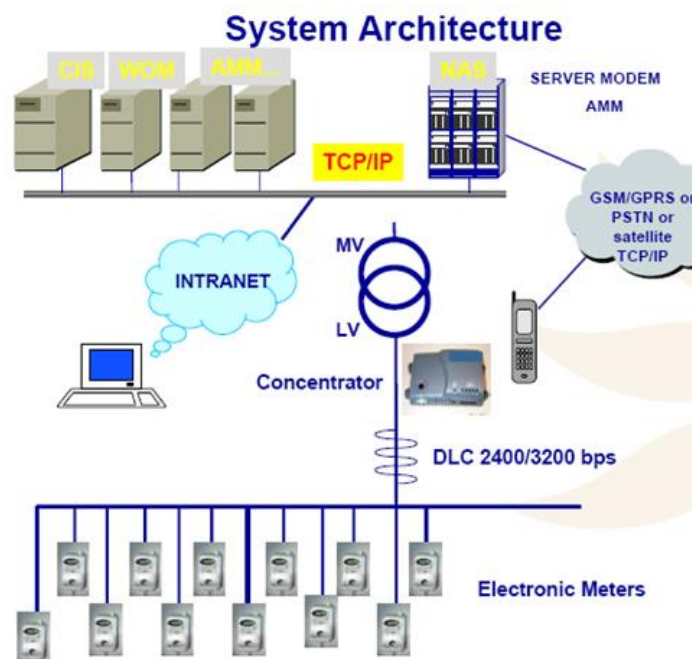


Fig. 2.7 The “Telegestore” system architecture (Enel)

The control centre at the top of the figure communicates via public telecommunication networks (GSM, GPRS, PSTN & satellite) with LV concentrators installed in every MV substation (one concentrator per transformer), as shown in Fig. 2.7. LV Concentrators have two-way communications with the control centre and meters through PLC half-duplex with net speed of 2400 bits/sec.

2.4.2 Initiatives in the UK to Deploy Smart Meters

The history and progress of the smart metering development in the UK is briefly listed below.

- The UK has thirty years of advanced metering history. It started in mid 1980s but with the energy-industry re-structuring, and the introduction of retail competition of meter development, except a few attempts, no significant progress took place from 1990-98 (Owen, 2006) (Samarakoon, 2009).
- From 2000 onwards, four significant policy reports were produced. Despite the efforts, consultations, reviews and policy initiatives, the policy-push on smart meters stalled (Owen 2006).
- In December 2005, the European Parliament issued the directive (The European Union, 2006) on energy end-user efficiency improvement. It requires member countries to provide meters that give actual energy consumption and actual time of use to improve the efficiency of demand side.
- Between 2005 to 2007 “*Energy Watch*” proposed the introduction of smart meters to benefit energy suppliers, consumers, energy distributors and finally the environment. From the consumers, it is expected to have a behavioural change using the updated information provided via a smart meter (Energy Watch, 2005, 2006). “*Energy Watch*” also analysed the cost benefits of smart meters (Energy Watch, 2007).
- In February 2006 Ofgem issued a consultation (Ofgem, 2006) to find out the actions to be taken to introduce smart meters in the context of the UK’s competitive domestic metering services market and also to realise the benefits of smart meters.
- In November 2006, the DTI issued the energy review consultation (DTI, 2006) to mandate and consult the provisions on detailed bills and smart meters. The response was issued in July 2007.
- In April 2007, the Dept. of BERR issued a report (Mott MacDonald, 2007) on costs and benefits of roll out options of smart meter and discussed various technology options of meters, displays, communications and roll out scenarios.
- In May 2007, the DTI issued the White Paper on Energy (DTI, 2007) which introduced smart meters for saving energy within next decade. In August 2007 BERR issued consultation (DBERR, 2007) on policies presented in the White Paper and in April 2008 issued the Government response to the consultation.

- The Energy Demand Research Project (EDRP) managed by Ofgem conducted trials from 2007. Out of four trials two were conducted by installing visual displays for 8,500 households and smart meters for 18,000 households (Ofgem, 2008).
- The Government decided to roll out of smart meters from January 2009 for the large scale non-half hourly metered customers whose annual consumption is above 732 MWh and completed installation by 2013 (DBERR, 2008a). BERR issued the final consultation on the above in January 2008 (DBERR, 2008b).
- BERR issued consultation on smart meters for medium scale customers in July 2008.
- Even though the White Paper expected to mandate the real-time electricity display devices to all new and replacement electricity meters, after the consultation on policies of the White Paper (DBERR, 2007), the Government has decided not to proceed with the mandated requirements, but to work with suppliers to reach a voluntary agreement to provide displays (DBERR, 2008a).
- It was finally agreed that the UK government aims to bring about the creation of an electricity and gas smart metering system, for all domestic and small non-domestic properties, by the end of 2020. The final system will allow suppliers, network operators and other parties (e.g. demand response aggregators) access to smart metering data and demand response functions. The access will be controlled depending on the interests of the company accessing the data (i.e. suppliers or network operators) and subject to consumer consent.
- New licensed bodies have been given responsibility for the operation of the smart metering system. The Data Communications Company (DCC) takes responsibility for the data and communication aspects of the smart metering system. It will do this with subcontracted Data Service Suppliers (DSPs) and Communication Service Providers (CSPs). The manufacture (to UK government specification) and installation of the smart meters is the responsibility of the Suppliers. A self-governed multiparty contract, the Smart Energy Code (SEC), “sets out the terms for the provision of the DCC’s smart meter communications services, and specifies other provisions to govern the end-to-end management of Smart Metering” (DECC, 2014). A detailed technical specification of smart metering equipment was also provided (DECC, 2013).

The key motivators of the smart metering development in the UK are for CO₂ emission reduction and to meet 20% energy saving expected in 2020; and also for energy saving by providing information through accurate bills and real time displays. There is a clear need to investigate how to use smart meter information to support the operation of distribution networks.

2.4.3 Smart Metering for Distribution Network Operation

Although currently there is no universal definition for a smart meter, a meter that can perform additional duties other than accurately measuring consumption and displaying the consumption can be considered as a smart meter.

Smart meter technology can be broadly categorised in the increasing order of sophistication as follows:

- Automated Meter Reading (AMR)
- Automated Meter Management (AMM)
- Interval metering with AMM
- Prepayment Meters (PPM)
- Advanced metering infrastructure (AMI)

Commercially available meters have overlapping functionalities, but in general, the functionalities can be broadly grouped as given below.

In order to use smart meter information to support distribution network operation, there is a urgent need to quantify the impact of smart metering applications on communications requirements, to develop an evaluation method to quantify the impact of smart metering communications infrastructure on distribution network operation, and to achieve a better understanding on the potential of using smart metering for outage management, which is one of the most critical distribution network operational functions.

Table 2.1. Comparison of functions of different smart meter technology (Samarakoon, 2009)

Functions	AMR	AMM	Interval metering with AMM	PPM	AMI
Has a communication link from meter to supplier to read meter remotely	✓	✓	✓	✓	✓
Has a communication link from supplier to meter		✓	✓	✓	✓
Network operator can remotely limit energy supply and disconnect if required		✓	✓	✓	✓
Tariffs can be changed remotely		✓	✓	✓	✓
Real time data can be displayed to user		✓	✓	✓	✓
Fraud and tamper protection		✓	✓	✓	✓
Measure energy consumption and related information at shorter intervals (half hourly or less) and store and send to the supplier			✓	✓	✓
Can have multiple tariffs structures (Time-of-use tariffs)			✓	✓	✓
Supplier can switch the meter between credit or prepayment				✓	✓
Remote calibration facility				✓	✓
Can provide detailed information such as historical cost and credit remaining				✓	✓
Allow for changes of tenancy				✓	✓
Credit entry through keypad				✓	✓
Can add credit remotely					✓
Can control appliances remotely					✓
Provide facilities for network design, operation, management					✓

Table 2.2. Comparison of benefits of different smart meter technology (Samarakoon, 2009)

Benefits	AMR	AMM	Interval metering with AMM	PPM	AMI
Manual meter reading is not required thus reducing the cost and practical difficulties of meter reading	✓	✓	✓	✓	✓
Allows to production of bills based on actual readings rather than inaccurate estimated bills	✓	✓	✓	✓	✓
Customer can change the supplier quickly as accurate meter readings are available	✓	✓	✓	✓	✓
Detect and notify fraud when a meter has been tampered with	✓	✓	✓	✓	✓
Visits and manual re-setting of meter are not necessary when price and tariff changes		✓	✓	✓	✓
Make the customer, energy, cost and efficiency aware so that consumption is adjusted to reduce the cost			✓	✓	✓
Improved facilities for pre-paid customers				✓	✓
Could help to avert large scale black-outs through controlled load shedding during critical peak events					✓

2.5 Summary

A growing recognition of the need to modernise the electric power grid to meet tomorrow's challenges has found articulation in the vision of a Smart Grid. This chapter firstly introduces the Smart Grid vision. Then the role and requirements of communications in the Smart Grid development are discussed. A literature survey is provided to introduce the suggested communications technologies that the operational functions of distribution networks are likely to utilise. Previous research on Smart Grids applications and analysis of the communications infrastructure is introduced. Finally, a review on the smart metering development in the UK is provided and its potential roles to support distribution network operation are discussed.

Chapter 3

Modelling of Smart Metering Communications

3.1 Introduction

In order to investigate how to use smart metering infrastructure to support distribution network operation, the impact of smart metering applications on communications requirements needs to be first analysed. In this chapter, modelling and simulation of smart metering communications infrastructure was carried out using the network simulation tool OPNET (Riverbed, 2016).

Ethernet over power line was used as the physical layer medium. Representative smart metering applications used for the analysis were chosen and implemented in IEC 62056 (BSI, 2001, 2007a-d). OPNET models were built including physical and application components. Several selected applications were simulated on a test network to examine the bandwidth impacts of last mile links under different conditions.

The simulations were carried out for channel utilisation at the physical, IP and application layers. The general structure of the simulation is illustrated in Fig 3.1.

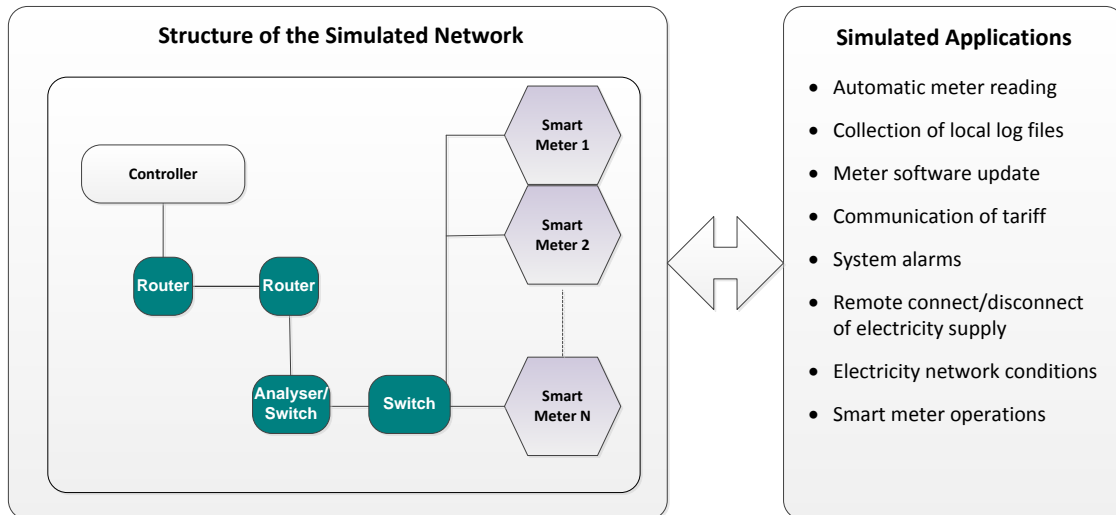


Fig. 3.1 General structure of the simulation

3.2 Assumptions for the Simulation

In different countries, the applications of smart meters differ as do the communications requirements. A number of factors were considered in the investigation of communications requirements of smart meters.

- Uncertainties in physical media. There are a number of options regarding which physical media could be used for smart metering communications, which include fibre, BPL, PLC, GPRS/GSM, etc.
- Flexible standards, e.g. the IEC 62056 standard is very flexible. Manufacturers and developers have flexibility in how they design applications and data objects;
- Uncertainties of smart meter applications. There are a number of different applications that the smart metering could be used for.

Given the above factors, a number of assumptions were applied to simplify the modelling of smart metering infrastructure.

- Ethernet over power line was used to model the physical media. In the modelling of smart metering using OPNET, Ethernet over power line was used for the physical layer and the data link layer. The medium was assumed to be shared and constrained. A PPP (Point to Point Protocol) link was used to model the low speed scenario.

- A single controller was used in the simulation of IEC 62056. IEC 62056 allows for multiple controllers with various functions. Communication initiation by smart meters is also allowed. A single controller was used in the simulation of IEC 62056 for simplicity, and it initiated all communications.
- TCP (Transmission Control Protocol) was used at the transport layer. TCP fits well with the controller controlled system, although it may be less efficient than UDP (User Datagram Protocol) broadcast for some applications.
- BER (Basic Encoding Rules) (BSI, 2007a-d) and A-XDR (Abstract External Data Representation) (BSI, 2001) were both used for the encoding of IEC 62056. Encoding was used to encode the information into patterns of lower level symbols. In communications systems encoding can be used to reduce the number of bits that must be transferred between devices as part of a transaction. IEC 62056 uses these two encoding standards to encode information into PDUs (Protocol Data Units).

The above simplifications have an insignificant impact on the overall results of the modelling but simplify the simulation significantly.

3.3 Modelling of Smart Metering Communication using OPNET

3.3.1 Modelling of Physical Components

The modelling of smart meter infrastructure used a multi-node network with a single controller, as illustrated in Figure 3.1. This allowed simulation of a shared-constrained link without the complexity of building customised models of components. A smart metering network with low speed links used for simulation is shown in Figure 3.2. A network with mixed high and low speed links that as used for simulation studies is shown in Figure 3.3. The low speed links were used to simulate the smart metering infrastructure with weak communications systems. The mixed high and low speed links were used to simulate the smart metering infrastructure with high-performance communications systems.

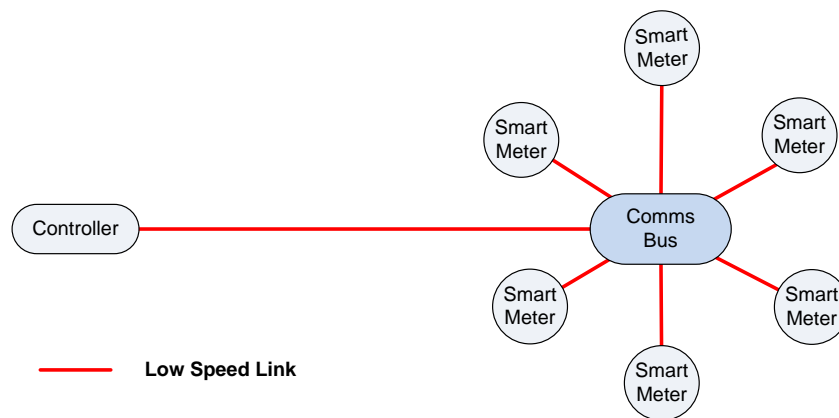


Fig. 3.2 A network with low speed links

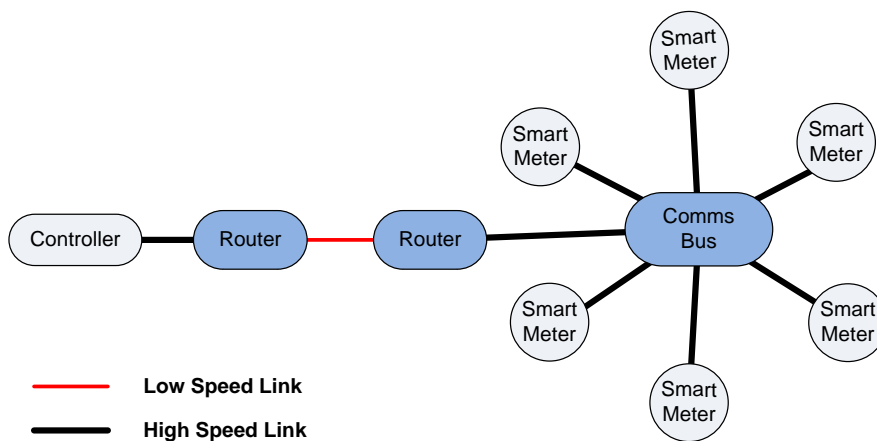


Fig. 3.3 Equivalent network with mixed high and low speed links

A PPP link was used to simulate the shared channel. It employed existing models and tools within the OPNET Modeler. It simulates a broad range of shared-constrained links that could potentially be used. The applications were structured such that the controller waited for the smart meter to respond before moving to the next phase of a transaction.

OPNET provides a number of prebuilt device models for simulating network components. These models have various levels of detail. Increased level of detail generally comes at a cost of simulation time as the details must be computed during the simulations. The components that were used in OPNET simulation include:

- Smart meter - a basic computer workstation (Dell Precision Workstation 360 model with 3200MHz and DDR400) was used to model a smart meter. This is sophisticated enough to support the features examined;
- Controller - a basic server (Intel D850EMV2 server with 2800MHz) was used to model a controller;
- Link - two types of links were used in the simulation in this chapter:
 - i. 10 MB Ethernet links - basic Ethernet was used to link devices within the scenario. The link speed of Ethernet was fast enough to impose any delay on the simulation. The use of 10MB Ethernet in the configuration allowed the use of analysers available within OPNET modeler; and
 - ii. low bandwidth PPP links - these are links that can be varied in speed and error rate. The PPP links (based on the “ppp_adv” model in OPNET) were configured with a 75% utilisation rate (default configuration for PPP links in OPNET).
- Analyser - an IP protocol analyser model (“ethernet8_switched_pkt_analyzer_adv”) is available in OPNET. It was used to capture network traffic for analysis. It was used for validation as it allows the source, destination, packet size, transmission protocol and packet times to be captured. These were compared to the expected transaction structure; and
- Router - It was used to convert between the 10MB Ethernet link and the PPP link. The use of the router (based on “slip2_gtwy_adv”) allows the use of the analyser to monitor the traffic passing across the network.

Characteristics of components that did not need to be modeled were disabled during the simulation. The components are able to be structured into distinct networks to permit simultaneous analysis of applications under different networking conditions.

3.3.2 Modelling of Applications

In order to investigate the smart meter communications, the key smart metering applications were simulated. OPNET applications were used and configured using application objects. The general structure of the simulation of applications is as follows:

- Phases - exchanges of packets between logical devices. A phase is a simple packet exchange between two devices. The packet exchange parameters including number of packets, packet size and protocol can be varied;
- Tasks - ordered sets of phases. OPNET aggregates a collection of tasks as an application task object. These can be considered as a toolbox for building applications;
- Applications - collections of tasks to be modelled as an application;
- Profiles - the same application can be used by entities differently. OPNET uses the application profile for configuring these differences. Profiles allow specific patterns of application usage to differ between devices.

There is flexibility between phases and tasks to construct communications. Profiles are applied to devices of the network and provide the basis for traffic generation within OPNET. The general structure and relationship between OPNET objects in modelling smart meter communications is illustrated in Figure 3.4.

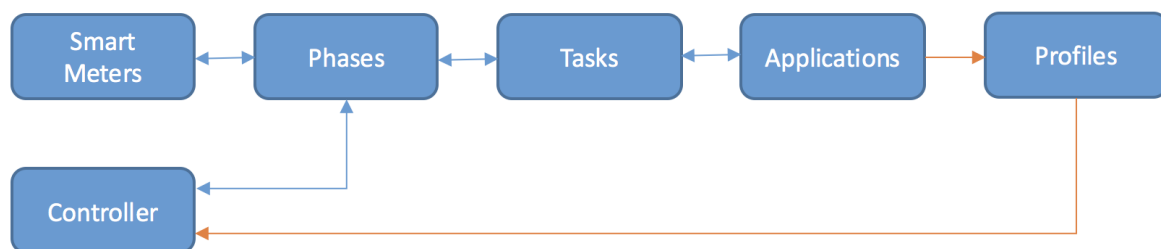


Fig. 3.4 Smart meter communications models in OPNET

There are potentially a large number of applications that could be implemented based on the smart metering communications infrastructure. In order to analyse the behavior of a given smart meter infrastructure, a representative set of applications needs be chosen and their characteristics defined and simulated. Eight applications were investigated in this Chapter.

The modelling of communications of each application requires modelling of details such as information and their frequency to be exchanged. IEC 62056 and the TCP/IP standards provide part of the information required for this. Additional information is also required, e.g. frequency of transactions and specifics of information transferred to meet application requirements. The following information was considered for each application:

- Application characteristics - a general introduction to the specific application that identifies the users and the frequency of operation;
- Transaction structure - information on how the application is implemented within IEC 62056;
- Size of data exchange - this part identifies how the IEC 62056 APDU (Application Layer Protocol Data Unit) is constructed. The sizing is structured into the following parts:
 - i. type - sum of the lengths of the OBIS (Object Identification System)/attribute codes which are used to identify the data item being requested, set or auctioned. Each OBIS/attribute code set can be encoded as 8 bytes;
 - ii. length - length of the data being sent as part of a GET response or a SET command. It is an optional parameter depending on whether the data object has a fixed length or not. The decision regarding whether to include it is based on consideration of whether the data length would be fixed or not;
 - iii. data - sum of the lengths of the actual data being sent. Sizing is determined from the estimate in the data items table;
 - iv. data long - IP networks generally implement a maximum transmission unit (MTU) size which limits the size of packets that are transmitted across the network. The number is typically around 512 bytes including IP and transmission level headers. Given this, APDUs longer than 450 bytes will be broken into smaller pieces to be transmitted;
 - v. data long end - for APDUs longer than 450 bytes the last part will be less than 450 bytes;
 - vi. padding - 5 bytes of padding was added to all WPDUs (Wrapper Protocol Data Units) to address the overhead of APDU header. The padding entry was

also used to define the size of APDUs that did not fit the standard A-XDR (Adapted eXtended Data Representation) encoding scheme. AARQ (Application Association ReQuest) and AARE (Application Association Response) messages are used for authentication. They are complex in structure and were modelled as simple byte strings of 39 and 51 bytes based on example in IEC 62056-53 standard document (BSI 2007b, p.126);

- vii. wrapper - APDU transactions across IP networks use a wrapper to allow use of a common TCP or UDP port while allowing separate application layer ports for accessing different logical devices. The wrapper facilitates this additional layer of addressing. It is 8 bytes and is included in all packet exchanges;
- Data items - identifies the data exchanged and its size. The size is an estimated value for most items except for time which is explicitly defined as 12 bytes in the IEC 62056 standard; and
- Packet exchange - this part identifies the packet exchange that results from a basic implementation of the application under TCP/IP and IEC 62056. More information is provided as follows which identifies the stages of transfer, the direction and the sizing of APDU, IP and TCP headers.

This provided the framework for modelling individual applications for simulation in OPNET Modeler. There are 8 applications modelled.

(1) **Automatic meter reading.** It is one of the basic functions of a smart meter to automatically collect energy consumption information periodically. Collection of energy consumption information is typically carried out monthly but is able to be done much more frequently using the smart metering infrastructure. The transaction mainly involves the controller requesting consumption information from a meter with the meter responding.

The key application characteristics are shown in Table 3.1.

Table 3.1. The key application characteristics of AMR

Reference	IEC 62056-53
Users	Energy Suppliers: the users of this function depend on the specific utility structure, i.e. whether the same entity managing generation and distribution will also look after energy supply. In the UK these functions are done by a number of energy suppliers, rather than distribution network operators.
Frequency of Operation	Usually monthly
Application Information Exchanged	The controller provides authentication details and identifies the meter reading information required. The meter sends back the meter reading information.
Communications Structure	Communications is structured into three parts: Establish Session, Exchange Information and Session Close. The byte size of the information exchanged is less than 500 bytes so generally would not be split into multiple IP packets.

The application transaction structure is shown in Table 3.2.

Table 3.2. The application transaction structure of AMR

Devices	Information	Description
Controller	Authentication	The controller authenticates to the meter before the transaction
Meter	Authentication Response	Acknowledgement is sent to controller that authentication is successful.
Controller	GET Request	GET request identifies information required.
Meter	GET Response	GET response will send meter reading information.

The objects exchanged and their sizes are shown in Table 3.3.

Table 3.3. The objective exchanged and their sizes of AMR

Data Objectives	Size (bytes)	Description
Date/time of current read	12	The standard size of IEC 62056 data/time
Date/time of last read	12	
Power consumption over a time period	4	4 bytes integer
Power consumption over a time period - mean	4	4 bytes integer
Power consumption over a time period - standard deviation	2	2 bytes integer
Peak period power consumption	4	4 bytes integer
Peak period power consumption - mean	4	4 bytes integer
Peak period power consumption - standard deviation	2	2 bytes integer
Off-peak period power consumption	4	4 bytes integer
Off-peak period power consumption - mean	4	4 bytes integer
Off-peak period power consumption - standard deviation	2	2 bytes integer

The packet exchange details are shown in Table 3.4. In the following tables, Syn represents Synchronisation, Ack: Acknowledge, Fin: Finish, AARQ: Application Association ReQuest, and AARE: Application Association Response.

Table 3.4. The details of packet exchanges of AMR

Session Part	Action	Direction	Related APDU	Info	PDU	TCP	IP	Total
TCP/IP Initiation	Controller initiates	->		Syn	0	24	20	44
	Meter responds			Syn, Ack	0	24	20	44
	Controller responds			Ack	0	20	20	40
Connection Establishment	Controller requests connection	->	AARE-AARQ_Establish_from_C	AARE	39	20	20	79
	Meter confirms connection			AARQ	51	20	20	91
Data Transfer	Controller sends GET request	->	Meter_Read_Simple_Get_from_C	Data	101	20	20	141
	Meter sends GETresponse			Data	89	20	20	129
TCP/IP Close	Meter requests close	->		Fin, Ack	0	20	20	40
	Controller responds			Ack	0	20	20	40
	Controller reponds			Fin, Ack	0	20	20	40
	Meter responds			Ack	0	20	20	40
Totals (bytes)					280	228	220	728

(2) **Collection of log files.** As an intelligent device, a smart meter generates and logs information such as smart meter status and alarms. The smart meter logs need to be collected periodically in order to ensure all important information is collected by the server.

The key application characteristics are shown in Table 3.5.

Table 3.5. The key application characteristics of collection of log files

Reference	IEC 62056-53
Assumptions	The log information normally only includes important and critical events (reloading, power failures, system errors, tamper alarms, etc) . A meter would normally capture 20 events per day with average length of 100 bytes.
Users	Smart Meter System Managers
Frequency of Operation	Usually weekly.
Application Information Exchanged	The controller requests the meter send the most recent log using a GET. The meter responds with the log.
Communications Structure	Communications is structured into three parts: Establish Session, Exchange Information, and Session Close. The byte size of the information exchanged is less than 450 bytes so generally would not be split into multiple IP packets.

The application transaction structure is shown below.

Table 3.6. The key application transaction structure of collection of log files

Devices	Information	Description
Controller	Authentication	The controller authenticates to the meter before the transaction
Meter	Authentication Response	Acknowledgement is sent to controller that authentication is successful.
Controller	GET Request	GET request identifies information required.
Meter	GET Response	GET response will send requested information, which will be split into chunks of approximately 450 bytes.
Controller	GET Request – Next	For each response packet from a meter

The objects exchanged and their sizes are shown in Table 3.7.

Table 3.7. The objectives exchanged and their sizes of collection of log files

Data Objectives	Size (bytes)	Description
Weekly-Log	14000	It includes 20 log entries per day (each log entry has a size of 100 bytes) for 7 days.

The packet exchange details are shown below.

Table 3.8. The details of packet exchanges of collection of log files

Session Part	Action	Direction	Related APDU	Info	PDU	TCP	IP	Total
TCP/IP Initiation	Controller initiates	-->		Syn		24	20	44
	Meter responds	<--		Syn, Ack		24	20	44
	Controller responds	-->		Ack		20	20	40
Connection Establishment	Controller requests connection	-->	AARE-AARQ_Establish_from_C	AARE	39	20	20	79
	Meter confirms connection	<--	AARE-AARQ_Confirm_from_M	AARQ	51	20	20	91
GET Instruction	Controller sends GET request	-->	Log Retrieval_Get_from_C	Data	21	20	20	61
	Controller sends SET request	-->	Log Retrieval_Get_Long_from_M	Data	450	20	20	490
	Meter sends SET response	<--	Log Retrieval_Get_Long_Cont_from_C	Data	13	20	20	53
	Repeated 31 Times							
		-->	Log Retrieval_Get_Long_End_from_M		65	20	20	105
TCP/IP Close	Meter requests close	-->		Fin, Ack		20	20	40
	Controller responds	<--		Ack		20	20	40
	Controller responds	<--		Fin, Ack		20	20	40
	Meter responds	-->		Ack		20	20	40
Totals (bytes)					14660	1428	9420	25508

(3) **Meter software update.** Software is a necessary component of smart metering, which involves significant complexity of source code. Software updates are required to fix software flaws, install new features and improve system security.

The key application characteristics are shown in Table 3.9.

Table 3.9. The key application characteristics of meter software update

Reference	IEC 62056-53
Assumptions	Controller issues IEC 62056 ACTION command to initiate transfer with a more conventional protocol such as FTP. It is assumed that most of the transfers would be in the 100 Kbyte range. In practice this would be dependent on sophistication of the meter and system architecture.
Users	Smart Meter System Managers
Frequency of Operation	Usually bi-annually. Smart meters software update requirements will be less frequent than general computer systems but will be required to upgrade functionality, fix functional flaws and resolve security issues.
Application Information Exchanged	Update of the meter software requires that the update patch be sent to the meter from the controller. The controller would use a SET command to transfer the information.
Communications Structure	Communications is structured into three parts: Establish Session, Exchange Information and Session Close. The byte size of the information exchanged is much greater than 500 bytes requiring multiple packets. The smart meter responds to the controller with a SET continue message after every packet is received.

The application transaction structure is shown below.

Table 3.10. The application transaction structure of meter software update

Devices	Information	Description
Controller	Authentication	The controller authenticates to the meter before the transaction
Meter	Authentication Response	Acknowledgement is sent to controller that authentication is successful.
Controller	SET REQUEST with data	These steps would be repeated for the duration of transfer.
Meter	SET continue	
Controller	SET REQUEST with data - continuation	

Meter	SET continue	
	Repeat these procedures	
Controller	SET REQUEST with final data	
Meter	SET acknowledgement	

The objects exchanged and their size are shown below.

Table 3.11. The objectives exchanged and their sizes of meter software update

Data Objectives	Size (bytes)	Description
Software-Update	100000	Estimation of size of patch

The packet exchange details are shown below.

Table 3.12. The details of packet exchanges of meter software update

Session Part	Action	Direction	Related APDU	Info	PDU	TCP	IP	Total
TCP/IP Initiation	Controller initiates	-->		Syn		24	20	44
	Meter responds	<--		Syn, Ack		24	20	44
	Controller responds	-->		Ack		20	20	40
Connection Establishment	Controller requests connection	-->	AARE-AARQ_Establish_from_C	AARE	39	20	20	79
	Meter confirms connection	<--	AARE-AARQ_Confirm_from_M	AARQ	51	20	20	91
SET Instruction	Controller sends SET request	-->	Software Update_Set_Long_from_C	Data	450	20	20	490
	Meter sends SET response	<--	Software Update_Set_Long_Cont_from_M	Data	13	20	20	53
	Repeated 221 Times							
		-->	Software Update_Set_Long_End_from_C		115	20	20	155
		-->	Software Update_Set_from_M		13	20	20	53
TCP/IP Close	Meter requests close	-->		Fin, Ack		20	20	40
	Controller responds	<--		Ack		20	20	40
	Controller responds	<--		Fin, Ack		20	20	40
	Meter responds	-->		Ack		20	20	40
Totals (bytes)					103156	9108	9100	121364

(4) **Communication of tariffs.** Price signals are an important vehicle to link electrical energy supply with demand. Conventionally a fixed electricity price is widely used which ignores the actual cost of electricity generation and transmission. Smart meters enable timely communication of tariff, e.g. time-of-use price signal or real time pricing, which can facilitate consumers to actively respond to generation and networks pressures, e.g. demand reduction during peak time and relief of network congestion. The controller will update the meter with the latest tariff information.

The key application characteristics are shown in Table 3.13.

Table 3.13. The key application characteristics of communication of tariffs

References	IEC 62056-53, and IEC 52056-62 (Sections 5.2, 5.5, 5.11)
Assumptions	Tariffs are decided in advance. They are not updated real time. It was assumed that they are updated monthly.
Users	Energy Suppliers
Frequency of Operation	Usually monthly
Application Information Exchanged	<p>IEC 62056 defines REGISTER, REGISTER ACTIVATION and ACTIVITY CALENDAR objects which were used to implement a tariff system. The calendar identifies times at which scripts are auctioned. A script was used to apply a mask to a set of registers to expose the tariff settings to be used at a specific time.</p> <p>The information that would likely be changed in updating the tariff are the scripts and associated masks. REGISTER ACTIVATION and ACTIVITY CALENDAR are not changed frequently as they identify the structure and activation of the tariff structure. REGISTER objects are updated infrequently to deal with large changes in pricing structure.</p>
Communications Structure	Communications is structured into three parts: Establish Session, Exchange Information, and Session Close. The byte size of the information exchanged is less than 450 bytes so generally would not be split into multiple IP packets.

The application transaction structure is shown in Table 3.14.

Table 3.14. The application transaction structure of communication of tariffs

Devices	Information	Description
Controller	Authentication	The controller authenticates to the meter before the transaction
Meter	Authentication Response	Acknowledgement is sent to controller that authentication is successful.
Controller	SET Request	
Meter	SET Response	

The objects exchanged and their size are shown in Table 3.15.

Table 3.15. The objectives exchanged and their sizes of communication of tariffs

Data Objectives	Size (bytes)	Description
OBIS Objects	96	8 scripts per day (6 bytes for each script) for 2 types of days (weekends and weekdays)
Script Data	320	8 scripts per day (20 bytes for each script) for 2 types of days (weekends and weekdays)

The packet exchange details are shown in Table 3.16.

Table 3.16. The details of packet exchanges of communication of tariffs

Session Part	Action	Direction	Related APDU	Info	APDU	TCP	IP	Total
TCP/IP Initiation	Controller initiates	Controller → Smart Meter		Syn	0	24	20	44
	Meter responds			Syn, Ack	0	24	20	44
	Controller responds			Ack	0	20	20	40
Connection Establishment	Controller requests connection		AARE-AARQ_Establish_from_C	AARE	39	20	20	79
	Meter confirms connection		AARE-AARQ_Confirm_from_M	AARQ	51	20	20	91
Data Transfer	Controller sends SET request		Tariff_Update_Set_from_C	Data	445	20	20	485
	Meter sends SET response		Tariff_Update_Set_from_M	Data	13	20	20	53
TCP/IP Close	Meter requests close			Fin, Ack	0	20	20	40
	Controller responds			Ack	0	20	20	40
	Controller responds			Fin, Ack	0	20	20	40
	Meter responds			Ack	0	20	20	40
Totals (bytes)					548	228	220	996

(5) **System alarms.** Smart meters are able to report serious alarms immediately after the trigger event happened. A broad number of events may happen and are usually logged in the smart meter. This feature is of interest to electricity grid operations as well as for smart meter support purposes. Some of these events should be reported quickly through alarms because they are indications of serious system conditions, e.g. disconnects, tampering and major system faults.

The key application characteristics are shown in Table 3.17.

Table 3.17. The key application characteristics of system alarms

Reference	IEC 62056-53
Assumptions	Major alarms are logged. It was assumed that the system logs are retrieved periodically. This allows use of UDP transport for immediate notification.
Users	Energy Suppliers, Distribution Network Operators, and Smart Meter System Managers
Frequency of Operation	Infrequently. Event driven and around 5-10 times per month

Application Information Exchanged	The information sent from the smart meter to the controller is a record of the event (date/time stamp, specific alarm code). Messages are sent using UDP. This is very similar to mechanism used in most computer systems.
Communications Structure	UDP was used from the smart meter to the controller.

The application transaction structure is shown in Table 3.18.

Table 3.18. The application transaction structure of system alarms

Devices	Information	Description
Controller	Authentication	The controller authenticates to the meter before the transaction
Meter	Authentication Response	Acknowledgement is sent to controller that authentication is successful.
Controller	GET Request	GET request identifies information required.
Meter	GET Response	GET response will send requested information.

The objects exchanged and their sizes are shown below.

Table 3.19. The objectives exchanged and their sizes of system alarms

Data Objectives	Size (bytes)	Description
Data	100	

The packet exchange details are shown in Table 3.20.

Table 3.20. The details of packet exchanges of system alarms

Session Part	Action	Direction		Related APDU	Info	PDU	TCP	IP	Total
TCP/IP Initiation	Controller initiates	Controller	Smart Meter		Syn	0	24	20	44
	Meter responds				Syn, Ack	0	24	20	44
	Controller responds				Ack	0	20	20	40
Connection Establishment	Controller requests connection			AARE-AARQ_Establish_from_C	AARE	39	20	20	79
	Meter confirms connection			AARE-AARQ_Confirm_from_M	AARQ	51	20	20	91
Data Transfer	Controller sends GET request			System_Alarm_Get_from_C	Data	21	20	20	61
	Meter sends GET response			System_Alarm_Get_from_M	Data	115	20	20	155
TCP/IP Close	Meter requests close				Fin, Ack	0	20	20	40
	Controller responds				Ack	0	20	20	40
	Controller responds				Fin, Ack	0	20	20	40
	Meter responds				Ack	0	20	20	40
Totals (bytes)						226	228	220	674

(6) **Remote connect/disconnect of electricity supply.** Consumers with a supply contract in place need the electricity service enabled. Consumers without a contract should have their power disconnected. An instruction is issued to a meter to disconnect or reconnect the power supply to the load.

The key application characteristics are shown in Table 3.21.

Table 3.21. The key application characteristics of Application 6

Reference	IEC 62056-53
Assumptions	<p>Remote connect and disconnect is usually done on an infrequent (no more than once a year) basis with reconnection happening within several-day disconnection in most instances. Disconnect and reconnect processes are similar.</p> <p>Disconnect and reconnect are normally done in pairs infrequently. When it is done the period between the disconnect and reconnect would be in the order of days.</p>
Users	Energy Suppliers

Frequency of Operation	Yearly
Application Information Exchanged	The disconnect and reconnect is an instruction. In addition to the instruction there is information collected from the meter as to its current measured state.
Communications Structure	Communications is structured into three parts: Establish Session, Exchange Information, and Session Close. The byte size of the information exchanged is less than 450 bytes so generally would not be split into multiple IP packets.

The application transaction structure is shown below.

Table 3.22. The application transaction structure of Application 6

Devices	Information	Description
Controller	Authentication	The controller authenticates to the meter before the transaction
Meter	Authentication Response	Acknowledgement is sent to controller that authentication is successful.
Controller	ACTION Request	ACTION request information for disconnect and reconnect are similar.
Meter	ACTION Response	ACTION request information for disconnect and reconnect are similar.

The objects exchanged and their size are shown below.

Table 3.23. The objectives exchanged and their sizes of Application 6

Data Objectives	Size (bytes)	Description
Date/time of disconnect or reconnect	12	
Meter_Reading	4	
Last_Meter_Reading_Date/Time	12	
Last_Meter_Consumption	4	
Last-Connect_Disconnect_Data/Time	12	

The packet exchange details are shown in Table 3.24.

Table 3.24. The details of packet exchanges of Application 6

Session Part	Action	Direction	Related APDU	Info	APDU	TCP	IP	Total
TCP/IP Initiation	Controller initiates	Controller → Smart Meter		Syn	0	24	20	44
	Meter responds			Syn, Ack	0	24	20	44
	Controller responds			Ack	0	20	20	40
Connection Establishment	Controller requests connection	Controller → Smart Meter		AARE-AARQ_Establish_from_C	AARE	39	20	79
	Meter confirms connection			AARE-AARQ_Confirm_from_M	AARQ	51	20	91
Data Transfer	Controller sends SET request	Controller → Smart Meter		Rmt_Connect_Disconnect_Action_fror Data	53	20	20	93
	Meter sends SET response			Rmt_Connect_Disconnect_Action_fror Data	67	20	20	107
TCP/IP Close	Meter requests close	Smart Meter → Controller		Fin, Ack	0	20	20	40
	Controller responds			Ack	0	20	20	40
	Controller reponds			Fin, Ack	0	20	20	40
	Meter responds			Ack	0	20	20	40
Totals (bytes)					210	228	220	658

(7) **Electricity network conditions.** There are usually very limited measurements on distribution networks. Smart meter infrastructure can be used to monitor the local electricity network for events such as voltage dips and outages. It can be used to support distribution network operation. A meter is able to collect near real-time information of meter point voltage, current and power (real and reactive power). This information is periodically collected by the controller. The period between collections can vary from seconds to weeks.

The key application characteristics are shown below.

Table 3.25. The key application characteristics of Application 7

Reference	IEC 62056-53
Users	Distribution Network Operators
Frequency of Operation	Hourly. The potential range of values is between once a minute to once an hour.
Application Information Exchanged	The controller requests the meter send the most recent statistics using a GET. The meter responds with the most recent set of statistics.

Communications Structure	Communications is structured into three parts: Establish Session, Exchange Information, and Session Close. The byte size of the information exchanged is less than 450 bytes so generally would not be split into multiple IP packets.
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The application transaction structure is shown below.

Table 3.26. The application transaction structure of Application 7

Devices	Information	Description
Controller	Authentication	The controller authenticates to the meter before the transaction
Meter	Authentication Response	Acknowledgement is sent to controller that authentication is successful.
Controller	GET Request	
Meter	GET Response	

The objects exchanged and their size are shown in Table 3.27.

Table 3.27. The objectives exchanged and their sizes of Application 7

Data Objectives	Size (bytes)	Description
Sample start time	12	
Sample duration (seconds)	4	
Voltage - mean	2	
Voltage - Standard Deviation	2	
Current - mean	2	
Current - Standard Deviation	2	
Consumption - mean	2	
Consumption - Standard Deviation	2	
Power Quality Event Information - voltage events	2	Events in reporting period
Power Quality Event Information - voltage event mean	2	Mean magnitude
Power Quality Event Information - voltage event standard deviation	2	std deviation in magnitude
Power Quality Event Information - current events	2	
Power Quality Event Information - current event mean	2	Mean magnitude
Power Quality Event Information - current event standard deviation	2	std deviation in magnitude

The packet exchange details are shown below.

Table 3.28. The details of packet exchanges of Application 7

Session Part	Action	Direction	Related APDU	Info	PDU	TCP	IP	Total
TCP/IP Initiation	Controller initiates	->		Syn		24	20	44
	Meter responds			Syn, Ack		24	20	44
	Controller responds			Ack		20	20	40
Connection Establishment	Controller requests connection	->	AARE-AARQ_Establish_from_C	AARE	39	20	20	79
	Meter confirms connection			AARQ	51	20	20	91
Data Transfer	Controller sends GET request	->	Net Ops Spt Sensor_Get_from_C	Data	125	20	20	165
	Meter sends GET response			Data	53	20	20	93
TCP/IP Close	Meter requests close	->		Fin, Ack		20	20	40
	Controller responds			Ack		20	20	40
	Controller responds			Fin, Ack		20	20	40
	Meter responds			Ack		20	20	40
Totals (bytes)					268	228	220	716

(8) **Operation of the Smart meter.** A smart meter requires parameter updates, e.g. time synchronization and password updates. Other parameters may also require update depending on the functionality implemented on the meter.

The key application characteristics are shown in Table 3.29.

Table 3.29. The key application characteristics of Application 8

Reference	IEC 62056-53
Users	Smart Metering Operators
Frequency of Operation	Weekly. Usually be done less frequently.
Application Information Exchanged	The controller provides authentication details and identifies the information to be updated as well as the new settings. The meter confirms the set operation.
Communications Structure	Communications is structured into three parts: Establish Session, Exchange Information, and Session Close. The byte size of the information exchanged is less than 450 bytes so generally would not be split into multiple IP packets.

The application transaction structure is shown in Table 3.30.

Table 3.30. The application transaction structure of Application 8

Devices	Information	Description
Controller	Authentication	The controller authenticates to the meter before the transaction
Meter	Authentication Response	Acknowledgement is sent to controller that authentication is successful.
Controller	SET Request	SET request with information required.
Meter	SET Response	SET response confirmation.

The objects exchanged and their size are shown below.

Table 3.31. The objectives exchanged and their sizes of Application 8

Data Objectives	Size (bytes)	Description
Time update	12	
Password update	15	

The packet exchange details are shown in Table 3.32.

Table 3.32. The details of packet exchanges of Application 8

Session Part	Action	Direction		Related APDU	Info	PDU	TCP	IP	Total
TCP/IP Initiation	Controller initiates	Controller	Smart Meter		Syn		24	20	44
	Meter responds				Syn, Ack		24	20	44
	Controller responds				Ack		20	20	40
Connection Establishment	Controller requests connection	Controller	Smart Meter	AARE-AARQ_Establish_from_C	AARE	39	20	20	79
	Meter confirms connection			AARE-AARQ_Confirm_from_M	AARQ	51	20	20	91
Data Transfer	Controller sends SET request	Controller	Smart Meter	Smt_Mtr_Support_Set_from_C	Data	60	20	20	100
	Meter sends SETresponse			Smt_Mtr_Support_Set_from_M	Data	13	20	20	53
TCP/IP Close	Meter requests close	Controller	Smart Meter		Fin, Ack		20	20	40
	Controller responds				Ack		20	20	40
	Controller reponds				Fin, Ack		20	20	40
	Meter responds				Ack		20	20	40
Totals (bytes)						163	228	220	611

The baseline timing of these smart meter applications is provided in Table 3.1.

Table 3.33. Baseline smart meter application timings

Application	Frequency	Start Time	Comment
Meter Reading	Daily	0030hrs	
Log Collection	Once	Day 1 – 0200hrs	Normally be run weekly.
Tariff Update	Once	Day 2 – 0100hrs	Normally be run monthly.
Software Update	Once	Day 2 – 0200hrs	Normally be run infrequently.
Network Operations Support	Hourly	3 minutes past each hour	

Remote Connect/ Disconnect	Once	Day 1 - 1200hrs	Normally be run infrequently.
Smart Meter Support	Once	Day 1 – 0500hrs	Normally be run weekly.
System Alarm	Hourly	1 minute past each hour	

3.3.3 OPNET Model Validation

The basic OPNET model validation used the following methods:

- scripting – OPNET’s scripting mechanism does basic validation of parameters as the script is run. Errors are logged for analysis and scripts can be refined and rerun as necessary to resolve problems. This mechanism captured most “typo” type problems;
- base transaction analysis - application transactions were mapped out as part of application analysis to identify the basic exchange of packets for tasks. A packet analyser was used in network models to capture packet transfers. This allowed packet analysis at the IP level and comparison against expected exchanges. This mechanism was the major mechanism used for validating configuration; and,
- trial result analysis - application traffic statistics were captured and compared to the expected application traffic over the simulation period.

Base transaction analysis was done as part of implementing the task/application/profile objects into OPNET. Simulation results were analysed using operational results generated by the case studies to validate the models.

3.4 Case Study

A 50-meter network was simulated along with the 8 applications based on the IEC 62056 standards. Given the complexity of the configuration it was essential that the operation of the applications be observed. The major mechanism was through the use of the (OPNET Modeler) Requesting Custom Application probe on the controller. Graphing the output from

this sensor allowed visual inspection of when applications were active. This was used to verify that applications were operating as expected.

The channel utilisation over time was examined to determine the impact of applications on the channel. Two types of examination were carried out:

- IP utilisation - the IP “interface.traffic” probe was used to capture the amount of traffic crossing the IP interface of the router wide area link. This provided statistics regarding the amount of IP packet data was being sent across the link. Data was collected from routers on both ends of the link to capture statistics on data inbound and outbound from the controller; and
- Physical utilisation - the “point-to-point.throughput” probe was used to capture the total amount of traffic crossing the point-to-point link. This provided statistics regarding the total traffic crossing the link including IP and the physical link (PPP protocol) overhead. This provided insight into the additional overhead that the physical layer will impose.

The IP and physical utilisation provide insights into the use of the channel. A 10-second sampling rate was used in the study.

OPNET Modeler logs conditions under which applications are experiencing profile or network condition problems. This includes conditions such as the application being unable to start because its start time is outside its operation period. The log also captures conditions under which TCP retransmits are required due to network congestion. The total IP packet count statistics available as part of the simulation were also captured and provided some indication of the scale of retransmits when they occurred.

To understand the impact of various factors on smart meter communications a number of trials were done with varied parameters for channel size, application information size and application frequency of operation, etc. These are summarised in Table 3.2.

Table 3.34. Trials

Simulation Title	Description	Configuration
Baseline	Applications implemented in 7.5 kb/s channel to examine the general characteristics of communications required to support	7.5 kb/s PPP link
Bandwidth	Implement link constraint (5.6 kb/s, 3.8 kb/s and 0.75 kb/s links) to examine the impact of link constraint on the system. The numbers are 75% of 7.5, 5 and 1kb/s. Specification of the serial interface on the router includes a parameter which limits the utilised bandwidth to 75% by default. This default was applied throughout the trials.	5.6 kb/s, 3.8 kb/s and 0.75 kb/s PPP links

3.4.1 Simulation Results

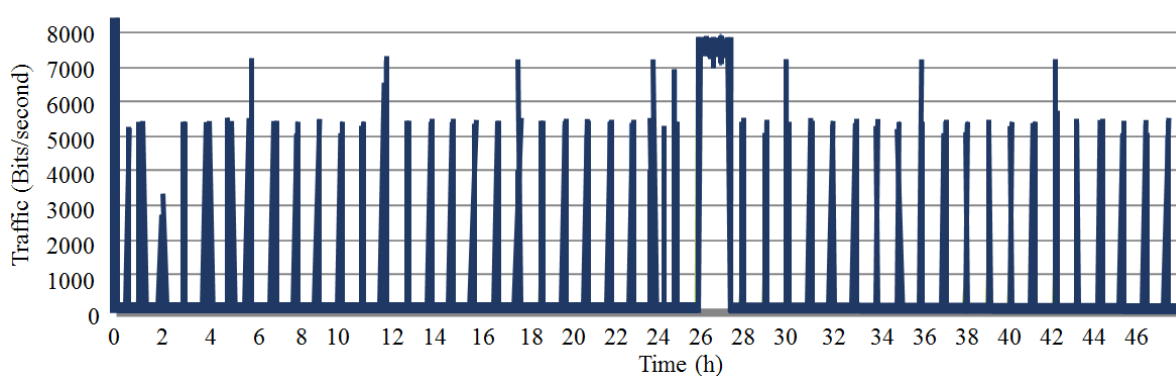


Fig. 3.5 IP channel utilisation - traffic from controller
based on the baseline network

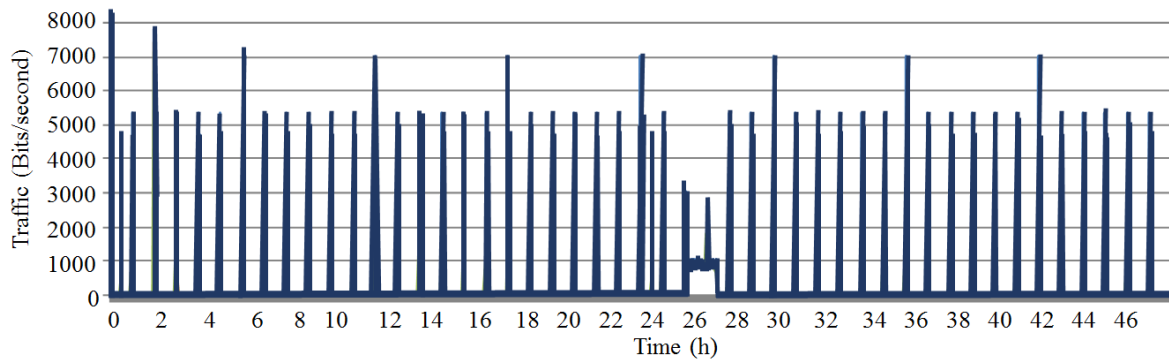


Fig. 3.6 IP channel utilisation - traffic to controller
based on the baseline network

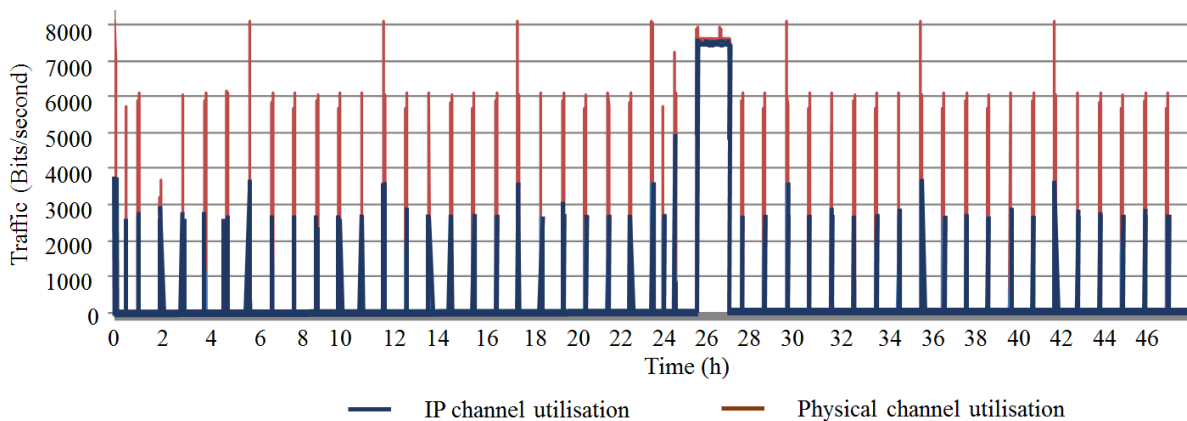


Fig. 3.7 Physical channel utilisation - traffic from controller
based on the baseline network (average of 1000 independent simulations)

The basic setup collected channel utilisation rates to and from the controller. These statistics were exported from OPNET Modeler into Microsoft Excel and graphed to allow straightforward analysis of channel utilisation. Channel utilisation characteristics of interest included:

- channel under-utilisation - in Figure 3.5 and Figure 3.6 it can be seen that the network has large periods where it is unused. This is expected as most of the applications involve small exchanges of small size and the minimum application interval is 1 hour;
- impact of large data transfers – in Figure 3.5 and Figure 3.6 it can be seen that the software update application (application begins at the 26 hour point) used the capacity of the channel for the period it is operational; and

- physical channel utilisation – Figure 3.7 shows the average IP and physical link utilisation rates for traffic from the controller using PPP. For most traffic the physical link rates significantly exceed the IP link rates. This is expected as most transactions involve exchanges of small amounts of information - the encapsulation is a relatively larger portion of the overall exchange. For large transfers (software update application at 26 hour point) there is little difference between the IP and physical rates. This is expected, as the physical encapsulation is a relatively small proportion of the overall information transfer.

3.4.2 Constrained Channel

The application timeline was the same as that used for the baseline. TCP retransmits were introduced which increased the number of packets by 0.1% for the 3.8 kb/s configuration and 26.0% for the 0.75 kb/s configuration. This is expected in a real system given the constraint of the network channel. Comparison of the traffic patterns for different channel sizes for traffic outbound from the controller is shown in Figure 3.8. As can be seen the network remained relatively unused for all links except for the software update (beginning at 26 hour point). As the link speed decreased, the length of time to complete this task increased moving from around 1.5 hours at 7.5 kb/s to 20 hours at 0.75 kb/s. Similar behaviour was found for the bulk log collection which has a larger than average transfer of data.

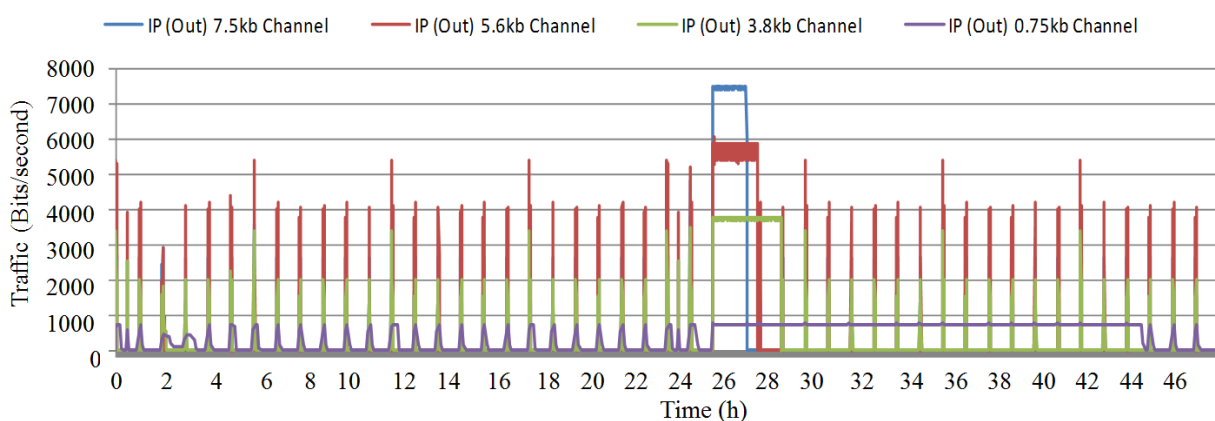


Fig. 3.8 Constrained - IP traffic - from controller

The major observations in the constrained link simulation were:

- bandwidth utilisation - decreasing the channel size results in overall increased bandwidth utilisation. Despite a 90% decrease in channel size the channel is still

relatively unused except for the software update. The frequency of such updates is likely to be very low given the relative simplicity of a smart meter as compared to other networking devices. The network will still have to be designed to accommodate such worst-case scenarios; and

- TCP retransmits - TCP retransmits are due to the expiry of the TCP timers which determine how long to wait for acknowledgements before deciding a packet was lost or damaged and retransmitting another. These, in many TCP/IP device implementations, are customer-defined parameters which can be adjusted. The suitability of this change as a mechanism for addressing the problem is dependent on the network and application context.
- With the exception of the large data transfers (for software update and bulk log collection) the hourly application implementation does not require a substantial channel size. However such time delay will have direct impact on the functions related to network operations which will be investigated in the following chapters.

3.5 Summary

The chapter examined the basic channel requirements for smart metering through the use of the OPNET Modeler communications simulation tool and the simulation of basic applications that could potentially be implemented in smart metering. Characterisation of applications was informed by IEC 62056 and literature survey. The communications were primarily examined at the IP layer as this is expected to be common in all modern implementations.

The specific method of simulation was discrete event simulation. This involves defining all of the individual exchanges of information between devices at the application layer. The IEC 62056 standards were used as the method of encoding the information to be exchanged as it is a recognized standard for smart metering that addresses communications over IP. The standard is efficient at information exchange and allows for sophisticated controller/meter architectures. OPNET Modeler was used to model the IP and TCP communications layers. These were implemented as phases, tasks and applications run on specific devices.

The physical architecture was implemented as a shared constrained network. This was considered the worst case implementation of a smart metering network. The shared and constrained characteristics were implemented on a router link to enable OPNET's network

analyser components to monitor traffic. The configuration was considered representative of a shared-constrained network. The smart metering simulated was based on 50 smart meters with a single controller. The baseline link size was chosen to be 7.5 kb. Applications were implemented as controller controlled using TCP/IP protocols. This was considered as worst case as some applications such as system alarm and demand broadcast could have been implemented more efficiently (from a communications perspective) using UDP.

The baseline trial suggests that a 7.5 kb/s shared channel would adequately meet the requirements of a 50-meter smart meter network. The overall observation was that individual communications requirements for smart meters are not particularly communications intensive and that infrequent large transactions would pose the most significant challenge.

This chapter's focus was on understanding the channel size required to support smart meter applications under a "worst case" low speed shared link environment which was controller controlled. The trials and analysis done suggest that the channel size required can be below 7.5 kb/sec. For non-shared channels the value would be considerably less.

The case study also shows that under constrained conditions, large time delay may be introduced that have direct impact on the functions related to network operations, which will be investigated in the following chapters.

Chapter 4

Evaluation Method of Smart Metering Infrastructure for Smart Grid Operation

4.1 Introduction

As discussed in previous chapters, future electricity networks must provide all consumers with a highly reliable, flexible, accessible and cost-effective power supply, fully exploiting the use of both large centralised generators and smaller distributed energy sources (European Commission, 2007). Smart Grid concepts are being promoted by many governments as a way of addressing these challenges.

ICT play a critical role within Smart Grids. Through increasing visibility they enable reduction of energy losses and increased efficiency of network operation, but also facilitate managing and controlling the ever more distributed power grid to ensure stability and increase security (European Commission, 2009). However, real-time measurements with communication channels are very limited in current distribution networks. Therefore the system states (voltages and power flows) utilised by Distribution Network Operators (DNOs) are either estimates or derived from state estimation based on pseudo nodal load measurements and a limited number of real-time measurements (Wu, 2008). The information provided by such ICT infrastructure is not reliable, which retards the implementation of Smart Grid functions.

However, the ICT infrastructure of distribution networks is soon expected to be enhanced by the large-scale deployment of smart meters, which has been discussed in Chapters 2 and 3. The EU has mandated the deployment of smart meters for its member states and the UK is committed to the full deployment of Smart Meters by 2020 (DECC, 2009). However, there is limited agreement on the role of smart meters in the operation of the future Smart Grid.

In this study, PLC serves as the communication infrastructure linking smart meters, through the low-voltage (LV) PLC network and the medium-voltage (MV) PLC network, with the MV concentrator. The acquired data is sent to the SCADA system from the MV concentrator via a high-performance communications medium (e.g. optical fiber, xDSL, GSM).

A state estimator is an essential front end of other Smart Grid applications. It processes the redundant measurements, filters bad data and provides a reliable set of information that can be utilised directly by other applications.

The communication infrastructure of Smart Grids is characterised by many levels of heterogeneity, for instance, some components may be managed by different service providers; specific networks and groups of users may have varying requirements and characteristics; diverse transmission media, e.g. PLC, optical fibre, radios; and varying implemented solutions, e.g. ATM, IPv4, IPv6 (Marchese, 2007). Therefore different configurations of the communications infrastructure provide different Qualities of Service (QoS).

Smart Grid applications require a specific level of assurance from the communications networks. Such requirements mainly focus on the quality of information provided by the ICT infrastructure. Regarding power system operation, the main requirements from Smart Grid applications are on accuracy and latency of real-time measurements.

Currently, metering and communications equipment should meet the accuracy requirements mandated by corresponding standards. For example, ANSI C12.20 sets the electricity meter accuracy to ± 0.05 percent or better. Hence the inaccuracy caused by this hardware is negligible. For the ICT infrastructure shown in Fig. 4.1, the electric power system information is acquired through a polling mechanism. Polling is defined as the master to slave mechanism for addressing slaves (for command or data request). The scheduling of the polling is the unique responsibility of the master (Brito, 2004) and was represented as a controller in Chapter 3. In Fig. 4.1, the LV concentrator acts not only as a slave for the MV PLC, but also the master for the LV PLC. The polling of a large number of smart meters will cause considerable latency (time delay). Because the power system loads are dynamic, time delays result in errors in the measurements. Therefore the latency performance of the

heterogeneous communications network shown in Fig. 4.1 was investigated in this Chapter, based on the smart metering communications model developed in Chapter 3.

4.3 Framework of the Evaluation Method

The framework of the proposed evaluation method is shown in Fig. 4.2. Several parameters representing the main characteristics of the ICT infrastructure, e.g. response time of a smart meter, are identified and made adjustable in the OPNET simulation model of the communications system. The characteristics of the electric power system, mainly the load variation behaviour, are analysed, and are used to quantify the relationship between the time delay and the measurement error for the power system being investigated. The state estimator proposed by Wu et al (2013) was utilised to refine the measured data. The Optimal Power Flow tool presented by Zimmerman (2007) was employed to evaluate the obtained information on the Smart Grid applications. Through the iterative procedure shown in Fig. 4.2, a cost-effective ICT infrastructure solution can be derived and evaluated, which is able to meet the requirements of the Smart Grid operation.

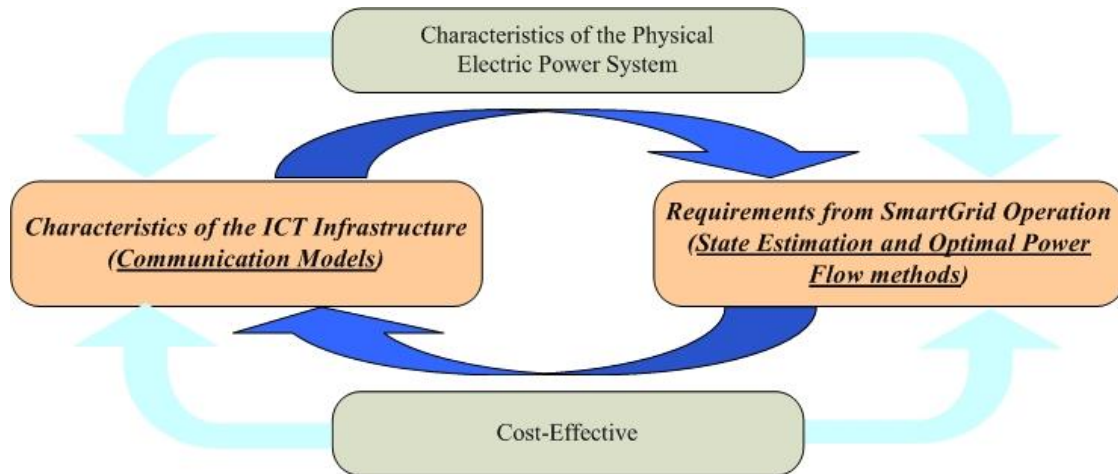


Fig. 4.2 Framework of the evaluation method

4.4 Communication System Modelling

Time delay of smart meters and the PLC based ICT infrastructure is defined as the duration of time from the polling demand generated in the MV master to the time when all data is brought back to the MV master from all smart meters.

The sources of time delay can be classified into two categories: hardware delay and software delay, which are shown in Fig. 4.3.

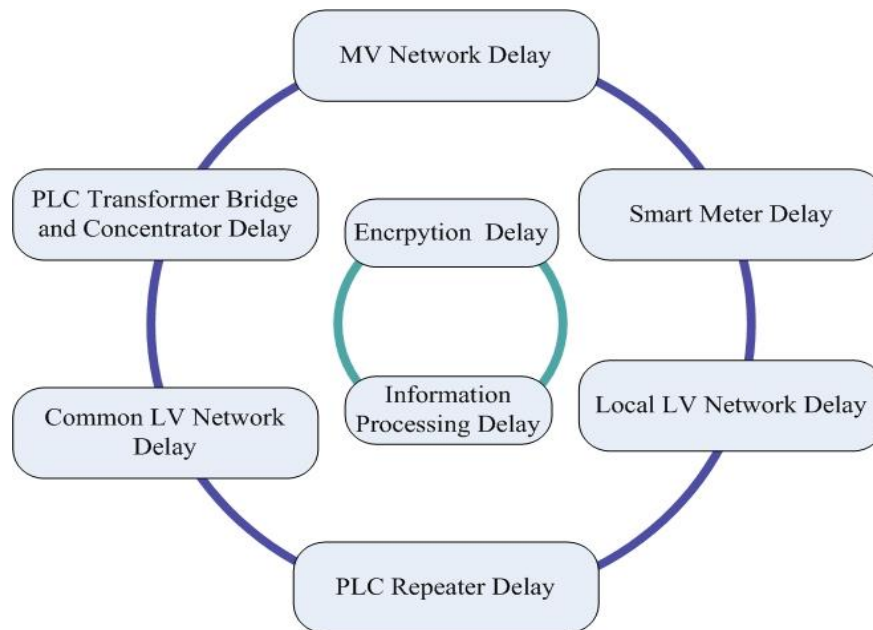


Fig. 4.3 Sources of time delay

Brito et al (2004) provides some statistics of the likely hardware time delay. For a PLC network, the maximum propagation delay time from the node that generates the data to the access point should take a maximum of 50 ms. The meter response time can vary between 200 ms to 1.5 seconds. The time delay of the PLC transformer bridge which interconnects MV PLC and LV PLC is between 10 and 20 ms.

Time delays are also introduced by software functions which are mainly used for the maintenance of information security and information privacy, and also for information processing, e.g. data fusion by the concentrator.

Once a packet gains access to the network, there is a high probability that it will flow to its intended recipient. However, if the packet is not received or if it is received in error, where one or more bits cannot be corrected by the Forward Error Correction (FEC) scheme, the packet will be retransmitted after a short waiting time. Obviously the retransmission will increase the time delay. The users usually are able to adjust the retransmission number (Held, 2006).

The simulation model of the proposed communications infrastructure was developed using OPNET and has been introduced in Chapter 3. The topology and main components used for

this chapter are shown in Fig. 4.4. The different time delay sources are considered and added to the OPNET models and also can be easily adjusted.

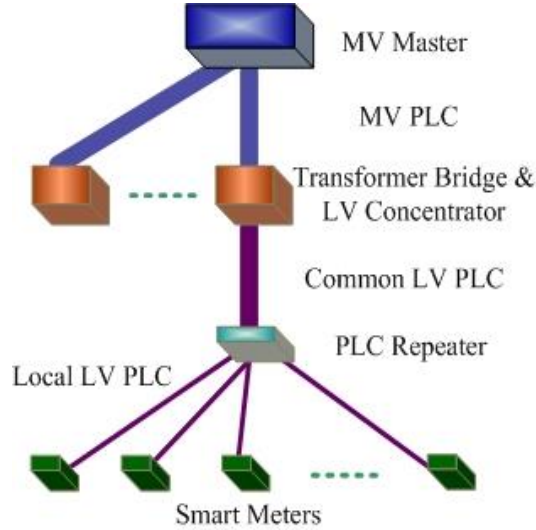


Fig. 4.4 Simulation model of the proposed communication infrastructure that is used in this chapter

4.5 Information Platform for Smart Grid Operation

In this section, the correlation between measurement errors and communications latency is analysed; state estimation technique is introduced which was used to refine measured data by smart meters; An Optimal Power Flow tool is also introduced which was employed to evaluate the impact of communications infrastructure performance on Smart Grid applications.

4.5.1 Measurement Errors Induced by Communication Latency

The output of the communications simulation model shown in Fig. 4.4 is the real-time measurements with a certain time delay. The relationship between the time delay and the information error was quantified through analysing the characteristics of load.

For a LV concentrator i on a MV feeder j , the load recorded at time t is represented by

$$L_{M_j,i}(t) = \sum_{k=1}^N L_{M_j,i,k}(t - \tau_k) = \sum_{k=1}^N L_{A_j,i,k}(t - \tau_k) \quad (4.1)$$

where N is the number of smart meters managed by concentrator i , τ_k is the time delay of the communications between concentrator i and smart meter k , and $L_{M-j,i,k}$ is the load measured by smart meter k . The subscript M denotes measured data and A denotes actual data.

We also have

$$L_{A-j,i}(t) = \sum_{k=1}^N L_{A-j,i,k}(t) \quad (4.2)$$

And the variation rate of the load demand is defined as

$$k = \frac{L_{A-j,i}(t) - L_{A-j,i}(t - \delta)}{L_{A-j,i}(t)\delta} = \frac{\sum_{k=1}^N (L_{A-j,i,k}(t) - L_{A-j,i,k}(t - \delta))}{\delta \sum_{k=1}^N L_{A-j,i,k}(t)} \quad (4.3)$$

where δ is the time difference between two observations. For the real electricity load demand, k is a function of j , i , t and δ . Based on Wu (2013) and European Commission (2007, 2009), the measurement error induced by the time delay is represented as

$$\begin{aligned} E_{A-j,i}(t) &= \frac{L_{A-j,i}(t) - L_{M-j,i}(t)}{L_{A-j,i}(t)} \\ &= \frac{(\tau k L_{A-j,i}(t) + L_{A-j,i}(t - \tau)) - L_{M-j,i}(t)}{L_{A-j,i}(t)} \\ &= \tau k + \frac{\sum_{k=1}^N L_{A-j,i,k}(t - \tau) - \sum_{k=1}^N L_{A-j,i,k}(t - \tau_k)}{\sum_{k=1}^N L_{A-j,i,k}(t)} \\ &= \tau k + \frac{\sum_{k=1}^N (L_{A-j,i,k}(t - \tau) - L_{A-j,i,k}(t - \tau_k))}{\sum_{k=1}^N L_{A-j,i,k}(t)} \end{aligned} \quad (4.4)$$

where τ is the polling time, i.e. the total time delay cause by polling all smart meters connected to one LV concentrator. When N is large, the right hand side of (4.4) is close to zero. So we have

$$E_{A-j,i}(t) \approx \tau k \quad (4.5)$$

Historical load information of a MV/LV transformer is easy to access. Hence k can be obtained based on load research using Equ. 4.3. Then the relationship between the time delay and the information error is quantified by Equ. 4.5.

For example, the load curves (active power) recorded at a MV/LV transformer located in a residential area are shown in Fig. 4.5. The comparison of the load data based on one-hour time delay is shown in Fig. 4.6. The worst case scenario can be utilised for the purpose of system design. So based on the information shown in Fig. 4.6, k can be approximated as 1%/minute, which means one percent measurement error is induced by one minute time delay. This result was used in the case study.

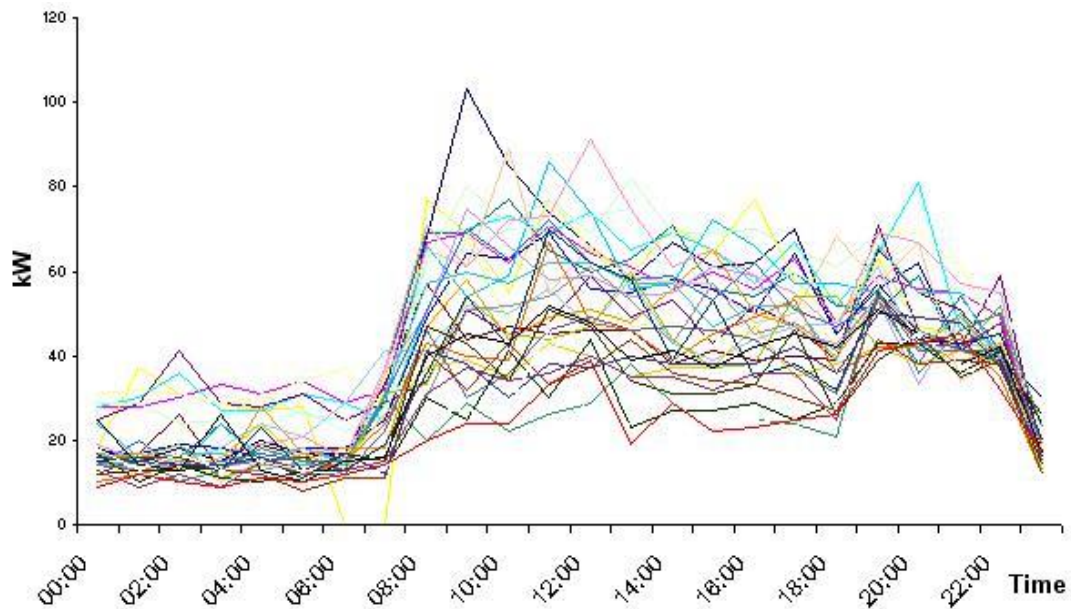


Fig. 4.5 Load data of a MV/LV transformer

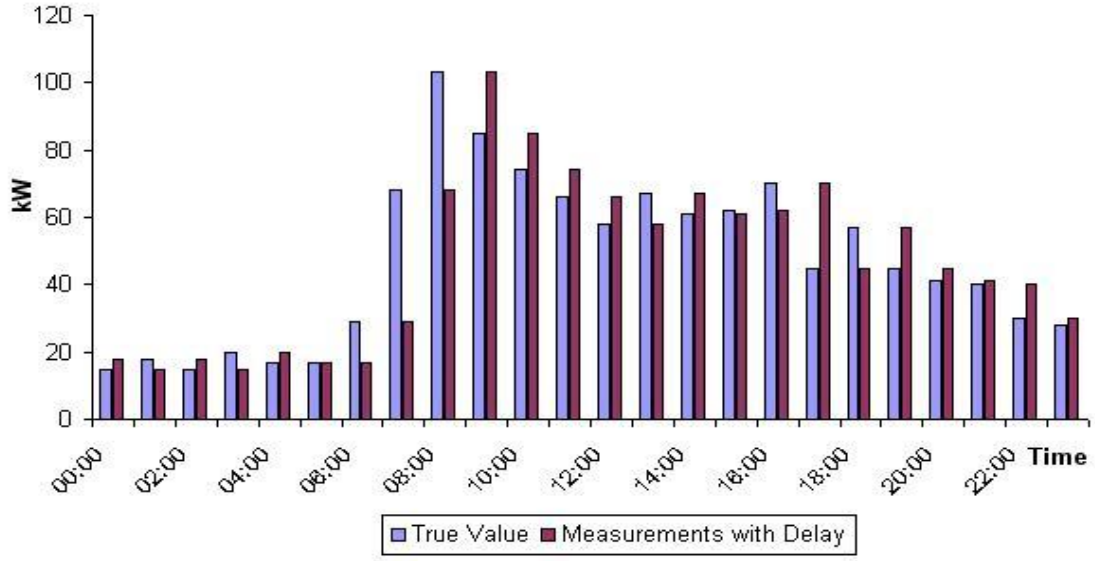


Fig. 4.6 Influence of the one-hour communication delay

4.5.2 State Estimator

The robust state estimator proposed by Wu et al (2013) was used to process the inaccurate information provided by the communications system. The output of the state estimator is to be used by the Smart Grid functions. The voltage magnitude and the phase angle of each node of the MV distribution network were chosen as the state variables. The state estimator provides a steady state solution for a balanced 3-phase distribution network.

The state estimator utilised is a maximum likelihood estimation, which minimises an objective function shown in Equ. 4.6 subjecting to the constraints given by the measurement equations Equ. 4.7.

$$\min \quad (\mathbf{z} - \mathbf{h}(\mathbf{x}))^T \bar{\mathbf{W}} (\mathbf{z} - \mathbf{h}(\mathbf{x})) \quad (4.6)$$

$$\text{subject to} \quad \mathbf{z} = \mathbf{h}(\mathbf{x}) + \mathbf{r} \quad (4.7)$$

where \mathbf{z} is the measurement vector, \mathbf{x} the state vector, $\mathbf{h}(\mathbf{x})$ the measurement functions, and \mathbf{r} the measurement residual vector. $\bar{\mathbf{W}}$ is the equivalent weight matrix, which includes functions of the measurement residuals. The following equations were used to solve (4.6) and (4.7) iteratively:

$$\Delta \mathbf{z}_n = \mathbf{z} - \mathbf{h}(\mathbf{x}_n) \quad (4.8)$$

$$\Delta \mathbf{x}_n = (\mathbf{H}^T \bar{\mathbf{W}} \mathbf{H})^{-1} \mathbf{H}^T \bar{\mathbf{W}} \Delta \mathbf{z}_n \quad (4.9)$$

$$\mathbf{x}_{n+1} = \mathbf{x}_n + \Delta \mathbf{x}_n \quad (4.10)$$

where n is the iteration number.

4.5.3 Optimal Power Flow

An OPF tool is used to evaluate the usability of the derived information. The OPF calculation can be viewed as a sequence of conventional Newton-Raphson power-flow calculations in which certain controllable parameters are automatically adjusted to satisfy the network constraints while minimising a specified objective function. The objective function of the OPF was chosen to minimise the network losses while preventing the load and operational limit violations.

An OPF tool provided by the MATLAB power system simulation package MATPOWER was used (Zimmerman, 2007). This OPF tool classifies the optimisation variables into three groups. The first group (labelled as \mathbf{x}) is a vector containing nodal voltage magnitudes and angles, and real and reactive generator power injections as shown in (4.11). The second group (\mathbf{y}) contains all the additional user defined variables and the helper variables those are used by the cost functions. The third group (\mathbf{z}) represents additional user defined variables.

$$\mathbf{x} = \begin{bmatrix} \boldsymbol{\theta} \\ \mathbf{V} \\ \mathbf{P}_g \\ \mathbf{Q}_g \end{bmatrix} \quad (4.11)$$

The optimisation problem then is formed as follows (Zimmerman 2007):

$$\min \sum_i^{N_G} (f_{c,P,i}(P_{Gi}) + f_{c,Q,i}(Q_{Gi})) + 0.5 \times \mathbf{w}^T \mathbf{C} \mathbf{w} + \mathbf{C}_w^T \mathbf{w} \quad (4.12)$$

where $f_{c,P,i}$ and $f_{c,Q,i}$ are the cost functions of active and reactive power generation for generator i ; N_G is the total number of generators; \mathbf{W} is a vector representing the \mathbf{x} and \mathbf{z} groups optimisation variables; \mathbf{C} is a symmetric, sparse matrix of quadratic coefficients and \mathbf{C}_w is a vector of linear coefficients. Both \mathbf{C} and \mathbf{C}_w are parameters specifying the generalised cost.

The constraints considered are (Zimmerman 2007):

Active power balance equations	$P(\theta, V) - P_g + P_d = 0$
Reactive power balance equations	$Q(\theta, V) - Q_g + Q_d = 0$
Apparent power flow limit of lines at the <i>from</i> end	$ S_f(\theta, V) - S_{max} \leq 0$
Apparent power flow limit of lines at the <i>to</i> end	$ S_t(\theta, V) - S_{max} \leq 0$
Voltage and generation variable limit	$x_{min} \leq x \leq x_{max}$
Limits on user defined variables	$z_{min} \leq z \leq z_{max}$

4.6 Test Results

A medium voltage 33-node system (Baran, 1989) with distributed generation, shown in Fig. 4.7, was used for the testing of the evaluation method. Detailed network information can be found in (Baran, 1989). Load curves shown in Fig. 4.5 were applied to the test system. DG1 has constant output of 300 kW and 120 kVAr, and DG2 has constant output of 100 kW and 30 kVAr. Based on the previous analysis, the relationship between the time delay and the information error for such load is quantified as one percent measurement error induced by one minute time delay. It is applied to both active power and reactive power.

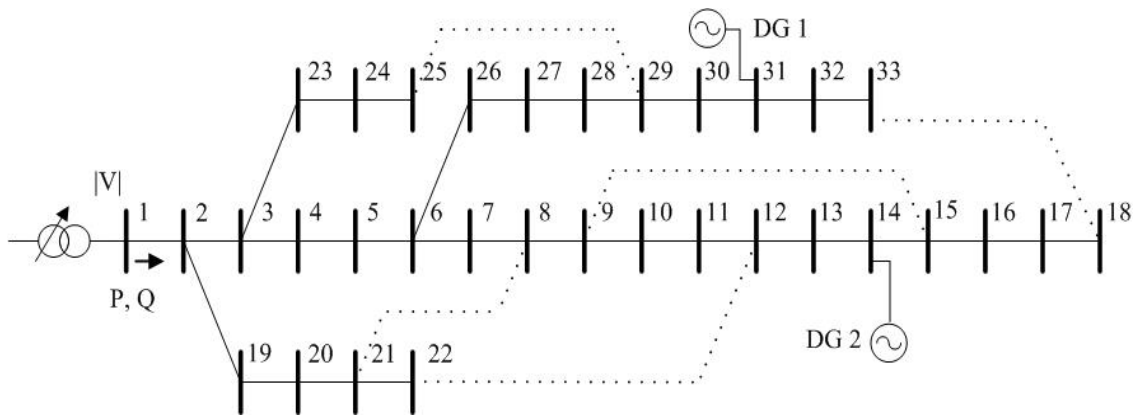


Fig. 4.7 Test system (Baran, 1989)

In the simulation model of the communications system, an LV concentrator was deployed at the MV/LV transformer of each busbar. All LV concentrators worked in parallel. Three scenarios were defined and the dominant parameters are shown in Table 4.1.

Table 4.1. Key parameters

Scenarios	Parameters ^a			
	T_{SM} /s	T_{CD} /s	R_{FR} /%	T_{RW} /s
Scenario 1	0.2 – 1.0	1.0	98	3
Scenario 2	0.2 – 1.5	1.0	98	3
Scenario 3	0.2 – 3.0	3.0	90	8

a. T_{SM} - Smart Meter Delay; T_{CD} - Communication Equipment Delay;

R_{FR} - Success Rate of the meter reading for the first trial;

T_{RW} - Waiting time prior to re-reading

Scenario 1 is to investigate the performance of the ICT infrastructure equipped with high-performance smart meters (He, 2010). Scenario 2 is based on the ICT infrastructure suggested by Brito et al (2004). Scenario 3 is to study low-performance ICT infrastructure evolved from the existing AMR system (He, 2010).

The time delay with different amount of smart meters managed by each LV concentrator under Scenario 1 is shown in Fig. 4.8. The time delay of a test system where 100 smart meters are managed by each LV concentrator is shown in Fig 4.9, which was run for 7 days. Based on this 100-smart-meter configuration, the nodal voltage profile from the state estimator is shown in Fig 4.10. The highlighted solid line shows the true value for a snapshot. The shadow surrounding it shows the error caused by the time delay (based on 100 independent simulations of the smart metering infrastructure). The variation interval is small which means such nodal voltage information can be used reliably by the Smart Grid functions, e.g. voltage control.

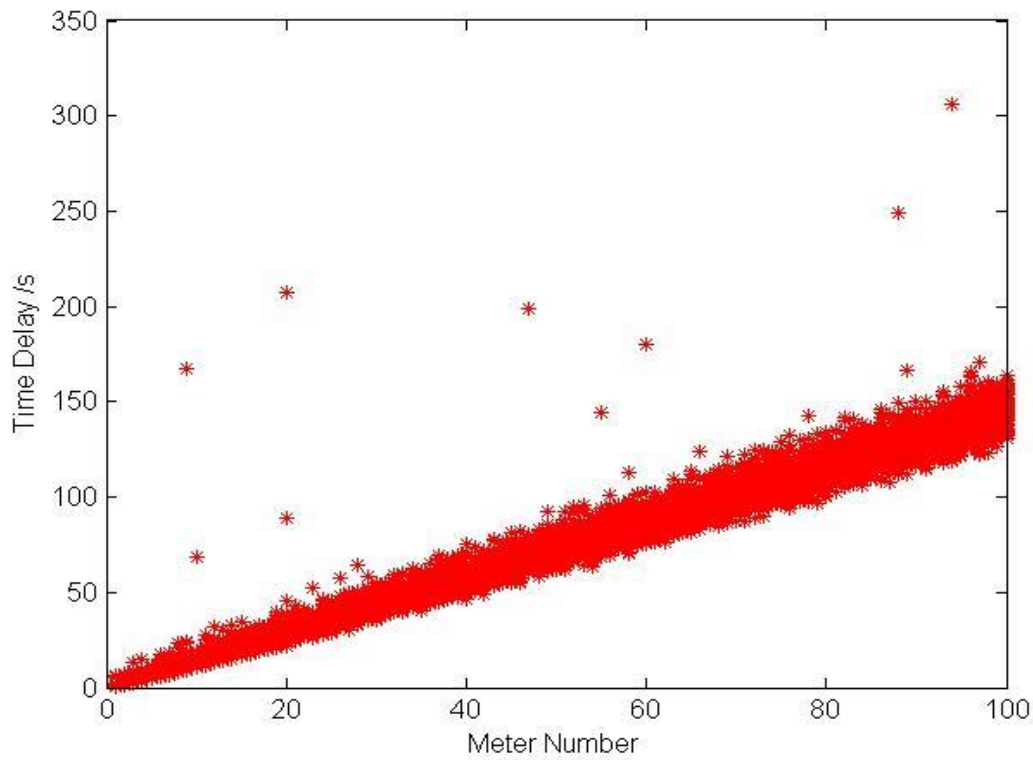


Fig. 4.8 Time delay with different meter number under Scenario 1

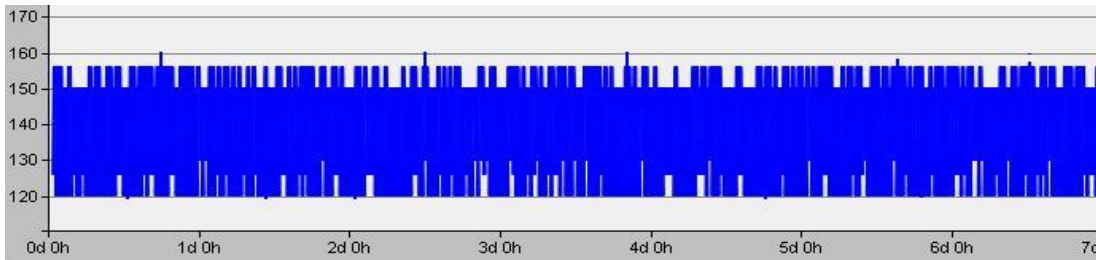


Fig. 4.9 Time delay with 100-meter configuration under Scenario 1 (units: second)

The x axis shows the time of 7-day simulation of the smart metering infrastructure and the y axis shows the time delay.

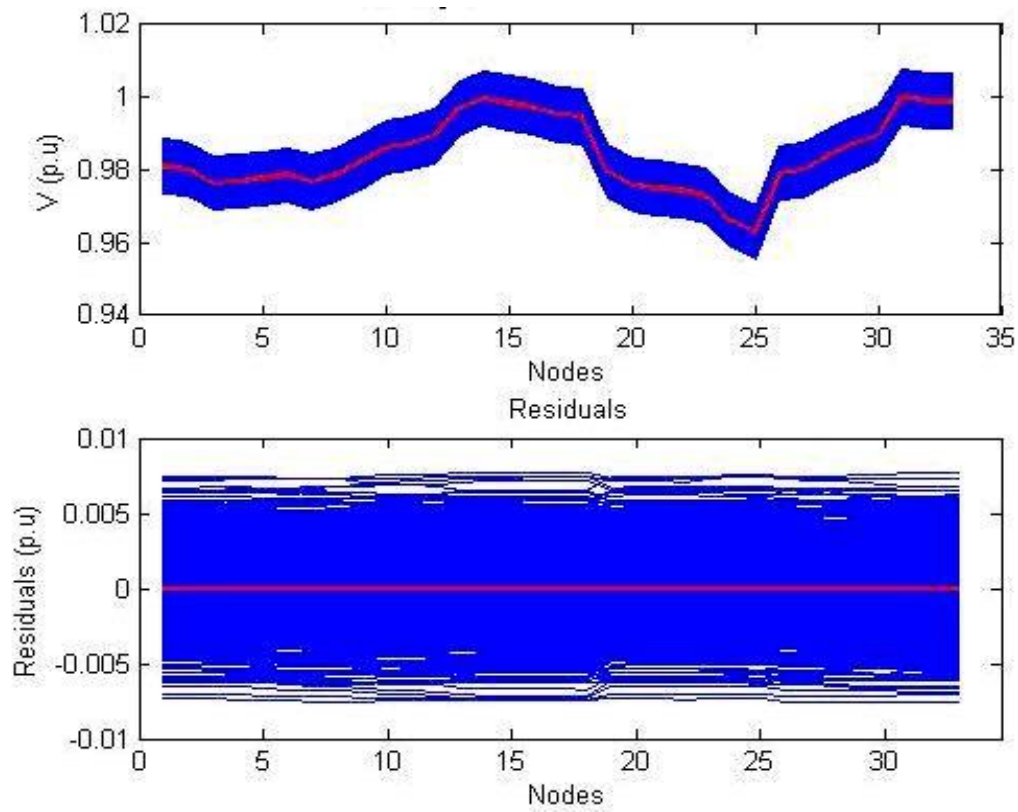


Fig. 4.10 Nodal voltage estimates provided by the state estimator under Scenario 1

The same method was applied to Scenario 2 and Scenario 3. The results are shown in Figs. 4.11 - 4.14.

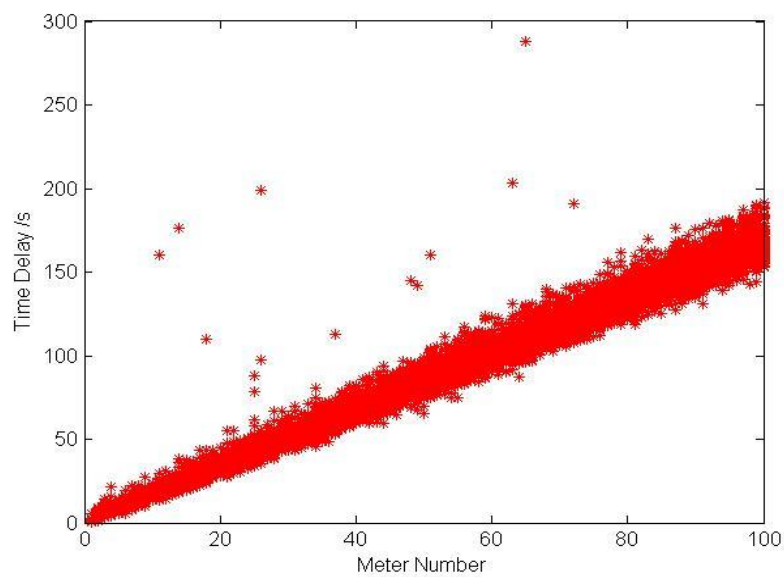


Fig. 4.11 Time delay with different meter number under Scenario 2

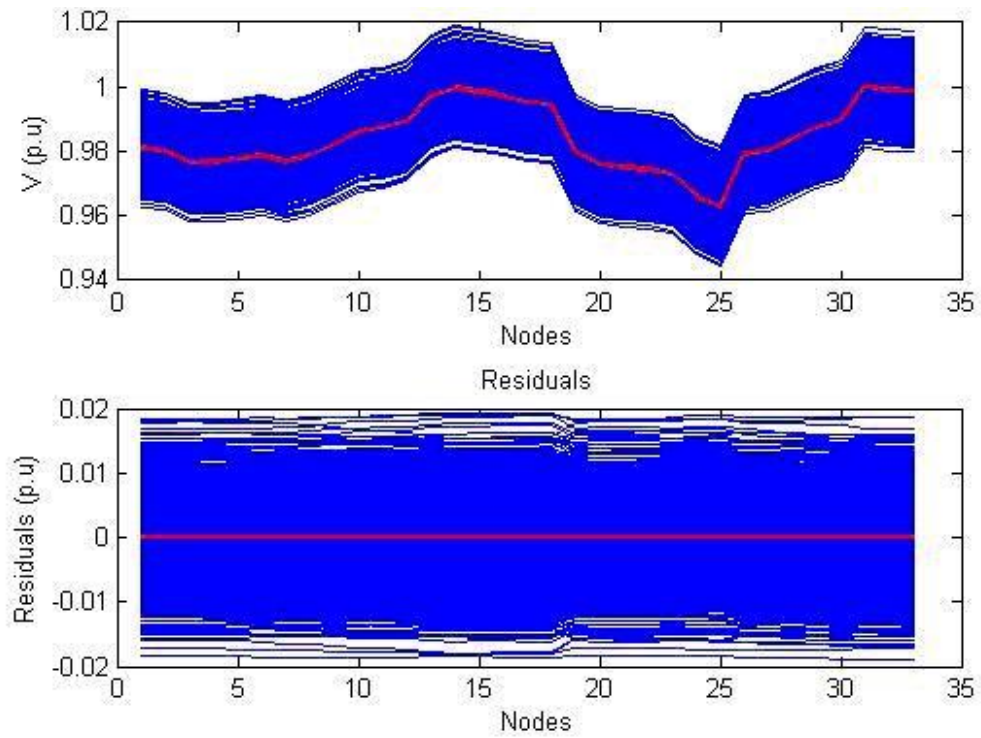


Fig. 4.12 Nodal voltage estimates provided by the state estimator under Scenario 2

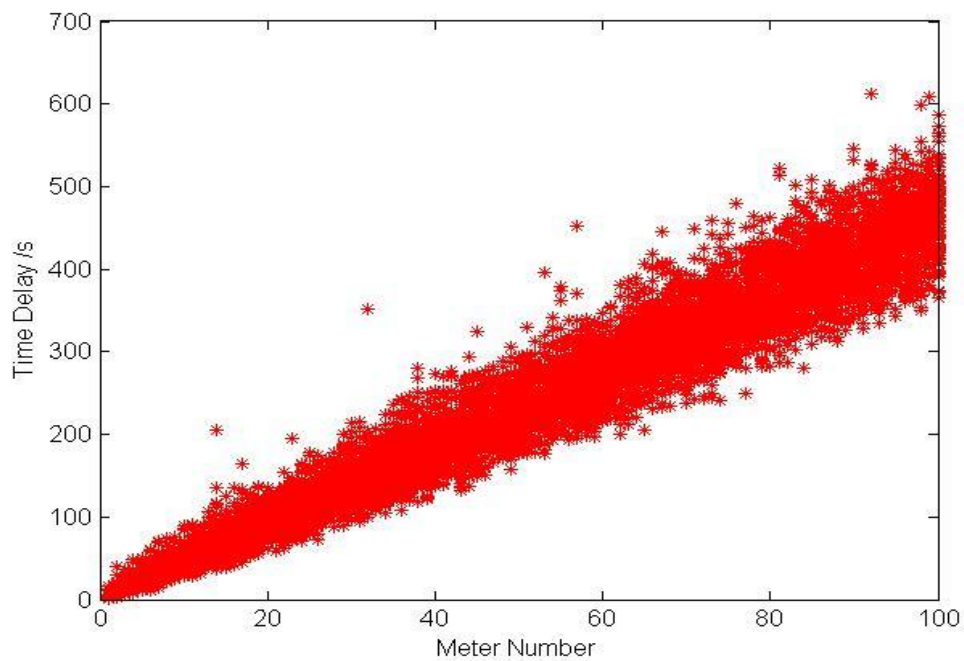


Fig. 4.13 Time delay with different meter number under Scenario 3

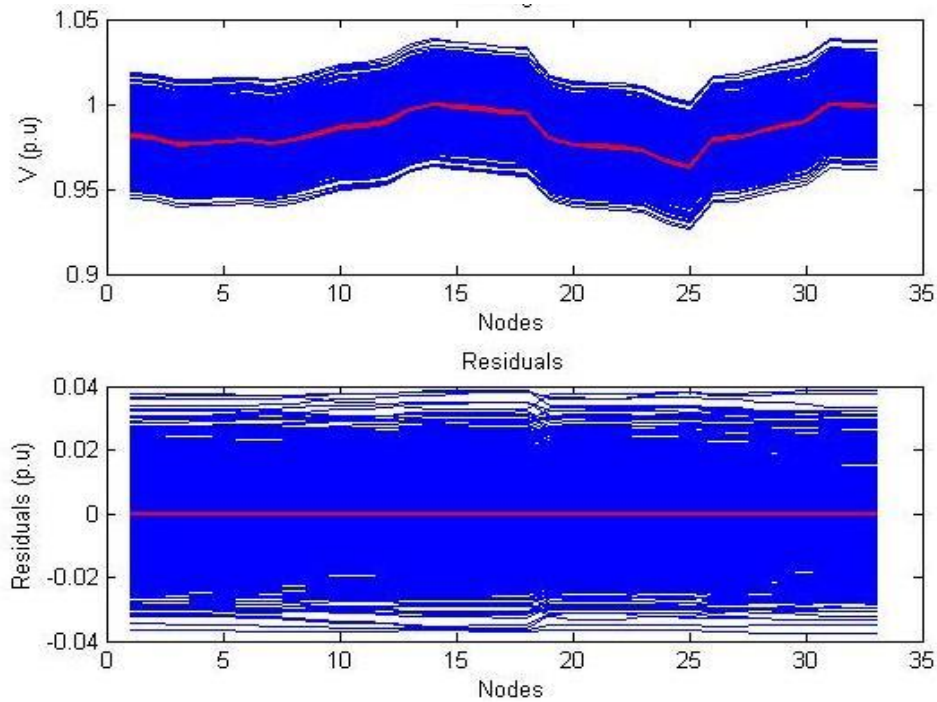


Fig. 4.14 Nodal voltage estimates provided by the state estimator under Scenario 3

The parameters of the simulation module of the communications system were adjusted to influence the time delay performance of the ICT infrastructure. After the mapping from the time delay to input error, the state estimator used the information provided by such ICT infrastructure and more refined information was obtained. The maximum nodal voltage errors based on different input errors are shown in Table 4.2.

If the nodal voltage limit is $\pm 6\%$ (the voltage limits of $\pm 6\%$ for 33kV/11kV networks were used here), as shown in this table, the input error larger than 25% (25 minutes time delay) makes it difficult for the approach to be used by the voltage control functions.

Table 4.2 Input/output error of the state estimator

<i>Maximum input error (P and Q)</i>	<i>Maximum output error (V)</i>
2%	0.77%
5%	1.91%
10%	3.90%
25%	9.60%

<i>Maximum input error (P and Q)</i>	<i>Maximum output error (V)</i>
50%	19.73%
100%	42.62%

The voltage and power flow can be managed within limits through control of On Load Tap Changer (OLTC) of transformers, and active power and reactive power output of the distributed generators. The implications of the quality of the information for active and reactive power-related control functions were drawn by the OPF tool. In this case the active power of DG1 can vary from 0.9 MW to 1.4MW, and DG2 can vary from 0.8 MW to 1.3 MW. Under a certain load condition, the system operating point is represented by the output of generators and the infeed of the bulk power system. For the test system shown in Fig 4.7, the operating points thus are represented in a 3-dimensional space. The operating points based on different input errors are shown in Fig. 4.15.

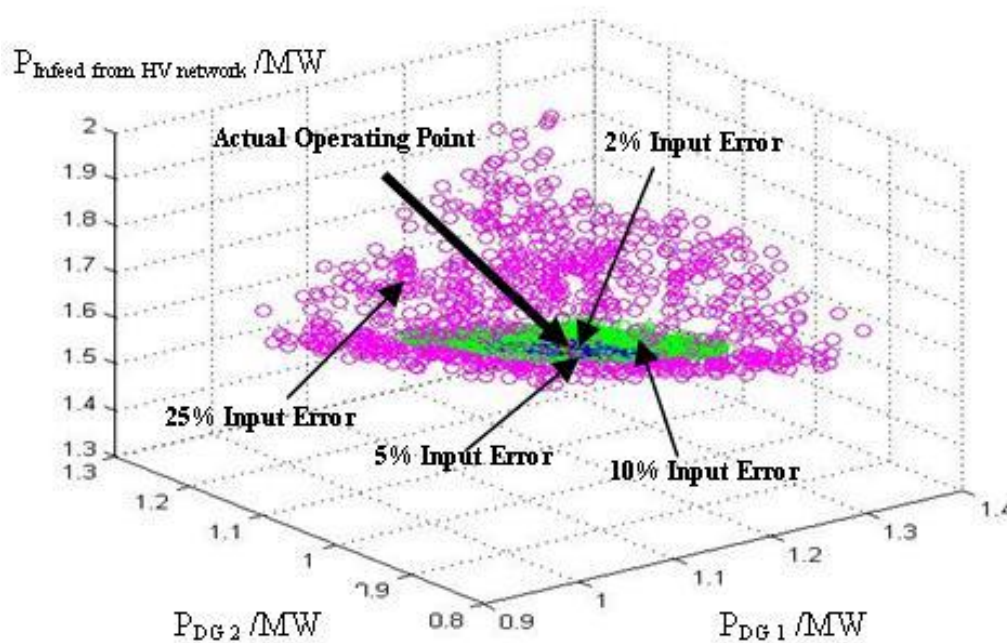


Fig. 4.15 Operating points based on different input errors

As shown in Fig 4.15, for the input errors less than 10%, the power control is feasible. 25% input error (25-minute time delay) drives the operating points far from the actual operating point. The power control function will be unreliable under such conditions.

4.7 Summary

A method was developed to evaluate the performance of smart metering infrastructure in supporting the Smart Grid operation. Smart meters and PLC based ICT infrastructure was modelled in OPNET. Several parameters representing the main characteristics of the ICT infrastructure were identified and made adjustable in the proposed model. A method to quantify the relationship between the time delay and the measurement error was proposed. The communications model was integrated with a state estimator and an OPF tool. The state estimator was utilised to refine the measuring data. The OPF tool was employed to evaluate the real-time information on behalf of the Smart Grid applications. The test results showed that the integrated tool can be used to design and evaluate ICT infrastructure for the smart distribution network operation.

Chapter 5

Integration of Smart Metering with Outage Management Systems

5.1 Introduction

The investigation on the ICT infrastructure for Smart Grids is normally based on some chosen advanced power system application. Outage management systems (OMS) play an important role in the operation of distribution networks and are one of the key applications in the distribution network control centre. Outage management has been identified as a promising power system application which can get benefit immediately from the large-scale roll-out of smart meters (Ekanayake, 2012).

In this Chapter, an outage area identification method based on topology analysis and smart meter information was developed. This method was combined with the smart metering communications models developed in Chapter 3 to evaluate the impact of the communications performance of smart metering infrastructure on outage management.

5.2 Outage Management Systems (OMS)

A conventional OMS is a system with trouble call centre, computer-based tools, and utility procedures to identify fault (Fault Identification), diagnose and locate fault (Fault Diagnosis & Fault Location), provide feedback to affected customers (Customer Notification), dispatch trouble/repair crews, restore supply (Supply Restoration), maintain historical records of the outage, and calculate statistical indices on electrical outages (Ekanayake, 2012)..

Outage management is a crucial processes in the operation of a distribution network with the goal to return the network from the emergency state back to normal. Various methods have been developed to assist the operators depending on the type of data available to drive this process.

Fig.5.1 illustrates how a typical OMS works.

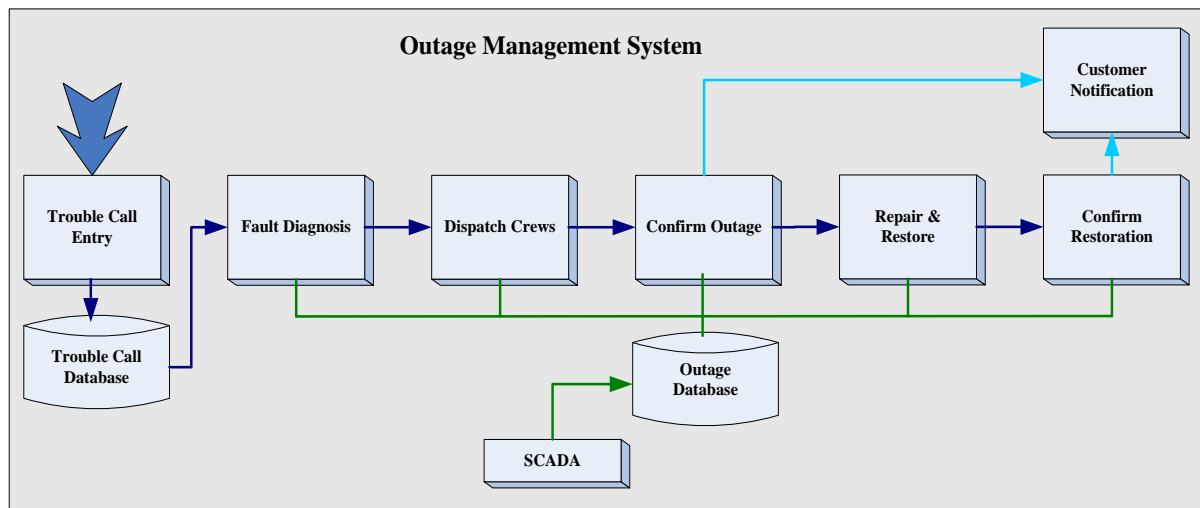


Fig. 5.1 Conventional Outage Management System

The main functions of a conventional OMS are as follow (Northcote-Green 2007) (Gaing 1995) (Kuru 2009) (Liu 2002):

Fault Identification

Fault Identification is usually done based on customer telephone calls through conventional human communication, or through automatic voice response systems (Computer Telephony Integration - CTI); automatic outage detection/reporting systems; or SCADA detection of breaker trip/lockout. In an ideal situation, the outages can be identified before the first call from customers though the SCADA system.

Fault Diagnosis and Fault Location

Fault diagnosis and fault location are carried out based on the grouping of customer trouble calls using reverse tracing of electric topology, and determine the common protective device suspected to be open, e.g. lateral fuses, sectionalisers, reclosers, or substation breakers. The extent of suspected outage (the outage area) will be calculated. The confirmation or

modification is done based on feedback from crews. Outage area identification method investigated in this chapter belongs to this category and focuses on the extent of outage.

Customer Notification

Timely, accurate feedback is almost as important as fixing the problem. Customer notification is a function of OMS to inform the customers about current status of outage response and the expected time of restoration.

Crew Dispatch Management

Computer-aided modelling of crews is used to help to analyse the capabilities, tools, equipment, work load, and carry out the real-time location tracking.

Repair and Restoration

If it is only a simple problem, the crew will do the direct repair and restore. If it is major outages, the fault will be isolated firstly and the un-faulted portions of a feeder will be restored. Automated Fault Detection, Isolation, and Restoration schemes by feeder automation are widely used currently.

Historical Records

Major information will be kept as historical records to keep track of all outages including root cause, number of customers and duration. Such information can be used for calculating the performance statistics, e.g. customer minute lost, and for the planning/budgeting maintenance activities, e.g. condition based maintenance.

OMS play a very important role in power system operation, therefore international standards have been provided by IEC TC57 WG14 on the interface for the integration of OMS with other systems, as shown in Fig. 5.2.

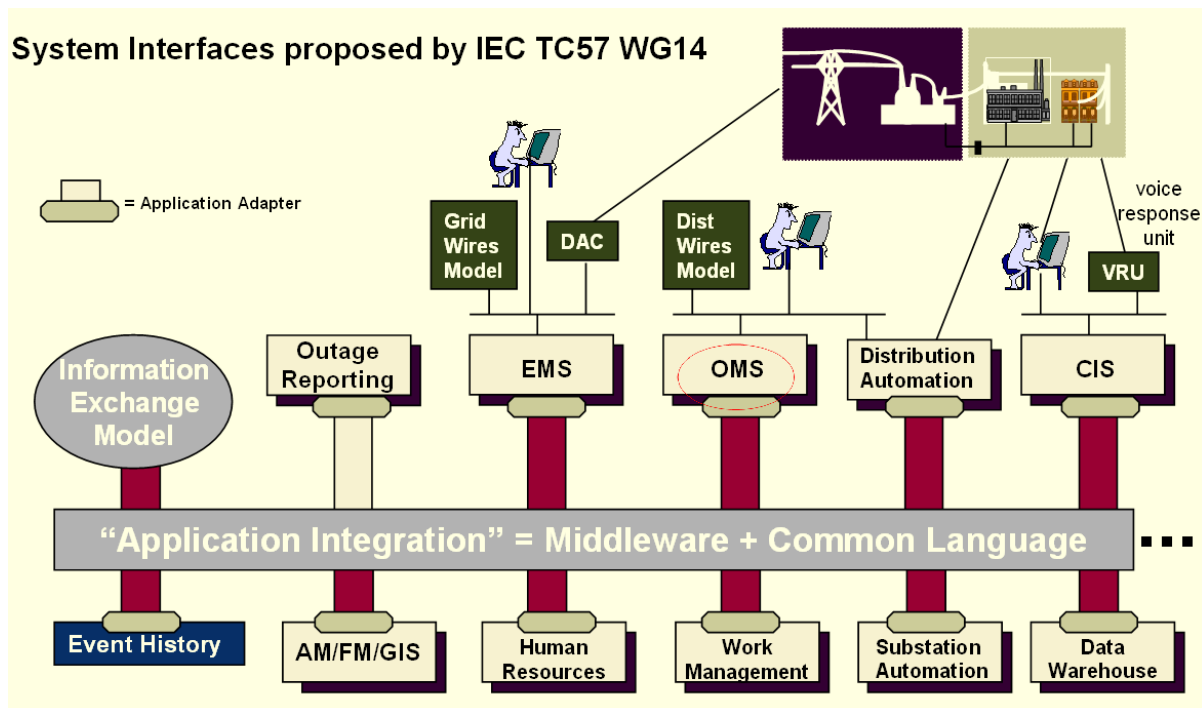


Fig. 5.2 System Interfaces proposed by IEC TC57 WG14

(http://www.iec.ch/dyn/www/f?p=103:14:0:::FSP_ORG_ID,FSP_LANG_ID:2393,25)

Conventional utilities use a trouble call approach based on very limited penetration of real-time control but good customer and network records. Currently more and more utilities are being equipped with effective real-time systems and extended control, therefore are able to use direct measurements from automated devices.

Trouble call systems are widely used in North America for MV distribution networks where the sizes of distribution primary substations are small. Except for large downtown networks, the LV feeder usually connects 6 to 10 customers from one MV/LV distribution transformer. This system structure makes it easier to establish the customer-network link within a trouble call management system. In contrast, European systems are usually with large secondary systems (up to 400 consumers per MV/LV distribution transformer). In this environment, a trouble call approach would have to operate from the LV system, where establishing the customer network link is very challenging. In these cases, smart metering infrastructure has a big potential to improve the performance of the OMS.

5.3 Integration of Smart Metering and OMS

Using smart metering for OMS has been a hot trend in the utility industry in the last few years (Northcote-Green 2007) (Liu 2002). The benefits from integrating smart metering and outage management are derived from reduction of average outage duration, crew and dispatcher efficiency savings, and reduction in restoration and trouble call centre costs.

Fig. 5.3 outlines the system and process integration of smart metering and OMS.

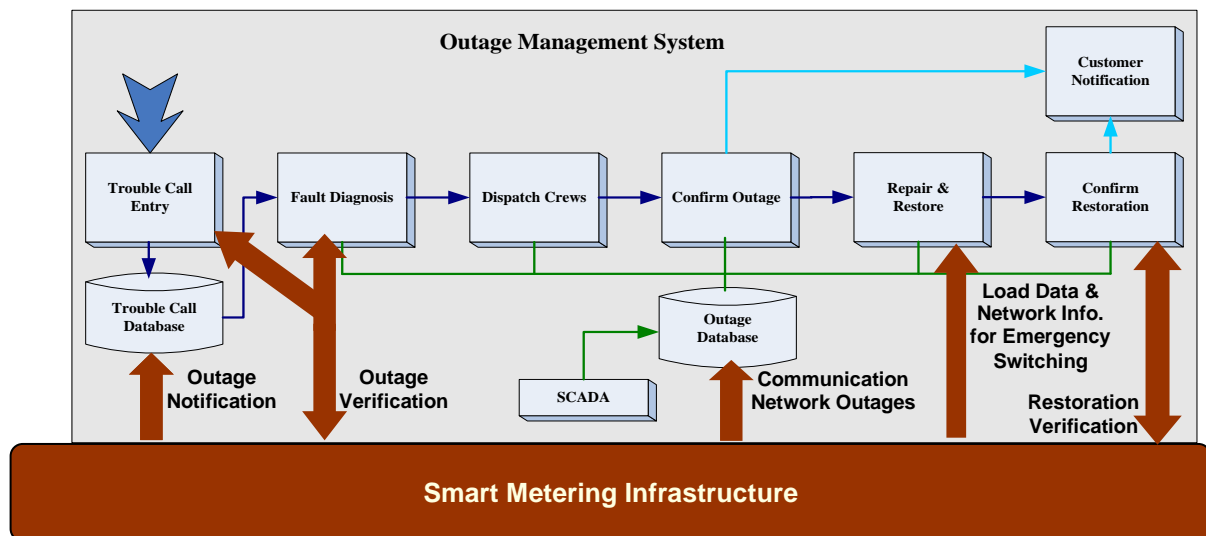


Fig. 5.3 Integration of smart metering and OMS

The last gasp messages from smart meters are very important which can be used as an input to the OMS. Fault Diagnosis and Fault Location algorithms will operate more efficiently and effectively with such additional data inputs. An OMS can consider a “last gasp” message in the same way as a customer phone call. Many OMS products today only require calls from less than 15% of customers affected by an outage to accurately predict the extend of the outage.

5.4 Outage Area Identification Using Smart Meter Information

The key components for the outage area identification method developed and their relations are shown in Fig 5.4.

At present, there is usually a limited topology model of MV and LV distribution networks. A topology analysis algorithm was developed (Section 5.4.1), which provides a simplified analysis model of a MV distribution network for outage area identification analysis.

If an outage occurs on a network, some customers may be out of service. An outage area identification algorithm (Section 5.4.2) was developed which uses the information from smart meters and is based on the simplified network model derived in 5.4.1. The outage area identification can act as one of the main functions of an OMS providing possible outage extent information. The availability and latency of smart meter information are mainly determined by the smart metering communications system, therefore the impact of smart meter communications on the outage area identification algorithm was also investigated (Section 5.4.3).

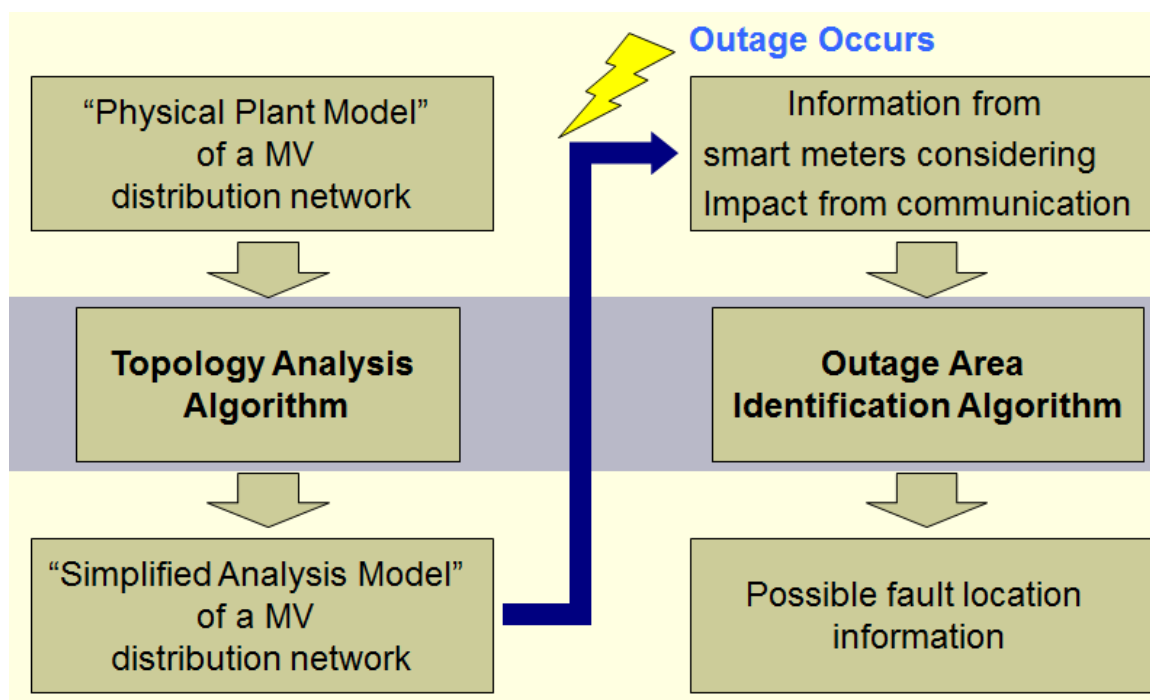


Fig. 5.4 Key components of outage area identification using smart meter information

5.4.1 Topology Analysis

An electric power distribution network consists of a variety of equipment which must be modelled in a simple, concise and standard form for analysis. The mapping between the physical plant model and the simple power systems analysis model is undertaken by the topology analysis tool which carries out network reduction. It reduces the amount of data

feeding into other modelling and analysis tools and allows easier interpretation of results by the operators. For example, a substation that contains 6 sections of busbar which are linked by several open/closed items of switchgear can be represented by a single electrical node for power system analysis. The topology analysis tool is able to distinguish the energised parts of the power system from the de-energised parts, and can identify the electrically separated “islands”.

Commonly used graph searching algorithms for topology analysis are depth-first and breadth-first methods (West 2000). A depth-first search starts at the root and explores as far as possible along each branch before backtracking. A breadth-first search begins at the root node and explores all the neighbouring nodes, then for each of those nearest nodes; it explores their unexplored neighbour nodes, and so on, until it finds the goal.

Table 5.1 lists glossary of terms used in topology analysis.

Table 5.1. Glossary of terms used in topology analysis

Terms	Description	Terms	Description
Infeeds	An infeed represents power input from a upstream network that is not modeled. The infeed is connected to a busbar in the physical plant model. An energised “island” will be obtained if the infeed status is “ON”.	Nodes	Nodes are outputs of the topology analysis. They represent a set of busbars connected by closed links.
Generators	A generator is connected to a busbar in the physical plant model. An energised “island” will be obtained if the generator status is “ON”.	Islands	Islands are outputs of the topology analysis. They represent a set of energised nodes connected by live branches. Electrically separate islands can be identified, and a separate power flow analysis is needed by each island with a separate slack node.
Links	A link is a zero impedance connection between two busbars, e.g. a circuit breaker, an isolator, or a very short cable. Each link has a status (“ON” or “OFF”). A link with “ON” status will merge the two busbars at each end into one node.	Branches	A branch has non-zero impedance, e.g. an overhead line, a cable, or a transformer. A branch is live if its status is “ON” and is part of an energised island; or dead if its status is “OFF” or is part of a de-energised network.
Loads	A load is connected to a busbar in the physical plant model.		

The topological analysis algorithm was developed based on depth first search (DFS). It selects one network infeed as the starting node n_1 . The graph searching process is started from a node u that is incident to node n_1 . Assume that a node k has been reached. If there is a new node l incident to k which has not been processed yet and the status of branch kl is “ON”, node k will be processed first: if there are generators or loads connected to k , they will be represented explicitly. If branch kl belongs to “Links” defined in Table 5.1, l will be merged with k and the kl will be removed, and all loads of these two nodes will be merged together and all generators will be represented explicitly. After node k has been processed, the searching process is continued from the node l (or node k if nodes k and l have been merged).

If there is no new node incident to k or the status of branch kl is “OFF”, the next step is to start again from the node from which the node k has been reached, and the searching process is continued. The graph searching is terminated at the moment when $k = n_1$. The DFS process searches each node of the graph only once.

Fig 5.5 (a) shows a one-line diagram of a distribution network, which is represented by physical plant model with 54 busbars, and Fig 5.5 (b) provides the equivalent power system analysis model with only 13 nodes derived from the topological tool introduced above. As can be seen by encircled section in Fig 5.5 (a), a number of circuit breakers/switches/fuses and busbar sections (Links) are represented by a single node (A) in the power system analysis model shown in Fig 5.5 (b).

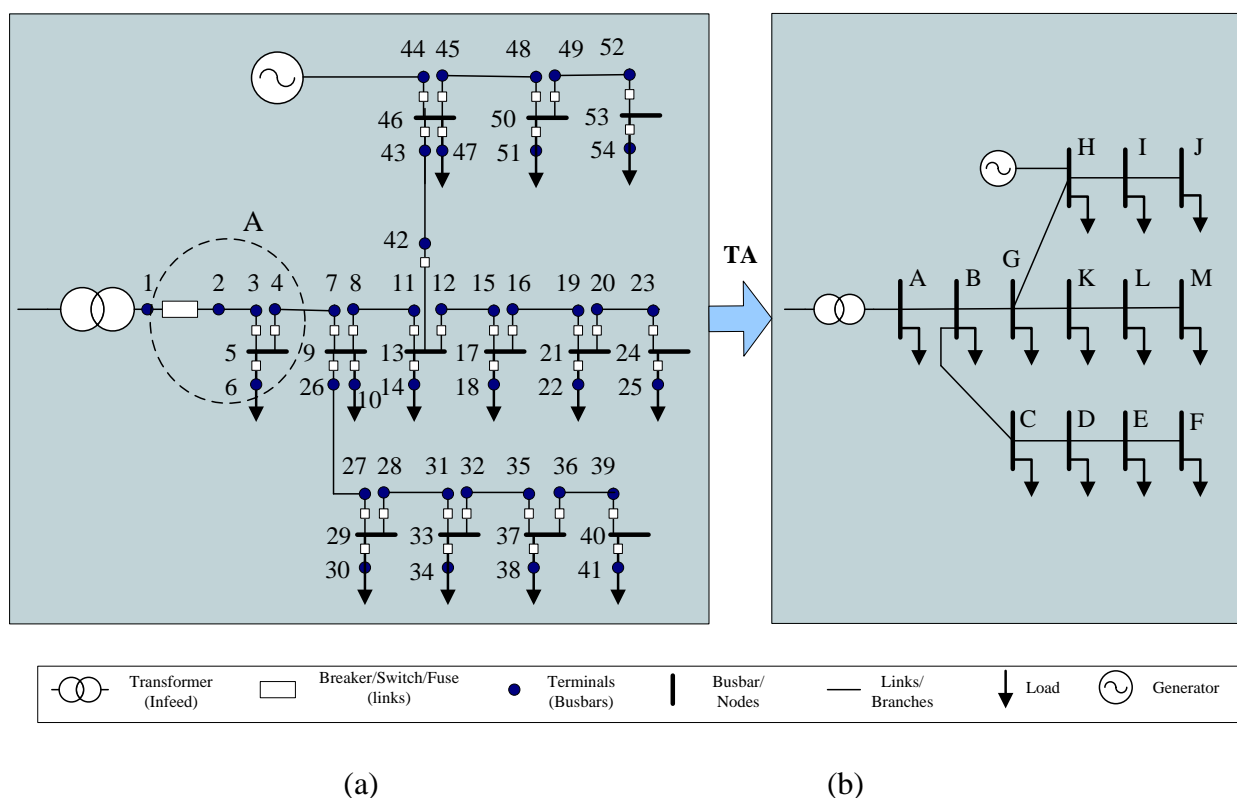


Fig 5.5 Example of topology analysis

5.4.2 Outage Area Identification Algorithm

The power system analysis model is used along with the smart meter information to provide the outage area identification function. To use smart metering to contribute to Fault Identification and Location, firstly an up-to-date power system analysis model is needed (provided by Section 5.4.1) and the switch device type and position are also necessary, as shown in Fig 5.6 (smart meters are linked to each MV/LV transformer, but only several smart meters are shown in this figure as illustration).

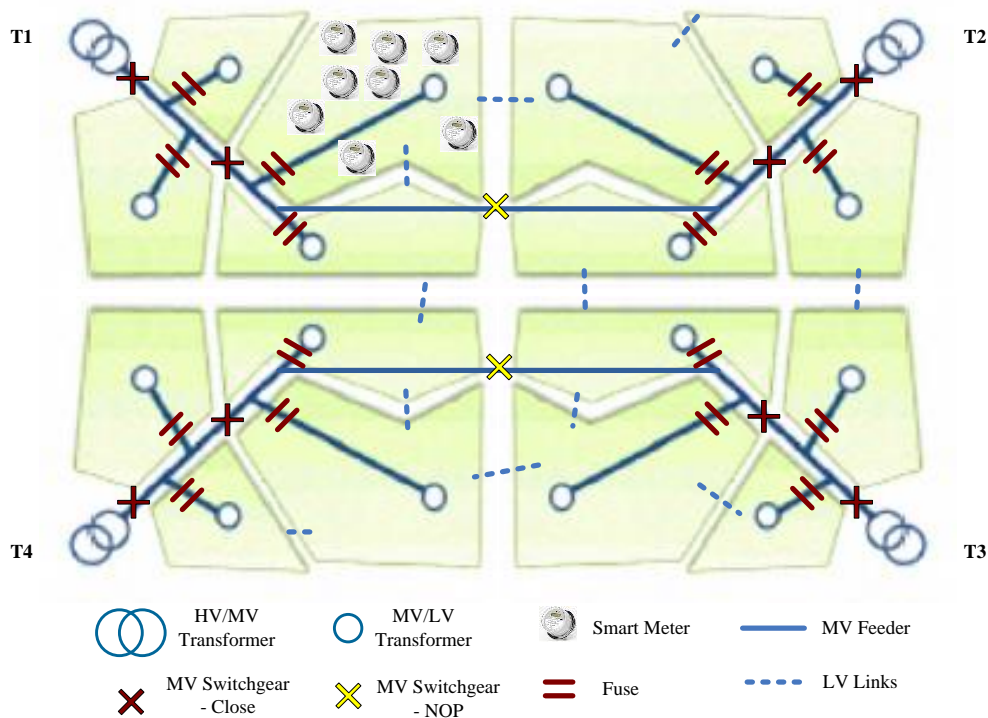


Fig 5.6 Network information needed by the outage area identification algorithm

If there are a large number of smart meters, more information is available to facilitate the decision-making. But this poses the question of how to deal with a large amount of “last gasp” messages with various communications latencies, hence an efficient algorithm is necessary for fault area identification based on multiple “last gasp” messages. The procedure used by the outage area identification algorithm is shown in Fig 5.7. The following definitions were used by the algorithm.

Each LV smart meter has one of the three statuses:

- “ON”: the smart meter is power on
- “OFF”: the smart meter is power off
- “UN”: the status of the smart meter is uncertain

Each MV node also has one of the three statuses:

- “ON”: default value, no “last gasp” information received
- “OFF”: “last gasp” information received from more than 10% LV smart meters

connected to this node (or from more than 3 LV smart meters connected to this node) (10% and 3-meter criteria were used in this thesis which may subject to change for different OMS)

- “UN”: there are “last gasp” information received from LV smart meters connected to this node, however the total amount is less than 10% (or less than 3 LV meters)

Each medium-voltage network branch has one of the two statuses:

- “Normal”: Both nodes at the two ends of this branch have “ON” status or both have “OFF” status
- “Boundary”: For the two nodes at the two ends of this branch, one has “ON” status and one has “OFF” status.

If an outage has occurred, the boundary branches will be identified and updated by the algorithm based on the available smart meter information. These boundary branches provide an estimation of the extent of outage areas.

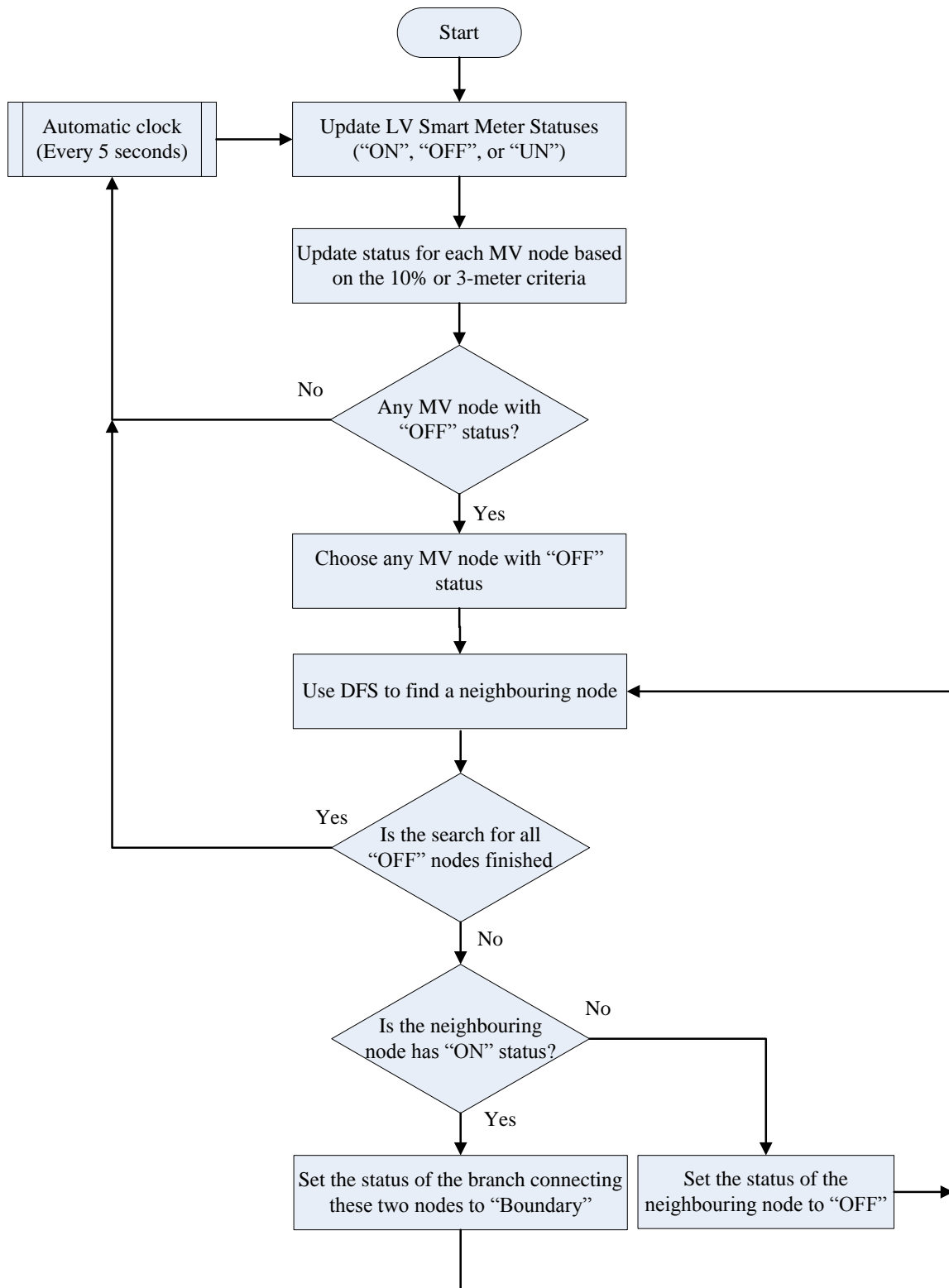


Fig 5.7 Flowchart of the Outage Area Identification algorithm
(DFS - depth first search)

5.5 Simplified Modelling of Smart Metering Infrastructure

A smart metering communications model was developed in Chapter 3 to calculate the system performance, e.g. throughput and delay. In this section, the smart metering communications model developed in Chapter 3 was adapted to provide the insight required for OMS. The details are shown below.

5.5.1 Physical and MAC Layer Modelling

Time division multiple access (TDMA) is a channel access method for shared medium networks. It allows several users to share the same frequency channel by dividing the signal into different time slots. The users transmit in rapid succession, one after the other, each using its own time slot. This allows multiple stations to share the same transmission medium (e.g. radio frequency channel) while using only a part of its channel capacity (Barry 2003).

The physical and MAC (Medium Access Control) layer modelling follows the principle of TDMA. Time slots permit the simplification of the existing complexity of the PLC medium. The duration of the time slot is not fixed, since it depends on the frequency of the channel and also on the size of the packet. It was assumed that the transmission of one packet always fits into one time slot, therefore the time slot duration was the basic time unit in the modelling.

It is assumed that a packet will be received with correct CRC (Cyclic Redundancy Check).

5.5.2 Network Layer Modelling

Master/slave is a basic communications model for sharing time slots between communications nodes. A master (i.e. controller in the OPNET model) is responsible for distribution of the time slots among its slaves (bandwidth sharing).

The MV and LV PLC network are independent from each other. For each voltage level, the medium access is controlled using the TDMA Master/Slave communications model. The gateway and the bridges/LV concentrators are Masters for the MV and LV networks, and the bridges/LV concentrators and LV smart meters are Slaves for the MV and LV networks. Masters initiate packet transfer and a slave can only send a packet back to the master when its master polls it except the last gasp information. This layer is also responsible for managing the repeating/routing of the packet from the sender.

Polling is one widely used master/slave mechanism for addressing slaves (for command or data request) in most automatic metering reading applications. The scheduling of the polling is the unique responsibility of the master (Brito 2004). Therefore polling with acknowledgement (ACK) was used in the network layer modelling.

Logical channel was used as a method to share time slots and it is a subset of the whole TDMA time slots which allows a clear separation of different traffic classes. Figure 5.8 shows the definition of time slots and channels.

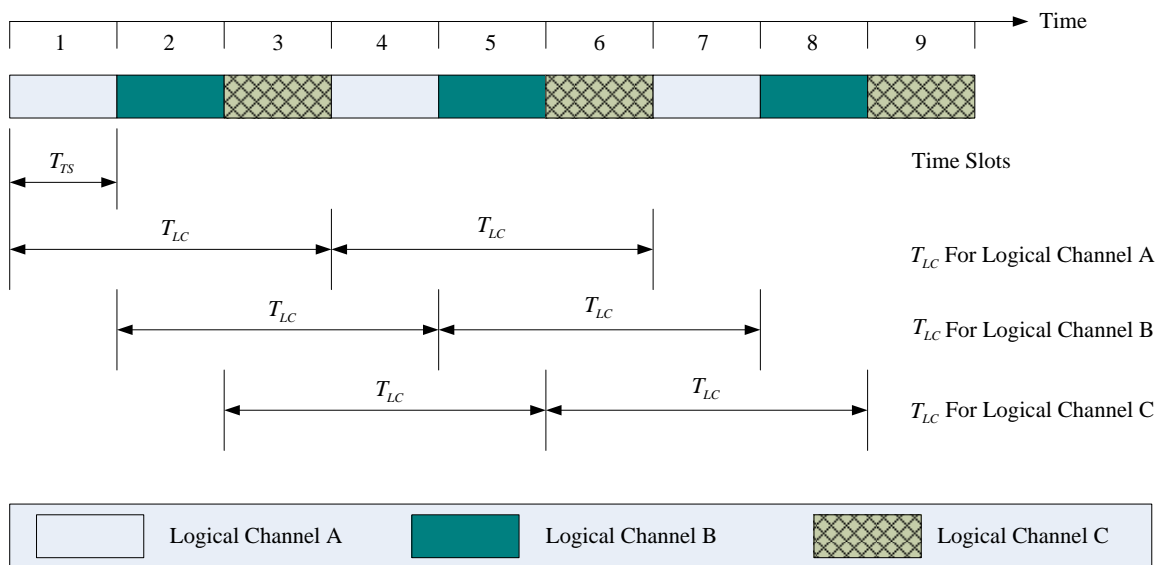


Fig 5.8 Time slots and channels

Figure 5.9 shows the round trip time of a meter reading, and Figure 5.10 illustrates some possibilities of the polling procedure used in this Chapter.

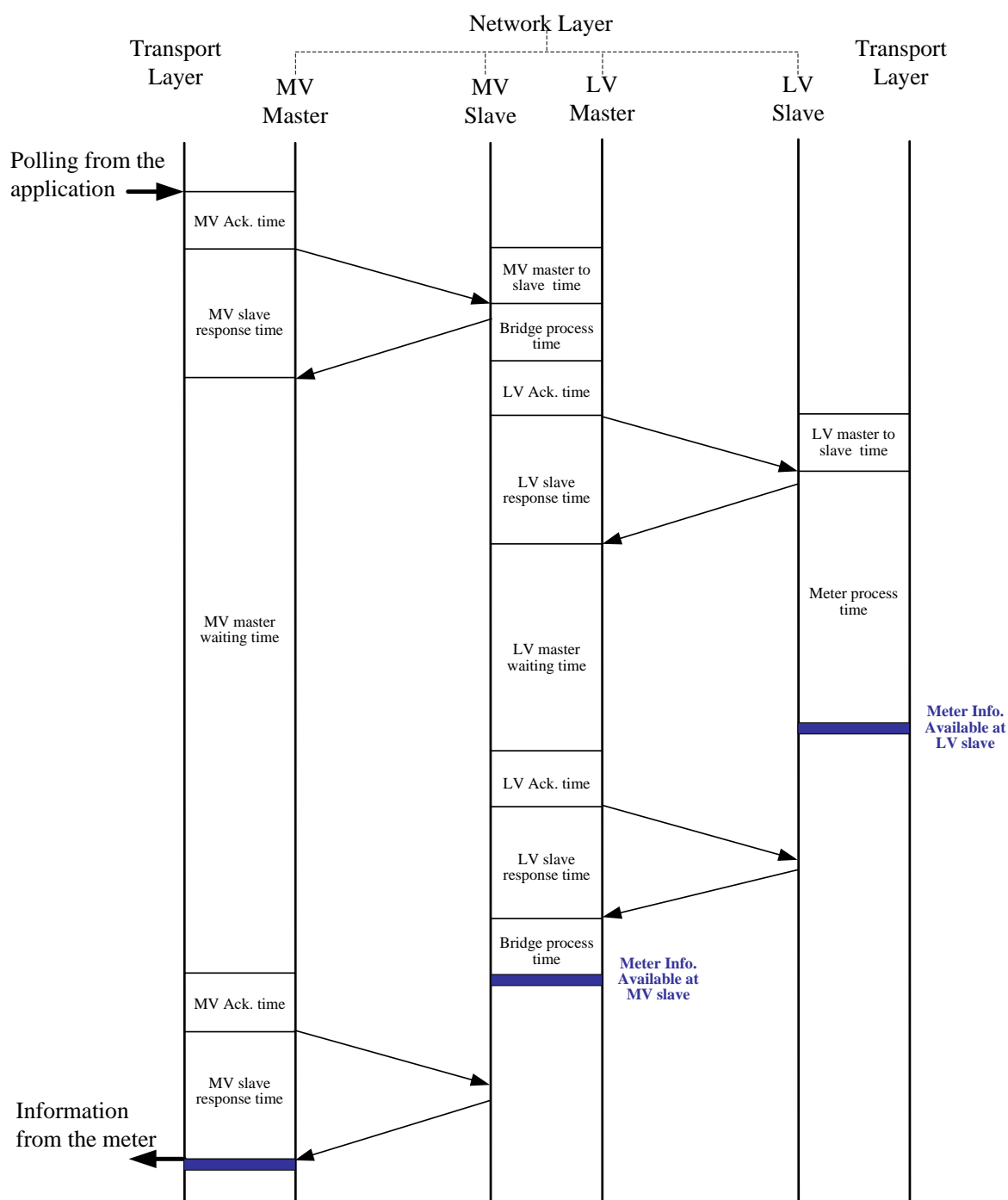


Fig 5.9 Example of a round trip time

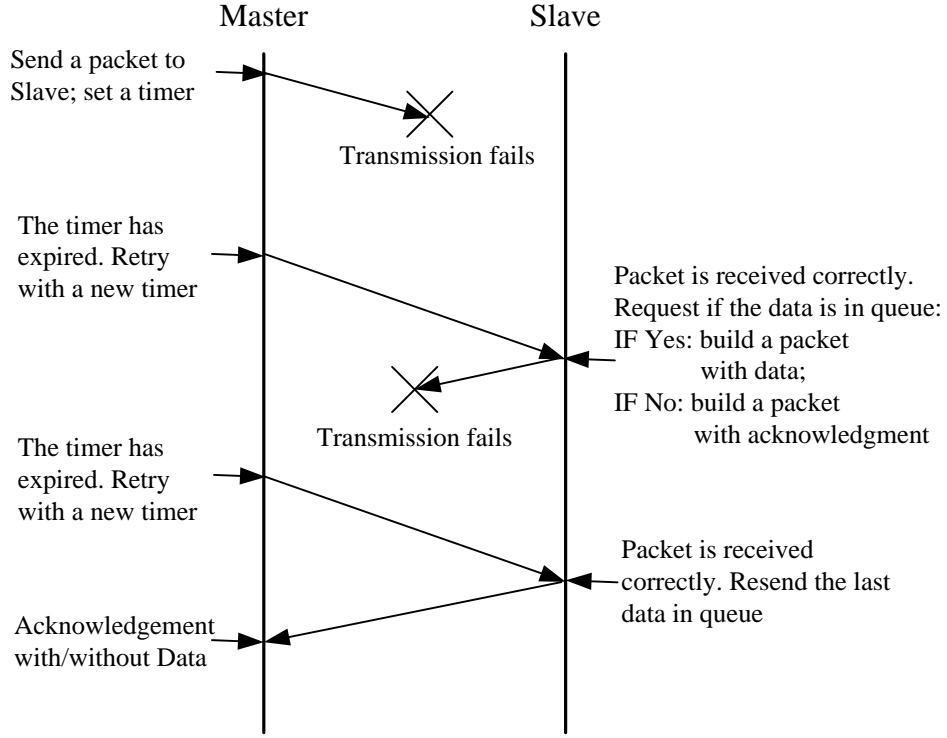


Fig 5.10 Possibilities of the polling procedure

The duration of a polling cycle is thus defined as:

$$T = \sum_{i=1}^N \left(\sum_{j=0}^{N_{re}(i,j)} (2 + R_{DL}(i,j) + R_{UL}(i,j)) T_{LC} + T_{SM}(i) \right) \quad (5.1)$$

where:

N : the number of smart meters

$N_{re}(i,j)$: Retry number of reading smart meter i , which is a probabilistic function of j

$R_{DL}(i)$: the repeat number of downlink for reading smart meter i

$R_{UL}(i)$: the repeat number of uplink for reading smart meter i

$T_{SM}(i)$: the response time of smart meter i

2: down steam and up steam readings

5.5.3 Package Definition

The data size of outage alarm from smart meter to DNO was assumed to be 25 bytes (Engage Consulting Limited 2010). The security checks (CRC) are assumed to be 22 bytes per packet of data sent, which includes DES (Data Encryption Standard) and AES (Advanced Encryption Standard) for the detection and prevention of unauthenticated access

and modification. The overhead per packet of data sent through the TCP/IP protocol amounts to up to 50 bytes. Therefore each raw data transaction will contain an additional 50 bytes. Additionally, the message negotiation and verification needs to be taken into account which adds further packet transactions. TCP/IP data transmission can easily add around 10 further transactions. Therefore it will be assumed that each data transmission will add a further 500 bytes. Therefore the total volume of a package used in this study was:

$$V_{package} = 25 + 22 + 50 + 500 = 597 \text{ bytes} \quad (5.2)$$

5.6 Case Study

The original physical plant model of a MV distribution network has 146 nodes, as shown in Fig 5.11. The equivalent 33-node model provide by topology analysis method is shown in Fig. 5.12 (Baran, 1989).

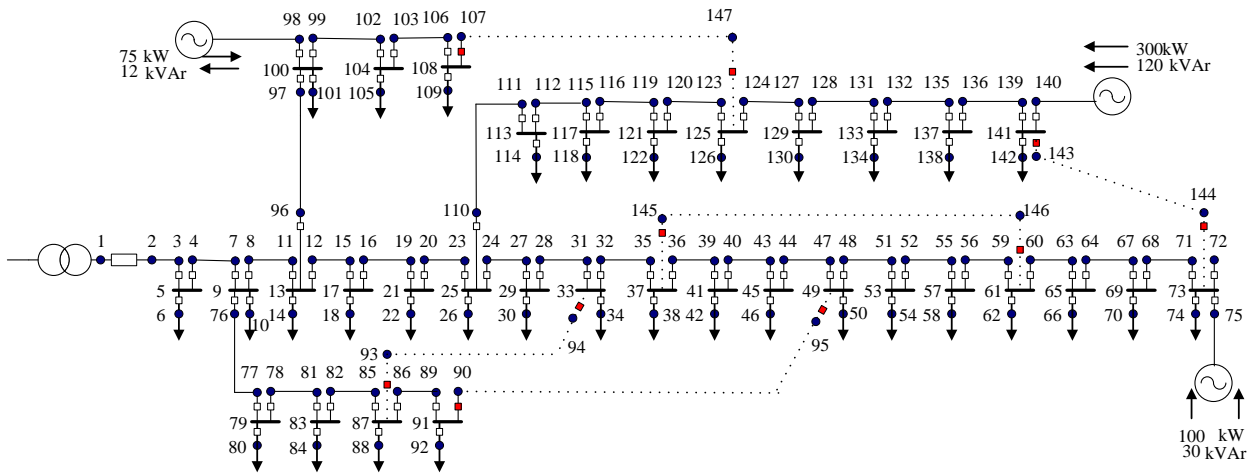


Fig 5.11 146-node physical plant model of a MV distribution network

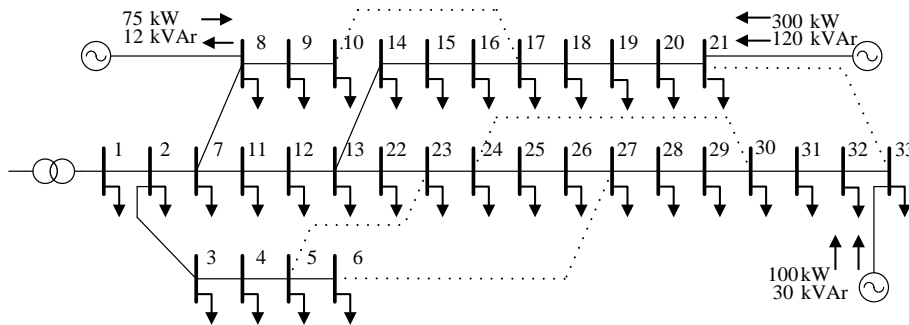


Fig 5.12 33-node simplified model

It was assumed that there was a fault that occurred on the feeder downstream of Node 13 and the fuse located at Branch 13-14 operated, and there were eight nodes (i.e. node 14 to node 21) that were out of service, as shown in Fig 5.13. In this section, a case study is shown which used the outage area identification algorithm developed to locate the boundary branch (a branch links the “ON” node and “OFF” node). 10% and 3 smart meters criteria were used to confirm an outage (i.e. the last gasp” information received from more than 10% of LV smart meters connected to one node will confirm the outage of this node, or from more than 3 LV smart meters connected to this node). All distributed generators in the faulted area were disconnected after the fault occurred.

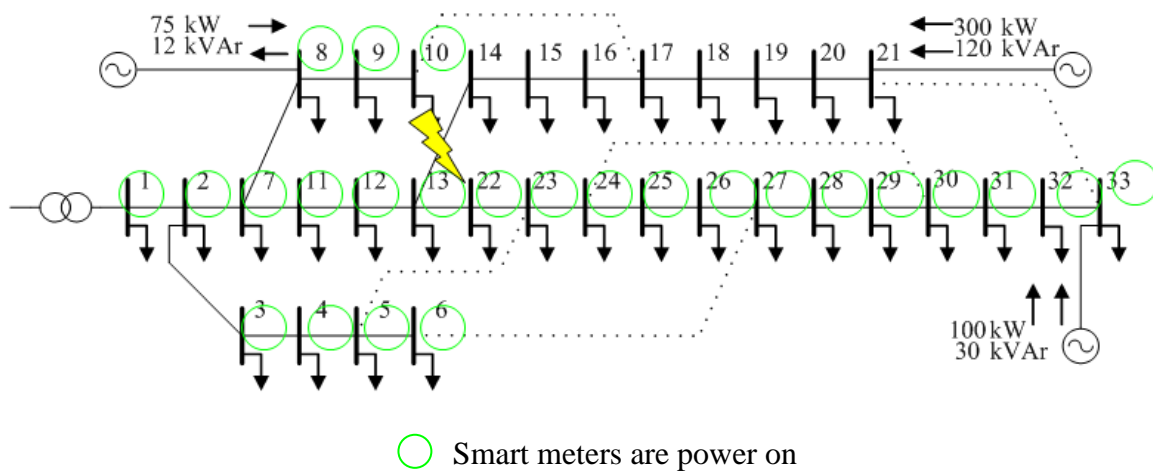


Fig 5.13 The 33-node network under fault condition

Firstly, the communication model was validated using the Ireland Trial information.

The key information of the Ireland Trial on Narrow band PLC (NPLC) is that 1,257 single phase meters for customers in 11 locations in Limerick and Ennis were installed for the power line carrier trial. Eight of the locations chosen were urban and three were village areas. The Trial employed 1st generation PLC technology which has been widely used for the past 10 years. The principle of PLC is that a high frequency information signal is added (‘modulated’) to the 50Hz power flow signal (‘carrier signal’) at the sending end and is removed at the receiving end (‘de-modulated’). The PLC product complies with IEC open standards. At the physical level, it uses a modulation scheme called S-FSK (Spread/Spaced Frequency Shift Key) which is defined by an IEC standard. This scheme uses a pair of discrete frequencies to transmit binary information. The fixed data communication rate is 1.2 kB/s. The communication protocol is defined by IEC in the DLMS/COSEM series of standards which is the IEC 62056 DLMS/COSEM (device language message

specification/companion specification for energy metering). It is an international standard for data exchange with utility meters. The standards allow suppliers flexibility on how they implement certain functions. First attempt success range between 55%-90%; retry has 10% success rate each time; no fault alarm function; typical latency values from 45 sec to 7 minutes were achieved for register reads in good networks. The results are shown in Fig 5.14. The trial set 00:00am as the time to send the smart meter data.

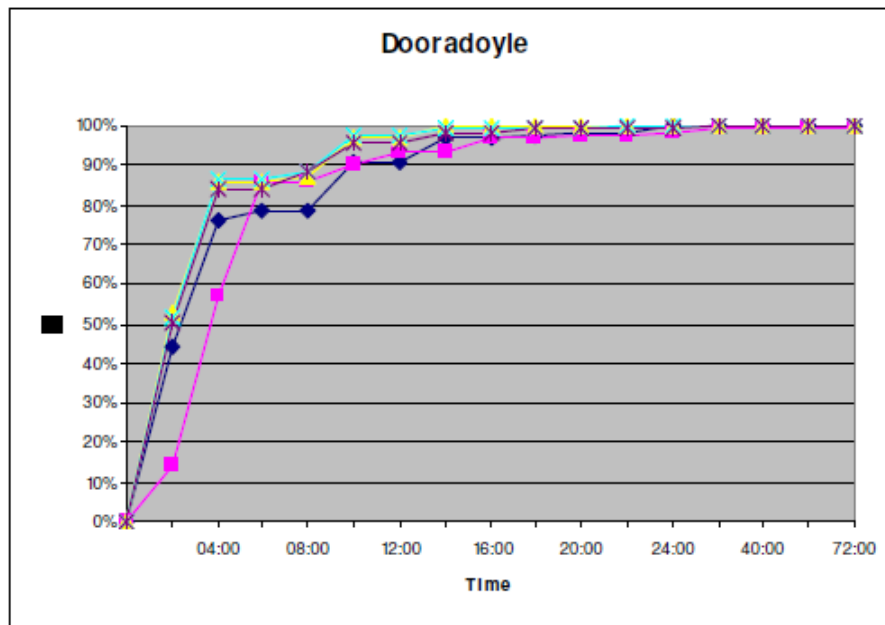


Fig 5.14 Results from the Ireland Trial on NPLC¹

It can be seen from the results that on average 60% of daily half hourly profile data was available at opening of business, rising to 75% by end of day and over 90% within 2 working days. This PLC trialled did not meet performance requirements of 99% next day profile data. Higher service levels would be achieved if monthly register read were the only read requirement, rather than 48 daily intervals reads. PLC is very much the technology of choice for most major European smart metering deployments. The on-going developments are moving to the next generation PLC based on OFDM. These newer PLC technologies should allow implementation of IP networking to meters. Success in these developments would support the use of next generation PLC as the most suitable technology for urban areas.

¹

<https://www.ucd.ie/t4cms/Electricity%20Smart%20Metering%20Technology%20Trials%20Findings%20Report.pdf>

Based on the available trial information, simulation of the Irish NPLC communications network based on the OPNET communications model is shown in Fig 5.15. It can be seen that the model was able to capture the main characteristics of the real data as shown in Fig 5.14. Using the same NPLC technologies, the correlation between the number of smart meters and the information arrival time is shown in Fig 5.16.

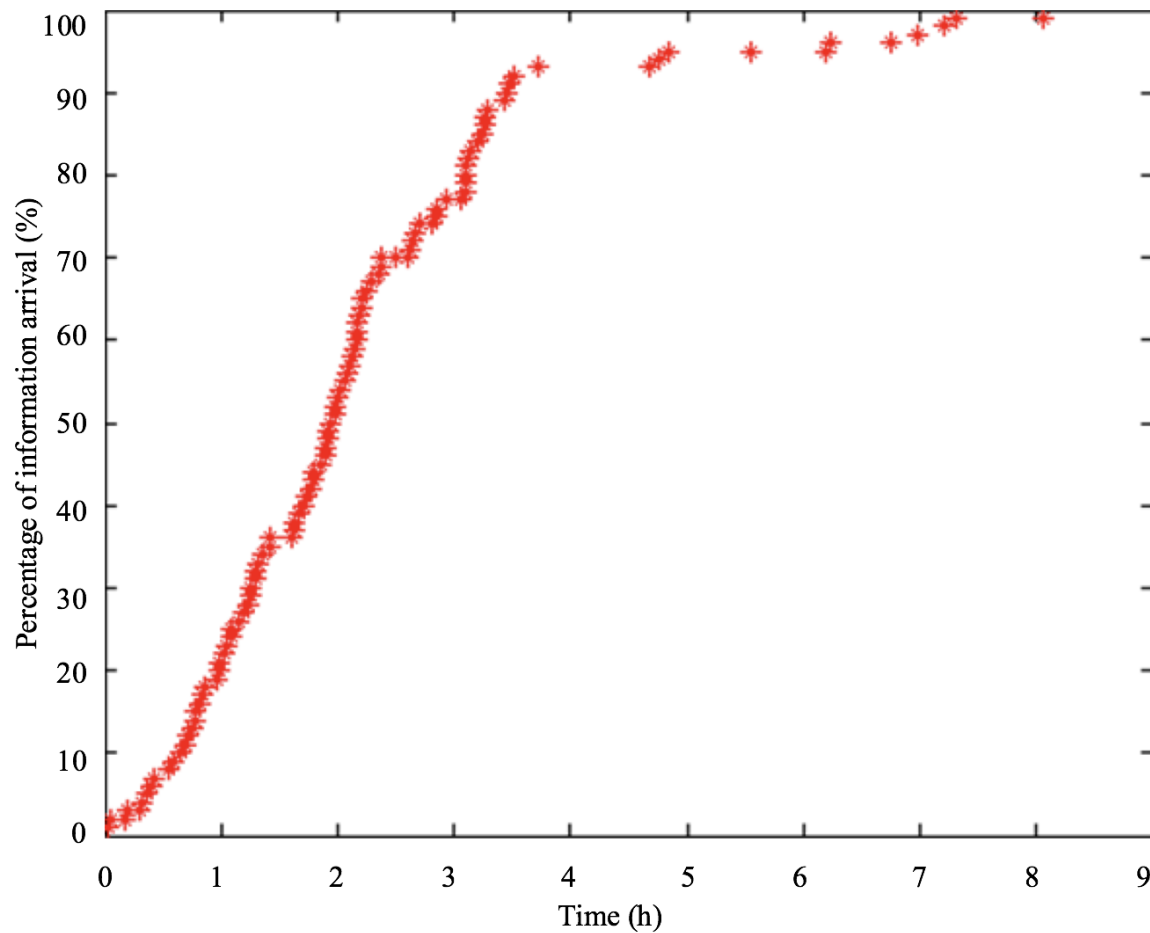


Fig 5.15 Results from simulation of the Irish NPLC communication network using OPNET

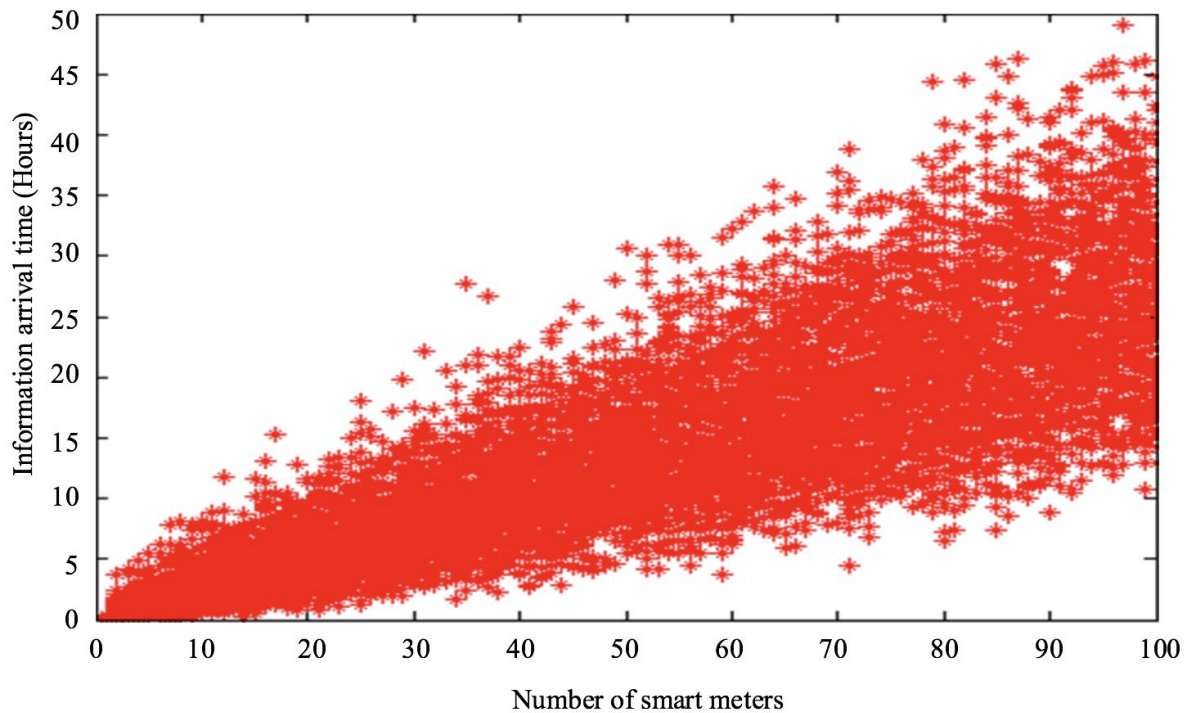


Fig 5.16 Correlation between the number of smart meters and information arrival time

The case shown in Fig 5.13 was used to investigate the effectiveness of the proposed outage area identification algorithm and the impact from the performance of the communications networks. NPLC was used whose key parameters are from the Irish trial.

Using 10% arrival as a criterion and considering all 8 out-of-service nodes (through last gasp message send by smart meters), the time used to collect the smart meter information is shown in Fig 5.17. It can be seen that it took 0.35 hours to confirm the outage of the first MV node, and 1.4 hours for all 8 nodes, using such NPLC communications. If the status of all 33 nodes needs to be checked (through last gasp message sent by out-of-service smart meters and polling for normal smart meters), it took almost 3 hours, as shown in Fig 5.18. If the criterion changed to 3 meters, which means that the status of one MV node can be confirmed from 3 LV smart meters connected to it, the outage area identification can be finished much faster. Fig 5.19 shows that it only needed 25 minutes for 8 nodes and Fig 5.20 shows that it needed 80 minutes for 33 nodes. Obviously, the 3-meter criterion was much more efficient.

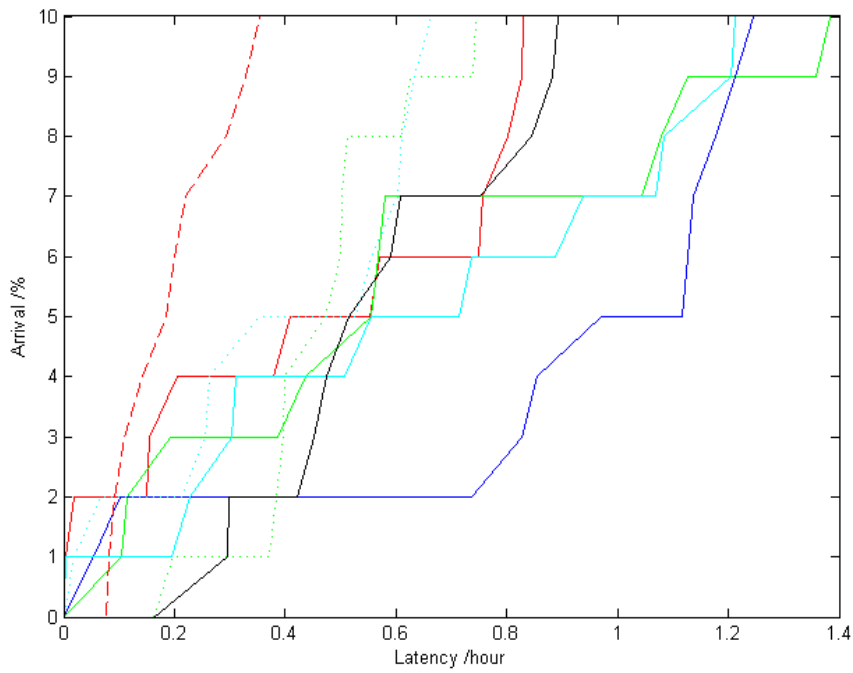


Fig. 5.17 10 % arrival criterion and 8 out-of-service MV nodes using NPLC
(Each curve represents the status of a MV node in terms of its LV smart meter data arrival rate, i.e. eight curves represent 8 MV nodes)

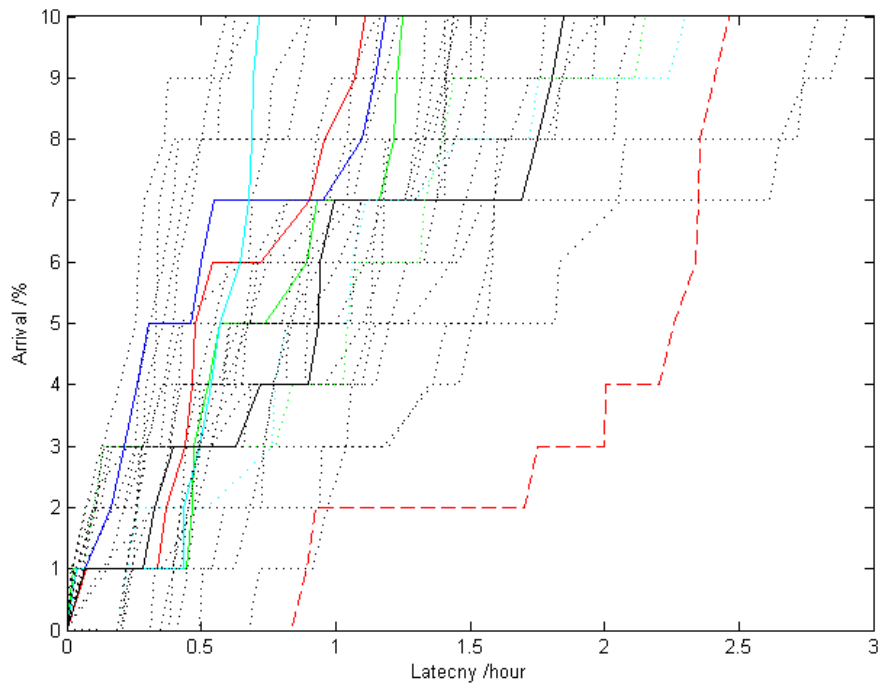


Fig. 5.18 10 % arrival criterion and 33 MV nodes using NPLC

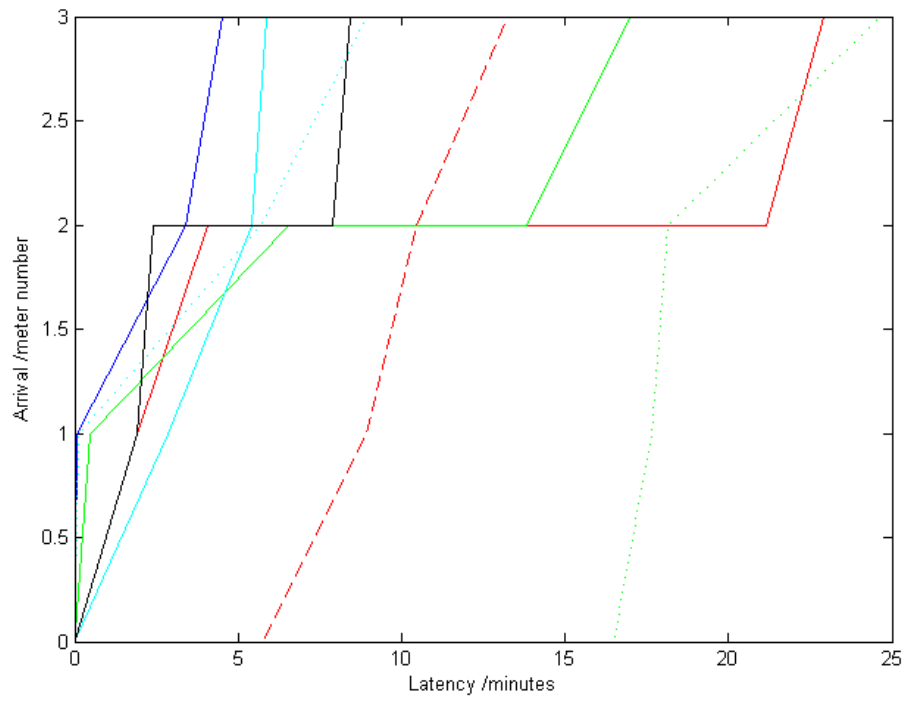


Fig. 5.19 3-meter arrival criterion and 8 out-of-service MV nodes using NPLC

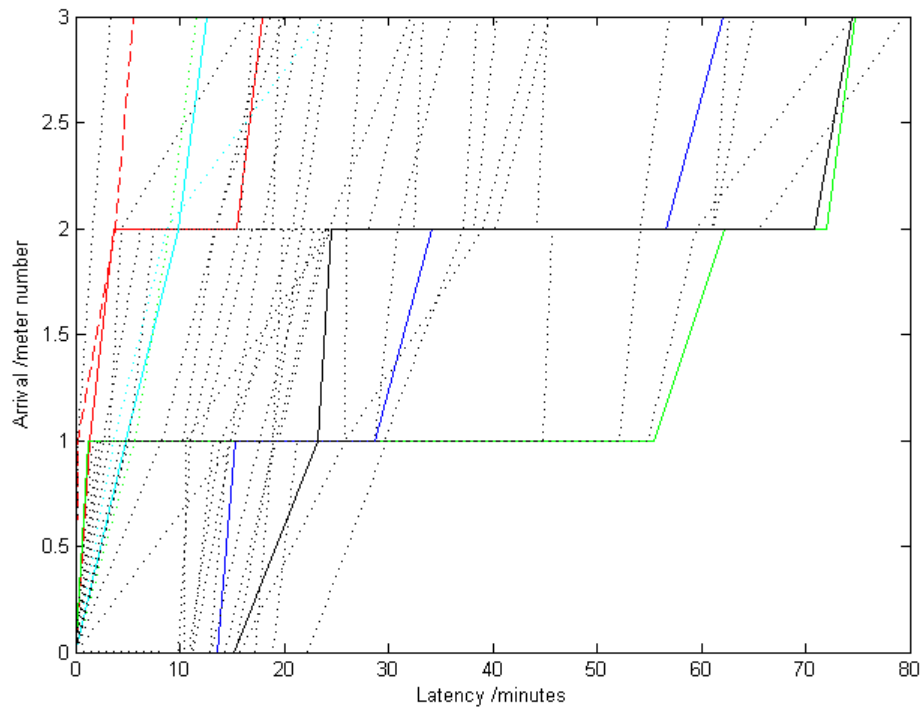


Fig. 5.20 3-meter arrival criterion and 33 MV nodes using NPLC

The performance of broad band PLC (BPLC) using OFDM modulation was also investigated. The key parameters are: 1100 customers distributed on 11 LV feeders, so each data concentrator has around 100 meters. First attempt success range >97%; Retry has 80% success rate each time; Successive retry times are 3. The fixed data communication rate is 5 MB/s. The same test on the 33-node network was carried out again and the results are shown in Figures 5.21 to 5.24. The results showed that BPLC has much superior performance compared to that of NPLC. The fault area identification can be achieved within 6 minutes with 10% arrival criterion and within 2 minutes with 3-meter criterion.

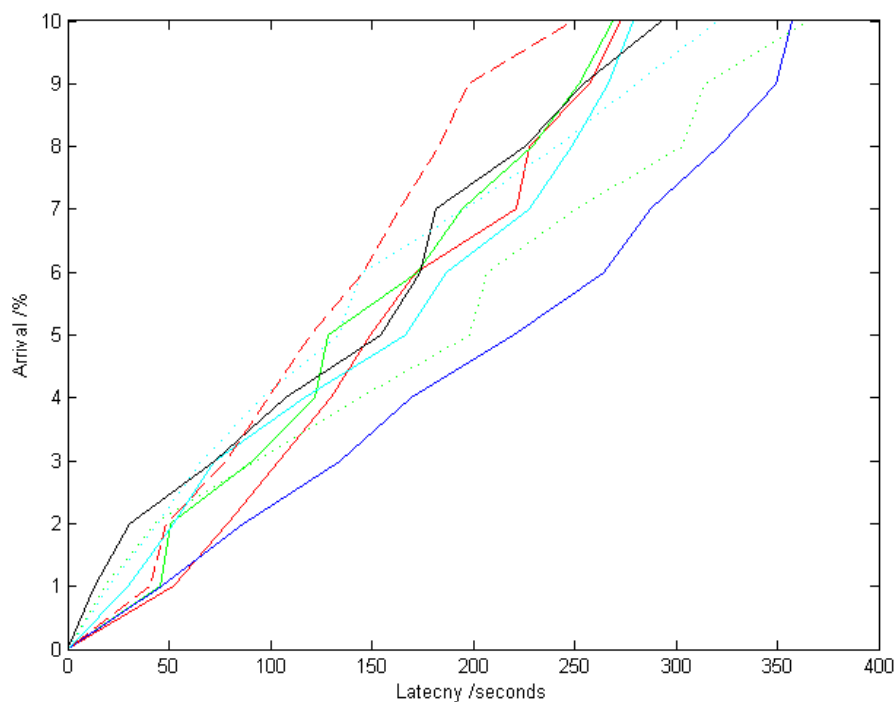


Fig. 5.21 10 % arrival criterion and 8 out-of-service MV nodes using BPLC

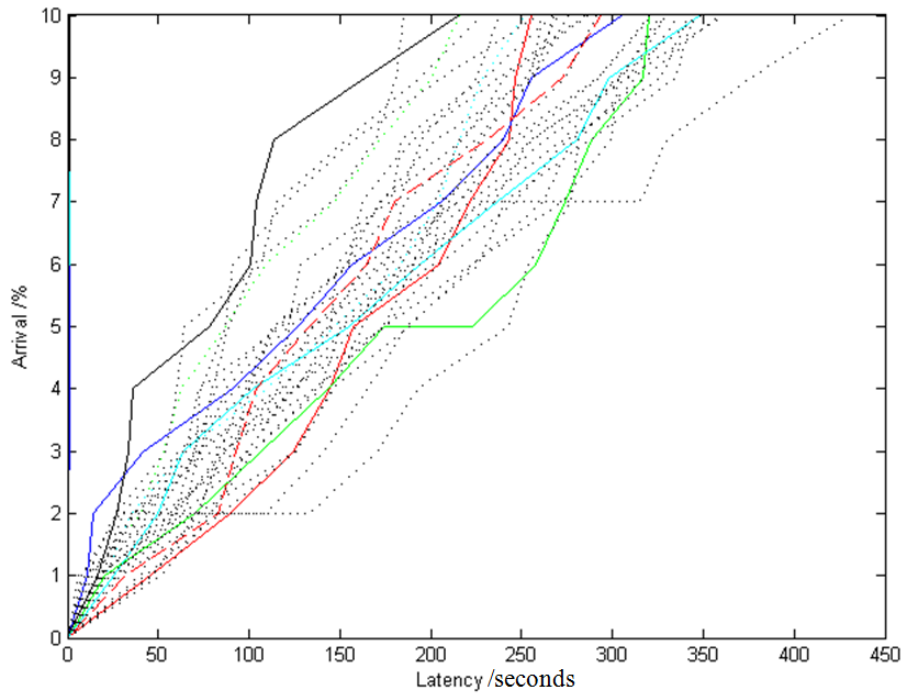


Fig. 5.22 10 % arrival criterion and 33 MV nodes using BPLC

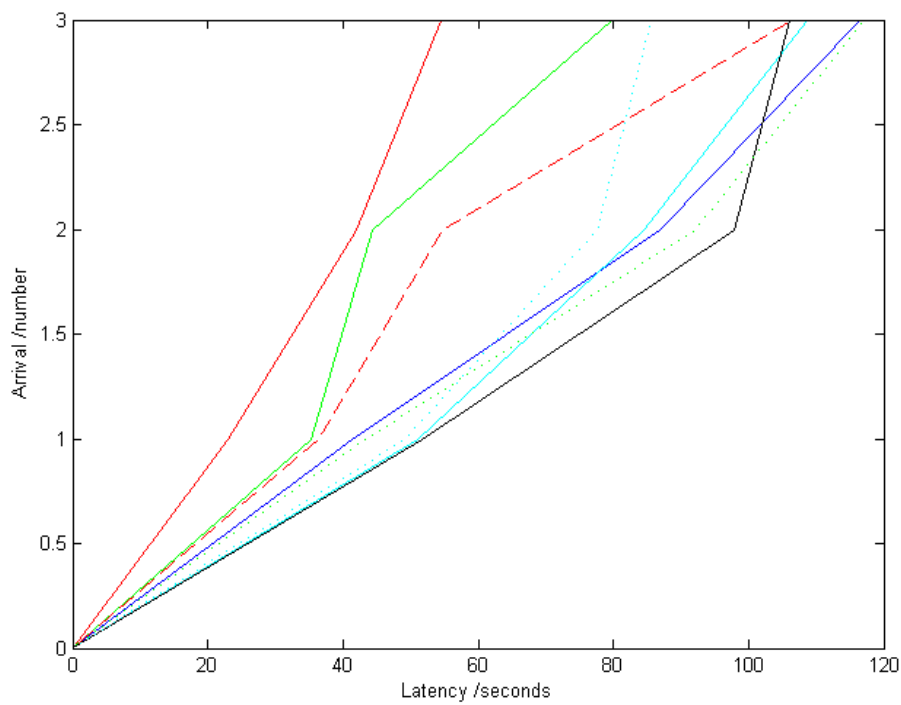


Fig. 5.23 3-meter arrival criterion and 8 out-of-service MV nodes using BPLC

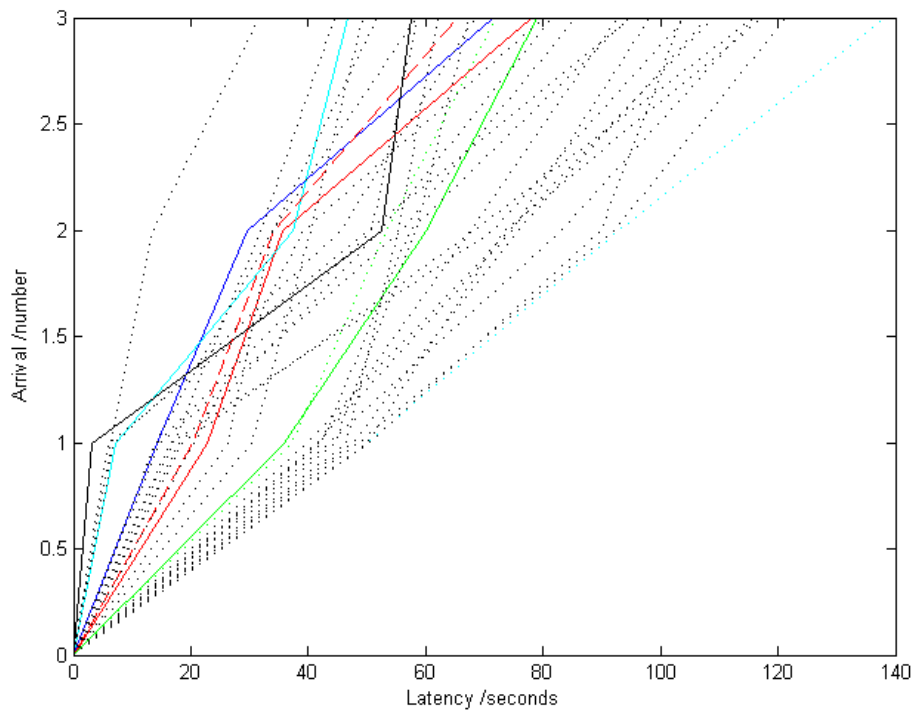


Fig. 5.24 3-meter arrival criterion and 33 MV nodes using BPLC

Using the same condition as the case study of 8 out-of-service MV nodes using BPLC, simulation were carried out to test the performance of the n -meter arrival criterion ($n = 1, 2, 3, 4, 5, 6$ were tested). An error rate of 1% was used for the smart meters (i.e. each smart meter has 1% probability to send wrong “ON” and “OFF” status information) and 5000 simulations were carried out to provide reliable results. The results are shown in Table 5.2.

Table 5.2. The performance of the n -meter arrival criterion

n	Minimum Arrival Time /s	Maximum Arrival Time /s	Average Arrival Time /s	Correctness Rate /%
1	24	113	45	98.10
2	31	115	64	99.70
3	35	122	73	99.96
4	43	141	97	99.98
5	45	158	110	100
6	51	176	122	100

It can be seen from the correctness rate of the outage area identification as shown in Table 5.2, if $n > 3$, the improvement of the correctness rate was not significant. In addition, considering the 3-customer criterion has been widely used in the OMS, obviously the 3-meter criterion is sufficient for the outage area identification. If the smart metering infrastructure has a very high performance, i.e. high speed and accuracy, even 1-meter criterion could be used and the time used for the outage area identification can be further reduced.

5.7 Summary

Using smart metering for the OMS has been a hot trend in the utility industry in the last few years. The last gasp messages from smart meters are an important input to the OMS. The benefits from integrating smart metering and outage management are derived from reduction of average outage duration, crew and dispatcher efficiency savings, and reduction in restoration and trouble call centre costs.

A topology analysis method was developed based on depth first search, which maps the physical plant model of a distribution network to a simplified analytical model. If an outage occurs on a network, some customers may be out of service. An outage area identification algorithm was developed which uses the information from smart meters and are based on the simplified network model. The outage area identification can act as one of the main functions of an OMS providing possible outage extent information. The impact of smart metering communications on the outage area identification algorithm was also investigated based on the OPNET communications model.

A 33-node MV network was used to investigate the effectiveness of the proposed outage area identification algorithm and the impact from the performance of the communications networks. Narrow band and broad band PLC networks were used whose key parameters were from the Irish trial. 10% and 3 smart meters arrival criteria were used to confirm an outage of a MV node. Test results showed that the arrival criterion has large impact on the performance of the outage area identification and 3-meter criterion is much more effective. BPLC showed superior performance compared to that of NPLC.

Chapter 6

Conclusions and Future Work

6.1 Conclusions

As an important form of energy, electricity offers the advantages of being clean, highly efficient and convenient for users. The power system that links the generation, transmission, distribution, and consumption of electricity is one of the most complex manmade systems constructed to date. In recent years, with the increasing demand for energy throughout the world and the associated environmental problems, conventional centralised power systems are facing significant challenges. The development of a highly efficient and environmentally friendly Smart Grid has become an important objective worldwide.

Distribution networks will play an important role in the future overall Smart Grid by providing a link between the transmission grid and consumers. A smart distribution network is an integration of advanced distribution automation, distributed generation and Microgrid technologies. Advanced information, communications and computation technologies are essential in a smart distribution network to support its planning, operation and control. However, conventionally the communications infrastructure at the distribution level is very limited in terms of functionality and availability, where the distribution network operation mostly relies on a simplified version of the transmission SCADA system.

In Great Britain, the Smart Grid has been primarily focused on the distribution networks and smart metering is widely considered as a critical step towards the Smart Grid future. The UK government has committed to the rollout of smart meters for both electricity and gas in all homes and most small businesses by the end of 2020. Although the purpose of the smart metering development is not primarily to benefit electric power networks, it does offer significant potential benefits for the power network planning, operation and management.

The aim of this work is to quantify the impact of smart metering applications on communications requirements, develop an evaluation method to quantify the impact of smart metering communications infrastructure on distribution network operation, and achieve a better understanding on the potential of using smart metering for outage management, which is one of the most critical distribution network operational functions.

The key contributions of this thesis are listed below.

- A smart metering communications infrastructure was modelled and simulated using OPNET. Eight representative smart metering applications used for the analysis were chosen and implemented based on IEC 62056. The communications were primarily examined at the IP layer and discrete event simulation was used during the investigation. The physical architecture was implemented as a shared constrained network that was considered as the worst case implementation of a smart metering network. The impact of smart metering applications on smart metering communications requirements has been investigated.
- An evaluation method was developed to quantify the impact of smart metering communications infrastructure on distribution network operation. The main characteristics of the smart metering communications infrastructure were modelled. The characteristics of the distribution network, mainly the load variation behaviour, were analysed and used to quantify the relationship between the time delay and the measurement error of the power system. The measured data from smart meters are used by state estimation which provides refined information to the distribution network operational functions. The impact of smart metering communications infrastructure on distribution network operation was quantified using optimal power flow.
- The potential of using smart metering for outage management was investigated. A topology analysis method was developed which maps the physical plant model of a distribution network to a simplified analytical model. An outage area identification algorithm was developed which uses the information from smart meters and are based on the simplified network model. The outage area identification can act as one of the main functions of an OMS providing possible outage extent information. The

impact of smart metering communications on the outage area identification algorithm was investigated based on the OPNET communications model.

The main conclusions of this thesis are discussed as follows.

(1) During the simulation of smart metering communications infrastructure, the baseline link size was chosen to be 7.5 kb/s. Controller controlled smart metering applications were implemented using TCP/IP protocols. This was considered the worst case as some applications such as system alarm and demand broadcast could have been implemented more efficiently. The analysis suggests that a 7.5 kb/s shared channel could adequately meet the requirements of a 50-meter smart meter network. It is shown that individual communications requirements for smart meters are not particularly communications intensive and that infrequent large transactions posed the most significant challenges on the communications infrastructure. For non-shared channels the channel size would be considerably less.

(2) Under constrained conditions, the communications network remained relatively unused for all links except for the periods software update or bulk log collections were carried out. As the link speed decreased, the length of time to complete a task increased moving from around 1.5 hours at 7.5 kb/s to 20 hours at 0.75 kb/s. Such large time delays have a direct impact on the functions related to distribution network operations.

(3) Smart metering usually cannot provide real-time measurements to distribution network operators. A method was developed to quantify the relationship between the time delay of smart metering and the measurements errors that are used by distribution network operations. If the nodal voltage limit is $\pm 6\%$, smart meter data with input error larger than 25% (around 25 minutes time delay) is difficult to use for the voltage control functions. For input errors less than 10%, power control is feasible. 25% input error (around 25-minute time delay) drives the operating points far from the actual operating point. The power control function will be unreliable under such conditions. Therefore, obviously fast data access is necessary for smart meter data to be used by the voltage control and the power control functions of a distribution network.

(4) Test results showed that smart metering has a potential to support outage management of a power distribution network. 10% and 3 smart meters arrival criteria were used and compared to confirm an outage of a MV node. Test results showed that the arrival criterion

has a large impact on the performance of the outage area identification and the 3-meter criterion is much more effective. BPLC showed superior performance compared to that of NPLC. For NPLC, Test results showed that it took 0.35 hours to confirm the outage of the first MV node, and 1.4 hours for all 8 nodes. If the status of all 33 nodes needs to be checked, it took almost 3 hours. If the criterion changed to 3 meters, it only needed 25 minutes for 8 nodes and 80 minutes for 33 nodes. Obviously, the 3-meter criterion is much more efficient. For BPLC, the identified can be achieved within 6 minutes with 10% arrival criterion and within 2 minutes with 3-meter criterion.

6.2 Future Work

The use of smart meter information for power system operation has a huge application potential. There are a number of key issues still need further investigation.

(1) Eight applications were chosen and used in this research. A more comprehensive list of smart metering applications could be considered in future research in order to accurately represent the main functionalities of smart metering. These applications can be further optimised for use over bandwidth or cost constrained links. Examination of potential methods for optimising the applications would warrant further research. Simulation could be designed for a long time (e.g. in 1 year) to capture the key performances of smart metering infrastructure under real conditions.

(2) The IEC 62056 standards were used in Chapter 3 and they allow for multiple controllers with different functions to meet different client requirements. Use of different architectures would change the way in which the communications channel is used thus the performance of the communications infrastructure. Examination of different communications architectures and their impact could be further investigated.

(3) The simulation and comparison of proposed applications over various physical media would also be of interest to determine how the physical layer impacts on overall communications requirements of smart metering.

(4) A smart metering communications network was modelled and simulated in this thesis. In order to investigate the interactions between the communications infrastructure and the power systems, additional simulation tools are needed to integrate the two sets of models.

Software tools such as the MATPOWER MATLAB package could be added to the platform via the standardised interface provided by OPNET.

(5) The thesis focused on a balanced 3-phase power system, especially for the investigation of state estimation and outage management. A priority for future work is to extend the work to un-balanced 3-phase networks and to consider the uncertainties of phase connection of smart meters.

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