USE OF SMART METERS FOR FREQUENCY AND VOLTAGE CONTROL

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Abstract

A load control scheme that used frequency measurements of a smart meter for controlling domestic appliances to provide primary response was investigated. An experimental rig was developed to test and demonstrate the scheme. The amount of loads to be controlled to limit the frequency drop of the Great Britain (GB) power system to a set of minimum allowable frequencies was found. Operating speeds and the limitations of the components of the load controller in providing primary response are discussed. It is shown that if smart meters are to play any role in primary response then the speed at which the system frequency is measured must be increased very considerably.

Load profile of fridges/freezers, washers/dryers and hobs/ovens in the GB power system were constructed. Then the percentages of appliances required to be in the load control scheme to shed the estimated amount of controllable loads, were calculated. It is found that the total controllable load requirement can be provided using fridges and freezers alone. Since many washers/dryers and hobs/ovens do not operate at night, they can not then provide a significant amount of controllable loads. However, using these appliances in the day time, the amount of fridges and freezers in the load control scheme can be reduced significantly.

The ability of the proposed smart metering system in the UK to report available demand response from the appliances to the network operator was investigated. It was found that the communication network would not support reporting demand response in near real-time. Using load profiles of appliances for 40,000 houses, it was shown that by installing aggregation devices at distribution transformers and substations, the demand response can be reported to the network operator every minute. By aggregating and sending changes only, the impact of reporting demand response in near real-time on communication network reduces significantly.

The ability of a state estimator to estimate distribution network voltages using smart meter measurements obtained on the previous day was evaluated. The improvement

of the accuracy of the estimated voltages with the number of nodes providing near real-time measurements obtained from distributed generators was also investigated. It was found that when the voltages are estimated using the previous day's measurements without using any near real-time measurement, the voltage error at all nodes were high. By using near-real time measurements obtained from distributed generators, the error can be reduced significantly.

Declaration

DECLARATION

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

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STATEMENT 1

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

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Dedication

To my mother, father,
wife Kamani and
sons Chatura and Navin

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Nomenclature

List of abbreviations

AMI	Advanced metering infrastructure
AMM	Automated Meter Management
AMR	Automated Meter Reading
CPP	Critical Peak Pricing
CVR	Conservation Voltage Reduction
DCC	DataCommsCo (Central Data Communication Company)
DECC	Department of Energy and Climate Change
DG	Distributed Generators
DLC	Direct Load Control
DMS	Distribution Management Systems
DNO	Distribution Network Operators
ENA	Energy Network Association
EPRI	Electric Power Research Institute
ERDP	Energy Demand Research Project
ESO	European Standards' Organisations
EV	Electric Vehicles
FCDM	Frequency Control Demand Management
FERC	Federal Energy Regulatory Commission
FFR	Firm Frequency Response
FR	Fast Reserve
GB	Great Britain
GE	General Electric Consumer and Industrial Company
GSP	Grid Supply Point
HAN	Home Area Network
HEMS	Home Energy Management Systems
HMI	Human Machine Interface
HP	Heat Pumps
IEA	International Energy Agency
IHD	In-Home Display

IRWLS	Iteratively Re-Weighted Least Square
IVVO	Integrated Voltage and VAr Optimisation
LAN	Local Area Network
LCM	Load Control and Monitoring
LFC	Load Frequency Control
LV	Low Voltage
M2M	Machine-to-Machine
MAN	Metropolitan Area Network
MV	Medium Voltage
NAN	Neighbourhood Area Network
NGET	National Grid Electricity Transmission plc
NIALM	Non-Intrusive Appliance Load Monitoring
NIST	National Institute of Standard and Technology
NPV	Net Present Values
OLTC	On-Load Tap Changers
PLC	Power Line Carrier
PPM	Prepayment Meters
RTP	Real Time Pricing
RTU	Remote Terminal Units
SCADA	Supervisory Control and Data Acquisition
SMCG	Smart Metering Co-ordination Group
SMDG	Smart Metering Design Group
TOU	Time-of-Use
UKGDS	UK Generic Distribution Network
UTC	Universal Coordinated Time
WAN	Wide Area Network
WLS	Weighted Least Squares algorithm

1 Introduction

1.1 Anticipated changes in the power system

Electricity transmission and distribution systems in many countries are ageing and need to be improved by re-conductoring or constructing new networks. These improvements are expensive. For example, in the UK, the budget for capital investments for transmission networks for 2007-2012 was £4.3bn and for distribution networks for 2005-2010 was £5.7bn [1]. In addition, obtaining planning permission and carrying out construction, especially in busy cities, is difficult.

Coal and oil generating plants are being closed for environmental reasons and nuclear plants are coming to the end of their useful life. In the UK, out of 80 GW of total generating plants, 22.5 GW of coal and nuclear plants are to be closed by 2020 [1]. About 30-35 GW of new generating capacity is needed within the next two decades. Developing new generating plants is expensive and obtaining planning permission is difficult.

Greenhouse gas emission reductions are needed to limit the increase of the Earth's average temperature to 2^{o}C above the pre-industrial levels (before 1850). Therefore the European Union has called for a reduction of greenhouse gas emission by 20% below 1990 levels [2] by 2020. In achieving that, the UK target is to reduce its emissions by 34% (below 1990 levels) by 2020 and 80% by 2050 [3].

The world's oil and gas reserves are depleting. They are concentrated in a few regions around the world. When considering the volatility of oil prices and the political instability of these regions, many governments would like to be less dependent on imported oil and gas [1]. By contrast, coal is found in many countries, but its CO_2 emissions are high: over twice those produced by burning gas.

In addition to the obvious desirable benefits of reducing overall energy use, many of the issues of improving electricity infrastructure may be addressed by reducing electricity peak power demand. The average utilisation of generation capacity and the networks is below 55% [4]. However, these assets must be able to meet peak demand. Therefore by reducing peak demand, the existing infrastructure can be used for some time thus delaying expenditure.

With the retirements of generating plants, pressure for reduced dependence on oil and gas and targets for emission reductions, there is a growing interest in constructing renewable generators. The EU target is to reduce energy consumption by 20% [5] and to increase the share of renewable energies in total energy consumption (electricity, heat and transport sectors) by 20% by 2020 [6]. The UK target is to increase the share of renewables from 2% to 15% by 2020. In achieving the EU target, the UK target is to obtain around 30% of electricity from renewables by 2020 and to make the electricity sector carbon free by 2050 [3].

The de-carbonised electrical power system of Great Britain (GB) will have new very large generators, such as nuclear, and hence the system needs to be ready to accept a higher sudden loss of generation. At present, the GB system is designed to accept 1320 MW of sudden loss of generation and this will be increased up to a new maximum of 1800 MW [7]. The GB system will also receive more energy from renewable sources connected through power electronic converters, particularly wind power, thus reducing the system inertia. When there is a sudden loss of generation, partly loaded generators increase their output. When the inertia is low, more partly loaded generators are needed to arrest the drop in frequency within the required time [7]. Running partly loaded generators is costly and increases CO_2 emissions. Instead of using partly loaded generators, loads can be controlled to reduce the demand temporarily.

It is also anticipated that more renewable generators will be added to the distribution networks in the future. Distribution networks at present have very limited numbers of measurements and only simple local controllers. They are essentially passive systems and the operators have very limited visibility of their operating states.

Historically, distribution circuits were designed to supply loads with power from the higher to the lower voltage circuits. The voltage is controlled by the On-Load-Tap-Changers (OLTC) installed at the medium voltage substations. When distributed generators are connected to the medium voltage and low voltage networks, the power flow of the networks may change. When the power flow changes, the voltage profile also changes, thus demanding active voltage control at all voltage levels.

Traditionally, OLTC based voltage control schemes used historical load profiles of the networks and a few real-time measurements from the substation. Because of the intermittent nature of renewable generators and increasingly active load control, it may be difficult to predict power flows in the future. Therefore voltage control based on historical load profiles will not be adequate and more near real-time load measurements will be needed [8].

1.2 Role of smart meters in the future power system

Smart meters are being introduced in many power systems worldwide. The initiatives of smart metering in the UK, the European Union, the USA, Australia and Canada are given in Appendix A. A smart meter is a digital energy meter with many functions to support future energy networks. It has two-way communication between the meter and energy supplier. It also has two-way communication to domestic appliances and an In-Home Display (IHD). In addition to the energy measurements that conventional meters record, it can obtain many measurements such as import/export of power and energy, voltage, frequency and harmonic distortion. These measurements can be obtained periodically at intervals of 15 minutes and stored internally. The stored measurements are transmitted to energy suppliers and network operators periodically. A smart meter has multiple registers to store multiple tariff schemes and the energy consumption under each scheme. Real-time power consumption, energy consumption and energy cost can be transmitted to the IHD at very short intervals. The Direct Load Control (DLC) capability of smart meters allows energy suppliers to send control commands to domestic appliances in an emergency.

Smart meters are being introduced primarily to read energy consumption measurements remotely and frequently and to provide real-time power consumption and price information to consumers. It is expected that the consumers would shift and reduce their energy consumption based on the information such as energy consumption and price. It is hoped that this change of energy consumption would reduce the average system demand as well as the peak demand.

However, the functions available within the smart meters will allow the implementation of new control methods that were not possible before. Domestic appliances would be controlled using direct load control commands originated from a load controller. Smart meters would be used as a gateway to transmit these load control commands. Smart meter measurements would be used to decide when to control domestic appliances. By using the energy measurements before and after a load control action, the load reduction due to the load control command would be calculated.

Active distribution network control requires voltage measurements of the network. Traditionally, very few measurements are available and hence voltage is estimated using state estimation algorithms [9]. These state estimation algorithms use a few local measurements from medium voltage (MV) substations, measurements from remote transformers/feeders and many pseudo measurements. Generally, the pseudo measurements have been obtained by load models or historical load data [10]. In the future, smart meters would provide many more measurements of the distribution network. These measurements would be used by state estimators to estimate the network voltages accurately. Usually smart meter measurements are recorded at short intervals but transmitted only periodically. The accuracy of state estimation would be improved by using the real-time measurements obtained by on-demand meter readings.

1.3 Research objectives

The first three chapters of the study described in this thesis investigated the use of smart meters for power system frequency control. The last part of the study investigated the use of smart meters for estimating distribution network voltages.

In Chapter 4, a load control scheme that provides primary response by controlling domestic appliances using smart meter frequency measurements was investigated.

The operating speeds and the limitations of the load control scheme in providing primary response are discussed. The amount of load control required, to maintain the frequency above a set of frequencies, was calculated. The proportion of appliances in the UK that need to be in the load control scheme to provide the required controllable load was found in Chapter 5. In Chapter 6, the possibility of using a smart metering communication network to report the amount of demand response available, in near-real time, was investigated.

In Chapter7, the possibility of using smart meter measurements, transmitted on the previous day, to estimate distribution network voltages in near real-time was investigated.

1.4 Contributions of the Thesis

The contribution of this work includes:

- Experimental investigation of the ability of a load controller that reads smart meter frequency measurements and controls domestic appliances through a Home Area Network to provide primary response.
- Calculating the loads that need to be controlled to maintain the Great Britain power system frequency above a set of frequencies.
- Constructing the load profiles of the controllable appliances (fridges/freezers, washers/dryers and hobs/ovens) and calculating the percentage of appliances that need to be in a load control scheme to provide primary response in the Great Britain power system.
- Comparing the ability of the proposed smart metering system in the UK, with a hierarchically arranged communication network with aggregation devices, to report the available demand response from appliance to the network operator once a minute.
- Investigating the ability of a state estimator to estimate the voltages of a distribution network using the measurements obtained on the previous day.
- Investigating the improvements in accuracy of the estimated voltages as the number of nodes providing near real-time measurements is increased.

1.5 Publications

A number of papers were published describing this work.

1. **K. Samarakoon**, J. Ekanayake, and N. Jenkins, "Investigation of Domestic Load Control to Provide Primary Frequency Response Using Smart Meters," *IEEE Transactions on Smart Grid*, vol. 3, no. 1, pp. 282-292, 2012.
2. L. J. Thomas, A. Burchill, **K. Samarakoon**, Y.He, J. Wu, J. Ekanayake, N. Jenkins, "Control of electricity network using smart meter data" CIGRE 2012. (Accepted for publication)
3. **K. Samarakoon** and J. Ekanayake, "Selective load control to provide primary frequency response in the wake of introducing new large thermal power plants to Sri Lanka," in *2011 6th IEEE International Conference on Industrial and Information Systems (ICIIS)*, pp. 204-209.
4. J.Wu, J. Ekanayake, **K. Samarakoon**, "Frequency response from electric vehicles," in First International Conference on Smart Grid, Green communications and IT Energy-aware Technologies (Energy 2011), 2011.
5. **K. Samarakoon**, J. Wu, J. Ekanayake, and N. Jenkins, "Use of delayed smart meter measurements for distribution state estimation," in *2011 IEEE Power and Energy Society General Meeting*, pp. 1-6.
6. W. M. T. Vijayananda, **K. Samarakoon**, and J. Ekanayake, "Development of a demonstration rig for providing primary frequency response through smart meters," in *Proc. 2010 45th International Universities Power Engineering Conference (UPEC)*, pp. 1-6.
7. **K. Samarakoon**, J. Ekanayake, and Jianzhong Wu, "Smart metering and self-healing of distribution networks," in *2010 IEEE International Conference on Sustainable Energy Technologies (ICSET)*, pp. 1-5.
8. **K. Samarakoon** and J. Ekanayake, "A survey of frequency control methods and demand side contribution in Sri Lanka and in Great Britain," in *2009 International Conference on Industrial and Information Systems (ICIIS)*, pp. 454-459.
9. **K. Samarakoon** and J. Ekanayake, "Demand side primary frequency response support through smart meter control," in *Universities Power Engineering Conference (UPEC), 2009 Proceedings of the 44th International*, pp. 1-5.

2 Smart metering and its applications

2.1 Smart meter

A traditional electro-mechanical energy meter has an aluminium disk placed between two coils. One coil is supplied by the voltage and the other carries the current. The fluxes produced by the voltage and current coils generate a torque thus causing the disc to rotate. Therefore the speed of rotation is directly proportional to the power flowing through the meter [11]. As the disk rotates, a mechanical counter connected to it through a gear arrangement, increments its counter thus displaying the number of rotations of the disk as energy.

The energy measured by the electro-mechanical meter is recorded manually by periodically reading the display. As this is labour intensive and the periodic measurements are not equally spaced, electronically read measurements that can be transmitted through a communication media are preferred. This is achieved by different methods of retrofitting on to existing meters. One commercially available retrofitting device named I-ModemAMR™ [12] uses, a reflector on the rotating disk of electro-mechanical meter, and an optical sensor to count the number of rotations of the disk. A device named Meter-Mimic™ [13] is fixed close to the existing meter, counts the number of rotations by using a ferromagnetic technology. The number of rotations is used to calculate the energy consumption. The NXE-OMR™ optical meter reader [14] reads the numbers of the mechanical counter optically and determines the energy consumption registered on the counter using optical character recognition techniques.

These retrofitted meters are connected to the energy supplier through a communication system. Instead of using separate communication modules for electricity, water and gas meters, a dumb meter/smart box Edelia™ [15] reads the measurements from the meters through a Home Area Network (HAN) and sends its measurements to suppliers through a Wide Area Network (WAN). MacDonald [16] suggests that, instead of using a separate smart box, the home communication hubs provided by communication companies can be used for sending the measurements.

An advanced smart box NXE-EDH^{TM} Energy Hub [14] can read measurements from a large number of meters through a Local Area Network (LAN) and hence is suitable for large buildings and industrial premises. This Energy Hub can store and process measurements internally and present information in different graphical formats via standard web browsers through intranets or the Internet.

Many countries consider that retrofitting is not suitable because of its limited capability for future expansion [17] and hence it is preferred to install electronic energy meters. As a result, electronic meters are being installed in many countries around the World, particularly in Europe, the USA, Canada and Australia [18] [19] [20]. Some of these initiatives are described in Appendix A.

The functionality of electronic energy meters varies widely. They can be categorised in increasing order of sophistication [18] [21] as;

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

A summary of the functionalities of these types of meters is given in Appendix B

AMR meter records total energy consumption in its internal register. These meters have one-way communication capability and send the energy measurement to the supplier or a meter reading agency, periodically.

AMM meters use two-way communication so that, in addition to sending measurements, the energy supplier can limit or disconnect the supply when consumers default on their payments. Tariffs can be changed remotely. The supplier will be informed if a meter is being tampered with. Some meters display information such as power and energy consumption, tariff and energy cost.

AMM Interval meters measure and store energy measurements at shorter intervals (half hourly or less) and send the measurements to the supplier periodically. These meters have data registers to store multiple tariff schemes and the energy consumption under the different tariff schemes.

PPM meters can work on pre-payment or credit tariff schemes and consumers can switch between the schemes. The consumers on pre-payment schemes can add credit through the keypad of a meter.

AMI meters which have advanced functions are treated as smart meters in this thesis. Although standardisation activities are being undertaken in the UK and Europe, there is no single specification to describe a smart meter. It is anticipated that smart meters would have functions that will facilitate demand side integration to help power system control.

The functional requirements catalogue [22] for the UK smart meter rollout was released with the response to the smart metering consultation on March 2011. The layout of smart metering components given in the catalogue is shown in Fig. 2.1. A HAN connects the smart meter, In-Home Display (IHD) and Other Devices. The HAN should communicate in real-time (better than 10 seconds, target of 5 second) to enable real-time update of IHD. The HAN is connected to a central data and communication entity (DCC) through a WAN. Smart meter data will be sent to the DCC through the HAN and the WAN. Smart meter functionality to support smart appliances, domestic micro-generators and auxiliary switches is also specified in the functional requirements. Suppliers, network operators and other authorised parties can read measurements from the DCC and send control commands to smart appliances and auxiliary switches to control them. Domestic micro-generators can send their measurements through the HAN.

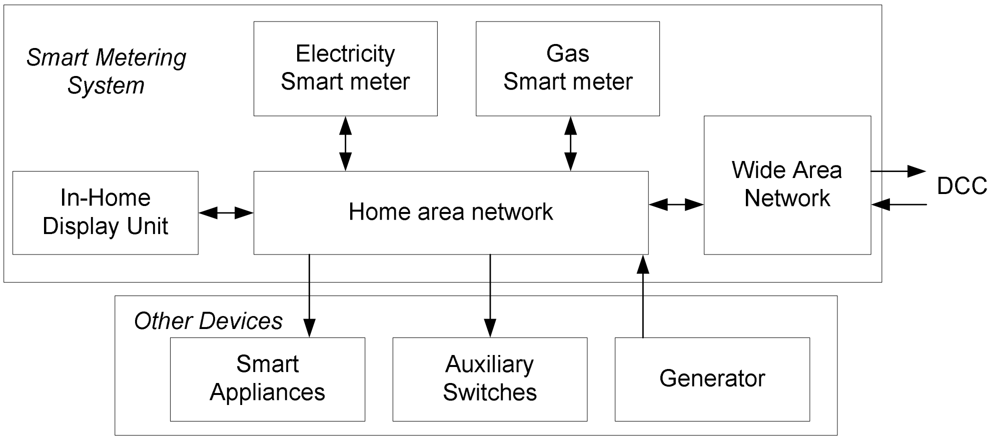


Fig. 2.1. Layout of the smart metering equipment, communication networks and DCC given in the UK functional requirements catalogue [22]

The European Union has given a mandate to the European Standards' Organisations (ESO); CEN, CENELEC and ETSI to develop smart meter standards for the Union [23]. In accordance with the mandate, the smart metering co-ordination group (SMCG) of ESO is developing a standard. The diagram of the meters, devices and communication paths given in the SMCG final report [24] is shown in Fig. 2.2. That figure has equipment and communication paths similar to the smart metering components of the UK consultation shown in Fig. 2.1. In addition, a Machine-to-Machine (M2M) Remote Gateway, which can communicate to the meters and Home Automation (similar to Other Devices in the UK consultation), is available in the draft standard of ESO. As shown in broken lines, alternative direct communication paths may exists between the gateway, meters and the Home Automation.

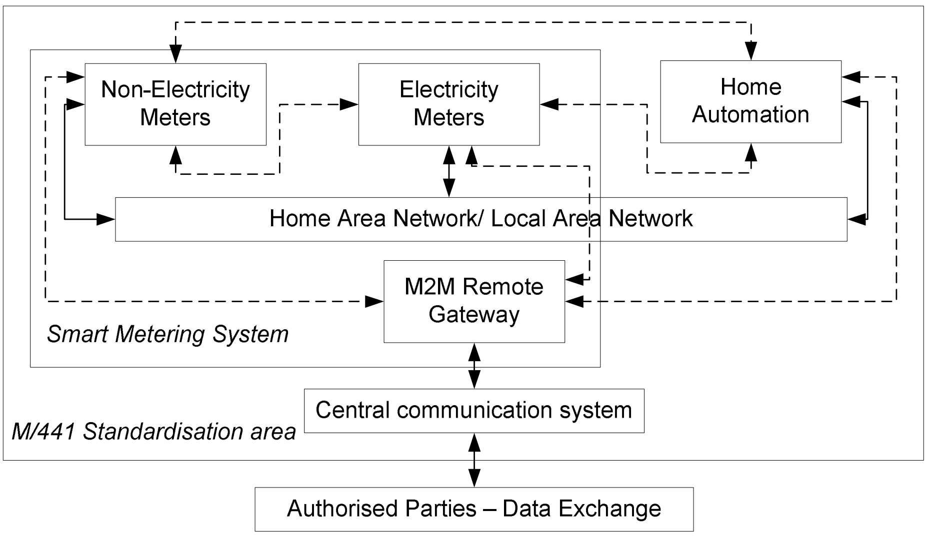


Fig. 2.2. Layout of the smart metering equipment and the communication networks of the EU smart meter standardisation activities [24]

The energy Independence and Security Act of the USA [25] stipulates the Government's policies for the development of smart grid. In these policies, smart metering is an integral part of the smart grid. As required in the mandate given in the act, the National Institute of Standard and Technology (NIST) have developed a Framework and Roadmap for Smart Grid Interoperability Standards [26]. Electric Power Research Institute (EPRI) identified six priority functions for the roadmap [27]. AMI, demand response and distributed grid management are the relevant functions for the work reported in this thesis. The Use Cases developed by the EPRI explain details of these functions. These Use Cases are given in Appendix C.

2.2 Smart meters for demand response

2.2.1 Providing information for peak reduction

Smart meters allow the implementation of time-varying price schemes which support the reduction of power system peak demand [18][28]. Energy suppliers send time-varying price information to smart meters through a Wide Area Network (WAN) [29][30]. Many smart meters have data registers to store the energy consumption with different price schemes. For example, in the UK, smart meters will be capable of storing price schemes that vary half hourly [22].

The importance of using time-varying prices for utilities was discussed by Vickrey [31] in 1971. In this paper, it was stated that if the price is varied based on supply and demand, the utilisation of utility assets can be improved thus lowering operating costs. In order to influence the customers' decision to buy electricity at a given price, the price must be known to the customers in advance. The changes in price that occur after agreeing to buy at a given price will not have any influence on the decision. If the price is fixed far in advance, as in fixed price schemes, the subsequent changes of supply and demand can not be taken into account. Therefore the time at which the price is sent to the customer, is important.

The most common time-varying price schemes are Time-of-Use pricing (TOU), Real Time Pricing (RTP) and Critical Peak Pricing (CPP) [28]. TOU pricing has two or more daily periods that reflect the hours when demand is high (peak) or low (off-peak). The peak price is higher than the off-peak price. RTP rates typically vary in near real-time (hourly or half-hourly) and prices are sent to smart meters on a day-ahead or hour-ahead basis. CPP rates are a hybrid of TOU and RTP. The basic structure of CPP is TOU with two or more daily periods. In addition to the basic structure, high real-time prices may be introduced in some TOU periods when system failures occur or when electricity prices are very high.

The French “Tempo” pricing scheme [28] is a variant of TOU pricing. Each day has normal and off-peak (10 pm-6 am) TOU periods. The TOU prices are changed daily based on forecast demand influenced by weather. The days are colour coded. Blue, White and Red colours are used for low, medium and high priced days. Customers have a display, plugged into a socket with coloured lights for the present day and the next day. Also the display indicates whether the present price is normal or off-peak.

Time-varying prices and energy consumption information are presented to customers so that they can identify the time period and appliances that contribute most to their electricity bill. A common method of presenting the price and energy information is to display them on In-Home-Displays (IHD) in real-time. Smart meters send information to IHDs through a Home Area Network (HAN) [29][30]. IHDs display present household demand and price per kWh, numerically or graphically [22][32][33][34][35]. Many displays can provide trends and historic energy consumption. Some IHDs have coloured indicators to show different pricing schemes (e.g. IHD used in the Queanbeyan trial given in IEA demand-side management survey report [36] and ecoMeter [32]). Some IHDs make a beep sound to alert the customers at the start of the critical-peak period (e.g. Queanbeyan trial [36]).

The Internet may also be used to provide pricing and energy consumption information to customers. The customers use their computers to access the information through the Internet (e.g. California, ISO New England, Olympic Peninsula demand response programs described in the IEA demand-side management survey report [36]).

The Energy Pricelight pilot project [37] used a glass orb that glows in six colours to indicate the energy price at a given time. The prices were given on a printed coloured chart. In this implementation, the glass orb received only the price information from the utility through pager signals. Hence, the orb did not have means to calculate or indicate the household energy consumption.

It is hoped that by providing time-varying price information and energy consumption to customers, they would voluntarily switch off appliances to reduce their electricity bill [31]. As peak prices are higher than off-peak prices, the appliances are likely to be switched off during the peak times thus reducing peak demand. The reduction of peak demand reduces the requirement for high cost generators. For example, Roscoe [38] estimated that, in the UK, peak demand could be reduced by 8-11 GW. The savings of capital cost for generators were estimated to be between £2.6bn to £3.6bn.

A number of implementations that use time-varying prices have been reported in the literature. A TOU scheme with two prices (called 'Economy 7') has been used in the UK since 1970 [39]. The energy meters in this scheme have two registers, one for each price. Initially, the appropriate register was selected using a timer switch. In 1984, radio controlled tele-switches were introduced to switch the registers. During nights, those meters record energy consumption in the low price register for seven hours, primarily to run night-storage heaters. At present, about 3 million meters use this price scheme [40].

Vickrey [31] discusses a price scheme with peak, normal and off-peak prices used by a French electricity supplier. The meter used in that scheme had three registers to record electricity consumption. The recording register was selected using a high intensity, high frequency pulse sent through the power line. In those UK and French price schemes, although the meters supported time-varying prices, the price information was not sent to the meters, but external control signals were used to select the registers for different prices.

In 1986, Rosenfeld [41] reported field trials that sent time-varying prices to microprocessor based energy meters to control domestic loads. Those trials were conducted in the UK and the USA. In the UK trial, the British Broadcasting Corporation broadcast a (fake) electricity price every 5 minutes. The meter then transmitted the price using Power Line Carrier (PLC) through the home's electrical wiring. A multi-position selector-switch that was plugged into wall sockets, read the price signal. The switch was labelled in pence/kWh and the user selected the price threshold that would switch on and off the appliance connected to the switch. When the price exceeded the threshold, the switch was off and when the price dropped, it was on. In the trial conducted in the USA using the same equipment, the price signals were transmitted over telephone lines to the meters. It was found that sending signals over the telephone system was unreliable at that time.

The use of smart meters to send price information to IHDs was investigated in pilot studies such as Queanbeyan and EnergyAustralia trials [36]. These studies were conducted to determine the benefits of smart metering. The Energy Demand Research Project (EDRP); a smart metering trail conducted in the UK has used about 18,000 smart meters for the trial. It was concluded that providing smart meters with IHDs yielded higher energy saving (around 3% higher) than providing smart meters without IHDs.

Schweppe [42] discussed the concept of sending time-varying prices to a domestic controller which automatically schedules the operating times of loads based on the price sent by the utility. In the ADRS trail in California [43][44], load control and monitoring (LCM) devices were installed at each controllable appliance. These devices receive price information through the Internet. Based on the price information, users set price thresholds to control the LCM devices. When these price thresholds are reached, the LCM devices automatically control the appliances.

2.2.2 Direct load control for peak reduction

Direct load control (DLC) remotely shuts down or changes the thermostat settings of customers electrical equipment (e.g. air conditioner, water heater) [20]. In 1980, Schweppe [42] discussed the possibility of using DLC commands to control loads. This reference noted that although DLC is efficient, it is unlikely that it would be politically or socially accepted.

The concept of sending DLC commands through energy meters was reported by Surratt [45] in 1991. In that concept, the DLC commands are sent through Power Line Carrier to control air-conditioners and water heaters. The users have an override capability and, if the loads were shed, the users receive a credit as a percentage of their electricity bill. Because the DLC command is sent through the meter, the load reduction could be calculated by the meter.

In the laboratory implementation of DLC reported by Wang [46], customers submitted bids for shedding their loads to a central controller. Based on the bid, the controller scheduled the loads to be shed. Proportionate to the peak demand, the controller sent DLC commands through smart meters to control loads.

In a pilot study conducted in Norway [47], domestic hot water and space heaters were controlled by DLC commands sent through smart meters.

In the USA, demand response aggregators use smart meters to send DLC commands to appliances such as pool pumps and air conditioners [48]. A control centre of an aggregator continuously monitors the total demand and sends commands to the customers who have contracts with the aggregator to control their loads.

Domestic controllers that use DLC commands sent by a demand response aggregator are reported in an International Energy Agency (IEA) report on smart metering and load control [28] (e.g. the Rippleband Load control system and the SD electricity manager). These controllers communicate with remote controlled sockets plugged into wall sockets in the house through a HAN. The remote controlled sockets switch on, off or vary the loads and calculate the energy consumption of the appliances plugged into them.

2.2.3 Determining the load changes due to demand response

Load profiles have long been used for network planning and operation [49]. Traditionally, these load profiles were calculated using load models and electricity billing data. When consumption habits of consumers were more or less consistent, these load profiles were sufficiently accurate. However, with demand response, such as time-varying prices and DLC, the load profiles obtained from traditional methods will become less accurate.

Smart meter measurements taken at short intervals (e.g. 15 or 30 minutes) can be used to calculate load profiles accurately. As an example, the trial conducted by The Carbon Trust in the UK [28], used load profiles to identify possibilities of reducing loads and then to advise consumers. The smart meter measurements, taken before and after the load reduction, were used to calculate the energy saving.

Since traditional energy meters do not have a communication facility, alternative means of sending load reduction information to the energy supplier are required. As an example, in the ADRS trail conducted in California [44], in addition to the energy meter supplied by the energy supplier, a separate meter with two-way communications [43] was installed at each controllable appliance. However, smart meters have two-way communication built into them. Hence, as reported in the IEA report on smart metering and load control [28], smart meters can be used to send load reduction information to the energy supplier.

To verify whether appliances have responded to a DLC command, it is necessary to identify the appliances that are in operation [50]. A Non-Intrusive Appliance Load Monitoring (NIALM) unit, a device that identifies appliances by using measurements taken at the metering point, was built by Hart [51] in 1984 and has been commercialised since 1993 [52]. That unit, which was attached to the metering point of the domestic circuit, measured current, active power and reactive power at 1 second intervals. The appliances in operation were identified by decomposing total current and power measurements using load curves of the appliances. Liang [53] described a NIALM method that used current waveforms obtained at a 12 kHz sampling rate.

The use of an energy meter for NIALM is reported by Pihala [54]. This was an advanced meter developed for power quality measurements and hence it was capable of recording energy consumption of a house at a rate of 1 Hz. As NIALM requires high computing power, Bergman [50] describes an algorithm that divides the computing capability required between the smart meter and a remote computer.

The ability of smart meters to use NIALM depends on the measurement rate. Smart meters take energy measurements to send to the energy supplier and also to send to an

IHD. At present, commercially available smart meters record measurements that are to be send to the supplier, at a minimum interval of 15 minutes. This recording rate is very slow compared to the 1 second intervals used for NIALM by Hart [51] and Pihala [54] and hence NIALM may not be implemented at the supplier site. However, in the UK, the measurements sent to the IHD are to be recorded at 5 second intervals. These measurements may be suitable for implementing NIALM at customer premises.

When appliance usage data is combined with household personal information, there is a risk of breeching customer privacy [55] [56]. Shein [56] discusses that data privacy could be breached by unauthorised hackers through communication systems or by parties which are authorised to run a restricted range of permitted applications. This paper notes that, to prevent hacking, data encryption and compression techniques can be used. Breaches of privacy by authorised users can be prevented by providing only data sufficient to run the permitted applications.

2.3 Smart meters for distribution network automation

Traditionally, distribution network automation was limited to operation of On-Load Tap Changers (OLTC) and the circuit breakers of primary substations (33/11 kV). Measurements obtained from remote terminal units (RTU) installed within a substation were used for this simple automation [9]. These RTUs measured currents, voltages and the status of the circuit breakers.

Introduction of supervisory control and data acquisition (SCADA) systems allows operators to visualise, monitor and control their networks remotely. In these systems, RTUs installed at selected locations in the network are used to obtain remote measurements.

At present, utilities install Distribution Management Systems (DMS) to automate the operation and control of distribution networks [57]. These systems include many applications such as:

- outage management,
- network analysis and optimisation,

- automated feeder switching and reconfiguration,
- crew monitoring and dispatching
- Volt/VAr control.

A DMS allows visualisation, monitoring and analysis of the automation functions through a co-ordinated suite of applications.

State estimators are used in DMS and SCADA systems to estimate the network parameters such as voltages and loads of distribution networks [9]. These parameters are displayed on operator control panels and are used for the distribution automation functions. In the past, owing to high cost, RTUs were not installed at all nodes of a distribution network and hence only a few measurements were available for state estimation. Therefore, state estimators used average load profiles calculated using historical billing data (pseudo measurements) together with the measurements obtained from RTUs.

Smart meter measurements can be used with the DMS to improve the accuracy of load profiles used for state estimation [58]. The estimated loads are verified against the measured values. In this implementation, smart meter measurements are also used to show the energisation status of the distribution network.

The accuracy of state estimation techniques can be further improved using smart meter measurements communicated in real-time (i.e. transmitted immediately after reading). Using simulations, this is demonstrated by Baran [58]. Wang [59] suggested a method to use smart meter measurements, communicated at 15 minute intervals, to calculate the total load of distribution transformers. These loads were used for the distribution state estimation algorithm developed by Wang [60].

However, present-day smart metering systems do not send measurements to the energy supplier in real time. Instead, smart meters read measurements at short intervals (e.g. 15 or 30 minutes) and store them in an internal memory [61] [62]. In existing smart metering systems in many countries, these measurements are sent at most once a day [61] [62] [63]. In some countries, these measurements are sent after one month or more. Boardman [57] notes that, with the improvement of communication infrastructure, DMS systems will get more near real-time smart meter measurements in the future.

In traditional Volt/VAr control, the operating set-points of voltage regulating equipment such as OLTCs and switched capacitors are calculated from off-line studies. To account for voltage estimation errors, network voltages are maintained above the low voltage limit with a tolerance. If the network voltages are known accurately, this tolerance may be reduced.

Conservation Voltage Reduction (CVR) is a reduction of electricity demand resulting from a reduction of network voltage [64]. When the network voltage is reduced, power consumption of resistive loads such as incandescent lights and heaters will be reduced proportionate to the square of the voltage [65]. When induction motors are running with constant torque, as voltage reduces, slip increases thus reducing power consumption slightly. Lightly loaded motors such as fans reduce their power consumption as the voltage is reduced [66]. Although power consumption of thermostatically controlled devices such as space heaters and refrigerators is reduced, their energy consumption will not be reduced because they will operate until the set temperature is reached. Therefore, the amount of demand reduction resulting from voltage reduction depends on the load mix of a network. Schneider [64] estimated that, in the USA, if CVR is introduced to all the distribution networks, it will reduce annual energy consumption by 3%. Since CVR does not need any load control action by consumers, it is the least intrusive demand response method.

For the CVR scheme reported by Krishner [67], voltmeters, built into energy meters, were installed at customer premises near the substation and near the feeder ends. The minimum and maximum voltages obtained from the meters, over a period of four months, were used to calculate the set-points of voltage regulating equipment. The operating set-points of voltage regulating equipment were adjusted such that network voltages are reduced as much as possible without violating the low voltage limit.

With widespread demand response, the voltages of distribution networks will be highly variable. When traditional CVR based on off-line studies is used, the high variability of network voltage causes the voltages at some nodes to drop below the limit. Further, objectives of different demand response may overlap in time and demand response in one circuit may affect the voltages of other circuits. Markushevich [68] notes that with the implementation of AMI and DMS, Integrated Voltage and VAr Optimisation (IVVO) can be used for coordinating the operation of different voltage control equipment.

Since smart meters take measurements at short intervals (15 or 30 min), they provide accurate voltage profiles of the network. Neal [69] reported two methods of using smart meter measurements, to operate voltage control capacitors for IVVO, in a demonstration project planned for a utility in the USA.

In the first method suggested by Neal [69], voltage measurements obtained from smart meters at selected locations, over a day or more, were used to compute the set-points of voltage control capacitors. These set-points were downloaded to the capacitor controllers. The paper notes that, this method was planned for existing smart metering systems which have measurement transmission delays and bandwidth limitations in communication systems.

In the second method suggested by Neal [69], real-time voltage measurements obtained from smart meters were used in a power flow algorithm to decide the operation of voltage controlling capacitors. This paper notes that, because the data transmission rate of existing smart meters is not sufficient, additional smart meters may be installed at selected locations in the network. The measurements from these additional meters will be transmitted through a high speed communication system.

The use of smart meters to control domestic appliances locally, in real-time, is considered by Strbac [70] to manage peak demand. This reference notes that, when many electric vehicles (EV) and heat pumps (HP) are connected to distribution networks, loads deviate very frequently and very significantly from pre-defined load profiles (in excess of 10 kW per household). This variation would potentially lead to violation of distribution network voltage and thermal limits thus demanding network reinforcements. By controlling domestic loads such as washing machines, dish washers, and tumble dryers locally in real-time with the help of smart meters, network reinforcements can be postponed. These smart meters must be equipped with suitable functionalities to facilitate real-time load control. The estimated net present values (NPV) of postponement of network reinforcements by using smart meter enabled active control in GB, are from £0.5bn to £10bn for different EV and HP penetrations. The paper notes that the estimated NPV indicates an allowable budget for introducing smart metering functionalities required for active distribution network control.

3 Frequency control using controllable loads

3.1 Frequency control of power systems

3.1.1 Importance of frequency control

In an AC power system, the balance between generation and demand determines the frequency. If generation and demand are not in balance, for example due to a loss of generation, a sudden change of demand or a change of power output of renewable sources, the frequency may change rapidly.

Large frequency drops would damage transformers and induction motors due to the high magnetising currents required for maintaining the flux [71]. These devices are widely used in transmission and distribution networks as well as in consumer appliances.

Turbine blades are designed to operate in a narrow band of frequencies to avoid mechanical vibrations of blades at their natural frequencies. Hence deviation beyond this band could damage the turbine [72]. As an example, a 50 Hz steam turbine may not be able to withstand frequency deviations greater than ±2.5 Hz [73]. The time-frequency estimates are given in Table 3.1 [74]. These limits are based on the total time that a turbine would operate under frequency during its life time. As an example, a 60 Hz steam turbine cannot operate at 58.8 Hz (0.97%) for more than 10 minutes over its life time.

TABLE 3.1. CONSERVATIVE ESTIMATES OF TIME-FREQUENCY LIMITATION OF A 60 HZ STEAM TURBINE [74]

Frequency at full load (Hz)	Minimum time to damage
59.4 (99%)	Continuous
58.8 (98%)	90 minutes
58.2 (97%)	10 minutes
57.6 (96%)	1 minute

When frequency drops, the air flow in generators and turbines will be reduced thus reducing cooling. Furthermore, the reduction in frequency causes generator control systems to increase their input power to maintain the generation and demand balance. The reduction in cooling and increase of power may result in an increase of the internal temperature of the turbine and generator windings. As the internal temperature increases, the protection devices will trip the generator thus increasing the imbalance between demand and generation.

The power output of coal plants depends on their motor driven auxiliary systems such as boiler feed water pumps, condensate pumps, coal pulverising and feeding equipment and draft fans. As system frequency decreases, these systems become less effective which further reduces the energy input to the turbine and the generator output. This reduction of generator output has a cascading effect on the power system where a loss of frequency leads to a loss of power which can cause frequency to drop further [74].

When frequency drops, generators increase their output by different amounts based on their droop characteristics (discussed in Section 3.1.2). This could cause sudden changes in power flows across a power system. The changes in power flow may overload some transmission lines. As a result some lines could trip which might lead to system instability [74] [75] [76].

A stable frequency is required for some industry applications such as rolling mills, paper industries and processing lines that depend on the speed of motors. In these applications the speed of some processes is maintained by using synchronous motors [75]. When the frequency drops, the process may be disturbed. This might lead to a substantial loss to the industry.

In the past, much equipment used the system frequency for synchronising their internal clock to a standard time [71]. When frequency deviates from its normal value, the synchronised clocks also deviate from the standard time. At present, with the advent of stable crystal oscillators, precise stable time signals are available for digital equipment. However, it may be still required to use power system frequency to correct the drift of the oscillator that occurs over a period of time.

Therefore, in a power system, it is an obligation of the system operator to maintain frequency within tight limits and, if frequency deviates, to restore it to normal frequency within a specified time period. These frequency and time limits may be specified as statutory requirements.

3.1.2 Frequency control principles

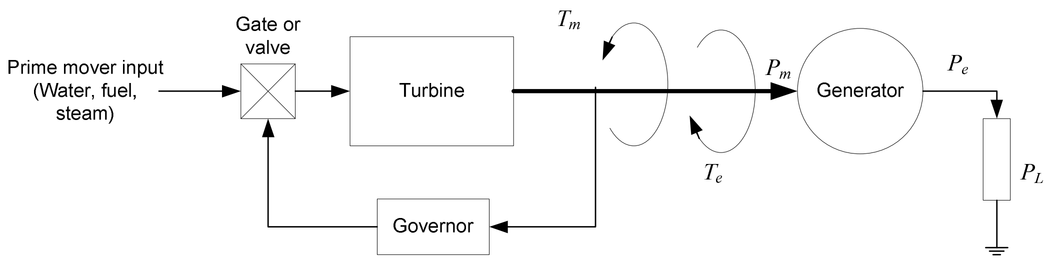


Fig. 3.1. Schematic diagram of a generator-turbine unit [71]

Using Newton's equation for rotating masses, Kundur [71] expressed the angular velocity of a turbine-generator unit (ω_m) as

$$J\frac{d\omega_m}{dt} = T_m - T_e \qquad (3.1)$$

where J is moment of inertia of rotating masses of the turbine-generator unit

T_m is the mechanical torque applied by the turbine to the shaft

T_e is the electrical torque applied by the generator to the shaft

t is time

The Inertia constant (H) of a generator-turbine unit is defined as the ratio of kinetic energy stored at the synchronous speed (ω_m^{syn}) to the generator kVA or MVA rating (S_B).

$$H = \frac{\frac{1}{2}J(\omega_m^{syn})^2}{S_B} \qquad (3.2)$$

Substituting *J* in (3.1)

$$2H\frac{d(\omega_m/\omega_m^{syn})}{dt}=\frac{T_m-T_e}{S_B/\omega_m^{syn}}$$

Since the base value of torque, $T_B=S_B/\omega_m^{syn}$ and denoting per unit values using superscript *pu*;

$$2H\frac{d(\omega_m^{pu})}{dt}=T_m^{pu}-T_e^{pu} \qquad (3.3)$$

Since the relationship between power (*P*), torque (*T*) and angular velocity (ω_m) is given by $P=T\omega_m$, considering small deviation from initial values (denoted by subscript 0); $P=P_0+\Delta P$, $T=T_0+\Delta T$ and $\omega_m=\omega_0+\Delta\omega_m$

Kundur [71] proved that $\Delta P_m-\Delta P_e=\Delta T_m-\Delta T_e$ (3.4)

where P_m is the power input by the turbine to the shaft

P_e is the power output of the generator (Windage, frication and winding losses are neglected)

Using (3.4), (3.3) can be written as $2H\frac{d(\Delta\omega_m^{pu})}{dt}=\Delta P_m^{pu}-\Delta P_e^{pu}$ (3.5)

When ω_e is the electrical angular velocity of the generator and since $\omega_m^{pu},\omega_e^{pu}$ are per unit values $\Delta\omega_m^{pu}=\Delta\omega_e^{pu}$

$$2H\frac{d(\Delta\omega_e^{pu})}{dt}=\Delta P_m^{pu}-\Delta P_e^{pu} \qquad (3.6)$$

Some loads, such as motors, change their power consumption with frequency and hence when frequency drops, the system demand also drops proportionately. The relationship between the demand and the frequency is given by the load-damping constant (*D*). For a power system, this constant is usually given as a percentage of demand change per one percent change of frequency (load-frequency sensitivity).

The overall frequency-dependent characteristic of system demand is expressed by Kundur [71] as

$$\Delta P_e^{pu} = \Delta P_L^{pu} + D\Delta\omega_m^{pu} \quad (3.7)$$

Where

ΔP_m^{pu} is the change in turbine power output

ΔP_L^{pu} is the change in power system demand

ΔP_e^{pu} is the change in generator power output

from (3.6) and (3.7); $\Delta P_m^{pu} - \Delta P_L^{pu} = 2H\dfrac{d\Delta\omega_e^{pu}}{dt} + D\Delta\omega_e^{pu}$ (3.8)

Equation 3.8 can be represented as in Fig. 3.2.

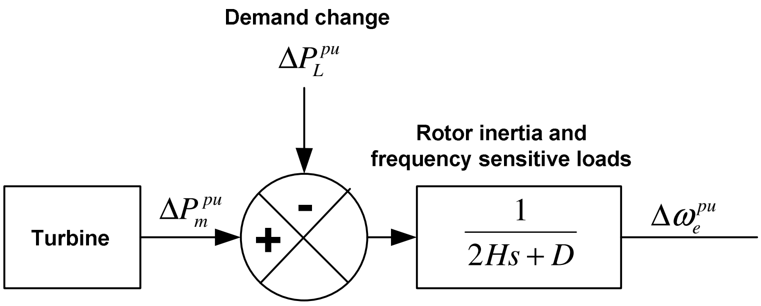


Fig. 3.2. Block diagram of a generator-turbine unit [71]

Speed of a turbine is maintained at synchronous speed by a governor which controls the input power to the prime mover. To share the output of generators running in parallel, droop control is used by the governors.

$$Droop(R) = \frac{Frequency\ change}{Generator\ power\ output\ change} \times 100\% \quad (3.10)$$

A typical Droop characteristic of a governor is shown in Fig. 3.3.

Using equation 3.10; $R = \dfrac{\Delta f}{\Delta P} \times 100 = \dfrac{(f_{NL} - f_{FL})}{1.0} \times 100\%$

where f_{NL} and f_{FL} are no load and full load frequencies.

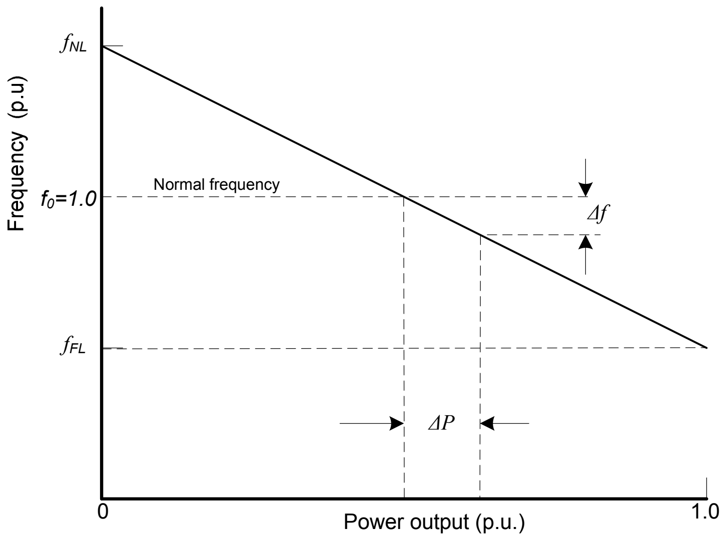


Fig. 3.3. Droop characteristics of a governor [71]

A single busbar model of a power system used by Bopp [77] is shown in Fig. 3.4. This model includes the block diagram given in Fig. 3.2, a typical governor block, turbine blocks and a block representing the droop.

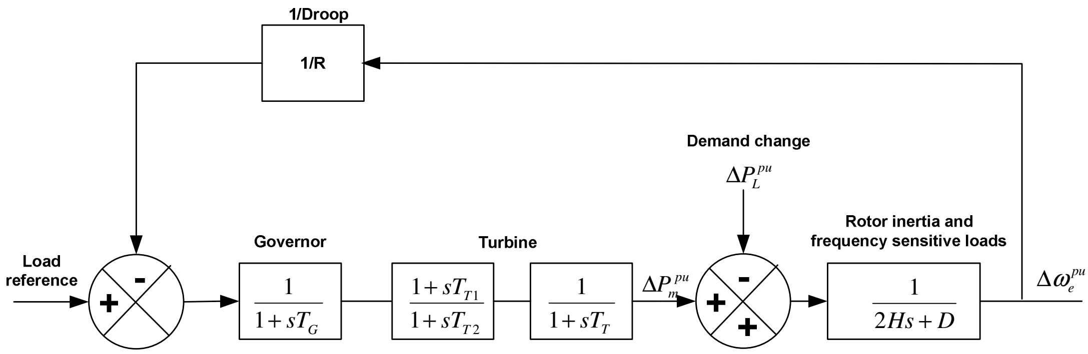


Fig. 3.4. Block diagram of generator-turbine unit with droop control [77]

The operation of a power system after a demand change is explained using this single busbar model. When the system demand (P_L) is not in balance with the generation, the system frequency deviates from its normal (f_0). After a sudden increase of load or loss of generation, the initial rate of change of frequency is determined by the inertia (H) of the generators of the power system.

When the system frequency changes the governors of the prime movers of large generating units can change their power output following the droop characteristics (R)

(operating point movement 1 in Fig. 3.5). However, the governors usually operate in a mode where they are insensitive to frequency (limited frequency sensitive mode [78]). The system control centre instructs a subset of generators in a power system to follow the droop characteristic. The action of generators running in frequency sensitive mode which stabilise the frequency drop is called primary frequency control.

Since the generators change their output following their droop characteristics, the frequency will be stabilised at a frequency other than the normal frequency. Therefore the system operator instructs a set of generators to increase or decrease their droop set-points (set-point change 2 in Fig. 3.5) so that the frequency is brought back to normal. This control action is called secondary frequency control or load-frequency control (LFC).

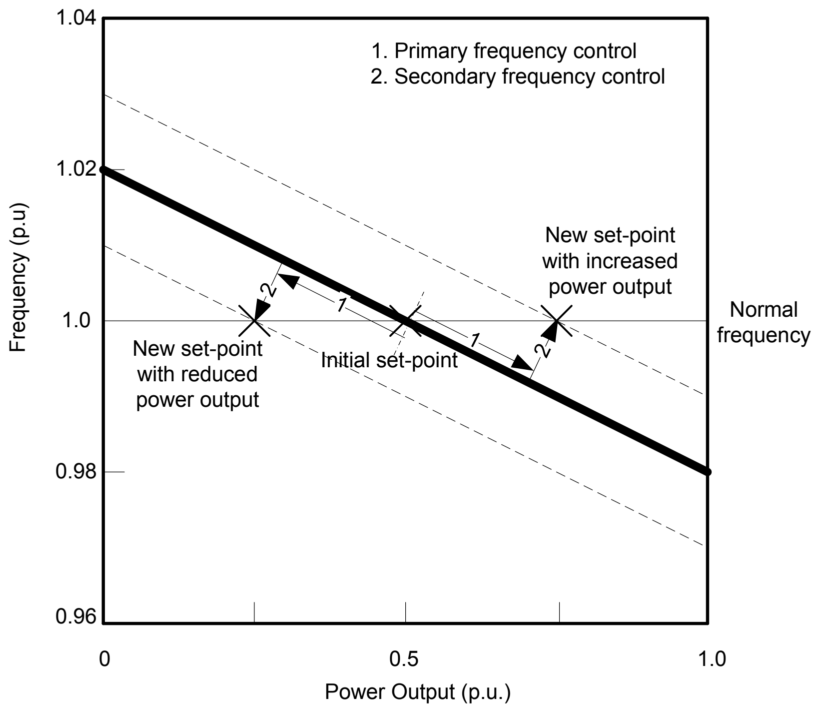


Fig. 3.5. Change of operating point due to primary and secondary frequency control (A modified figure given by Weedy [79])

3.1.3 Frequency response services of the Great Britain

The steady state system frequency limits of the Great Britain (GB) power system are 50 ± 0.5 Hz [80]. However, during normal operation, the GB transmission system operator (NGET: National Grid Electricity Transmission plc) maintains the frequency at 50± 0.2 Hz. For a maximum 1320 MW loss of generation, the drop in frequency is limited to 49.2 Hz and it is restored to 49.5 Hz within 1 minute.

In order to maintain frequency, NGET uses frequency response services. When the frequency goes high, *high frequency response* is used to reduce the frequency. A sudden drop in frequency is contained using *primary response* (Fig. 3.6). This should be delivered within ten seconds and maintained for another twenty seconds [81]. The system frequency is brought back to normal using *secondary response* which last 30 seconds to 30 minutes. If the frequency continues to drop below 48.8 Hz, demand is disconnected (load shedding) to prevent shutdown of the power system [82].

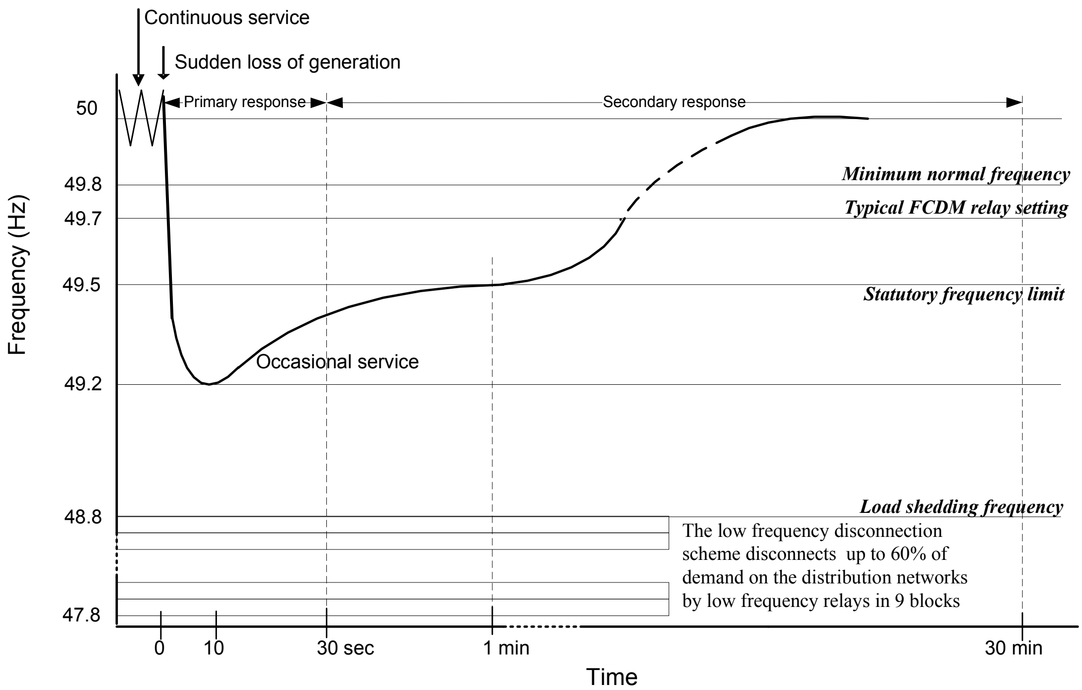


Fig. 3.6. Frequency response services used to limit frequency drops in the GB system [81] [82]

Frequency response services are procured through bi-lateral contracts [83]. *Mandatory Frequency Response* is a mandatory service that all the large generators (greater than 100 MW) should be capable of delivering. These generators operate on droop control (usually 3-5% droop). High frequency response is provided by reducing generators' output. Primary and secondary responses are provided from partially loaded generators increasing their output. For those generators which were called upon to provide mandatory frequency response, NGET paid £80 million in 2010 as holding payment and £2.6 million for the response delivered [84].

Firm Frequency Response (FFR) and *Frequency Control Demand Management* (FCDM) are frequency response services which are procured through tenders. In FFR, the generators and large loads having capacity more than 10 MW change their power output or input within 30 seconds in response to the change in frequency and maintain the change for 10 minutes [85]. In FCDM, loads (greater than 3 MW) reduce their demand, within 2 seconds of detecting a frequency drop and maintain the load at reduced level for 30 minutes, using frequency sensitive relays normally set at 49.7 Hz [86]. NGET currently procures about 500 MW of FFR and FCDM and paid a total £55 million in 2010 [84].

After obtaining frequency response within a short time (2 s and 30 s), reserve services are used to bring the frequency back to normal. *Fast Reserve* (FR) is a reserve service which is called upon immediately after frequency response services. Large generators and loads having capacity more than 50 MW that can change their output or input at 25 MW/minute provide this service [87]. These generators and loads must respond within 2 minutes of instruction by the transmission network operator. At present, about 180 MW of FR is kept ready in the GB system. About £46 million was spent during 2010 to procure FR through contracts [84].

In the future, a de-carbonised GB electrical power system will have new large generators and it will also receive more energy from renewable sources, particularly wind power. Therefore it needs to be ready to accept higher sudden loss of generation (presently up to a new maximum of 1800 MW) [88] and hence more primary response will be required. The estimated cost of the increase is £160 million per year [89].

The use of controllable demand reduces the requirement for primary response from generators that are maintained partially loaded and hence reduces system operating cost and CO_2 emissions. The reduction in cost and CO_2 emissions would make a business case to procure frequency response from demand control by providing financial incentives to consumers. For example, when 30 GW of wind power and large nuclear plants are added to the power system, the market value of frequency response that would be provided by all refrigerators in the UK is estimated to be £222 million per year and the cost of CO_2 reduction is £28 million per year [90].

3.1.4 Frequency response using controllable loads

Providing frequency response by demand reduction based on local frequency measurements was discussed by Schweppe [42] as early as in 1980. This patented idea was for an automatic frequency responsive switch to control loads (e.g. a smelter for industrial load or a water heater for a domestic load). A measureable parameter (e.g. the inside temperature of a smelter or a water heater) and the system frequency were used to decide when to switch the loads on or off. For example, if the temperature of a smelter was within its maximum and minimum limits and the frequency was low, it was switched off at a lower temperature than its maximum. Likewise, when the frequency was high it was switched on at a higher temperature than its minimum. The result was linear variation of the smelter temperature set point with the system frequency.

A simulation study that varied the switching temperatures of fridges linearly with the system frequency was undertaken by Short [91]. As shown in Fig. 3.7, when the frequency was lower (or higher) than normal, fridges switched off (or on) at a higher (or lower) temperature than the switching temperatures for normal operation. The results showed that, for a sudden generation loss of 1320 MW, the frequency drop can be reduced by about 0.4 Hz when there is control of fridges. In the simulation, forty million fridges were switched off to provide 1320 MW of frequency response.

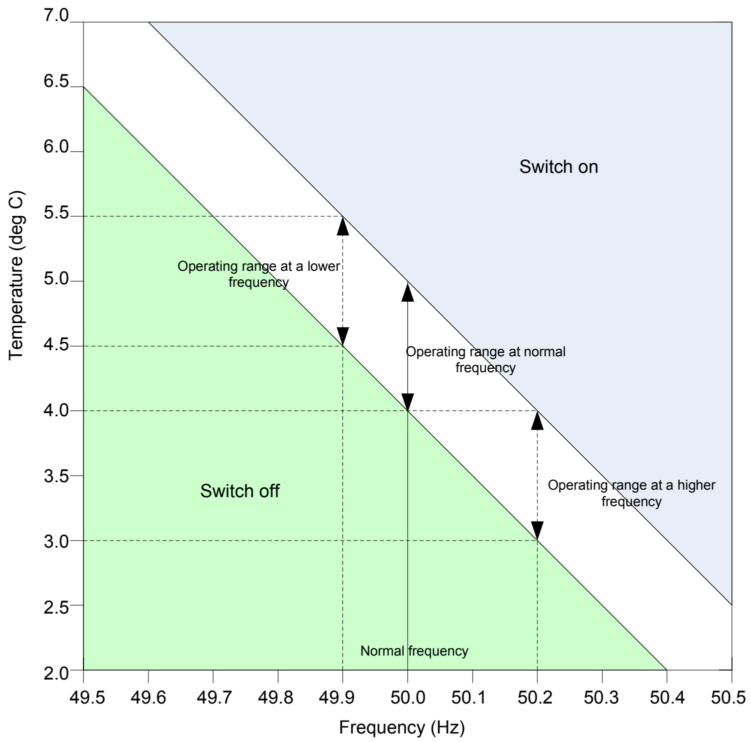


Fig. 3.7. Switching temperatures of a fridge at different frequencies used in simulations undertaken by Short [91]

The controller patented by Hirst [92] used two high/low limits of frequency and two high/low limits of a measureable parameter (e.g. the temperature in a fridge) to decide when to switch on or off loads. The two limits provided a hysteresis band to prevent unwanted rapid switching that could occur when only one limit was used.

A load control method that sheds loads over a period of time based on the system frequency sampling interval is reported by Black [93]. This reference notes that when the system frequency at which the loads are switched off was pre-defined, all loads would shed at the same time resulting in large discontinuities in demand. To prevent switching off all the loads at the same time, a sampling interval was set considering the number of devices that should be switched off within the sampling interval. The devices sampled the system frequency at the same rate, but at different times in relation to each other – spread uniformly across the pre-defined sampling interval. Hence, the time at which each load was switched off was also uniformly distributed over the interval. A long (short) sample interval reduced (increased) the number of loads switched off within the sampling interval.

The use of a probabilistic function between a measured parameter (e.g. temperature of a smelter) and the frequency to avoid switching off many loads at the same time was stated by Brokish [94]. The probabilistic function was designed such that, for a given temperature, when the frequency drop was high, then the probability of switching off loads was high. When the drop was low, the probability of switching off was low. Because of this probabilistic function, when the frequency and the temperature reached the switching levels, all loads were not switched on or off at the same time.

Schweppe [42] discusses three possible locations of a load controller (in this instance, a frequency responsive switch). In the first case, each appliance had a controller with control logic, power supply unit, an actuator to switch/control power and sensors to measure the frequency/measurable parameters. In the second case, the appliance controllers shared a power supply unit and a frequency sensor. In the third case, a single controller was used to detect changes in system frequency and control a number of appliances.

Controllers that can be fitted into appliances are commercially available. The RLtec™ controller [95] can be fitted to fridges. This controller continuously monitors the frequency and changes the operating time of compressor based on the frequency. The response time of the RLtec™ controller was less than 2 seconds. The GridFriendly™ controller [96] [97] can be fitted into dryers, refrigerators, water and space heaters, air conditioners and coffee makers. When the frequency drops, the load is switched off. After the frequency has recovered, the load is switched on. In a demonstration reported by Hammerstrom [96], when the frequency dropped below 59.95 Hz, the GridFriendly™ controller switched off appliances within ¼ second. 16 seconds after the frequency recovered above 59.96 Hz, the appliances were switched on. Considering the operating times, the load controllers fitted inside appliances are suitable to provide primary response.

Schweppe [42] discusses the possibility of using prices sent by a utility to consumers at very short intervals (spot pricing, e.g. 5 min) to obtain frequency response. Berger [98] presents a method of providing primary response using spot prices that were calculated, by an automatic load controller situated in premises, as a function of the system frequency. Because the system frequency was measured locally, the price calculations were quick (order of seconds). The automatic controllers reacted to the calculated spot prices and varied the demand to provide primary response.

A load controller that can provide primary response using local frequency measurements is reported by Molina-García [99]. Fridge and freezers, HVAC (heating, ventilation and air conditioning) equipment, and water heaters were the three controllable load groups. These load groups were switched off at different frequencies based on the frequency drop (between 0.03 Hz - 0.2 Hz) and the time elapsed from the drop (0 - 40 s). When the drop was high, the loads were switched off after a short elapse time whereas when the drop was low, the loads were switched off after a long elapse time. They were switched on after a pre-defined time. A random delay (0.5 - 2.5 s) avoided switching off and on all loads at the same time. Because of the narrow operating frequency range between 0.03 to 0.2 Hz, this load controller would be suitable for continuous service (Fig. 3.6) where frequency is maintained above 49.8 Hz at all times.

3.1.5 Frequency response using Direct Load Control

Demonstrations and at least one implementation of Direct Load Control (DLC) to provide frequency response can be found in the USA. In the USA, primary response (called frequency-responsive reserve) should be delivered within 10 seconds after a frequency drop. Secondary response is delivered by 10-minute spinning reserve and 10-minute non-synchronised reserve [100][101].

A demonstration reported by Eto [102] used DLC to control air conditioners. In this demonstration, control signals from a central controller were sent through radio signals to a radio controlled switch installed at the air conditioners. The response time of the air-conditioners in this demonstration was 20 seconds. To verify the response, load measurements were obtained from a number of customer sites, in real-time (within 4-10 seconds), using current transducers fixed in the radio controlled switches.

In the USA, DLC has been used by one demand response Aggregator to provide frequency response services [103]. The Aggregator continuously reads the requests to provide frequency response sent by the transmission network operator. When a request is received, the Aggregator sends DLC commands to control loads. Usually the Aggregator takes 2-5 minutes, after receipt of the system operator's request, to control the loads using DLC. Smart meter measurements, sent every minute, are used to verify the load reduction. At the end of the frequency event, the Aggregator sends commands to restore the loads.

A controller installed in a customer's premises in California was successfully tested by Lawrence Berkeley National Laboratory [104] to provide secondary response using DLC. This controller was developed initially for an automatic demand response system for reducing peak demand based on price information [105]. In the system that was tested, the system operator sent DLC signals to this controller through a communication network. The controllers had predefined load control actions able to be customised by the customers. Upon receipt of the control signal, these predefined actions were carried out by the controller.

3.2 Smart meters for frequency response

3.2.1 Smart meter functions required for frequency response

The European Smart Meter Alliance has identified [106] system frequency control as a possible function of smart metering systems. It was noted that smart meters may include DLC functions with outputs that can control appliances (e.g. auxiliary switches) and functionality to measure frequency locally to enable frequency response.

The functional requirements catalogue of the UK [22] indicates that the smart metering system will have the functionality for DLC. The DLC commands will be sent by remote authorised parties to smart meters through the WAN and then smart meters will send DLC commands to loads through the HAN.

The initial draft of the UK smart meter functional requirements, had frequency measurement as one of the functions [61]. Frequency was to be measured at half hourly intervals. However, this function was removed following the responses to the consultation [22]. The initial consultation noted that frequency measurement functionality was included for power quality measurements after considering work commissioned by the Energy Network Association (ENA). Further, the ENA smart metering system requirements update [107] specified that smart meters will be able to control appliances remotely to provide frequency response.

Smart meters that can measure frequency are available commercially. The Echelon™ ANSI IP smart meter [108] can record frequency measurements at a minimum interval of only 5 minutes and hence it is not suitable for primary response. The Elite™ smart meter [109] of Secure Meters Ltd. used in the study reported in this thesis can read and display frequency approximately at a rate of one second and the values can be read on-demand through a serial port.

3.2.2 Use of direct load control to provide primary response

Although DLC commands can be used to control appliances remotely to obtain frequency response, in the examples described in Section 3.1.5, DLC commands were not sent through smart meters. Instead, the commands were sent directly to a controller installed inside or outside appliances. Smart meters were used only to verify the load reduction after demand response. However, examples can be found in the literature where commercial demand response Aggregators use smart meters as communication gateways to send DLC commands to appliances to reduce the power system peak [48].

The smart meter communication network in the UK will not be dedicated to demand response. It will be used to send smart meter measurements, alarms and control commands between smart meters and suppliers, network operators and other authorised parties [110]. The fastest response time of communication messages used for DLC, specified in the WAN requirements for the DCC [111], is 30 seconds and some messages can take as long as 600 seconds to arrive.

To obtain sufficient primary response from domestic appliances, a very large number of appliances need to be switched off within ten seconds. A large number of appliances can be controlled by a single DLC command if broadcasting is used. The

WAN requirements for the DCC [111] specify that the WAN should be able to send DLC commands to 5% of appliances within 30 seconds. It was estimated in the Department of Energy and Climate Change (DECC) publication on dynamic demand [90] that, to obtain 700-1000 MW of frequency response services, forty million frequency responsive refrigerators would be required in the UK. Therefore, at the rate specified in the WAN requirements for the DCC [111], only 50 MW of demand response can be obtained within 30 seconds. At this rate, about 16 MW of primary response can be obtained because the loads contributing to primary response should reduce their load within 10 seconds.

In the UK, the frequency response service that provides primary response using load control (Frequency Control Demand Management (FCDM) described in Section 3.1.3) does not use DLC. Instead FCDM uses under-frequency load shedding relays which use local frequency measurement to decide when to switch off a cluster of loads. The IEEE Communication Delivery Time Performance Standard 1646 [112] specifies the maximum communication time delay, between an under-frequency relay and a breaker used for under-frequency load shedding, as 10 ms. With many data routing devices in the communication path of a smart metering communication system [113], it is unlikely that DLC commands sent by the network operator would reach smart meters within 10 ms to provide primary response.

Considering the expected broadcasting rate, the communication and processing delays and the way that communication infrastructure will be organised, DLC is unlikely to be able to provide primary response through the UK smart metering system. Therefore, instead of using DLC, the possibility of controlling appliances locally, by using frequency measurements obtained from a smart meter, was investigated in this thesis.

3.3 Domestic controllers for controlling appliances

Smart meters need a controller built into them if they are to decide when to switch off loads using a local frequency measurement. The UK functional requirements catalogue [22] does not mention a controller built into meters to facilitate load control locally. However, the draft specifications [114] of the Smart Metering Design Group (SMDG) commissioned by the UK government noted that the UK smart metering system will support meter variants with internal load control functions.

The smart metering layout given in the SMCG final report [24] has a Home Automation module for controlling loads (shown in Fig. 2.2). The draft specifications [114] of the SMDG noted that the UK smart metering system will support load control using a separate load controller. The load controllers considered by SMCG and SMDG will communicate with a smart meter through the HAN. However, the UK smart meter design requirements [61] do not mention a domestic load controller.

Development of a domestic controller for a Home Energy Management System (HEMS), implemented in twenty houses in Japan, is reported by Kushiro [115]. In this HEMS each house had a domestic controller which communicated with smart appliances through the HAN. The communication protocols were standardised to share information of all domestic appliances, sensors, security and health care equipment used in the HAN. Each smart meter and domestic controller were connected to a central controller through the Internet. The central controller collected energy data from the smart meters and sent energy consumption information, weather information and energy saving advice to display on the domestic controllers. The display unit of each domestic controller allowed users to set control settings of the appliances. Programs in the domestic controller decided the optimum operation of air conditioners and lights using the user settings, weather information and the occupancy/illumination sensor data. Based on the optimum operation, the controller then sent control commands to appliances.

3.4 Controllable domestic appliances

The Smart-A project [116] supported by the European Commission evaluated the potential of using domestic appliances for demand response in electricity networks. This project considered the following ten appliances in its study;

- refrigerators and freezers,
- dishwashers,

- washing machines and tumble dryers,
- ovens and stoves,
- air conditioners,
- circulation pumps for heating systems,
- electric storage heaters and water heating.

In this project, two types of load shifting methods were discussed. In the first method, the starting of an appliance was delayed by using the start time delay function or by specifying a time when the operating cycle should be completed. In the second method, an appliance cycle was interrupted for a limited period of time (maximum of 15 to 30 minutes).

Smart appliances with functions supporting demand response are being developed by appliance manufacturers. A white paper of the Association of Home Appliance Manufacturers [117] notes that smart appliances may have functions such as;

- capability to adjust the load as a response to Time of Use (TOU) tariffs,
- respond to commands sent by energy suppliers by shifting the usage or shedding or reducing load based on pre-defined user guidelines,
- adjust its operation to response emergency situations of electricity network,
- to be able to control through HEMS through the HAN.

As an example, General Electric Consumer and Industrial Company (GE) has developed smart appliances for demonstration projects [118]. Refrigerators, cookers, microwave ovens, washing machines and dish washers have demand response functions given in Table 3.2.

TABLE 3.2. DEMAND RESPONSE FUNCTIONS OF SMART APPLIANCES DEVELOPED BY GE FOR DEMONSTRATION PROJECTS [118]

Appliance	Demand response functions
Refrigerator	Delayed defrost Modification of run time during the power system peak Energy saving by changing temperature
Washing machine Dish washer	Delayed wash and dry Modify cycle time Energy saving washing cycles
Cooker	Cooking with reduced power
Water heater	Reduced power during the power system peak

In a pilot program conducted by Louisville Gas & Electric Company, USA [119], the GE appliances in each house received a signal from the supplier, through the smart meter, which alerted the appliances when peak prices were in effect. The appliances were pre-programmed to avoid or reduce energy use during the system peak time (if it is not overridden by the user).

3.5 Discussion

Smart meters are being installed around the world primarily for providing accurate and timely energy consumption information to consumers. It is anticipated that this information will help to reduce power system average demand as well as peak demand. Some smart metering systems, such as that planned for the UK, will be able to control loads remotely to reduce the power system demand in emergencies. The functions required for demand reduction; i.e. receiving price information and a DLC function will be built into smart meters. Price information would allow consumers to reduce demand voluntarily and DLC commands will carry out load control automatically.

Although it is anticipated that smart meters will support control of electricity network frequency and voltage, the requirements of smart meters for these controls are yet to be established. Therefore, in this study, the use of smart meter functions for frequency control and distribution network voltage control was investigated.

3.5.1 Use of smart meters for frequency control

After a sudden loss of generation, primary and secondary frequency response services are called upon to maintain frequency within limits. Although significant loss of generation is a rare event, the Great Britain (GB) transmission network operator spends a substantial amount of money as holding payments to be ready for a loss of generation of 1320 MW. The de-carbonised GB power system should be ready for a loss of 1800 MW and the cost of procuring frequency response services would increase significantly.

Frequency response can be obtained by controlling loads thus reducing operating cost and CO_2 emissions. At present only large loads provide frequency response services. It has been estimated that domestic appliances have a potential to provide frequency response (discussed in Section 3.1.3).

Smart meter interest groups have identified that smart meters could support frequency response using DLC. Considering the time taken to send a DLC command to appliances, providing primary response using DLC may be optimistic. As discussed in Section 3.1.4, research papers report the possibility of using spot prices for providing primary response. These spot prices were not sent through communication network, but calculated by a load controller using local frequency measurements.

3.5.2 Controlling loads locally to provide primary response

Primary response can be obtained by controlling loads using local frequency measurements. Appliances fitted with load controllers, that use local frequency measurements to provide frequency response, are commercially available.

Although frequency measurement was removed from the UK smart meter functional specifications, the European smart metering interest groups expect that smart meters will have this function. Some commercially available smart meters have a frequency measuring function and some meters can send frequency and energy measurements through the HAN.

Research conducted on providing primary response using smart meters was not found in the literature review. In the study described in this thesis, the use of smart meters to provide primary response by controlling domestic appliances was investigated (discussed in Chapter 4, 5 and 6).

3.5.3 Smart meter measurements for distribution network state estimation

Voltage and energy measurements obtained from smart meters can be used to visualise the status of distribution networks in SCADA and DMS. Smart meter energy measurements taken for billing can be used as pseudo measurements for state estimators and to improve load models that are used for network control. In some smart meter implementations, real-time voltage measurements are obtained by sending on-demand meter reading requests to a selected set of smart meters. In the literature, it was shown by simulations, that real-time or near real-time smart meter measurements can improve the accuracy of state estimation.

However, in present-day smart metering system implementations, the measurements are not transmitted in real-time, but they are transmitted at most once a day. Therefore, the possibility of using these measurements for state estimation was investigated and reported in Chapter 7.

4 Primary response from a load control scheme

4.1 Introduction

Primary response can be provided by controlling domestic appliances using controllers fitted into them (discussed in Section 3.1.4). These individual controllers act independently and hence coordination and optimisation of their switching operations is difficult. In contrast, a single controller, which controls all appliances in a house, can coordinate and optimise load control by using information from the energy supplier, smart meter and sensors installed in the house (discussed in Section 3.3).

In the UK, the smart meter specifications published in the DECC consultations do not mention a load controller built into a smart meter or a domestic load controller. However, a domestic load controller that communicates with the smart meter through the HAN is discussed in the specifications given by SMCG and SMDG (discussed in Section 3.3).

In the study described in this chapter, a load control scheme, with a domestic load controller, was developed. The ability of the load control scheme to control domestic loads to provide primary response was investigated. The scheme used local frequency measurements obtained through a smart meter. A laboratory experimental rig was developed using commercially available components to test and demonstrate the load control scheme for a single house [120][121].

The amount of load to be controlled to limit the frequency drop of the Great Britain system to a set of minimum allowable frequencies was found using computer simulations. Operating speeds and the limitations of the components of the load controller in providing primary response are discussed.

It is assumed that the control of the smart appliances (discussed in Section 3.4) will be able to stop the appliances operation at a suitable stage of its operating cycle and then allow it to continue, upon receipt of remote signals sent by the load controller. In order to ensure the effectiveness of the load control scheme, it is assumed that suitable financial incentives will be introduced to consumers so that they will accept the switching off of the required amount of controllable loads.

4.2 Experimental domestic load control scheme

4.2.1 Load control scheme

The experimental load control scheme shown in Fig. 4.1 was developed using commercially available components [121]. The final assembly is shown in Fig. 4.2. The scheme comprised a smart meter, a smart load controller and smart sockets which communicated through a Home Area Network (HAN). The smart meter measured the power system frequency and stored the measurement in its internal register. The smart load controller, which was implemented in a PC (a laptop with IntelTM Core 2 Duo T7250 2 GHz processor), read the frequency. Based on the frequency, an algorithm, which ran in the computer, decided when to switch off and switch on different loads. The smart load controller then sent control signals over the HAN to smart sockets that were fitted into existing wall sockets. Upon receipt of a load control signal, the smart socket switched the appliance that was plugged into the socket. In this experiment the appliances were represented by lamp loads. A frequency convertor was used to vary the frequency of the power supply to mimic the frequency variations of the power system. A step frequency drop (50 – 48.8 Hz) was created by the convertor to simulate a sudden drop in the frequency of the power system. A digital power meter was used to record the load changes that followed the frequency drop. The same control signal given to the frequency convertor was used to trigger the recording of the power meter.

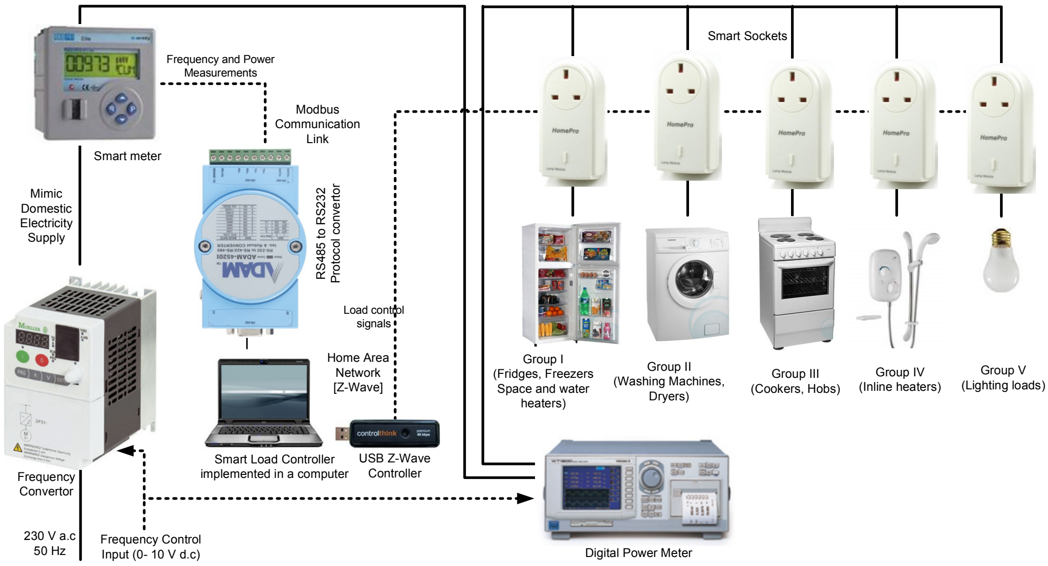


Fig. 4.1. Layout of the components of the experimental load control scheme (The appliances were represented by lamp loads)

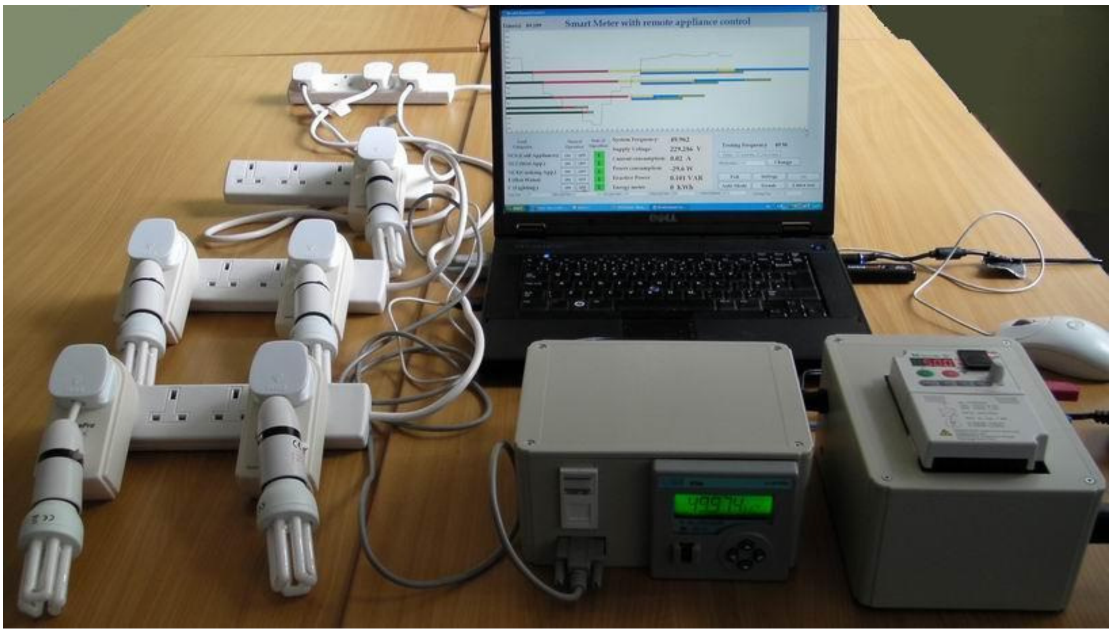


Fig. 4.2. The assembly of components of the experimental load control scheme

4.2.2 Implementation of the controller

The load controller, implemented in a PC, consisted of software modules (Fig. 4.3) for the load control algorithm, communication libraries and Human Machine Interface (HMI). The controller continuously ran the software modules in a loop reading the smart meter, running the algorithm and updating the HMI.

The algorithm called functions in the communication libraries to transfer data between the algorithm and smart meter or smart sockets through the ports of the computer. The communication libraries encode (or decode) the data so that the data could be sent (or received) using communication protocols of the smart meter and smart sockets. The HMI displayed the frequency and the states of the algorithm as graphs.

Commercially available software libraries were used in the implementation. The load control algorithm and HMI were developed using MS Visual Basic™ software [122].

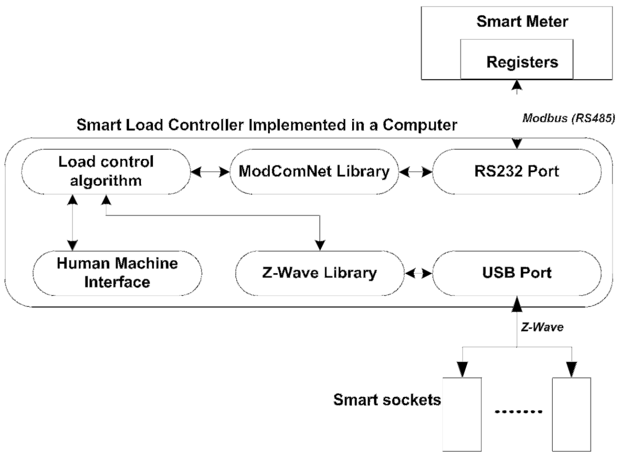


Fig. 4.3. Software modules and hardware of the control scheme

The frequency and power measurements of the smart meter were read by the algorithm, via a RS 485 to RS 232 protocol-converter, using Modbus protocol. The algorithm used the Consolitech ModComNet™ software library [123] to read the registers of the smart meter.

In the implementation of the HAN, the smart sockets communicated with the Z-Wave controller using the Z-Wave protocol. The controller was connected to the computer through a USB port. ControlThink™ Z-Wave software library [124] was used by the algorithm to send control signals to the smart sockets.

4.3 Primary frequency response from domestic load control scheme

4.3.1 Appliances controlled by the load control algorithm

The load control algorithm was used to control lamp loads which represented domestic appliances such as fridges, freezers, heaters, washers, dryers, hobs, ovens, in-line heaters and lighting.

As shown in Table 4.1, the appliances were grouped considering their characteristics. Load Group I was thermostatically controlled devices, such as fridges and space heaters which have induction motors or heaters. Load Group II was domestic wet-appliances with induction motors and heaters. Load Group III and IV were the appliances with resistive heating elements. Load Group V was lighting loads.

The load types of Load Groups III-V are insensitive to a drop in system frequency while the induction motors of Load Groups I and II would show some natural reduction in load with the drop in frequency.

Pearmine [125] reported that the load-frequency sensitivity of the Great Britain power system is 2% MW/Hz. The amount of controllable load considered in this study was 200 – 1000 MW. The reduction of the load of appliances due to frequency drop to 49.2 Hz (minimum allowable frequency) would therefore be a maximum of 16 MW and hence the load reduction with frequency was neglected in this study. Similarly any natural reduction in load with depressed system voltage was ignored.

When the system frequency fell, the algorithm switched off the loads at different frequencies. Then it switched on the loads when a predefined time had passed or the frequency had recovered. A random time delay was applied to the switching on of each Load Group in a house. As the load controller in each house decided this random time independently, the reconnection times of each Load Group across the distribution system was random thus avoiding an abrupt demand increase.

All loads were switched off and some Load Groups were reconnected during the primary response period (0-30 s) when Load Frequency Control (LFC) of generators does not operate. The reconnection of some Load Groups was carried out during the secondary response period when LFC would be operating. Because LFC is a slow process, the output of the generators would respond to the reconnection of the loads in a similar way to any sudden load change. The algorithm waited until the system frequency was restored to normal before responding to any further frequency drops. Therefore it is not anticipated that the load control scheme would cause adverse interactions with LFC.

The frequencies at which a Load Group was switched and the times they were disconnected are given in Table 4.1. These times were chosen based on the degree of disturbance that would be caused to the consumer. The maximum switch off time (in Table 4.1) determines the disturbance to the consumers. The switching off of fridges and heaters (maximum off time 5 min) and hobs/ovens (maximum off time 2 min) is unlikely to be noticed due to their thermal storage. As washers and dryers take a considerable time to complete their normal operation, the small increase of the operating time (maximum 3.5 min) is unlikely to be significant. In-line heaters and lighting loads were switched off only for a very short time period (maximum 15 s and 4 s respectively) just above 48.8 Hz; the frequency at which the network operator would initiate wide-spread load shedding to avert the collapse of the power system.

TABLE 4.1. THE FREQUENCIES AND TIME PERIODS OF THE LOAD CONTROL SCHEME

Load Group	Appliances	F_{OFF} (Hz)	F_{ON} (Hz)	T_{OFF} (s)	T_M (s)	T_D (s)	T_R (s)	Maximum off time $T_{OFF}+T_M+T_D+T_R$
I	Electric space and water heaters, Fridges and freezers	49.7	49.8	30	150	90	30	5 min
II	Dish washers, Clothes washers, Tumble dryers	49.5	49.7	30	90	60	30	3.5 min
III	Hobs and ovens	49.3	49.5	30	30	30	30	2 min
IV	Electrical in-line heaters	49.0	NA	10	NA	NA	5	15 s
V	Lighting loads	48.9	NA	2	NA	NA	2	4 s

For all Load Groups $F_{NOMINAL}$=50Hz

4.3.2 Load control algorithm

The algorithm is explained using the state diagram shown in Fig. 4.4. When the system frequency is normal, the loads remained in state 1 continuously checking the frequency. When the frequency dropped below *Switching Off Frequency* (F_{OFF}) of a particular Load Group in Table 4.1, the algorithm moved to state 2 and sent control signals to all loads in that Load Group to switch them off. In state 2, the algorithm kept the loads switched off for *Load Switch Off Period* (T_{OFF}). Then in-line heaters moved to state 5, lighting loads moved to state 6 whereas other loads moved to state 3.

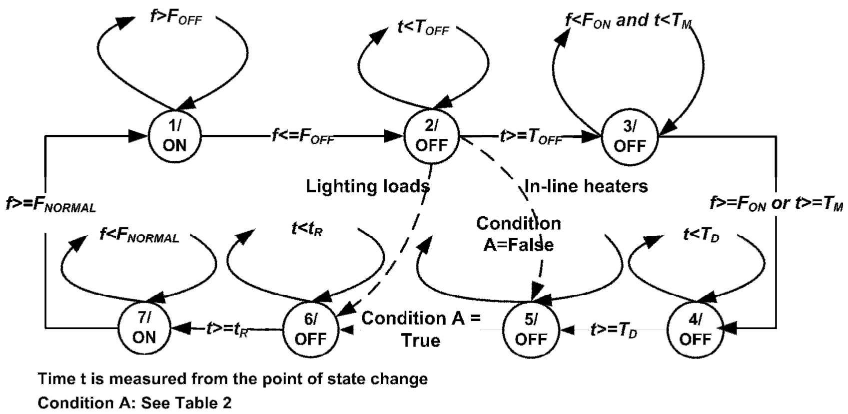


Fig. 4.4. The state diagram of a Load Group

In state 3, the frequency was monitored for *Frequency Monitoring Period* (T_M) to check whether it had recovered up to *Switching On Frequency* (F_{ON}). If the frequency had recovered during T_M, the algorithm moved to state 4 without waiting to complete T_M. The algorithm waited in state 4 for; *Delay Period* (T_D) - a period which avoided switching on loads immediately after the frequency recovery. Then it moved to state 5.

In the implementation of the algorithm in the controller, all state transitions of lighting loads were independent and other Load Groups had independent state transitions up to state 5. Therefore the state transition of one Load Group was in advance of or trailed the transitions of other Load Groups. In state 5, the algorithm checks condition A (see Table 4.2). If condition A was true it moved to state 6; otherwise it remained in state 5.

TABLE 4.2. THE CONDITION A OF DIFFERENT LOADS GROUPS

Load Group	Appliances	Condition A was true if
I	Electric space and water heaters, Fridges and freezers	All the loads in Load Groups II, III, IV and V were switched on
II	Dish washers, Clothes washers and Tumble dryers	All the loads in Load Groups III, IV and V were switched on
III	Hobs and ovens	All the loads in Load Groups IV and V were switched on
IV	Electrical in-line heaters	All the loads in Load Group V were switched on

In state 6, the algorithm generated a uniformly distributed random number t_R ($0 \leq t_R \leq T_R$) and waited for t_R time before moving to state 7. When moving to state 7, the algorithm sent control signals to reconnect all the loads of a Load Group. After reconnecting the loads, the algorithm waited (in state 7) until the system frequency was restored to F_{NORMAL}. This waiting in state 7 prevented retriggering the algorithm due to the frequency fluctuations that might occur in the power system.

4.3.3 Simulation of an example frequency event

The HMI screen shown in Fig. 4.5 was obtained by gradually reducing the output frequency of the converter (by changing the Frequency Control Input signal in Fig. 4.1 using a potentiometer) and then increasing it to 50 Hz. The change of frequency was plotted as a solid line.

When frequency dropped below F_{OFF} of each Load Group (in Table 4.1), the algorithm started the state transitions (moving from state 1 to 2 as described in Section 4.3.2). The states of each Load Group were drawn as a horizontal bar chart (heaters and fridges to lighting loads are from top to bottom). The different colours in each bar show different states (see the legend).

In this example, as the frequency was increased to 50 Hz before the end of monitoring period (T_M) of the first three Load Groups (heaters and fridges, washers and dryers and hobs and ovens), the algorithm moved out from state 3 without waiting to complete T_M. The additional horizontal bars appeared just below the first three bars to show the remaining operating times due to the frequency recovery.

The short vertical lines within the T_R times show the actual switching on instance based on the randomly generated switching on time (t_R).

The instantaneous, minimum, average, and maximum loop times taken by the software modules (the controller ran the modules in a loop) were measured by the software internally and displayed on the HMI (circled in Fig. 4.5). The time taken to read the meter and switch off a Load Group are also displayed.

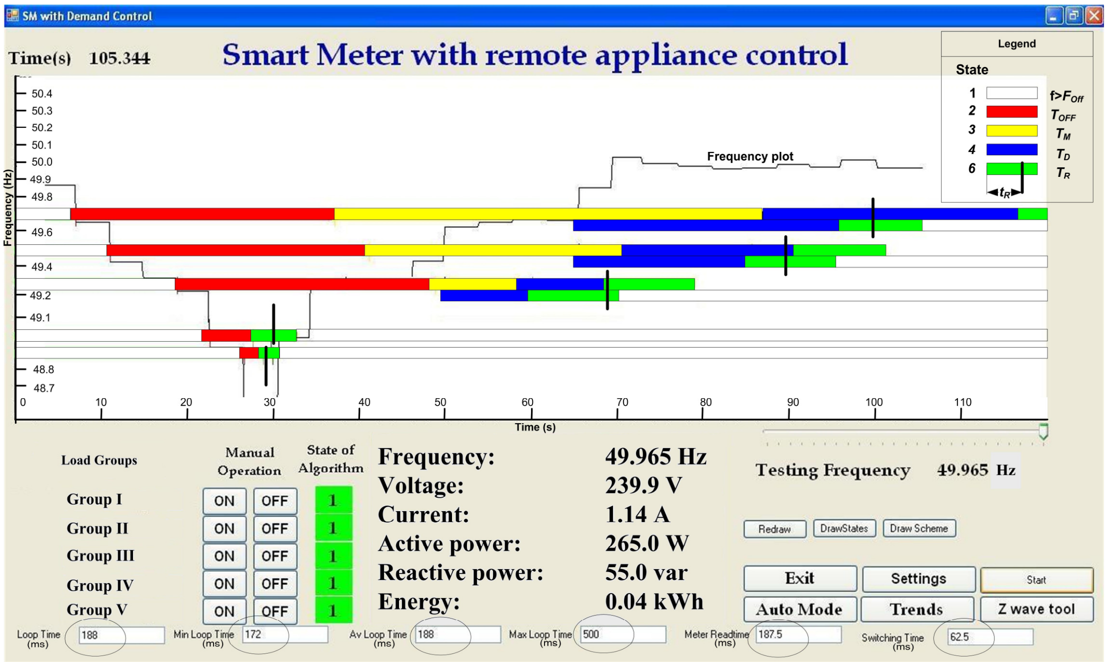


Fig. 4.5. Human Machine Interface

4.3.4 Operating times of the experimental rig

The total operating time of the experimental rig was made up of the operating times of the frequency convertor (t_1) and four different elements of the load control scheme (t_2 to t_5) as shown in Fig. 4.6 and Fig. 4.7. The total operating time (t_1+t_2+t_3+t_4+t_5) of the experiment rig was obtained by giving a step input to the frequency convertor (by changing the Frequency Control Input in Fig. 4.1 using a switch). The same step input was used to trigger the power meter (in Fig. 4.1). The output plots (e.g. in Fig. 4.8) of the power meter showed the total time taken to switch off all the Load Groups varied between 3.3 s and 4.6 s. The time taken to switch off the last 4 Load Groups (time measured from the trailing edge which shows switching off of the first Load Group) was 250 ms and hence the time taken to switch off one Load Group was 62.5 ms.

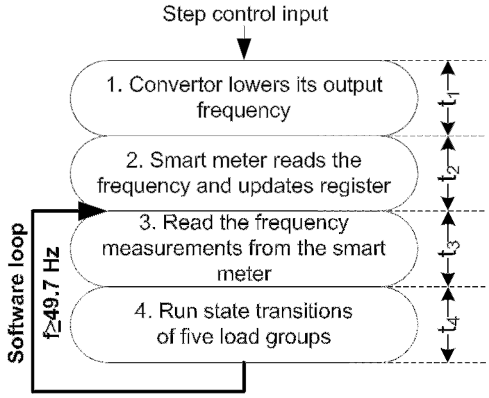


Fig. 4.6. Operating times of the components of the experimental rig when the frequency ≥ 49.7 Hz

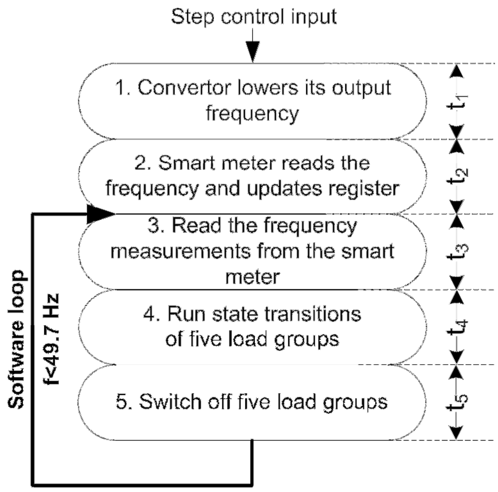


Fig. 4.7. Operating times of the components of the experimental rig when the frequency < 49.7 Hz

The operating time of the frequency convertor (t_1 = 100 ms) was obtained by measuring the time taken to drop the frequency to 48.8 Hz when a step control input was applied (see Fig. 4.9).

When the frequency was above 49.7 Hz, the load control software continuously looped through steps 3 to 4 (Fig. 4.6). When the frequency dropped, the load control software looped through step 5 (Fig. 4.7) to switch off loads. The load control software continuously measured the time to complete every software loop and calculated the average loop time and the maximum loop time. These values were displayed on the HMI (Fig. 4.5). Because the software spent most of the time going through steps 3 and 4 without switching off loads, the average loop time was t_3+t_4. The maximum loop time gave $t_3+t_4+t_5$ when the software went through step 5 to switched off loads

The time measurements obtained from the experimental rig and the times displayed on the HMI are summarised in Table 4.3. These times were used to calculate the operating times of the load control scheme and are given in Table 4.4.

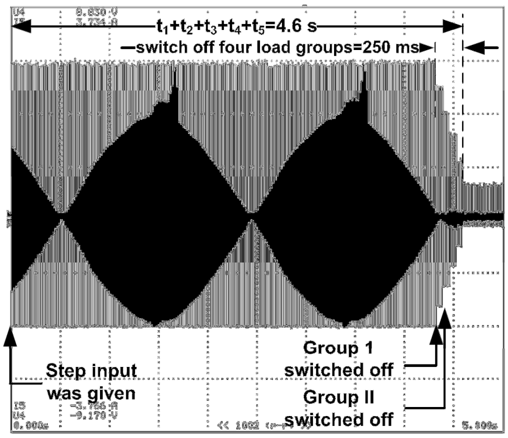


Fig. 4.8. Step responses of the load control scheme

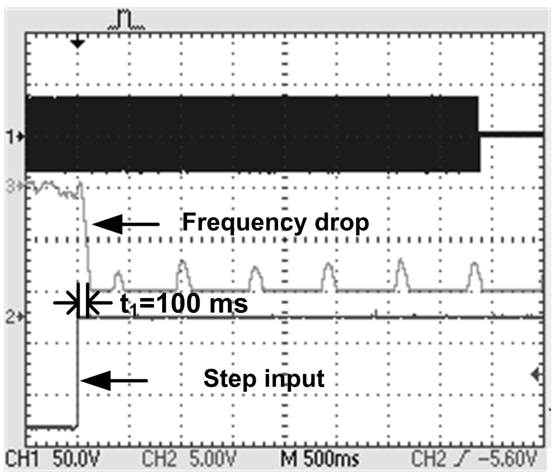


Fig. 4.9. Step response of the frequency convertor

TABLE 4.3. THE TIME MEASUREMENTS OBTAINED BY USING THE TEST RIG AND THE HMI

Time measurements	Times obtained by step responses and from the HMI		Source of the time measurements
To reduce the frequency by the convertor	t_1	100 ms	Fig. 4.9
To read the meter measurements by the software	t_3	187.5 ms	Fig. 4.5 (HMI)
Average loop time	t_3+t_4	188 ms	Fig. 4.5 (HMI)
To switch off one Load Group (out of five Load Groups in Table 4.1)	$t_5/5$	62.5 ms	Fig. 4.8
Maximum loop time	$t_3+t_4+t_5$	500 ms	Fig. 4.5 (HMI)
To switch off all Load Groups from the step signal	$t_1+t_2+t_3+t_4+t_5$	3.3 s to 4.6 s	Fig. 4.8

TABLE 4.4. THE TIMES TAKEN BY THE DIFFERENT ELEMENTS OF THE LOAD CONTROL SCHEME

Time taken to	Times taken by the elements of the load control scheme	
read the frequency by the smart meter and update register	t_2	2.7 s to 4.0 s
read the meter frequency measurement by the load controller	t_3	187.5 ms
complete state transitions	t_4	0.5 ms
switch off one Load Group (out of five Load Groups)	$t_5/5$	62.5 ms

4.4 Capability of the controller

The capability of the load controller to provide primary response was assessed using a simulation model of the Great Britain power system. First, the likely frequency drops without load control on a summer day were obtained. Then the amount of controllable loads required to maintain the frequency above a set of minimum allowable frequencies was assessed. Finally the reduction of the effectiveness of primary response from controllable loads due to communication delays of the control system was estimated.

4.4.1 Model of Great Britain power system

The single busbar model of the Great Britain (GB) power system used by Bopp [77] was modified (as shown in Fig. 4.10) to include five controllable Load Groups. These Load Groups reduced loads according to the load control algorithm described in Section 4.3.2. A block 'Control scheme delay' was added to represent the time delay of the load control scheme.

The inertia constant of the current GB system was estimated using the low frequency incident that occurred on 27 May 2008 (Fig. 4.11) [82]. This incident was caused by the sudden loss of generators of 345 MW and 1,237 MW (the total system demand was 41,550 MW). These two generation losses were applied to the model and the inertia constant (*H*) was varied to fit the frequency variation to that of the real event shown in Fig. 4.11. It was found that an inertia constant of 9 s gives a good fit and that value was used in subsequent simulations.

In addition, with the introduction of power electronically coupled wind generators, Ekanayake [126] has suggested that the system inertia constant might drop to as low as 3 s in 2020. Therefore an inertia constant of 3 s was used to represent the GB system in 2020.

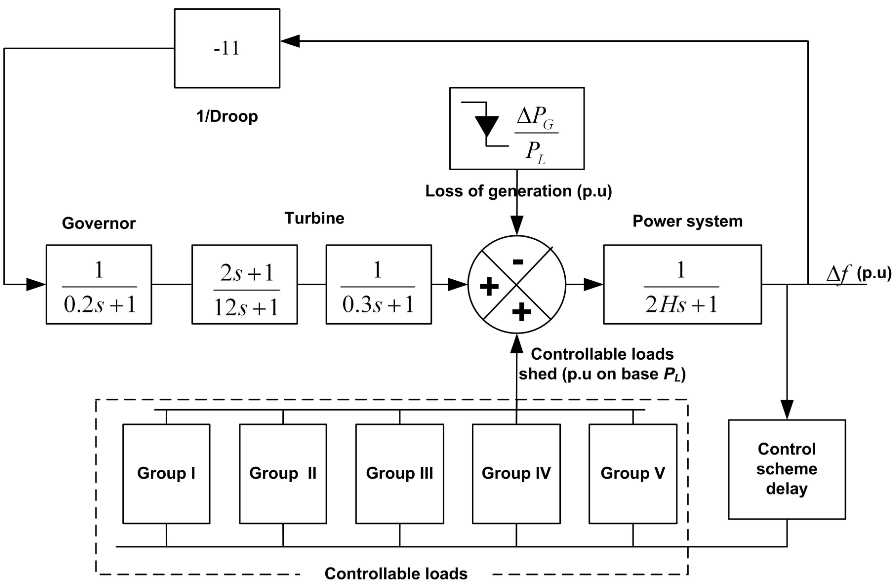


Fig. 4.10. The modified model of the Great Britain power system [77] with a 'Control scheme delay' and the 'Controllable loads'

The loss of generation (ΔP_G in Fig. 4.10.) used in the simulations was either 1320 MW (the expected maximum loss of generation at present) or 1800 MW (the expected maximum loss of generation in 2020). The model used per unit loss of generation on the base value equal to the system load (P_L in Fig. 4.10.) at the time considered for a simulation.

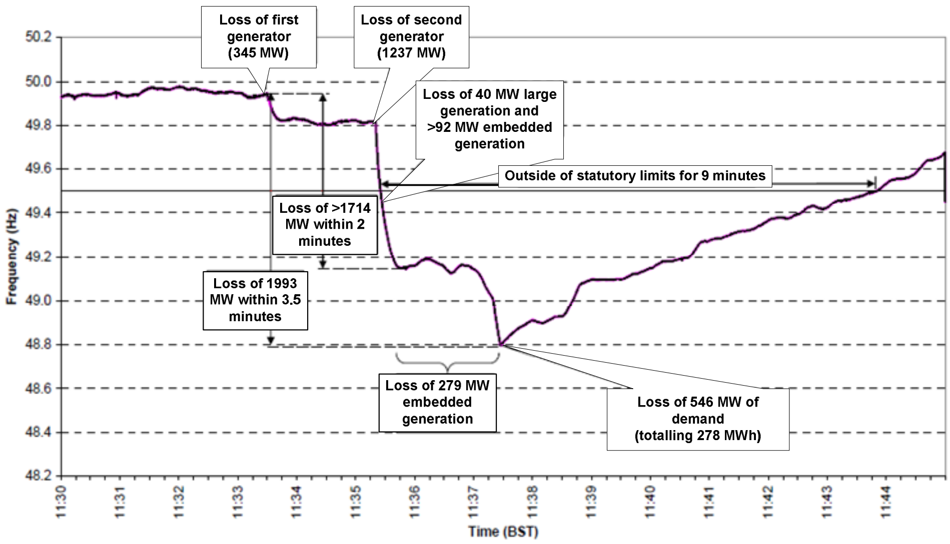


Fig. 4.11. Frequency deviations of frequency event that occurred in 27 May 2008 [82]

The impact of a loss of generation is greater when the system load is low (as the number of generators and extent of spinning load contributing to system inertia is reduced). Therefore the system load throughout 20th July 2008, the day when the load was at its minimum in that year, was used in the simulations. The load profile on that day is shown in Fig. 4.12. For the simulations carried out for 2020 (that used a loss of generation of 1800 MW), it was assumed that the system load was also that shown in Fig. 4.12.

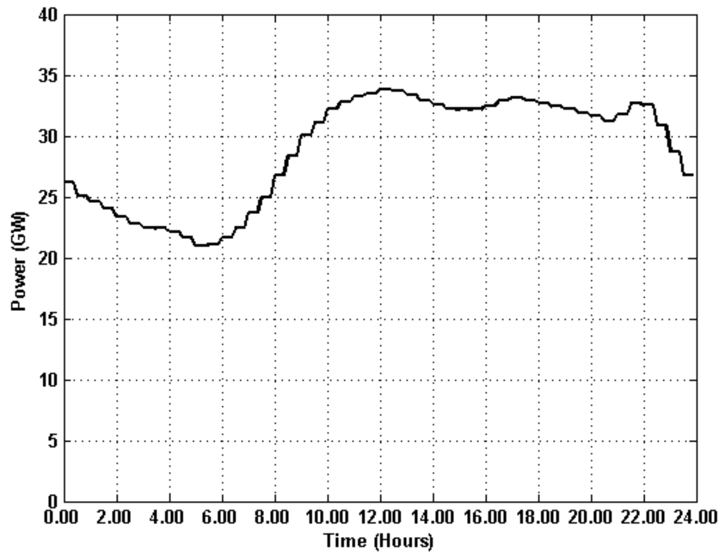


Fig. 4.12. The GB system load on 20th July 2008 [127]

4.4.2 Frequency drops without load control

Simulations were carried out to investigate the likely drop in system frequency that might have occurred on 20th July 2008 without load control. A loss of generation (ΔP_G) of 1320 MW and 1800 MW and inertia constants (H) of 3 s and 9 s were considered. For a given loss of generation and inertia constant, forty eight simulations, at every 30 min starting from 12.00 midnight, were done. The loss of generation in p.u was calculated using the system load shown in Fig. 4.12 at every 30 min.

An example frequency plots of one simulation time instance (at 5.30 hrs) is given in Fig. 4.13. Also, the minimum frequency obtained from each simulation was plotted against the time of the day and these are shown in Fig. 4.14.

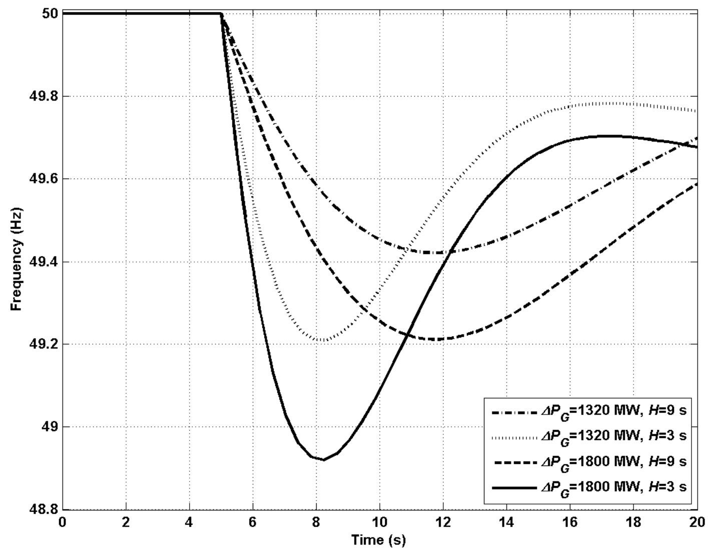


Fig. 4.13. Frequency due to different loss of generation (ΔP_G) and different inertia constants (H) with a system load of 22 GW (at 5.30 hrs)

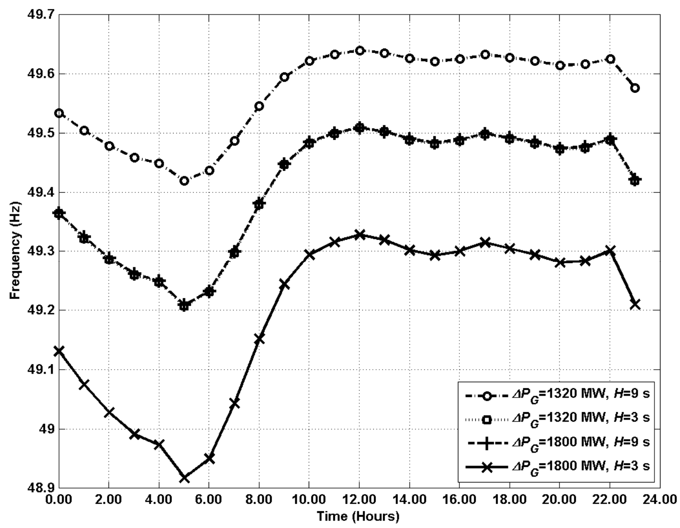


Fig. 4.14. Minimum frequency at every 30 min due to different loss of generation (ΔP_G) and different inertia constants (H)

4.4.3 Estimating the load requirement for controllable loads

A set of frequencies (49.2, 49.3, 49.4 and 49.5 Hz), between the operating limits of the GB system, was chosen as "minimum allowable frequencies". It was assumed that the total controllable load was made up from an equal amount of load from each controllable Load Group and there was no delay in the control scheme. Simulations were carried out to estimate the amount of controllable load required to be shed to maintain the minimum allowable frequencies with different loss of generation and different inertia constants.

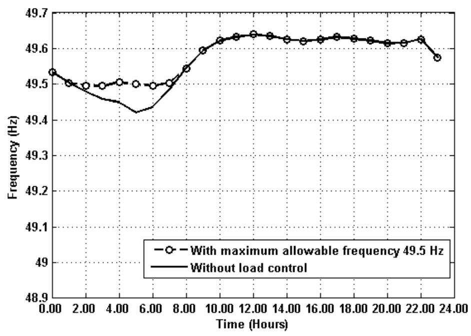
The likely frequency drop with and without load control is given in Fig. 4.15(a) for a loss of generators of 1320 MW and inertia constant of 9 s. This represents the present GB system. The simulations were carried out for every 30 min and the minimum frequencies were plotted in Fig. 4.15(a).

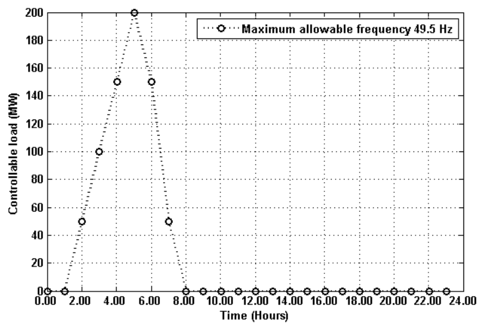
Without load control, the frequency remains above 49.5 Hz except between 2.00 hrs to 7.00 hrs at low system load. During that period, the frequency did not drop below 49.4 Hz. These frequency drops are in accordance with present GB system operating practice because sufficient primary response is maintained to limit the frequency drop to 49.2 Hz and to restore the frequency to 49.5 Hz.

When load control was enabled, the controllable loads were shed to keep the frequency above the minimum allowable frequency of 49.5 Hz. The controllable loads that were shed are plotted in Fig. 4.15(b). During the hours of low load, 2.00 hrs to 7.00 hrs, 200 MW of controllable load needed to be shed to maintain the system frequency above 49.5 Hz.

Similar simulations were done for the other three combinations of loss of generation and inertia constant. The graphs of minimum frequency and the amount of controllable loads that were shed to achieve the minimum allowable frequencies of 49.5, 49.4, 49.3 and 49.2 Hz are shown in Fig. 4.16 when ΔP_G = 1320 MW, H = 3 s, in Fig. 4.17 when ΔP_G = 1800 MW, H = 9 s and in Fig. 4.18 when ΔP_G = 1800 MW and H = 3 s.

When the system inertia was reduced to 3 s (the anticipated situation when many converter connected generators are installed in the GB system) and the loss of generation is 1320 MW, the frequency dropped below 49.5 Hz for events during the period between 22.00 hrs in the night and 10.00 hrs in the morning (see Fig. 4.16). A maximum of 500 MW of controllable load is sufficient to maintain the frequency above 49.5 Hz during that period.





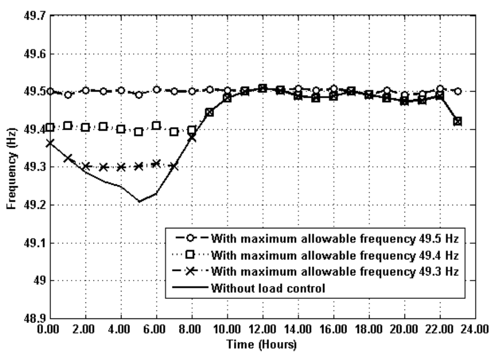
(a) Minimum frequency for an event at every 30 min

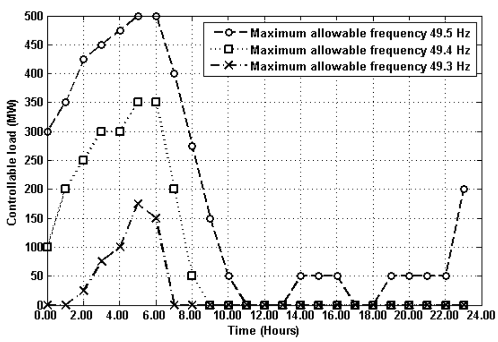
(b) Controllable loads shed at every 30 min

Loss of generation =1320 MW, Power system inertia (*H*) = 9 s

Fig. 4.15. Minimum system frequency and the amount of controllable loads that were shed to keep minimum allowable frequency above 49.5 Hz

When the maximum loss of power infeed is increased to 1800 MW (when larger generating plants are installed in the GB system) even with the present system inertia of 9 s, about 700 MW of controllable loads are required to maintain the frequency above 49.5 Hz (see Fig. 4.17).



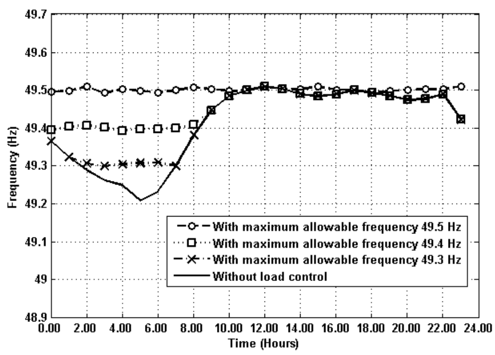


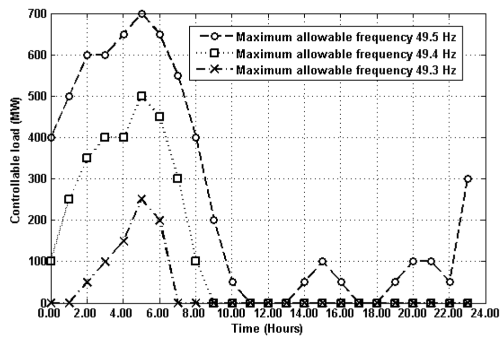
(a) Minimum frequency for an event at every 30 min

(b) Controllable loads shed at every 30 min

Loss of generation =1320 MW, Power system inertia (*H*) = 3 s

Fig. 4.16. Minimum system frequency and the amount of controllable loads that were shed to keep minimum allowable frequency above 49.3, 49.4 and 49.5 Hz

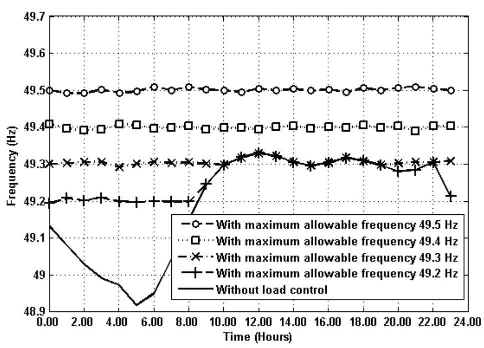


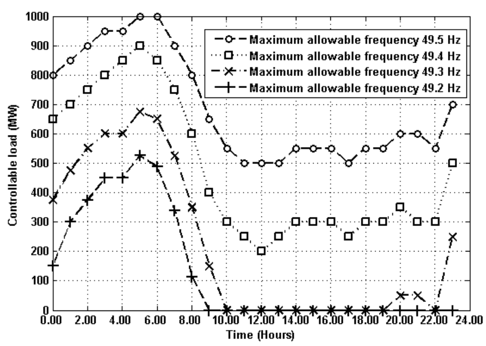


(a) Minimum frequency for an event at every 30 min	(b) Controllable loads shed at every 30 min
Loss of generation =1800 MW, Power system inertia (H) = 9 s	

Fig. 4.17. Minimum system frequency and the amount of controllable loads that were shed to keep minimum allowable frequency above 49.3, 49.4 and 49.5 Hz

A possible future situation is shown in Fig. 4.18 when a small number of very large generators may lead to a requirement for a loss of generation infeed of 1800 MW and when the system inertia is reduced to 3 s, e.g. due to many variable speed wind generators installed in the system. In this case a maximum of about 600 MW of controllable load is required at all times and another 400 MW (totalling to 1000 MW) is required between 22.00 hrs in the night and 10.00 hrs in the morning to maintain the frequency above 49.5 Hz.





(a) Minimum frequency for an event at every 30 min	(b) Controllable loads shed at every 30 min
Loss of generation =1800 MW, Power system inertia (H) = 3 s	

Fig. 4.18. Minimum system frequency and the amount of controllable loads that were shed to keep minimum allowable frequency above 49.2, 49.3, 49.4 and 49.5 Hz

4.4.4 Effects of delay within the control scheme

The effect of delay within the control scheme was simulated by the ‘Control scheme delay’ shown in Fig. 4.10. This was varied from 0 s to 5 s.

Fig. 4.19 shows the results of simulations for a loss of generation of 1320 MW when the system inertia was 9 s, the system demand was 22 GW and 200 MW of controllable loads were shed. 200 MW, chosen from Fig. 4.15(b), is the maximum amount of controllable loads shed for these system conditions. When the delay was increased from 0 to 5 s, the minimum frequency decreased from 49.5 Hz to about 49.42 Hz. The minimum frequency 49.42 Hz is the same minimum frequency shown in Fig. 4.13 where there was no load control scheme.

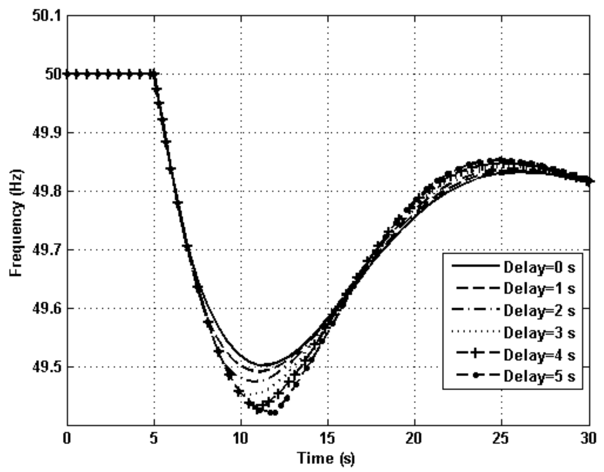
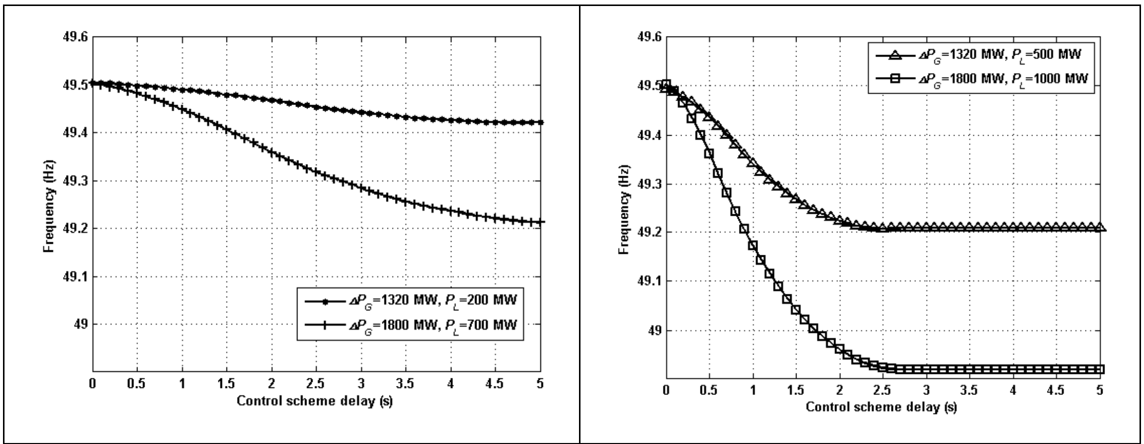


Fig. 4.19. Frequency due to a loss of generation of 1320 MW for different delays of the control scheme when 200 MW of controllable loads were shed (System inertia = 9 s, system load = 22 GW)

Similar simulations were carried out for loss of generation of 1320 MW and 1800 MW and the system inertia of 9 s and 3 s with the Control scheme delay increased in steps of 0.1 second. The minimum frequencies from those simulations are shown in Fig. 4.20. The amounts of controllable loads shed (P_L) were chosen from Fig. 4.15(b), 4.16(b), 4.17(b) and 4.18(b).

Fig. 4.20 shows that as the communication delay was increased, the effect of the load control reduced gradually. When the system inertia was 9 s (similar to that of the present GB system), a delay of 5 s led to no effect of the Controllable Loads. When the system inertia was 3 s, a delay of 2 s led to no effect of the Controllable Loads

If the delay is less than 200 ms, the minimum frequency is approximately equal to the 49.5 Hz; which is the minimum frequency when there is no delay in the control scheme.



(a) System inertia (H) = 9 s	(b) System inertia (H) = 3 s

Fig. 4.20. Minimum system frequency for different control scheme delays, loss of generation and system inertia

4.5 Discussion

An experimental load control scheme was developed using a commercially available smart meter, smart load controller and smart sockets. When the power system frequency drops, the controller switched off domestic loads to provide primary frequency response. Based on the disturbance that would be caused to the consumer, different domestic loads were switched off at different frequencies and switched on when a predefined time has passed or the frequency had recovered.

Simulations were carried out of the GB system in years 2008 and 2020 assuming different inertia constants (3 and 9 sec) and anticipated maximum loss of generation (1320 and 1800 MW). The amounts of controllable loads required to maintain the system frequency above a set of target frequencies were assessed.

For the present 2008 system, 200 MW of controllable loads are required to be shed (in addition to the frequency response services maintained at present in the GB system) to limit the frequency to 49.5 Hz. For possible future 2020 system, with the presence of many convertor connected generators and very large generators, about 1000 MW of controllable loads will be required.

The operating time of the experimental load control scheme was assessed. It was found that the commercially available smart meter used in this study took 80 – 85% of the total operating time (3.3 to 4.6 s) to update its frequency measurements.

The delay of the control scheme is critical for providing primary response. With the anticipated large number of converter connected generators in 2020, a delay more than 2 s lead to no contribution from the controllable loads. The maximum primary response can be obtained if the delay is less than 200 ms thus demanding fast frequency measurements from smart meters. This has important implications for the policy and specification to be adopted as the UK rolls out more than 20 million electricity Smart Meters. If these devices are to play any role in primary frequency response control systems using domestic load control then the speed at which system frequency is measured must be increased very considerably.

5 Controllable loads available in Great Britain

5.1 Introduction

In Chapter 4, the amount of controllable load that needs to be shed in order to maintain the GB system frequency above a set of frequencies was calculated for different system inertias and maximum generation losses. To shed a given amount of controllable load, a sufficient number of appliances from each Load Group (defined in Section 4.4.1) must be included in the load control scheme because only a portion of the appliance stock are running at a given time. In this chapter, the percentage of appliances that should be included in the load control scheme, to shed the amount of loads estimated in Chapter 4, was calculated.

5.2 Obtaining load profiles using load models

Load profiles have long been used for planning and operation of electricity networks [49]. Since real-time measurements of loads are not available, these load profiles are obtained using load models. Two load modelling methods are found in the literature.

In the first method, past electricity demand data was used to forecast the future demand [128]. Typically, in this method, demand was represented as a function of independent variables such as time, temperature and day (e.g. weekday or weekend). Past billing data and weather data were used to calculate the parameters of this function. Load forecasting methods are commonly used where there was little or no knowledge about the stock of appliances and their power consumption patterns.

The second method, called *end-use models*, is a method where the *load curves*[1] of appliances and the likelihood of using appliances in a house are used to calculate the system load profile. Three variants of end-use models are found in the literature.

[1] The graph of power consumption of an appliance per one cycle of its operation.

Capasso [129] expressed the likelihood of appliance use as a probability distribution. First, this probability distribution was constructed by multiplying the probability distribution of a consumer being at home and the probability distribution of doing activities that use an appliance. Starting from the appliance having the highest probability in each hour, the time at which each appliance would be switched on by a user (named *starting time*) was found by generating random samples that satisfy the probability distribution. At each starting time, the load curve of the appliance was added to the daily load profile[2] of the house if the following conditions were satisfied:

- The appliance's daily energy consumption did not exceed the average daily energy consumption given in national statistics.
- The total household demand did not exceed the maximum power supply rating.

The load profiles of houses were then added together to calculate the total load profile of all houses selected in the study.

In contrast, Paatero [130] expressed the probability of starting an appliance as an equation. This equation is a function of:

- A probability distribution of appliance use in each hour.
- A probability distribution that represents influences of social and weather effects.
- A probability distribution that represents seasonal variations of household demand.
- The average number of times an appliance is switched on per day (named *starting frequency).*
- $1/N_{Steps}$ where $N_{Steps} =$ Number of time steps per hour used in the simulation for constructing the load profile.

To construct the total load profile of a group of houses, Paatero [130] first defined a set of appliances in each house. Then, for each appliance, the starting probability was calculated for each time step. When the starting probability was greater than a random number generated between 0 and 1, that time was used as a starting time. At this

[2] The graph of power consumption of all operating cycles that happens during a day

starting time, the load curve of the appliance was added to the daily load profile of the appliance. At the end of the load curve, the appliance was assumed to be off and the calculation of starting time was repeated for the remaining time steps in a day. This was repeated for all appliances in the house. Then, the load profiles of the appliances in a house were added together to construct the load profile of the house. The load profiles of houses were then added together to calculate the total load profile of all houses selected in the study.

A variant of the end-use model was used by the Smart-A project where the entire load curve of an appliance was multiplied by the probability of appliance use at each 15 minute period in a day [131]. Each multiplied load curve was added to the load profile of the appliance at the same time at which the probability was obtained. Then this average profile was multiplied by the number of appliances in a country to get the total load profile of the appliance type in the power system.

A combination of *end-use modelling* methods used by Capasso [129] and Paatero [130], was used by Richardson [132] to construct the load profiles. As it was done by Paatero [130], simulations were done at each time step to find the starting time. Instead of using an equation to find starting times (as done by Paatero [130]), they were found by using probability distributions (as done by Capasso [129]) constructed by using the UK Time Use Survey data. The number of starts per day was calculated using the total annual energy consumption and the energy consumption during a load cycle given by Paatero [130]. Each probability distribution was scaled so that when a large number of simulations were done using the scaled probability distribution it gave a mean value equal to the number of starts per day.

The method explained by Richardson [132] was used to construct the load profiles of the Load Groups in the study reported in this chapter (see Sections 5.3 - 5.5). The load profiles of the appliance types given in Table 5.1 were constructed. Out of the Load Groups defined in Section 4.4.1, only Load Groups I – III were selected because they are the Load Groups that are most likely to be switched off during a frequency drop. Frequency drops below 49.0 Hz in the GB system that would switch off Load Group IV and V are very rare [82].

First the load profile of each appliance type in a Load Group was constructed. Then these load profiles were added together to construct a load profile for each Load Group. Finally, the percentages of controllable loads required to be in the load control scheme, to shed the amount of controllable loads estimated in Section 4.4.3, were calculated.

TABLE 5.1. APPLIANCE TYPES OF LOAD GROUPS

Load Group	Appliance Type
I	Fridge, Upright freezer, Chest freezer, Fridge freezer
II	Tumble dryer, Clothes washer, Dish washer, Washer-dryer
III	Hobs, Ovens

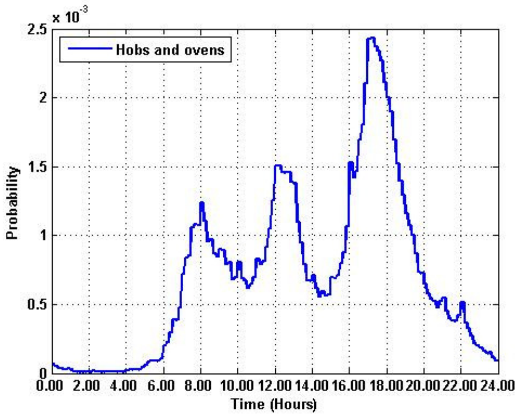
5.3 Probability distributions of appliance use

The probability distribution of appliance use was required for the end-use modelling method discussed in Section 5.5. A user will switch on an appliance when it is required by their activity. The UK Time Use Survey [133] has diary data of how people, who participated in the survey, spent their time at 10 minutes intervals throughout the day. The survey data was used to construct the probability distribution of different appliances used in this study.

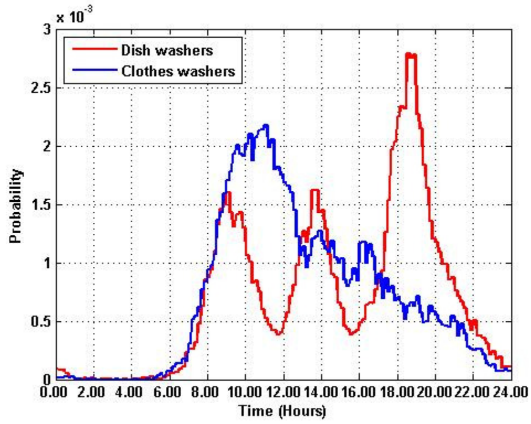
In order to obtain the probability distribution of using hobs and ovens, two activities listed in the survey, named *food preparation* and *baking,* were used. It was assumed that, during 50% of the total food preparation and baking time, ovens and hobs were on. First, for each 10 minute interval, the number of people who did food preparation and baking were counted. Then the counted number was divided by 2 to account for the 50% on time of hobs and ovens. The result of the division was then binned into 10 minute intervals to create a histogram. The value in each bin was then divided by 10 to get the histogram of the number of people using hobs and ovens at each minute (assuming that the probability of using these appliances during each 10 minute interval is uniformly distributed). Then the histogram was divided by the number of samples to obtain a probability distribution of using hobs and ovens. Normalised probability distribution is shown in Fig. 5.1(a). Since the number of samples is large and the bin size is small, this distribution was assumed to be a continuous probability distribution [134].

Similarly, the activity named *laundry* was used to obtain the probability distribution of clothes washers and the activity named *dish washing* was used to obtain the probability distribution of dish washers Fig. 5.1(b). Mansouri [135] notes that 50% of regular users switch on tumble dryers immediately after a washing cycle is completed. Therefore, the probability distribution of using clothes washer was shifted on the time axis by the average operating time of a clothes washer (given by Paatero [130]) to obtain probability distribution of using tumble dryers.

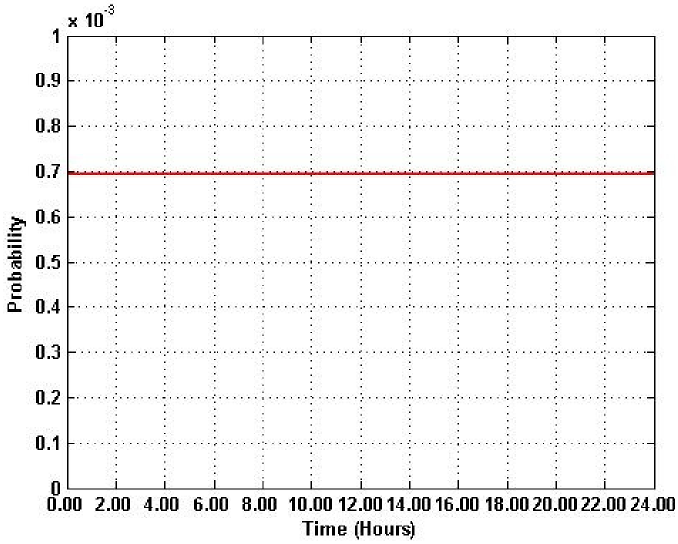
The compressor of a fridge or a freezer starts and stops automatically depending on the inside temperature and the thermostat setting. By neglecting the effects of door opening and closing and the variation of the room temperature, it was assumed that the probability of starting a fridge is a uniform distribution (shown in Fig. 5.1(c)).



(a) Probability distribution of using hobs and ovens



(b) Probability distributions of using clothes washers and dish washers



(c) Probability distribution of starting a fridge or freezer

Fig. 5.1. Probability distribution of using hobs and ovens, dish washers, clothes washers and starting a fridge or a freezer

5.4 Appliance load curves

When an appliance is switched on, its power consumption varies with time or cyclically varies until it is switched off. The power consumption over one cycle is given as a load curve. Load curves of the appliances given by Paatero [130] were used. An example load curve of a clothes washer is given in Fig. 5.2. This curve has three power levels (P_1, P_2, P_3) during the time periods; t_1, t_2, t_3.

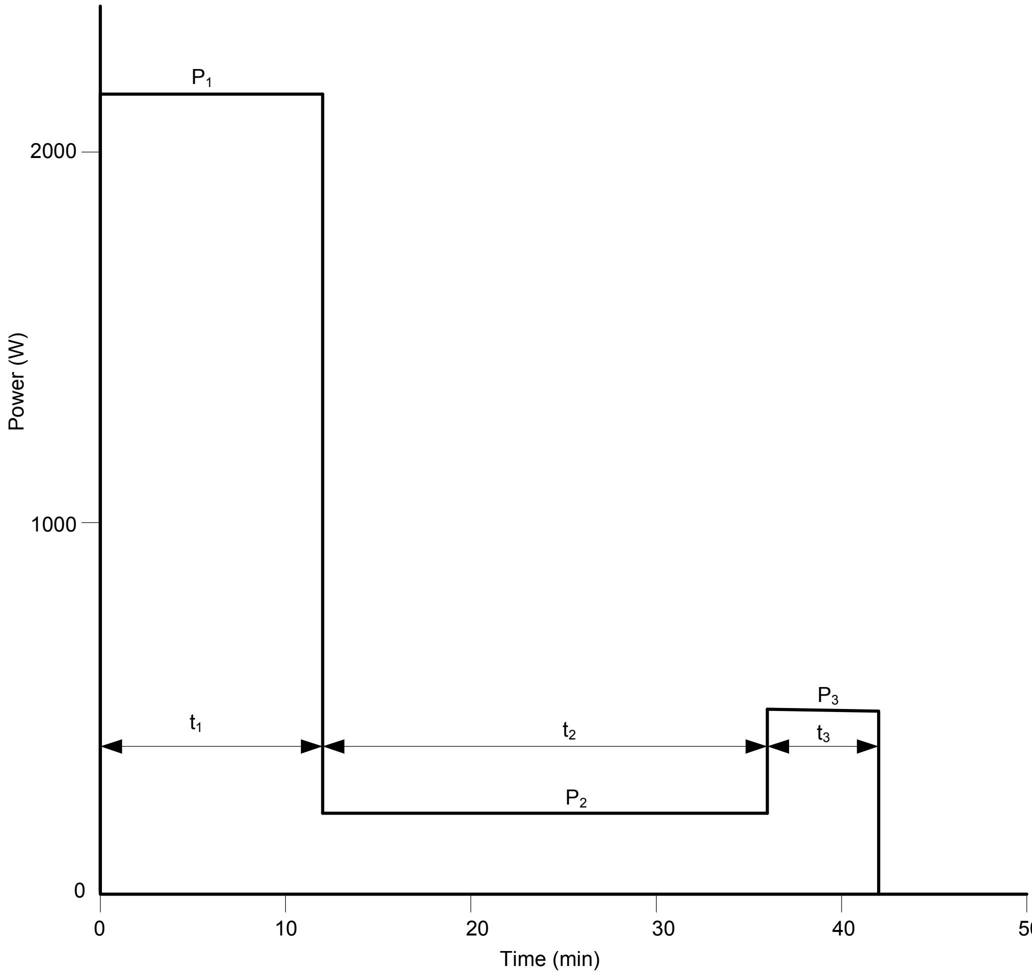


Fig. 5.2. An example load curve of a clothes washer

Table 5.2 gives a summary of appliance load curves for each type of appliance in the Load Group I-III (discussed in Section 4.4.1). The appliance load curves are given in the format [(P_1 x t_1) + (P_2 x t_2) ….]. The number of starts per day for an appliance type was calculated by using the total energy consumption per load cycle, the number of appliances in the UK and the total annual energy consumption of the appliance type. The number of appliances and the total annual energy consumption of each appliance type in the UK, given by DECC [136], are also shown in the table.

TABLE 5.2. SUMMARY OF APPLIANCE LOAD CURVES, DAILY STARTING FREQUENCIES AND THE NUMBER OF APPLIANCES IN THE UK

Appliance		Power consumption of appliance load curve expressed as $[(P_1 \times t_1) + (P_2 \times t_2)..]$ given in Fig. 5.2 Power(W) x Operating time (minutes) [130]	Number of starts per day	Number of appliances in the UK [136] (Thousands)	Total annual energy consumption in the UK [136] (GWh)
Group	Type				
I	Fridge	(110x12)+(0x24)	25	9914	2000
	Upright freezer	(155x12)+(0x12)	28	8115	2570
	Chest freezer	(190x12)+(0x12)	24	4181	1372
	Fridge freezer	(190x12)+(0x12)	32	18220	8153
II	Tumble dryer	2500 x 72	0.34 (125/year)	11860	4431
	Clothes washer	(2150x12)+(210x24)+(450x6)	1.02 (374/year)	21082	4408
	Dish washer	(1800x18)+(220x18)+(1800x6)+(220x12)	1.11 (404/year)	9646	3233
	Washer-dryer	(2150x12)+(210x24)+(450x6)+(2500x72)	0.44 (162/year)	4105	2361
III	Hobs	(1050x12)+(525x18)+(220x12)	1.77 (646/year)	12079	3210
	Ovens	(2100x24)+(700x6)+(1440x6)+(0x6)	0.50 (182/year)	16923	3245

5.5 Load profile construction

A load profile of each appliance type was constructed using the probability distributions given in Section 5.3 and the appliance load curves given in Section 5.4. The flowchart in Fig. 5.3 shows the three steps in constructing a load profile of an appliance type.

In step (i), the probability distribution for each appliance type was selected from the probability distributions constructed in Section 5.3. The selected probability distribution was then scaled so that when a large number of *starting times*[3] were

[3] the time at which an appliance is switched on during a day

obtained using the scaled probability distribution, it gave a mean value equal to the number of starts per day given in Table 5.2.

In step (ii) *starting times* were found using the probability distribution selected in step (i). Simulations were done in 1 minute steps starting from 0.00 hrs of the day. For each simulation step, a random number between 0 and 1 was generated. If this random number lay within the probability distribution at the simulation time then at that time, the appliance was assumed to be on and the time was selected as a starting time (ST). The total operating time of the appliance load curve (given in Table 5.2) was added to the starting time and simulations were continued from that time until the next starting time was found. This was repeated for the whole day. One simulation run gave the number of starts of one appliance within the day.

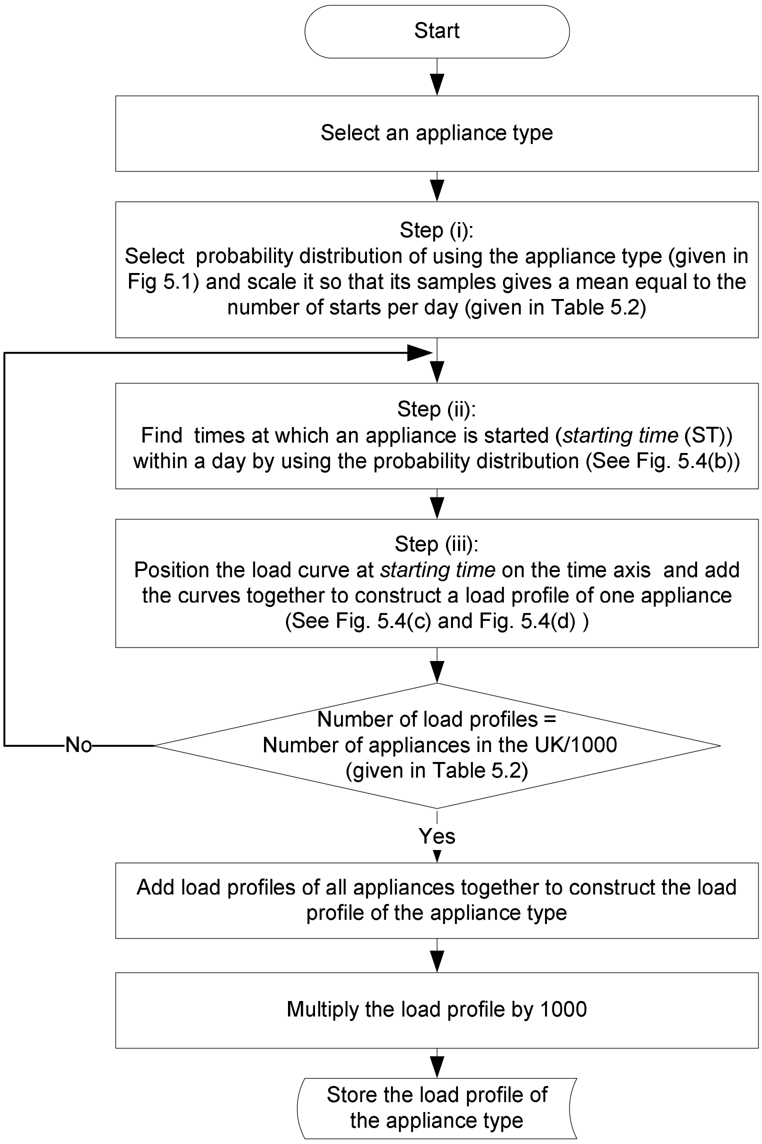
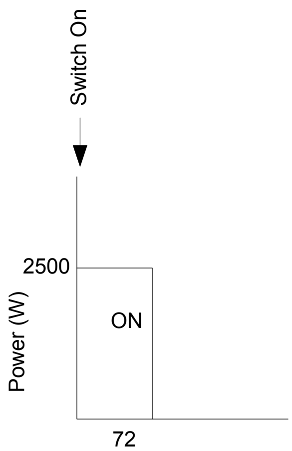
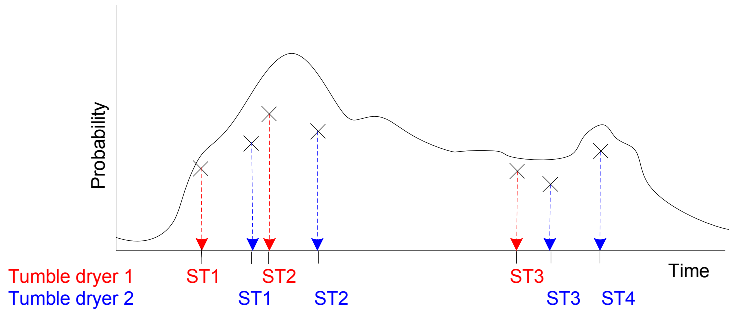


Fig. 5.3. Steps in generating appliance load profiles

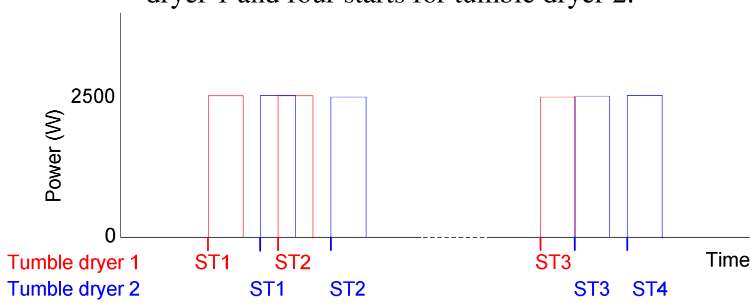
In step (iii), the appliance load curve was added to the load profile of the appliance at the starting time found in step (ii). An example of constructing a load profile for two tumble dryers is shown graphically in Fig. 5.4. For this illustration, it was assumed that two simulation runs were done and the first tumble dryer started three times a day and the second tumble dryer started four times a day. Then, as shown in Fig 5.4(c), typical load curve of tumble dryers (Fig 5.4(a)) was positioned on the time axis at each starting time. Then all these curves were added together to make the daily load profile of two tumble dryers (Fig. 5.4(d)).



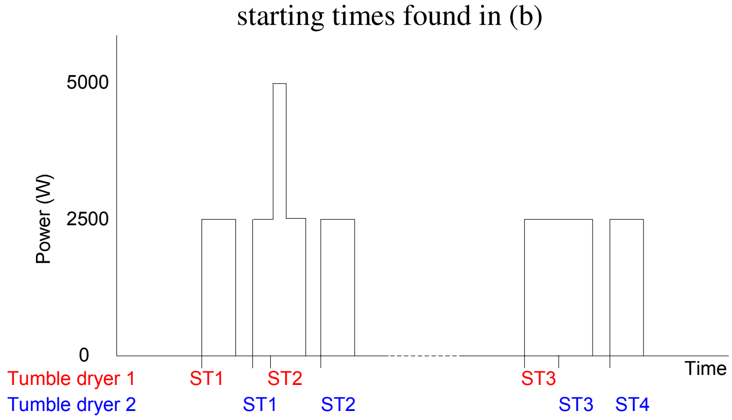
(a) Load curve of a tumble dryer



(b) Starting times (ST) were found using the probability distribution of using tumble dryers and a random number generated at each time step. Two simulation runs gave three starts for tumble dryer 1 and four starts for tumble dryer 2.



(c) Typical load curve of tumble dryers was positioned at each starting times found in (b)



(d) The load curves in (c) were added together to construct the load profile of two tumble dryers.

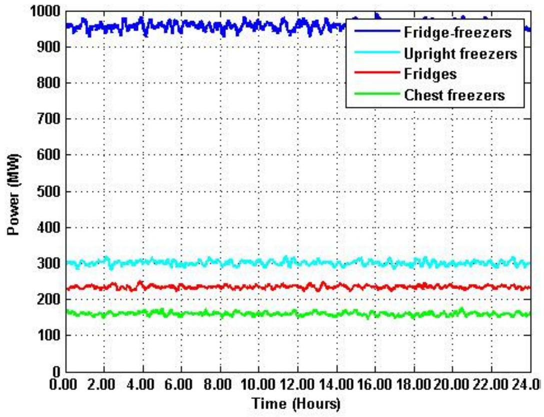
Fig. 5.4. Illustration of constructing the load profile of two tumble dryers using starting times and a load curve

Steps (ii) and (iii) were repeated until the total number of simulation runs was equal to one thousandth of the number of appliances in the UK. Since steps (ii) and (iii) were repeated for the number of appliances/1000, the load profile was then multiplied by one thousand to obtain the total load profile for all the appliances in the UK.

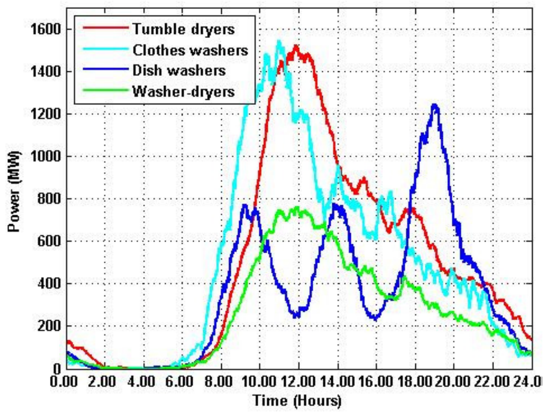
It was assumed that, the number of repetitions of steps (ii) and (iii) was adequate to provide a sufficient number of random samples to make an accurate load profile. By neglecting the load contribution of appliances in Northern Ireland (3% of the UK population [137]) it was assumed that these load profiles would give approximate appliance load profiles of Great Britain power system.

5.6 Load profiles of Load Groups

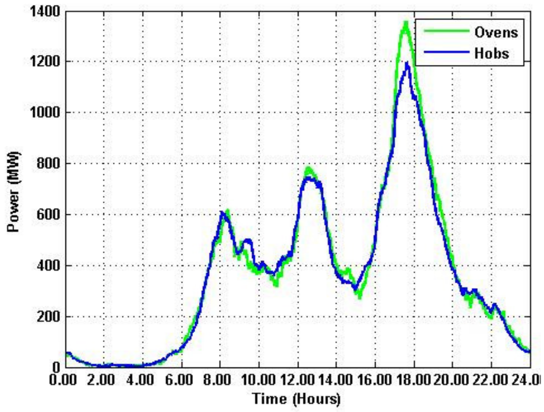
The load profile of each Load Group, given in Table 5.1, was constructed using the procedure explained in Section 5.5. As one Load Group includes more than one appliance type (see Table 5.1), the profiles of all appliance types in each Load Group were first constructed. These profiles were then added together to make the load profile of the Load Group (e.g. the profiles of hobs and ovens were added to make the load profile of Load Group III). The load profile of each constituent appliance in Load Groups I, II and III are shown in Fig. 5.5(a), Fig. 5.5(b) and Fig. 5.5(c). The total load profile of each Load Group, for the total number of appliances in the UK (given in Table 5.2), is shown in Fig. 5.5(d).



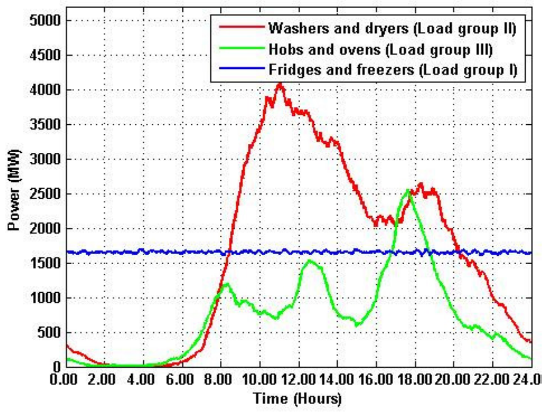
(a) Load profiles of fridges and freezers (Load Group I)



(b) Load profiles of washers and dryers (Load Group II)



(c) Load profiles of hobs and ovens (Load Group III)



(d) Total load profiles of Load Groups I, II and III

Fig. 5.5. Load profiles of appliance types and the total load profiles of Load Groups

5.7 Controllable loads available

Fig. 5.5(d) shows that 1600 MW of load was available form Load Group I throughout the day. Loads in Load Group II are a minimum of 1000 MW from 8.00 to 22.00 hrs, with a maximum load of 4000 MW. In this time period, Load Group III has a minimum value of 500 MW with two peaks of 1250 MW and 2500 MW. The minimum load of each Load Group is summarised in Table 5.3.

TABLE 5.3. MINIMUM LOADS AVAILABLE FROM LOAD GROUPS

Load Group	Appliance type	Available minimum load	
		8.00 - 22.00 hrs	22.00 - 10.00
I	Fridges and freezers	1600 MW	
II	Washers and dryers	1000 MW	0 MW
III	Hobs and ovens	500 MW	0 MW

Some of the loads given in Table 5.3 may be shed to provide primary response, if they are included in the load control scheme. Assuming suitable incentives are offered to consumers, the percentages of loads from each Load Group that should be included in the load control scheme, to shed the amount of loads estimated in Chapter 4, were calculated. These load requirements were estimated to maintain the GB system frequency above a set of frequencies for different system inertias and maximum generation losses. The controllable load requirements are summarised in Table 5.4.

TABLE 5.4. MAXIMUM CONTROLLABLE LOAD REQUIREMENTS ESTIMATED IN CHAPTER 4

State of GB power system		Maximum controllable load requirement (MW)						
Maximum loss of generation (MW)	Inertia (s)	10.00 - 22.00 hrs			22.00 - 10.00 hrs			
		49.3 Hz	49.4 Hz	49.5 Hz	49.2 Hz	49.3 Hz	49.4 Hz	49.5 Hz
1320	9	-	-	-	-	-	-	200
1320	3	-	-	50	-	175	350	500
1800	9	-	-	100	-	250	500	700
1800	3	50	350	600	500	700	900	1000

Table 5.3 shows that Load Group I has 1600 MW throughout the day and hence they can provide the total controllable load requirement in all cases given in Table 5.4, at any time of the day. As shown in Table 5.5, 63% of appliances from Load Group I need to be in the load control scheme if this Load Group alone is to provide the controllable load requirements given in Table 5.4.

TABLE 5.5. PERCENTAGES OF APPLIANCES OF LOAD GROUP I THAT NEED TO BE IN THE LOAD CONTROL SCHEME IF THEY ARE ALONE TO PROVIDE THE CONTROLLABLE LOAD REQUIREMENTS GIVEN IN TABLE 5.4

State of GB power system		Percentage of loads in the load control scheme (%)						
Maximum loss of generation (MW)	Inertia (s)	10.00 - 22.00 hrs			22.00 - 10.00 hrs			
		49.3 Hz	49.4 Hz	49.5 Hz	49.2 Hz	49.3 Hz	49.4 Hz	49.5 Hz
1320	9	-	-	-	-	-	-	13
1320	3	-	-	3	-	11	22	31
1800	9	-	-	6	-	16	31	44
1800	3	3	22	38	31	44	56	63

In the load control scheme discussed in Chapter 4, it was assumed that the controllable load requirement was shared equally among all three Load Groups. When the load requirement is shared by the Load Groups, 13% from Load Group I, 20% from Load group II and 40% from Load Group III need to be in the load control scheme during 10.00 - 22.00 hrs (shown in Table 5.6). However, during 22.00 - 10.00 hrs there are no loads from Load Group II and III available and hence the total controllable load requirement needs to be supplied by Load Group I (given under 22.00 - 10.00 hrs in Table 5.5).

TABLE 5.6. PERCENTAGES OF LOADS THAT NEED TO BE IN THE LOAD CONTROL SCHEME DURING 10.00 - 22.00 HRS WHEN THE LOAD REQUIREMENT IS SHARED EQUALLY AMONG LOAD GROUPS I, II AND III

State of GB power system		Percentage of loads in the load control scheme (%)								
Maximum loss of generation (MW)	Inertia (s)	Load Group I			Load Group II			Load Group III		
		49.3 Hz	49.4 Hz	49.5 Hz	49.3 Hz	49.4 Hz	49.5 Hz	49.3 Hz	49.4 Hz	49.5 Hz
1320	9	-	-	-	-	-	-	-	-	-
1320	3	-	-	1	-	-	2	-	-	3
1800	9	-	-	2	-	-	3	-	-	7
1800	3	1	7	13	2	12	20	3	23	40

5.8 Discussion

The total load profiles of appliances in three Load Groups; i.e. fridges/freezers, washers/dryers and hobs/ovens, were constructed. It was found that, in Great Britain, about 1600 MW of controllable load from fridges/freezers was available throughout the day. About 1000 - 4000 MW of washers/dryers and 500 - 2000 MW of hob/ovens are available between 10.00 and 22.00 hrs.

Using the total load profile of each Load Group, the percentages of controllable loads required to be in the load control scheme, to shed the amount of controllable loads estimated in Section 4.4.3, were calculated.

It was found that the estimated controllable load requirement can be obtained using only fridges/freezers as they are available throughout the day. During 22.00 - 10.00 hrs, 63% of fridges/freezers need to be in the load control scheme and 38% is needed during 10.00 - 22.00 hrs if they are alone to provide the controllable loads.

When the controllable load requirement was high (22.00 - 10.00 hrs) there was no significant load available from washers/dryers or hobs/ovens. Loads from these appliances were available only when the controllable load requirement was low (10.00 - 22.00 hrs). In this period, when the controllable load requirement was shared among three Load Groups, the requirement of fridges/freezers can be reduced to 13% while 20% of washers/dryers and 40% of hobs/ovens are in the load control scheme.

6 Reporting available controllable loads to network operator

6.1 Introduction

The UK transmission network operator; National Grid Electricity Transmission plc (NGET) expects domestic appliances to report back their ability to provide demand response. The consultation on operating transmission networks in 2020 issued by NGET [138] noted that, although frequency response can be delivered using controllers installed within appliances (e.g. refrigerators), it is more valuable for the network operator if these services will be integrated with smart metering and its communication system. This is mainly due to difficulties of estimating the exact amount of demand response available at a given time as different parties will be responsible for providing demand response and it will be provided to support different ancillary services. Through smart meter integration NGET expects to set appliance operating modes remotely to provide different balancing services, even at the expense of a small increase of data volume. Therefore in this chapter, the number of measurements needed to be sent to NGET, to notify the power consumption of controllable loads operating in houses, was calculated.

6.2 Communication network of the UK smart metering system

In the UK smart metering system, according to the WAN requirements for the DCC [111], smart meter messages given in Table 6.1 are only accessible to distribution network operators (DNO) and energy suppliers. Unless DNO or energy suppliers forward the messages to NGET, there is no transmission of information to the transmission network operator.

Even if the messages in Table 6.1 are sent to the transmission network operator, none of them are suitable for reporting demand response, because their data sending rate is too low. Some messages are sent 6 - 48 times a day and some are sent 1 - 4 times a year. Since appliance loads vary frequently, the power consumption measurements of the loads need to be sent by smart meters at a high rate (e.g. 1 per minute) if they are to report the available demand response to the transmission network operator.

TABLE 6.1. MESSAGES SENT BY SMART METERS IN THE UK SMART METERING SYSTEM [111]

Message	Message size	Rate of sending messages	Guaranteed response	Covering meter population	Users
Scheduled reads	544 bytes	6-48/day	10-60 min	100%	Energy suppliers
On demand reads	544 bytes	1/year	10-30 sec	100%	Energy suppliers
Diagnostic messages	160 bytes	1/year	10 sec	100%	Energy suppliers
Quality reads	300 bytes	48/day	300 sec	10%	DNO
Quality reads of three months	141,472 bytes	4/year	12 hrs	10%	DNO
On demand quality reads	300 bytes	12/day	30 sec	10%	DNO

In the UK smart metering system, the data sent by smart meters will be first sent to the DCC through a WAN (see Fig. 6.1) [139]. Suppliers and network operators access these data from the DCC through a gateway.

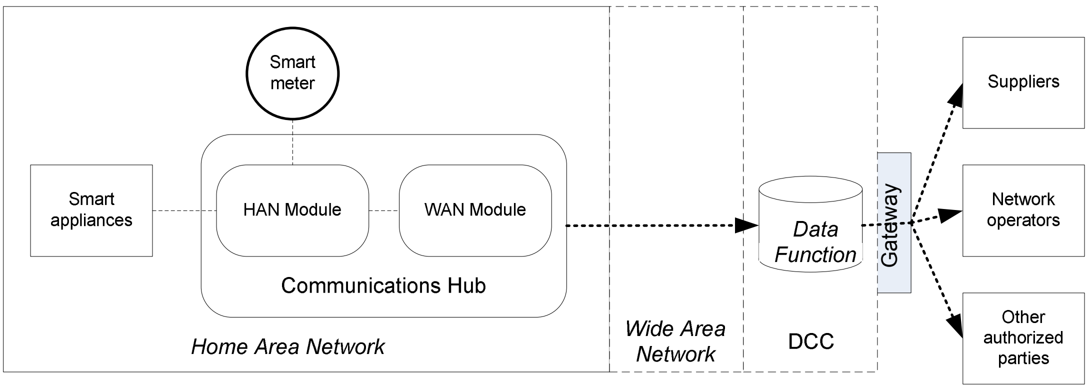


Fig. 6.1. Communication networks of the UK smart metering system [139]

Since there will be 27 million domestic smart meters in the UK, to send one power measurement from controllable loads per minute, the communication network, data-function and gateway must be capable of sending a large volume of data per minute (about 81 million measurements; calculated in Section 6.4). This is unlikely because the UK smart metering communication system will be used to send measurements, alarms and control commands [110] and hence it will not be dedicated for demand response.

6.3 A communication network for notifying available controllable loads

Aggregating measurements at different stages of a hierarchically arranged communication network would reduce the number of measurements to be sent. Therefore, the possibility of using a hierarchical communication network to aggregate and send measurements to NGET is addressed.

Data aggregation is found in the smart metering system in Italy. In this system, first, smart meters send data to a concentrator installed at 11 kV transformers, through a Neighbourhood Area Network (NAN). Then these data are sent to a data centre through a WAN [140]. Some of these concentrators have data processing capability to sum daily energy consumption of selected meters to detect illegal tapping of lines [141]. The concentrators can compress data to reduce communication bandwidth use.

In the UK smart metering system, data aggregation is discussed as a means of protecting privacy of customers [142].

When the communication network is hierarchically arranged, the aggregated power measurement at one level of the hierarchy provides the total power consumption of the network below that level. Therefore it is advantageous to design the hierarchy such that it follows the hierarchy of electricity distribution networks. The aggregated measurements and alarms sent by smart meters can be used locally for distribution network control without sending messages to higher levels of the hierarchy, thus reducing data traffic at the higher levels.

A commercially available hierarchical communication system which follows the electrical network is used in Ontario, Canada [143]. It has multi-tier smart grid architecture formed by HANs, NAN and a WAN. This system integrates 1.3 million smart meters, distribution control systems and a meter data management centre. The data from HANs are collected at a concentrator to form a NAN. The WAN interconnects all NANs and distribution network devices such as substations, capacitor banks and voltage regulators. The WAN supports demand response and distribution automation. A NAN has a data rate of 250 kbps and the WAN has 54 Mbps data rate.

6.4 Number of measurements sent through communication networks

In the study reported in this chapter, the number of power measurements sent through a communication network to report available controllable loads was calculated for five different cases. These cases included a baseline case (where all measurements were sent to NGET through the DCC) and four cases of data aggregation done at different levels of a hierarchical communication network. It was assumed that the power measurements of controllable loads were sent to NGET at every minute, although sending data at this rate is not discussed in the UK smart metering system.

A hierarchical communication network that follows the electricity distribution network was assumed (shown in Fig. 6.2). A domestic controller installed in each house sends measurements to a concentrator (a device that aggregates received measurements) installed at the 11/0.4 kV transformer, forming a NAN. A concentrator at each 11/0.4 kV transformer sends measurements to a concentrator in the upstream 132/11 kV or 33/11 kV substation. A Metropolitan Area Network (MAN) is formed by the concentrators in 11/0.4 kV transformers and the concentrator in 132/11 kV or 33/11 kV substation. The concentrator in each 132/11 kV or 33/11 kV substation sends data to the DCC through a WAN. Then NGET accesses data from the DCC through the WAN.

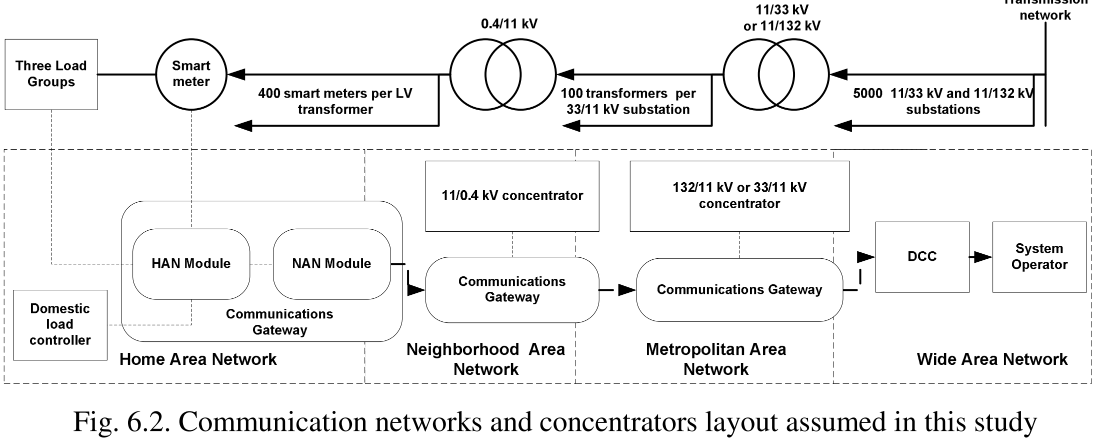


Fig. 6.2. Communication networks and concentrators layout assumed in this study

The number of smart meters, transformers and substations, given in Fig. 6.2, were taken from references that provide information about the UK electricity network. Based on a study conducted by PB Power [144] (which assumes 96 premises per feeder and four feeders per transformer), it was assumed that maximum 400 premises are supplied by one 11/0.4 KV transformer. In the data used for developing UK Generic Distribution Network (UKGDS) [145], overhead lines have the highest number (98) of transformers per line and hence it was assumed that a 11 kV network has one hundred 11/0.4 kV transformers. A NGET website [146] notes that the UK distribution networks have about five thousand 132/11 kV and 33/11 kV substations.

Load profiles of three Load Groups (given in Table 5.1) in 40,000 houses were constructed using the method explained in Section 5.5 (400 houses x 100 11/0.4 kV transformers). As an example, load profiles of the three Load Groups in a house are shown in Fig. 6.3. To calculate the number of appliances in a house, it was assumed that these 40,000 houses have a number of appliances proportionate to the number of appliances in the UK (given in Table 5.2).

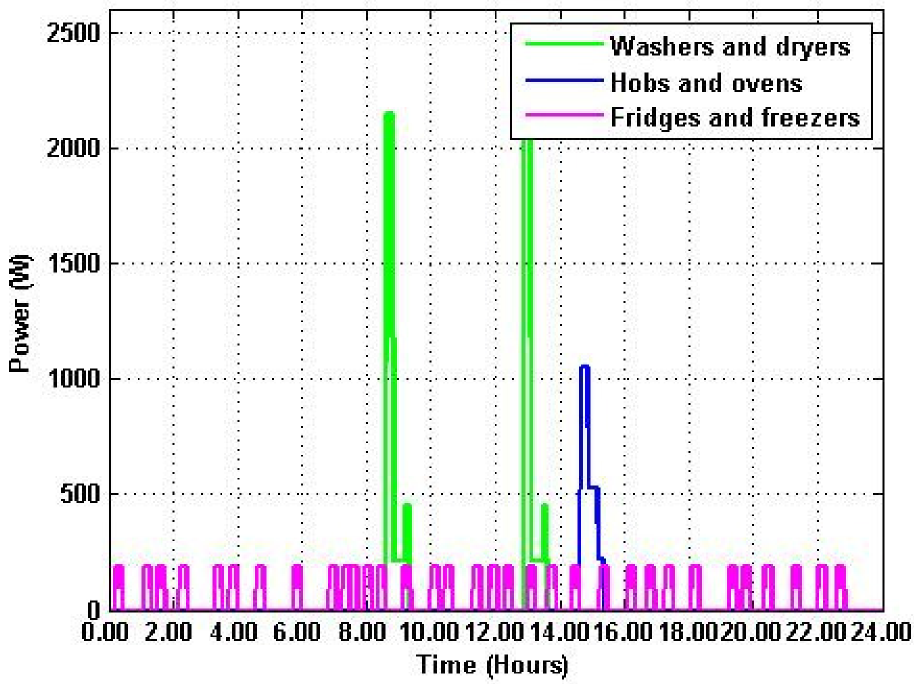


Fig. 6.3. Example load profiles of three Load Groups in a house

Present-day smart meters do not have a built-in function to calculate the power consumption of each appliance separately. Therefore, it was assumed that a domestic load controller installed in each house, calculates the power consumption of each Load Group and sends the calculated values through the smart meter.

Case 1: Smart meters send measurements to NGET through a Neighbourhood Area Network (NAN), Metropolitan Area Network (MAN) and then the Wide Area Network (WAN)

This is the baseline case where each smart meter sends three measurements per minute, one for each of the three Load Groups (given in Table 5.1) to NGET through a NAN, MAN and the WAN. Since the NAN covers a maximum of 400 smart meters (and that 100% houses are in the load control scheme) then, at most 1200 measurements per minute were sent through each NAN to the concentrator at 11/0.4 kV transformers. Since it is assumed that a MAN is formed by concentrators at one hundred 11/0.4 kV transformers (with each collecting data from 400 smart meters) the MAN must deliver 120k measurements per minute. Each MAN sends these measurements to NGET through the WAN and hence the WAN receives measurement from all smart meters in the UK. Since three measurements per minute are sent from each meter, for 27 million meters, 81M measurements needed to be sent per minute through the WAN.

The number of measurements sent through a NAN, a MAN and the WAN is given in Table 6.2 for the cases when 25%, 50%, 75% and 100% of houses in each network were included in the load control scheme.

TABLE 6.2. NUMBER OF MEASUREMENTS SENT THROUGH A NAN, MAN AND THE WAN

Percentage of households in the load control scheme	25%	50%	75%	100%
Number of measurements send by a smart meter per min (one for each Load Group)	3			
Number of measurements sent through a NAN per min (Assuming 400 smart meters per NAN)	300	600	900	1200
Number of measurements sent through a MAN per min (Assuming 40000 smart meters per MAN)	30k	60k	90k	120k
Number of measurements sent through the WAN per min (Assuming 27M smart meters)	21M	41M	61M	81M

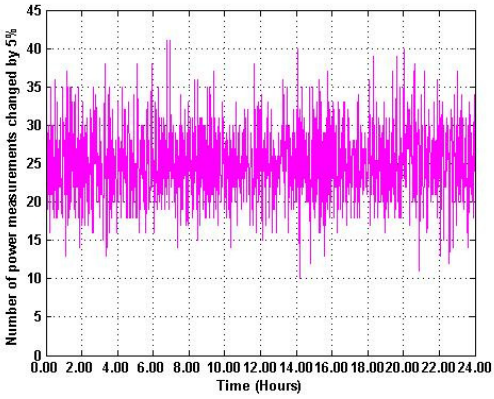
Case 2: Domestic load controller sends messages only after a change was detected in the power measurements

In this case, it was assumed that a domestic load controller compared the present power measurement of each Load Group (given in Table 5.1) with the last measurement that was sent to NGET. The controller sends measurements to NGET only if the power consumption changed more than ±5% from the last measurement.

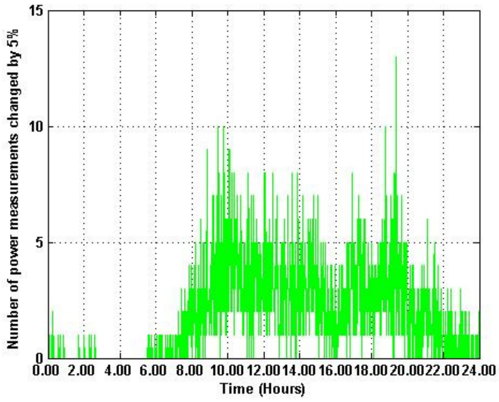
The load profile of Load Groups in each household (an example is given in Fig 6.3) was used to find whether the power consumption between two consecutive measurements changed. The power consumption changes per minute for three Load Groups in all 400 houses fed by a single 11/0.4 kV transformer were counted to calculate the total number of measurement changes (assuming 100% houses were in the load control scheme).

An example of the changes in 400 houses fed by one transformer is given in Fig. 6.4. This example shows that about 10 to 45 power changes in Load Group I occur per minute across all 400 houses. Therefore, instead of sending 400 measurements (one per house per Load Group), a maximum of 45 measurements per minute were sent to a 11/0.4 kV concentrator through a NAN for Load Group I.

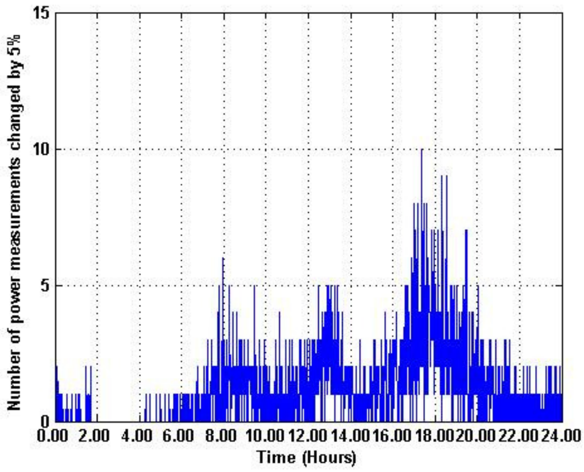
From similar plots for 100 transformers, the maximum numbers of power changes per transformer were found and they are given in Table 6.3. To send these changes to a concentrator at 11/0.4 kV transformer, a NAN must be able to send 80 measurements per minute. Since these 80 measurements were sent by 400 smart meters, the average number of measurements sent per meter was 0.2 per minute.



(a) Load Group 1(Fridges and freezers)



(b) Load Group II (Washers and dryers)



(c) Load Group III (Hobs and ovens)

Fig. 6.4. Number of power measurement changes of 400 houses (fed by one 11/0.4 kV transformer) at each minute

TABLE 6.3. MAXIMUM NUMBER OF POWER MEASUREMENT CHANGES FOR EACH LOAD GROUP

Load Group	Maximum number of power measurement changes
I	50
II	15
III	15
Total	80

A MAN formed by one hundred 11/0.4 kV transformers received 8k measurements; 80 from each 11/0.4 kV transformer. The measurements received through each MAN were sent to NGET through the WAN. Therefore, given a rate of 0.2 measurements per minute per meter, 27 million meters sent 5.4M measurements through the WAN.

The above calculations were done assuming 100% of houses (i.e. all 400 houses of a 11/0.4 kV network) were in the load control scheme. Using similar graphs, the number of measurements sent by smart meters were calculated when 25%, 50% and 75% of houses were in the load control scheme (given in Table 6.4).

TABLE 6.4. THE NUMBER OF MEASUREMENTS SENT THROUGH A NAN, MAN AND THE WAN WHEN DOMESTIC CONTROLLER SENT MEASUREMENT CHANGES MORE THAN ±5%

Percentage of houses in the load control scheme	25%	50%	75%	100%
Maximum number of measurements sent by a domestic load controller through a NAN per min (assuming 400 smart meters per NAN)	35	50	65	80
Number of measurements sent through a MAN per min (assuming 40000 smart meters per MAN)	3.5k	5k	6.5k	8k
Number of measurements sent through the WAN per min(assuming 27M smart meters in the WAN)	2.4M	3.4M	4.4M	5.4M

Case 3: A concentrator installed at each 11/0.4 kV transformer sends summed power measurements to the upstream 132/11 kV or 33/11 kV substation

In this case, a concentrator at each 11/0.4 kV transformer sums the power measurements sent by smart meters before sending to the concentrator at the upstream 132/11 kV or 33/11 kV substation. The concentrator at each 11/0.4 kV transformer sends three measurements per minute (one for each Load Group). Therefore, the Metropolitan Area Network (MAN) (formed by concentrators at one hundred 11/0.4 kV transformers and one 132/11 kV or 33/11 kV substation) carries 300 messages. Further, in this case the percentage of houses in the load control scheme has no effect on the number of measurements sent. Examples of summed power measurements at one 11/0.4 kV transformer are shown in Fig. 6.5.

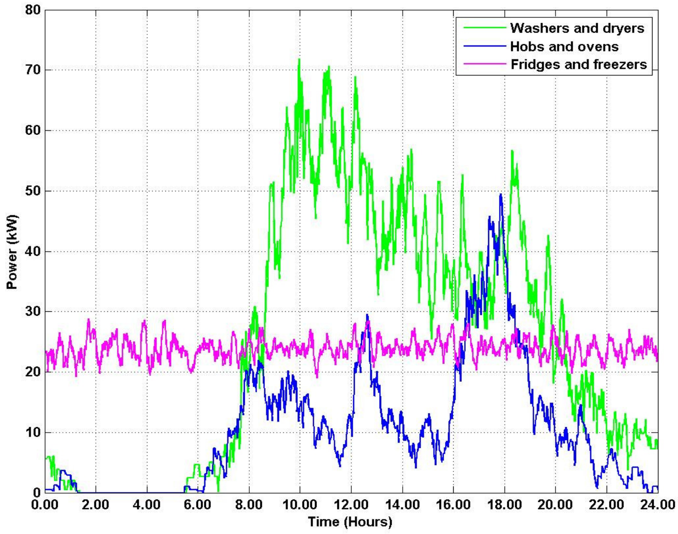


Fig. 6.5. Example total power consumption of each Load Group at one 11/0.4 kV transformer

Since there are about five thousand 132/11 kV and 33/11 kV substations in the UK [146], with 300 measurements per substation, about 1500k measurements are sent through the WAN to NGET per minute.

Case 4: A concentrator installed at each 11/0.4 kV transformer summed measurements and send them only after a change was detected

In this case, instead of sending three measurements at each minute, one for each of the three Load Groups from each 11/0.4 kV transformer, a measurement is sent only if the power consumption changed more than ±5% from the last measurement. Using the total power consumption of each Load Group at each 11/0.4 kV transformer (e.g. in Fig. 6.5) the number of power changes for one hundred 11/0.4 kV transformers was calculated. A graph of the number of power changes is given in Fig. 6.6. For example, this graph shows that, for one hundred 11/0.4 kV transformers, about 10-35 measurement changes occur in Load Group I (fridges and freezers) at each minute.

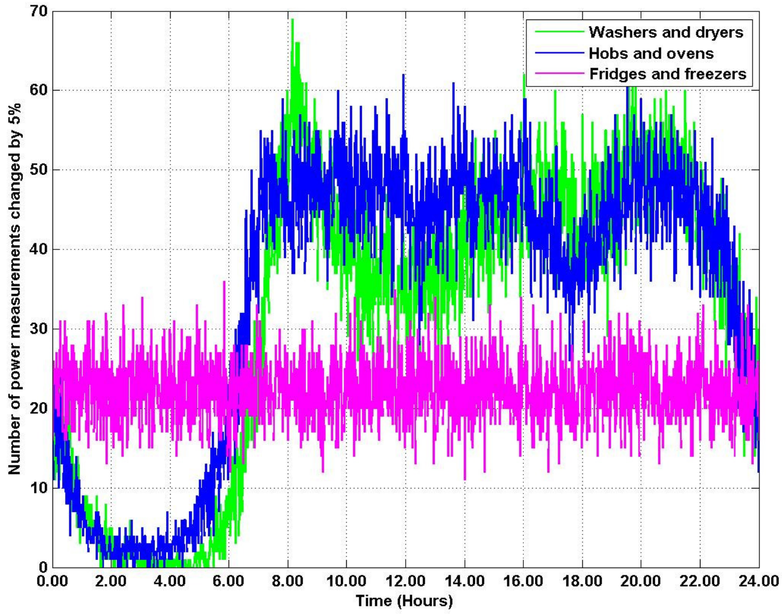


Fig. 6.6. Number of power measurement changes of three Load Groups for one hundred 11/0.4 kV transformers

The maximum number of measurement changes for three Load Groups are given in Table 6.5. As shown in Table 6.5, instead of sending 300 measurements per minute for one hundred 11/0.4 kV transformers (one measurement per Load Group) only about 170 measurements per minute were required. These 170 measurements were sent thorough a MAN formed by one hundred 11/0.4 kV transformers and a 132/11 kV or 33/11 kV substation. Since there are about five thousand 132/11 kV and 33/11 kV substations in the UK, 850k measurements per minute were sent to NGET from all substations through the WAN.

TABLE 6.5. MAXIMUM NUMBER OF POWER MEASUREMENT CHANGES FOR EACH LOAD GROUP

Load Group	Maximum number of power measurement changes
I	35
II	65
III	70
Total	170

Case 5: A concentrator installed at each 132/11 kV or 33/11 kV substation sends summed measurements to NGET

In this case, a concentrator installed at each 132/11 kV or 33/11 kV substation, summed measurements sent by concentrators at 11/0.4 kV transformers and sends only three measurements, one for each Load Group, to NGET. Therefore, from five thousand 132/11 kV and 33/11 kV substations in the UK [146], 15000 measurements were sent to NGET per minute.

The number of measurements sent in communication networks for all five cases, when 100% of houses were in the load control scheme, are summarised in Table 6.6.

TABLE 6.6. NUMBER OF MEASUREMENTS SENT IN EACH COMMUNICATION NETWORK WHEN 100% OF HOUSES WERE IN THE LOAD CONTROL SCHEME

Case		Number of measurements sent in each network per minute		
		NAN	MAN	WAN
1	Smart meters send measurements to NGET through a NAN, MAN and then the WAN	1200	120k	81M
2	Domestic load controller send messages only after a change was detected in the power measurements	80	8k	5.4M
3	A concentrator installed at each 11/0.4 kV transformer sends summed power measurements to NGET		300	1500k
4	A concentrator installed at each 11/0.4 kV transformer sums measurements and sends them only after a detected change		170	850k
5	A concentrator installed at each 132/11 kV or 33/11 kV substation sends summed measurements to NGET			15k

6.5 Message size required for sending measurements

In digital data communication, the size of a message can be given in bits or bytes. One byte has 8 bits. When a bit represents one (the weight of a bit), two bytes can represent any positive integer less than 65536 (i.e. 2^{8x2}). In this study, it was assumed that two bytes are used to send measurements in each network. The weight of a bit was selected so that the power measurements sent in each network can be represented with a sufficient accuracy. The power measurements represented by a bit and the maximum power measurements that can be sent using two bytes are shown in Table 6.7.

TABLE 6.7. MAXIMUM POWER MEASUREMENT THAT CAN BE SENT USING TWO BYTES

Two bytes are used to send a measurement of a;	Minimum power measurement (Represented by one bit)	Maximum power measurement (Represented by two bytes)
Smart meter	1 W	65535 W
11/0.4 kV Transformer	100 W	6553.5 kW
132/11 kV or 33/11 kV substation	1 kW	65535 kW

The total number of bytes sent in each network, for the measurements given in Table 6.6 (when 100% of houses are in the load control scheme), are shown in Table 6.8. However, the actual message sizes may increase with communication protocol overheads and data security requirements.

TABLE 6.8. NUMBER OF BYTES SENT IN HIERARCHICAL COMMUNICATION NETWORKS

Case (Discussed in Section 6.4)		Number of bytes sent in each network per minute		
		NAN	MAN	WAN
1	Smart meters send measurements to NGET through a NAN, MAN and then the WAN	2400	240k	162M
2	Domestic load controller send messages only after a change was detected in the power measurements	160	16k	10.8M
3	A concentrator installed at each 11/0.4 kV transformer sends summed power measurements to NGET		600	3.0M
4	A concentrator installed at each 11/0.4 kV transformer sums measurements and sends them only after a detected change		340	1.7M
5	A concentrator installed at each 132/11 kV or 33/11 kV substation sends summed measurements to NGET			30k

Using the number of messages sent by meters (discussed in Section 6.4), the average number of bytes sent per day per meter was calculated (given in Table 6.9).

TABLE 6.9. AVERAGE NUMBER OF BYTES SENT PER DAY, PER METER

Case (Discussed in Section 6.4)		Average number of bytes sent per day per meter
1	Smart meters send measurements to NGET through a NAN, MAN and then the WAN	8640
2	Domestic load controller send messages only after a change was detected in the power measurements	576
3	A concentrator installed at each 11/0.4 kV transformer sends summed power measurements to NGET	22
4	A concentrator installed at each 11/0.4 kV transformer sums measurements and sends them only after a detected change	13
5	A concentrator installed at each 132/11 kV or 33/11 kV substation sends summed measurements to NGET	2

6.6 Discussion

NGET indicated that it is advantageous if domestic appliances can notify the availability of demand response periodically. Therefore, the number of power measurements needs to be sent to NGET at one minute interval, to notify the amount of controllable loads available, was calculated. It was shown that, when all smart meters send load measurements to NGET at one minute intervals, 81M measurements need to be sent per minute.

However, by using concentrators installed at different levels of a hierarchical communication network, the number of measurements sent through the networks can be reduced. When the concentrators send only changes in power measurements, the number of measurements can be reduced further. By aggregating and sending only the changes, the number of measurements sent in the WAN per minute can be reduced from 81M to 15k.

If the communication network that is being planned in the UK smart metering system can accommodate messages of 300-400 bytes per minute in a NAN and a MAN and about 30 kB per minute of messages in the WAN, the available frequency response from controllable loads can be reported to NGET every minute.

The WAN requirements for the DCC [111] notes that the message named ‘scheduled reads’ (given in Table 6.1) that sends 544 bytes 48 times a day would have high impact on the WAN (i.e. 26,112 bytes per day per meter). Comparing with that, sending 81M power measurements of controllable Load Groups to NGET once a minute would also have high impact on the WAN (i.e. about 8700 bytes per day per meter). However, by aggregating and sending only measurement changes, the impact on the WAN could be drastically reduced (as shown in Table 6.9, the average number of bytes sent per meter per day can be reduced from about 8700 to 2).

7 Smart meter measurements for distribution system voltage estimation

Note: The Iteratively Re-Weighted Least Square (IRWLS) state estimation developed by Dr. Jianzhong Wu [147] was used in the study reported in this chapter.

7.1 Introduction

The rate of collecting and transmitting smart meter measurements varies from utility to utility. In some present-day smart metering implementations, energy measurements are taken at intervals of a half hour or less. Although this measuring rate may be sufficient to estimate the distribution network voltage in near real-time, these measurements are not transmitted immediately after taking them. Instead, they are stored internally and sent to the energy supplier periodically, at most once a day.

Therefore, in the study reported in this chapter, the ability of a state estimator to estimate distribution network voltages using domestic smart meter measurements sent on the previous day was investigated. For a weekday, the state estimator used measurements from the previous weekday. For a Saturday or Sunday the state estimator used measurements from the previous Saturday or Sunday. The ability of near real-time measurements, obtained on the same day from distributed generators (at 15 minute intervals), to improve the accuracy of the estimations was also investigated.

7.2 Transmission interval of smart meter measurements

A review issued by Energy Community Regulatory Board of the EU [63] gives the smart meter data transmitting rates of Italy and six non-EU countries. As shown in Fig.7.1, only two countries send data more than once a month.

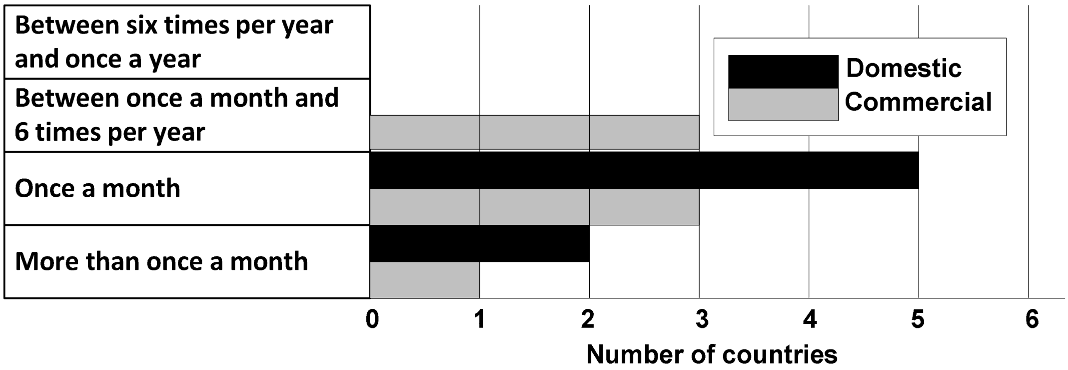


Fig. 7.1. Number of countries that have different smart meter measurement transmitting rates in six non-EU countries and Italy [63]

Federal Energy Regulatory Commission (FERC) of the USA defines smart meters with advanced metering infrastructure (AMI) functions as the ones that collect measurements at intervals of an hour or less and send measurements daily, or more frequently, to a central data collection point through a communication network. A survey done by FERC showed (Fig. 7.2) that 5.9% of existing meters (as at 2006) had the ability to take measurements at an interval less than an hour and to send once a day [62]. However, the survey done in 2008 revealed that, out of these metes only 0.6% actually took measurements at a rate less than an hour and sent measurements daily [148]. FERC expects that the number of meters that use these AMI functions would increase to 56% by 2019 under a business as usual scenario [149].

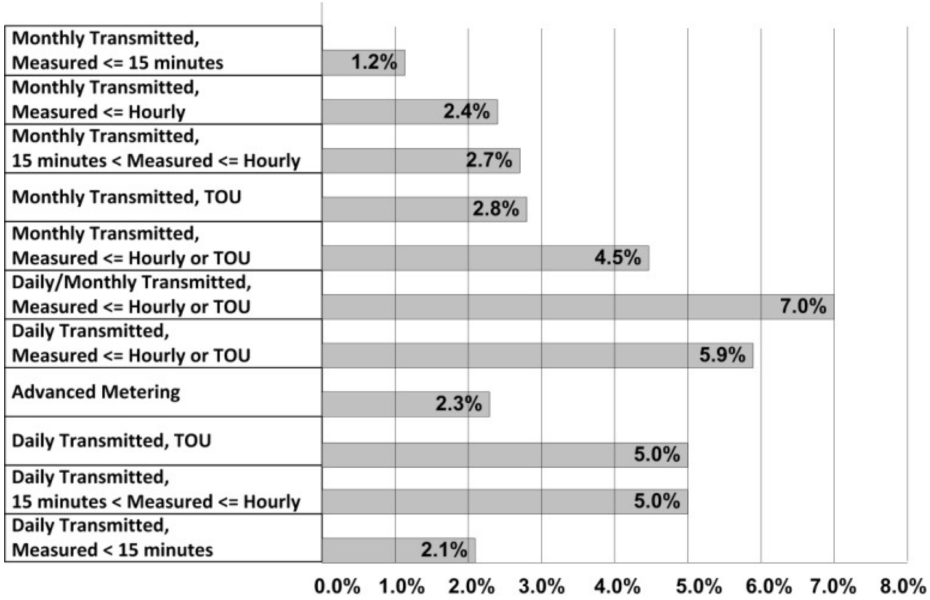


Fig. 7.2. Percentages of smart meters with different measuring and transmitting rates in the USA in 2006 [62]

In the UK smart meter design requirements [61], the smart meters are to measure import and export energy half hourly and measurements from all meters are to be sent to DCC within a day.

7.3 Smart meter measurements for distribution system state estimation

State estimators are used in Distribution Management Systems (DMS) and SCADA systems to estimate the network parameters such as voltages and the loads of distribution networks [9]. State estimation algorithms use few local measurements from medium voltage substations (e.g. 132/11 kV or 33/11 kV), measurements from remote transformers/feeders and many pseudo measurements. Generally, the pseudo measurements are obtained from load models or historical load data [10].

With the deployment of smart meters, it is anticipated that load measurements will be available for state estimation from all customer premises. Baran [58] showed that, when real-time smart meter measurements are used, the accuracy of distribution state estimation can be increased. Wang [59] used smart meter measurements that communicated at 15 min intervals to estimate the active and reactive power of low voltage transformers (e.g. 11/0.4 kV) at any time of a day.

In the study reported in this chapter, it is assumed that smart meter measurements are obtained at 15 min intervals and sent to the DCC within 24 hours. Therefore, at any given time, a measurement set taken up to 24 hours before that time is available to the state estimator. It is also assumed that the state estimator uses real-time measurements (sent within 15 minutes) obtained from distributed generators on the network.

7.4 Principles of state estimation

Using the power flow equations, the power injected to a network node, or power flow between two nodes can be expressed as functions of voltage magnitude (v) and phase angle (θ) of network nodes [150]. For a network with N number of nodes (i = *1..N*), the functions for power injection measurements (p_i, q_i) to node i are in the form of $p_i = h_1(v_i, v_k, \theta_i, \theta_k)$, $q_i = h_2(v_i, v_k, \theta_i, \theta_k)$ where k = *1..N* and $k \neq i$. The functions for power flow (p_{ij}, q_{ij}) between nodes i and j are in the form of $p_{ij} = h_3(v_i, v_j, \theta_i, \theta_j)$, $q_{ij} = h_4(v_i, v_j, \theta_i, \theta_j)$ for all i = *1..N* and j = *1..N* and $i \neq j$.

When these power measurements are selected as the measurements for the state estimator, the measurement vector (z) can be written as $z^T = [\, p_i \quad q_i \quad p_{ij} \quad q_{ij} \,]$.

When the node voltage magnitude (v_i) and phase (θ_j) are taken as states, the state vector x can be written as $x = \begin{bmatrix} v_i \\ \theta_j \end{bmatrix}$ for i = *1..N* and j = *2..N*. The node 1 is used as the reference bus and hence $\theta_1 = 0$.

The measurement functions h_1, h_2, h_3, h_4 can be written as a vector $h(x)$ that gives the relationship between state vector (x) and measurement vector (z) as $z = h(x) + e$

where $h(x) = \begin{bmatrix} h_1(x) \\ h_2(x) \\ h_3(x) \\ h_4(x) \end{bmatrix}$ and e is the measurement error vector.

The relationships between state variables and the measurements are given in Appendix E.

The Weighted Least Squares algorithm (WLS) is used commonly for state estimation [151]. The WLS algorithm minimises the weighted sum of the squares of the measurement errors given by (7.5).

$$J(x) = \sum_{i=1}^{m}((z_i - h_i(x))^2 W_{ii} \quad \text{where } m = \text{number of measurements}$$

$$J(x) = (z - h(x))^T W (z - h(x)) \tag{7.5}$$

Where $z - h(x)$ = measurement error vector (e) and W = weight matrix.

The weight matrix W is a diagonal matrix where the weights of the measurements are in the main diagonal. The weights indicate the accuracy of measurements. In WLS, the reciprocal of measurement variances ($1/\sigma^2$) are used as weights so that the influence of the measurements with higher variance to the final estimate is less.

The Iteratively Re-Weighted Least Square (IRWLS) algorithm is considered as a more robust estimator [152] and so was used in this study. In the IRWLS, measurement weights (W) are modified at each iteration of the state estimator so that the measurements estimated to contain large errors are given smaller weights.

7.5 State estimation of a distribution network

The distribution network layout given in Fig. 7.3 was assumed. Smart meters installed at houses and at 11kV distributed generators are connected to the DCC through communication networks. A state estimator runs in a Distribution Network Controller installed at the 33/11 kV substation. The state estimator estimates the distribution network voltages using the smart meter measurements obtained through the Wide Area Network (WAN).

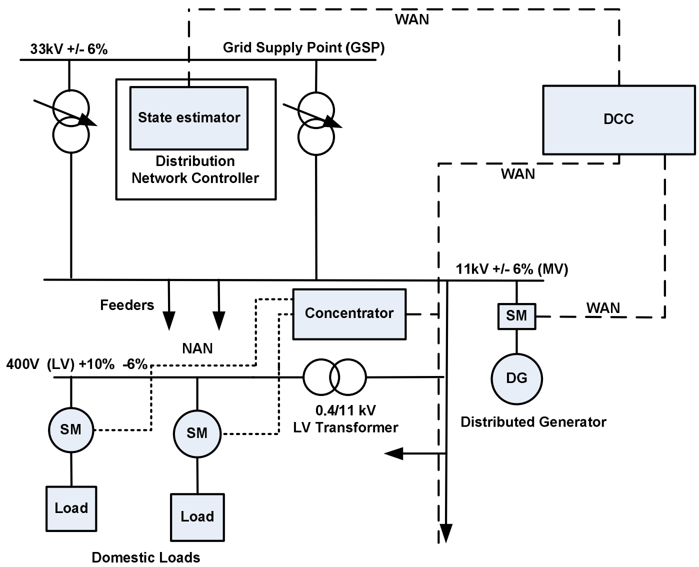


Fig. 7.3. Distribution network layout

It was assumed that domestic smart meters measure active power (P) and reactive power (Q) of the loads at 15 min intervals and store the measurements internally. The measurements are sent to the DCC within 24 hrs. Therefore, at any given time (*t*), the state estimator has the measurements obtained twenty four hours before that time (*t* - 24 hrs).

Smart meters installed at distributed generators measure P, Q and voltage magnitude (*V*) at 15 min intervals and send the measurements immediately to the Distribution Network Controller, through the DCC.

It is assumed that smart meter measurements are time stamped and that the internal clocks of all smart meters are synchronised to the Universal Coordinated Time (UTC).

The data flow of the state estimator is shown in Fig. 7.4. The load of each 11/0.4 kV transformer is calculated by summing the previous day's power measurements obtained from the smart meters fed by the transformer (this is possible because these measurements were time synchronised). The previous day's transformer loads and the near real-time (at every 15 min) power measurements obtained from distributed generators (DG) are used as power injection measurements for the state estimator (p_i, q_i discussed in Section 7.4). The power flow measurements at the Grid Supply Point (GSP) (P, Q from the 33 kV network to the 11 kV network) (p_{ij}, q_{ij}), and the voltage magnitudes at the GSP and the distributed generators (v_i) are also used for the state estimation.

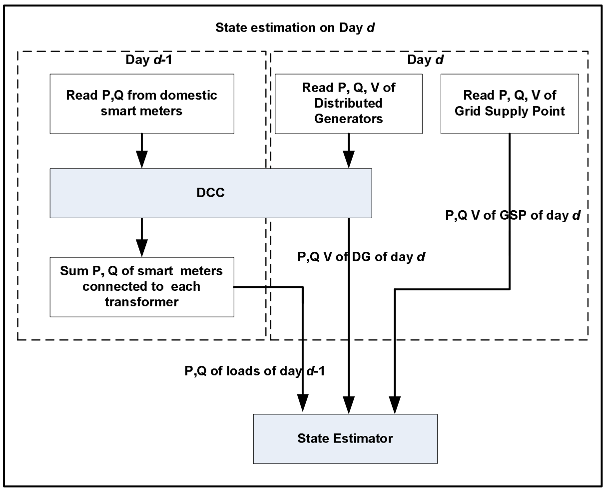


Fig. 7.4. Data flowchart of the state estimation

7.6 Simulations

A seventy five node network of the UK generic distribution system (UKGDS) [153] given in Fig. 7.5 was used as the test network for the state estimator.

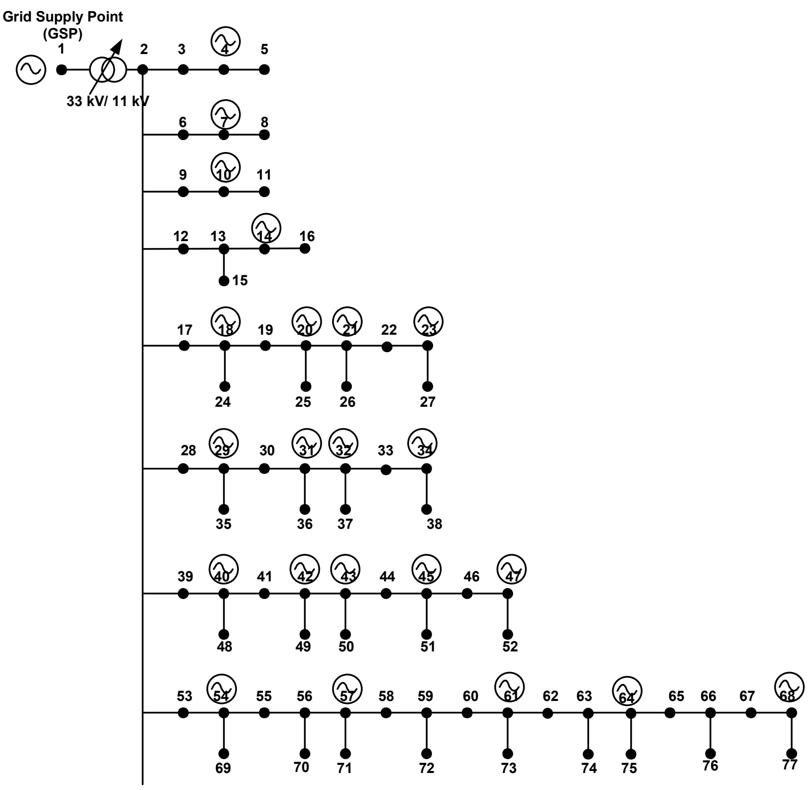


Fig. 7.5. UKGDS 11 kV under ground urban network

Load profiles for each load node in the test network were constructed using standard load profiles developed for the Irish electricity market [154]. These standard profiles were developed for nine consumer categories (e.g. urban domestic, rural domestic etc, the complete list is given in Appendix D) by installing sample domestic meters in Irish households. These standard profiles are normalised over a period of one year and hence each load profile was scaled to get the maximum load equal to unity. Assuming that each test network node feeds only one consumer category, the load profiles were assigned to each load node. The nodes assigned to each standard load profile are given in Appendix D. The assigned load profile was multiplied by P and Q values for each node given in the UKGDS test network.

Random variations were added to the load profiles obtained from the Irish standard profiles because these load profiles were smooth due to the aggregation of a large number of samples. In the UK, as the average number of customers per 11/0.4 kV transformer is about 200 [155], the actual load profiles would have significant variation. Therefore, three sets of load profiles were constructed by adding maximum of ±10%, ±25%, and ±50% random variations at each time step (15 min) of the aggregated load profiles.

Output profiles for each generator node of the network were constructed using the generator profiles given in the UKGDS. Since the UKGDS generator profiles are also normalised to give a maximum power equal to unity, they were multiplied by P and Q values of each generator node given in the UKGDS to calculate the output P and Q profiles of the generator. Then maximum random deviations of ±10%, ±25%, and ±50% were added at each time step of the generator profiles to account for the variability of generator output (photovoltaic, combined heat and power, small hydro and wind).

The data flow chart for the simulation is shown in Fig. 7.6. Although it was assumed in Section 7.5 that the state estimator uses voltage measurements obtained from distributed generators and the GSP, these measurements were not available for the simulation. Therefore, the voltage $V_{d,t}$ for a selected day *d* and $V_{d-1,t}$ for the previous day *d-1* at time *t* for each node were calculated using the standard Newton-Raphson power flow algorithm in Matpower software package [156].

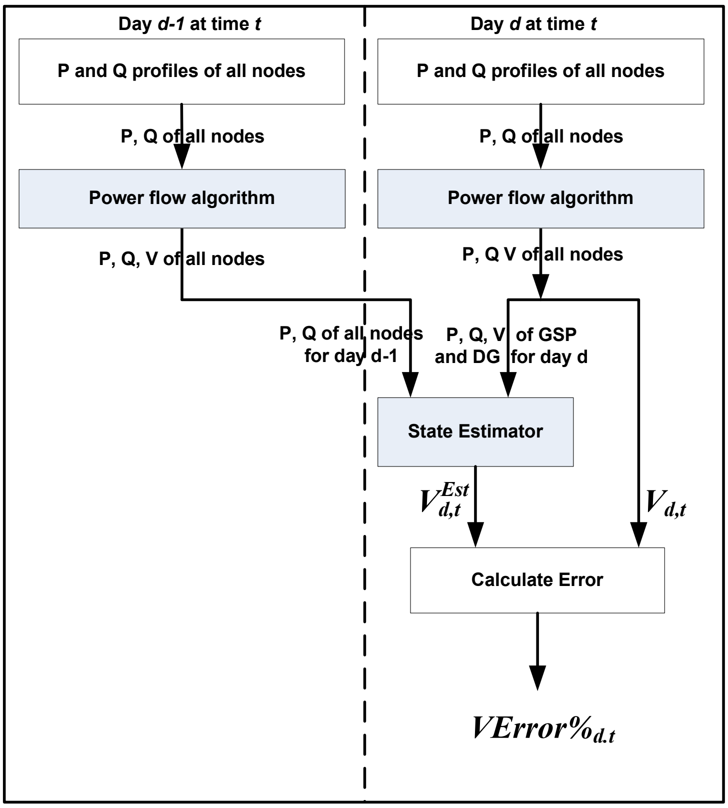


Fig. 7.6. Data flow chart of the simulation

The Iteratively Re-Weighted Least Square (IRWLS) state estimator developed by Wu [147] was used to estimate the voltages of the network nodes. In IRWLS state estimators, higher weights in weight matrix W (discussed in Section 7.4) indicate more accurate measurements. Therefore in this study, initially for each time step, the previous day's measurements were given low weights (0.3) and near real-time measurements were given higher (0.9) weights. At each iteration, the IRWLS algorithm modifies the weights automatically by giving smaller weights to measurements that contain large errors. If the state estimator did not converge, the weights of the recent measurements were reduced from 0.9 to 0.3 in steps of 0.2 and then the weights of past measurements were increased from 0.3 to 0.9 in steps of 0.2 until the state estimator converged.

The node voltages ($V_{d,t}^{Est}$) on the given day d at each time t, were estimated using:

- the previous day's (*d-1*) P and Q of loads at time t

- a different number of nodes providing near real-time P, Q and V measurements within the previous 15 minute period from time t on day d.

Simulations were carried out for seven cases given in Table 7.1. In the first case (base case) no real time measurements were used. For the second case near real-time measurements were obtained only from the GSP. For the other five cases, near real-time measurements were obtained from the GSP and 1, 2, 6, 11 and 22 distributed generators. For the generators that did not provide real-time measurements, the previous day's measurements were used.

TABLE 7.1. SIMULATION CASES AND THE NODES THAT PROVIDED NEAR REAL-TIME MEASUREMENTS

Case	Number of near real-time measurements	Near real-time measurements obtained from	Nodes that provided the near real-time measurements
1	0	None	-
2	1	GSP	1
3	2	GSP and 1 DG	1, 68
4	3	GSP and 2 DGs	1, 32, 68
5	7	GSP and 6 DGs	1, 14, 23, 34, 45, 61, 68
6	12	GSP and 11 DGs	1, 4, 10, 18, 21, 29, 32, 40, 43, 47, 57, 68
7	23	GSP and 22 DGs	1 and all DG nodes

To get an accurate state estimation, the nodes that provided near real-time measurements were selected such that they are distributed across the network (See Table 7.1). Since the first near real-time measurement was from the upstream end of the network (i.e. from the GSP) the second node was selected from the downstream end of the network (i.e. node 68) (this is the case where 1 generator provided near real-time measurements). For the cases with 2, 6, and 11 distributed generators providing near real-time measurements, they were evenly distributed across the network among the generators that did not provide near-real time measurements.

For each case, the error percentage of estimated voltages for each node was calculated using equation (7.6).

$$VError\%_{d,t} = \frac{(V_{d,t}^{Est} - V_{d,t}) \times 100}{V_{d,t}} \qquad (7.6)$$

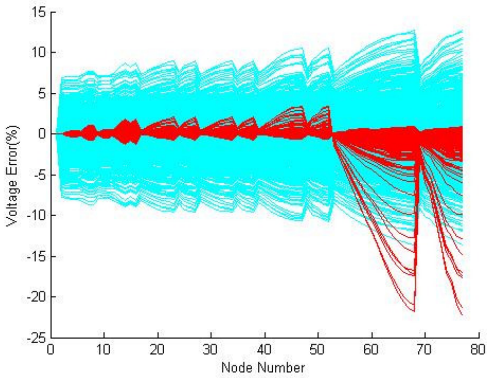
7.7 Results

The seven cases discussed in Section 7.6 were simulated using load and generator output profiles for ten days and the voltage error percentages ($VError\%_{d,t}$) were calculated for every node.

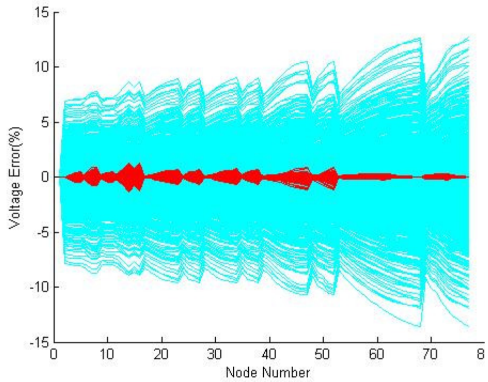
Fig. 7.7 shows the voltage error ($VError\%_{d,t}$) with and without near real-time measurements (in blue and red), when maximum ±50% random variations were added to the load and generator profiles. Each curve on the graph shows the error percentage of the voltages at distribution network nodes at a given time *t*. Points for every 15 minutes over 10 days were plotted on the same graph.

Blue coloured plots show that, when the previous day measurements were used without any near-real time measurement, the voltage errors were as high as 15%. When a near real-time measurement at the GSP was used (red coloured plot in Fig. 7.7(a)) the voltage error of the nodes close to the GSP was reduced below 5%. However, in this case the error at the downstream end of the network (nodes 55-77) was increased from 15% to 25%.

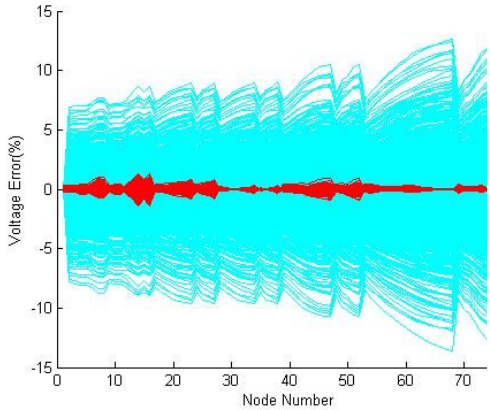
When near real-time measurements at the GSP and at end of the network were used (red coloured plot in Fig. 7.7(b)) the voltage error across the entire network was reduced. The last nodes of each branch (e.g. nodes 5, 8, 11) had errors of about 3%. As the number of near real-time measurements was increased, the errors at these nodes were also reduced.



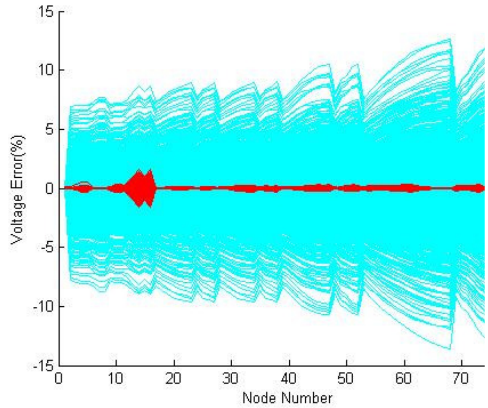
(a) Near real-time measurements were from GSP



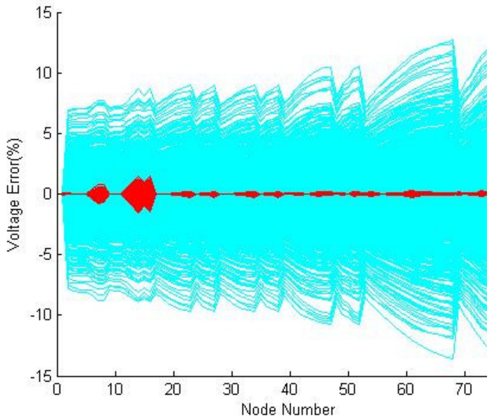
(b) Near real-time measurements were from GSP and 1 DG



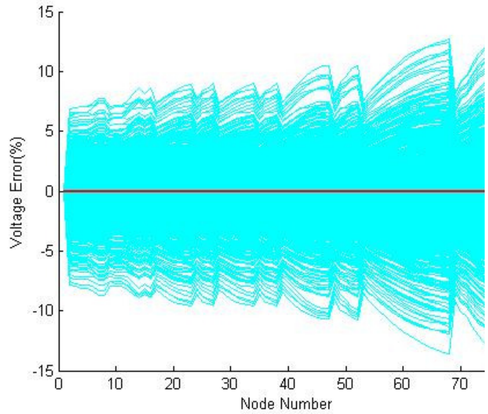
(c) Near real-time measurements were from GSP and 2 DGs



(d) Near real-time measurements were from GSP and 6 DGs



(e) Near real-time measurements were from GSP and 11 DGs



(f) Near real-time measurements were from GSP and 22 DGs

Fig. 7.7. Voltage error percentages at nodes calculated using previous day's measurements when load and generation variation is 50 %
In blue: without near real-time measurements
In red: with near real-time measurements

The relative frequencies[4] of the voltage errors were calculated using the voltage error percentages given in Fig. 7.7. First, the voltage error percentages were put into one hundred bins. This was done for the 77 nodes for every 15 minutes (96 values per day) over 10 days. Then, each bin was divided by the total number of voltage errors (i.e.77x96x10) to obtain the relative frequencies. The relative frequency diagrams show the spread of the voltage errors (given in Fig. 7.8 and 7.9). The standard deviation (σ) of these voltage errors gives a measure of the spread of error. When the error percentage is assumed to be a normal distribution, 99.6% of errors lie within ±3σ interval. The standard deviation is given below the title of each plot.

The relative frequency diagram in Fig. 7.8 shows that when previous day's measurements were used without any near-real time measurements, about 99% of voltage errors were less than 9% (3σ interval).

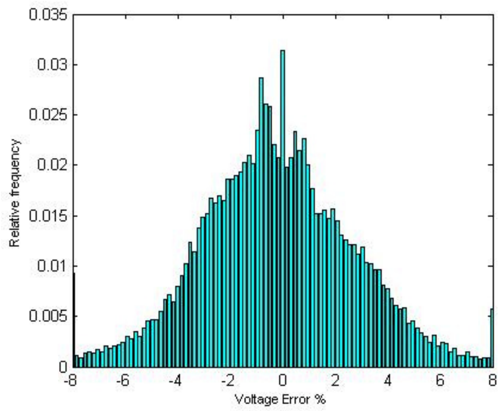
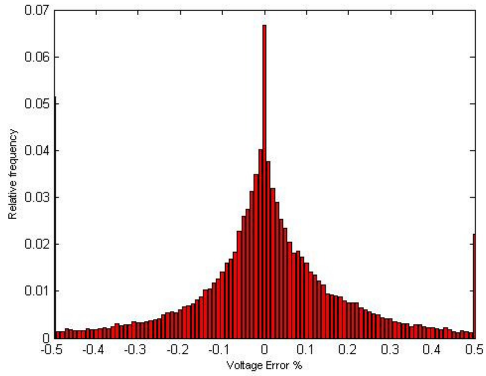


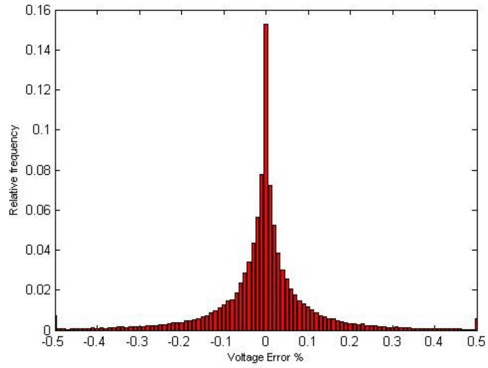
Fig. 7.8. Relative frequency diagrams of voltage error percentage using previous day's measurements without near real-time measurements when load and generation variation is 50%
(Standard deviation = 3)

Fig. 7.9(a) - 7.9(f) show the relative frequency diagram for the cases where a different number of nodes provided near real-time data. When the number of near real-time measurements was increased from one (from the GSP) to 22 (from all distributed generators) about 99% of voltage errors reduced from 2.1% to 0.006% (3σ interval).

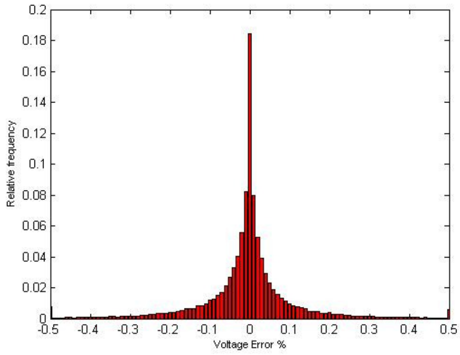
[4] The ratio between the number of occurrences of an event and the total number of observations



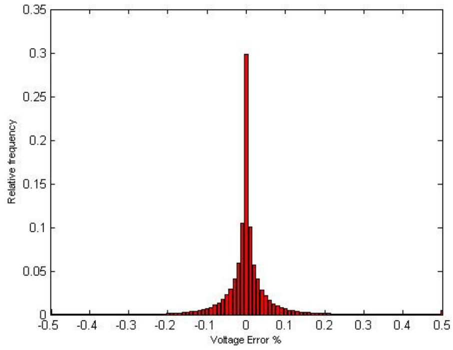
(a) Near real-time measurement was only from GSP
(Standard deviation = 0.7)



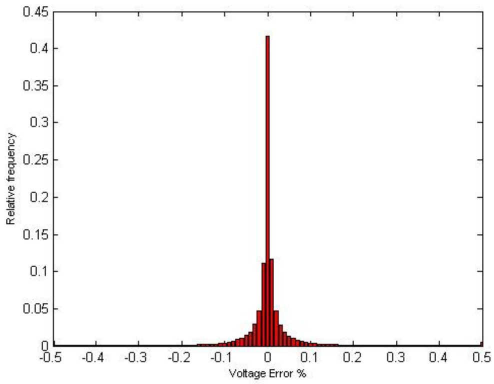
(b) Near real-time measurements were from GSP and 1 DGs
(Standard deviation = 0.14)



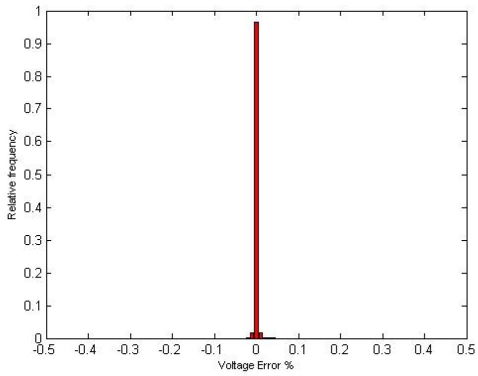
(c) Near real-time measurements were from GSP and 2 DGs
(Standard deviation = 0.13)



(d) Near real-time measurements were from GSP and 6 DGs
(Standard deviation = 0.1)



(e) Near real-time measurements were from GSP and 11 DGs
(Standard deviation = 0.1)



(f) Near real-time data measurements were from GSP and 22 DGs
(Standard deviation = 0.002)

Fig. 7.9. Relative frequency diagrams of voltage error percentage using previous day's measurements with near real-time data when load and generation variation is 50%

Similar graphs and the standard deviations of voltage errors were obtained for the cases where 0%, 10% and 25% load and generation variations.

Fig. 7.10 shows the graphs of standard deviations for 0%, 10%, 25% and 50% load and generation variations. Each plot shows the change of standard deviation with respect to a different number of nodes providing near real-time measurements (from the GSP only, from the GSP and 1, 2, 6, 11 and 22 distributed generators.

When the variations of load and generation lay within 25% of their average profiles, about 99% of the voltage error was reduced below 0.6% (3σ interval) by using one near real-time measurement at the grid supply point. If the loads and generators variation was between 25% - 50% the error was reduced to 0.6% by using two near real-time measurements; one from the GSP and one from the distributed generator at the down stream end of the network.

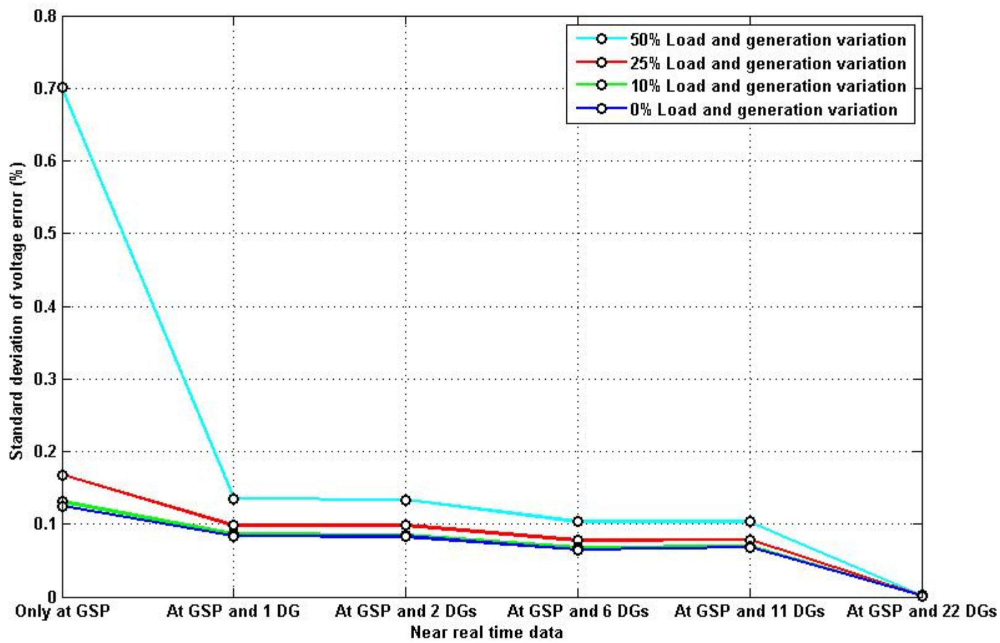


Fig. 7.10. Graph of standard deviation of voltage error with different number of near real-time data

7.8 Discussion

Although smart meters can obtain measurements in near real-time (e.g. with a delay of 15 min or 30 min) in present-day smart metering systems, readings are not sent to the energy supplier immediately. Instead, many smart metering systems, including the UK, expect to send measurements within 24 hours. Therefore, the ability of a state estimator to estimate the voltages of a distribution network using the measurements obtained on the previous day was evaluated. Assuming distributed generators transmit measurements in near real-time, the improvement in accuracy of the estimated voltages with an increasing number of near real-time measurements (15 minute intervals) was also investigated.

From the simulations, it was found that when the voltages estimated using previous day's measurements without using any near real-time measurement, the voltage error at all nodes was high (about 99% of nodes have errors less than 9% and the maximum error is about 15%).

However, distribution network voltages can be estimated more reliably by the robust state estimator using the previous day's measurements and a small number of near real-time measurements obtained from smart meters.

The near real-time measurements obtained from the grid supply point (GSP) reduces the error of the nodes close to the GSP (to about 5%), but increases the error at the downstream end of the network (to about 25%).

When two near real-time measurements; one from GSP and one from the downstream end of the network were used, they reduce the error of many nodes of the network (below 0.6 %). Maximum errors occur at the downstream end of each branch (about 2%).

When near real-time measurements from all distributed generators are used, the voltage errors can be reduced significantly (below 0.01%).

8 Conclusions

Smart meters are being introduced across the world. The UK is expecting to complete the installation of about 27 million domestic electricity smart meters by 2020. The primary aim of the UK in introducing smart meters is to provide energy consumption and electricity price information to consumers so that they would volunteer to reduce demand or shift demand to a period where the price is low. This information will be presented to the consumers through an ‘In Home Display’.

It is also anticipated that smart meters would aid power system operations and control. During power system emergencies, domestic appliances will be controlled remotely using Direct Load Control (DLC) commands sent by the energy supplier or demand response aggregators. Within a house, the DLC commands will be sent to the appliances through a Home Area Network formed by the smart meter and appliances in each house.

8.1 Primary response from a load control scheme

At present, the Great Britain (GB) power system anticipates a maximum sudden generation loss of 1320 MW. In the future, a de-carbonised GB power system will have new large generators and it will also receive a significant amount of energy from renewable sources, particularly wind power. Therefore the power system needs to be ready to accept a higher sudden loss of generation (presently up to a new maximum of 1800 MW). The use of controllable demand reduces the requirement for frequency response from partially loaded generators and hence reduces system operating cost and CO_2 emissions.

Smart meter interest groups have identified that smart meters could support frequency response using DLC. However, considering the time taken to send a DLC command to appliances, providing primary response using DLC may be unrealistic. Therefore domestic appliances need to be controlled locally. Primary response can be provided by controlling intelligent domestic appliances. These appliances use local frequency measurements to decide their control actions. The individual appliances act independently and hence coordination and optimisation of their switching operations is difficult.

In contrast, a single controller can control appliances in a house to provide primary response, by using the frequency measurements obtained from the smart meter. The switching operations of different appliances can be coordinated by the controller. A load controller that reads power system frequency from a smart meter and switches off loads when the system frequency drops was developed during this research project. A load control scheme that switches off domestic loads to provide primary response was investigated.

The commercially available smart meter used in this load control scheme experiment took a significant proportion (about 85%) of the total operating time to update its frequency measurements. From simulations, it was found that the delay of the control scheme is critical for providing primary response. For example, when power system inertia is low and for a sudden loss of 1800 MW of generation, a delay of more than 2 s leads to no contribution from the controllable loads. Therefore, to get the maximum primary response by controlling domestic loads, the time taken by a smart meter to measure the system frequency and to update its internal register must be less than 200 ms.

A frequency measuring capability was one of the functions in the initial UK smart metering specifications. The requirement for this function has since been removed. Further, a domestic load controller is not mentioned in the specifications. If smart meters are to be used for providing primary response through domestic load control, the UK smart metering model needs a domestic load controller with bi-directional communication in the Home Area Network. A frequency measuring function is also required and the load controller must be able to read frequency measurements from the smart meter.

8.2 Controllable loads available in Great Britain

To shed a given amount of controllable loads, a sufficient number of appliances need to be in the load control scheme because only a portion of the appliance stock is running at a given time. Therefore, the load profiles of the controllable loads (fridges/freezers, washers/dryers and hob/ovens) in Great Britain were constructed. It was found that, about 1600 MW of controllable loads from fridges/freezers is available throughout the day. About 1000 - 4000 MW of washers/dryers and 500 - 2000 MW of hobs/ovens are available between 10.00 and 22.00 hrs.

From simulations, it was found that in addition to the frequency response services maintained at present in the GB system, a maximum of 200 MW of controllable loads is required for the present power system which is ready to accept a maximum 1320 MW of generation loss. About 1000 MW will be required in the future when the system inertia is low and the anticipated maximum loss of generation is high (1800 MW).

1000 MW of controllable loads can be obtained using only fridges/freezers throughout the day. For that, 63% of fridges in the UK need to be in the load control scheme between 22.00 - 10.00 hrs and during rest of the period about 38% of fridges/freezers need to be in the scheme.

Between 10.00 - 22.00 hrs, a significant amount of loads are available from washers/dryers and hobs/ovens. During this period, when controllable load requirement is shared among these appliances and fridges/freezers, the requirement of fridges/freezers can be reduced to 13% when 20% of washers/dryers and 40% of hobs/ovens are in the load control scheme.

8.3 Reporting available controllable loads to network operator

For reliable operation of the power system, the network operator must ensure that sufficient primary response is available at all times. It is expected that domestic appliances in a load control scheme will reduce their demand in an emergency. However, at a given time, a controllable load may not be consuming a sufficient amount of power to reduce the load by an amount that the network operator anticipated. Therefore, it is desirable to report the available demand response to the network operator in near real-time. This enables the network operator to increase the amount of primary response obtained from partially loaded generators, if demand response is insufficient to provide primary response.

At present, all messages specified in the UK smart metering system are for energy suppliers and distribution network operators. Even if these messages are sent to the transmission network operator, none of the messages are suitable for reporting demand response in near real-time. In the UK smart metering communication network, all data is sent to the DCC through the Wide Area Network (WAN).

Using load profiles of fridges, cooking appliances and washers and dryers for 40,000 houses, the ability of the proposed smart metering system in the UK to report available demand response from the appliances to the network operator was assessed. It was found that, to report the available demand response once a minute, a large number of power measurements (about 81 million) must be sent through the WAN continuously.

However, when measurements are aggregated at different stages of the communication network, the number of measurements sent can be reduced. To aggregate measurements at different stages, the communication networks need to be arranged hierarchically and need aggregation devices at different levels of the hierarchy.

The ability of a hierarchically arranged communication network that follows the same hierarchy of electricity network to report the demand response was assessed. It was shown that, by using aggregation devices installed at distribution transformers and substations, the demand response capability can be reported to the network operator once a minute. By aggregating and sending a message only when measured values change more than ±5%, the number of measurements sent can be reduced from 81 million to 15 thousand thus reducing the impact on communication network significantly.

In order to facilitate data aggregation, the communication network that is being planned in the UK smart metering system needs to be hierarchically arranged and aggregation devices must be installed at distribution transformers and substations. If the communication network can accommodate messages of 300-400 bytes per minute in a Neighbourhood Area Network and a Metropolitan Area Network and about 30 kbytes per minute of messages in the Wide Area Network, the available demand response can be reported to the network operator every minute

8.4 Smart meter measurements for distribution system voltage estimation

In present-day smart metering systems, measurements are recorded at 15 or 30 minutes intervals and sent at most once a day. Therefore, the ability of a state estimator to estimate the voltages of a distribution network using the measurements obtained on previous day was evaluated. The improvements in accuracy of the estimated voltages, with an increasing number of nodes providing near real-time measurements obtained from distributed generators, was also investigated.

A generic distribution network in the UK was used. Load profiles obtained using smart meters installed in Ireland were used to construct load profiles. Generator profiles given in the UK generic network were used as the output profiles for generators. Variations up to ±50% were added to these load and generator profiles. An Iteratively Re-Weighted Least Square state estimator was used.

It was found that, when the voltages are estimated using the measurements sent on the previous day, the voltage errors of all nodes were about 9% - 15%. By using near real-time measurements obtained from two nodes (i.e. about 3% of total number of nodes of the test network), the error can be reduced below 0.6%. By using near-real time measurements from 22 generators (i.e. about 38% of the nodes) the error can be reduced to below 0.01%.

8.5 Future work

The following future research work was identified to extend the work reported in this thesis:

a) Use of other controllable loads to obtain frequency response

In this study, only fridges/freezers, washers/dryers and ovens/hobs were used as controllable loads which have minimum affect to consumers when switched off. These loads were switched off for a short period. Since new types of controllable loads are being introduced to the power system, the ability of using these new loads for providing frequency response should be investigated. For example, new smart appliances with load shifting capability are commercially available. In these appliances, the operating time can be shifted after each cycle of operation so that they have extra flexibility in providing primary and secondary response. Electrical vehicles may be used to provide primary, secondary and high frequency response by using as a load or as a power source. The effect of using these controllable loads on the GB power system to provide frequency response should be investigated.

At present, the GB transmission network operator procures about 500 MW of frequency response services and about 180 MW of Fast Reserve. These services are procured from large generators and loads. In this study, it was assumed that the network operator continues to procure these services. Instead of procuring these services from large generators/loads, if the network operator uses controllable domestic loads, the money spent to procure these services may be used as incentives to attract domestic consumers to load control schemes. To ascertain the ability of using domestic controllable loads instead of large generators/loads to provide these services, the available response should be estimated in real time.

It was shown that fridges need to provide the total controllable load requirement as other loads considered in this research do not operate in the night. However, storage water and space heaters operate in the night. With increased load shifting, more washers/dryers would operate in the night. Electrical vehicles also would charge during the night when the tariff is low. Therefore, the amount of controllable loads available from these appliances must be evaluated.

Further in this study, it was assumed that the transmission network operator can use the power consumption measurements of load groups transmitted at every minute to the DCC to calculate the available frequency response. However, when frequency drops, shiftable loads and electrical vehicles will reduce their loads based on the decision made by a controller installed within these loads. Since, this controller may not switch off the load immediately, the power consumption measurements of loads alone will not be sufficient to calculate the available demand response accurately at any time. Therefore, ways of calculating demand response of shiftable loads and electrical vehicles accurately and the type massages that need to be sent to DCC should be found.

b) **Calculating the number of messages send through the WAN to control voltages of distribution networks in near real-time**

In this thesis, the ability of a state estimator to estimate the voltages of a distribution network accurately was investigated. After estimating the voltages, control actions must be taken to eliminate any violation of the voltage limits and also to reduce voltages if conservation voltage reduction is done. In future distribution networks, several controlling possibilities will be available. For examples, loads of domestic appliances, active and reactive power of distributed generators, position of switched capacitors, tap position of 11/0.4 kV on-load tap changers may be controlled. With these options, the optimum control actions that could be provided in a coordinated manner must be investigated. Several load flows may be required to ascertain that selected actions are the optimum and do not violate the voltage limits. The communication requirement for such a coordinated optimum control should also be assessed.

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Appendix A: Smart metering initiatives

The United Kingdom

Owen and Ward [1] discuss the early smart metering initiatives in the UK. From the mid 1980's onwards, the former Electricity Council and number of Area Boards explored new metering technologies and initiated field trials. However, with the energy-industry re-structuring and the introduction of retail competition of meter development, no significant progress took place from 1990 to 1998. From 2000 onwards, four significant policy reports were produced. However, the policy-push on smart meters stalled after 2002.

In December 2005, the European Parliament issued the Energy End-use Efficiency and Energy Services Directive [2]. It required member countries to install meters that provide actual energy consumption and time of use, to improve the efficiency of demand side.

Between 2005 and 2007 *"Energy Watch"* proposed to introduce smart meters because they would benefit electricity suppliers, consumers, distributors and the environment. Consumers would change their electricity consumption pattern using the updated information provided by smart meters [3][4]. The benefits to the customer would be between £36 – £42 per year and additional £4 per year from the social benefit of saving CO_2 emissions [5].

In 2006, the Office of Gas and Electric Markets (OfGEM) issued a Domestic Metering Innovation Consultation [6] to find out the actions to be taken to introduce smart meters in the context of the UK's competitive domestic metering services market. In November 2006, the Department of Trade and Industry (DTI) issued Energy Billing and Metering Consultation [7] to obtain views on how to implement the requirements of the Energy End-use Efficiency and Energy Services Directive [2] of the EU.

Since April 1998, all sites with maximum demand of 100 kVA (about 107,000 sites) must have meters to obtain half-hourly measurements. In May 2007, DTI issued the White Paper on Energy [8] which intended to introduce smart meters for all business, that do not have half-hourly meters, within the next 5 years and for all households over a period of 10 years. Until then, real-time displays were to be provided with new meter installations. The costs and the benefits of roll out options of smart meters and various technology options of meters, displays, communications is discussed by Mott MacDonald [9] in a report written for Department of Business, Enterprise and Regulatory Reforms (BERR) in April 2007. In August 2007 BERR issued the Consultation on Policies Presented in the White Paper [10]. In the response to the consultation issued on April 2008 [11], the government decided to install smart meters (around 160,000 meters) to business in profile class 5-8 (called large business sites). The government also decided not to mandate the installation of real-time displays, but to reach a voluntary agreement with suppliers to provide displays in short and medium terms.

In July 2008 two consultations were issued. The first one was the draft licence modifications for installing smart meters at large business sites from January 2009 to 2014 [12]. This came into force on 6th April 2009. The other consultation was on installing smart meters for medium and small non domestic customers.

In October 2008, the UK government announced that it intends to mandate smart meters for all households [13].

The consultation on smart metering [14] issued on May 2009 gave the government's response to the consultation on draft licence modifications and proposed to mandate smart meters to medium and small non domestic customers (about 2.2 million customers with profile class 3 and 4). The consultation also gave proposals on the delivery model and the functionality of meters installing for domestic customers.

The Low Carbon Transition Plan issued in 2009 has decided to complete the installation of smart meters and display units to the domestic sector by the end of 2020 through about £8bn of private sector investments [15].

The consultation on the smart metering implementation program [16] for all domestic and medium and small non domestic customers was issued in July 2010. This consultation proposed smart metering functional requirements, communication, data management and rollout approach. It has a detailed list of specifications produced by Energy Network Association (ENA). An update of the specifications produced by ENA was published by Engage Consulting Limited [17].

The response to the consultation indicated that roll out would start in 2014 and would be completed in 2019. The consultation issued on August 2011 [18] seeks views on draft licence modifications for smart meter rollout. It also proposed to the ways of developing and managing technical specifications of smart meters.

The Energy Demand Research Project (EDRP) managed by OfGEM conducted trials from 2007 to 2011[19]. Four trials were conducted that involved over 60,000 households and 18,000 smart meters and 8,500 real-time display devices (RTD). It was concluded that smart meters and RTD could save around 3% of energy.

The Europe

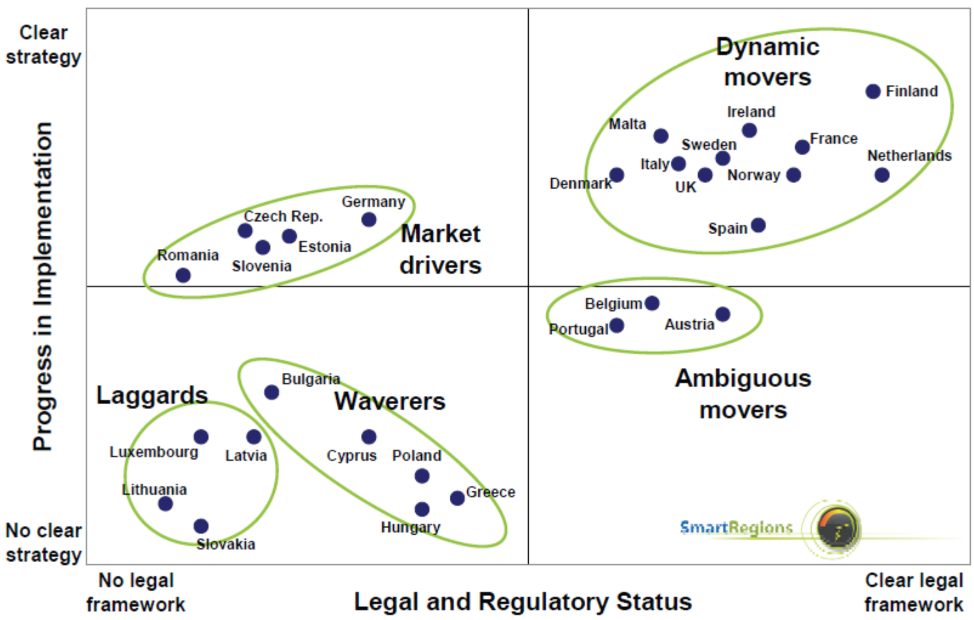

Fig. A.1. The implementation progress of smart meters and legal and regulatory status of the European countries [20]

The European Commission

The Metering Directive [21] adopted in 2004 required that utility meters, including electric and gas meters, approved in one member state are automatically approved in all other member states. The Energy Efficiency Action Plan (EEAP) [22] issued in 2006 required that the members to propose the ways of providing detailed billing and metering by 2009. EEAP include many directives including Energy End-use Efficiency and Energy Services Directive [2] which required installing electronic meters that provide actual energy consumption and the information on actual time of use.

A directive on electricity markets [23] issued in 2009 under the 3rd Energy Package required the implementation of intelligent metering systems that will assist active participation of consumers in electricity market. It also required the roll out of smart meters for at least 80% of the consumers of each member country by 2020.

The European Commission's recommendation on Information and Communication Technology (ICT) [24] issued in 2009 stated that smart meter can provide real-time information flows and new control methods. It recommended agreeing on minimum functional specifications of smart metres by 2010. It also recommended setting up a timeframe by 2012 for rolling out of smart meters in each country.

In 2009, a Standardisation mandate [25] was issued to European Standard Organisations to create a European standard, for the development of an open architecture to enable interoperability of utility meters, in early 2012.

The memorandum [26] issued in 2008 states that the EU policy measures are not sufficient to achieve 20% energy saving by 2020. Therefore, an Energy Efficiency Plan [27] was issued in 2011 which expected that ICT and smart meters would act as the backbone for smart appliances to save energy.

Italy

Italy is the first country that started a large scale smart meter installation. From the early 1990s, Italy had AMR and AMM for energy intensive customers. In 2006 installing smart meters was mandated. The smart meter installation was started in

2008 and it was anticipated to complete the installation of 95% of 36 million customers by the end of 2011 [20]. The main motivations were to reduce theft, reduce visits to consumer premises and to reduce blackouts [28].

Sweden

In 2003, Sweden mandated that all energy meters to be read monthly by July 2009 thus reducing the inaccurate bills. Hence, it became the first country that indirectly mandated the installation of remote metering and also the first to achieve 100% smart meter installation. However, only large customers (about 750,000 meters) can perform half hourly metering and remaining 3.9 million meters need additional investment to increase reading frequency.

Netherlands

In 2007, Netherlands proposed to install 12 million electricity and gas smart meter to all households by 2013. In 2010 the roll out was postponed following concerns that remote monitoring of energy consumption would lead to privacy violations. After amending the relevant legislation in 2011 by allowing consumers to choose remote meter reading, Netherlands will start installing smart meters from 2012 [29].

Other European countries

Other European countries such as Austria, Finland, Greece, Ireland, Malta, Portugal and Spain have legislation or national programs for smart meter installations [20]. France, Poland and Norway (where, at present, smart meters should be installed only for large customers) are planning to introduce smart metering proposals soon. Some countries already have announced their smart meter rolling out targets to all consumers. The targets are; Finland by 2014, Norway by 2016, Spain by 2018 and France 96% by 2016. Many countries are conducting pilot studies. Though Germany does not have a legal framework to install smart meters, suppliers have to offer smart meters and time-of-use tariff to all customers by 2011.

The United States of America

In the USA, consumers have been using AMR from early 90s. The Energy Policy Act of 2005 required the utilities to offer time based tariffs [30] which urged utilities to introduce smart meters. At present 16 states have policies promoting smart meters [31] and about 8 million energy meters are AMI [32]. It is expected that 80 -141 million meters will be installed by 2019 under different development scenarios.

Energy Independence and Security Act of 2007 [33] gave policies for smart grid in which smart metering is an integral part. As per direction of the act, the Federal Energy Regulatory Commission (FERC) developed National Action Plan on Demand Response [34]. The demand response potential in 2009 is about 37 GW (6% of peak demand). This is mainly from direct load control (which has been in place for decades). Through smart metering systems, price signals can be sent to consumers for obtaining demand response. With the price signals, the estimated demand response potential in 2019 is 38 – 188 GW (9% - 20% of peak demand) for different participation scenarios [32].

As per the requirement of the act, National Institute of Standard and Technology (NIST) have developed a Framework and Roadmap for Smart Grid Interoperability Standards [35]. The Use Cases discussed in this roadmap, which were developed by Electric Power Research Institute (EPRI) [36], include six priority functionalities. Out of the six functionalities, AMI, demand response and distributed grid management are relevant for the work done in this thesis (given in Appendix C).

Other notable initiatives

In Australia, the state of Victoria is leading the smart meter installation. It mandated smart meter installation in 2006 to install 2.66 million smart meters. The roll out was started in 2009 and to be completed by 2013. At present 630,000 meters had been installed [37]. Interval meters with disconnection switch, Home Area Interface and mandatory TOU billing function are used. Smart meter data is transmitted daily.

In Canada more than 5 million smart meters are installed mainly due to the actions taken by Ontario from 2002. Ontario had already achieved nearly 100% (about 4.7 million) smart meter rollout by the end of 2010 [38] [31]. A disconnection switch and an interface to HANs are not standard functions because those functions were not standard at the time Ontario started its smart meter rollout. Smart meters rolled out in British Columbia and Quebec have those functions as standard. The TOU billing is a voluntary function in all Canadian states.

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Appendix B: Functionalities of electronic energy meters

TABLE B.1. COMPARISON OF FUNCTIONALITIES OF DIFFERENT ELECTRONIC ENERGY METER TYPES

Functions	AMR	AMM	AMM interval meter	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 could be changed remotely		✓	✓	✓	✓
Real time data can be displayed to user		✓	✓	✓	✓
Fraud and temper protection		✓	✓	✓	✓
Measure energy consumption and more 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 historic cost and credit remaining				✓	✓
Allow to change the tenancy				✓	✓
Credit entry through keypad				✓	✓
Can add credit remotely					✓
Can control appliances remotely					✓
Provide facilities for network design, operation, management					✓

Appendix C: Priority functions and their Use Cases for USA Smart Grid

The six smart grid priority functions identified by the Electric Power Research Institute (EPRI) [1] are given in this Appendix. The Use Cases of the functions relevant to the work reported in this thesis i.e. AMI, demand response and distributed grid management are also listed and they are numbered using lower case letters.

1. Wide-Area Situational Awareness (WASA)
2. Demand Response
    a. Direct Load Control
    b. Demand response management systems manages demand in response to pricing signal
    c. Customer reduces their usage in response to pricing or voluntary load reduction events
    d. External clients use the AMI to interact with devices at customer site
    e. Customer uses an Energy Management System (EMS) or In-Home Display (IHD)
    f. Utility procures energy and settles wholesale transactions
    g. Demand response service provider manage energy and ancillary services aggregation
    h. Customer uses smart appliances
    i. Volt, VAr, Watt Control (VVWC) with Demand Response (DR), Distributed Energy Resources (DER), Plug-in Electric Vehicles (PEV) and Electric Storage (ES).
3. Electric Storage
4. Electric Transportation
5. AMI
    a. External clients use AMI system to interact with devices at customer site
    b. Demand response management system manages demand through Direct Load Control

c. Building automation software/system optimization using electric storage
d. Outage detection and restoration using AMI

6. Distribution Grid Management (DGM)
   a. Monitoring distribution operations with DR, DER, PEV, and ES
   b. Service restoration
   c. VVWC with DR, DER, PEV, and ES
   d. Coordination of emergency and restorative actions in distribution
   e. Impact of PEV as load and electric storage on distribution operations

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Appendix D: Standard load profiles developed for Irish electricity market

TABLE D.1. IRISH STANDARD LOAD PROFILES USED FOR THE DISTRIBUTION NETWORK NODES GIVEN IN FIG. 7.5

Standard load profile	Nodes assigned to the profile
Urban Domestic	3, 12, 21, 30, 39, 48, 57, 66, 75
Urban Domestic Night Saver	4, 13, 22, 31, 40, 49, 58, 67, 76
Rural Domestic	5, 14, 23, 32, 41, 50, 59, 68, 77
Rural Domestic Night Saver	6, 15, 24, 33, 42, 51, 60, 69
Non Maximum Demand Non Domestic	7, 16, 25, 34, 43, 52, 61, 70
Non Maximum Demand Non Domestic Night Saver	8, 17, 26, 35, 44, 53, 62,71
Maximum Demand Load Factor <30%	9, 18, 27, 36, 45, 54, 63, 72
Maximum Demand Load Factor 30% -50%	10, 19, 28, 37, 46, 55, 64, 73
Maximum Demand Load Factor >30%	11, 20, 29, 38, 47, 56, 65, 74

Appendix E: Relationships between the state variables and measurements

Power injection measurements

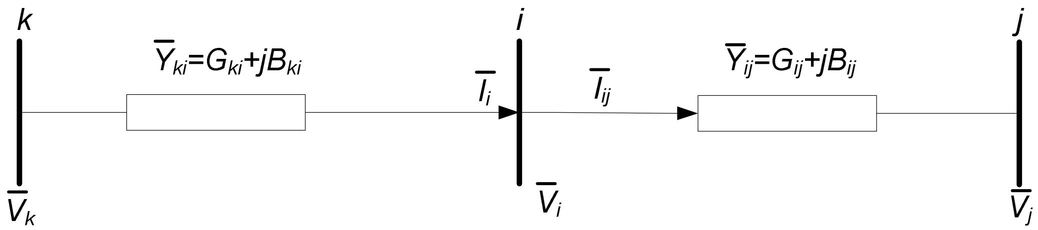

Fig. E.1. Three busbar section of a distribution network [1]

$$\overline{I}_i = \sum_{k=1}^{N} \overline{Y}_{ik} \overline{V}_k \text{ and } i \neq k \qquad \text{(E.1)}$$

Power injected to busbar i is $p_i + jq_i = \overline{V}_i \overline{I}_i^*$

$$p_i + jq_i = \sum_{k=1}^{N} v_i v_k (G_{ik} - jB_{ik}) \angle (\theta_i - \theta_k) \qquad \text{(E.2)}$$

Equation E.2 is in the form of $p_i = h_1(v_i, v_k, \theta_i, \theta_k)$, $q_i = h_2(v_i, v_k, \theta_i, \theta_k)$ where $k = 1..N$ and $k \neq i$ as discussed in Section 7.4 .

Power flow measurements

Neglecting line charging capacitance, power flow from busbar i to j

$$\bar{I}_{ij} = \bar{Y}_{ij}(\bar{V}_i - \bar{V}_j) \text{ and } i \neq j \qquad \text{(E.3)}$$

$$\bar{I}_{ij} = (G_{ij} + jB_{ij})(v_i\angle\theta_i - v_j\angle\theta_j)$$

$$p_{ij} + jq_{ij} = \bar{V}_i \bar{I}_{ij}^*$$

$$= v_i\angle\theta_i[(G_{ij} + jB_{ij})(v_i\angle\theta_i - v_j\angle\theta_j)]^*$$
$$= (G_{ij} - jB_{ij})(v_i^2 - v_i v_j\angle\theta_i - \angle\theta_j) \qquad \text{(E.4)}$$

Equation E.4 is in the form of $p_{ij} = h_3(v_i, v_j, \theta_i, \theta_j)$, $q_{ij} = h_4(v_i, v_j, \theta_i, \theta_j)$ for all i = *1..N* and j = *1..N* and $i \neq j$ as discussed in Section 7.4.

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