Demand Side Approaches for Congestion Management in Electricity Market

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by

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Declaration

This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.

Signed: Date:

Abstract

Since the early 1990s, deregulation of the power industry and the introduction of electricity market has unbundled the vertically integrated optimization of power system operation into distinct different optimization problems for generation and transmission operation separately. On top of that distribution network operation is also separately optimised. The increasing integration of renewable generation challenges the power system operation and the system operator plays an increasingly crucial role to organise the delivery of electricity through power trading associated with different forms of contracts. Among all the duties undertaken by the system operator, congestion management has become increasingly difficult but it is of absolute importance. However, most congestion management methods only concern with solutions from the supply side but assuming that the demand side remains unchanged. As the supply side is becoming less controllable and less predictable under the new generation environment, the quest for solution from the demand side arises.

This thesis focuses on the investigation of network congestion arising in liberalised electricity markets and the management of congestion from the demand side with respect to identified existing and future challenges. To this purpose, new methodologies based on Demand Side Management are developed and modelled on Matlab platform. A simple but practical index, namely Economical Demand Management (EDM) index, is proposed for finding solution to manage the congestion from demand side based on Optimal Power Flow calculation and Locational Marginal Pricing. The efficacy of the proposed index has been validated on IEEE 14 and IEEE 30 systems. The values of the indices can be used to allocate the optimal load adjustment and determine the amount of demand side participation. Furthermore, a new load control methodology in the form of smart appliances that can be employed in the smart grid frame is also developed in this thesis. The proposed methodology is illustrated as a generalised technique based on load shifting, which has been mathematically formulated as a linear-constrained quadratic minimization problem. The proposed algorithm allows different control strategies to be applied according to the different attributes of the appliances, which is sufficiently general to be implemented in the real world. The implementation of the proposed load control methodology using case studies on a set of nationwide domestic smart appliance load shifting have been carried out with UK Power System data. Furthermore, combination of the proposed load control methodology and EDM index for congestion relief has been simulated on a network model. Also, their potential impacts from both economical and environmental aspects have been evaluated.

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My final, but not the least, gratitude goes to my parents, Bei He and Xiang Sun, for their unconditional love, encouragement and support during my PhD study.

Dedication

This thesis is dedicated to my mother, my father and my grandmother

Who did not live long enough to witness this achievement.

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Glossary

AC OPF	AC Optimal Power Flow
ADA	Appliances Data Acquisition
AMI	Advanced Metering Infrastructure
BAS	Building Automation Systems
BETTA	British Electricity Trading and Transmission Arrangements
CCS	Carbon capture and storage
CfD	Contracts for Difference
CPP	Critical Peak Pricing
DC OPF	DC Optimal Power Flow
DLA	Demand Load Aggregator
DLC	Direct Load Control
DNO	Distribution Network Operator
DMA	Demand Management Aggregator
DSM	Demand Side Management
FTR	Financial Transmission Rights
GOAL	Generating Ordering and Loading
HVAC	Heating, Ventilation and Air Conditioner
ICT	Information and Communication Technologies
ISO/SO	Independent System Operator/ System Operator
ISO-NE	The ISO of New England‘s electricity supply in the US
ISO-NY	The ISO of New York state‘s electricity supply in the US
VOLL	Value of Lost Load
LOLP	Loss of Load Probability
LMP	Locational Marginal Pricing

NETA	New Electricity Trading Arrangements
OTC	Over-The-Counter market
PLC	Power-Line Communication
PJM	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PPP	Pool Purchasing Price
RTP	Real Time Pricing
SBP	System Buy Price
SCADA	Supervisory Control and Data Acquisition
SHC	Smart Household Control
SLC	Smart Load Control
SMP	System Marginal Price
SSP	System Sell Price
TOU	Time of Use tariffs

Chapter 1 Introduction

1.1 Overview

Electricity is an essential and basic commodity in modern society. However, it is significantly difficult to establish a free market for it due to its unique characteristics. Therefore, the power industry had been monopolised by large utilities almost since their emergence. However, since 1980s, the interest in reducing energy prices and industry costs has prompted liberalised markets to replace the monopoly markets. The vertically integrated electricity industry was unbundled into independent power generation companies, transmission companies and distribution companies. In the following years, liberalised electricity markets evolved which enabled the market entry of new market players beside the formerly integrated utilities. The competition is introduced into the marketplace to reduce overall costs, improve the efficiency of system operation and facilitate the long-term development of power systems. However, the transmission and distribution networks remained a natural monopoly. Therefore, the regulation of the transmission and distribution networks by public authorities and guaranteed non-discriminatory access to network capacities has played an important role in liberalised electricity markets. To put it in another way, the deregulation of power industry and introduction of electricity market has broken up the formerly integrated optimization of the power system into distinct different optimization problems for generation and transmission operation.

More recently, concern over the potential effect of global warming caused by greenhouse gases, especially carbon dioxide, is forcing greater change. In UK, the government target has been set to reduce the UK's greenhouse gas emissions by at least 80% (from the 1990 baseline) by 2050[1]. Deployment of renewable generation to replace the fossil electricity generation is a pressing priority given the need to reduce the risks of greenhouse gases emissions, caused in large part by fossil fuels, into minimum. Therefore, there has been a drastic increase in renewable generation capacity installation in past decade, with further plans to enhance the renewables capacity in near future. The increasing utilization of renewable generation has led to various challenges to the operation of the power system and electricity market, from system reliability issues to investment of the transmission network.

Basically, technical and economic features of electricity transmission limit the access to network capacities. Firstly, power flows in transmission networks follow Kirchhoff‘s laws. In general, the distribution of power flows within the transmission network depends on the network topology and the electro-technical characteristics of transmission lines. Secondly, transmission capacity is limited. Transmission lines are normally limited by several constraints. These constraints can either be physical limits like thermal, voltage limits or specified limits to ensure system security and reliability. If these constraints has become binding, a transmission line becomes congested. However, constructing a congestion-free network is not economical and inefficient according to the economic characteristics of transmission network investments[2]. The economic characteristics of transmission networks and their investments are long lifetimes, capital-intensive, lumpy, and irreversible investments in transmission capacities [3, 4]. Furthermore, the increasing integration of renewable generation might incur severe congestion due to the decentralized and their fluctuating characteristics. Besides, the intermittent and chronological nature of renewable generation makes the output of generators difficult to predict in advance and hard to control in real time. Thus, efficient operation of the network in the short-term and adequate expansion in the long-term are required due to the physical and economic characteristics of transmission networks in the liberalised market environment.

In some liberalised electricity industries, generators are self-dispatched and as a result the independent system operator has limited control over generating resources for maintaining the power system reliability and security. Furthermore, the increasing renewable generators further limit the control from Independent System Operator (ISO) due to their characteristics. From the viewpoint of electricity market, congestion occurs when the transmission network fails to accommodate all of the power transactions without violating power system operating constraints. Hence, one of the main ISO duties is congestion management, which has become increasingly difficult but absolutely important. In the pre-deregulated power industry, the congestion management scheme was simple: the system operator could directly redispatch generator units and the congestion was relieved. With the open access of the transmission system, power flow is primarily determined by power trading or by contracts in the electricity market which make it complex and difficult for system operator to ration the limited transmission capacity in an equitable, secure and economical manner. Hence, the solution to congestion management is a complex one and different opinions exist of how best to handle the problem. To allocate transmission capacity effectively, congestion management methods have been developed and are diversely applied in modern electricity markets. In published literature, many methods are proposed for congestion management in electricity network. References [5, 6] summarized the main approaches to the congestion management in recent years and evaluated their efficacy under different electricity market regimes. In [7, 8] , the authors reported the cost-free approach to relieve the congestion, such as operation of transformer taps, network reconfiguration and operation of FACTS devices. However, the congestions may not be fully relieved with those cost-free methods. Therefore, market-based methods including generator re-dispatch and counter-trade are required. In [9], a coordinated congestion dispatching model was proposed, with a controlled ratio between the incremental rate in the pool purchasing cost and the curtailment rate of contracts to directly reflect the priority of different trades in the hybrid market. In[10], the authors proposed a congestion management method based on congestion zones/clusters using the AC load flow Jacobian sensitivity. An alternative approach was presented in [11], which is based on parallel markets for link based transmission capacity rights and energy trading.

However, most congestion management methods only concern the solutions from the supply side as the traditional electricity industry has been formed on the assumption of unresponsiveness and inelastic demand particularly in the short-term. As the generation side is becoming less controllable and less predictable under this new circumstance, the quest for solution from the demand side arises. This thesis will attempt to address the network congestion issues from the demand side. After the oil crisis arose in 1970s, one of the programmes set up to better manage energy consumption was Demand Side Management (DSM). DSM generally compromises different initiatives to modify and reshape the consumer demand pattern, with the aim of achieving not only net energy savings but also a more efficient utilization of the energy itself. More recently, examples of integrating demand side have been made in [12-14].In [15], the effect of introduction of demand elasticity into the congestion management scheme was evaluated and the authors concluded that it could achieve better economic performance besides maintaining the system security. The integration of demand side into the congestion management process is considered as an efficient approach. The load at congestion period can be temporarily reduced through demand side management (DSM) activities, such as voluntary or mandatory load shifting and load curtailment. These attempts to introduce the interactions between the supply and demand sides would have effect in reducing market power and at the same time lower price spikes. In [16], the authors review existing demand response programmes in the United States and around the world. New York ISO (NYISO) provides its consumers four demand response options including voluntary load curtailment programmes and dispatchable load [17]. Similarly, in Pennsylvania-New Jersey-Maryland market, system operator considers curtailing some load as part of the PJM Interruptible Load for Reliability (ILR) programme[18]. In 2005, the European Union adopted the "Smart Grid" concept - a vision of intelligent, flexibly controllable electrical generation, distribution and consumption[19]. The emergence of smart grid, which integrates the two-way communication and information technologies into power system for enhancing system operation, customer service and environment benefits, facilitates the execution of DSM programmes. In the domestic sector, the advanced communication techniques in smart grid frame enable the appliances to send status information to system operators. Thus, the system operators can foresee the amount of load which can be managed and thereby using proper methodology to manage the load to optimise the system operation. The development of smart appliances facilitates this process by providing more automatic intelligent control according to interactions between system operators, such as time shifting the operation of appliances and interruption for a limited period. This thesis will investigate and develop smart appliance control techniques and algorithm to support the wide deployment of smart appliances in the network.

1.2 Objective of the Thesis

The main objective of this thesis is to study selected aspects of network congestion arising in liberalised electricity markets and its management methods from demand side with respect to the identified existing and future challenges. This can be decomposed thus:

- To review current deregulated electricity market designs and corresponding congestion management schemes. In addition, the advantages and disadvantages of each congestion management scheme are discussed following numerical electricity network examples.
- To overview the development of renewable generation techniques and demand side management.
- To develop a set of indices for demand side participation to solve network congestion problems an equitable, secure and economical manner. The values of the indices are used to allocate the optimal load adjustment and determine the amount of demand-side participation. The proposed index is integrated into the congestion management scheme based on the principle of locational marginal pricing.
- To evaluate the efficacy of proposed congestion management methods in different test situations.
- To propose a direct load control methodology within smart grid scheme. A domestic appliance load control algorithm is proposed. The load control algorithm is an optimisation algorithm which schedules the connection time of individual appliances to minimise the difference in load profile from a pre-defined load shape for specific optimising purpose.
- To investigate the potentially beneficial effects of the proposed algorithm for different purposes, i.e. Demand Flattening and Congestion Management.

1.3 Original Contributions of the Thesis

Based on the objectives previously presented, the original contributions of this thesis can be stated as below:

- A useful overview of the deregulated electricity markets, which includes the histories of power industries evolution and current status of different electricity market, is provided in the thesis. The basic congestion management methods are reviewed and discussed.
- A review on the state-of-the-art research activities in renewable generation techniques and DSM in the vision of future networks is presented. Several types of DSM techniques are highlighted and their applications in current power systems are introduced.
- A set of indices are proposed for combining DSM with congestion management in a physically and economically efficient way. The efficacy of the proposed index is tested by using case studies based on the IEEE 14 and 30 node systems.
- A new method to optimise the control of smart appliances in the smart grid frame is proposed. This proposed method compromises different control strategies for different appliance groups. The corresponding control possibilities over appliances are mathematically formulated and successfully integrated into the load control optimisation algorithm. The proposed load control optimization algorithm is sufficiently general to be applied on a wide range of appliances.
- Based on the proposed load control method, a serial of case studies are conducted in order to evaluate the potentially beneficial effects under different scenarios. The load control over smart appliances can be used for different purposes. The simulation is completed on the Matlab software platform. The simulation results prove that the proposed load control method has positive impact not only on the physical operation of power system, but also on the short-term/long-term economic benefits and carbon emission reduction.

1.4 Outline of the Thesis

Chapter 1 presents an overview of deregulated electricity industry and new developments of power systems today. Then, the importance of researching the congestion management under this circumstance is explained, and solutions from demand side management are explored. Objectives, contributions and structure of this thesis are also presented in this chapter.

Chapter 2 reviews the generic electricity market structures and concepts of different congestion schemes. This chapter starts with an overview of three conceptually different designs of electricity markets: Pool Market, Bilateral Market and Hybrid Market. The practical examples of each market design are briefly presented to give a better understanding of the concept. Then the congestion management methods for each market design are presented respectively. Three main congestion management methods for pool markets, namely Uniform Marginal Prices, Locational Marginal Prices and Zonal Prices, are discussed in details with numerical electricity network examples. After that, the congestion management methods for bilateral markets are illustrated. Finally, the financial instruments for hedging congestion risk are briefly overviewed.

Chapter 3 mainly reviews the state-of-the-art renewable generation techniques and demand side management (DSM) with the vision of future networks.

Chapter 4 introduces Economic Demand Management (EDM) index for congestion management in order to better meet the criterion of the need of electricity trading mechanism in the deregulated electricity market. This set of transparent indices is proposed to combine DSM with congestion relief solution to improve physical and economic efficiency of traditional congestion management. After illustrating the mathematic theory, the effectiveness of the proposed index is investigated through case studies based on the IEEE 14 and 30 node systems.

Chapter 5 develops a load control methodology for smart appliances that can be employed in the smart grid frame. The proposed methodology is a generalised technique based on load shifting, which is mathematically formulated as a minimization problem. Different control strategies are applied according to the different attributes of the appliances in this methodology.

In Chapter 6, the proposed methodology described on Chapter 5 is implemented and the effect of such control procedure is simulated in the UK power system. The simulations assume that all the UK domestic customers can be simultaneously controlled, and executes the control actions for two different control purposes respectively: demand flattening and system balancing. The economic and environmental benefits related to the DSM are investigated by the comparison between simulation results from the case without DSM and the case with DSM respectively.

Chapter 7 demonstrates the effect of combining proposed load control algorithm with LMP-based congestion management scheme in the network where intermittent generation has substantial installed capacity in the power network. The modified IEEE-14 node system is used for case study. The possible benefits are evaluated to the extent of economic and environment. Furthermore, the importance of each domestic appliance group on congestion management has also been investigated.

Chapter 8 summarises the whole thesis and presents possible future research work

1.5 Publication

Based on the results of the research work reported in this thesis, the following papers have been published:

1.Jingling Sun, K.L.Lo , "A congestion management method with demand elasticity and PTDF approach," Universities Power Engineering Conference (UPEC), 2012 47th International , 4-7 Sept. 2012

2.Ling Liu , Xiaoqing Ma and Jingling Sun, ―An Investigation of the Relationship between Economic Growth and Electricity Consumption with Different Industrial Structures in Different Regions of China‖, Universities Power Engineering Conference (UPEC), 2013 48th International , 2-5 Sept,2013

3.Jingling Sun, K.L Lo and Ivana Kockar ,‖Relieve of Network Congestion through Economical Demand Side Management‖, IET Generation, Transmission & Distribution, March 2014 (Submitted)

4.Jingling Sun and K.L.Lo , ‖The Potential of Demand Side Management(DSM) in congestion management‖, under preparation for journal submission

5.Jingling Sun and K.L.Lo, ‖Investigation of DSM benefit in congestion management in the network with wind penetration‖, under preparation for journal submission

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Chapter 2 Deregulated Electricity Market Design and Congestion Management Scheme

2.1 Introduction

A combination of privatization, industry restructuring, deregulation and liberalization has been launched in many nationalized industries across the world in the early 1980s.The motivation of this revolution is to drive electricity prices towards the marginal costs through competition and provide strong incentives to industries in order to minimize their production costs. The successful achievement of this revolution in other industries, such as telecommunication, railway and wireless communication, accelerated the deregulation and restructure of the electricity industry. Chile is the leader of restructuring the state-owned power industry and the success of the process encourages more countries to follow the trend[1]. UK, Canada and United States became involved in the electricity deregulation as followers in 1990s and then more countries have followed up with reasonably comprehensive privatization, deregulation and restructure in their generation and supply sectors across the world.

The deregulation in the electricity industry involves unbundling verticalintegrated industry, which used to perform all functions together including generation, transmission and distribution, into several sections and introducing competition in the individual section. The state-owned power companies are privatized after the unbundling and the liberalized industries are built up for power trading. As depicted in Figure 2.1, three basic sections are disaggregated based on the traditional integrated mode from production of electricity to the demand consumption. The competition has been introduced in the generation sector and supply sector. The monopoly generation company has been divided into several smaller generation companies (GENCOs) while more new generation companies were established and joined in the competition. At the same time, distribution and supply sectors underwent similar progress. The distribution companies (DISCOs) who operate the distribution networks are regional monopolistic and the suppliers can use the distribution network with the capacity rights assigned by the DISCOs[2, 3].

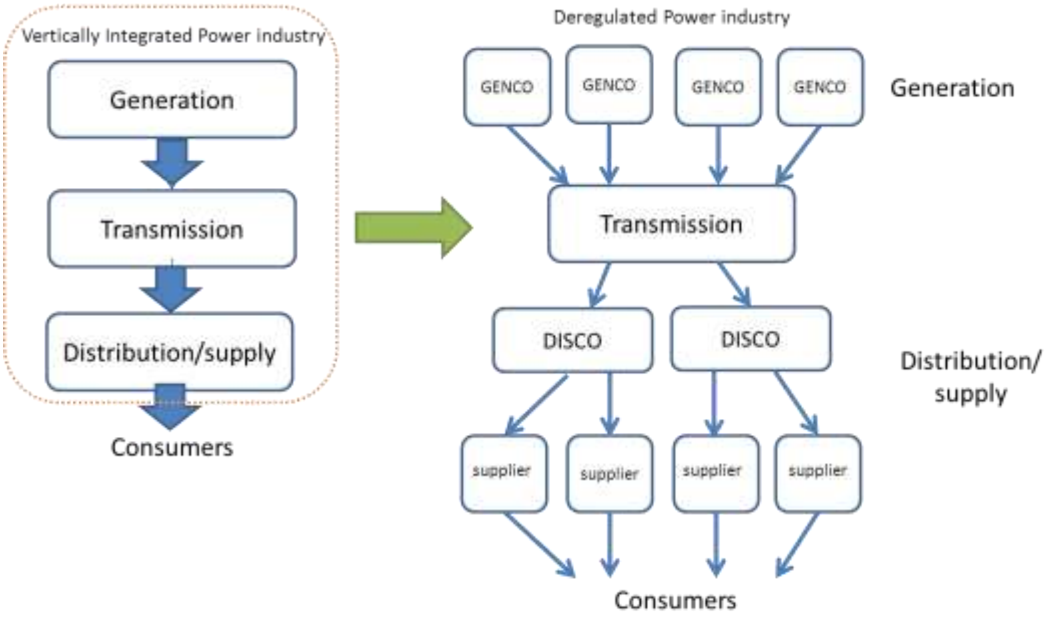

Figure 2.1 Unbundling of Power industry

As the characteristics of the electricity industry and deregulation process in different countries are different, the design of electricity market and their operation rules varies globally. Several electricity markets have been set up around the world and they continue to evolve with the technical, economic and political factors. Good experiences can be gained through study and analysis of those market schemes. Therefore, several typical structures of electricity markets will be studied and analysed in this chapter. The discussions go through the implementation of those markets and their operational rules.

Unlike other commodities, electricity is expensive to be stored and requires an exact match between supply and demand at any time. Thus, the transmission of electricity plays a critical role in the electricity market. Power delivery takes place according to Kirchhoff‿s laws over the transmission networks, which are subject to physical capacity limitations[4]. In the traditional vertically integrated mode, the single electricity utility had full details of the network operation and it could secure the electricity transmission by mandating the dispatch of all the assets in the system. After deregulation, the transmission sector maintains natural monopoly as free competition is not economically sustainable. As a consequence of competition in the other sectors of the power industry, the market participants are only interested in financial benefits of electricity supply, and not the physical limitation of the transmission network. Hence, problems of transmission network, especially transmission congestion, are inevitably growing. To tackle these problems, an independent system operator (ISO) is created to cater for the transmission network operation in the electricity market environment. The independence of these transmission operators from the interests of supply and generation implies a clear and effective way to solve the inherent conflicts of economic interests and security of the electricity delivery[5]. Its responsibilities include providing open access of the transmission network to the market participants and maintaining the network operation reliability under the Grid Code. To fulfil those responsibilities, an efficient congestion management scheme and a transmission pricing design plays a crucial role. A major challenge in designing a congestion management scheme is accounting for the interaction between physical transmission laws, principles of economics and the structure of market design. As different market schemes allow for different congestion management approaches, this chapter intends to illustrate congestion management concepts based on different electricity market designs.

The rest of this chapter is organized as follows: The original vertically integrated utility mode is provided in section 2.2. The basic electricity market structures are reviewed briefly in section 2.3. The role of ISO is explained in section 2.4 followed by the discussion of basic congestion management methods in section 2.5. After that, the available instruments for hedging against congestion risk are described in section 2.6. Finally, section 2.7 gives some concluding remarks and summary.

2.2 Traditional Utility Model Prior to Deregulation

Before studying the deregulated electricity market, it is necessary to understand how the electricity system worked under the traditional central utility mode. The electricity industries had been dominated by large utilities combined with an overall authority over generation, transmission and distribution of power within their areas of operation almost since their emergence [6]. These utilities were referred to as monopoly utilities and most of them were state-owned and regulated by the government. They were mandated to operate within a designated region and provide an electric service to everyone in that region. The control and operation issues for the vertically integrated electricity system had been widely examined over years. The single utilities mastered all the information of power system operation and generation cost curve of each unit in the system. They could centrally dispatch and re-dispatch these units by using the optimal power flow tool to match the demand in real-time with generation fuel cost minimization.

The electricity price for the consumers was set according to the overall cost of generation, transmission and distribution of power and it was uniform in the domain where utilities control. Apart from the system operation, the power network planning was centrally managed by the monopolistic utility. All activities such as long-term infrastructure expansion, generation plant investment, maintenance of network were coordinated centrally. However, the above-mentioned activities had led to large-scale investments in costly technologies, and concentration on engineering excellence instead of cost minimization and high quality service[7] .The risks of the investment were passed through directly to the consumers. Apart from that, the lack of competition in the potentially competitive generation and supply businesses brought high prices to consumers. Therefore, the deregulation and restructure is imperative to improve the efficiency of the whole electricity industries.

2.3 Deregulated Electricity Markets

In pace with the electricity industry deregulation, competition can be established on several levels in the electricity industry. One of the most pertinent issues for the competitive market is how to efficiently arrange electricity trading among all market participants in the marketplace. There is no straightforward solution to this issue since diversity exists in electricity market structures and regulatory policies among different countries. Hence, it is important to comprehend the existing electricity market structures beforehand. Generally, all the restructured electricity markets can be categorized into three basic structures: pool market, bilateral market and hybrid market.

2.3.1 Pool Market

The pool is one of the first mechanisms of electricity market and represents one of the innovations in the deregulation of electricity industry. All the trading of power is controlled by an independent system operator which is also known as a pool operator. The generators upload their energy bid prices and the scheduled generation outputs normally on a day-ahead basis. The system operator predicts total system demand day-ahead and sorts out a schedule of generation to meet this forecasted demand with the least cost of generation. The system operator also accounts for determination of pool prices based on the bids collected from the market participants[8]. Basically, there are two forms of pool market structure: mandatory pool and voluntary pool. The electricity market in Singapore and Australia, and the former UK Pool are typical examples of the mandatory pool market, in which all the energy trades have to take place in the pool. The Nord pool can be considered as a typical voluntary market which allows the energy trading outside the pool system.

2.3.1.1 Former UK Pool

In the period 1990-2001, England & Wales power industry comprised 3 dominant privatized generating companies which generated electricity, a transmission company and 12 distribution/supply private-owned companies for distributing and retailing electricity. The transmission company, namely National Grid Company (NGC), obtained the ownership of the transmission network and accounted for the operation of the transmission system. NGC worked as a system operator in UK and was responsible for the operation of the electricity market.

The electricity pool of England and Wales was set up to facilitate the competitive bidding process between generators by scheduling the proper generators to meet the forecast demand and setting electricity price every half hour on dayahead basis. The principles of the pool were relatively simple and largely inherited from the former vertical integrated mode. Demand was forecasted for each half hour period a day ahead by National Grid Company (ISO) and bids were collected by 10am from generators which wished to operate for the following day. Then, the system operator accepted bids from generators, beginning with the cheapest, until the forecast demand was reached. Generators were defined as _in merit‘ when their bids were successful and _out of merit‘ when unsuccessful for the trading day. Then, the system operator used the software Generating Ordering and Loading(GOAL) to generate a least cost generation schedule[9]. This is known as an Unconstrained Schedule. The System Marginal Price (SMP) is the bid price of the most expensive generator required to satisfy the forecasted demand. The price paid to all in-merit generators is the Pool Purchase Price (PPP) which is the sum of SMP and Capacity payment (CP) whose value is relative to Loss of Load Probability (LOLP) and Value of Loss Load (VOLL), defined as below:

$$\mathrm{PPP} = \mathrm{SMP} + \mathrm{CP} \tag{2.1}$$

$$\mathrm{CP} = \mathrm{LOLP} \times \max(\,0, \mathrm{VOLL} - \mathrm{SMP}) \tag{2.2}$$

Capacity Payment is the reward for the generator with capacity declared to be available, irrespective of whether it is called upon or not. LOLP is determined for each half-hour as the probability that available electricity capacity cannot meet the actual level of demand. VOLL is the estimated amount that customers are willing to pay to avoid supply interruption[10]. The Capacity Payment might increase when expected capacity shortage occurs, and decrease when generation capacity exceeds demand. The PPP is known with certainty from ex-ante perspective.

To cover the service needed to secure the power system in electrical equilibrium, the Uplifts were added in PPP to set Pool Selling Price (PSP) in form of ex post mechanism. The Uplifts present the difference between unconstrained schedule and the constrained schedule during the trading day which takes the transmission constraints, demand forecast errors, ancillary service and other security aspects into account. Therefore, it can only be known at the end of the trading day. The PSP is the price paid by the suppliers purchasing the electricity from the Pool, as given in (2.3). The system operator combines the PPP and PSP for settlement of the payments at the end of each day[11].

$$\mathrm{PSP} = \mathrm{PPP} + \mathrm{Uplifts} \tag{2.3}$$

The price of electricity within a pool varies from one market period,30 minutes being one period, to the next depending on the electricity supply and demand and the bidding behaviours of generating companies during a single day. Buyers and sellers seek to hedge against this price volatility by entering into a type of bilateral contract---Contract for Differences outside the pool which will be elaborated in section 2.6.1.By this means, the risk of price fluctuation for the pool participants is hedged.

2.3.1.2 Experience from UK pool

To some extent, the UK Pool electricity market, which operated in the period 1990-2001, was highly successful. Its centralized structure made it easy for the early electricity market to adopt. The supply of electricity was entirely secure over these 11 years, which can be considered as a critical impetus to establish an efficient electricity market. However, the electricity price drop still hardly emulated the cost reduction of the generation. There was not a significant price decrease in the retail market and the benefits of electricity deregulation hadn‘t been fully passed to the consumers. This can be partially attributed to the fact that the three dominant generating companies can easily exercise their market power and manipulate the market operation through strategic bidding. The dominant generating companies determined the electricity price most of time and it was discovered that they increased the pool electricity price deliberately at certain periods which the forecast price was moving downward[12]. In addition, the pool market concentrated the competition in the generation side and lacked the responses from the demand side which provoked complaints from the electricity purchasers. Those problems prompted a regulatory review of the pool mechanism and led to the implementation of a new model with bilateral contracts under NETA (New Electricity Trading Arrangements) in 2001.

2.3.2 Bilateral Market

In the bilateral market, the market participants are entitled to arrange their power trading through bilateral contracts that remain entirely commercially confidential on any terms they choose without the interference of system operator. Thus, the electricity is traded as other commodities and the contract price is set by the participants individually, which averts the risk of price volatility. The responsibilities of System Operator are narrowed to manage the real-time balancing and provide ancillary service. The economic efficiency is promoted by direct interaction between generation side and the demand side. BETTA (British Electricity Trading and Transmission Arrangement) is a typical example of a bilateral market.

2.3.2.1 UK BETTA

In March 2001, the England & Wales Power Pool was replaced by NETA. In 2005, the UK governments extended the NETA arrangement to cover Scotland network and renamed it as BETTA. The majority of electricity is traded through the contracts between individual participants. The structure of the market under BETTA is shown as Figure 2.2 below.

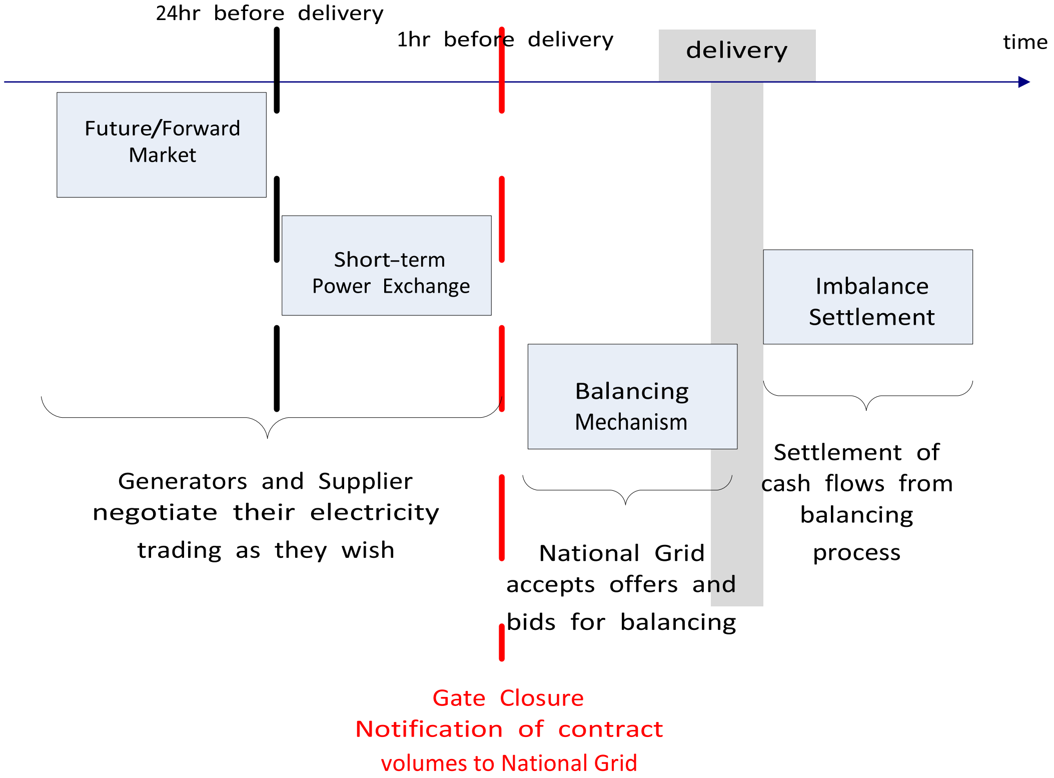

Figure 2.2 Structure of BETTA

In order to meet the needs of market participants, a variety of market options have emerged including the forward and future markets for long-term contracts up to several years and the short-term power exchanges for participants to adjust their contract positions in the last 24 hours[13]. Under this structure, generators are selfdispatched rather than being centrally dispatched by the System Operator. The market operates on a rolling half hourly basis. One hour ahead of real time, all trading has to go into abeyance (Gate closure) and the market participants are required to declare their final details of contracted energy to the System Operator, the National Grid Company[14]. The balancing mechanism is initiated after the gate closure. The system operator NGC starts collecting bids and offers from generators and suppliers to align the generation and demand whilst ensuring system security. The participants would be paid or charged regarding their individual offer/bid prices if their offers/bids are successfully accepted by System Operator. Even then, the participation of bilateral market and balancing mechanism is voluntary. The only mandatory part for market participants is the imbalance settlement after real time operation. The participants would be charged or paid if the differences between the real time metered volume and contracted volume exist. Generally, two cash-out prices, System Buy Price (SBP) and System Sell Price (SSP), are calculated based on the weighted average of the offers and bids which NGC collects in the balancing mechanism respectively. The System Sell Price (SSP) will be paid to the participants if the generator produces more than the contracted amount of electricity or the supplier has a demand less than the contracted amount. The System Buy Price (SBP) will be paid by the participants if the generator produced less than the contracted amount of electricity, or a supplier had a demand more than the contracted amount. Thus, the cost for tackling the real-time imbalance is targeted back to the participants who fail to adjust their contractual positions[15].

2.3.1.2 Experience from UK BETTA

Under the BETTA structure, several markets have emerged for electricity trading and the demand side market participants are involved in the competition. More price information is available, thus the market liquidity has increased remarkably compared to the pool mechanism. The reduction on the wholesale prices and retail prices reflect the great success of the BETTA mechanism. However, there are still some disadvantages in this mechanism. The dual imbalance settlement prices have prompted criticism as the persistently high and volatile System Buy Price has encouraged the generator to increase output and supplier to reduce demand in real time operation for avoidance of penalties in the imbalance settlement. Thus, the generators part-load their set and operate below the optimum generation efficiency, which wastes primary fuel and leads to additional emissions[14].The suppliers keep their contracts above the maximum of forecast demand to avoid the penalty which would result in an over-contracted market. The level of reserve tends to be increased due to the inefficiency of the balancing arrangement which make the whole system operation costly. Moreover, the balancing mechanism of BETTA encourages the market participants to self-balance and rewards participants who are capable for guaranteeing specific levels of generation or supply in advance and agreed flexibility in output/demand at short notice. However, most of the renewable generators, wind energy in particular, produce inherently intermittent and cannot predict levels of energy generation accurately. Thereby, the renewables are most likely to face the penalties in the imbalance settlement and have been proven less profitable under BETTA. In order to tackle this issue and secure the participation of renewable generators, Renewables Obligation Certificates (ROC) have come into effect in England and Wales since 2002, and Scotland followed by Northern Ireland since 2005[16].This sets an obligation on UK electricity suppliers to purchase an increasing proportion of electricity from renewable generators[17]. In such a manner, it sets priority on renewable generation to negate the detrimental effects of BETTA structure[14].

2.3.3Hybrid Market

Actually, many electricity markets combine the characteristics of Pool market and Bilateral trading market. In this structure, the market participants not only can conduct electricity trading in pool but also enter into bilateral contracts with each other in the light of their financial interest. Typical examples of hybrid markets are Nordic electricity market, PJM (Pennsylvania,New Jersey,Maryland) and California ISO.

2.3.3.1 Nordic electricity market

The Nordic uniform power market consists of the electricity markets of Norway, Sweden, Finland and Denmark which is the first truly multinational power market. The Nordic electricity market jointed with Sweden and Norway was initiated in 1996 and the Norwegian-Swedish Exchange named as Nord Pool was established as the rudiment of Nord Pool. Later, Finland and Denmark joined the common Nordic market separately in 1998 and 2000. The Nord Pool(Nordic power exchange) acts as market operator while 4 system operators, namely Statnett SF (Norway), Svenska Kraftnät (Sweden), Fingrid (Finland) and Energinet.dk (Denmark), cater for the transmission network management in four countries respectively[18]. The power generations in these countries are highly mixed. In Norway, the power generation mainly relies on the hydropower. In Denmark, the main generation method is thermal power. The generation pattern in Sweden and Finland is the mixture of hydro, nuclear and thermal plants.

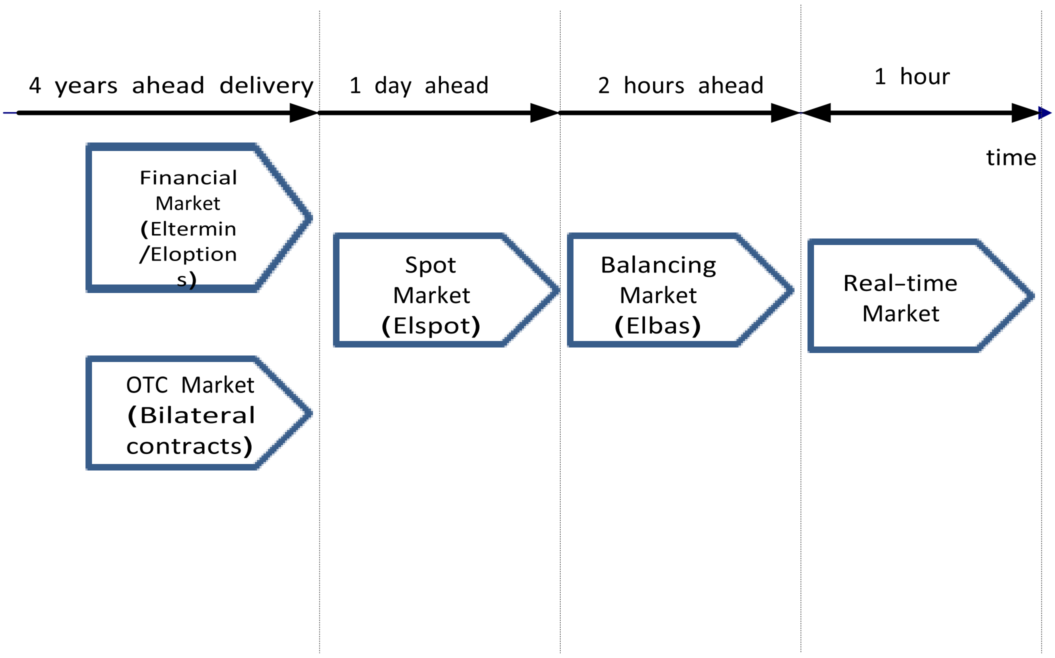

Figure 2.3 Nordic Electricity Market Structure

The electricity can be traded not only in the Over the Counter (OTC) market but also the non-mandatory financial market provided by the Nord pool. The financial market is composed of Eltermin and Eloptions markets. The Eltermin market allows the participants to hedge their price risk up to four years ahead through the standardized forward and futures contracts scaled from days to years. For future contracts, the value of each participant's contract portfolio is calculated daily derived from a change in the market price of the contracts. For the forward contract, the settlement would be completed at the end of contract period[19]. Eloptions market is important for risk management and critical for predicting future income and costs related to trade in electricity contracts. Options can be traded in the market which provides participants the opportunities to hedge the risk of price volatility.

The Nord pool also operates a physical-delivery market which consists of Elspot and Elbas markets. The Elspot market is a day-ahead hourly market where power contracts of a minimum of one-hour duration are traded for delivery the next day[20]. The spot price is the balance price for the aggregate supply and demand curves .It can be treated as a reference price both for the financial market and for the rest of the power market. The Elbas market, which acts as a supplement to Elspot for power balance, is a continuous intra-day physical market for balancing purposes where trades in electricity can be conducted up to one hour before delivery. In the real time operation, system operators organize real-time markets where bids are submitted for upward regulation (increased generation or reduced consumption) and downward regulation (decreased generation or increased consumption)[21]. Then system operators rank the bids and select the cheapest bids from market participants to balance the real time operation.

2.3.3.2 Experience from Nordic Electricity Market

The electricity systems in the Nordic region are closely connected with several interconnectors, to facilitate the physical power delivery and trading in the integrated Nordic electricity market. The power generation in Nordic countries is dominated by hydropower, in which capacity depends on precipitation while the start-up cost can be negligible. The simple but sound market design of the Nordic electricity market made it possible to integrate a large portion of hydropower and provide the right incentives for efficient allocation of resources in the power sector to a very large extent[22].The merging of electricity markets in four countries has diluted the market power of major generators with adopting distance-independent transmission prices which will be elaborated in section 2.5.1.3.Unfortunately, the possibility to exercise market power during a specific hour at the specific area still exists due to the transmission constraints in system. Moreover, a number of financial products have been created for hedging risk of price volatility, such as options and future contracts for electricity trading. This indicates that the Nordic electricity market is a mature and liquid financial electricity market[23]. However, a slow rate of growth in demand and overcapacity in generation and transmission indicates that there has been no need for investment in new generation capacity temporarily[24]. Needless to say, those favourable conditions can not last forever and the mechanism for securing new generation capacity investment has to be enhanced for long-term success.

2.3.3.3 US power market

To create efficient electricity markets with clear rules, the Federal Energy Regulatory Commission (FERC) of the USA issued a notice of proposal rulemaking containing the Standard Market Design in July 2002.The major elements of SMD include[25]:

- Single, non-discriminatory open access transmission pricing
- Independent Transmission Providers (ITPs)
- Interaction of Spot Markets and Bilateral Contracts
- Locational Marginal Pricing(LMP)and Congestion Management
- Market Power Mitigation and Monitoring
- Long-Term Resource Adequacy

The FERC suggested that all the deregulated markets in United States should adopt this market design. Currently, the PJM, California, New York and New England market rely on this structure. The operation principles of two typical US electricity markets, namely PJM and former California ISO, are described below for their representativeness.

2.3.3.3.1PJM market

PJM is the regional transmission organization which operates the grid serving the demand in Pennsylvania, New Jersey, Maryland and other states in the eastern part of United States. The PJM market is the largest competitive electricity wholesale market in the world and covers the largest grid interconnection in the North America.

According to the PJM annual report 2012, the generating capacity of PJM has exceeded 185600 MW and more than 800 participants are involved in wholesale electricity trading[26]. The PJM operates the energy market based on the Locational Marginal Pricing model which mainly includes an energy market, a capacity market based on the Reliability Pricing Model auction, and an ancillary service market.

The energy market is a multi-settlement design that consists of the day-ahead market and real-time market. The day-ahead market provides the marketplace for the market participants to trade energy for next day delivery. The hourly clearing price is calculated through the Locational Marginal Pricing model depending on the bids, offers and bilateral transaction schedules submitted in the day-ahead market before its closure[27]. The market design objectives are to provide the participants opportunities to lock in the trading price, schedule one day ahead for hedging the risk of volatile real-time price and incentivise the generation resource to follow the realtime dispatch for weakening the market force. The day-ahead schedules and resulting day-ahead LMP prices are calculated after the closure of the day-ahead market[28]. All the purchases and sales in the day-ahead market are settled with the day-ahead LMP prices.

The PJM real-time market operates on real-time conditions and balances the actual demands and energy schedules. On one hand, the generators are paid real-time LMP that is calculated based on real-time operation if there is any surplus compared to their day-ahead schedule. On the other hand, they will pay real-time LMP for the generation deviation if deficits occur. The multi-settlement design provides the participants with risk hedging in the day-ahead market and balancing system operation in the real-time market. This design mode provides the participants with a robust financial market and a reliable energy system.

The most important part of PJM market is the LMP based congestion management scheme. The LMP aims at optimizing the system operation with the consideration of system constraints and providing the correct economic signals to the market participants. When there is congestion in the system, the LMP can be drastically high in the congested area. The detailed methodology will be illustrated in section 2.5.1.2. However, ISO may collect more from the load side than the generator side when the system is congested. This excess collection is referred to as ―congestion revenue‖ or ―merchandise surplus‖. To hedge against the adverse effect of higher LMP payment, Financial Transmission Rights(FTR) have been put into practice to assist market participants in hedging their price risk whilst delivering energy on the transmission network. FTRs are financial instruments that entitle the holder to a share of the congestion revenue based on the hourly congestion price differences across a transmission path in the Day-Ahead market. The market participants can bid for monthly and long-term FTRs in PJM‗s FTR Auction or buy FTRs in a secondary bilateral market.

Besides, PJM operates two ancillary services markets, namely Synchronized Reserve and Regulation, to support the reliable operation of the transmission system and one capacity market to stimulate investment in maintaining existing generation and encouraging the development of new sources of capacity for long term grid stability[29, 30].

2.3.3.3.2 California market before crisis

California led the deregulation of the electricity utility in the United States in 1996. However, the fatal flaw of the market design and regulation policy became the hidden risk of the electricity crisis in 2000.

The California Independent System Operator (ISO) and Power Exchange （PX） were established after the deregulation of electricity market. CAISO was responsible to operate the transmission system and ensure its reliability and stability while PX was set for the wholesale trading of electricity among the participants. Bilateral contracts were prohibited and the trading of electricity mostly took place in the spot market, which provided generators with plenty of opportunities to increase prices unreasonably and exposed the participants to risks. There was no explicit capacity guarantee strategy or obligation in California. Therefore, investments in new generation capacity were postponed, which led the unbalance of supply and demand in the crisis. The utility company could only buy electricity in uncapped price but sell the energy to the end-customer in a capped price due to government price caps on retail price.

In the summer of the 2000, the drought and market manipulation triggered the large-scale blackout in the western United States. As the traders kept the generating units offline for maintenance to increase price in the peak-demand period, the balance of supply and demand was broken. The distribution companies could not reconcile the unreasonably high wholesale prices and capped retail prices which caused the bankruptcy of Pacific Gas and Electric Company (PG&E) and huge economic loss of other distribution companies in California[31].

After the crisis, the Federal Energy Regulatory Commission initiated new regulatory policy and system operating rules, such as implementing the resource adequacy requirements and improving market monitoring[32].

2.3.3.4 Experience from US electricity market

In PJM, the multi-settlement system based on LMP promotes liquidity and transparency in the market whilst supporting reliable grid operations through efficient price signals. The provision of FTRs assists the allocation of congestion revenue and allows participants to hedge against the congestion risks. A variety of financial products activates competition in market and sufficient trading in the forward market stabilizes the wholesale price. A capacity market is operated to incentivize investment in new and existing resources, which guarantees the long-term resource adequacy.

In contrast to the success of PJM market, the lessons learned from failure of California market can be outlined as following:

A, Electricity trading should combine the spot market with long-term contracts trading. In the California market, more than 90% of electricity is traded in the spot market, whereas only 10%-20% of power trading takes place in the spot market in PJM[33]. Since the price in the spot market is highly volatile, the long-term contracts can hedge the price risks and let the participants lock in the reasonable price range.

B, Adequacy of capacity is an important issue in the electricity market design. There should be enough incentives to new generation and infrastructure investments. The utility companies should fulfil the capacity obligation to make sure the system can develop stably and reliably.

C, Comprehensive regulation by government is needed. The fatal deficit of the California regulation policy is only partial regulation in the retail market, which neglects the potential for market power abuse in wholesale market.

2.4 The Role of ISO

In the deregulated electricity market, the independent system operator plays a vital role in providing the market participants equitable and open access to the transmission services. The responsibilities of ISO in different electricity markets may differ from each other. In the pool markets and hybrid markets, ISOs are responsible for energy trading and system operation. The duties would include generation scheduling according to economic merit, maintaining the transmission system security and reliability, carrying out financial settlement for all electricity trading and facilitating the market operation in the short-term and long term. In the bilateral market, such as BETTA, ISOs don't participate in the energy trading and their main roles have been narrowed down to manage real-time system balancing and provide ancillary services. Above all, the basic role of the system operator is to secure the power transaction and manage the transmission network. Congestion management is an important element of transmission network management, especially when the deregulated market environment has brought challenges to the system operator in managing transmission network .This will be elaborated in the following sections.

2.5 Generic Congestion Management in the Market Environment

The competitions and open access to transmission networks increase the frequency of transmission congestion in the system. Transmission congestion is actually the scarcity of transmission capacity to supply the demand due to transmission stability, voltage and thermal constraints. Transmission congestions result in price volatility, prevent the entrance of new contracts and make the whole power system unreliable. In the pre-deregulated power industry, the congestion management scheme was simple: the system operator could directly re-dispatch generator units and the congestion was relieved. With the open access of the transmission system, power flow is primarily determined by power trading, which makes it complex and difficult for system operator to ration the limited transmission capacity in an equitable, secure and economical manner. Therefore, the congestion management plays a vital role in the efficient operation of electricity market. The main task of congestion management is to efficiently allocate inadequate transmission capacity which includes all measures for handling transmission network access should congestion occur. Congestion management schemes can be evaluated through the following criteria according to the European Transmission System Operator(ETSO)[33]:

- Non-discriminate: Every market participant shares the equality and the price of the specific commodity in the identical place and time should be the same for all participants.

- Give correct economic signals: The congestion management method should stimulate the improvement of the systems in order to relieve the transmission constraints.

- Be transparent: The whole mechanism should be transparent for all market participants.

- Be feasible: The available resources, such as information and computer systems, should be capable of working out necessary results in real-time operation.

• Be able to interact with other systems: The implemented congestion management method should be able to interact with the surrounding system operators and their specific methodologies properly to maintain system reliability and stability.

Due to the different market structures around the world, congestion management implementations appear highly diverse. In spite of this diversity, those schemes with similar attributes could be categorized into a major congestion management scheme. As the concepts of congestion management are strongly connected to electricity market design, this section provides an overview of representative congestion management schemes with respect to different market structures. The major congestion management schemes can be categorized as below:

Table 2.1 Management methods in Electricity Market

Congestion management in Pool market	Congestion management in Bilateral market
Uniform Pricing	Countertrading
Locational Marginal Pricing	Transaction curtailment
Zonal Pricing	

2.5.1Congestion Management in Pool and Hybrid Markets

2.5.1.1 Uniform Marginal Pricing

Uniform Marginal Pricing (UMP) can be referred to as ―re-dispatch first, compensate later‖. This method was implemented in the former England-Wales pool mechanism. The operation of this congestion management scheme can be divided into two distinct stages: market dispatch (MD) and congestion re-dispatch (CR).

In the MD period, all the bids from the generators are collected and placed in an ascending order based on the bidding prices. According to predicted demand profiles, the cheapest generators are chosen to meet the forecast demand and the bidding price of the marginal generator (the most expensive one among the selected generators) is the market clearing price, also known as the system marginal price (SMP). Then, the second stage congestion re-dispatch (CR) would be launched by the system operators if the transmission constraints are binding. The SO would redispatch the generators to satisfy demand and minimize the re-dispatch costs without violating the system constraints.

2.5.1.1.1 Basic Algorithm

In the Market Dispatch process, system constraints and transmission loss are not taken into account. The SMP and PPP are set at this stage as ex-ante prices. The unconstraint dispatch algorithm can be stated as below:

$$\min \sum_{i=1}^{N_{Gen}} C_{Gen_i} (P_{Gen_i}) \quad (2.4)$$

Subject to:

$$\sum_{i=1}^{N_{Gen}} P_{Gen_i} = \sum_{j=1}^{N_{Load}} P_{Load_j} \quad (2.5)$$

$$0 \leq P_{Geni} \leq P_{Genimax} \quad (2.6)$$

where $C_{Gen_i}(P_{Gen_i}) = Bid\ price \times P_{Gen_i}$(the bid-based generation cost of generator i)

P_{Gen_i} is the power generated by generator i

P_{Load_j} is the forecast load j

N_{Load} is the total number of loads

N_{Gen} is the total number of generators $P_{Gen_i}{}^{max}$

is the maximum capacity of generator i

Equation (2.5) states the power balance between generation and demand while constraint (2.6) illustrates the output of generator should not exceed its maximum capacity. If there are no constraints in real time, the SO would stick to this generation schedule.

When congestion occurs, the SO needs to re-dispatch the generators to meet the demand. The objective function (2.4) is subjected to an additional inequality constraint for the transmission lines in system. This inequality constraint is given as:

$$P_{branch_k} \leq P_{branch_k}{}^{max} \tag{2.7}$$

where P_{branch_k} is the power flow on branch k,

$P_{branch_k}{}^{max}$ is the maximum power flow limit on the branch k

This also refers to security-constrained re-dispatch and a new generation schedule is drawn up with this adjusted algorithm. Then, the generators are
―constrained on‖ or ―constrained off‖ according to this new schedule. The cost deviation between the constrained schedules and the original unconstrained ones is referred to as Uplift which would be allocated to all the consumers.

2.5.1.1.2 Pricing Scheme

As mentioned in section 2.3.1.1, the System Marginal Price (SMP) is the bid price of the most expensive generator required to satisfy the forecasted demand and Pool Purchase Price (PPP) is the adjusted price paid to the generators with consideration of capacity payment. The Pool Sell Price (PSP) is the price paid by customer for their metered demand which consists of PPP and Uplift, as shown in equation (2.8). The Uplift includes the cost of re-dispatch, ancillary services and transmission system losses. In our case, the costs of ancillary service and transmission losses are neglected and Uplift only represents the cost of re-dispatch.
The cost would be allocated on all consumers as equation (2.9):

$$\mathrm{PSP} = \mathrm{PPP} + \mathrm{Uplift} \tag{2.8}$$

$$\text{Uplift} = \frac{\text{constrained dispatch cost} - \text{unconstrained dispatch cost}}{\text{total load}} \tag{2.9}$$

In the congestion re-dispatch stage, some in-merit generators cannot generate to the amount they are willing to produce in the unconstrained dispatch stage. These generators are said to be ―constrained off‖. On the other hand, some generators have to generate more than the amount they are willing to produce in the unconstrained dispatch stage and some out-of-merit generators have to be dispatched to relieve the congestion. These generators are said to be ―constrained on‖. All of the generators are paid with PPP and then compensated for the difference between their bid prices and PPP using an adjustment calculation as below:

Adjustment for Constrained off generators:

$$\text{Adjustment}_{Genoff} = (unconstrained\ generation\ \ amount\ - constrained\, generation\, amount) \times (PPP - Bid\ price_{Genoff}) \tag{2.10}$$

Adjustment for Constrained on generators:

$$\text{Adjustment}_{Genon} = (constrained\ generation\ \ amount\ - unconstrained\, generation\, amount) \times (Bid\ price_{Genon} - PPP) \tag{2.11}$$

2.5.1.1.3 Example of Uniform Marginal Pricing

The network in Figure 2.4 is considered for simple illustration of the Uniform Marginal Pricing mechanism. The network consists of two generators G1 and G2 and two loads L1 and L2. Both G1 and G2 have the maximum generation capacity 200MW. The inelastic loads L1 and L2 are 50MW and 150MW respectively. The bid prices of G1 and G2 are £10/MW and £30/MW respectively. The transmission line is assumed lossless.

Figure 2.4 Example Network

When there is no constraint in the transmission system, the cheapest generator G1 generate is operated to its full capacity for supplying all demand in the whole system and the resulting SMP is £10/MW according to the bid price of G1. In this case, LOLP is assumed to be zero, therefore the capacity payment can be neglected and PPP is equal to SMP. The generator G1 is paid with PPP £10/MWh.The total generation cost is equal to £2000/h.

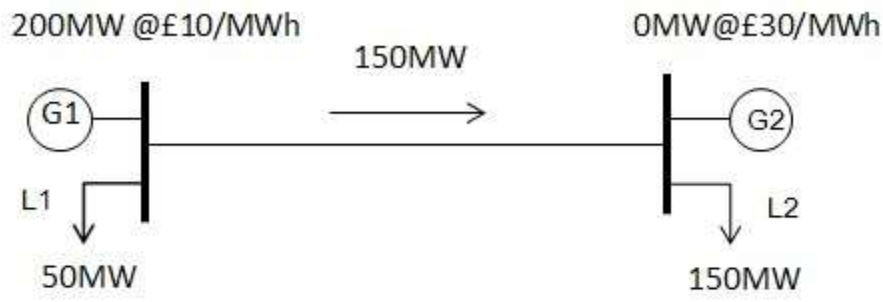

Figure 2.5 Unconstrained Case

When the capacity of transmission line is limited to 100MW as shown in Figure 2.6, output of G1 is constrained off to 150MW and the more expensive generator G2 is dispatched to generate 50MW to meet the demand. The generators are paid with PPP £10/MWh as the unconstrained case. The generation cost of congestion re-dispatch is :

$$150MW \times £10/MWh + 50MW \times £30/MWh = £3000/h$$

Uplift can be calculated as below:

$$Uplift = \frac{\text{constrained dispatch cost} - \text{unconstrained dispatch cost}}{\text{total load}}$$

$$= \frac{£3000/h - £2000/h}{200MW} = £5/MWh$$

Therefore, The Pool Sell Price (PSP) paid by consumers is set as:

$$PSP = PPP + Uplift = £15/MWh$$

The adjustment fee paid to G1 and G2 can be calculated as below:

$$Adjustment_{G1} = (200MW - 150MW) \times (£10/MWh - £10/MWh) = £0/h$$
$$Adjustment_{G2} = (50MW - 0MW) \times (£30/MWh - £10/MWh) = £1000/h$$

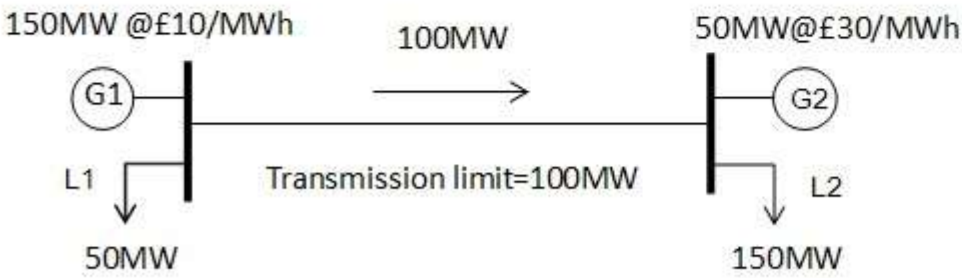

Figure 2.6 Constrained Case

2.5.1.1.4 Lessons Learn from Uniform Marginal Scheme

The initial appeal of Uniform Marginal Scheme is its apparent simplicity as only one uniform price is set in the whole market[34]. This allows the system operator to collect revenue and allocate the congestion cost. In this scheme, the system operator centrally dispatches the generator to relieve congestion which can be considered as the extension of vertically integrated industry in a deregulated market. This results in some defects. The market participants have to obey the schedule of the system operator and can only get the information of trading price which cannot reflect the cost of congestion directly. This is somehow not transparent. The system operator allocates congestion cost equally on every participant in the market through the same price setting, thereby no locational incentives are provided for generation and transmission investment. Furthermore, the contribution of individual participants hasn‘t been distinguished in this scheme. It is clear that the lack of market information deteriorates the long term sustainability of electricity market.

2.5.1.2 Locational Marginal Price

In order to provide clear economic signals for encouraging efficient use of transmission network and generation resource, the Locational Marginal Pricing method has become the dominant approach used in the United States power markets to manage transmission congestion and calculate electricity prices. LMP was firstly proposed by F.C. Schweppe in 1988[35]. Locational Marginal Pricing, which is also known as Nodal Pricing, is defined as the marginal price of next increment of 1 MWh power at a specific bus, which includes the cost of generation and physical delivery. In the absence of congestion and transmission losses, the LMP of each node in the system is set as the system marginal price based on the bids collected from market participants, which implies no congestion cost and loss cost have been imposed on the market participants. In practical contexts, the LMP of each node is different from each other due to transmission loss and congestion. To complete this process, the ISO runs the Optimal Power Flow to calculate the MW dispatch of each generator and LMP of each node. Using LMP scheme, generators are paid by LMP and the consumers are charged according to the LMP at their nodes.

2.5.1.2.1 OPF Algorithm

Optimal power flow (OPF) was first proposed by Carpentier in 1960s. OPF integrates the power flow calculation with the minimization of an economic objective function subject to the equality and inequality constraints of network operation. There are basically two forms of OPF models: ACOPF and DCOPF. The ACOPF model addresses the real and reactive power flows at the same time through power balance equations based on the normal AC model. It is considered as the most accurate mathematical model and the simulation results can be used as benchmark data. However, the solver takes a long time to converge due to its nonlinear approach, especially for the implementation in large scale power system. Therefore, ACOPF is normally adopted for verification purposes rather than real application. In contrast to ACOPF, conventional DCOPF only addresses the real power flow, neglecting voltage support, reactive power management and transmission losses. Due to this simplification, DC power flow model is a much less complicated linear programming model which has surpassed ACOPF in terms of calculation speed and convergence. Hence, DCOPF is very often used for LMP calculation in most markets because of its simplicity, robustness and higher speed of convergence[36].In this section, the DCOPF algorithm will be illustrated.

In generic DCOPF modelling, the following assumptions are made as below which is reasonable for conventional high-voltage transmission systems:

1. The angle difference across each branch $\delta_{ij} = \delta_i - \delta_j$ is small so that $sin\delta_{ij} = \delta_{ij}$ and $cos\delta_{ij} \approx 1$

2. The voltage profile is flat.

3. The resistance of each branch is negligible compared to the branch reactance and can therefore be set to zero. Hence the dc model reduces the power flow problem to a set of linear equations.

DCOPF is modelled by an optimization problem. Basically, the optimization objective has variable forms other than the minimum generation cost, such as the minimum transmission losses or the maximum social welfare. Here, the objective function is to minimize the generation cost for simple illustration. Power flow equations, line flow limits, generation limits are the constraints of this optimization problem. Consider a power network with N nodes and L lines, objective function and constraints are modelled as equation (2.12):

$$\min f = \sum_{i \in N} C_i(P_i^g) \tag{2.12}$$

Where $C_i(P_i^g)$ is the bid-based cost function of generator at node i,

$$C_i(P_i^g) = \frac{1}{2}c_{2i}(P_i^g)^2 + c_{1i}P_i^g + c_{0i}$$

Subjected to:

1) The real power balance constraint at node i:

$$P_i^g - P_i^d - \sum_{j=1}^{N} P_{ij} = 0 \tag{2.13}$$

2) The maximum and minimum output constraints of the generators:

$$P_{i,min}^g \leq P_i^g \leq P_{i,max}^g \tag{2.14}$$

3) The capacity constraints of the transmission line l:

$$|P_l| < P_l^{max} \tag{2.15}$$

where P_i^g is the real power generated at node i , P_i^d is the real power demand at node i , P_{ij} is the power flow between node i and j while $\sum_{j=1}^{N} P_{ij}$ is the sum of real power flowing out of node $P_{i,min}^g$ and $P_{i,max}^g$ i;are respectively the minimum and maximum

generation constraints at node i ; P_l is the power flow on transmission line l and P_l^{max} are the upper and lower limit of the real power capacity of line i-j.

2.5.1.2.2LMP

For transparency and simplicity, a reduced DCOPF model with losses can be derived with the replacement of real power balance constraint equation at bus i by the total real power balance equation considering power loss among all nodes in the system. The power loss modelling in DCOPF can be found in[37, 38]. This can be considered as an equivalent formulation that will not change the optimal solution of the DCOPF solution. The constraint (2.13) can be rewritten as:

$$-\sum_{i=1}^{N} P_i^g + \sum_{i=1}^{N} P_i^d + P_{loss} = 0 \tag{2.16}$$

where P_{loss} denotes system loss.

According to the above-mentioned problem, the corresponding Langrangian formula can be stated as[39]:

$$\mathrm{L} = \sum_{i=1}^{N} C_i\left(P_i^g\right) + \lambda_0\left(-\sum_{i=1}^{N} P_i^g + \sum_{i=1}^{N} P_i^d + P_{loss}\right) + \sum_{l=1}^{L} \mu_l(|P_l \quad P_l^{max}) + \sum_{i=1}^{N} \pi_i^{max}\left(P_i^g - P_{i,max}^g\right) + \sum_{i=1}^{N} \pi_i^{min}\left(P_{i,min}^g - P_i^g\right) \tag{2.17}$$

where λ_0 is Lagrangean multiplier on the energy balance constraint of whole system; N is the total number of nodes and L is the total number of branches in the system. μ_l refers to the Lagrange multipliers of the transmission constraint of line l. π_i^{max} and π_i^{min} minimum and maximum generation limits of unit i.

From Langrangean, the following expression for LMP of node i can be derived as below[40]:

$$\mathrm{LMP}_i = \frac{\partial L}{\partial P_i^d} = \lambda_0\left(1 + \frac{\partial P_{loss}}{\partial P_i^d}\right) + \sum_{l=1}^{L} \mu_l \times \frac{\partial P_l}{\partial P_i^d}$$

$$= \lambda_0 + \lambda_0 \times \left(\frac{\partial P_{loss}}{\partial P_i^d}\right) + \sum_{l=1}^{L} \mu_l \times T_{i-l} \tag{2.18}$$

T_{i-l} is the sensitivity factor for real power at the node i with respect to the network constraint on line l;

Thus, LMP can be furthered decomposed into three components: the marginal energy price, marginal congestion price, and marginal loss price. The LMP formulation can be expressed as equation (2.20)-(2.22),which is consistent with industry practices[41]:

$$\mathrm{LMP}_i = LMP_i^{energy} + \mathrm{LMP}_i^{loss} + \mathrm{LMP}_i^{congestion} \tag{2.19}$$

$$LMP_i^{energy} = \lambda_0 \tag{2.20}$$

$$\mathrm{LMP}_i^{loss} = \lambda_0 \times \left(\partial P_{loss} / \partial P_i^d\right) \tag{2.21}$$

$$\mathrm{LMP}_i^{congestion} = \sum_{l=1}^{L} \mu_l \times T_{i-l} \tag{2.22}$$

where LMP_i^{energy} is incremental energy cost at the corresponding node i, which refers to the system marginal cost of reference node;

LMP_i^{loss} is the incremental cost due to thermal transmission losses at corresponding node i;

$\mathrm{LMP}_i^{congestion}$ is the incremental cost of network constraints at corresponding node i.

2.5.1.2.3 Example of Locational Marginal Price

The two-node network illustrated in this section serves to elaborate how the LMP system works to manage congestion. In the unconstrained situation, the LMP of each node is equal to £10/MWh which is equal to the marginal cost of meeting the last increment of demand.

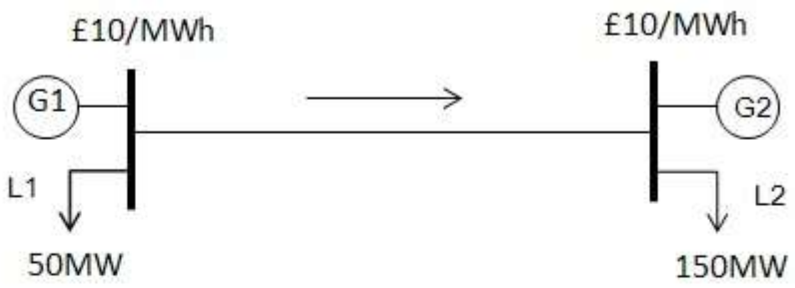

Figure 2.7 Unconstrained Case

If transmission limit 100 MW is binding on the system, the cheap generator can no longer operate at its maximum capacity as the power flow of the transmission line would exceed its limit. The expensive generator G2 is dispatched to serve the load. According to the LMP theory, the next MW of supply to meet the demand increment at node 2 comes from G2, then the LMP of node 2 is £30/MWh. For node 1, the 1 MW increment of demand only involves increasing the output of generator 1. Therefore,the LMP of node 1 remains at £10/MWh.Table 2 lists the demand charges and generator payments.

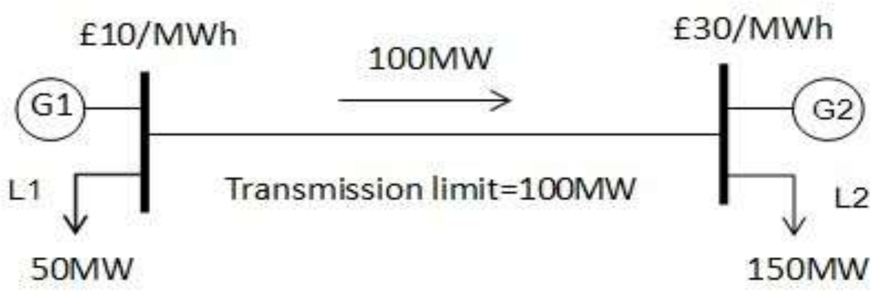

Figure 2.8 Constrained Case

Table 2.2 Settlement of LMP system

	Unconstrained	Constrained
LMP of Node 1(£/MWh)	10	10
LMP of Node 2(£/MWh)	10	30
Payment to Generator 1 (£/h)	200*10=2000	10*150=1500
Payment to Generator 2(£/h)	0	30*50=1500

Demand Charges of Node 1(£/h)	10*50=500	10*50=500
Demand Charges of Node 2(£/h)	10*150=1500	30*150=4500
Congestion surplus=Total Demand Charges –Total Generation Payment	0	2000

The difference between total demand payment and generation payment is 2000£/h, which refers to congestion revenue or merchandise surplus. This surplus accrues whenever there is congestion in the system. The congestion revenue can be used for transmission network investment or funding FTR to reimburse the consumers which will be elaborated in section 2.6.2.

2.5.1.2.4 Lessons Learned from Locational Marginal Price

Currently, the trading mechanism based on LMP has been implemented by a number of ISOs such as the PJM, New York ISO, ISO-New England and California ISO[42, 43]. As Locational Marginal Pricing builds on the physical topology and parameters of the network, it allows for a more efficient use of the network, reduces the opportunity for generator gaming and provides a clear economic signal to market participants[44]. The impacts of congestions and losses on the economic costs of providing electricity to different nodes are reflected in the nodal price differences. Hence, the LMP system is transparent. With clear price signals, LMP represents the best approach available for operating large, interconnected power pools efficiently and reliably. In the long term, LMP provides guidance and objective information about the value of potential generation and transmission investments in specific locations, which can gradually achieve a fair competitive market environment.

However, LMP implementation in real deregulated electricity markets is not exactly the same as described by theory. Firstly, as most electricity markets are bidbased, not cost-based, there might be some collusion between market participants. Thus LMP based on the bid cannot fully reflect the short run marginal cost of system and the market operation in some cases[45]. Therefore, the role of the market monitor is still crucial for assessing and maintaining competitive conditions and successful market operations. Secondly, LMP might provide inaccurate incentives for investment in generation or transmission infrastructure. This can be partially attributed to the fact that the actual investment decision of infrastructure depends on many factors other than the economics signal, such as the political impact and technical issues. Lastly, the LMPs in the system are volatile in real-time operation and ISO can collect congestion revenue from market participants which would enhance market circumstances unfavourable to efficiency[46]. To tackle this issue, financial instruments designs, such as Financial Transmission Rights(FTR)/Congestion Revenue Rights (CRR), are implemented to provide market participants price risk hedging and to help offset the high LMP payments by the load.

2.5.1.3 Zonal Pricing

Zonal pricing is introduced into the market to establish different electricity prices for different zones in the network when congestion occurs. This scheme has been applied in Norway, Denmark, Australia, and California market before 2009[47]. In general, the zones are defined by the system operator based on engineering study and historical data. The electricity market is cleared and the system marginal price is calculated based on the supply and demand schedule bids given by the market participants. If there is no congestion in the system, the clearing price in every zone is identical to this system marginal price. If demand for the transmission services exceeds the transmission capability, the whole system is divided into the predefined zones and individual zonal prices are calculated according to the bids collected from the market participants in each zone. After the market is split, there are likely to be some zones with a generation surplus which can be defined as the low-price zone and some zones with a generation deficit which are determined as the high-price zones[48]. For the electricity price inside the zone is identical, zonal pricing can be considered as the combination of Uniform pricing and nodal pricing where uniform price is applied inside the zone whilst nodal prices are set among different zones. In the following stage, the system operator may purchase electricity from the low price zone and sell it to the high price zone to maximize the utilization of the tie-lines which haven't reached their upper limits. Thus, the electricity in the generation surplus zones can be sold in higher price and the consumer in the high price zone can benefit from a cheaper electricity price. At the same time, the transmission capacities among the zones are fully utilized. The following example illustrates this process:

There are two specific zones in the whole system as shown in Figure 2.9. The zone 1 consists of node 1, node 2 and node 3 while the zone 2 consists of node 4, node 5 and node 6. The maximum transfer capacity between zone 1 and zone 2 is $P_{tieline}{}^{max}$. $\text{Demand}_{\text{all}}$ and $\text{Generation}_{\text{all}}$ denote the total demand and generation amount in the whole system respectively. In the first step, the market is cleared without the consideration of transmission constraints and the system marginal price P_S is set for the whole market as shown in Figure 2.10.

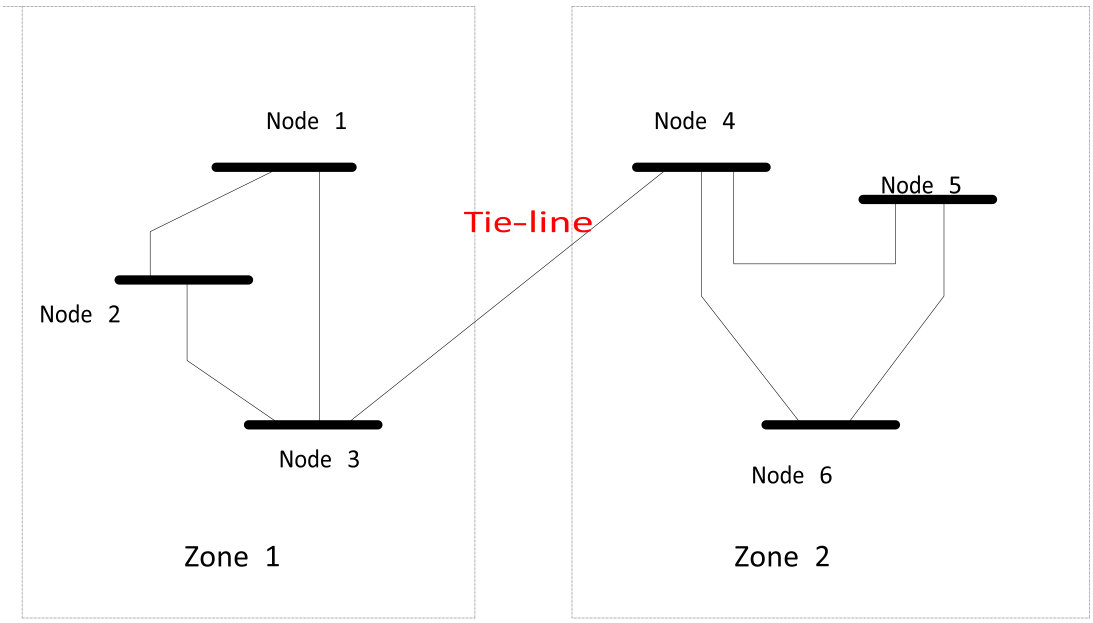

Figure 2.9 Definition of zones in the system

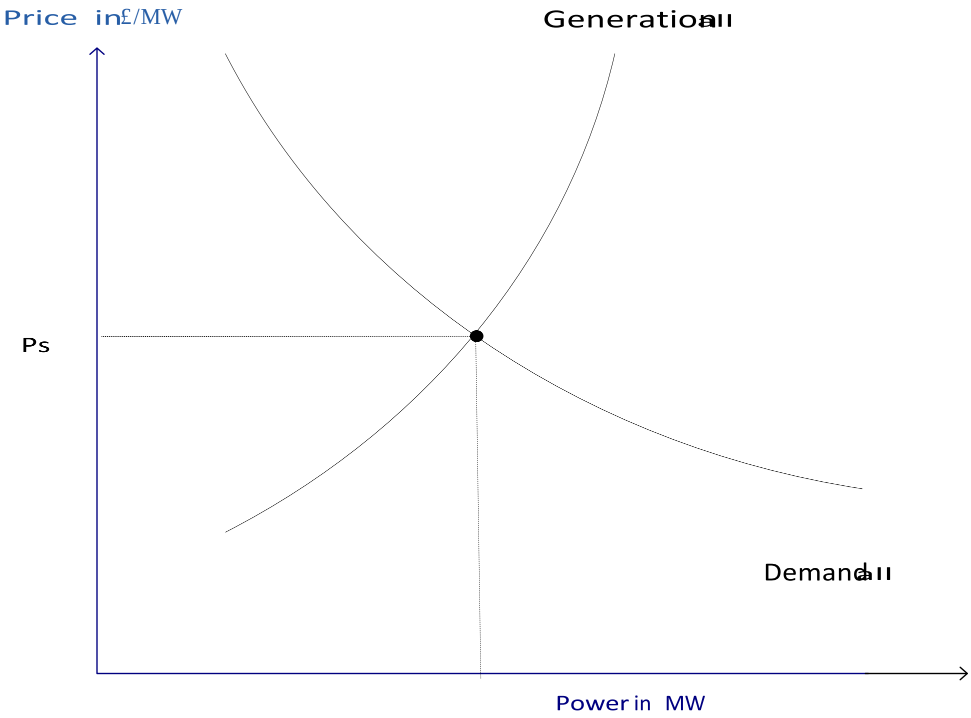

Figure 2.10 System Marginal Price of whole electricity market

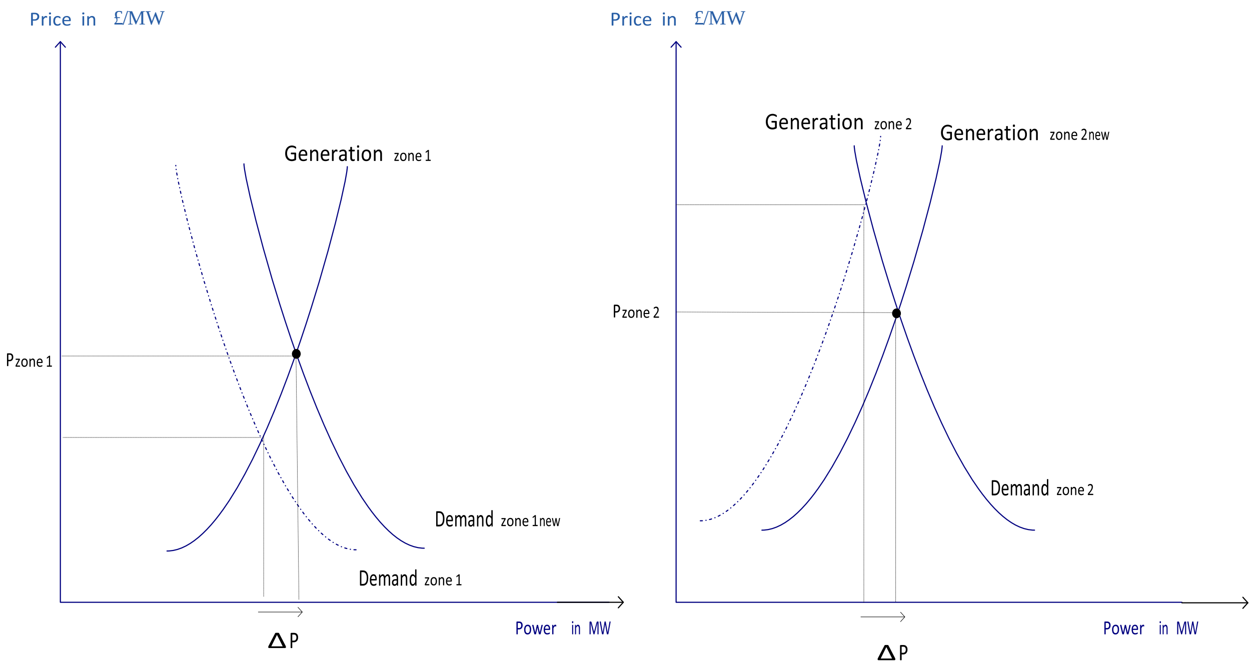

Figure 2.11 Market spliting- Low price zone(Left) and High price zone(Right)

When the power flow $P_{tieline}$ between zone 1 and zone 2 in the above unconstrained case exceeds the maximum transfer capacity $P_{tieline}^{max}$, congestion occurs and the system operator would split the market into two predefined zones in this case. It is defined as market splitting process and will be explained as below with Figure 2.11. After market splitting, there likely to be a low price zone and a high price zone. The low price zone in this case is zone 1 and the high price zone is zone 2 with their own zonal price at p_{zone1} and p_{zone2} respectively. The supply curve of zone 2 (high price zone) is adjusted to $\text{Generation}_{zone2}$ as below.

$$\text{Generation}_{zone2new} = \text{Generation}_{zone2} + \Delta\text{P} \tag{2.23}$$

Likely, the generation in zone 1 can meet a new demand:

$$\text{Demand}_{zone1new} = Demand_{zone1} + \Delta P \tag{2.24}$$

ΔP is the power trading between two zones, which cannot exceeds the maximum transfer capacity $P_{tieline}^{max}$ .In this way, the system operator can buy electricity at a high price zone and sell it to the low price zone. The power prices among the whole system tend to converge and the transmission capacity of the network is rationally utilized. However, the System operator may collect revenue due to congestion and this would be used for network investment or allocated on the market participants.

2.5.1.3.1 Lessons Learned from Zonal pricing

Zonal pricing can be considered as the compromise between LMP and Uniform Marginal Price. In accordance with LMP, the zonal pricing scheme passes economical price signals to participants by splitting the market into several zones in the context of congestion. Zonal pricing is regarded as a simpler and inexpensive congestion management approach as it decreases the complexity and reduces the number of different pricing points in comparison with LMP.

However, difficulties can be encountered in defining zones boundaries and managing the intra-zone congestion. The system operator manages the inter-zonal congestion through charging participants for the different zonal marginal costs and the intra-zonal congestion through uplift regardless of cost causation. For the sake of simplification, only the congestions on interconnections (paths connecting two areas) are targeted by the system operator. Thus, the boundaries of zones are defined based on the assumption that the intra-zonal congestion is infrequent and the corresponding congestion cost is considerably small. However, this assumption turns out to be true only at the beginning of system operation. With the evolution of actual dispatch pattern of electricity market and involvement of new generation resources, the intrazonal congestion might become significant and the setting process of new zones usually lags behind considerably[49]. Therefore, the freezing zone definition sometimes distorts the actual marginal prices and assigns uniform prices to nodes which in reality bear different costs and should thus be priced differently. Even when the intra-zonal congestion are small probability events according to the original assumption, it still might result in infeasible re-dispatch and unfair trade inside the zone. As a consequence, this potentially provides generators more opportunities to game in the market for high profits. To some extent, zonal pricing appears to be inferior to LMP when it comes to market power. In [50] and [51], the authors presented a set of examples to illustrate that LMP is better suited to prevent market power when compared to the zonal approach.

2.5.2 Congestion Management in Bilateral Markets

In bilateral market, the market participants arrange their own trades without the obligation to reveal contract information and intervention of ISO concerning economic decisions. It is the participants‘ responsibility to ensure the agreed contracts without violating the system constraints and take the risk with transaction rejected by ISO due to the system security issues. Ideally, there would be no congestion in the system and thereby no intervention needs to be executed by ISO. However, the scheduled transactions may not satisfy the security criterion with the unpredictable failure in the real time operation. Furthermore, many contracts are firmed up days, months or even years ahead of the actual delivery periods, the operation conditions of transmission network might vary and the originally secured transaction may turn out to be insecure. Under this circumstance, ISO has to modify or reschedule the power transactions to make the new set of transactions compliant with the system security criterion. In general, the congestion management approaches in bilateral markets can be categorized into two groups: countertrading and transaction curtailment. These methods are briefly discussed below.

2.5.2.1 Countertrading

Countertrading can be considered as a form of re-dispatching with the market-oriented purpose. Once congestion is observed in the transmission system, the transmission system operators would execute counter-trade against the flow on the congestion line until the congestion is relieved. This method is straight-forward but not fully applicable in practice as ISO cannot interfere in energy trading directly. It is considered as an applicable approach only if there are demands not being committed to any bilateral contracts or incentives are given to the transactions which incur counter-flow in the overloaded line at the congestion periods. Countertrading is a real-time remedial method for congestion relief applied in Norwegian system and also an exclusive congestion management concept in the Swedish market[52].

2.5.2.2 Transaction Curtailment

The alternative method to manage congestion is to decrease the power flow in the overloaded lines through curtailment of the contracted power transactions. As the power flow in the transmission line can be treated as the sum of power flow contribution from the each transaction according to the superposition theorem, ISO can curtail a certain amount of power transaction which depends on specific curtailment rules. There are four basic curtailment rules listed below:

- First come First serve: Under this approach, ISO curtails the transaction in a reverse order of contract submission when congestion occurs. The last submitted transaction would be rejected first to solve the overloading, and curtailment would take place in descending order until congestion is relieved.

This approach is simple but somehow rigid because it hasn‘t taken the power flow contribution of bilateral transactions into account. Consequently, some of the last submitted transactions might potentially provide the counter-flow on the overloaded line and the abrupt curtailment would further deteriorate the congestion in system. Thus, it can be concluded that the efficiency of this method relies on the order of transaction submission.

- Pro rata (proportional):In this rule, no priority is specified. Thus, ISO curtails the transactions according to their contribution to the power flow on the overloaded lines. The transaction which contributes more on the power flow on congested lines would be curtailed more and vice versa. This rule is transparent but might involve participants in an economically inefficient use of the whole system[53].

- Minimum-net curtailment: As different bilateral transaction curtailment is related to different flow sensitivity to the power flow on the congested line, the curtailment of one certain transaction would be more effective to relieve the congested line than others. Thus, this approach attempts to minimise the energy curtailments as a means to relieve congestion. This approach is transparent. However, it is not a market-based method as well, thereby cannot provide long-term incentives.

- Willingness to pay: Under this scheme, the participants submit the bids to show how much they are willing to pay for avoiding the transaction curtailment imposed by ISO. Thus, when the curtailment is needed for congestion relief, the ISO would select the curtailment starting with the ones with lowest willing to pay bids. Meanwhile, ISO can collect willingness-to-pay payment from the participants. It is a market-based approach that allocates the transmission capacity to those who value it most highly. However, this method is not physically efficient in some cases as it doesn‘t consider the contribution of transaction curtailment to the congested line and the flow sensitivities. Therefore, this method is always combined with other congestion approach in practice[53].

2.6 Financial Instruments for Hedging Congestion Risk

The price volatility risk due to congestion which market participants are exposed to can be counted as one of the disadvantages associated with electricity markets. Seen from generators‘ point of view, the risk of low prices is financially unpalatable as they have to recover costs which typically consist of the capital investment cost and various fixed operational costs, such as maintenance, use of system charges, etc. On the other hand, from the suppliers‘ point of view, it is difficult for them to guarantee stable profits with the volatile prices in the electricity market. Furthermore, the end customers are subject to fixed tariffs on long-term contracts with suppliers. Therefore, they are not exposed to volatile electricity prices directly. Thus, the bankruptcy risk of suppliers might arise when spikey prices in some extreme cases hit the wholesale market.

Therefore, financial instruments have been developed in order to guarantee an acceptable level of price stability in electricity market. These include forwards and futures contracts, Contracts for Difference and Financial Transmission Rights. With these financial products, the market participants can manage their risks and secure their benefits with the cost slightly more than average.

2.6.1 Contract for Difference(CfD)

A Contract for Difference (CfD) is one of such financial instruments which exist in order to hedge against the deviation between a volatile price and a certain reference price. There are several variations of CfDs in different electricity markets. CfDs available in the former England and Wales Pool are aimed to hedge the price risk between pool price and a predefined reference price while CfDs available in the Nord pool are targeted to hedge against the difference between the zonal price and the system price in a specific time period.

Under the UK pool, the payoff from CfD is stated as below

$$\mathrm{CfD} = \mathrm{P}_{contract}(p_{pool} - p_{strike}) \tag{2.25}$$

where $P_{contract}$ is the volume of the CfD contract p_{pool}
is Pool Price.
p_{strike} is Strike Price, which is the agreed price in the CfD contract

The payments of CfD are calculated as the difference between the pool prices and strike prices times the contracted volume during the delivery period. When the pool price is higher than the strike price, the generator has to pay CfD payments to the supplier. Conversely, when the pool price is lower than the strike price, the supplier must pay the generator the difference. Thus, both sides of market participants effectively ―trade‖ bilaterally, even though all power trading is physically done through a pool. The CfDs implemented in the Nord pool work under similar principles as described above.

2.6.2 Financial Transmission Right

In general, prices in LMP based markets vary not only with time but also with location. Thus, market participants are exposed to more risks than those in the nonlocational markets. When locational price differs between the generators and load, the generator or load may be charged the congestion fee. According to the description in [54], an FTR is a financial instrument which entitles the holders to receive value of congestion as established by locational price difference between source and sink nodes for a defined amount of transaction and a defined duration. FTRs have been used in PJM since 1998 and consequently implemented in New York, California and New England[55]. The economic value of FTR can be formulated as below:

$$\mathrm{FTR} = \mathrm{P}_{FTR} \times (LMP_{sink} - LMP_{source}) \tag{2.26}$$

where LMP_{source} is the LMP price at the node where the power is scheduled to be injected into the power system (source),

LMP_{sink} is the LMP price at the node where the power is scheduled to be withdrawn from the power system (sink),

P_{FTR} denotes the quantity of active power reserved on the path from source and sink nodes.

The FTRs in the forms of obligation or option provide a mechanism for hedging LMP risk and redistributing congestion surplus which is collected by ISO. It can be either a benefit or a liability on the holders. It appears as a benefit when the contracted power transaction runs in the same direction as actual congested flow. This occurs when the LMP of the sink node is higher than that of the source node. In this case, an FTR is a perfect hedge against volatile LMP prices.

However, it may become a liability when the contracted power transaction runs in the inverse direction to the actual congested flow. It happens when the LMP of the source node is higher than that of the sink node.

The FTRs can be allocated in different ways. Under some market rules, the FTRs can be given for free to the market participants who invest in the transmission lines. For other market participants, the allocation of FTRs usually takes place in auctions which are conducted by the ISO and secondary markets where existing FTRs are electronically bought and sold on a bilateral basis[3].

2.7 Summary

This chapter discusses the generic electricity market structures and concepts of congestion schemes. The chapter starts with the overview of three conceptually different designs of electricity markets: pool market, bilateral market and hybrid market. The pool market is a completely centralized model emphasizing competition among generators while the bilateral market is a decentralized model focusing on encouraging greater interaction between the market participants. The hybrid market is a combination of these two designs which provides more flexibility for power trading. In addition, the practical examples of each market design are briefly presented to give a better understanding of the concept. Then the congestion management methods for pool markets and bilateral markets are presented respectively. Three main congestion management methods for pool markets, namely Uniform marginal prices, Locational marginal prices and Zonal prices, are discussed in detail with numerical electricity network examples. After that, the congestion management methods for bilateral markets are illustrated. Finally, the financial instruments for hedging congestion risk are briefly overviewed.

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Chapter 3 Future Network Challenge-Renewable Generation and Demand Side Management

3.1 Introduction

This chapter mainly reviews the state-of-the-art renewable generation techniques and demand side management (DSM) with the vision of future networks. Deployment of renewable generation to replace the fossil electricity generation is a pressing priority to reduce the risks of climate change caused by rapidly rising concentrations of greenhouse gases from fossil fuels. Several renewable generation techniques will be elaborated in section 3.2. The past decade has seen a drastic increase in renewable generation capacity installation globally, with further plans to enhance the renewables capacity in many countries. However, the intermittent and chronological nature of renewable generation makes the output of generators difficult to predict in advance and hard to control in real-time, hence, bringing more challenges to network operation and planning. Combined with the liberalisation of electricity markets, the generation side becomes less controllable and less predictable, the quest for solution from the demand side arises and thus enabling new drivers and possibilities to implement demand side management in the future network. The remaining sections provide a detailed overview of the demand side management options comprising of objectives, methods, and experiences, with the emphasis on the demand response programmes.

3.2 Renewable Generation

Energy plays a crucial role in the development of economy. The energy system has developed significantly over time. Two main transitions can be distinguished in the history of the energy system. The first was the transition from wood to coal with industrialisation, initiated by the invention of steam engine in the late 18th century. The coal, which could be transported and stored easily, allowed high power densities and related services to be sited independently. The second transition was related to the proliferation of electricity, resulting in a diversification of both energy end-use technologies and energy supply sources[1]. Electricity is the first energy carrier that could be generated from a form of fuel and easily converted into light, heat or work at the point of end users. Nowadays, most of the energy supply sources by which electricity is being generated from are fossil fuels, such as coal, gas and oil .The characteristics of fossil fuels comprise a broad spectrum of quality, concentration and accessibility but have a definite limited reserve, which means the supplies of fossil fuels will not last forever. Moreover, the usage of fossil fuels also raises serious environmental issues such as acid rain, water pollution and environment damage due to the mining, extraction and transportation of fossil fuels[2]. It has also contributed to a rise in atmospheric levels of greenhouse gas, raising global climate change concerns. Figure 3.1 shows the estimated life-cycle of GHG emissions from conventional fossil fuel energy technologies.

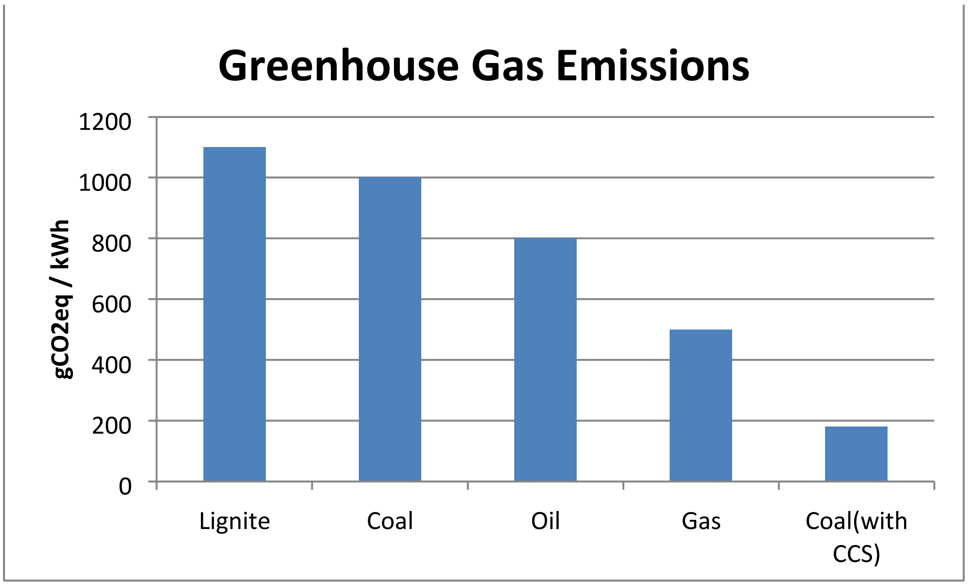


Figure 3.1 Average GHG emissions from conventional power generation technologies[3]

To tackle the problems mentioned above, all of which resulted from operating an unsustainable cycle of electricity generation, many countries in the world are trying to find solutions to change their production, transmission and consumption pattern for the future. Deployment of renewable generation to replace the fossil electricity generation could benefit the electricity industry and make a more sustainable cycle of generating electricity. In the UK, we can identify the tendency of increasing renewables penetration by comparing data from DECC[4]. The proportion of energy resources of UK electricity generation during mid 2012 and mid 2013 is shown as below. It can be seen from Figure 3.2 and Figure 3.3 that the proportion of renewables increased by 5.8% in 2013 compared with 2012.

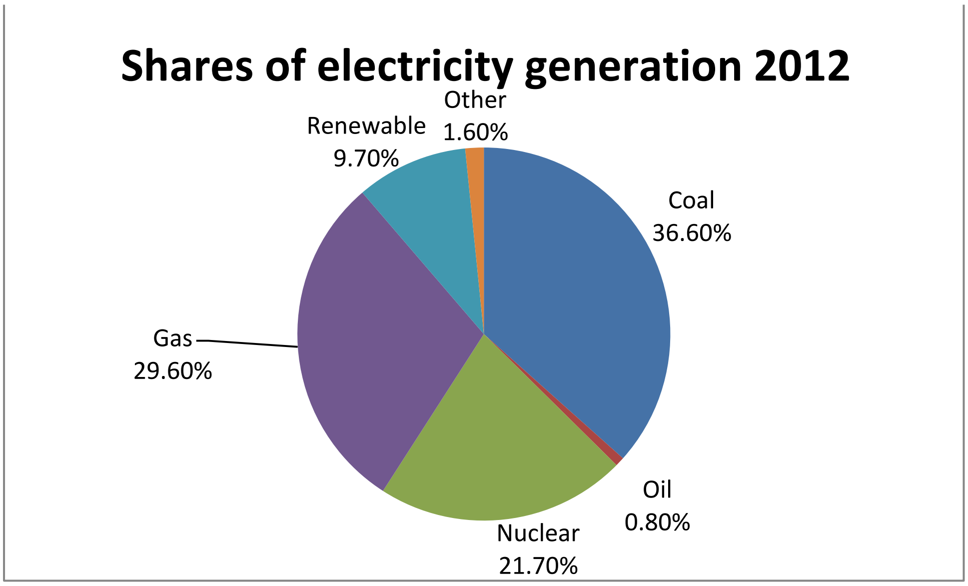


Figure 3.2 The share of energy resources of UK electricity generation in mid-2012[4]

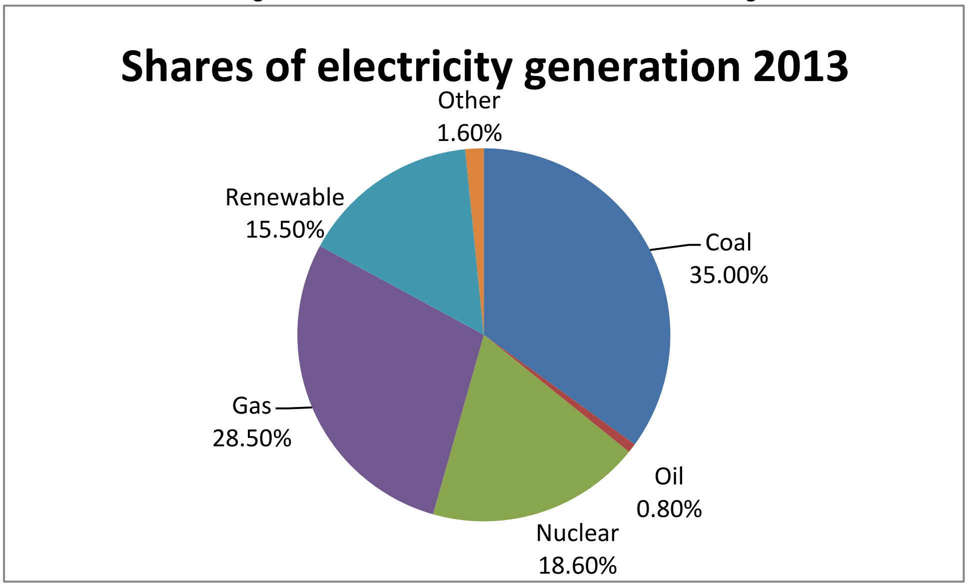


Figure 3.3 The share of energy resources of UK electricity generation in mid-2013[4]

Generally, several energy sources are known as renewable energy:

- Biomass

Biomass takes the form of a fuel that can be stored and used for electricity generation when required in the same way as fossil fuels. However, unlike fossil fuels, it must be produced and consumed locally, as transportation over long distance is not economically efficient. Thus, the size of biomass power plants are smaller in comparison with that of the conventional generating units[5]. There are mainly three types of indigenous biomass fuel: forestry materials, energy crops and agricultural residues. The production of electricity from biomass can be achieved by three basic thermochemical conversion technologies: direct combustion, gasification and pyrolysis. In UK, approximately 3.7 million tonnes of woodchips and pellets were burnt to generate electricity in 2012 according to the most recent Ofgem data[6].However, electricity production using biomass fuels is somehow not competitive on price with electricity from fossil fuels without government subsidies because it is still a developing industry[5]. Moreover, using biomass fuels particularly wood might have negative impacts on the environment. For instance, expansion of biofuel crops might accelerate tropical deforestation, which would then lower CO_2 absorption and threaten habitats of plants and animals.

- Solar Power

Solar power is the conversion of sunlight into electricity, either directly using photovoltaic cell, or indirectly using concentrated solar thermal systems. Photovoltaic (PV) cells use semiconductor devices for the direct conversion of the solar radiation into electricity, as shown in Figure 3.4 below. By contrast, solar thermal electric systems primarily convert solar energy into thermal energy in the form of steam, which then is used to drive a turbo generator. Figure 3.5 shows Andasol solar power station located near Guadix in Andalusia, Spain, which is Europe's first commercial parabolic trough solar thermal power plant. However, the initial investment cost of either technology is substantially higher than traditional generating techniques[5]. Moreover, the efficiency of electricity generation varies in a large scale, since it depends on solar radiation and climate factors. At present, PV cell costs have fallen dramatically over time and will continue to fall further with technological improvements. The thermal storage system and the combination of fossil fuel combustion can be options for concentrated solar thermal electric systems to offset the impact of the low efficiency of electricity production due to intermittent radiation [5]. Thus, it is believed that solar power will provide a considerable proportion of renewable energy contribution in the future.

Figure 3.4 Photovoltaic Cell in practical application*7+

Figure 3.5 Andasol Solar Power Station*8+

In 2012, 31,100 MW of PV were installed worldwide, which can be considered as an all-time annual high that pushed total global PV capacity above 100,000 megawatts. Among all the countries, Germany achieved nearly one third of global PV capacity and it added more than 7,000 MW of PV in 2012, reaching 32,000 MW[9].

- Hydropower

Hydropower is power derived from the energy of falling water or running water .It can be considered as an indirect form of solar energy as the solar radiation evaporates water from the sea which then ascends, and eventually condensing to form–clouds. Some of the resulting rain falls to the high land, thus, gaining potential energy in the form of height. Hydro power is the result of extracting some of this energy as the water eventually flows back towards the ocean. Even though hydro power systems can be categorized in different ways, the generally accepted classification based on the ability to generate power is demonstrated in Table 3.1.

Table 3.1

The classification of hydro power systems[10]

Power Generation Capacity (Watts)	Type of Hydro Power plant
<100 kW	Micro
100-1000kW	Mini
1MW-10MW	Small
10MW-300MW	Medium
>300MW	Large

Moreover, based on the type of storage in hydro power plants, they can be categorized into storage type or "run-of-the-river" type. In the former one, a dam is constructed to act as reservoir of water sources and allows generation to be timed to meet the demands of the power system, which is usually implemented in small to large hydropower plants. The latter one however, is constructed by directing the water source (which may vary according to seasons) to the turbine which is more common in micro, mini and small hydro power plants.

Hydropower currently produces around 17% of the world's electricity and makes up 90% of the world's renewable power[11]. In UK, hydroelectric power stations accounted for 1.65 GW of installed electrical generating capacity, being 1.8% of total generating capacity and 18% of renewable energy generating capacity in 2012[12].The advantages of hydropower include the high efficiency of electricity generation(typical 85-92%) ,long life span of operation and relative low maintenance cost. Moreover, start-up/shut-down costs and ramping costs of hydroelectric generating units are low, thereby, enhancing hydropower‘s market competiveness. However, Hydropower also has some environmental issues, primarily related to its effects on riverine ecosystems and habitats of aquatic wildlife.

- Wind

Wind energy is currently considered as the most promising, costeffective and developed renewable resource for electricity generation. Wind power has a number of benefits that makes it stand out from other renewables. Firstly, wind is globally available in abundance both onshore and offshore. Secondly, investment cost is relatively low when compared to other renewable sources, such as solar power. In addition, wind power generation can provide a stable long-term price that is competitive with new coal- or gas-fired power plants. This can be attributed to the zero fuel consumption and is not affected by the fluctuation of fuel prices.

There has been a significant growth of wind power generation across the world following the establishment of first wind farm in Denmark in 1891. Figure 3.6 and Figure 3.7 show the global annual installed wind capacity and cumulative installed wind capacity since 1996 until 2012 respectively. It can be observed that the total installed capacity increased more than 46 times and the annual installed capacity surged 35 times in 16 years. According to the International Energy Agency, electricity generated from wind could soar from
2.6% today to 18% of the world‘s electricity by 2050[13].

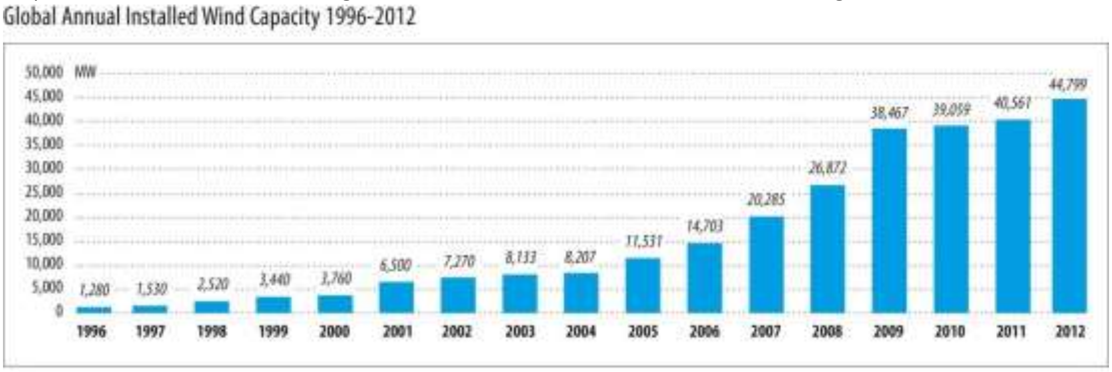


Figure 3.6 Global Annual Installed Wind Capacity[14]

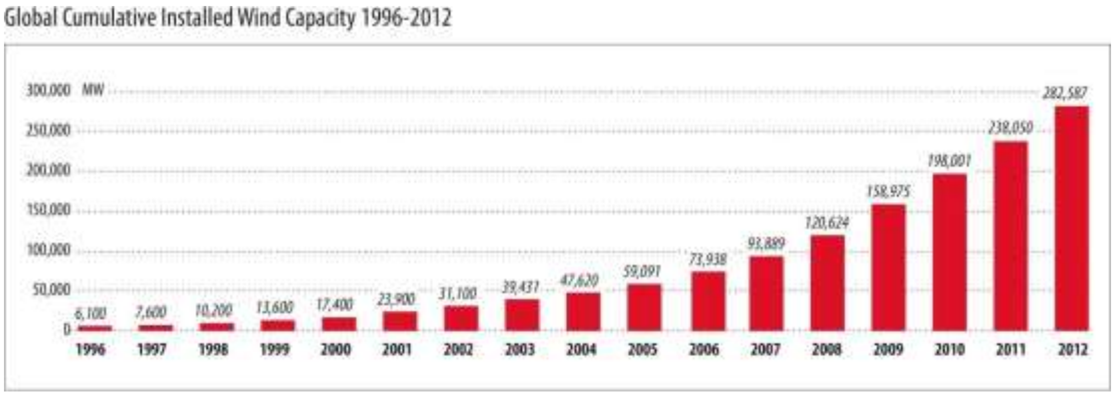


Figure 3.7 Global Cumulative Installed Wind Capacity[14]

- Tidal and Wave Power

Tidal and wave power is a form of hydropower which converts the energy of tides into electricity. Nowadays, electricity can be generated from tides and waves through two main methods: tidal and wave stream generators which exploit kinetic energy of moving water to power turbines and tidal barrages which make use of the potential energy obtained through the difference in tidal height like a conventional hydro dam. Tidal and wave power is much more predictable than wind power and solar power. However, tidal power plants are always related to high upfront costs needed for construction and limited availability of sites with sufficiently high tidal ranges or flow velocities. Many recent technological developments and improvements, both in design and turbine technology, boost the total availability of tidal and wave energy. In recent years, tidal and wave energy gained increasing interest in the UK as it has an abundance of marine energy resource. Tidal and wave energy has the potential to meet up to 20% of the UK‘s current electricity demand as estimation, representing a 30-to-50 GW installed capacity. Between 200 and 300 megawatts (MWs) of generation capacity may be able to be deployed by 2020, and at the higher end of the range, up to 27GWs by 2050 [15].

3.3 Demand Side Management

The term ―Demand-Side Management (DSM)‖ first appeared in 1973 when the energy crisis in many countries brought chaos and incurred economic and social welfare loss. After that, consumers, utility companies, and the whole society, have become aware of the importance of energy conservation. The concept of energy conservation and load management, which was the original name of DSM, emerged from this background.

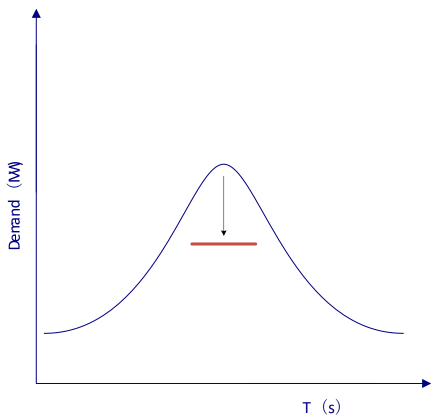
With the deregulation of the electricity industry and the electricity consumption booming in many countries, the efficient use of available energy sources becomes essential to retain market competitiveness and system reliability. The traditional way to achieve the efficient use of power system resource is through the Supply Side Management(SSM),which refers to actions taken to ensure the generation, transmission and distribution of energy are conducted efficiently [16]. The construction of new power plants and transmission lines are driven by this new circumstance. However, the limited primary energy resources, enormous budget of network augmentation and increasing carbon emission comply with Supply Side Management (SSM), which is somehow neither cost-effective nor environmental friendly. Thus, the whole solution to improve energy efficiency cannot and should not lie only on the supply side. Advances in technology have led to greater potential for more efficient energy utilisation through DSM. In practice, DSM comprises different initiatives to modify and reshape the consumer demand pattern, with the aim of achieving not only net energy savings but also a more efficient utilization of the energy itself. It offers several clear benefits, such as lower costs of electricity, increased security of supply at times of network stress, improved operating efficiency, deferred network investment and improved electricity markets. In addition, DSM can also deliver important non-financial benefits, such as carbon savings and reduced pollution. The issues of DSM techniques will be illustrated in this section. .

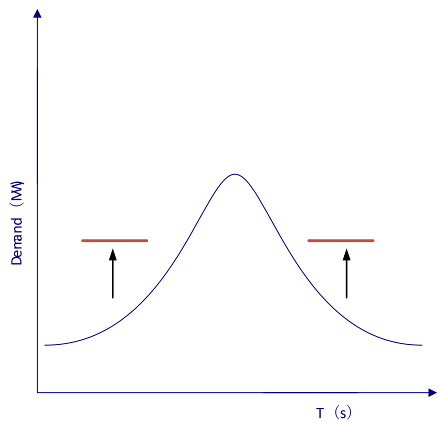
3.3.1 Objectives of DSM

DSM is defined as all the utility activities designed to influence amount or timing of customer use of electricity in ways that will produce desired changes in the utility's load shape[17]. The different actions falling under the umbrella of DSM include:

- Power saving technologies, such as power saving light bulbs
- Arrangements for reducing loads on request monetary incentives, such as interruptible contracts and direct load control
- Distributed generation, such as stand-by generators in households or photovoltaic panels on rooftops
- Variable-rated electricity tariffs, such as time of use, real time pricing, etc.

These actions aim to achieve a particular load shape objective of the utility. The load shape indicates the daily and seasonal electricity demand and it can be altered with six broad objectives: peak clipping, valley filling, load shifting, strategic conservation, strategic load growth, and flexible load shape. These six objectives are illustrated in Figure 3.8.





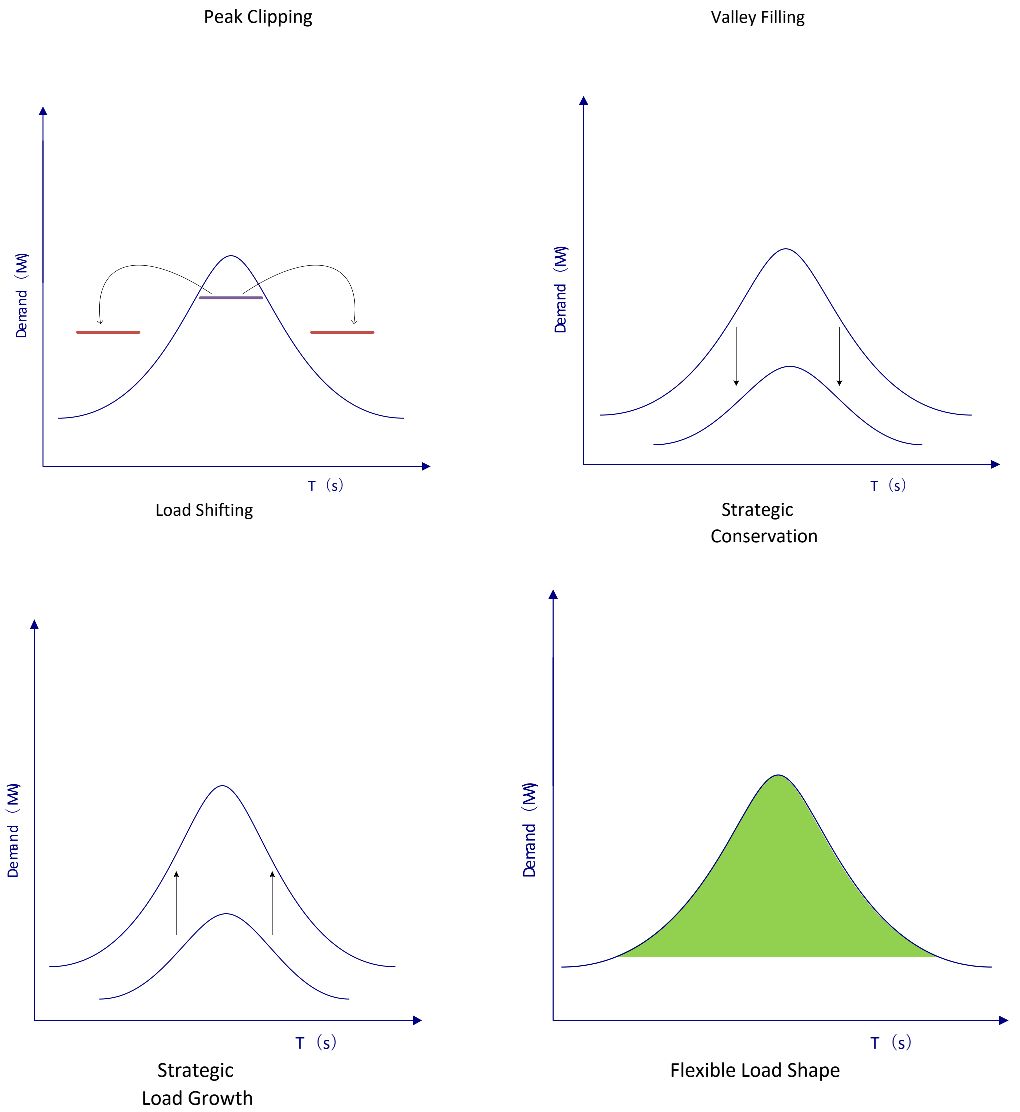


Figure 3.8 Load Shape Objectives for DSM Programme [17]

- Peak Clipping

Peak Clipping, which reduces the peak load using direct load control, is one of the most traditional forms of DSM. It can reduce the need to operate at its most expensive unit and postpone the needs for future capacity additions. In this way, the cost of utility service is lowered[16]. Peak clipping plays a vital role in system operation, especially for those utilities that do not possess enough generating capabilities during peak hours.

- Valley Filling

Valley Filling is another traditional form of the DSM and aims to boost the off-peak time load using direct load control. It can lower the cost of service by spreading fixed capacity costs over a longer margin of energy sales and reducing average fuel costs. Valley filling can be achieved by several methods, such as electric-based thermal energy storage which displaces the load served by fossil fuel.

- Load Shifting

This term refers to shifting existing loads from peak time to off-peak time which can be considered as a combination of peak clipping and valley filling. It is widely applied as the most effective load management technique in current distribution networks. Prevalent implementations include usage of storage water/space heating, coolness storage and customer load shift[18]. With the development of smart appliances techniques, more appliances, such as washing machine and fridges, are becoming suitable for load shifting from the consumers‘ side.

- Strategic Conservation

Strategic Conservation aims to decrease the overall load through reduction in consumption as well as a change in the usage pattern. The focused programmes to promote the application of energy efficiency measures are adopted to reduce energy consumption and to reduce the peak demand indirectly. The examples include utilizing energy efficient motors to replace the traditional motors, development of energy efficient appliances and installation of double glazing windows in households.

- Strategic Load Growth

Strategic Load Growth is to optimise the daily response in the circumstance of large demand introduction beyond the valley filling strategy. It includes increasing the market share of the load supported by the energy conversion and storage systems and distribution generation, such as small scale renewable generators or CHP. In the future, electrification based on new emerging electric techniques, such as electrical vehicle and industrial process heating, can be considered as an option to achieve load growth [18]. This lowers the average cost of service by spreading fixed cost over a relatively long margin of energy sales, which benefits all the customers.

- Flexible Load Shape

This approach is relative to the reliability .The demand can be flexible if customers are willing to be controlled at the critical period in exchange for the various incentive payments. The variations of interruptible or curtailable loads, integrated energy management system, and individual customer load control device are suitable for the implementation of this approach.

3.3.2 DSM Techniques

The most common DSM techniques can be classified as below:

- Load Management

Load management is considered as an effective part of DSM. It is defined as sets of objectives designed to control and modify the patterns of demands of various consumers of power utilities[19]. Load management may be initiated to reduce capital expenditures, reduce the cost of service, improve capacity utilisation, or enhance system reliability[20]. Load management programmes provide payments or incentives to participants who reduce or adjust their electricity usage when called upon by the system operator for reliability or economic issues. The load shape of the power system can be altered through shifting load to off-peak periods, adjusting or curtailing load during operation process, or allowing utility to control specific loads directly. The participants of programmes can be rewarded through discounted retail rates or incentive payments according to individual programme design.

- Strategic Conservation

As another important demand side management technique, the strategic conservation methods aim at reducing customers‘ load through the improvement of energy conservation. The term ―strategic‖ is distinguished from ―naturally occur‖, in which the latter term represents the change that would occur without utility stimulation. The energy conservation programmes are initiated to encourage the acquisition, installation, and use of energy efficiency measures in customer facilities by providing financial incentives and services to customers or contractors[21]. Some educational programmes to inform the public about governmental strategies on energy saving are often involved. In the domestic sector, weatherisation programmes (such as fiberglass insulation in roofs of buildings) and promotion of energy saving light bulbs along with incentives are good examples of strategic conservation strategies. In the commercial and industrial sectors, the programmes involved could be replacing inefficient motors with energy efficient motors, developing cogeneration feasibilities and improving the power factor.

- Electrification

Electrification can be considered as a future tendency of DSM. It is very important to combine different consumers with different load patterns. This will result in a flattened demand curve of which peak load is smoothed. Despite the possibility of elevated demands on generation outputs to meet the increasing base load, generation units served for base load are usually cheaper to run in comparison with the ones for the peak load. Examples can include the wide spread manifestation of electric motors, robotics and industry automation in the industrial sector and the increased applications of electrical vehicles in the domestic sector. The electrification provides the potential to increase the energy intensity, which results in improved overall productivity by reducing dependence on fossil fuel and raw materials.

- Customer Generation

Customer Generation, which refers to small-scale generation embedded within customer sites, is intended to primarily offset customers‘ electricity usage and sell the extra power to the national grid. These energy generation systems can be treated as a type of demand side resource to ―back-up‖ supply during a power outage or to meet the peak demand. It involves a large number of generation technologies: small turbines with a steam cycle, gas turbines, micro turbines, diesel or gas-fuelled reciprocating engines, photovoltaic systems, small hydro turbines and wind turbines. Among them, the small scale renewable generators with zero/low carbon energy sources have become popular due to their environmentally friendly characteristics and independence from fossil fuels. The emergence of micro-grid enables the multiple customer generators to gather and form a small-scale version of the centralized electricity system together with local loads, which could provide highly reliable electric power through isolation from the large network. It is also considered as an ideal way to integrate renewable resources on the community level and allow for demand side participation in the electricity industries.

This thesis focuses on evaluating the impact of DSM integration in congestion management through direct load control. The idea is to use load management measures to reshape the load profile, in order to minimize the operation cost and decrease electricity volatility. Therefore, the review focuses on load management, which is progressively being replaced by the term Demand Response due to the terminology shift.

3.3.3 Demand Response (Load Management)

As mentioned in Chapter 2, deregulation of power industries has been accompanied by numerous problems, such as transmission congestion, generation capacity scarcity, wholesale price volatility, and reduced system reliability. Moreover, the increasing penetration of renewables limits the control flexibility of supply side and makes the problem worse. These circumstances have driven the adoption of demand response programmes where distribution network operators and other aggregators are requested to control and manage the load patterns for their endusers.

Thus, demand response has recently re-emerged as a critical element to facilitate the fine-tuning of restructured power industries[22].

In general, Demand Response (DR) programmes can be broadly categorized along two dimensions. The first dimension characterises how and when utilities call upon participants to adjust their load pattern. Participants can be called on for either emergency/reliability conditions or for economic purposes. Economic programmes are usually offered by electricity suppliers. These programmes offer customers incentives to reduce loads during non-emergency periods or set differential tariff according to the time of electricity usage. These programmes are usually triggered by the circumstance when utility cost of service exceeds some specified limit. Unlike economic based programmes, reliability-based programmes are usually mandatory through contracts incorporating the requirement that the demand side resource have to be made available upon request. These programmes are usually executed during system contingencies such as generator or line failures. The participants might face a penalty if they fail to comply with a request. The second dimension features the means how utilities motivate their customers to participate in DR programmes. Generally, these programmes can be categorized into load response and price response programmes. In the price response programmes, utilities would utilise pricing and rate structures to induce customer behaviours or responses by affecting how much customers pay for electric service. The electricity tariff would vary at different periods of the day, which fully or partially expose customers to the fluctuating range of wholesale power market prices[23]. The price response programmes can involve Time Of Use tariffs (TOU), Critical Peak Pricing (CPP) and Real Time Pricing (RTP) and Demand bidding etc. Alternatively, with load response based programmes, straight communication signals (telephone, radio or Internet) would be sent to notify participants about reliability or economic events and merit load response in exchange for direct utility payment including bill credits or discount rate for their participation. Typical examples of this type of programmes include interruptible /curtailable load and Direct Load Control. Figure 3.9 illustrates those DR programmes in terms of these two dimensions:

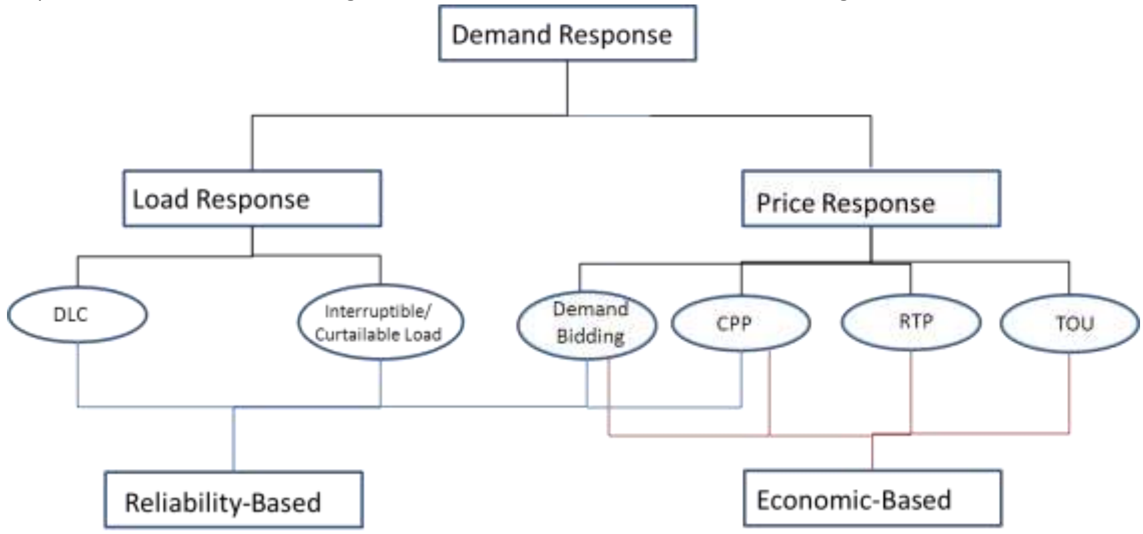


Figure 3.9 Category of DR programmes

3.3.3.1 Overview of Price Response Based Programmes

The price response based programmes provide price signals to consumers to induce change in energy demand patterns. The designs of these programmes aim at lowering the service cost of utilities and saving consumers‘ bill through providing customers time-varying rates that reflect the cost of electricity in different time periods. Armed with this information, the load shape is estimated to be flattened because customers consume less electricity at times when electricity prices are high. These programmes usually require the installation of smart meters which are capable to record the electricity usage over the different price intervals. The most common programmes include Real-Time Pricing (RTP), Critical-Peak Pricing (CPP) and Time-Of-Use (TOU) tariffs.

3.3.3.1.1 Types of Price Response Based Programmes

- Time of Use (TOU) tariffs

Time of Use (TOU) tariffs are programmes that price electricity depending on the time of day it used. This reflects the different costs of generating and distributing electricity throughout the day. It is a stepped rate structure that consists of a peak rate, an off-peak rate, and sometimes a shoulderpeak rate for pre-determined blocks of time assigned by the utilities. Further segmentation of rates may include seasonal rates. The example of TOU tariffs provided by the IESO, Ontario is illustrated in Table 3.2.

Table 3.2 Time-Of-Use prices[24]

Winter Weekdays Nov 1 to April 30		
Time	**Period**	**¢/kWh**
7 am to 11 am	Peak	**12.9**
11 am to 5 pm	Shoulder Peak	**10.9**
5 pm to 7 pm	Peak	**12.9**
7 pm to 7 am	Off-Peak	**7.2**
Weekends & Holidays		
All day	Off-Peak	**7.2**

- Critical Peak Pricing

CPP rates contain a pre-specified much higher electricity price combined with TOU rate or normal flat rate on critical days. The CPP rates are called on during system contingencies or during high wholesale electricity prices period whereby a limited number of days or hours per year are agreed in advance but their timings are unknown. Thus, they are usually notified a day ahead. The most well-known programme is the Electricité de France (EDF)'s ―Tempo‖ tariffs, targeting domestic customers with over 9kW peak demand[25]. The prices vary according to the time of day and year. It assigns a ―colour‖ for each day (blue for low price day, approximately 300 days per year, white for medium price day, approximately 43 days per year ,and red for high price day ,approximately 22 days per year) and every day at 5 pm, customers are able to know the ―colour‖ of the following day by several means: checking the Tempo Internet website, subscribing to an email alert of the tariff or reading the information on solid state meter provided by EDF that could be plugged into any electrical socket, as shown in Figure 3.10. Customers can then reduce their consumption during higher priced period

Figure 3.10 Regular EDF residential solid-state meter[26]

- Critical Peak Rebate

Critical Peak Rebate (CPR) programmes provide rebates to customers who reduce electricity usage at critical peak events. Similar to CPP, advanced notification can be given if such events are scheduled. CPR customers still pay electricity bill based on a traditional flat rate or TOU tariff when no events are called. During a critical event, a customer‘s demand must be compared to baseline usage to determine the amount of reduction[27]. Consequently, the customer can get credit for load reduction, but no penalty is implicated if the load increases.

- Real Time Pricing (RTP)

Real-time pricing (RTP) gives consumers a price for electricity that typically varies hourly or half-hourly to reflect the real cost of electricity in the wholesale market[28]. Generally, customers are notified of RTP prices on a dayahead or hour-ahead basis. This permits customers the opportunity to vary demand and energy use in response to price. Participants are set a baseline load shape which is known as Customer Baseline (CBL). If the customer consumes more energy in an hour than their CBL for that hour, then the customer would be charged for surplus energy at the spot market price of that hour. On the other hand, if the customer uses less energy in that hour, the utilities will credit the customer for energy not used. It should be noted that in some programmes, utilities may set every participating customer‘s CBL to zero usage, known as one-part RTP programmes. In that case, no credits are rewarded since there is no CBL and the customers are charged directly with respect to the electricity price in the spot market.

- Demand Bidding

Demand bidding enables customers to offer bids for load curtailment based on wholesale electricity market prices. There are basically two types of demand bidding strategies. Under one type of strategy, participants name the price at which they are willing to withdraw their load on the market. In the other type of structure, the utility or independent system operator (ISO) determines the price they are willing to pay, and customers determine how much load they are willing to reduce. The utility or ISO then ranks the bids, and accepts bids according to the market requirement. All participants are typically paid the highest accepted bid or a minimum capped rate in the case of certain developing Demand Side Bidding markets[28].

At the moment, demand bidding markets usually have a minimum load bid (e.g. 1 or 10 MW) .Thus, the participants are most commonly large commercial and industrial customers. For small industrial, commercial and domestic customers, new types of aggregators are needed to group loads together and place aggregated bids into the market.

3.3.3.1.2 Metrics for evaluating Price Response Based Programme

3.3.3.1.2.1 Peak Demand Reduction

The primary objective of DR programmes is to decrease the peak demand. Therefore, the actual peak demand reduction is considered as an indicator to evaluate a DR programme or to compare between several DR programmes sharing similar situations. The percentage peak demand reduction can be implemented as a normalized version of indicator[29]. Both of them are used to evaluate the efficacy of price response based programmes, including the load response based programmes elaborated in the following section.

3.3.3.1.2.2 Demand Elasticity

With the price response based Demand Response programme, customers are exposed to more volatile electricity prices which vary with time and location. The customers may adjust their electricity consumption profile if there is a commensurate cost reduction due to this electricity consumption adjustment. Therefore, a correlation exists between demand and price, which is known as demand-price elasticity. This can be illustrated using the demand-price curve shown in Figure 3.11.

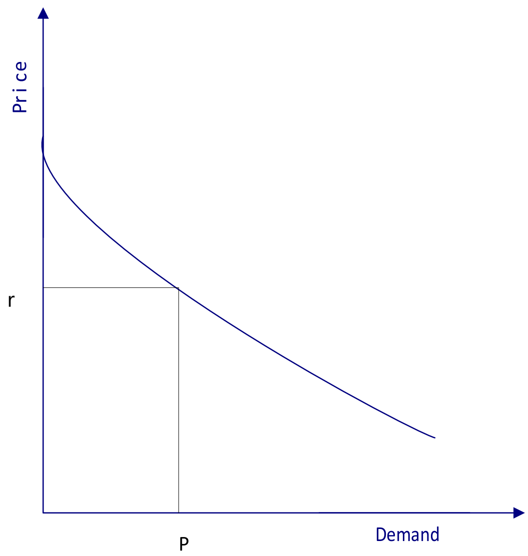


Figure 3.11 Demand price curve

Demand elasticity is an important index which measures the level of demand response of the electricity following its price change. The algorithm for calculation of the demand elasticity is defined as the percentage change in demand quantity ($\Delta P/P$) divided by the percentage change in price ($\Delta r/r$)[30]. It can be mathematically expressed as:

$$e = \frac{\Delta P/P}{\Delta r/r} \tag{3.1}$$

where ΔP and Δr are changes of demand and price respectively; P and r are the base demand and the base price at the given equilibrium point respectively.

As customers face varied electricity tariff with price response DR programmes during the day, they might reschedule their demands from high-price periods to low-price periods to save on electricity bills. Thus, the demand change of one time period is impacted by not only the electricity price in the same period but also the electricity prices in other time periods. Therefore, demand-price elasticity coefficient to represent the demand price correlation can be decomposed into selfelasticity and cross elasticity according to [31]. The self-elasticity measures the effect of the price change on the demand change in the same time slot. Cross-time elasticity can be used to represent the cross-time effects between electricity demands and prices in different time slots. These two types of elasticity coefficients are expressed as Equations (3.2) and (3.3), respectively.

$$e_{ii} = \frac{\Delta P_i / P}{\Delta \rho_i / \rho} \tag{3.2}$$

$$e_{ij} = \frac{\Delta P_i / P}{\Delta \rho_j / \rho} \tag{3.3}$$

where ΔP_i and $\Delta \rho_i$, represent demand and price changes at period i respectively; $\Delta \rho_j$ represents the price change at period j.

The self-elasticity coefficient e_{ii} indicates the effect of price change on demand change at the same period *i*. while the cross-elasticity coefficient e_{ij} relates demand change at period *i* to price change at period j.

3.3.3.2 Overview of Load response Based Programmes

In load-response based programs, utilities offer customers various economic incentives for cutting their electricity demand during specific periods of time.

Programme participants could be considered as ―sellers‖ because they provide load reductions in exchange for payments offered by the utility. There are a number of different forms of load-response programmes, varying with the programme objectives, design components and targeted customers. Some programmes may penalize customers who enrol but fail to respond or fulfill their contractual commitments when called upon.

3.3.3.2.1 Interruptible/Curtailable Programmes

Customers participating in interruptible-load programmes must agree to switch off major portions or even all of their facility‘s loads for specified periods of time by signing up interruptible/curtailable load contracts with utilities. Utilities must notify participants minutes to hours, or even up to a day ahead of the event. The minimum notification margin, maximum number of events and durations per year must be specified upfront by utilities. The participants can receive lower electricity bills during normal operation, as well as additional incentives for each event which includes monthly capacity credits or per event credits based on market pricing. Some penalties can be imposed for non-performance. Such programmes have traditionally been offered to the largest consumers (usually industrial, sometimes commercial).

In California, three major investor-owned utilities, San Diego Gas & Electric (SDG&E) , Southern California Edison (SCE) and Pacific Gas and Electric (PG&E), offer the Base Interruptible Programme(BIP) which is a programme for customers who can reduce their electrical usage to a pre-determined amount, also known as the Firm Service Level (FSL), within 15 or 30 minutes of notice[32]. In exchange, customers would be offered monthly capacity credits based on the difference between their average peak period demand and their selected FSL for each month. Customers who fail to reduce their load down to their FSL are subjected to financial forfeits assessed on a kWh basis. In addition, small customers may also be enrolled in these programmes through an aggregator.

3.3.3.2.2Direct Load Control

Direct Load Control(DLC) is the most common Demand Response programme which shapes the load curve by directly switching different appliances on or off with short notices (3 minutes or less) as subjected to a certain mutually agreed contract. These programmes mainly target residential customers and small commercial customers for equipment such as air conditioners, water heaters or space heaters[29]. The utilities offer incentive payments to participants as rewards, e.g.
tariff discounts and fixed monthly payments credited to the customers‘ utility bill, plus event participation payment. Most DLC programmes allow the participants to override events if they experience discomfort or aren‘t willing to comply with the notification. However, there is a penalty for customers who override their programing.

DLC has received significant attention from power engineers in recent decades. Numerous methodologies were applied to optimize the DLC scheduling, such as linear programming, dynamic programming and fuzzy logic programming etc. Some diversity can also be found regarding the objectives achieved by DLC programmes, which may basically be divided into two categories: the first one is minimising peak demand and the other one is minimising operational costs. In the literature, various DLC techniques and algorithms have been developed to accomplish objectives mentioned above.

Lee and Wilkins in [33] presented a linear programming methodology for scheduling the control actions of water heaters to minimise peak or energy production cost. The method of the diversified controlled water heater load shape is based on empirical data obtained from field tests. The payback effect of the controlled water heater demand for different control actions was also modelled in their study.

Hsu and Su in [34] proposed a dynamic programming (DP) method to coordinate the DLC strategies and unit commitment to minimise the system production cost. The DLC dispatch was integrated into unit commitment formula and both the generation schedule and the amount of load control at each interval were computed together. The resulting fuel cost saving of proposed variable DLC strategy was greater than that of the case where the fixed load control strategy was implemented at each interval. In [35], a relaxed dynamic programming based algorithm for direct load control strategy was implemented to generate a daily optimal or near-optimal air conditioner loads control scheduling with energy payback and load uncertainty. The proposed scheme combines load control, cycling control and timer control in order to maximise cost savings for consumers. Field tests of controlling the air conditioner loads demonstrate the effectiveness of the proposed load control strategy. Another DLC strategy based on heuristic-based Evolutionary Algorithm to handle several types of controllable loads in a large system is proposed in [36]. The simulation studies were carried out on a smart grid system which allowed customers to make informed decisions regarding their energy consumption.

The DLC programmes might aim at achieving other goals rather than conventional peak demand reduction and cost saving maximisation. In [37], the authors proposed a method to shift the residential house ventilation and air conditioning (HVAC) load by using the congestion price as a signal to shift power consumption from high-price periods to low-price periods to reduce the load in congested areas. The sensitivities of load reduction at each node corresponding to the line loading reduction at each line were studied with network analysis. Then, the magnitude of required demand resources can be determined to relieve the congestion in the network. A dynamic programming approach has been introduced in [38] to minimise the load reduction in order to reduce the customers' discomfort and to maintain the incomes of utility. This method dynamically specifies the target load level and facilitates utilities to control the growth rates of peak loads in their attempt to match their schedules of system planning, thereby maximising the benefit. DLC can also be used to reduce system spinning reserve requirement which can contribute a significant additional system operating cost saving [39]. DLC strategy was also studied in a multi-objective framework which allows compromising several objectives to satisfy both utilities and consumers: minimising peak demand as perceived by the distribution network dispatch center, maximising profits resulting from energy sale and minimizing discomfort of customers during event periods[40].

At the moment, there are some US utilities offering a variety types of DLC programmes, such as Austin Energy and Wisconsin Public Service[28]. Customers participating in these programmes usually receive a fixed rebate on their monthly bills. The conventional participated appliances are associated with thermal storage, such as air conditioner and water heater. With the development of smart appliance techniques, more domestic appliances, such as washing machines and dish-washers, are able to participate in the DLC programmes. In Europe, the Smart-A project was launched to identify and evaluate the potential synergies of controllable domestic appliances which energy usage and service may both be rescheduled to another period with acceptability of customers in future network.

3.3.4 Limitation and Barrier of DSM implementation

There are several issues that need to be addressed within the DSM programmes reviewed above. Firstly, most DSM programmes focus on the benefits of the supply side. In the other words, most strategies aim to increase the profit of utilities or reduce the power system peak load for deferment of new power plants investment or avoidance of operating emergency generators. However, these strategies do not actively reduce energy demand. In contrast, some programmes encourage participants to use more electricity during low price periods in which some of the usage might be not necessary. This would lead to electrical energy wastage and deteriorate the already high-levels of greenhouse gas emissions.

Secondly, from customers‘ point of view, as most DSM programmes do not prioritise customers‘ comfort, uncomfortable environments/conditions could be one of the main reasons which hinder the execution of some programmes. Surveys of customers‘

satisfaction levels are usually carried out in a qualitative way in which the corresponding results always lag behind the actual control actions. Therefore, new methodologies to quantify the impact related to control actions in real-time are needed. Thirdly, from the utility's point of view, lack of sufficient financial incentive makes utilities reluctant to invest in the customer side since it does not contribute to the utility asset base directly. Moreover, even if power companies were willing to invest in DSM, there is no efficient mechanisms available currently for them to recover their investments[41, 42].

However, these barriers can be removed through careful design of DSM programmes and appropriate government policies and regulations.

- Undertake proper load/ market research to identify end-use patterns and market barriers

For designing effective DSM programmes, it is crucial to know how electricity is used and which kind of barriers are preventing customers from using efficient technologies. Load research should be undertaken to estimate load curves for each sector or region with local sub-metering, customer bill analysis and customer surveys. Meanwhile, market research is needed to better understand the target market, identify barriers and evaluate possible solutions. This can be carried out through surveys which are applicable to determine current equipment usage, decision making criteria, and evaluate different types of programmes[43].

- Capitalise DSM Investments and allow recovery in rates of amortisation expenses over time as a cost of electric service.

It has become standard rate-making practice to recover the capital costs of generation, transmission, and distribution assets over time since these facilities can provide service for over 20 years or more. The costs of supply investments are ordinarily recovered through electricity rates. Such basic ratemaking treatment should be applied equally to recover the investment of DSM resources as electricity savings from DSM also defer the need to construct more generation, transmission, and distribution facilities. Thus, it stands to reason that demand-side investment should be accorded the same rate treatment [42].

- Efficient education and marketing on customers' side

Customer education on the benefits of DSM programmes can be targeted to different sectors with different education goals, which makes customers aware of the importance of DSM and clarify the misunderstandings associated with some programmes.

- Deployment of two way communication system and smart meters in Smart Grid Framework

Smart grid provides the scalability to make DSM cost-effective and convenient. With the help of two way communication system, feedbacks from the customer side can be obtained on real time basis and thus, the inconveniences experienced can be minimised. It also gains the possibility to accurately estimate the consumption profiles of each customer, which then provides very valuable information to the utility. Subsequently, the utilities can accurately develop optimal programmes and tariff structures with the information provided.

3.4 Summary

This chapter has presented the developmental trends of future network. As global installed renewable capacity increases rapidly with concerns on energy security and global warming in mind, it is necessary to have a general idea on the development status of renewable generation. Thus, several different types of renewable generation techniques were presented in this chapter.

With the renewable generation integration and market deregulation, the potential of demand side to solve system operation issues are explored. Several types of demand side management programmes were overviewed in this chapter. Demand response was also highlighted and the applications in current power systems were introduced. The barriers to implement DSM and the possible measures to tackle these issues were also included in this review. The following chapters will illustrate a novel congestion management method which combines the DSM in solution and evaluate the efficacy of the proposed method in network with different scenarios.

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Chapter 4 Proposed Economic Demand Management (EDM) Index for Congestion Relief

4.1 Introduction

As introduced previously, the Locational Marginal Price, also known as nodal price, is defined as the marginal price of the next increment of 1 MWh power at a specific node, which includes the cost of generation and physical delivery. The LMPbased method aims at optimizing the system operation with the consideration of system constraints and providing the correct economic signals to the market participants. When there is congestion in the system, the LMP can be dramatically high in the congested area. Several congestion management approaches based on the LMP pricing are reported in [1, 2], but in these methods, the system operator focused the management on the supply side only and considered the demand side as being fixed.

The high locational prices under congested conditions can be partly attributed to the lack of demand participation in the price signals. In the traditional network, as the fixed energy price applied on the demand side and customers demand is assumed to be fixed, generators in the network can strategically raise the price of electricity. The unsuccessful handling of the California electricity crisis of 2000 and 2001 is a good example, which demonstrates that the exclusion of the demand side in current congestion management model could incur the high risk of system failure. More recently, concern over the potential impact of demand side is increasing along with the advent of smart grid and renewable generation integration. In[3], the effect of introduction of demand elasticity into the congestion management scheme was evaluated and the authors concluded that it could achieve better economic performance besides maintaining the system security. The attempts to introduce the active demand side would have effects in reducing market power and lowering price spikes at the same time. Thus, the integration of demand side into the congestion management process is considered as an efficient approach. Technically, the congestion could be alleviated by lowering the demand temporarily by various forms of DSM programmes. However, as the contribution of demand adjustment from each node to the power flow change on a specific transmission line is different, the system operator has to select the targeted nodes wisely for optimal congestion relief solutions. Besides, the economic impact of demand adjustment to each participant and the whole market should be taken into account in the congestion management as well since it is the most pressing issue of the deregulated electricity market. However, the current DSM programmes are somewhat rigid and opaque due to the complexity of the actual power system and the absence of demand side feedback, which could lead to economic loss on the consumer benefits because of the specific implemented relief activity of the transmission system operators. Therefore, it is critical to evaluate the economic benefit of load adjustment when it is executed to alleviate congestions in a power system. The strategy to decide how the demand should be adjusted is discussed in this chapter.

In this chapter, a set of indices are proposed to determine the demand-side participants at the nodes based on LMP scheme. The necessary economic information of the electricity market and consumers, such as customer power outage costs, is taken into account. The individual indices measure the physical sensitivity of a specific node to the power flow in congested line and the potential financial cost of demand adjustment of each consumer respectively. The overall index combines the physical and economical indices for measuring the efficiency of the congestion relief progresses.

This chapter begins with section 4.2 which demonstrates the methodology and mathematical model of the proposed index. In section 4.3, the proposed index is integrated into the congestion management scheme and the metrics for evaluating the efficacy of congestion management are presented. In section 4.4, the IEEE 14 –node system and 30-node system for the case studies are expressed followed by the discussions and analysis with the simulation results. Section 4.5 summarizes this chapter.

4.2 The Proposed Indices for Economical Demand Management in Congestion Relief Solution

In this section, a set of performance indices is defined to determine DSM participants: the normalised physical transmission congestion relief index and the normalised economic demand adjustment index.

4.2.1 Normalized Physical Transmission Congestion Relief Index

The primary goal of demand management is to effectively solve congestion in the system with the minimization of demand adjustment and lowering the electricity prices in the congested area in the post-congestion period. The impact of the load adjustment on congestion relief can be estimated by the sensitivity of power flow change on the branch to load change at the nodes, which is somewhat similar to the DC Power Transfer Distribution Factor (DC-PTDF) [4, 5]. This sensitivity is defined as the normalized physical transmission congestion relief index here. It can be calculated as follows：

$$S_{nk} = \frac{dP_k}{dP_n} \quad (4.1)$$

where P_k represents the real power flow on the branch k; and P_n represents the real power consumed at node n. In other words S_{nk} is the sensitivity of the change of active power flow in branch ‗k‘ with a change in power withdrawn at node ‗n‘.

The power flow injected from node i into the power system can be expressed as:

$$P_i = P_{gi} - P_{di} = V_i \sum_{j=1}^{N} V_j [G_{ij} \cos(\delta_i - \delta_j) + B_{ij} \sin(\delta_i - \delta_j)] \quad (4.2)$$

$$= \sum_{j=1}^{N} |V_i||V_j||Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j)$$

$$Q_i = Q_{gi} - Q_{di}$$

$$= \sum_{j=1}^{N} |V_i||V_j| \left[G_{ij} \sin(\delta_i - \delta_j) - B_{ij} \cos(\delta_i - \delta_j) \right]$$

$$= -\sum_{j=1}^{N} |V_i||V_j||Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) \qquad (4.3)$$

$$\forall i = 1, \dots, N$$

where P_i and Q_i are the real and reactive power injected to the power system at node i respectively; ; N is the total number of nodes; $|Y_{ij}|, \theta_{ij}$ are taken from the network admittance matrix [Y_{node}].

The power flow on the branch *i-j* between node *i* and node *j* can be calculated as:

$$P_{ij} = -|V_i||V_j||Y_{ij}| \cos(\theta_{ij} + \delta_j - \delta_i) + |V_i|^2 |Y_{ij}| \cos\theta_{ij} \qquad (4.4)$$

$$Q_{ij} = |V_i||V_j||Y_{ij}| \sin(\theta_{ij} + \delta_j - \delta_i) - |V_i|^2 |Y_{ij}| \sin\theta_{ij} \qquad (4.5)$$

With Taylor series expansion, the change in power flow at node i ΔP_i and ΔQ_i can be formulated in the form of the Jacobian matrix as:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta \delta \\ \Delta |V| \end{bmatrix} \qquad (4.6)$$

where $[J_1] = \frac{\partial P}{\partial \delta}$; $[J_2] = \frac{\partial P}{\partial |V|}$; $[J_3] = \frac{\partial Q}{\partial \delta}$; $[J_4] = \frac{\partial Q}{\partial |V|}$

As the active power is more sensitive to the perturbation of the voltage angle difference, the coupling between ΔP and $\Delta|V|$ can be neglected. In this work, the DC power flow simplification will be applied to achieve fast computing speed. However, the full AC power flow approach can be incorporated in a similar way without any difficulty. With the simplified DC power flow, the matrix equation for the system is determined as:

$$\begin{bmatrix} \Delta P_1 \\ \cdots \\ \cdots \\ \Delta P_N \end{bmatrix} = \begin{bmatrix} B_{11} & \cdots & \cdots & B_{1N} \\ \cdots & \cdots & \cdots & \cdots \\ \cdots & \cdots & \cdots & \cdots \\ B_{N1} & \cdots & \cdots & B_{NN} \end{bmatrix} \begin{bmatrix} \Delta\theta_1 \\ \cdots \\ \cdots \\ \Delta\theta_N \end{bmatrix} \tag{4.7}$$

The element of susceptance matrix [B] can be calculated as:

The off-diagonal elements

$$B_{ij} = -\frac{1}{x_{ij}} \tag{4.8}$$

The diagonal elements:

$$B_{ii} = \sum_{j=1}^{N} \frac{1}{x_{ij}} \tag{4.9}$$

Thus, The DC power flow can be expressed as:

$$[\Delta P] = [B][\Delta\theta] \tag{4.10}$$

Therefore, it can be obtained the following equation based on (4.10):

$$[\Delta\theta] = [X][\Delta P] \tag{4.11}$$

where [X] is the inverse of the modified [B] matrix [B'] adding a row and a column of zeros respect to the slack node(considered to be node 1 in this example case).The $n \times n$ matrix [B] cannot be inversed. Thus, the row and column responding to slack node in power network is eliminated and n-1×n-1 inverse matrix $[B']^{-1}$ is computed.

$$[X] = \begin{bmatrix} 0 & \cdots & \cdots & 0 \\ \vdots & & & \\ \vdots & & [B']^{-1} & \\ 0 & & & \end{bmatrix} \quad (4.12)$$

Ignoring the reactive power flow and simplifying with DC power flow model, equation (4.4) can be rewritten as:

$$P_{ij} = \frac{\theta_i - \theta_j}{x_{ij}} \quad (4.13)$$

where x_{ij} denotes the reactance of the branch ij.

Rewriting the equation (4.1) with the combination of equations (4.13) gives:

$$S_{nk} = \frac{dP_k}{dP_n} = \frac{dP_{ij}}{dP_n} = \frac{d}{dP_n}\left(\frac{\theta_i - \theta_j}{x_{ij}}\right) = \frac{1}{x_{ij}}\left(\frac{d\theta_i}{dP_n} - \frac{d\theta_j}{dP_n}\right) \quad (4.14)$$

Eventually, the physical congestion relief index can be obtained as:

$$S_{nk} = \frac{1}{x_{ij}}\left(X_{in} - X_{jn}\right) \quad (4.15)$$

where X_{in}, X_{jn} represent the *in* and *jn* elements from the [X] matrix respectively.

Using the physical congestion relief index, the expected change on line *k* following the change in the load at node n, is expressed as:

$$\Delta P_k = S_{nk} \Delta P_n \tag{4.16}$$

The equation can be rewritten to illustrate the required amount of adjustment at node n corresponding to the expected reduction of power flow on line *k*:

$$\Delta P_n = \Delta P_k / S_{nk} \tag{4.17}$$

For scaling the effect of power flow change, the normalized index is proposed here:

$$\mathrm{I}_S = \begin{cases} 1, & (S_{\mathrm{nk}} = S_{max}) \\ \frac{S_{nk}-S_{min}}{S_{max}-S_{min}}, & (S_{max} \geq S_{\mathrm{nk}} \geq S_{min}) \\ 0, & (S_{\mathrm{nk}} = S_{\mathrm{min}}) \end{cases} \tag{4.18}$$

where S_{max} is the highest sensitivity according to S_{nk} ranking after calculation, S_{min} is the lowest sensitivity above zero among the system.

Here, I_S is scaled from 0 to 1. The higher the I_S , the lesser the demand curtailment is needed. When I_S =1 it indicates that the curtailment at that node can achieve the best congestion relief effect. When I_S =0, it means that the load curtailment has no impact on the congestion relief.

4.2.2 Power Outage Cost and Normalized Economic Demand Adjustment Index

With the development of customer-owned backup generation and energy management systems, more creative methods for integrating demand management have been introduced into utility operations. In some DSM programmes, mostly direct load control programmes and interruptible load contracts, the consumers are enticed with the promise of an incentive fee as the reward paid by the utility. The incentive fee is related to the power outage cost function that measures the economic loss related to load reduction and the willingness to participate in the contingency. In other words, the power outage cost can be considered as an index to estimate the economic impact of execution of demand-side programmes. Since the utility wants to pay as little as possible to achieve the goal that encourages customer participation, consumers with low power outage cost and high willingness to curtail will be given priority in the programme. It is possible for a system operator to use existing utility data and load behaviour to estimate the power outage cost as demonstrated in [6] . As illustrated in Figure 4.1, a possible consumer marginal benefit from electricity consumption can be estimated as a linear function. The pink shaded area in Figure 4.1 shows the loss of the surplus as a consumer reduces its load. This loss of surplus due to load reduction refers to the power outage cost of the customer. As the marginal benefit is assumed to be linear in many cases, its loss of surplus is quadratic, as shown in Figure 4.2. The Marginal Benefits in Figure 4.1 and Cost of Curtailment in Figure 4.2 are expressed with per unit values.

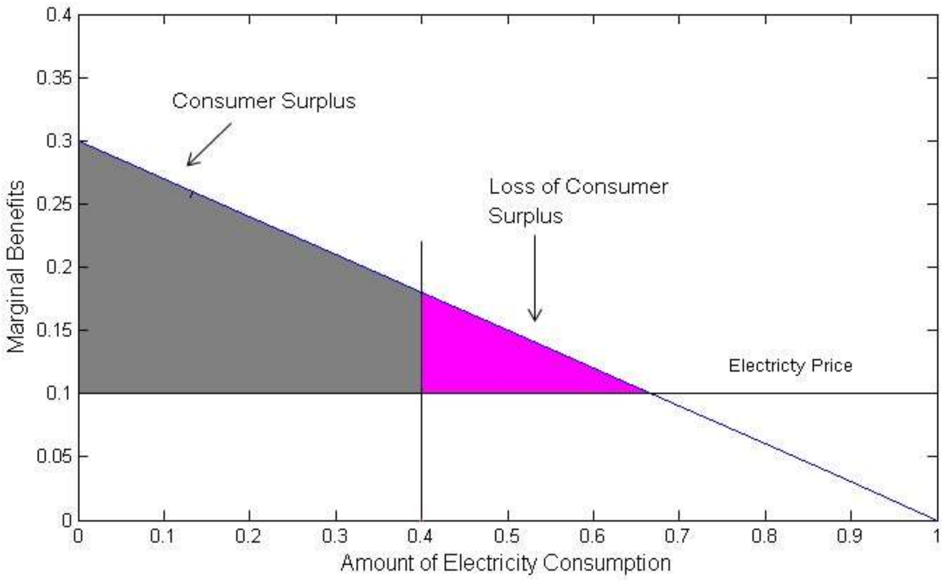

Figure 4.1 Consumer marginal benefit from electricity usage[7]

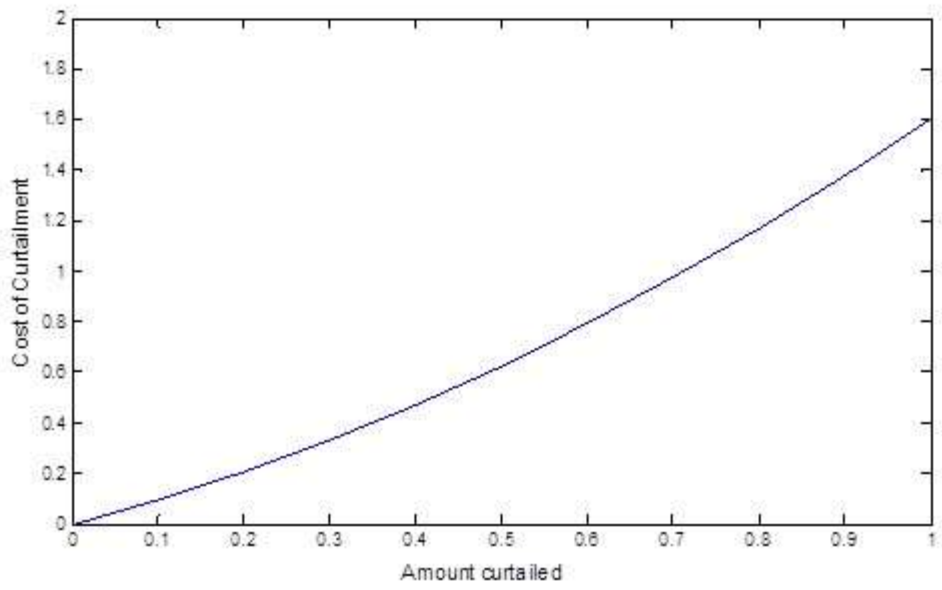

Figure 4.2 Shape of power outage cost function for a customer[7]

The quadratic power outage cost function can be expressed as:

$$F_n(\alpha_n) = K_1\alpha_n^2 + K_2\alpha_n \qquad (4.19)$$

$\alpha_n = \Delta P_n / P_n^0$ where P_n^0 is the real power consumed by demand at node n,

ΔP_n is the real power reduced to solve the contingency,

α_n is the ratio of the demand reduction to the original demand; K_1 and K_2 are coefficients of the cost function that relates to the consumer type and willingness to curtail. It is worthwhile to note that this power outage cost function could be used to estimate the economic impact on demand aggregator that gathers small consumers to participate in DSM programme.

Generally, the lower the power outage cost, the higher the priority for load reduction and the less the incentive fee will be paid by the system operator. A normalized index measuring the economic efficiency of load reduction at congestion period is expressed as:

$$\mathrm{I}_F = \begin{cases} 1, & (F_n \leq F_{min}) \\ \frac{F_{max}-F_n}{F_{max}-F_{min}}, & (F_{max} \geq F_n \geq F_{min}) \\ 0, & (F_n \geq F_{\max}) \end{cases} \tag{4.20}$$

where F_{max} is the highest power outage cost among all nodes, above which the ISO will not notify the consumers to change the load at this node due to the high cost. F_{min} is the lowest power outage cost.

Here, I_F is also scaled from 0 to 1. The higher the I_F, the lesser the power outage cost. I_F =1 means that the load reduction at that node has the least impact on the consumers and would cost the system operator little to achieve the relief activities. I_F=0 means that the load adjustment should be avoided as the cost is extremely high or the estimated $\square_n$ is larger than 1. When the estimated $\square_n$ is larger than 1, it means the required demand reduction is larger than the original amount of demand. Under this circumstance, I_F is set to be zero directly as the load adjustment is not applicable.

Alternatively, consumers can reveal their willingness and possible financial loss due to demand adjustment directly in Demand bidding, which exists in many electricity market schemes. As the consumers can submit bids to curtail or redistribute their demand and gain reward based on their bids,the proposed economic index can be transferred into another form based on the demand-side bid prices provided by the consumers.

4.2.3 Economical Demand Management Index

Combining I_F with the physical congestion relief index, the overall economic demand management index can be obtained as:

$$\mathrm{I} = I_S \cdot I_F \tag{4.21}$$

The overall index ranges from 0 to 1.The overall index measures the contribution of potential demand adjustment to congestion relief and the economic impact due to load adjustment. The value of the index also indicates the load curtailment acceptance of the customers as well. The nodes with high economical demand management index values should be assigned high priority by the system operator and optimal congestion relief effect could be achieved by the temporary load reduction at those nodes.

4.3 Assessment of Proposed Index in Congestion Management Scheme

4.3.1 Congestion Management Model with Economic Demand Management Index

Figure 4.3 depicts the main scheme of the congestion management method combined with economical demand management index. The scheme in this chapter is aimed for real-time operation.

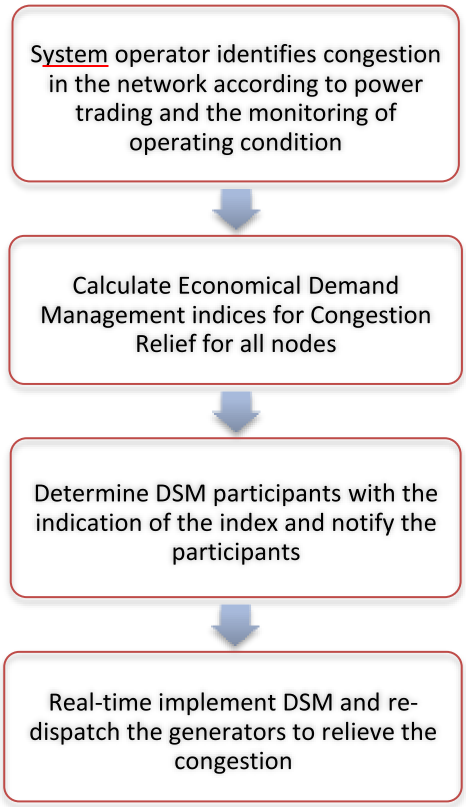

Figure 4.3 The flowchart of congestion management method with proposed index

In the first stage of the scheme, the system operator obtains system operating conditions and identifies locations of congestion in the network. Then the economical demand management index is calculated according to the identified congested lines in the network. The load nodes are ranked according to the index values for selection of participants in DSM programme. Next, DSM programmes are called according to the index and the system operator notifies the participants in advance. Finally, the system operator performs Optimal Power Flow calculation and re-dispatches the generators with respect to the new demand profile. In order to create an effective and rapid method, the provided model is based on DC optimal power flow. The objective function and constraints are listed below.

The objective function of OPF in this congestion management scheme is to minimize the generation cost. Consider a power network with N nodes and L lines, the objective function is expressed as:

$$\min f = \sum_{i \in N} C_i\left(P_i^g\right) \tag{4.22}$$

where $C_i(P_i^g)$ is the cost function of generator at node i,

$$C_i\left(P_i^g\right) = c_{2i}(P_i^g)^2 + c_{1i}P_i^g + c_{0i} \tag{4.23}$$

Subjected to:

4) The real power flow equation at a node i:

$$P_{ig} - P_{id} - \sum_{\substack{i=1 \\ j \neq i}}^{N} B_{ij} \sin\theta_{ij} = 0 \tag{4.24}$$

5) The maximum and minimum output constraints of the generators:

$$P_{i,g\min} \le P_{ig} \le P_{i,g\max} \tag{4.25}$$

6) The capacity constraints of the transmission lines

$$P_{ij,\min} \le P_{ij} \le P_{ij,\max} \tag{4.26}$$

where P_i^g is the real power generated at node i , P_i^d is the real power demand at node i ;

$\theta_{ij} = \theta_i - \theta_j$ is the angle difference between node i and j,

B_{ij} is the susceptance of the line i-j, $P_{i,\ g\min}$, $P_{i,g\max}$ are respectively the minimum and maximum generation constraints at node i ;$P_{ij,\ \min}$, $P_{ij,\ \max}$ are respectively the upper and lower limit of the real power capacity of line i-j.

4.3.2 The Metrics for Evaluating Performance of Congestion Management Method

Re-dispatch Impacts

The occurrence of congestion may result in a change of the original schedule submitted to ISO in order to avoid any violations of the transmission constraints. Hence, in the supply-demand balance of the transmission constrained market, the quantity of generator outputs may be adjusted. These adjustments have additional influences in terms of the power that may have to be supplied by out-of-merit-order generators or those generators in the balancing market, and the loss of benefits increase due to the inability to supply some of the demand physically or in an economical way. It is a consensus that re-dispatches increase the system operation cost since the out-of-merit-order generators are involved on top of the scheduled ones. The minimization of re-dispatch of generators therefore ensures that the deviation from the economical settlement of the market is at a minimum. In a market with bilateral contracts, the interest is to maintain the desired contract transactions.

Merchandise Surplus

The LMP mechanism would lead to merchandise surplus due to system congestion. The merchandise surplus can be used as an index to evaluate the congestion management. The formula of merchandise surplus is shown as below:

$$S_M = \sum \rho_{id} P_{id} - \sum \rho_{ig} P_{ig} \qquad (4.27)$$

where ρ_i^d is the demand price when the demand P_i^d is consumed at node i ; ρ_i^g is the generator price when P_i^g is active power generated at node i .

The merchandise surplus is equal to zero when the network experiences no congestion and there are no losses. In practice, the merchandise surplus is usually greater than zero when congestion and losses exist. Allowing the system operator to retain this surplus will create perverse incentives [8]. Therefore, smaller merchandise surplus indicates the more efficient and economical use of power network. It can be applied as a measure of the congestion cost allocation and congestion management efficiency.

LMP Volatility

The LMP level can be analysed through a weighted average LMP defined as (4.28):

$$\bar{\rho} = \sum_{i\in N} \rho_i \cdot P_i / \sum_{i\in N} P_i \tag{4.28}$$

The usual standard deviation computed with reference to this average price $\bar{\rho}$, can be used to assess the node-price volatility, and is represented as below:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{N}(\rho_i - \bar{\rho})^2}{N}} \tag{4.29}$$

Congestion Rent

In a congested network, the LMP varies according to the system operation circumstances. Congestion rent is a product of the LMP difference between two ends and the power flow in a specific line, which is collected by the system operator. The distribution of collected rent varies from utility to utility. Mathematically, congestion rent for the branch i-j can be calculated as follows:

$$\text{Congestion Rent} = (\rho_i - \rho_j) \cdot P_{ij} \tag{4.30}$$

4.4 Case Studies and Discussion

The efficacy of the proposed index is analysed and demonstrated with the case studies of IEEE 14 node and 30 node systems programmed in Matlab to evaluate its efficiency. It is also compared with the traditional method without demand-side participation. The code of proposed index has been verified correct and the simulation results are reliable. The definitions of the two methods are defined below:

Proposed Method: Congestion management with Economical Demand Management index based on the LMP method

Traditional Method: traditional LMP-based congestion management without demand-side participation

4.4.1 IEEE 14 Node System

The IEEE-14 node system is employed to illustrate congestion management methodology with proposed index. There are 5 generators respectively at node 1, 2, 3, 6 and 8. The branch parameters and other system data could be found in Appendix. Figure 4.4 shows the target system. Table 4.1 lists the cost functions of the generators and generation capacity.

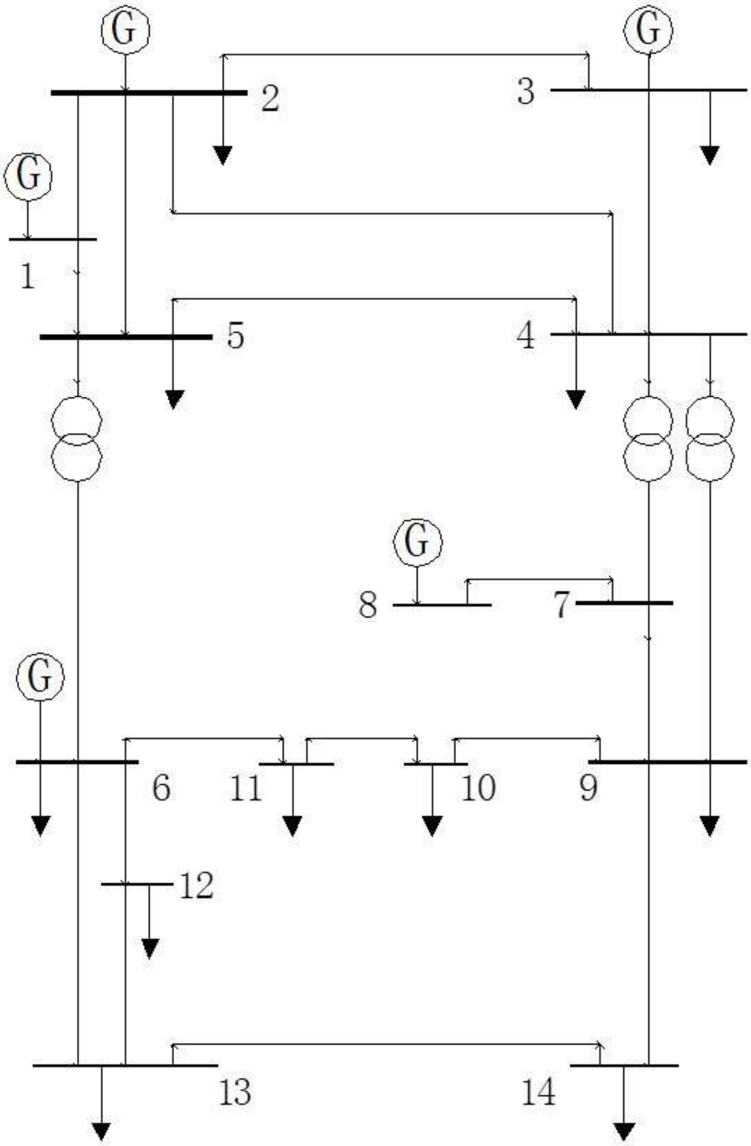

Figure 4.4 IEEE 14 node System[9]

Table 4.1

Generator Cost Function in IEEE-14 system

Generator	C_{2i}	C_{1i}	C_{2i}	$P_{max}(MW)$	$P_{min}(MW)$
1	0.043	20	0	332.4	0
2	0.25	20	0	140	0
3	0.01	40	0	100	0
6	0.01	40	0	100	0
8	0.01	40	0	100	0

When there were no constraints binding in the network, the node price of each load is set as the market clearing price 39.02 £/MWh. The power flow on each line is tabulated below.

Table 4.2
Power flow results of uncongested IEEE 14 node system

Branch Number	Start	End	Power flow(MW)
1	1	2	149.49
2	1	5	71.49
3	2	3	69.97
4	2	4	55.04
5	2	5	40.82
6	3	4	-24.24
7	4	5	-61.90
8	4	7	28.36
9	4	9	16.55
10	5	6	42.80
11	6	11	6.73
12	6	12	7.61
13	6	13	17.25
14	7	8	0
15	7	9	28.36
16	9	10	5.77
17	9	14	9.64
18	10	11	-3.23

19	12	13	1.51
20	13	14	5.26

To demonstrate the proposed methodology, the capacity of branch 6-13 is limited to 15MW and as a result it is 2.25MW overloaded in that branch which is set as ΔP_k. The power outage cost of the IEEE-14 node system is listed in Table 4.3.

Table 4.3

Function of power outage cost of IEEE-14 system(per unit value)[10]

Node	$F_i(\alpha_i)$	Node	$F_i(\alpha_i)$
2	$0.0705\alpha_2{}^2 + 0.195\alpha_2$	3	$0.377\alpha_3{}^2 + 0.195\alpha_3$
4	$0.143\alpha_4{}^2 + 0.478\alpha_4$	5	$0.0217\alpha_5{}^2 + 0.0722\alpha_5$
6	$0.0336\alpha_6{}^2 + 0.0896\alpha_6$	9	$0.0664\alpha_9{}^2 + 0.266\alpha_9$
10	$0.0245\alpha_{10}{}^2 + 0.0765\alpha_{10}$	11	$0.0084\alpha_{11}{}^2 + 0.0315\alpha_{11}$
12	$0.0189\alpha_{12}{}^2 + 0.0549\alpha_{12}$	13	$0.0428\alpha_{13}{}^2 + 0.108\alpha_{13}$
14	$0.0466\alpha_{14}{}^2 + 0.127\alpha_{14}$		

Table 4.4 shows the calculated economical load management index, which is the last column of the table. The largest element in that column corresponds to node 13 and it corresponds to the ability of a load reduction of 3.79MW (ΔPn) to relieve 2.25MW overload on branch 6-13 according to (4.17). This is the most economical solution to tackle the congestion in this case. The post-congestion LMP profiles in the congestion case with traditional method and proposed method are depicted in Figure 4.5.

Table 4.4

Economical Load Management Index of Case 1

Node	S	ΔPn(MW)	α	Is	I_F	I
4	0.0091	247.36	0	0	0	0
5	0	0	0	0	0	0
7	0.062	36.29	0	0.1023	0	0
9	0.0904	24.87	0.8733	0.1503	0	0
10	0.0563	39.96	0	0.0926	0	0

11	0	0	0	0	0	0
12	0.2886	7.80	0	0.4859	0	0
13	**0.5936**	**3.79**	**0.2808**	**1**	**1**	**1**
14	0.3104	7.25	0.4864	0.5318	0.9763	0.5094

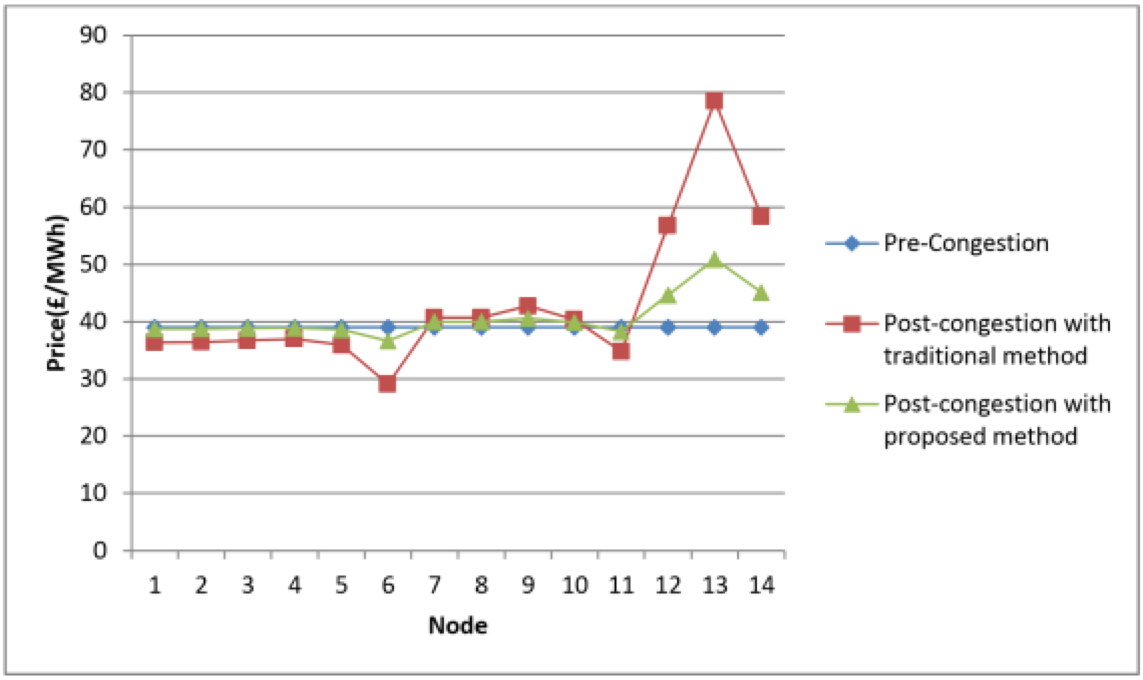

Figure 4.5 LMP in all nodes for the branch 6-13 congestion

As shown in Figure 4.5, the pre-congestion LMP of each node is uniform, as represented by the star-dotted curve. The square-dotted curve and triangle-dotted curve represent post-congestion LMP profiles with the traditional method and the proposed method respectively. The marginal prices of node 12, 13, 14 increase drastically with the traditional LMP method when the congestion occurs. It can be seen that the post-congestion LMP volatility of the proposed method decreases compared to the traditional method and the price spike is removed with the proposed method. The LMP of each node with the proposed method is tending to the market clearing price obtained in the unconstrained circumstance.

The generators re-dispatch results and system production costs in a generation schedule using the traditional method and the proposed method are tabulated in Table 4.5 and Table 4.6 respectively. In Table 4.5, generator 1 is redispatched downwards whilst generator 2 and generator 8 are re-dispatched upwards. The outputs of generators 3 and 6 are unchanged in the process. The absolute redispatch amount of power of the proposed method is 12.80 MW, which is noticeably lower than that of the traditional LMP method of 81.96MW. This means less redispatch payment will be needed, and the bilateral contract violation would be minimized if bilateral contracts exist between the generators and the consumers. Due to the dispatch of out-of-merit generators, the system cost has increased to £7740/hr with the traditional method when compared to a pre-congestion system production cost of £7622.59/hr. The difference between the two costs can be considered as the cost of congestion from the societal point of view. In solving the congestion, system operators have to give up 40.3MW from generator 1 (cheaper unit) and dispatch 84.1MW from generators 2 and 8(the latter being more expensive units) using the traditional LMP method. The system production cost of the proposed method is £7495.33/hr due to the reduction of partial load at node 13 and re-dispatch of less expensive generators in the system.

Table 4.5 Generators Re-dispatch Results

Generator	P-scheduled (MW)	Traditional LMP Method(MW)	Proposed Method (MW)	Total absolute redispatch with traditional method (MW)	Total absolute redispatch with proposed method (MW)
1	229.97	189.67	217.73	81.96	12.80
2	38.03	32.85	37.47		
3	0	0	0		
6	0	0	0		
8	0	36.48	0		

Table 4.6

System Production Cost

System production cost before congestion (£/h)	Post-congestion System production cost with traditional method (£/h)	Post-congestion System production cost with proposed method (£/h)
7622.59	7740.66	7495.33

The merchandise surplus corresponding to the traditional method and the proposed method are shown in Figure 4.6. With the traditional LMP method, the merchandise surplus is £1066.3 and the standard deviation of the LMP is 12.953. Using the proposed method, the value of merchandise surplus is tending to zero and is much lower than that of traditional method whilst the standard deviation of the LMP is 3.744. A comparison of the impact of congestion rent between the two methods is shown graphically in Figure 4.7. The results demonstrate that the congestion rent is reduced significantly with the proposed method, which means that congestion is relieved more efficiently.

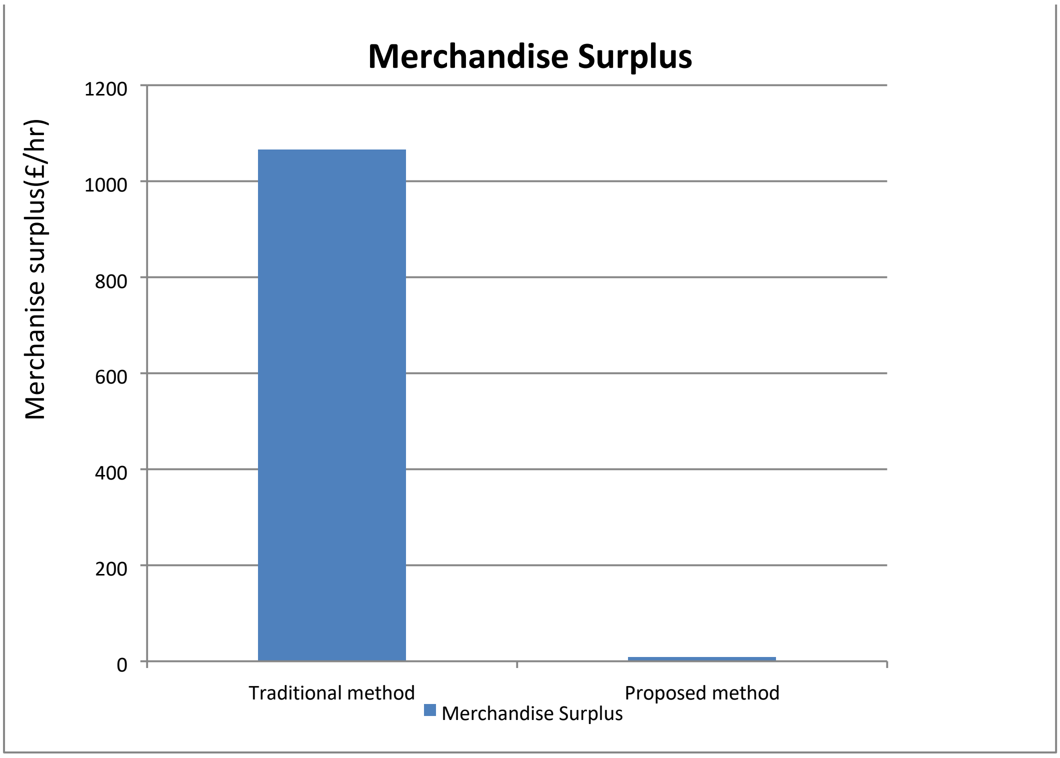

Figure 4.6 Merchandise surplus and standard deviation of LMP

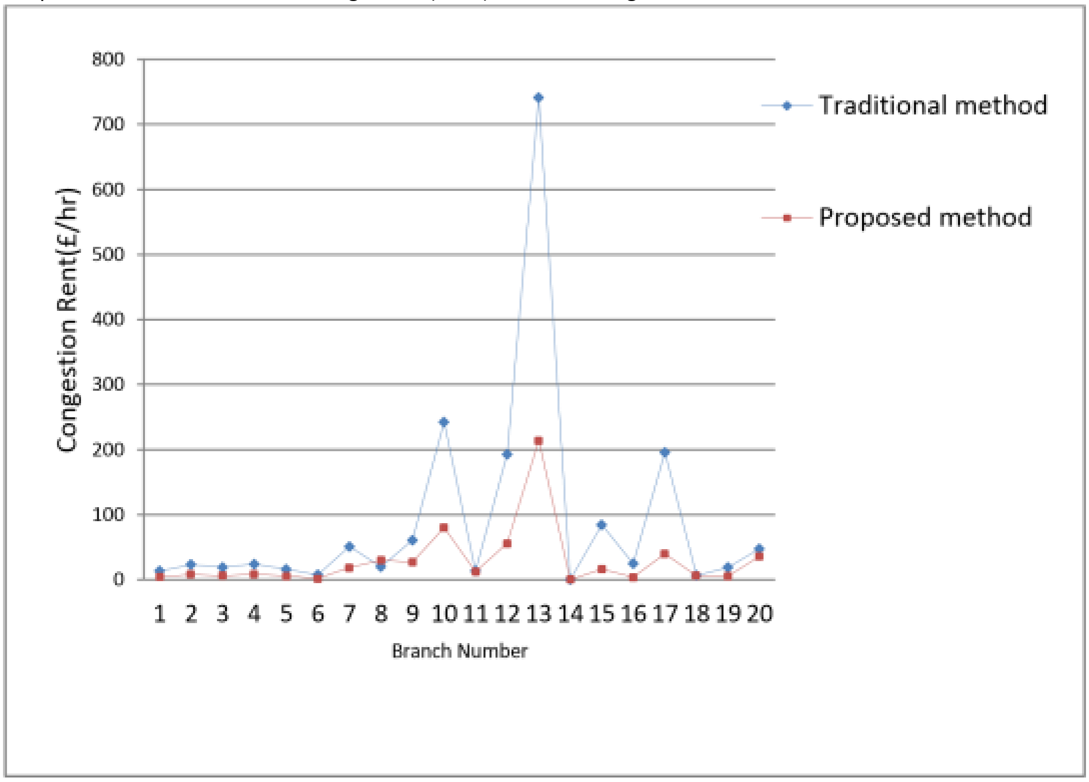

Figure 4.7 Congestion rent with traditional LMP method and proposed method

4.4.2 IEEE 30 Node System

The proposed methodology has also been applied on the IEEE 30-node system for evaluating the efficiency of handling the congestion. This sample system includes six generators and 41 transmission branches. The data of IEEE 30-node can be obtained from [9] and is listed in Appendix. Figure 4.8 shows the target system.
The data of power outage costs are listed as Table 4.7.

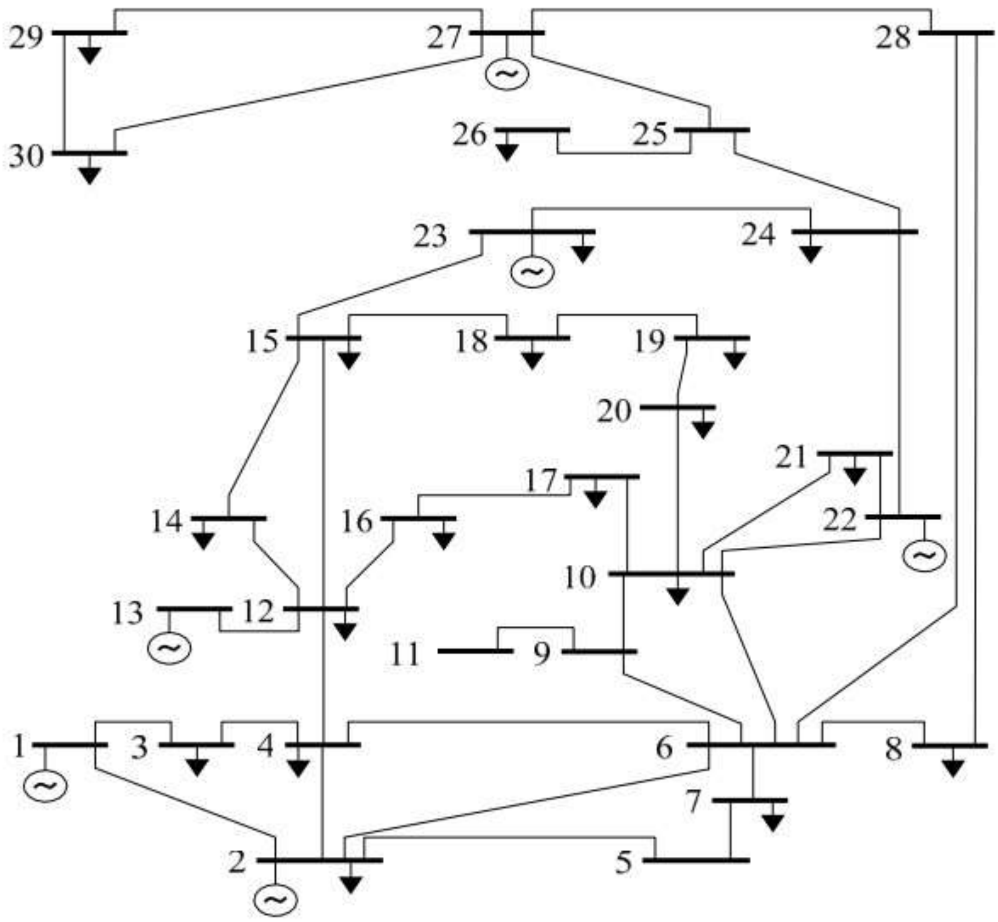

Figure 4.8 IEEE 30 node system[9]

Table 4.7

Function of power outage cost of IEEE 30 system (per unit value) [10]

Node	**$F_i(\alpha_i)$**	**Node**	**$F_i(\alpha_i)$**
2	$0.0655\alpha_2{}^2 + 0.3298\alpha_2$	3	$0.00963\alpha_3{}^2 + 0.0384\alpha_3$
4	$0.0219\alpha_4{}^2 + 0.1094\alpha_4$	5	$0.2104\alpha_5{}^2 + 1.2058\alpha_5$
7	$0.0693\alpha_7{}^2 + 0.3465\alpha_7$	8	$0.108\alpha_8{}^2 + 0.432\alpha_8$
10	$0.0209\alpha_{10}{}^2 + 0.0835\alpha_{10}$	12	$0.0341\alpha_{12}{}^2 + 0.1702\alpha_{12}$
14	$0.0236\alpha_{14}{}^2 + 0.0942\alpha_{14}$	15	$0.0328\alpha_{15}{}^2 + 0.1312\alpha_{15}$
16	$0.0133\alpha_{16}{}^2 + 0.0532\alpha_{16}$	17	$0.0324\alpha_{17}{}^2 + 0.1296\alpha_{17}$
18	$0.0109\alpha_{18}{}^2 + 0.0435\alpha_{18}$	19	$0.0274\alpha_{19}{}^2 + 0.1368\alpha_{19}$
20	$0.00924\alpha_{20}{}^2 + 0.0352\alpha_{20}$	21	$0.0532\alpha_{21}{}^2 + 0.266\alpha_{21}$
23	$0.0133\alpha_{16}{}^2 + 0.0532\alpha_{16}$	24	$0.0331\alpha_{24}{}^2 + 0.1322\alpha_{24}$
26	$0.0121\alpha_{26}{}^2 + 0.0482\alpha_{26}$	29	$0.00867\alpha_{29}{}^2 + 0.033\alpha_{29}$
30	$0.0339\alpha_{30}{}^2 + 0.1696\alpha_{30}$		

When there were no constraints binding in the network, the node price of each load is set as the market clearing price 5.067 £/*MWh*. The power flow on each line is shown in Table 4.8

Table 4.8

Power flow results of uncongested IEEE 30 node system

Branch Number	Start	End	Power Flow（MW）
1	1	2	39.86
2	1	3	36.80
3	2	4	35.16
4	3	4	34.40
5	2	5	22.70
6	2	6	40.30
7	4	6	31.93
8	5	7	22.70
9	6	7	0.10
10	6	8	29.09
11	6	9	16.97
12	6	10	9.70
13	9	11	0
14	9	10	16.97
15	4	12	30.03
16	12	13	0
17	12	14	5.99
18	12	15	11.64
19	12	16	1.20
20	14	15	-0.21
21	16	17	-2.30
22	15	18	2.89
23	18	19	-0.31
24	19	20	-9.81

25	10	20	12.01
26	10	17	11.30
27	10	21	-0.07
28	10	22	-2.37
29	21	22	-17.57
30	15	23	0.34
31	22	24	12.60
32	23	24	-2.86
33	24	25	1.04
34	25	26	3.50
35	25	27	-2.46
36	28	27	15.46
37	27	29	6.04
38	27	30	6.96
39	29	30	3.64
40	8	28	-0.91
41	6	28	16.37

4.4.2.1 Scenario 1: Branch 10-17 congested

When the capacity limit of branch 10-17 is set to be 10MW, congestion occurs. The amount of congestion is equal to 1.3 MW. The calculated overall economic demand management index is listed as Table 4.9.

Table 4.9

Economical Load Management Index for relieving congestion in Branch 10-17

Index for relieving congestion in branch 10-17					
Node	S	ΔP_n	I_S	I_F	I
2	0	0	0	0	0
3	0.0070	185.1816	0	0	0
4	0.0085	152.9761	0.0020	0	0
5	0	0	0	0	0

7	0	0	0	0	0
8	0	0	0	0	0
10	0	0	0	0	0
12	0.1848	7.0342	0.2422	0	0
14	0.1419	9.1594	0.1838	0	0
15	0.10895	11.9325	0.1388	0	0
16	0.47013	2.7652	0.6308	0.7460	0.4705
17	**0.74119**	**1.7539**	**1**	**1**	**1**
18	0.02038	63.7925	0.0182	0	0
19	0	0	0	0	0
20	0	0	0	0	0
21	0	0	0	0	0
23	0.03976	32.6927	0	0	0
24	0	0	0	0	0
26	0	0	0	0	0
29	0	0	0	0	0
30	0	0	0	0	0

The index demonstrated that the load reduction at node 17 would be the optimal solution to tackle the congestion of branch 10-17. With the load reduction of 1.754 MW, the congestion can be relieved efficiently. The comparison between the traditional method and the proposed method are demonstrated in Figure 4.9, Figure 4.10 and Figure 4.11 respectively. The LMP profile is flat with the proposed method as shown in Figure 4.9, which indicates the congestion is removed completely.

Figure 4.10 shows the comparison results of merchandise surplus. Both of these metrics equal to zero when the proposed method is used.

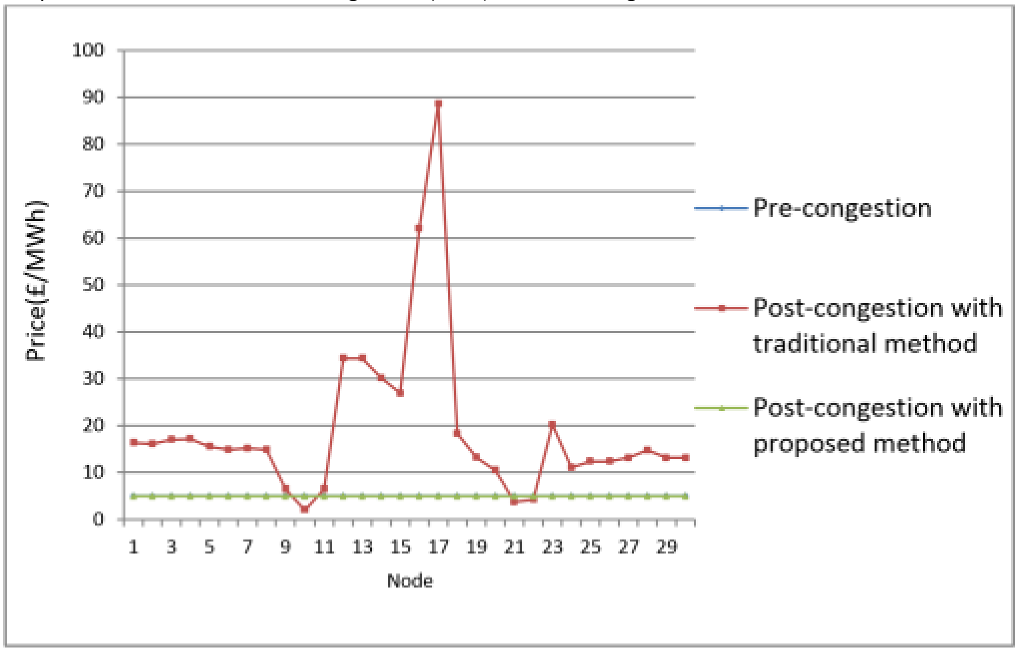

Figure 4.9 LMP in all nodes for the branch 10-17 congestion

Figure 4.10 Merchandise surplus and standard deviation of LMP

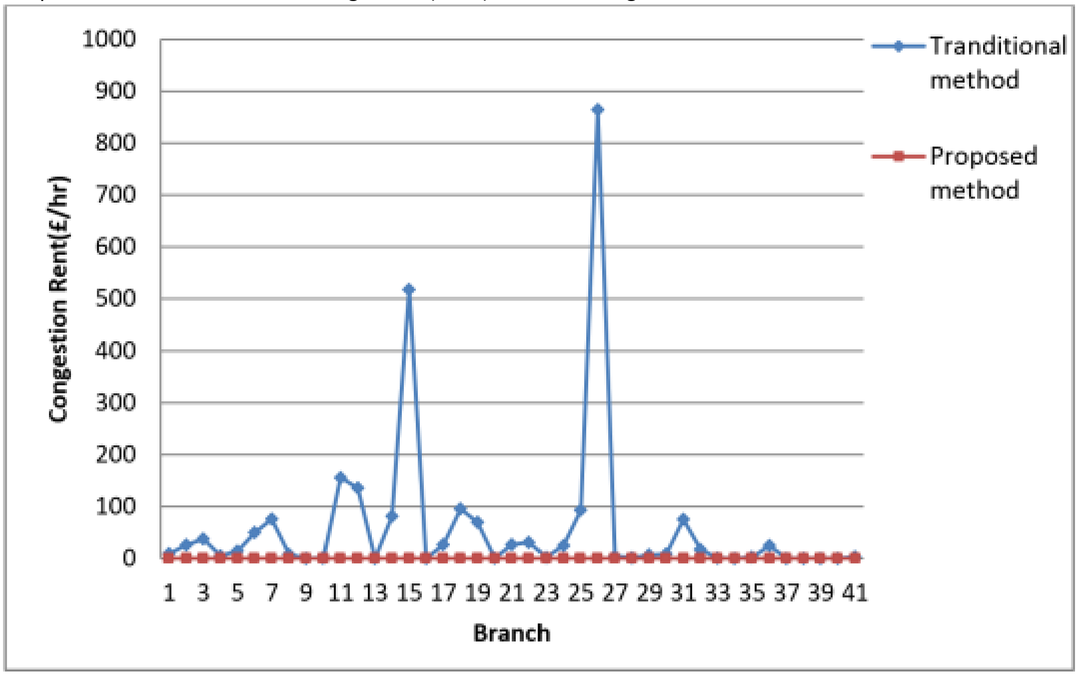

Figure 4.11 Congestion rent with traditional LMP method and proposed method

Table 4.10

Results of Re-dispatched Generations

Generator	P-scheduled (MW)	Traditional LMP Method (MW)	Proposed Method (MW)	Total absolute redispatch with traditional method (MW)	Total absolute redispatch with proposed method (MW)
1	76.67	80	75.34	12.44	1.75
2	80.00	80	80		
13	0	2.89			
22	32.53	26.31	32.11		
23	0	0	0		
27	0	0	0		

Table 4.11 System Production Costs

System production cost before congestion (£/h)	Post-congestion: System production cost with traditional method (£/h)	Post-congestion: System production cost with proposed method (£/h)
621.57	702.41	612.75

The total absolute amount of re-dispatch for generators with the proposed method is lower than that with the traditional method and the system production cost with the proposed method is much lower than that of traditional method as shown in Table 4.10 and Table 4.11.

4.4.2.2 Scenario 2: Branch 2-6 and 22-24 congested

It is assumed a contingency occurs and that branches 2-6 and 22-24 become congested with capacity limits 37MW and 12 MW respectively. The amounts of congestion are equal to 3.30MW and 0.60MW respectively. The calculated overall economic load management index is listed in Table 4.12.

Table 4.12

Economical Load Management Index for relieving congestion in Branch 2-6 and 22-24

Index for relieving congestion in Branch 2-6					
Node	S	ΔP_n(MW)	Is	I_F	I
2	0	0	0	0	0
3	0.1801	18.3282	0.2760	0	0
4	0.2180	15.1404	0.4801	0	0
5	0.1288	25.6191	0	0	0
7	0.2402	13.7374	0.6	0.2073	0
8	**0.3143**	**10.2009**	**0.9988**	**1**	**0.9988**
10	0.2896	11.3946	0.9121	0	0
12	0.2572	12.8305	0.6915	0	0
15	0.2655	12.4289	0.7362	0	0
16	0.2710	12.1776	0.7657	0	0
17	0.2841	11.6160	0.8363	0	0
18	0.2739	12.0473	0.7815	0	0
19	0.2789	11.8322	0.8083	0	0
20	0.2816	11.7200	0.8227	0	0
21	0.2890	11.4207	0.8625	0.5432	0.4685
23	0.2743	12.0324	0.7833	0	0
24	0.2861	11.5356	0.8469	0	0
26	0.2956	11.1653	0.8981	0	0
29	0.3016	10.9416	0.9306	0	0
30	0.3016	10.9416	0.9306	0	0
Index for relieving congestion in branch 22-24					
Node	S	ΔP_n(MW)	Is	I_F	I
2	0	0	0	0	0
3	0.0015	394.7368	0	0	0

4	0.0019	324.3244	0.0015	0	0
5	0	0	0	0	0
7	0	0	0	0	0
8	0.00106	566.0378	0	0	0
10	0	0	0	0	0
12	0.04014	14.9476	0.0753	0	0
15	0.09414	6.3734	0.1794	0.6075	0.1090
16	0	0	0	0	0
17	0	0	0	0	0
18	0.0120	49.8754	0.0211	0	0
19	0	0	0	0	0
20	0	0	0	0	0
21	0	0	0	0	0
23	0.2753	2.1792	0.5286	0.9162	0.4843
24	**0.5199**	**1.154**	**1**	**1**	**1**
26	0.3452	1.7382	0.6633	0.9683	0.6422
29	0.2340	2.564	0.4490	0.9084	0.4079
30	0.2340	2.564	0.4490	0.8991	0.4037

The indices under column I of Table 4.12 illustrate that the curtailment at node 8 and node 24 can be the most efficient solution to alleviate the overload on branch 2-6 and branch 22-24 respectively. Then, the congestions are relieved with the generator re-dispatch and reduction of 10.2 MW and 1.154MW loads from node 8 and 24 respectively. The comparison between the traditional method and the proposed method are demonstrated in Figure 4.12, Figure 4.13 and Figure 4.14 respectively. The LMP profile is smoother with the proposed method as shown in Figure 4.12. Figure 4.13 shows the comparison results of merchandise surplus. Both of these metrics reduce significantly when the proposed method is used. This verifies again that the proposed method could relieve system congestion with a higher economic efficiency. The congestion rent of each branch decreases when both congestions are relieved as presented in Figure 4.14. Results of re-dispatched generation and system production costs in post-congestion stage are listed in Table 4.13 and Table 4.14 respectively.

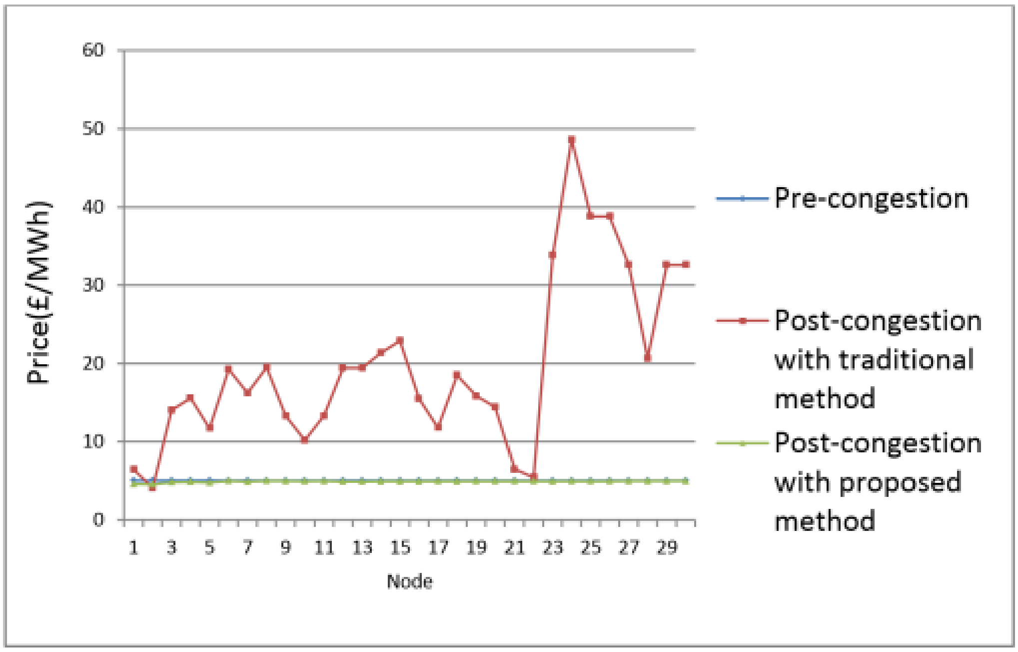

Figure 4.12LMP in all nodes for congestion in branch 2-6 and 22-24

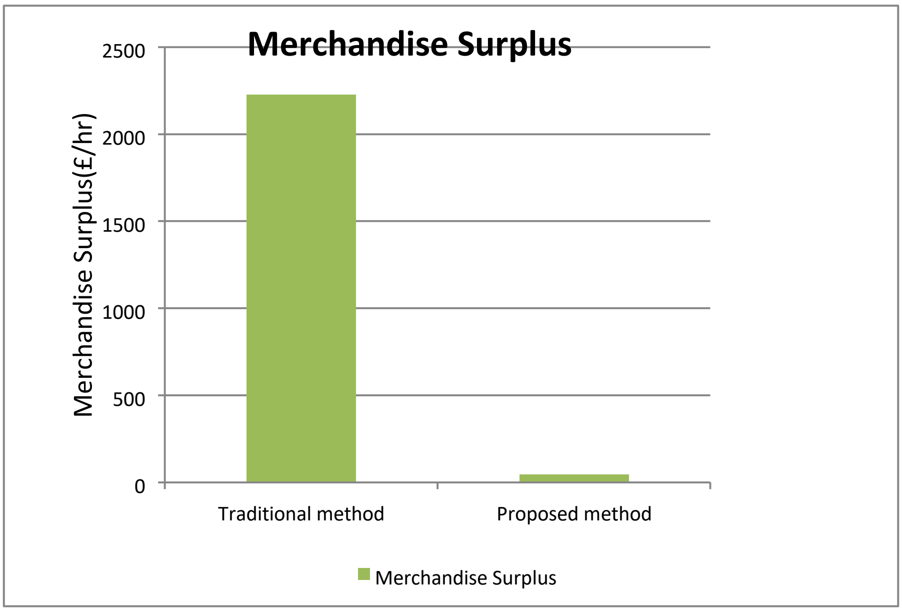

Figure 4.13 The standard deviation of LMP and merchandise surplus for solving the congestion

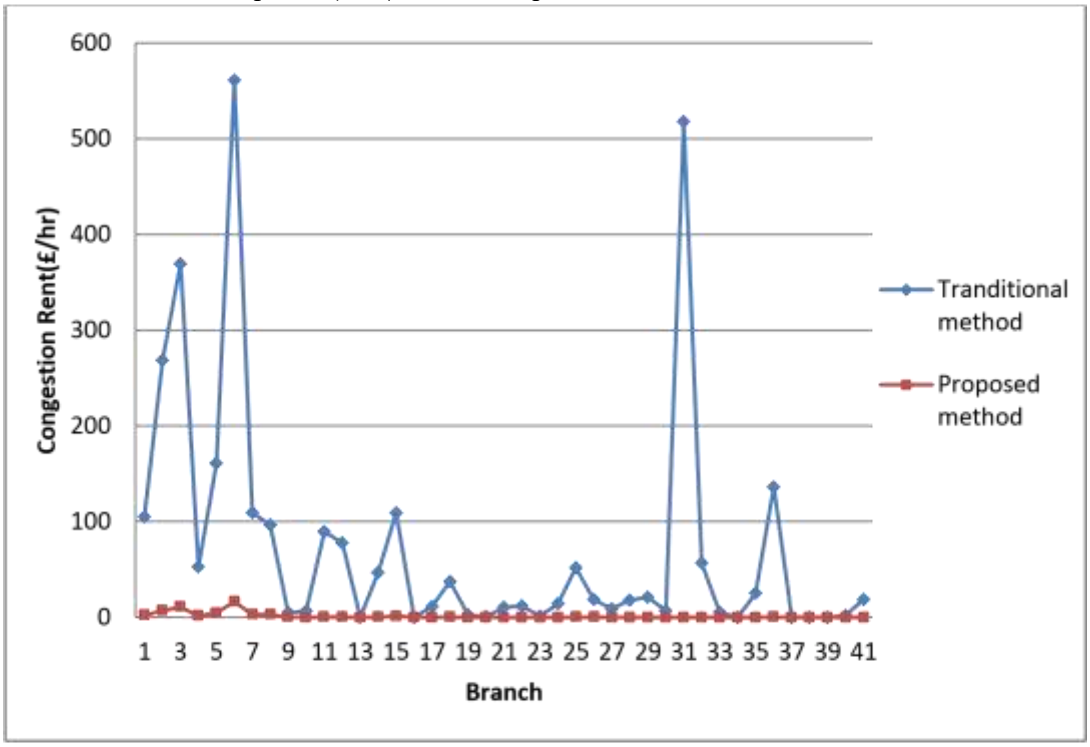

Figure 4.14 Congestion rent with traditional LMP method and proposed method

Table 4.13 Results of Re-dispatched Generations

Generator	P-scheduled (MW)	Traditional LMP Method (MW)	Proposed Method (MW)	Total absolute redispatch with traditional method (MW)	Total absolute re-dispatch with proposed method (MW)
1	76.67	80	66.1	24.25	11.2
2	80.00	67.89	80		
13	0	0	0		
22	32.53	35.76	31.9		
23	0	0	0		
27	0	5.58	0		

Table 4.14 System Production Costs

System Production cost before congestion (£/h)	Postcongestion: System Production cost with traditional method (£/h)	Postcongestion: System Production cost with proposed method (£/h)
621.57	784.50	567.09

Comparing the generation re-dispatch results, the total absolute amount of redispatch for generators with the traditional method is higher than that with the proposed method. The reduction of output of cheapest generator is minimized with the proposed method and it decreases the need for more expensive generators in the system. The system production cost with the proposed method is much lower than that of the traditional method. This illustrates that the congestion is relieved in a more optimal manner.

4.5 Summary

A set of indices is developed and the values of the indices are used to allocate the optimal load adjustment and determine the amount of demand side participation. The proposed index is integrated into the congestion management scheme based on the principle of locational marginal pricing. The theory and the effectiveness of the proposed index are illustrated through case studies based on the IEEE 14 and 30 node systems. The simulation results show that the congestion management method with the proposed index could tackle congestion effectively in a power system.

In addition, this chapter has illustrated the impacts of economical demand management on the LMP spikes and production cost decrement. The simulation results demonstrate that the demand side management is an appropriate tool to manage the LMP in an electricity market. Moreover, it can be concluded that the participation of demand-side in a congestion management scheme could increase the market efficiency and enhance the market performance.

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Chapter 5 Demand adjustment through direct control of Smart appliances

5.1 Introduction

It is well established that the smart grid plays a crucial part in current power system operation and control. In smart grid, both the supply and demand side can participate in a balanced effort. The demand side can contribute by moving the loads in different time scale, thereby momentarily adjusting the consumption[1].In UK, the domestic sector represented around 37 percent of total electricity consumption and was the largest consuming sector of electricity(according to data in[2]) as depicted in Figure 5.1.Therefore, considerable efforts have been undertaken to demonstrate the enormous potential of DSM in domestic sector to improve system operation condition ,e.g. system peak reduction as well as power losses and operation cost minimization. Household appliances account for a major part of the residential electricity consumption. In order to release the potential of DSM, these appliances have to be integrated with the ability to monitor their energy usage and, possibly, to remotely control their electricity usage [3]. A key in this context could be the socalled smart appliances. According to the definition in[4], the term ―smart appliance‖ refers to a product that uses electricity as its main power source in which has the capability to receive, interpret and act on a signal received from a utility, third party energy service provider (Demand Load Aggregator) or home energy management device(Smart Household Control module), and automatically adjusts its operation depending on both the signal's contents and settings from the consumer. This capability can be built-in or added through an external device that easily connects to the appliance. Nowadays, there is an increasing realisation that smart grid infrastructure (Advanced Metering Infrastructure (AMI) and two-way secure communication networks across utility service territories and within customer premises, etc.) will experience a huge development over the coming years. This opens up new possibilities for the direct control of smart appliances. Classical direct load control methodologies involve the periodic curtailment of domestic and commercial appliances which contain certain thermal inertia, such as electric waterheaters, air-conditioning units or space-heaters. However, with the diversification and extension of smart appliances, the traditional DLC methodologies might be not suitable for the control of newly invented smart appliances, such as washing machine, dishwasher and refrigerator. Thus, novel direct load control methodologies with respect to the different characteristics of smart appliances are needed. Therefore, this chapter explores this field and proposes a DSM methodology for smart appliances control under the smart grid scheme.

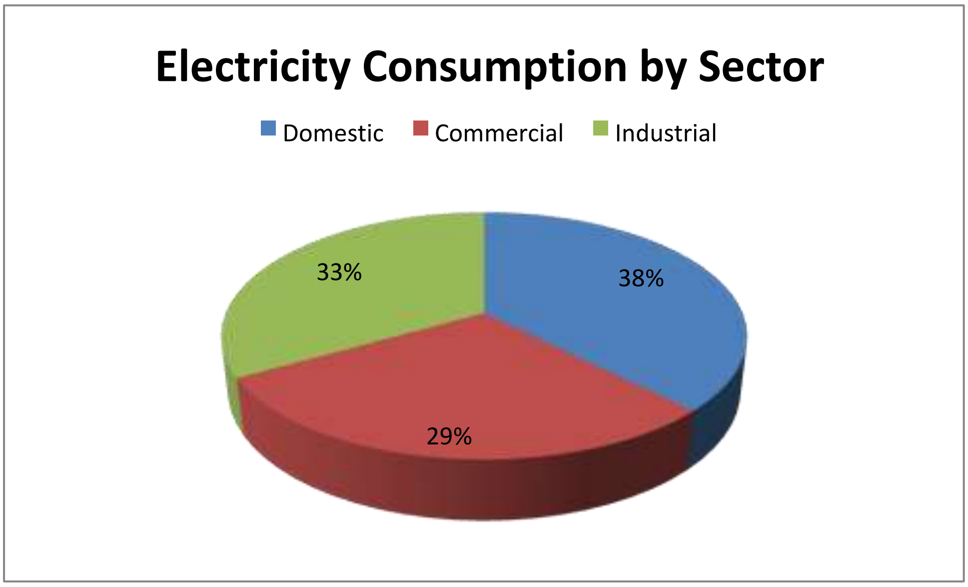

Figure 5.1 Electricity Consumption by Sector

In this chapter, Section 5.2 describes the properties of several smart appliances and detailed data on the appliances which will be applied in the study. Section 5.3 explains the proposed DSM structure and the control strategies of different groups of smart appliances whereas section 5.4 gives the formulas of proposed load control algorithm .The control activities of appliances are executed based on results from the proposed load shifting algorithms. Subsequently, Section
5.5 concludes the whole chapter.

5.2 Descriptions of Smart Appliances Participating in DSM

The management and coordination of energy generation and consumption is the primary interest of many research papers. In [5], the author simulated load shifting response of domestic sector under the real-time electricity pricing scheme. They point out the potential benefits of controlling household appliance operations. It is common to characterise domestic appliances under specific categories : lighting appliances, cold appliances, cooking appliances, brown appliances, space heating, water heating and wet appliances[6, 7]. The definition of each type of domestic appliances is listed in Table 5.1. The approximated average UK electrical demand for 25 million households including the disaggregated data of different load types [5, 8] is shown in Figure 5.2

Table 5.1 Domestic Appliance

Domestic load types.	Members
Lighting Appliances	Incandescent light bulbs, led lamps, Fluorescent light bulbs.
Cold Appliances	Refrigerators, Freezers
Cooking Appliances	Electric ovens, Microwaves, Kettles, Drinks makers, Sandwich toasters, Cookers, Food preparation appliances etc.
Brown Appliances	Televisions, VCRs (video cassette recorders), Hi-fi systems, Record players Satellite control boxes for TVs, Cable control boxes for TVs Cassette recorders, Radios, X-boxes (games etc.)
Space Heating	Heat pumps, Radiators, Air conditioners
Water Heating	Electric water heater

Wet Appliance	Washing machines, Tumble dryers, Dishwashers etc.

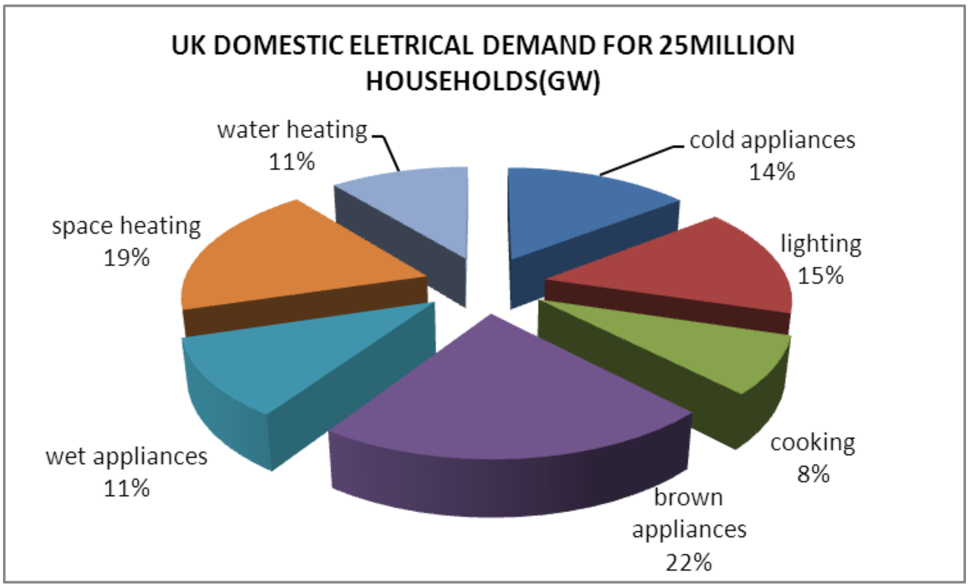

Figure 5.2UK domestic electrical demand for 25 million households(GW)[8]

According to the individual characteristics of each appliance group and the results of quantitative (survey) and qualitative (expert interviews, focus group interviews) user research in several European countries [9], wet appliances, cold appliances and water heating appliances are considered relatively flexible to be controlled with high customer acceptability while lighting, cooking and brown appliances are not that suitable for load control as it would affect the customer‘s comfort remarkably. However, 90% of water heater appliances operate overnight which is usually during off-peak period and the electricity price is low if consumers choose time-variable tariff[10]. Therefore, the potential load shifting of water heating appliances is relatively small and thus it is not considered in this work. The electric space heating appliance is expensive and perceived as non-environmentally friendly, hence, it is estimated that customers will be highly motivated to find better solutions. For the future however, the potentials might be rather low, as consumers prefer other heating technologies, if possible. Therefore for this thesis, the control strategies for smart appliances in the future network are focused on:

Wet appliances

- Washing machines
- Dryers
- Dishwashers

Cold appliances

- Refrigerator
- Freezer

The consumption data used in this study is mainly based on a Smart-A project[11] that was carried out by the European Commission through the IEE programme.

5.2.1 Wet Appliances

Washing machine

A washing machine contains two main components - a tub and a drum rotating around a horizontal axis. Water is filled into the tub up to a certain level which is maintained throughout the main cleaning process. The cleaning can be done at various temperatures (mainly 30, 40, 60 or 90°C), depending on the clothes to be washed. The water is heated up to the desired temperature by electricity or gas. When the desired temperature is reached, the drum is rotated by a motor to complete cleansing and rinsing cycles. At the end of the whole washing process, the drum is spun at a high speed to extract water from the load.

The washing machine penetration level is quite high in households in Europe, normally reported as 95%[9]. In this study, the data of power demand of appliances is from [12] in 1/4 h time slot , and here resolved in 1/2h for faster computation and smaller memory need for programming. The power consumption pattern of a typical washing machine is depicted in Figure 5.3. It can be observed that the highest consumption of power occurs during the water heating period. The power consumption from the motor is much smaller than that required for water heating.

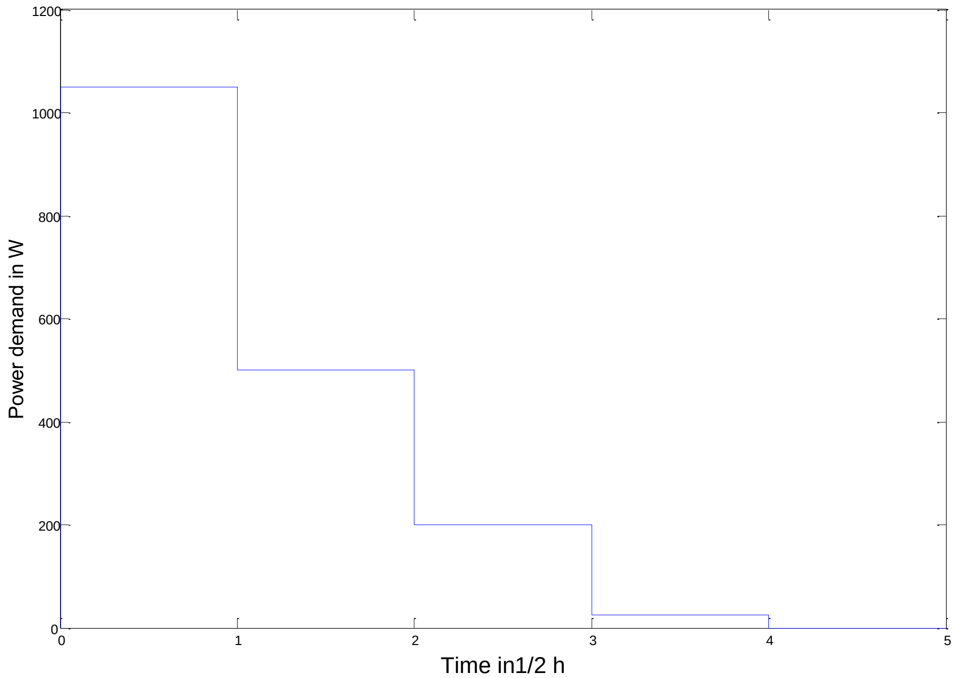

Figure 5.3 General consumption pattern of washing machine

Dish washer

Dishwashers contain a basket, rotating water sprays as well as air and water heating chambers. Dishes are stacked in the basket. Water is filled into the tub up to a defined quantity or low level which is then maintained throughout the individual steps of the cleaning process. Water is heated to temperatures ranging from 50 to 70 $\circ$C, depending on the programme selected by the consumer. The cleaning is done at the desired temperature. At the end of the washing cycle, hot air is passed over the dishes for drying.

A typical consumption cycle of a dishwasher is illustrated in Figure 5.4. Essentially, there are two phases that consume high power. These correspond to the water/air heating periods during which resistive heating elements are engaged.

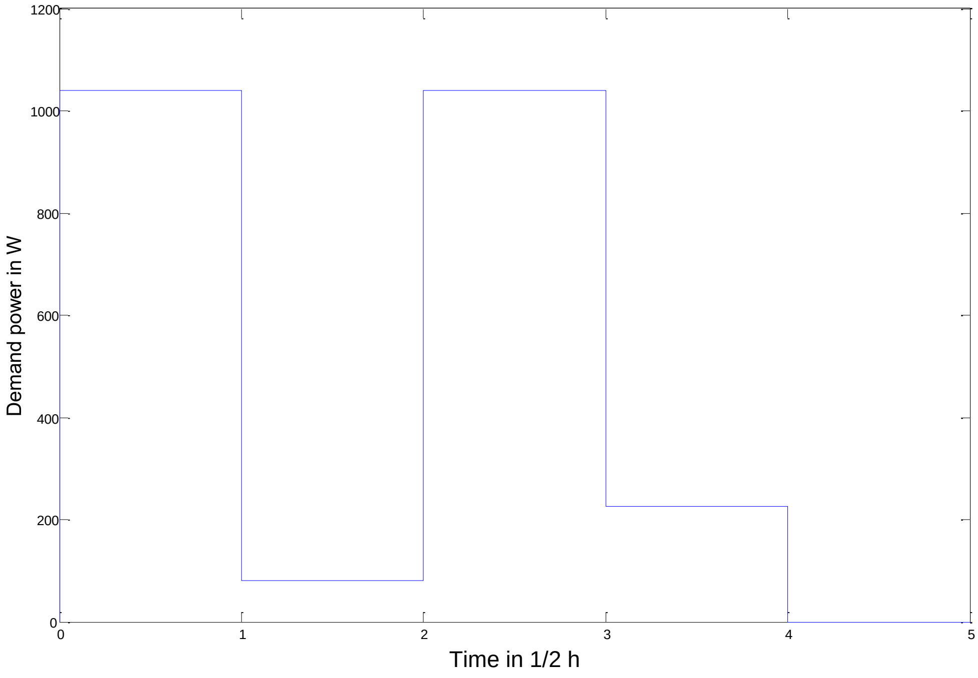

Figure 5.4 General consumption pattern for dish washer

Tumble Dryer

A tumble dryer consists of a drum, fan and a heating element. The heating element is used to heat the air which is then blown over the wet clothes by a fan. The drum spins during the operation of the dryer in order to maximise the exposure of clothes to the heated air. The drum and the fan are spun by an induction motor.

Figure 5.5 shows typical consumption cycle of dryer respectively.

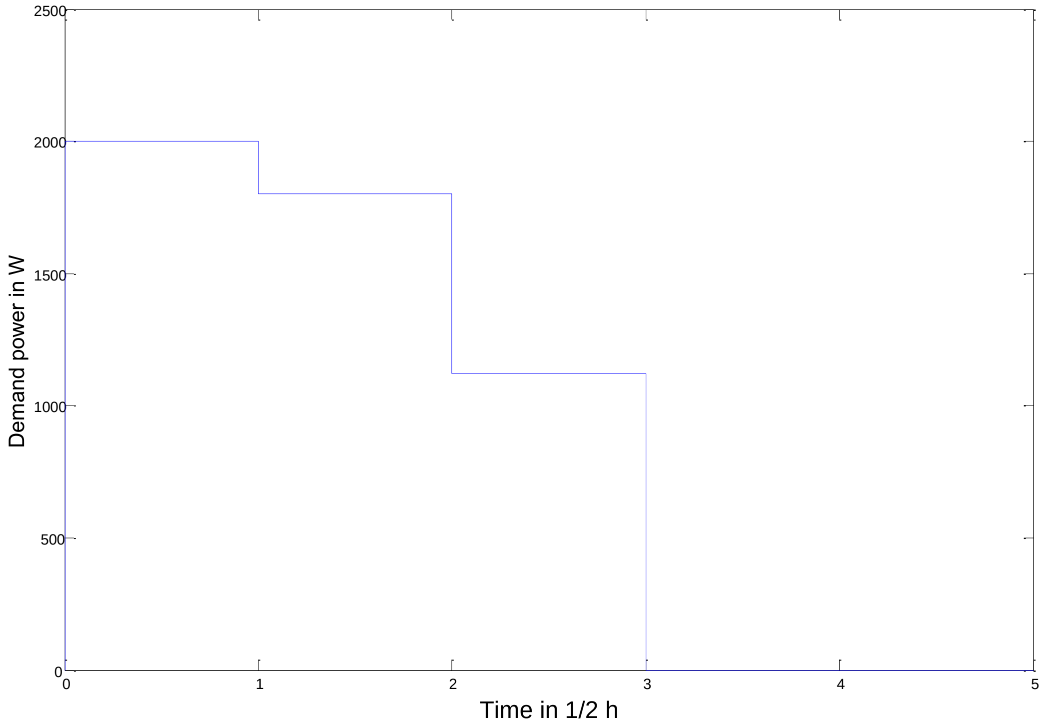

Figure 5.5General consumption pattern for a dryer

5.2.2 Cold Appliances:

Refrigerator:

The refrigerator contains refrigerant which aids with the cooling process. Evaporation of the liquid refrigerant subsequently absorbs heat from the refrigerated inner space. After complete evaporation , the compressor in the refrigerator compresses the refrigerant into liquid form while releasing heat corresponding to the value absorbed at evaporator level and the thermal equivalent of the work of the compressor. Following condensation, the refrigerator is expanded by an expansion valve which throttles the refrigerant fluid back to the evaporator and controls the refrigerant flow. This cycle is repeated in order to maintain the temperature set-point within the fridge. The compressor demands motor and electrical energy but have limitations on the maximum time they can operate continuously and the minimum duration for resting after activity. This is because the compressor in the fridge cannot have a 100% duty cycle as the thermal energy dissipated by the compressor can cause damage to the internal components.

For a DSM application with control on a refrigerator, firstly, a model of a refrigerator is needed. According to[13] , The inner temperature T of refrigerator for an equidistant series of time steps is given by

$$T_{i+1} = \varepsilon T_i + (1-\varepsilon)\left(T_O - \eta \frac{P_i}{A}\right), with\ \varepsilon = e^{-\frac{\tau A}{m_c}} \tag{5.1}$$

Ti represents the refrigerator inner temperature at time t_i , ε is the system inertia which depends on the insulation *A*, the thermal mass m_c (thermal storage capacity), and the time span τ between the two time points t_i and t_{i+1}. Parameter P_i denotes the electrical power required during the last time interval depending on whether the compressor was turned on or off, and η is the efficiency of the compressor. For simplification purposes, T_o which refers to the ambient temperature, is assumed to be constant while the events of opening and closing of refrigerator doors (which can affect the operation frequency of compression) are not taken into account. When the compressor is switched on, P_i is a positive integer in the equation. After the inner temperature reaches the minimum Temperature T_{min}, the compressor is switched off and P_i=0 until the temperature exceeds the maximum temperature T_{max} again. By using this model, a correlation between the internal temperature of the refrigerator and the power demand can be drawn and modified as shown in Figure 5.6. In this thesis, the cycle of refrigerator compressor is 1 hour (2 time steps in 1/2h) and the number of operation cycles of refrigerator is 24 cycles per day based on the assumption and simplification above.

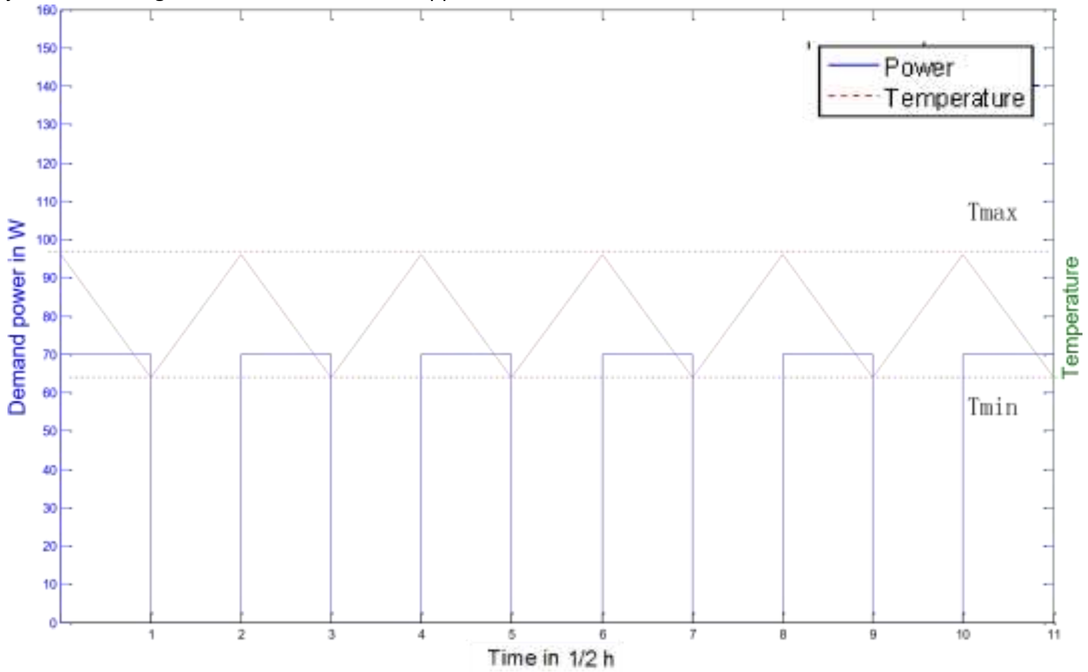

Figure 5.6 General consumption pattern for a refrigerator

Freezer:

Freezers usually consist of a box-type insulated compartment standing alone or builtin with a line of other kitchen units or in combination with a refrigerator. The operating principle of the freezer is similar to that of the refrigerator, as explained above. However, the inner temperature of freezer has to be kept subzero degrees celsius. The correlation between the internal temperature of the freezer and the power demand can be depicted as below:

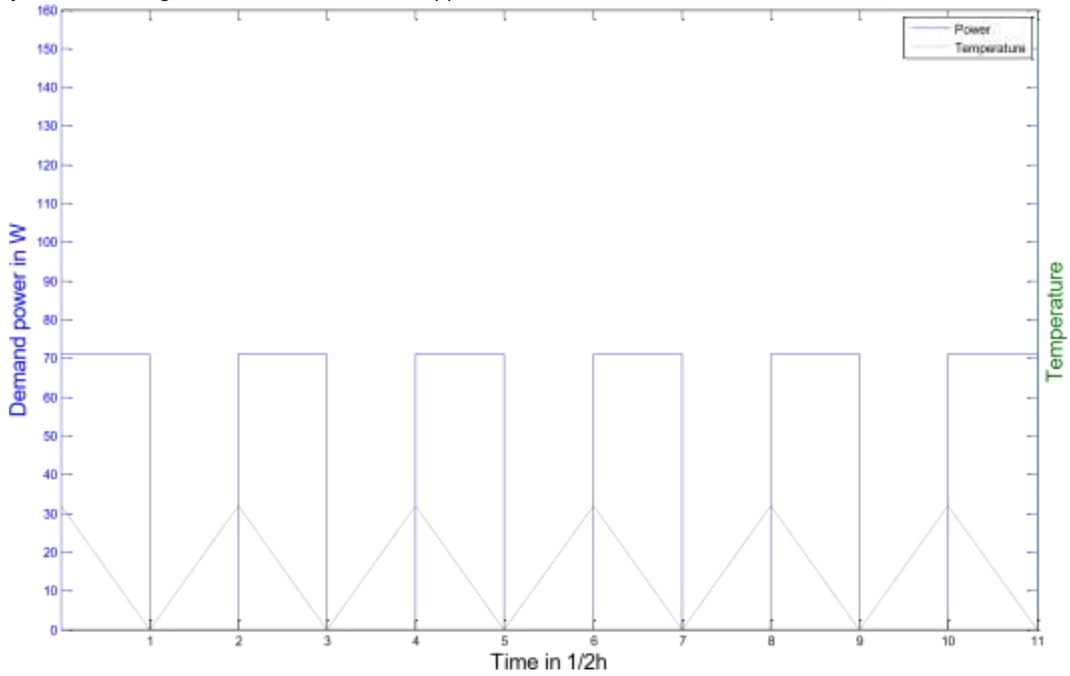

Figure 5.7 General consumption pattern for a freezer

5.3 DSM Architecture and Control Strategies for Different Group of Smart Appliances

5.3.1 Active DSM Structure

Crucial factors to enable effective active load control with good time response include a powerful two way communication structure and reliable power electronics controller devices, which allow the implementation of algorithms for active demand management. This communication network encompasses all target appliances in the network infrastructures.

There are recent information and communication technologies(ICT) being applied to support demand response, such as Advanced Metering Infrastructure (AMI) and Building Automation Systems (BAS)[14].These techniques, along with embedded control systems in appliances, are powerful tools to enable demand response in real time operation.

There are two major parts of the proposed DSM architecture, the user side and the distribution network operator (DNO) side. The network can establish a connection between DNO and end user through sending and receiving information. The connection would be made either by the grid infrastructures with Power-line communication (PLC) technologies or by the internet. The hardware with software installed at the user side is capable in reporting the available demand to DNO for cyclical demand management. On the other hand, DNO may optionally send load control orders based on control algorithm, hence, establishing a centralized control strategy.

On the user side, there are three modules:

- ***Appliances Data Acquisition*** — All the controllable appliances have embedded control hardware that gather and report the equipment functioning state and other parameters, e.g. temperature and power consumption. These hardwares must have electronic capabilities to treat data, control the appliance and possess wireless communication. Besides that, they have better cost effective and ergonomic design, not causing discomfort for costumers due to the control activities or increasing expenditure on its application.
- ***Smart Household Control*** — The data acquired from appliances are dealt with, and the available demand for management in one household is calculated by the module Smart Household Control (SHC). This information is then sent to DNO. The hardware and software of this module are installed in the household, and is in permanent communication with Appliances Data Acquisition (ADA) module and DNO. This module is also capable to receive the control order from DNO and pass it to the Smart Load Control (SLC) module which will be explained as below.
- ***Smart Load Control*** — In the case of load control order from DNO, this module proceeds to manage the operation status of single appliance, such as

switching on /off the appliance according to the control signal. The respective hardware is embedded in all appliances or added through an external device that easily connects to the appliance, along with ADA. Its design must guarantee equipment safe functioning based on characteristic of each appliance. This module is also capable in working independently in any single appliance regardless of the others network modules functioning. Thus, the appliance still can work normally whilst encountering communication troubles with Smart Household Control (SHC) or Appliances Data Acquisition (ADA).

As for the DNO side, there is one module:

- ***Demand Management Aggregator*** — in a similar manner to Supervisory Control and Data Acquisition (SCADA) and all adjacent functionalities, Demand Management Aggregator (DMA) collects information about distribution and transmission network state, as well as information about demand response and load control possibilities at residential level received from SLH. The DMA utilises the proposed load control algorithm in the following section to optimise the load profile for different purposes and determines the control actions for appliances before the control period. The control signals are sent to the households and appliances in the user side through network in real time. This module can work independently as well. In this option, it would be necessary to create a new intervener in the electricity network: Demand Load Aggregator (DLA). The DLA will be responsible for aggregating and organising all the information gathered from SLC, and take the necessary actions for grid operation optimisation. For a better understanding, Figure 5.8 illustrates this structure:

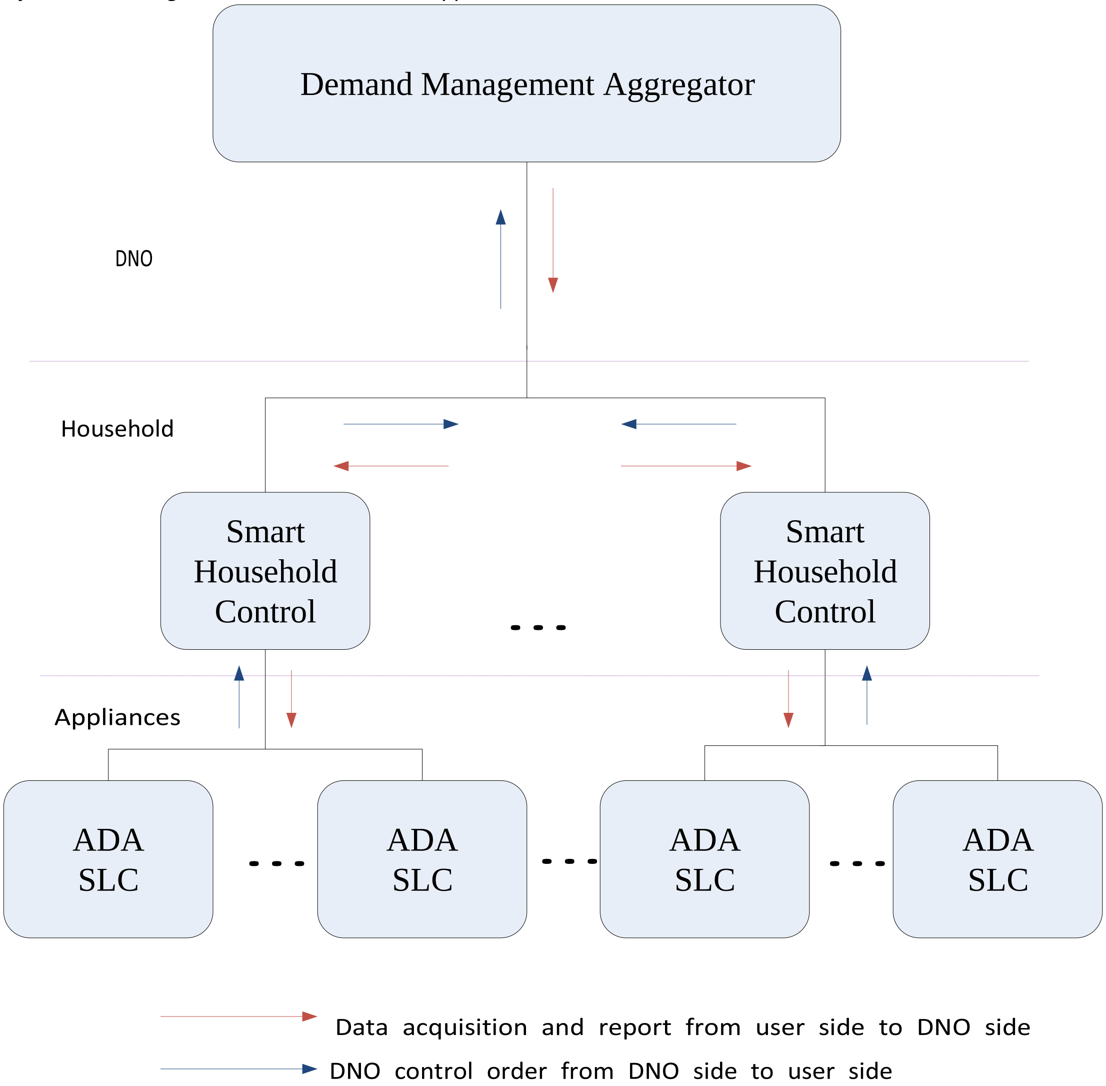

Figure 5.8 Proposed DSM structure

5.3.2 Control Strategy for Wet Appliances

For wet appliances, several smart control options are available as suggested in[12]:

1. delay the start of operation
2. interrupt the water heating phase until a certain time
3. reduce the power demand by automatically choosing a lower temperature for the programme and prolonging the operation time

4. prolong the final rinsing phase to shift the final spinning operation (for the case of washing machine).

Option 2-4 is relative to the operation cycle of wet appliances and may deteriorate the efficiency and life of appliances, and thus, will not be included in this study. This study only considers the option 1 for smart controlling of wet appliances. The control strategy is illustrated in Figure 5.9 .In this control scheme, the control actions have to be executed in real time during the control period, making use of the two way communication capabilities of smart grid.

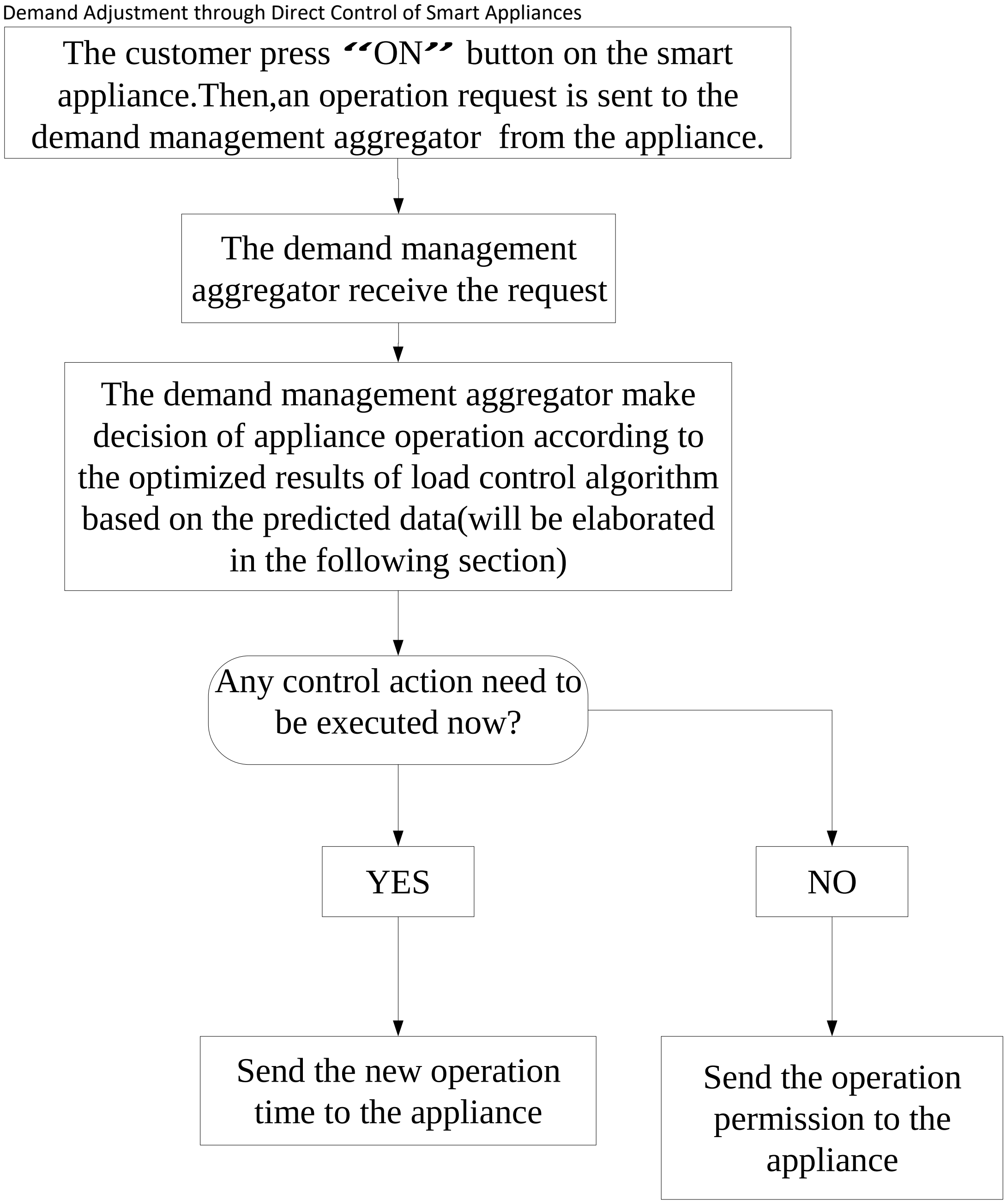

Figure 5.9 Control Strategy for wet appliances

If the operation time of wet appliances has to be delayed to optimise the solution from demand aggregator, the power demand change in the time window, in the case of a washing machine as example, can be illustrated as shown in Figure 5.10.

If large amount of smart appliances are taking part in the direct load control programme, the significant effect on changing demand profile can be achieved. According to a customer acceptance study[8], the possible maximum delay time for wet appliances is assumed to be 6 hours in this work.

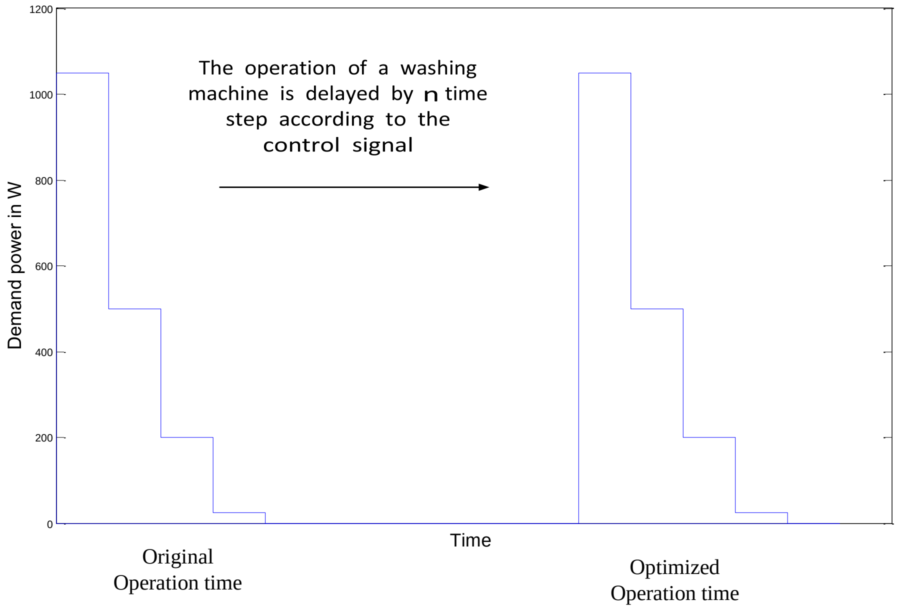

Figure 5.10 Demand power change of a washing machine on the time horizon

5.3.3 Control Strategy of Cold Appliances

Even though cold appliances are connected to the grid all the time and operate in cycles, it still may be possible to shift at least part of the time of use of fridges and freezers by taking advantage of the thermal inertia. Possible smart control options are listed below:

1. interrupt the cooling process
2. delay the cooling process and allow the appliance to warm up to higher maximum temperature
3. pre-cool the appliance to lower than the normal minimum temperature in advance
4. prolong the cooling process by reducing the speed of the motor.

5. change of temperature setting
6. change of temperature variation

Option 1 and 4 might deteriorate the efficiency and life span of the compressor due to interference of the compressor cycle. Option 6 is relative the thermal insulation improvement of appliances, which has mainly to do with design of products. That is out of the scope of this work. Option 2 and 3 are usually combined with option 5. However, option 2 will be disregarded as well since it may increase the likelihood of foodborne illness and other food safety issues. According to[15], regarding on food safety, the inner temperature of refrigerators is better to be kept at 40°F(4.44°C) or below. Thus, option 3 together with option 5 is suitably selected to be studied in this work. The control strategy of cold appliances can be illustrated as Figure 5.11 .

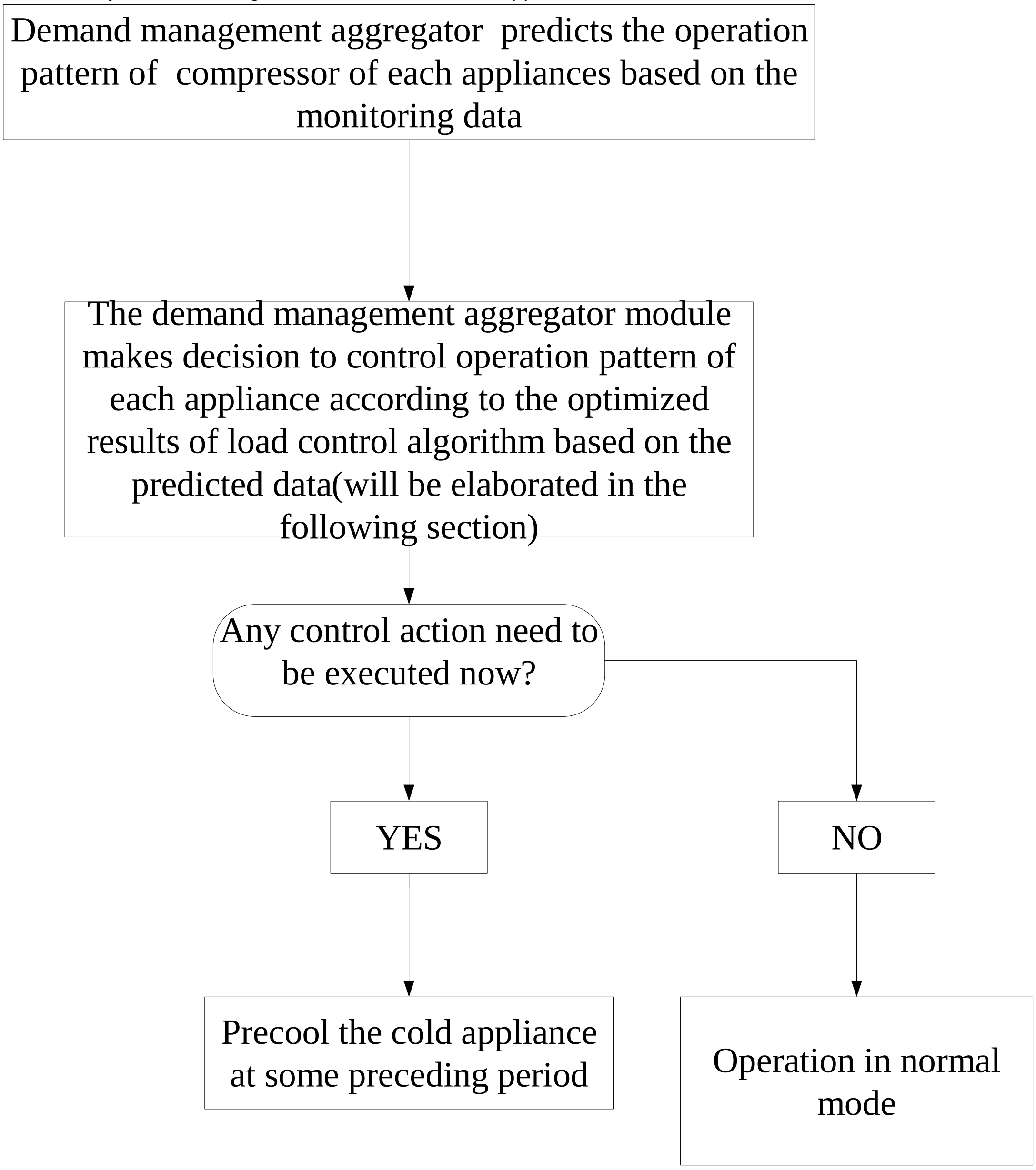

Figure 5.11 Control strategy for cold appliances

If one operation cycle of cold appliances has to be shifted forward to optimise the solution from demand management aggregator, then, the power demand change and temperature change in the time window, in the case of a refrigerator as example, can be illustrated as Figure 5.12.

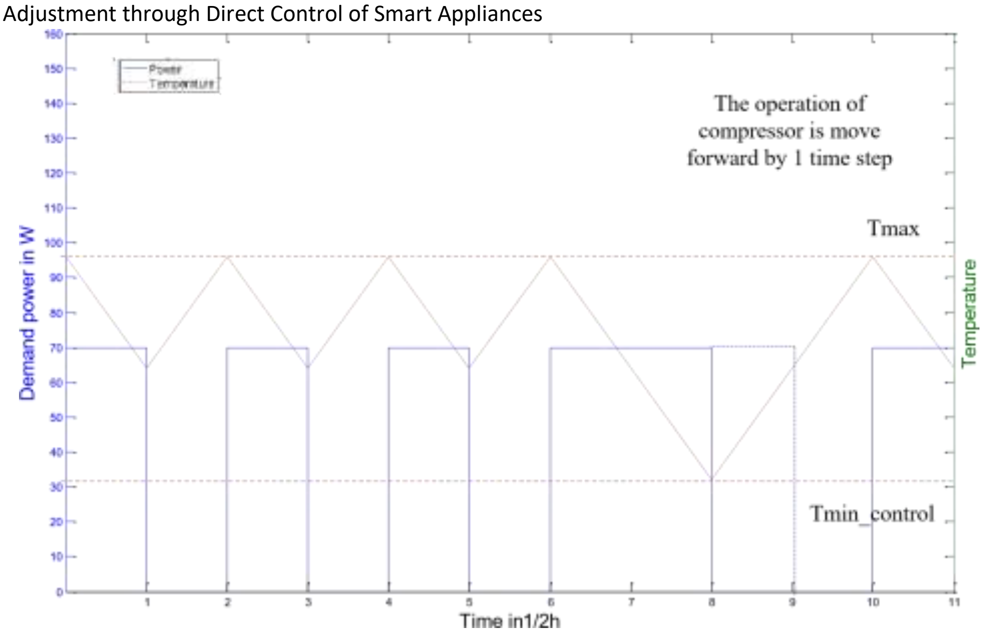

Figure 5.12 Demand power change of a refrigerator on the time horizon

In this work, the possible maximum precool time steps for the cold appliance is assumed to be 1.5 hours (namely 3 time steps in 1/2h) as it operates cyclically and it is not necessary to have a long precool time. Moreover, the operation of the compressor is set to be shifted to 2n-1 (n=1,2) time step ahead only since the compressor operates every two time steps and thus, the operation of compressor should be shifted to the predicted non-operation time step.

5.4 Mathematical Formulations

The proposed load control algorithm is extended from the work presented in [16]. It was originally designated for load shifting the wet appliances and water heaters backwards. In following section, the proposed algorithm will extend the original algorithm to involve cold appliances in the load control. The structure of the proposed control algorithm is given in Figure 5.13 .

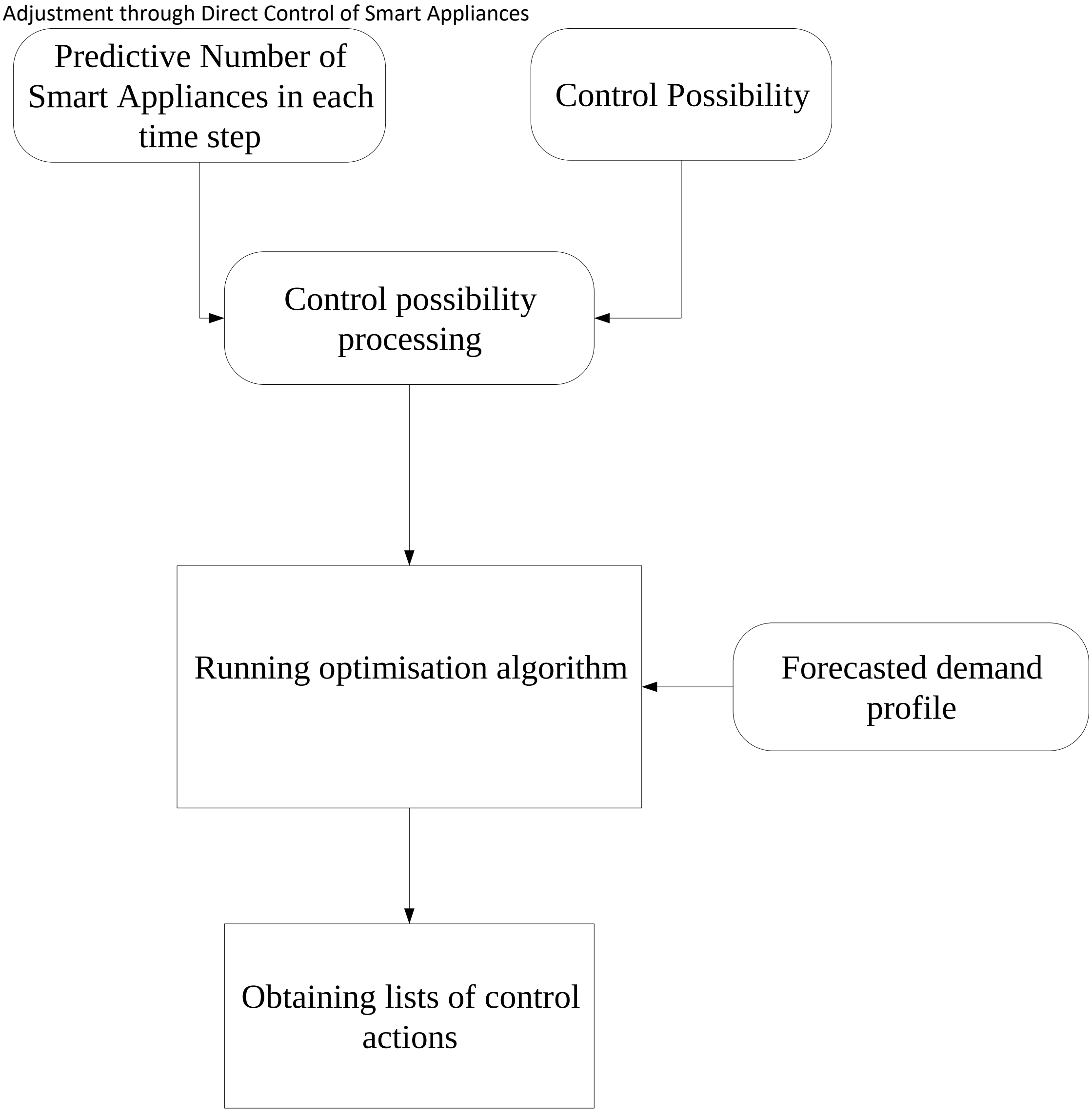

Figure 5.13 Basic structure of load control algorithm

5.4.1Input for Control Possibility Pre-processing

5.4.1.1Predicted Number of Smart Appliances in Each Time Step

The number of smart appliances to be connected to the network for each device type in each time step can be predicted by the historical data collected from the user side modules or by presetting information from the user side (i.e customer presets the operation time of washing machine) before the start of load control.

5.4.1.2 Control possibility

Control possibilities can be defined as to whether the load control is allowed or not for individual appliance. If the load control is allowed by the appliance, a further question needs to be considered: how much time step can be shifted forward (for cold appliances) and backward (for wet appliances). If the load control is not allowed, then no load control action can be executed on that appliance.

5.4.2Control Possibility Pre-processing

The control possibilities pre-processing stage is necessary since the following optimisation algorithm requires two values for each appliance type and expected connection time step:

1. First possible time step where the appliance can be moved to. (***s***).

2. Number of time steps that are also possible connection times. (***w***).

As the control strategies for cold appliances and wet appliances are different, the principles for the calculation of these values are slightly different:

For Cold appliance *c*:

1. First possible time step $s_c(t)$ where the cold appliance of type *c*, which cycle is expected to start at time step t, can be shifted forward to. Without explicit specification, the first possible time step for cold appliance is considered to be $s_c(t)=t-1$
2. Number $w_c(t)$ of time steps, which precedes from $s_c(t)$,are possible precooling times. If precooling is not allowed or not possible, then $w_c(t)$ is zero. If the precooling is allowed, the number of possible connection time steps must be smaller than the maximum allowed precool time steps. At the same time, the precool cycle cannot be overlapped on the preceding cycles in normal mode and cannot be shifted before the optimization time horizon T. Under both conditions, it can be expressed as :

$$\mathrm{w}_c(t) = \min(Precool_c^{Max}, s_c(\mathrm{t})) \quad (5.2)$$

$$\mathrm{w}_c(t) \neq t - nd_c, n = 1,2, \dots, \left\lceil \frac{Precool_c^{Max}}{d_c} \right\rceil \quad (5.3)$$

where index *c* denotes type of cold appliance, t is the time step the appliance is predicted to connected. d_c is the duration of operation cycle and $Precool_c^{Max}$ is the maximum allowed time for precooling.

For Wet appliance *w*:

1. First possible time step $s_w(t)$ where the wet appliance of type w, which cycle is expected to start at time step t, can be shifted backward. Without explicit specification, the first possible time step for wet appliance is considered to be $s_w(t)=t+1$.
2. Number $w_w(t)$ of time steps, which precedes from $s_w(t)$,are possible connection times. If delay is not allowed or not possible, then $w_w(t)$ is zero.

If the delay is allowed, the number of possible connection time steps must be equal to or smaller than the maximum allowed delay. In addition, the operation of appliances must be finished by the end of time horizon *T*.it can be expressed as:

$$\mathrm{w}_w(t) = \min(Delay_w^{Max} - 1, T - \mathrm{s}_w(\mathrm{t}) - \mathrm{d}_w + 1) \quad (5.4)$$

where index *w* denotes type of wet appliance, t is the time step the appliance is predicted to be connected. d_w is the duration of operation cycle and $Delay_w^{Max}$ is the maximum allowable time for operation delay. The constraint($T - \mathrm{s}_w(\mathrm{t}) - \mathrm{d}_w + 1$)ensures all the appliances are finished their operation cycles within the optimisation time horizon.

5.4.3 Optimisation Control Algorithm

The DSM strategy in this thesis schedules the connection moments of each controllable appliance in the system in a way that brings the load consumption curve as close as to the objective load consumption curve. The load control technique is mathematically formulated as below.

$$Min \sum_{t=1}^{N} (load(t) - objective(t))^2 \tag{5.5}$$

where *objective (t)* is the value of the objective curve at time step *t* and *load (t)* is the actual consumption at time step *t*, as given below:

$$\text{load}(t) = \text{Forecasted}(t) + \text{Connected}(t) - \text{Disconnected}(t) \tag{5.6}$$

where *Forecasted(t)* is forecasted demand of the aggregator of area in time step t. *Connected (t)* and *Disconnected (t)* are demands which are connected and disconnected in time step t respectively. *Connected (t)* consists of two components: the increase of demand corresponding to cold appliances and the increase of demand corresponding to wet appliances. Each component includes two parts: the increase of demand at time step t due to the connection of devices at time step t and the increase of demand due to the connection of devices preceding time *t* according to the load shifting schedule, which is given as:

$$\text{Connected}(t) = \text{Connected}_c(t) + Connected_w(t) \tag{5.7}$$

$$\text{Connected}_c(t) = \sum_{i=1}^{T} \sum_{c=1}^{n1} X_{cti} \cdot p_{1c} + \sum_{l=1}^{\text{dcn}} \sum_{\substack{i=1 \\ i \neq t-l}}^{T} \sum_{c=1}^{n1} X_{c(t-l)i} \cdot p_{(l+1)c} \tag{5.8}$$

$$\text{Connected}_w(t) = \sum_{i=1}^{T} \sum_{w=1}^{n2} X_{wit} \cdot \text{p}_{1w} + \sum_{l=1}^{dwn} \sum_{\substack{i=1 \\ i \neq t-l}}^{T} \sum_{w=1}^{n2} X_{wi(t-l)} \cdot p_{(l+1)w} \tag{5.9}$$

where X_{cti} is the number of cold appliances of type c which were originally expected to operate at time step *i* and then shifted their operation forward to time step *t*. n_1 is the total number of cold appliance groups, *dcn* is the total duration of the cold appliance group c. X_{wit} is the number of wet appliances of type w which were originally expected to operate at time step *i* and then are shifted their operation backward to time step *t*. n_2 is the total number of wet appliance groups, *dwn* is the total duration of the wet appliance group *w*. P_{lc} and P_{lw} are power consumption during l*th* time step of the operation cycle of cold appliance and wet appliance respectively.

For the cold appliance, connections can only be shifted forward, therefore:

$$\forall t > s_c(i) \qquad Xcti = 0 \tag{5.10}$$

The possible number of time steps that all cold appliances can be shifted to are limited by the maximum allowable precool time $Precool_c^{Max}$ and thus:

$$\forall t < (s_c(\text{i}) - w_c(t)) \qquad X_{cti} = 0 \tag{5.11}$$

For wet appliance, connections can only be delayed and not brought forwards, therefore:

$$\forall t < s_w(i) \qquad Xwit = 0 \tag{5.12}$$

The possible number of time steps that all wet appliances can be shifted to is limited by the maximum allowable time delay $Delay_W^{Max}$ and thus:

$$\forall t > (\text{s}_w(\text{t}) + w_w(t)) \qquad X_{wit} = 0 \tag{5.13}$$

Disconnected(t) consists of two components as well: the increase of load corresponding to cold appliances and the increase of load corresponding to wet appliances. Each component further includes two parts: the decrease of load at time step *t* due to the disconnection of appliances (which were originally expected to start consumption at time step *t*) and the decrease of load due to appliances shift in connection times (that were expected to start consumption in the preceding time step t).

$$\text{Disconnected(t)} = Disconnected_c(t) + Disconnected_w(t) \tag{5.14}$$

$$\text{Disconnected}_c(t) = \sum_{\substack{j=1 \\ j \neq t}}^{T} \sum_{c=1}^{n1} X_{cjt} \cdot p_{1c} + \sum_{l=1}^{dcn} \sum_{\substack{j=1 \\ j \neq t-l}}^{T} \sum_{c=1}^{n1} X_{cj(t-l)} \cdot p_{(l+1)c} \tag{5.15}$$

$$\text{Disconnected}_w(t) = \sum_{\substack{j=1 \\ j \neq t}}^{T} \sum_{w=1}^{n2} X_{wtj} \cdot p_{1w} + \sum_{l=1}^{dwn} \sum_{\substack{j=1 \\ j \neq t-l}}^{T} \sum_{w=1}^{n2} X_{w(t-l)j} \cdot p_{(l+1)w} \tag{5.16}$$

Similarly

$$\forall j > t \qquad X_{cjt} = 0 \tag{5.17}$$

$\forall j < (t\text{-}Precool_c^{Max})$ $\quad X_{cjt} = 0$ (5.18) $\forall$

$j<t$ $\quad X_{wtj} = 0$ (5.19)

$\forall j > (t + Delay_w^{Max})$ $\quad X_{wtj} = 0$ (5.20)

where X_{cjt} is the number of cold appliances of type c which shifted their operation from time step *t* to *j*. n_1 and *dcn* are the same as aforementioned.

X_{wtj} is the number of wet appliances of type w that are delayed from time step t to j, *dwn* and n_2 are the same as aforementioned.

The objective function is subjected to the following constraints:

- The amount of appliances which are shifted away from a time step cannot exceed the amount of available appliances for control at that time step:

$$\sum_{i=1}^{T} X_{cti} \leq con_{ic} \quad (5.21)$$

$$\sum_{i=1}^{T} X_{wit} \leq con_{iw} \quad (5.22)$$

where con_{ic} and con_{iw} represent the total number of controllable appliances that originally start their consumption at time step *i* in cold appliance group and wet appliance group respectively, which can be obtained as described in section 5.4.1.1.

- The number of controlled appliances must not be negative:

$X_{cij} >= 0, \forall i,j \in T$ (5.23)

$X_{wij} >= 0, \forall i,j \in T$ (5.24)

- Value for X_{cij} and X_{wij} must be integers

5.5 Solution to Potential Conflicting Situation in Realtime Control

As the proposed load control algorithm is run in advance, before the start of the control horizon, the solution and a list of control actions is obtained based on the forecast data. However, owing to the inevitability of forecast error and unpredictability of customer behaviours in real-time, the following potentially conflicting situations may arise:

1. The number of controllable appliances originally operated at time step *t* in real time is less than predicted. Regarding the wet appliances, it indicates that DNO cannot control a certain number of appliances according to the load control algorithm because some of them are not operated at the expected time. Regarding the cold appliances, it implies that less appliances are available for precooling due to the forecast error. A possible solution would be to reschedule the non-executed control actions to the next time step.
2. The number of controllable appliances originally operated at time step *t* in real time is more than predicted. In this case, DNO doesn‘t execute the control actions on the excess appliances. In other words, those appliances would operate under the normal mode.

5.6 Summary

Overall, this chapter proposes a novel load control methodology that can be employed in the future smart grid. The proposed methodology is a generalised technique based on load shifting, which has been mathematically formulated as a minimization problem. Different control strategies have been applied according to the different attributes of the appliances in the proposed methodology. Subsequently, corresponding control possibilities are mathematically formulated and successfully integrated into the load control optimisation algorithm. The proposed load control optimisation algorithm is sufficiently general to be applied on a wide range of appliances. Simulations based on the proposed methodology will be carried out in subsequent chapters.

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Chapter 6 Impacts of DSM on UK Power System

6.1 Introduction

To achieve the expected targets of reduction of carbon emissions from the electricity sector by 2050, future UK electricity system is likely to include a large penetration of intermittent renewable generation and nuclear generation. According to Figure 6.1, it can be observed that the generation mix is evolving from a mix dominated by conventional power stations providing predictable and flexible electricity to a mix with a significantly greater proportion of variable and inflexible generation. As each part of the power system is impacted mutually, changing of the generation mix would inevitably challenge the development and operation of the power network. For instance, severe overloading might occur due to the connection of offshore wind generation and potential nuclear power plants, particularly in North Wales, South West England and along the English East Coast between the Humber and East Anglia. Additional to this, less flexibility can be provided from the supply side due to the intermittent and inflexible nature of generation mix. This flexibility, which is traditionally provided by conventional generation, can also be obtained from the demand side if the right technology is implemented. Fortunately, a key element of the smart grid will be the ability of the network to elicit a useful response from demand side, which enhances the provision of system flexibility. In this work, the focus of finding the role of demand response is based on the smart appliances.

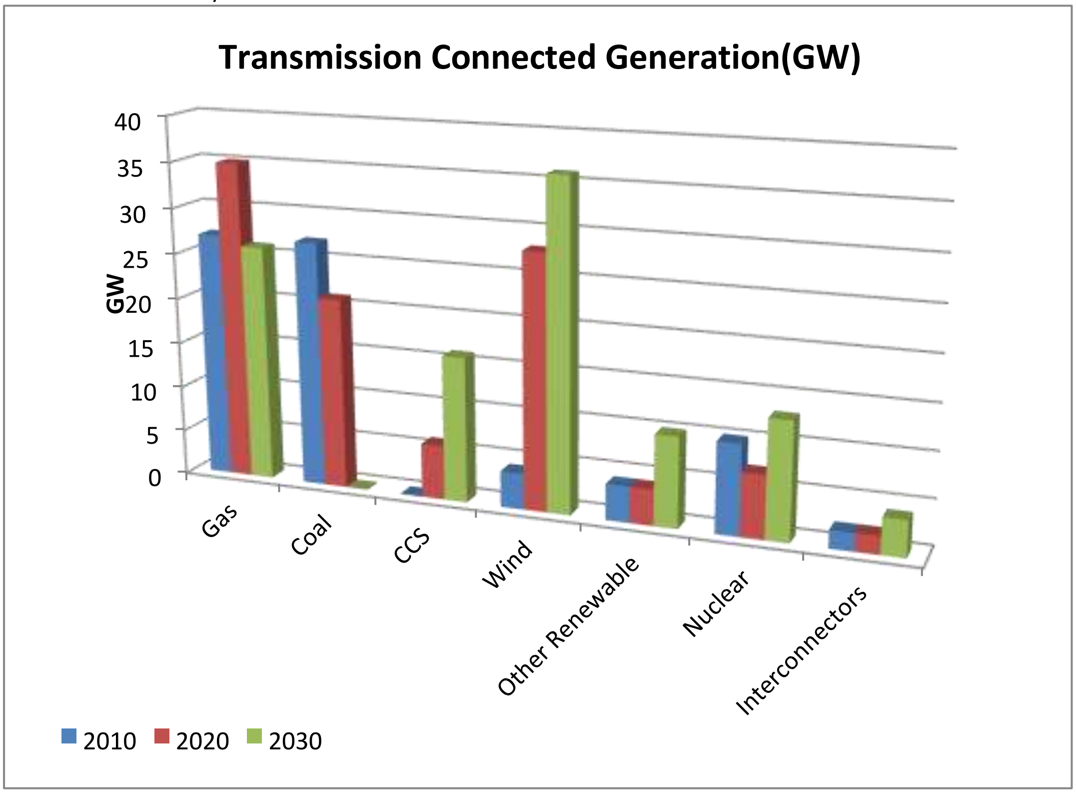


Figure 6.1 The changing generation mix from 2010 to 2030[1]

In this chapter, a wide investigation is carried out and the possibilities offered by a nationwide demand response in the form of smart appliances are evaluated. The particular case studies aim to investigate the potentially beneficial effects that the shifting algorithm could bring if all the 25 million UK households were fitted with the required control goal, such as demand flattening and system balancing services provision.

Generally, UK power system is a highly controlled system where the total installed generation capacity is safely above the maximum demand peak. The total generation capacity and maximum load over 1970-2012 is shown in Figure 6.2. Currently the UK has around 80GW of electricity generating capacity, which gives it a capacity margin of above 20%.

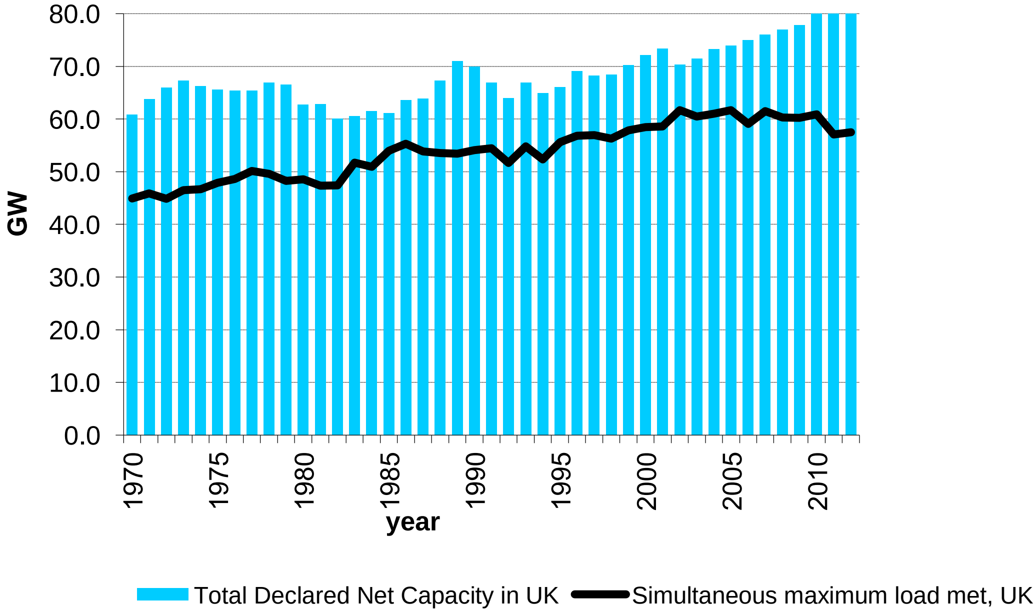


Figure 6.2 Electricity generating capacity and simultaneous maximum load met for major power producers[2]

Figure 6.3 shows the energy shares of different generation types in 2012. It can be observed that almost two-thirds of the electricity is generated from gas and coal while one–third from other fuel sources such as nuclear, renewable and oil engines. Even with the increase of renewable generation and nuclear power integrating into the network, electricity generated from conventional fossil fuel power stations still dominates the electrical energy production, which produces significantly large amount of carbon dioxide emissions, especially as peak load power plants[3].Therefore, the impact on carbon emission with DSM will also be studied in this chapter. In addition, the economic and operational impact of DSM is quantified and supported by evaluating several case studies.

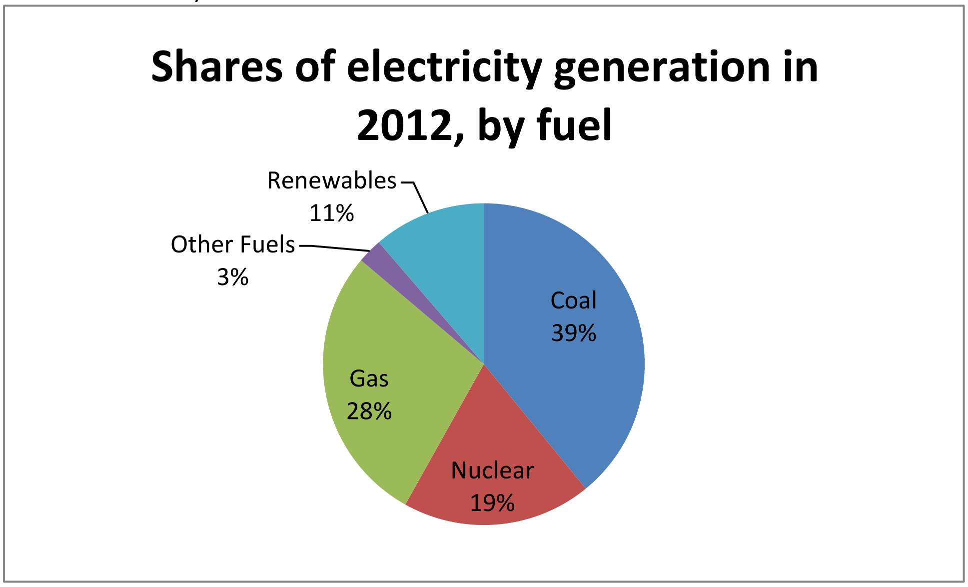


Figure 6.3 Shares of electricity generation in 2012, by fuel

Due to data availability reasons, the case studies on this thesis use data from year 2012. Figure 6.4 shows the actual Load Duration Curve of UK power system with the historic data available on the National Grid website[4].

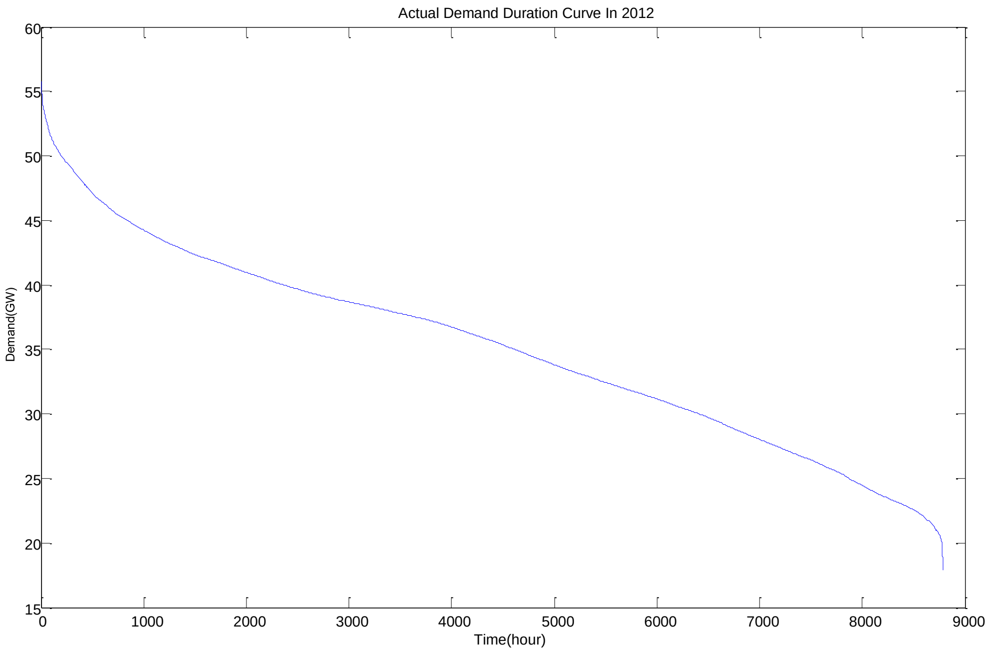


Figure 6.4 Actual demand duration curve in 2012

6.2 UK Demand Model

6.2.1 Annual Demand Profile

The month average data used in the case studies are provided by Brattle Group[5, 6]. The data below represents the monthly behaviour of weekday and weekend in the year 2012, as shown in Figure 6.5 and Figure 6.6 respectively. If daily actual values over the whole year are considered, data manipulation and required computational efforts make the calculation difficult to handle. Therefore, the usage of month average data makes the problem easier with minor impact on accuracy. The annual load duration curve is depicted as Figure 6.7 .

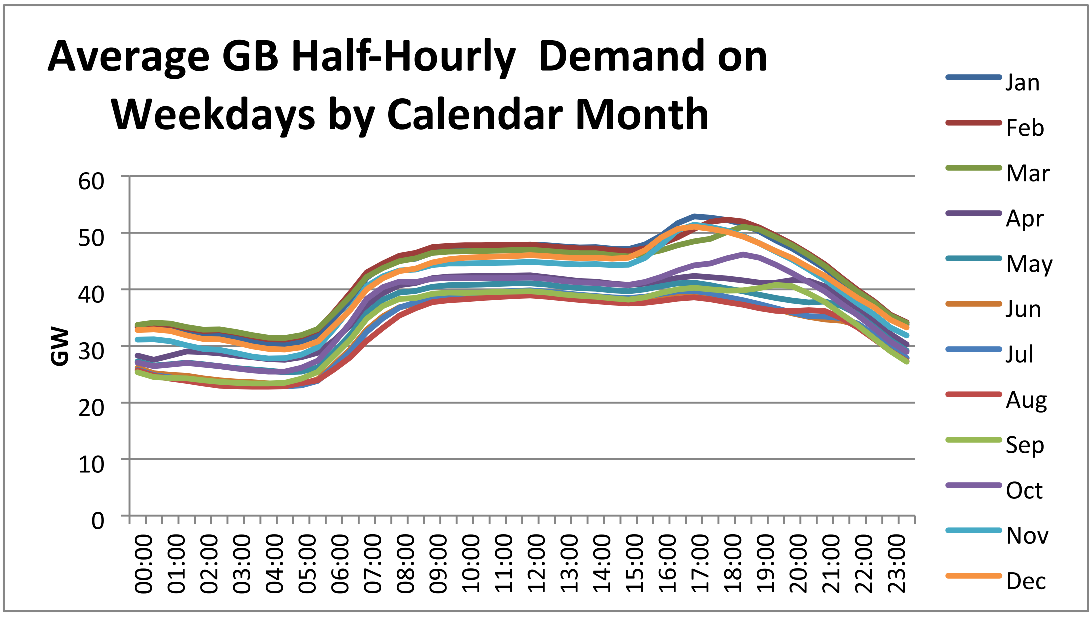


Figure 6.5 Average GB Half-Hourly Demand on Weekdays by Calendar Month

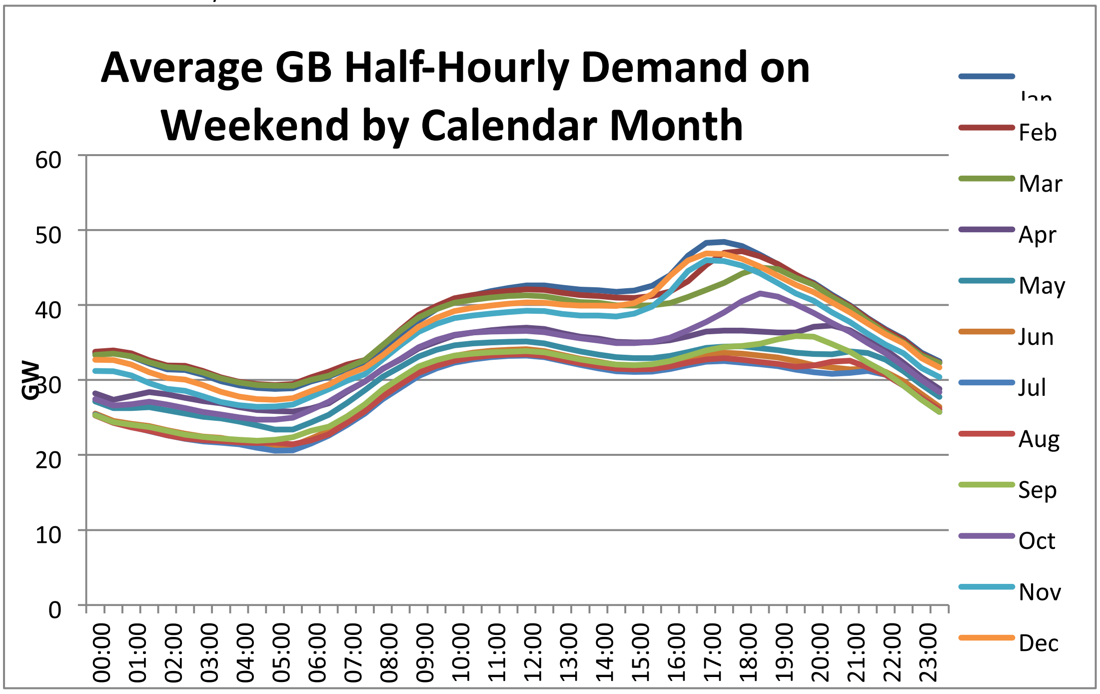


Figure 6.6 Average GB Half-Hourly Demand on Weekend by Calendar Month

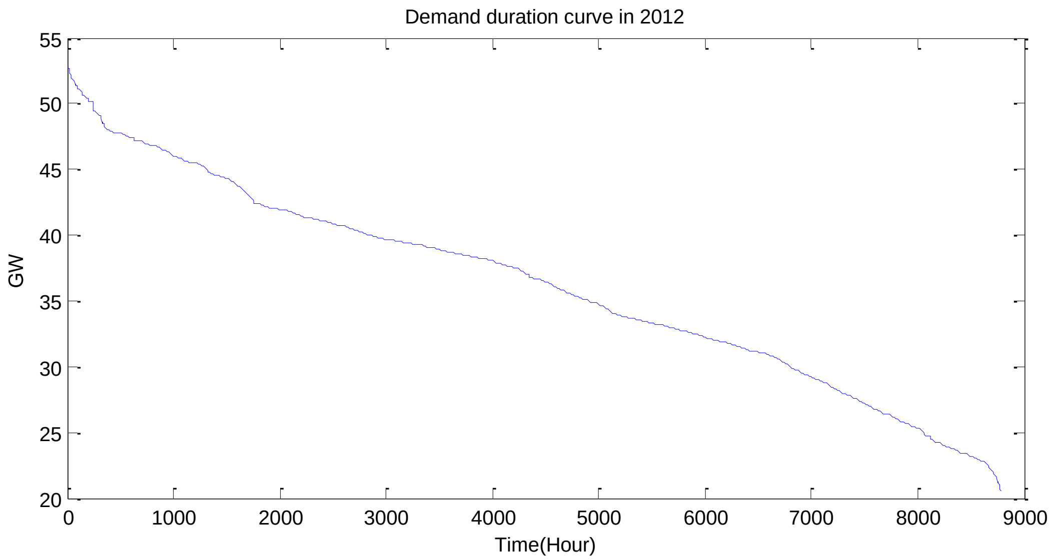


Figure 6.7 Demand duration curve

6.2.2 Estimation of Smart Appliance behaviours

As mentioned in chapter 5, the original number of appliances to be connected to the network for each type in each time step can be predicted by historical data collected from the user side modules or by pre-setting information from the user side before the start of load control. As the task of obtaining real world data from distribution network is hard, the expected number of available smart appliances can be estimated from the diversified load curve and consumption cycle pattern, using the methodology proposed in [7]. The diversified load curve and consumption cycle pattern for each type of appliance can be obtained with the data published in [8].The formula for estimating the expected number of available appliances may be expressed as below:

$$C_t = \sum_{k=1}^{d} D_{t-(k-1)} \cdot p_k \tag{6.1}$$

D_t is the number of appliance starting their consumption at time step t, which is an unknown. The power value C_t for each time step can be obtained from diversified load curve, which is composed of the demand of the appliances starting their operation at time step t and the demand of appliances starting their operation ahead time step t; d represents the duration of the device load consumption pattern and $p_k(k=1,2,\ldots,d)$ is the device consumption at each time step of the operation cycle.

6.3 Parameters for Evaluating impacts of Demand Response for Demand Flattening Purpose

6.3.1 Energy Cost

The calculation of cost of energy has to be based on electricity price forecasts. Therefore, proper price model is needed for assessing the economic impact of demand response. Figure 6.8 shows a typical electricity price curve in an electricity market.

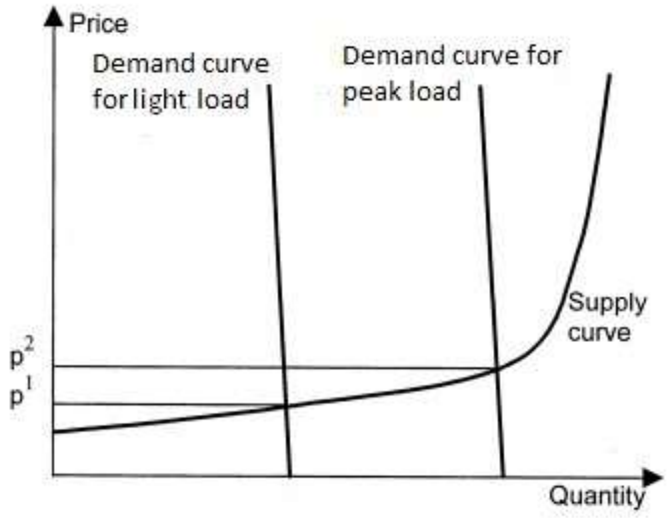


Figure 6.8 Typical supply and demand curves for electrical energy[13]

While most of the capacity is offered within a relatively narrow price band, the price for the most expensive generation increases sharply. Since the demand for electricity is cyclical, there is not a single demand curve. In fact, the demand curve shifts from left to right depending on the time of day and day of the week. Two representative curves are shown. The one on the left corresponds to light load conditions and the one on the right to peak load conditions [13]. p_1 and p_2 correspond to the intersections between supply curve and demand curves . The electricity price is mainly controlled by the generation curve in a market where the demand curve shows inelastic behaviour.

In this work, the electricity wholesale price is extracted from curves fitted to typical data from the UK balancing mechanism[14]. The system buy prices (SBP) are tabulated against the actual system demand over 12 representative days during 2012 in Figure 6.9, which included times when demand approached the supply capacity.

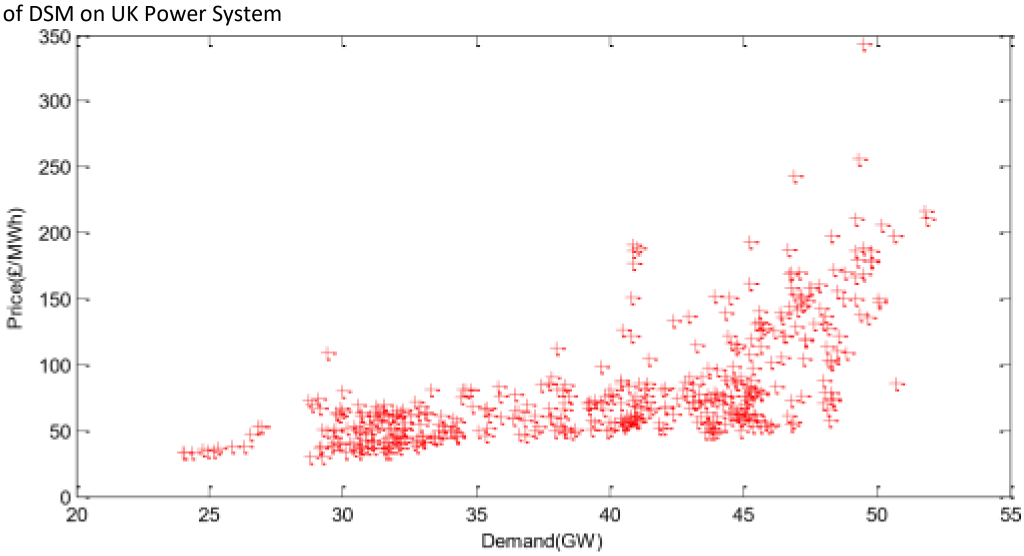


Figure 6.9 Wholesale prices in typical days

The pricing model is a curve fitted to these data. The first step is to normalise the demand with value □□, which rises to unity as demand approaches the supply capacity. Factor □ is formulated as (6.2), which accounts for the capacity of the largest generator in the system. When demand is close enough to the total generation capacity, the power must be purchased from the largest single generator in order to avoid a shortfall. Then, it becomes pivotal in the marketplace and the price rises rapidly as system supply security is decreased[15].

$$\alpha = \frac{Demand}{\text{Supply capacity} - \text{Biggest generator capacity}} \qquad (6.2)$$

The price curve can then be created using (6.3), where A, B and C are fitted coefficients, and the price is with the unit *£/MWh*. The price curve is capped at £1000/*MWh.*

$$Price = Ae^{B\alpha} + C \qquad (6.3)$$

The price curve derived from the available data is expressed as (6.4) and depicted as Figure 6.10.

$$Price = 0.005853 * e^{15.08\alpha} + 50.25 \qquad (6.4)$$

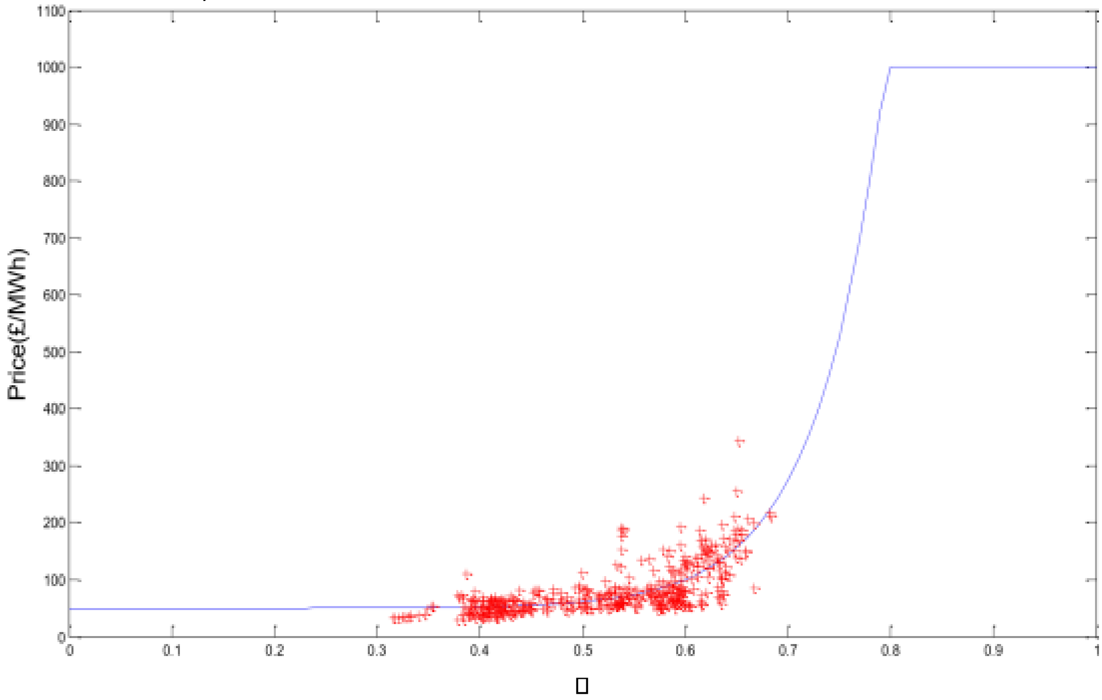


Figure 6.10 Wholesale price model, based upon System Buy Price (SBP)

Thus, the cost of energy can be expressed as (6.5):

$$Cost = \sum_{t=1}^{T}(price_t \times load_t) \tag{6.5}$$

where $price_t$ is the price at time step t which can be estimated by the pricing model, $load_t$ is the demand at time step t. As an example, the wholesale price based on the monthly average demand on weekday in January can be calculated and depicted as Figure 6.12.

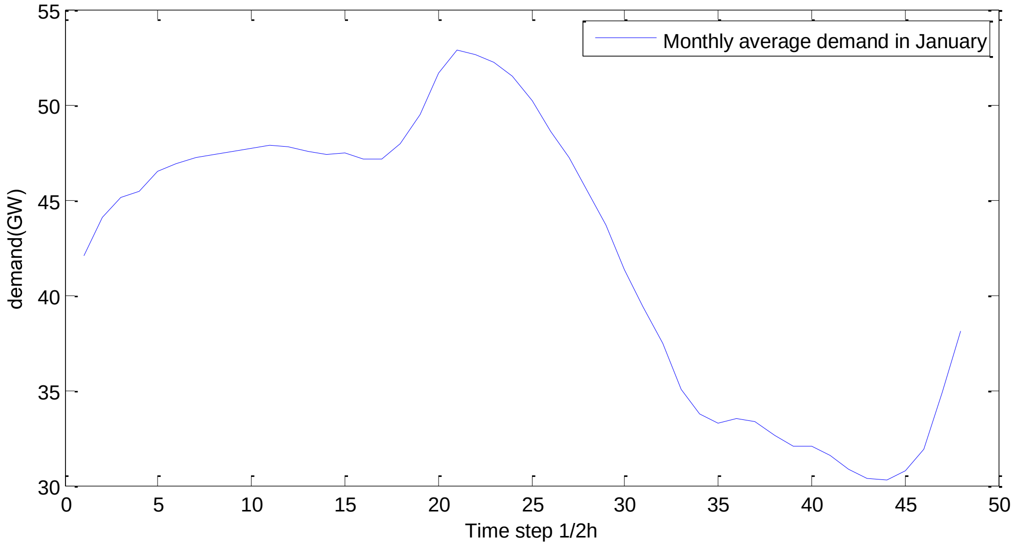


Figure 6.11 Monthly Average Demand on weekday in January

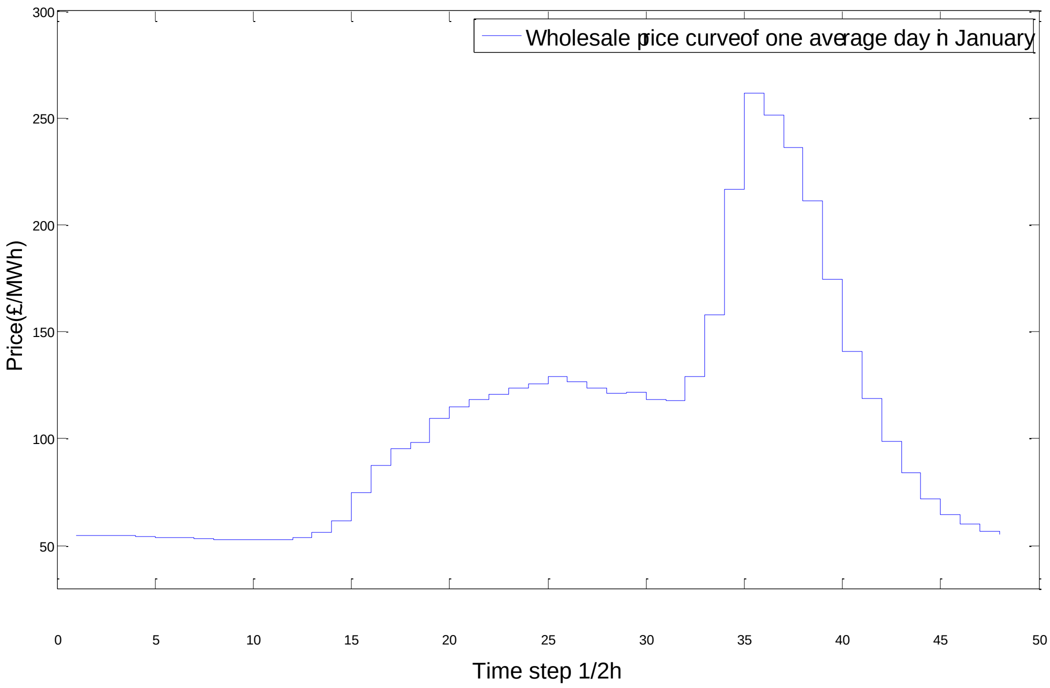


Figure 6.12 Wholesale price curve of one average weekday in January

The daily energy cost on one average weekday in January can be calculated as:

$$Cost_{Jan\_average\_weekday} = \sum_{t=1}^{48}(price_t \times load_t) = 1.1573 \times 10^8 £ \qquad (6.6)$$

The annual energy cost can be extrapolated with the average monthly weekday and weekend data among 12 months.

6.3.2 Carbon Emission

More recently, concern over the potential impact of global warming and greenhouse gas emission is forcing greater changes. As governments around the world tried to introduce a way to reduce greenhouse emission, a series of intensive global negotiations were conducted, in which more than 160 nations took part, culminating in the Kyoto Protocol in 1997. Carbon dioxide (CO_2) is the main greenhouse gas, accounting for about 83 percent of total UK greenhouse gas emissions. Electricity power generation emissions represent a significant contribution to overall emissions. Therefore, the impact of demand response in terms of greenhouse gas emission reduction is also studied. The demand response with objectives of demand flattening can reduce the connection hour of peaking plants of which are highly pollutant, such as high cost gas combustion turbine, steam plants and oil-fire plants. What‘s more, the objective of DSM algorithm can be set to maximise the utilisation of renewable energy which can further decrease the occupation of highly pollutant fossil fuel plants.

Table 6.1

Carbon emissions from different generation technologies[9]

Type of generation technology	Carbon emission(gCO_2eq/KWh)

Coal	810
Gas	410
Biomass	80
PV	58
Marine	50
Hydro	10
Wind	5
Nuclear	5

6.3.3 Cost of New Generation Capacity Investment:

Another potential advantage of DSM is to lessen the need for building new power plants and network reinforcement. This will result in savings on the capital costs of building new power plants and transmission network assets. The capacity margin is an important index to evaluate the security of supply. It is defined as the level by which available electricity generation capacity exceeds the maximum expected level of demand. It is normally expressed as the percentage calculated by:

$$capacity\ margin(\%) = \frac{total\ avalable\ capacity - peak\ demand}{peak\ demand} \times 100 \qquad (6.7)$$

Traditionally, total available capacity was taken as the sum of full theoretical or _nameplate‘ capacities of all power plants in the network. The capacity margin calculated with the above equation is now referred to as _gross capacity margin‘. However, with the increasing penetration of variable renewable resources, where average output is considerably lower than their full rated nameplate capacity, an alternative capacity margin measure _de-rated capacity margin‘ is increasingly preferable. With this indicator, the nameplate capacity of each generation type is _derated‘ by a de-rating factor which derived from the analysis of the historical availability performance of the different generating technologies[10]. The winter availability of different generating technologies is listed in Table 6.2. In this thesis, the de-rated capacity margin is used to indicate the potential generation capacity investment reduction due to DSM.

Table 6.2

Generation availability[11]

Type of plant	Winter Availability
Coal/Biomass	87%
Gas CCGT/Gas CHP	86%
Gas OCGT	77%
Nuclear	83%
Wind	20-22%

The capital cost, which includes the cost of building the power plant and connecting it to the grid including any network reinforcement, is one of the major costs of investing electricity generation. Table 6.3 shows the capital cost of different type of generation.

Table 6.3

Capital cost of power plants[12]

Type of Plant	Capital cost,£/kW
Gas	400
Coal	800

Nuclear	1770
Wind-onshore	800
Wind-offshore	1330

6.4 Case Studies

6.4.1 Case Study 1: DSM for Demand Flattening

In this case study, the primary objective is to reduce the peak demand and fill the valley. On a typical day, valley of the load consumption curve will be before the peak hours. If the load control window is from 0 to 24 h, only the cold appliance can be shifted to the valley hours and wet appliances cannot be shifted to valley hours. Therefore, load control period is set from 7th hour of current day to 7th hour of the following day, which compromises the control of both types of appliances and helps to better understand the effect of DSM. The appliances in all households are assumed to be involved in the DSM programme for investigating the impact of overall system demand response. The other information is tabulated in Table 6.4.

Table 6.4

Base information of smart appliances participated in the case studies

Appliance Type	Washing Machine	Tumble Dryer	Dishwasher	Refrigerator	Freezer
Maximum Control Allowance	3h	3h	3h	1.5h	1.5h
Total number of devices	23.75millions	13.25 millions	7 millions	25 millions	10millions

The monthly average demand data is used and the price of each time step is obtained from the price model demonstrated in 6.3.Figure 6.13 -Figure 6.16 show the average monthly domestic demand curves, representing the weekday and weekend in each calendar month over 2012. For each month, two load curves are plotted: the original domestic demand curve without load control which is used as forecasted demand curve (shown as dashed lines), obtained final domestic demand curve after load control with proposed algorithm (shown as solid lines).As seen from the results, the peak demand reduction in the domestic sector is significant with the proposed algorithm.

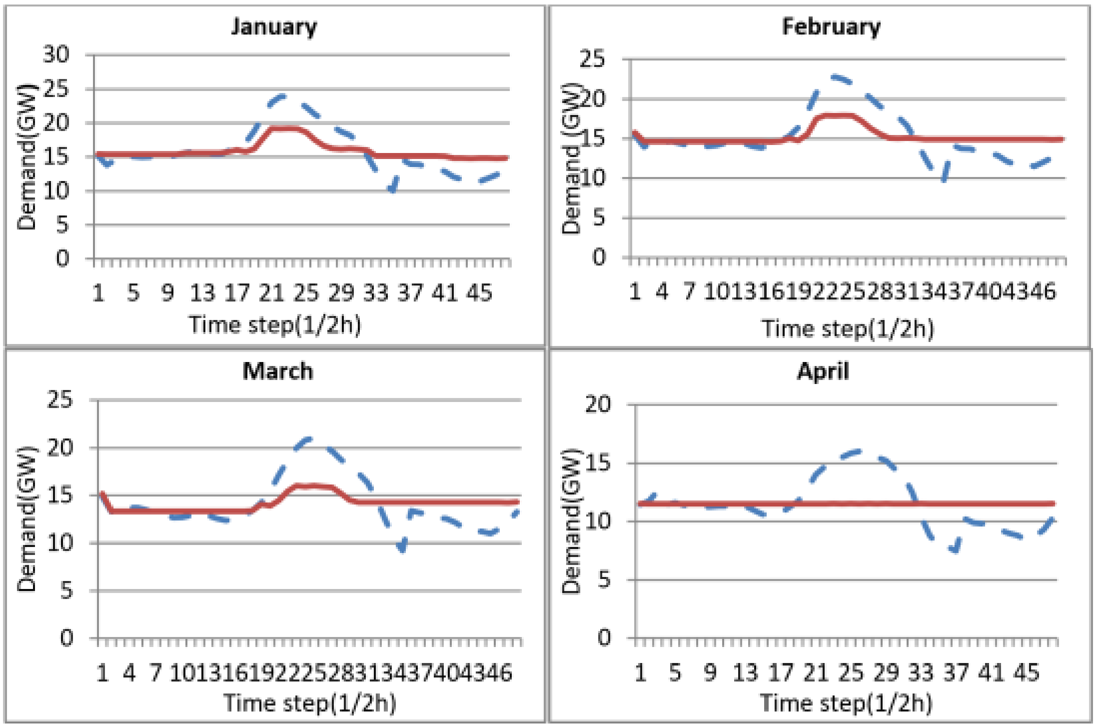
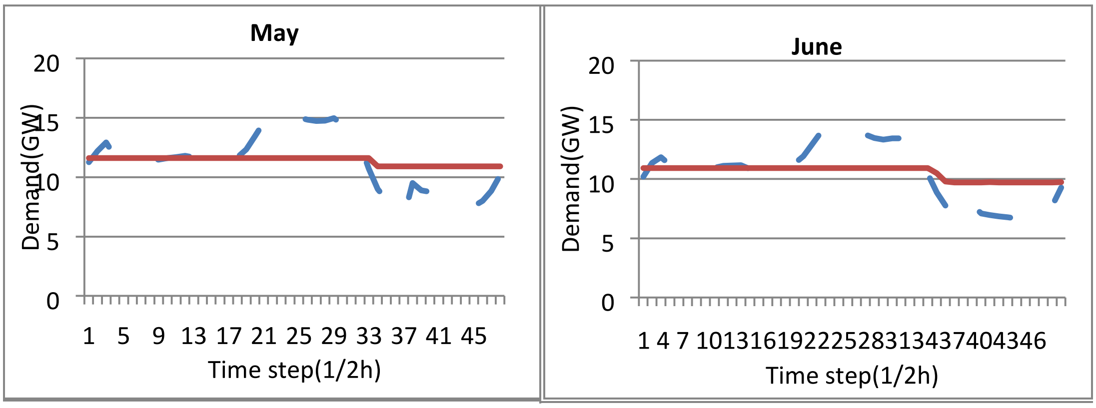


Figure 6.13 Forecast and final domestic load curves on the weekday (January – April)



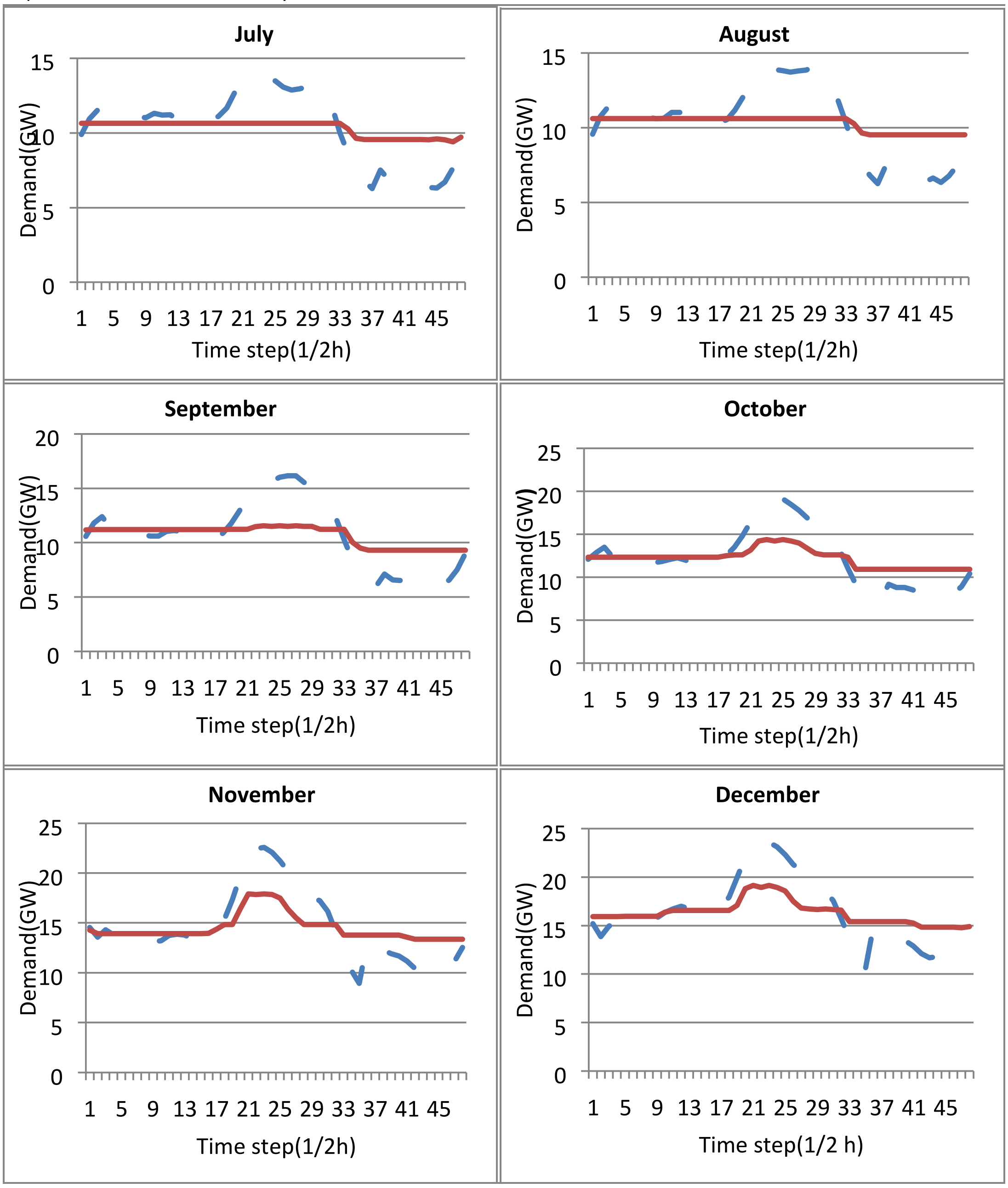


Figure 6.14 Forecast and final domestic load curves on the weekday (May-December)

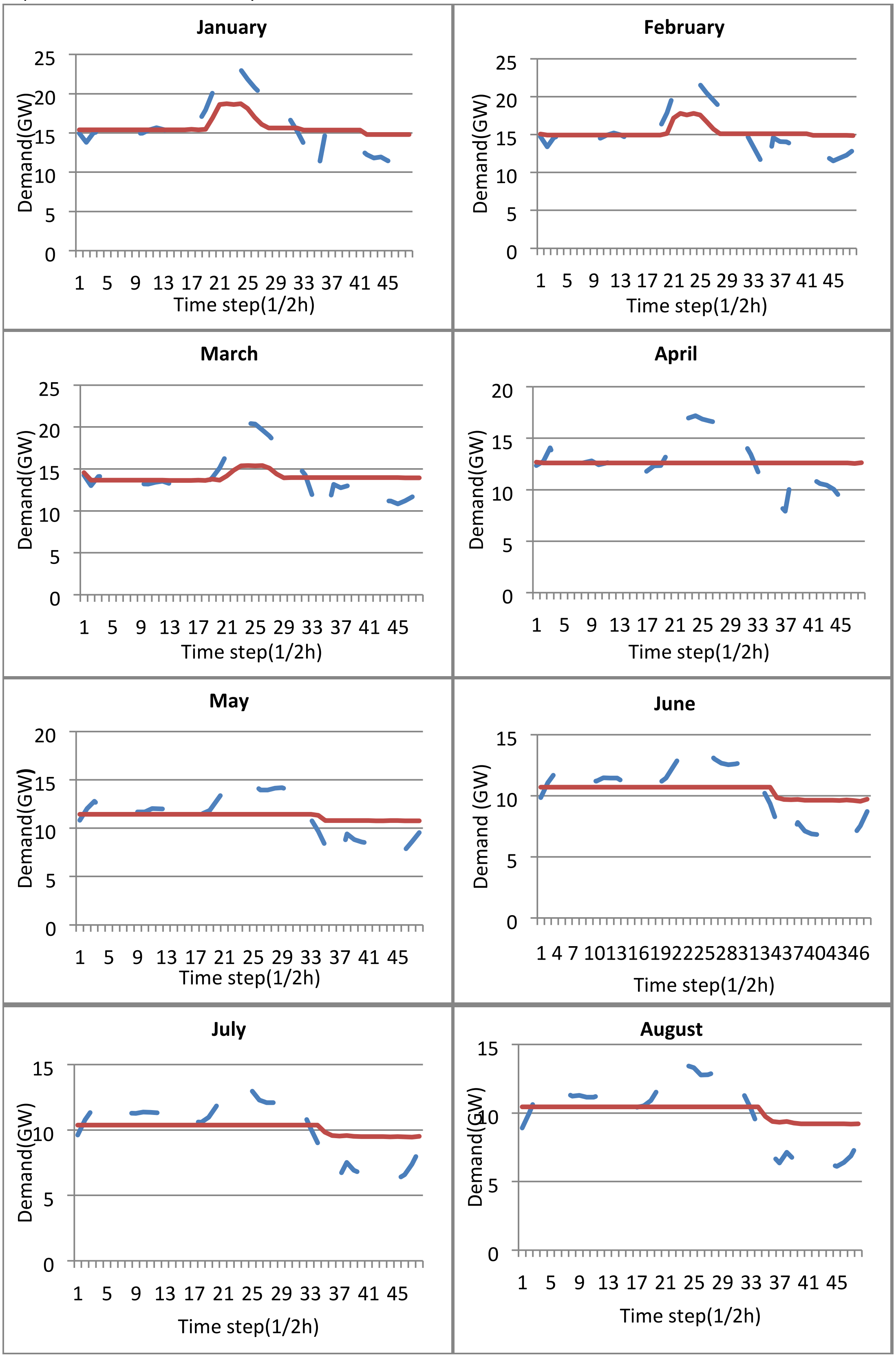


Figure 6.15 Forecast and final domestic load curves on the weekend (January-August)

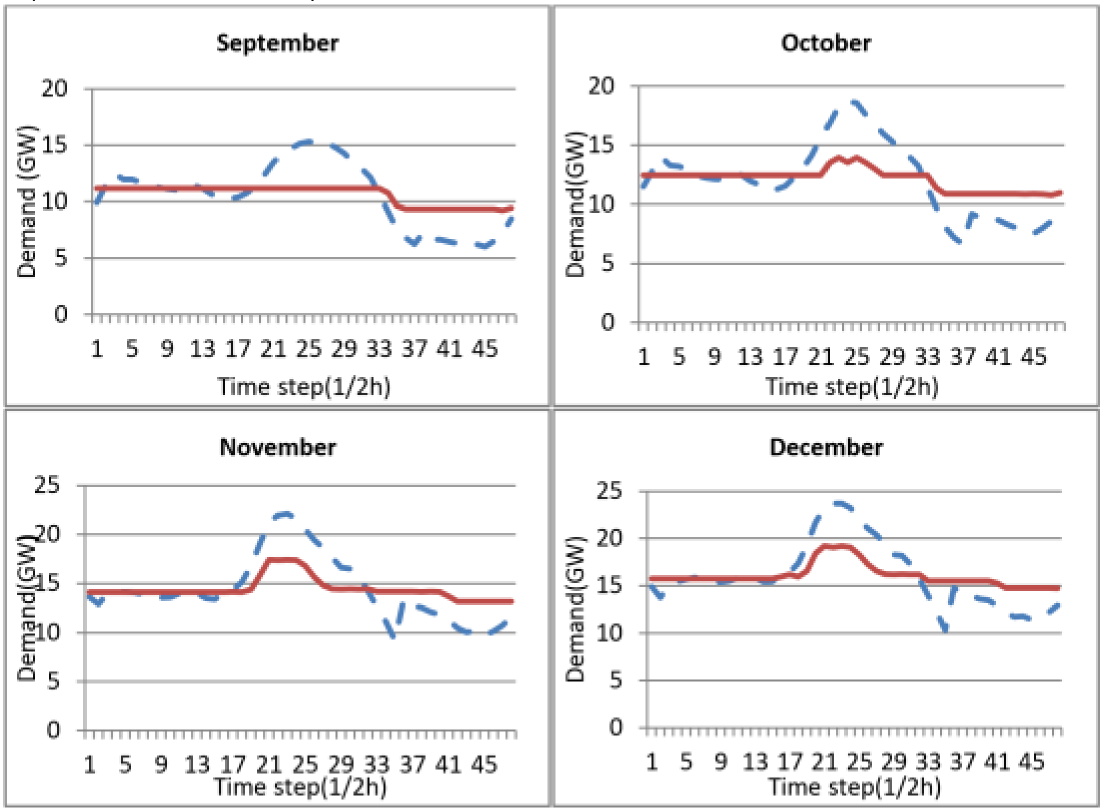


Figure 6.16 Forecast and final domestic load curves on the weekend (SeptemberDecember)

Figure 6.17-Figure 6.20 below show the average monthly total demand curves, representing the weekday and weekend in each calendar month over 2012. For each month, two load curves are plotted: the overall demand curve without load control which is used as forecasted input (shown as dash line),and the obtained final overall demand curve after load control in domestic sector(shown as solid line).As seen from the results, the annual maximum peak demand decreases from 52.89 GW to 49.07 GW.

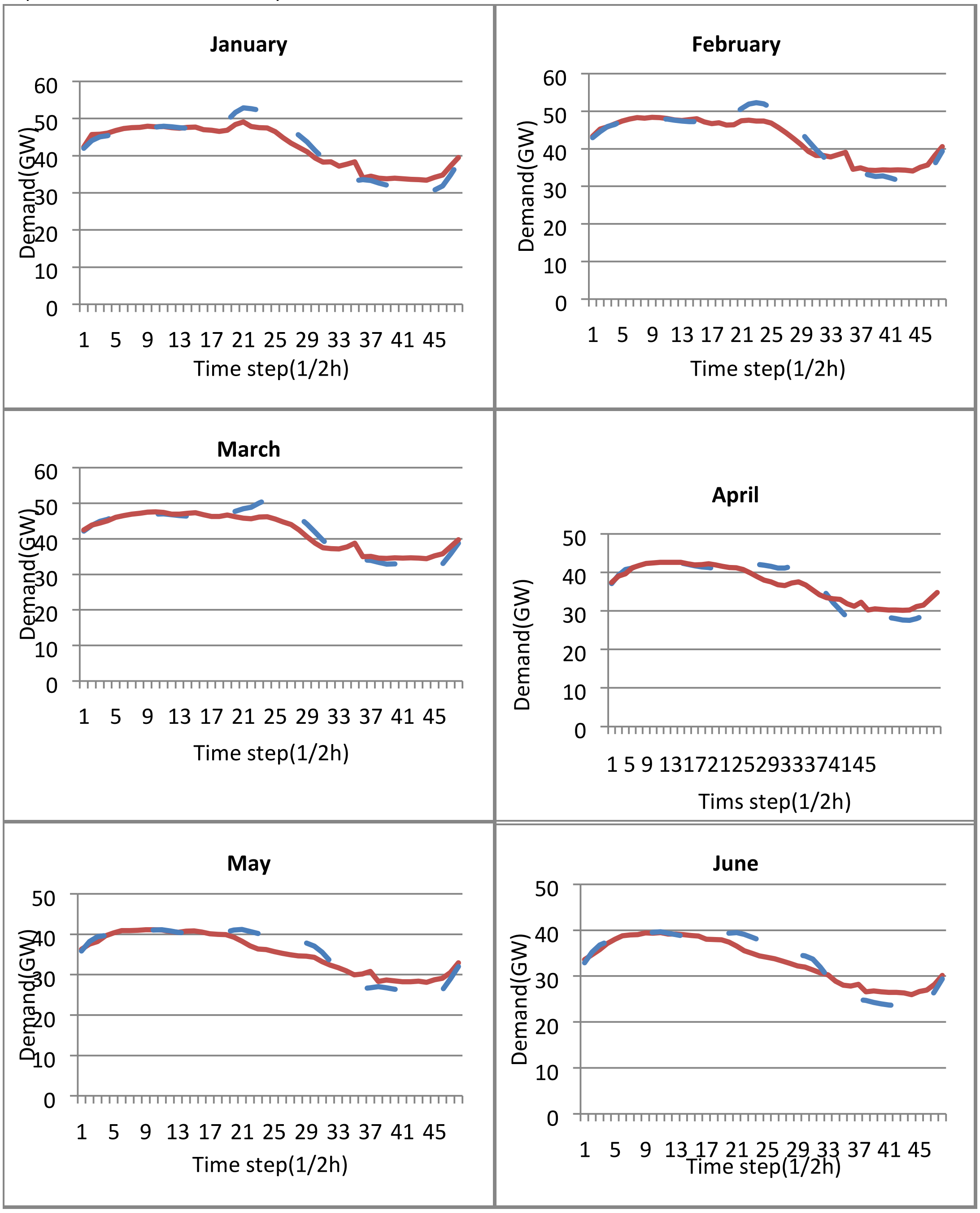


Figure 6.17 Forecast and final load curves on the weekday (January –June)

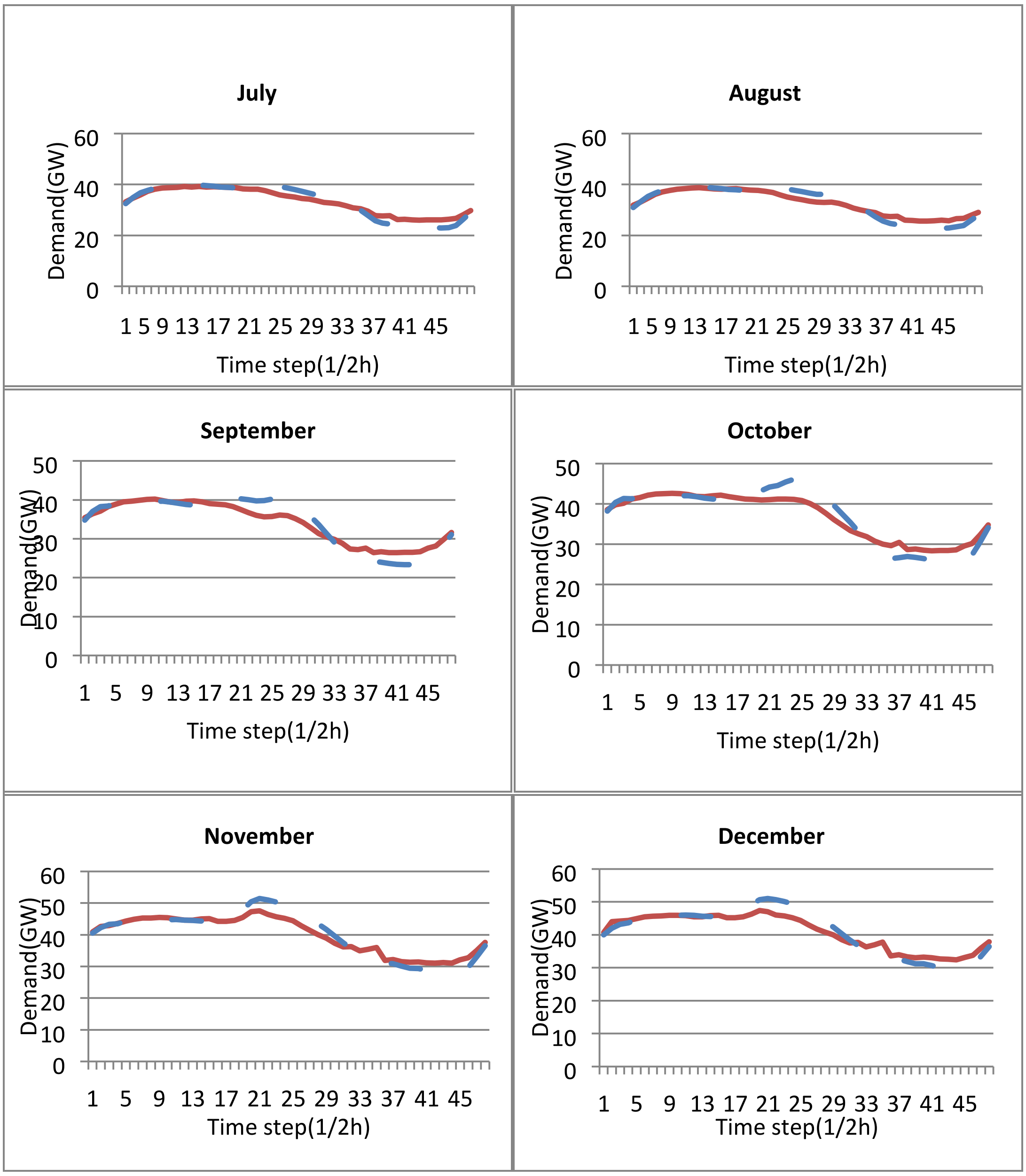


Figure 6.18 Forecast and final load curves on the weekday with monthly average data(July-December)

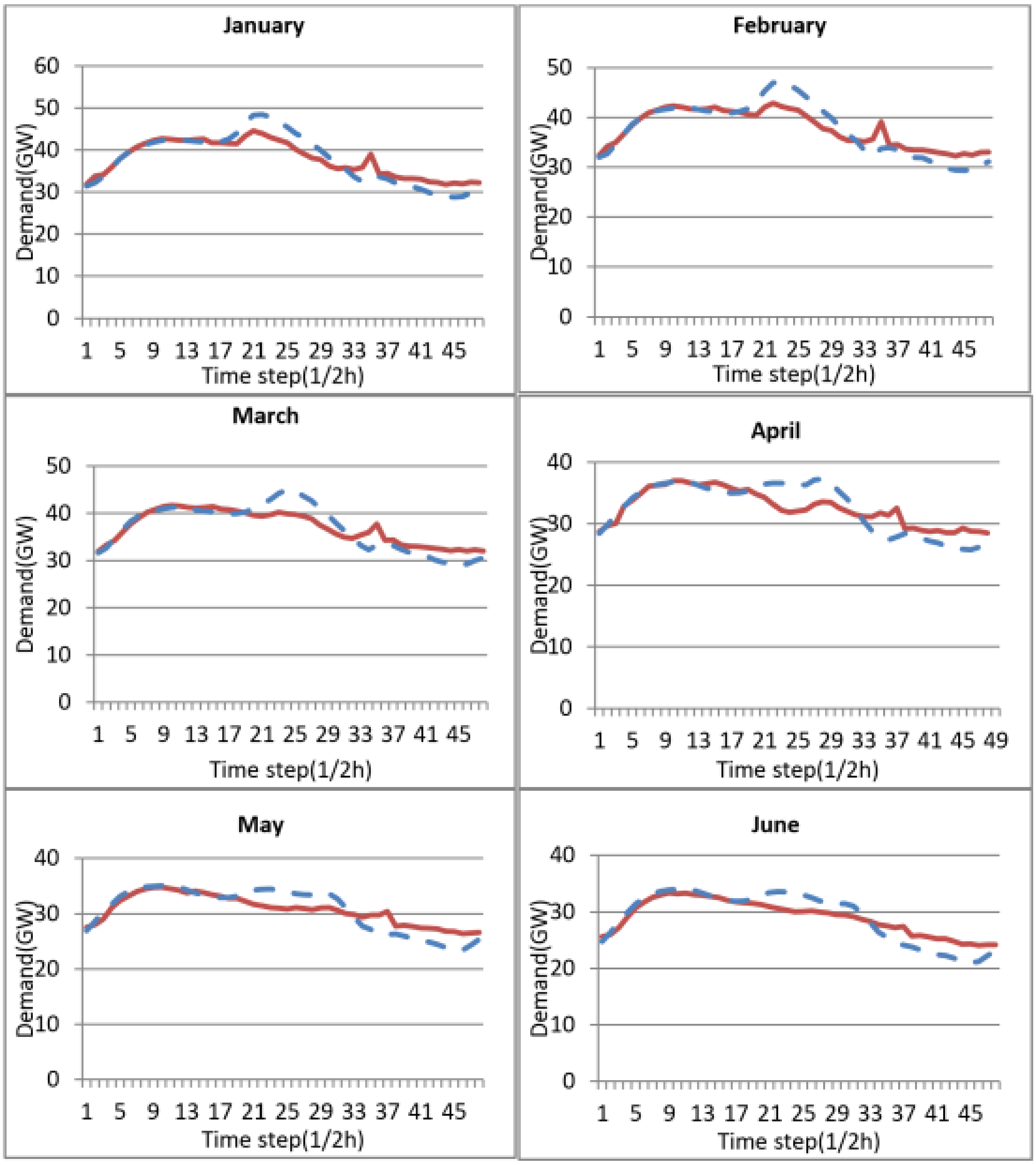


Figure 6.19 Forecast and final load curves on the weekend with monthly average data (January-June)

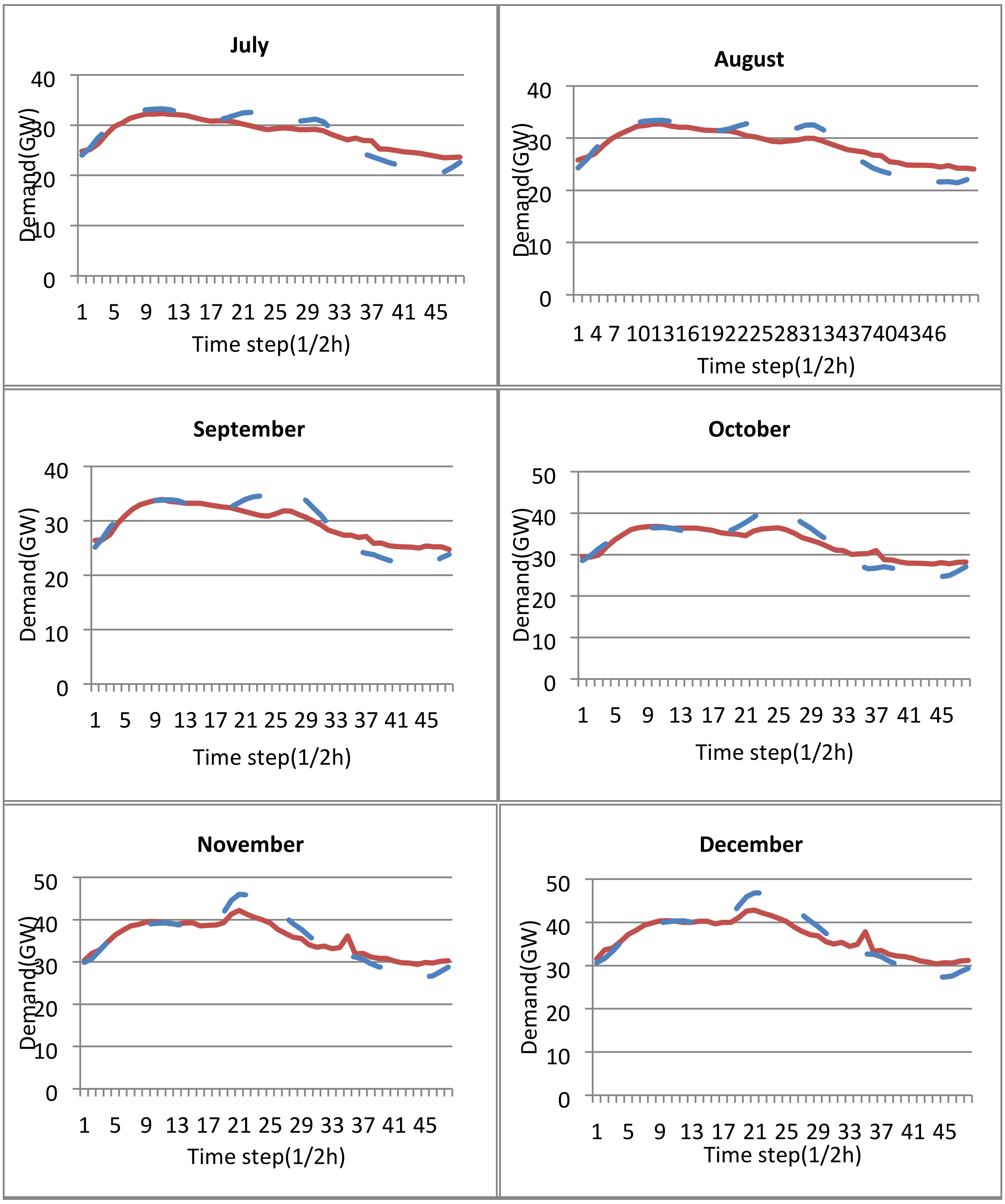


Figure 6.20 Forecasted and final load curves on the weekend with monthly average data (July-December)

The annual demand curve can be extrapolated through multiplying load curve of weekday/weekend of each calendar month by the number of corresponding day.

Figure 6.21 shows the change on the load duration curve.

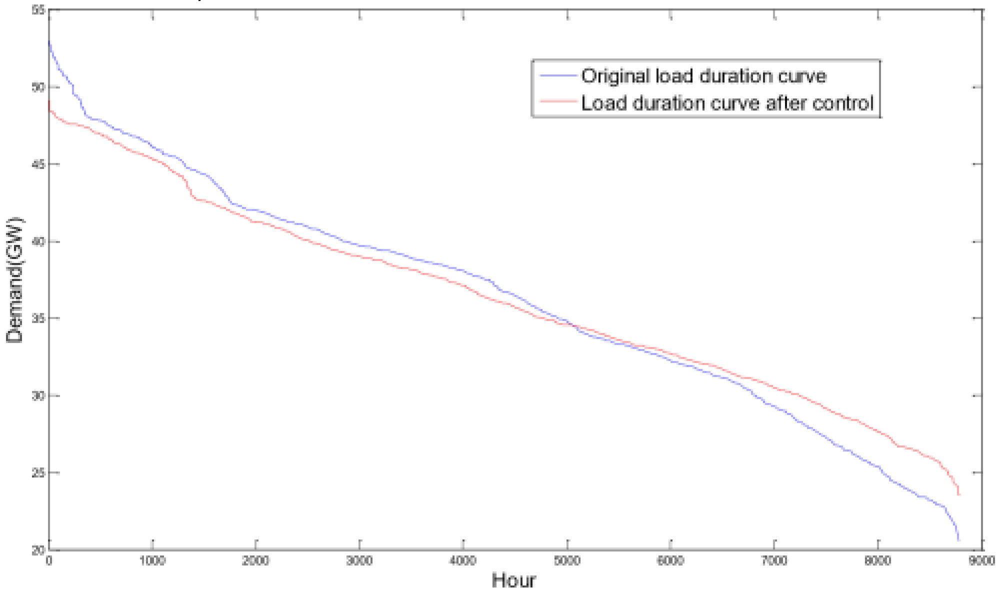


Figure 6.21 Demand duration curve

6.4.1.1Results and Discussion

6.4.1.1.1Impact on Energy Cost

The annual wholesale electricity price according to the original demand curve achieved through the pricing model in 6.3.1 is depicted in Figure 6.22 .

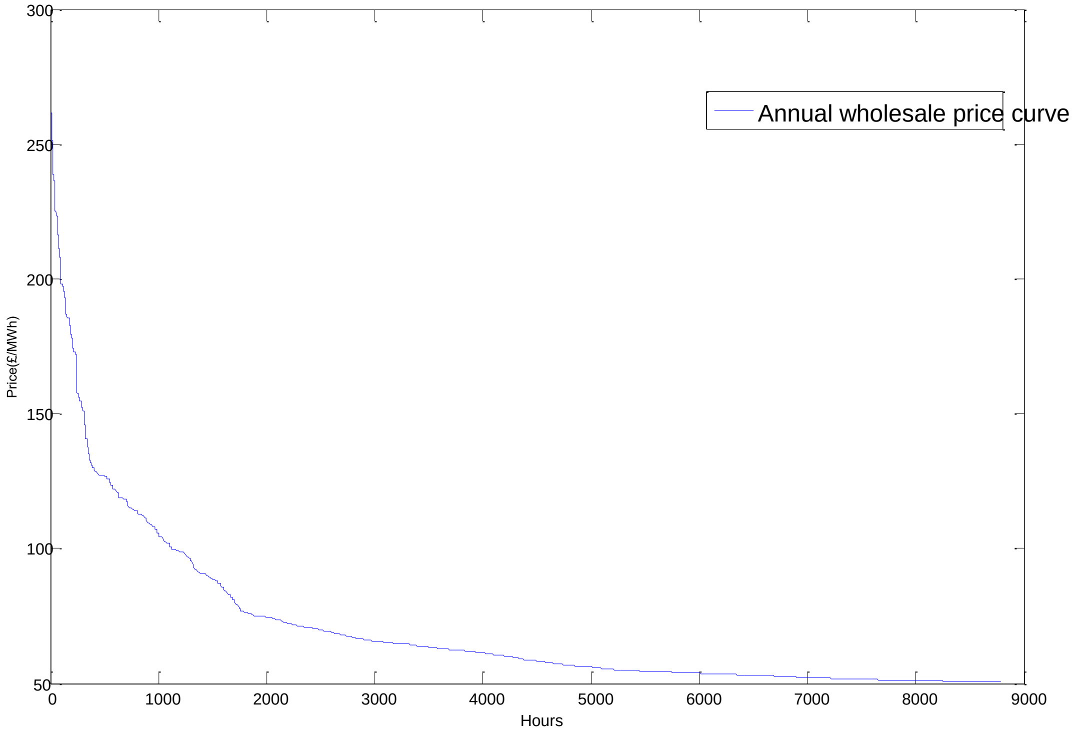


Figure 6.22 Annual wholesale price curve with original demand curve

However, it should be made aware that the demand response would result in significant modifications in the total load, which consequently affect the final wholesale price of electricity, especially when the demand is located close to the steep part of the generation curve. Therefore, the wholesale price should be adjusted with the final demand after control. Figure 6.23 depicts the wholesale electricity price adjusted with DSM in red line.

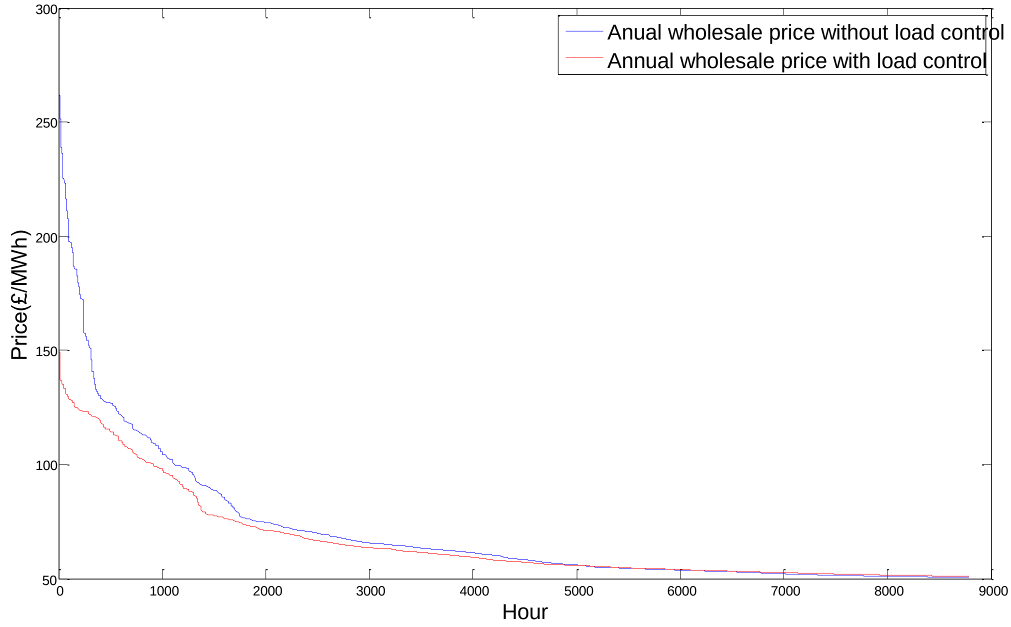


Figure 6.23 Annual wholesale price curve with demand curve(with and without load control)

Comparing the curves in Figure 6.23, it can be observed that the peak value of wholesale price decrease drastically due to the reduction of maximum demand. The impact of annual energy cost will be evaluated through two scenarios: energy cost with the wholesale price based on the original demand and energy cost with wholesale price adjusted with the demand response. Table 6.5 tabulates the annual energy cost estimated under these two scenarios.

Table 6.5 Annual energy cost

	Scenario 1:Wholesale price based on the original demand	Scenario 2:Wholesale price adjusted with the DSM
Original annual cost (without DR)(£)	$2.41*10^{10}$	
Annual energy cost(£)	$2.39*10^{10}$	$2.21*10^{10}$
Reduction of annual Cost(£)	$2.43*10^{8}$	$2.05*10^{9}$
Percentage of Cost Reduction (%)	1.01	8.51

As seen from the results, the annual energy cost reduces under both scenarios. However, the energy cost reduces more when the wholesale price adjusts with the demand change simultaneously as the reduction of peak demand can decrease the significant portion of wholesale price. It is observable that a nationwide DSM scenario where the wholesale price is fixed as the forecasted demand and not affected by the change of load is not that economically interesting and cost effective.

6.4.1.1.2 Impact on Carbon Emission

To calculate the CO_2 emission, the load duration curve is decomposed into three parts according to the amount of demand: The base load range is 32 GW and below, the intermediate load range from 32GW to 42 GW and the peak load indicate the demand above 42GW. The way in which demand was covered at each part is calculated with percentage for each generation technology, as listed in Table 6.6. The task of obtaining real-world data of demand coverage with different generation techniques is difficult, therefore the demand coverage is assigned according to the assumption in this work. Then, the carbon emissions can be estimated based on the carbon footprints of each generation technology from Table 6.1 and the amount of annual output of each generation type subsequently.

Furthermore, the amount of displaced carbon emission can be translated to cost saving with a terminology known as ―Social Cost of Carbon‖ in the UK. The social cost of carbon (SCC) measures the full cost of an incremental unit of carbon (or greenhouse gas equivalent) emitted now, calculating the full cost of the damage it imposes over the whole of its time in the atmosphere. The SCC signals how much society should be willing to pay now theoretically, to avoid the future damage caused by incremental carbon emissions. According to [16], the average SCC over the 2008 – 2020 period is estimated as £23 per tonne of CO_2 under central fossil fuel price assumption. To translate the emission levels to cost, the CO_2 emissions is multiplied by SCC and the results are tabulated in Table 6.7.

Table 6.6

Demand coverage with different generation technologies

	Peak load range	Intermediate load range	Base load range
Coal	45%	25%	25%
Gas	50%	30%	20%
Nuclear	0%	30%	40%
Renewable	5%	15%	15%

Table 6.7

Carbon emission results

	Not DSM	DSM actions are scheduled

Annual CO2 emission(t)	$9.581*10^7$	$9.503*10^7$
Emission reduction(t)	0	$7.77*10^5$
Percentage of reduction(%)	0	0.81
Cost of carbon emission(£)	$2.20*10^9$	$2.19*10^9$
Cost saving of carbon emission(£)	0	$1.79*10^7$

As shown in Table 6.7, with the execution of DSM, the total amount of CO_2 emission per year is decreased from $9.581*10^7$ t to $9.503*10^7$ t. The obtained reduction on carbon is a 0.81 % and corresponding saving on the cost is $1.79*10^7$£, which represents a significant improvement.

6.4.1.1.3 Impact on Power System Investment:

In 2012, the de-rated capacity margin is 14% as reported in [11] and it can be expressed as (6.8).

$$\text{derated capacity margin}(\%) = \frac{derated\ available\ capacity - peak\ demand}{peak\ demand} \times 100$$

(6.8)

With proper control of smart appliances, the maximum peak demand decreases by 3.82 GW and corresponding generation capacity investment can be deferred whilst maintaining the constant de-rated capacity margin as 2012. The possible deferral generation capacity respective to different generation technologies can be roughly estimated with the following equation:

$$G_{defer} = \frac{(Peakdemand_{old} - Peakdemand_{new}) * (1 + de\text{-}rated\ capacity\ margin)}{Generation\ availability} \quad (6.9)$$

With the data from Table 6.2 and Table 6.3 , the values of deferral investment respective to different generation techniques are listed in Table 6.8.

Table 6.8
Potential deferral generation capacity investment

	Coal	Gas(CCGT)	Nuclear	Onshore wind	Offshore wind
Possible generation capacity deferred(GW)	5.01	5.06	5.25	21.77	21.77
Investment cost reduction(10^9£)	4.01	2.02	9.29	17.42	28.95

6.4.2 Case Study 2: Demand Response for System Balancing with Wind Integration

A large increase in the quantity and proportion of electricity generated from variable renewable sources, such as wave, wind and solar power, challenges the operation and development of power systems. Wind is considered as the main renewable resource for research in this thesis. However, the intermittent nature of output from wind turbines due to weather conditions is often considered as hazardous to maintain system balance. This case study investigates ability on the demand side to provide system balancing service when a large portion of wind generation is integrated into the power system.

This case study is simulated using 25 million UK households for a 7-day timeframe in the midwinter season. This level of peak wind capacity is equal to 10.5 GW according to the data available in 2013.Thus, the generation capacity is set at 50 GW thermal plus 10.5 GW wind generation in this case.

The total wind farm generation output over the timeframe is depicted in Figure 6.24.Although total peak generation capacity is 60.5 GW, enough for UK winter peak demand, during low-wind events the thermal generation capacity of 50 GW is not sufficient. Note that transmission and distribution losses are ignored in this analysis, and that the generation capacities should be regarded as capacities available at the point of end user demand. The simulation for this baseline scenario (shown in Figure 6.24), which without DSM, clearly shows times when daily peak demand surpasses capacity (highlighted with red circles).Time step is 1/2h for Figure 6.24-Figure 6.26.

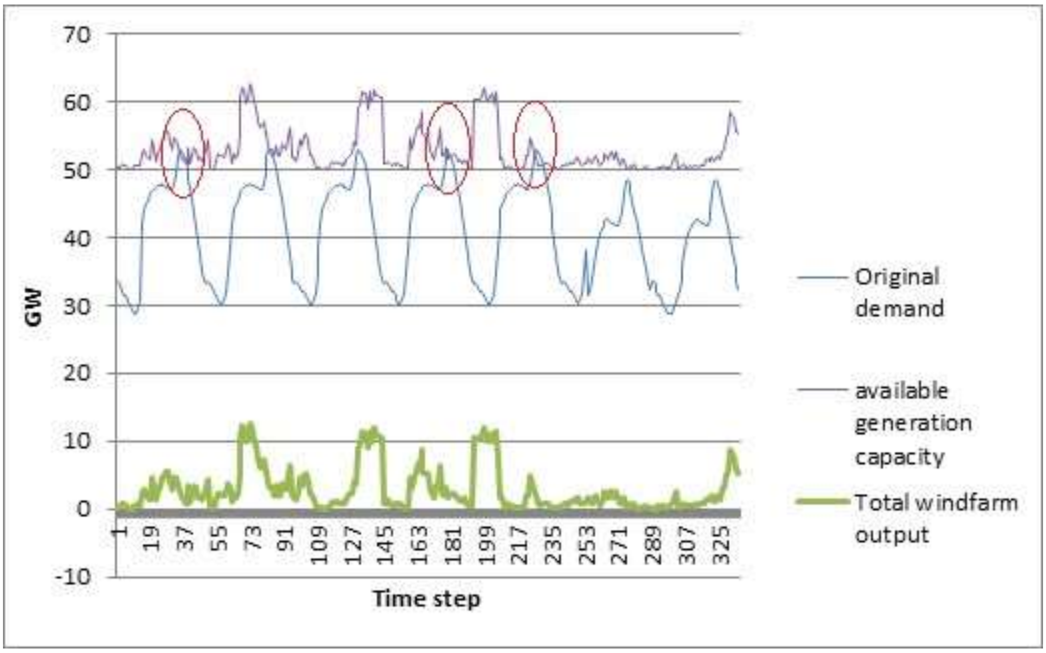


Figure 6.24 Case study 2 overview

Wholesale price is simulated as the mechanism described in section 6.3.The wholesale price for this case is depicted as Figure 6.25.

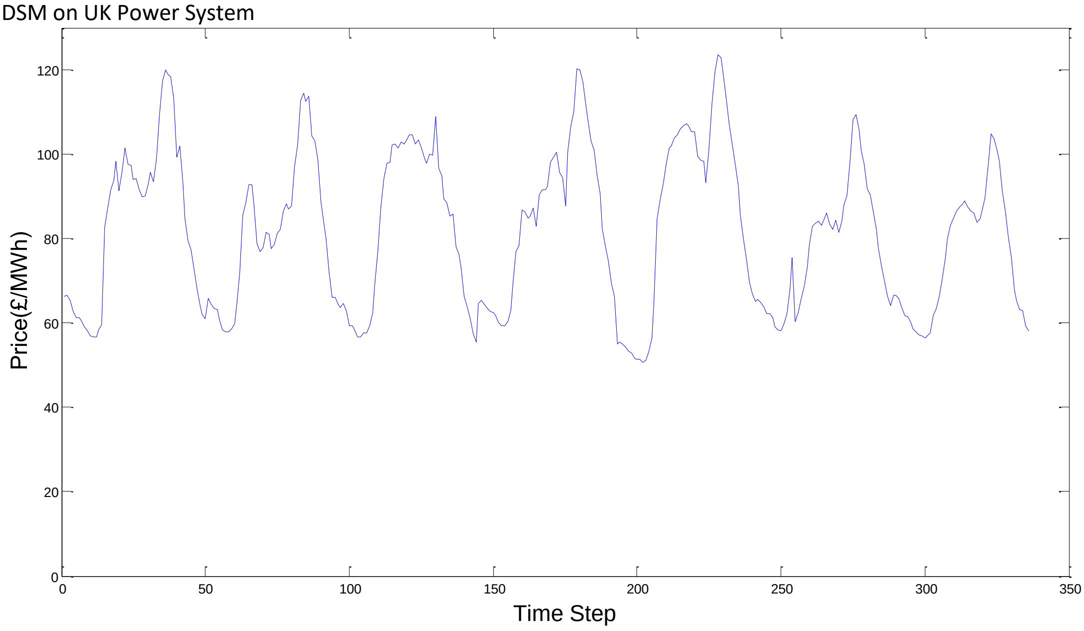


Figure 6.25 Wholesale electricity price in the base case

The effect of the demand response on overall demand profile is shown by the red line in Figure 6.26 which is driven by available generation capacity scarcity. The demand is reduced at times of peak demand. No peak demand surpluses the available generation capacity and there is no generation shortfall over the time frame.

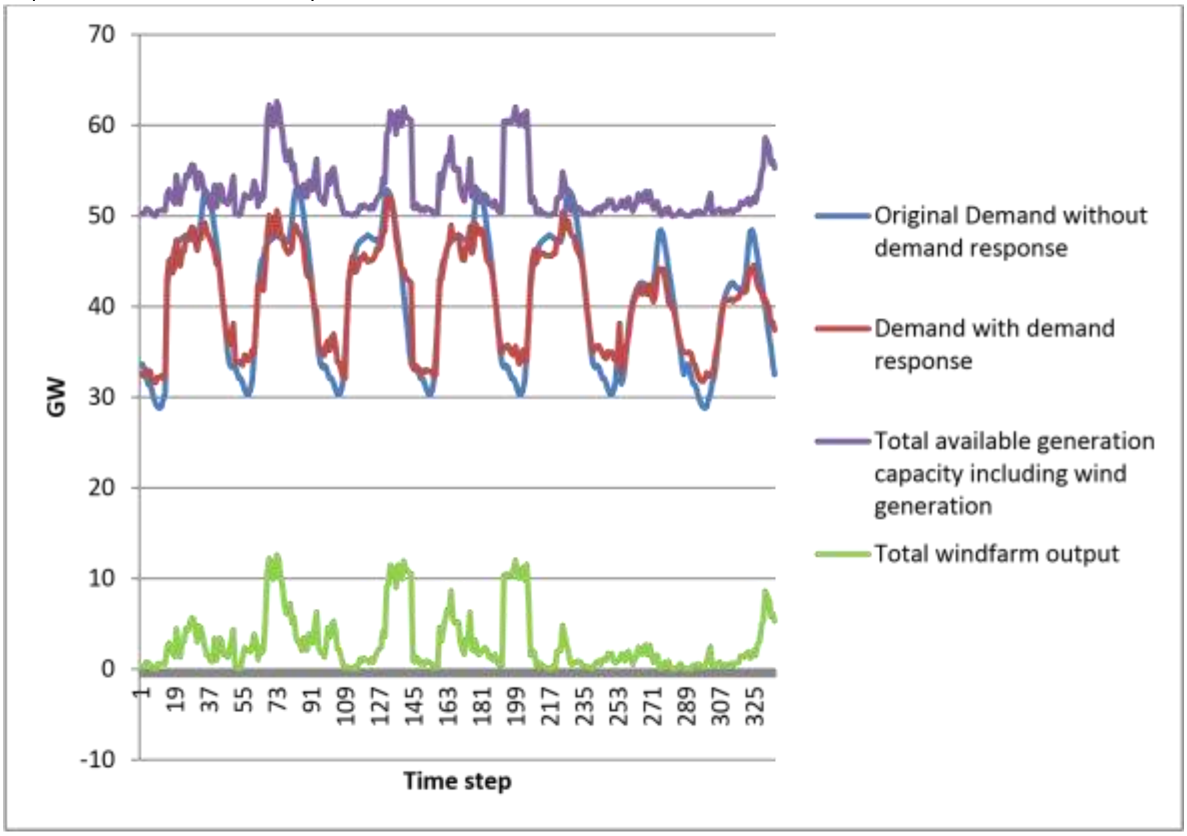


Figure 6.26 Demand curve of case study 2

6.4.2.1Results and Discussion

6.4.2.1.1 Impact on Wholesale Price:

It is observable directly from Figure 6.27 that the prices at the peak demand periods decrease significantly and the price volatility over the time frame decreases drastically.

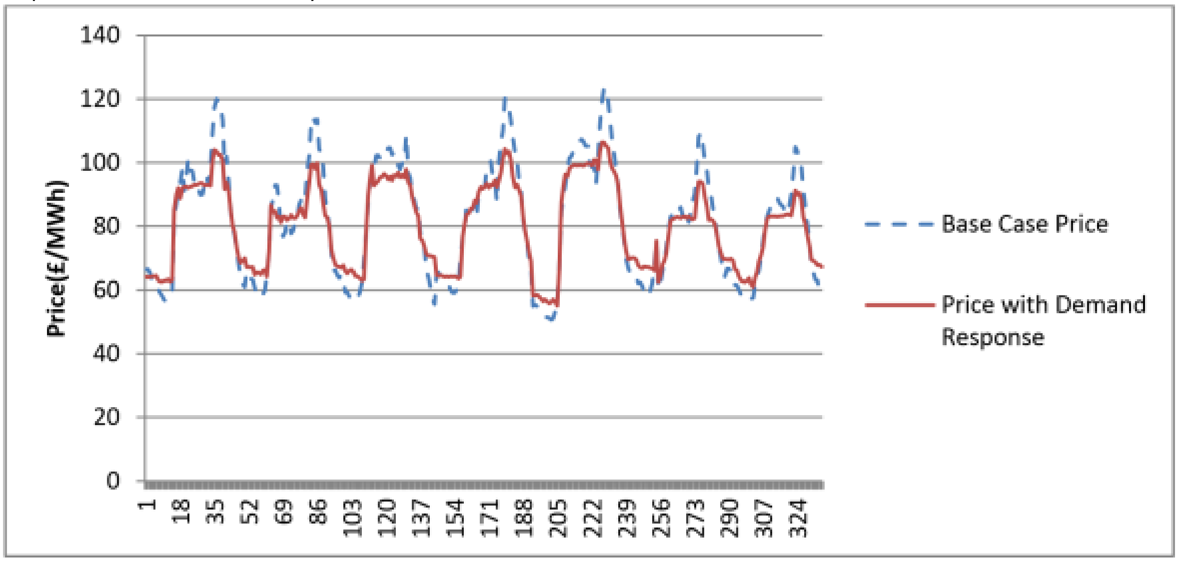


Figure 6.27 Wholesale prices in case study 2

6.4.2.1.2 Impact on Energy Cost

In this case, the wholesale price is assumed to be affected by the real-time load. It can be seen from Figure 6.28 that energy cost over the control time frame is decreased from $5.838*10^8$£ to $5.652*10^8$£ ,which means saving on the energy cost can be achieved with demand response in the form of smart appliances.

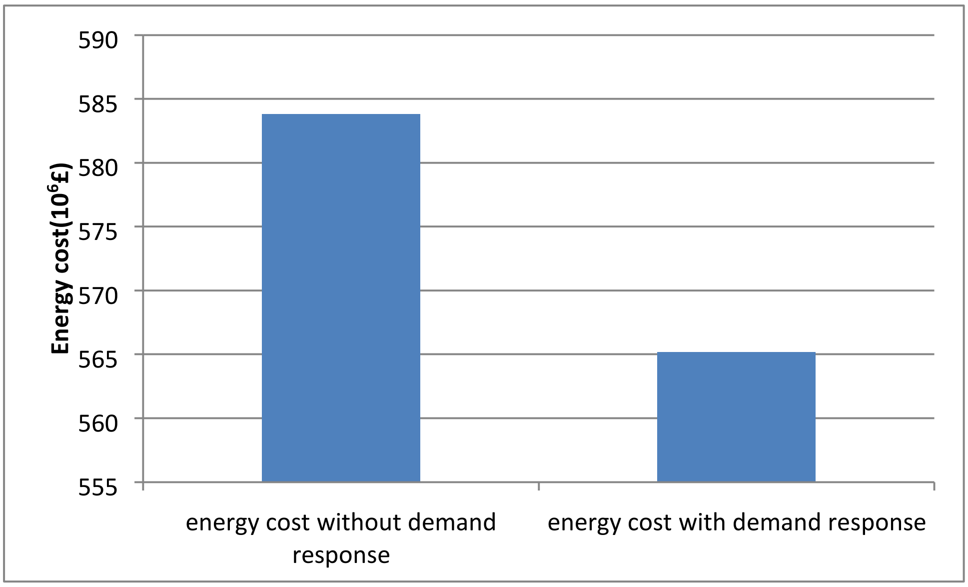


Figure 6.28 Energy costs in case study 2

6.4.2.1.3 Impact on Spinning Reserve

Both wind generation and the load exhibit variability on a minute-by-minute, hourly, and daily basis. This variability impacts the system operator‘s ability to keep generation balanced with demand, and thus a certain amount of generation must be kept available to deal with unexpected changes (i.e. the spinning reserve)[17].

In a power system, spinning reserve can be defined as the unutilized synchronized capacity which can be activated within specified time. Scheduling a sufficient level of spinning reserve in a power system is required to maintain enough available generation capacity for reliable system operation. Conventionally, the spinning reserve is usually designed to equal to a certain percentage of system load demand, the maximum tie lines capacities or maximum of committed units [18]. Since wind generation is non-dispatchable, similar to the load; from the system operator‘s perspective wind can be treated as a negative load, and thus all reserve calculations are conducted on the net load. Here, the spinning reserve requirement is set as 10% of real-time net load[18]. It is observable from the results in Figure 6.29 that the maximum spinning reserves at peak-time decreases from 5.11GW to 4.71 GW. This can be attributed to the fact that the load change can be controlled to better follow the wind generation output change, which lowers the net load at the peak time. It can also be observed that the required spinning reserve with load control is higher than that without load control due to the load shifting effect. Normally, the spinning reserve price rises near the load peak because generation is needed to serve load and thus not available as reserve. Meanwhile, there is an increase in the amount of required spinning reserve at the overnight time .However, there is ample partially loaded generation available to supply spinning reserve overnight and spinning reserve price is low. Therefore, the introduction of DSM can reduce the required spinning reserve at the peak time and thereby maintain the system reliability in a cost effective way.

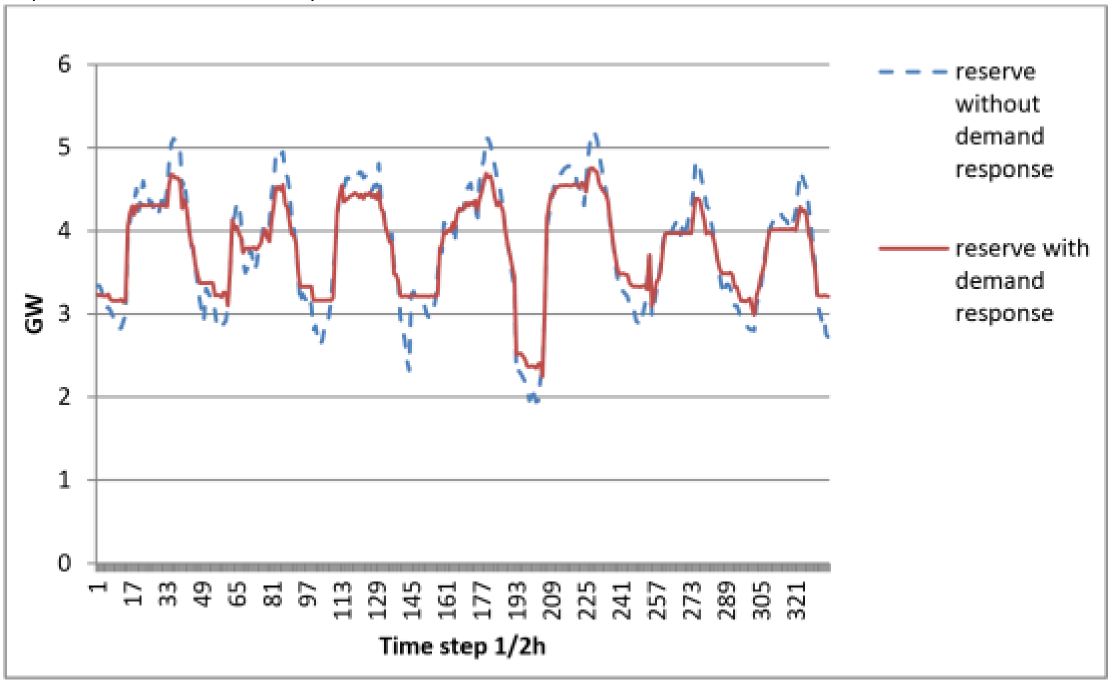


Figure 6.29 Required spinning reserve in case study 2

6.5 Summary

In this chapter, the impact of DSM in the form of smart appliance on UK power system is evaluated. The data in the year 2012 is selected for case studies. The case studies have been carried out for different purposes, such as demand flattening and system balancing .In the demand flattening case, the simulation results show that the demand response programme can reduce the peak load and fill the load valley efficiently. The economic and environmental benefits related to the demand response programme are investigated by the comparison between base case simulation results and the simulation results which includes DSM techniques in the power system. As seen from the results, reduction in the peak load demand and boost in valley load demand improves grid sustainability by reducing the overall cost and carbon emission levels. Furthermore, this leads to the avoidance of the construction of an under-utilized electrical infrastructure in terms of generation capacity.

In the system balancing case, the impacts of DSM on the power system operation have been investigated in several aspects. The results of this study illustrate the positive effects that the implementation of DSM in the power system can have on system balance provision and energy cost reduction when wind generation is integrated.

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Chapter 7 Congestion Management with DSM in the Power Network with Wind Generation Integration

7.1 Introduction

Wind availability is highly dependent on the geographical and meteorological aspects of an area and is hard to predict accurately. Installation of wind power in the network will further push the transmission tie-lines to their power transfer constraints and incur problems such as network congestion, voltage security or even voltage stability where the network is already under stress due to the uncertainty of generation and demand and power market transactions. As the congestion management method based on the existing network is designed to meet the operation criteria of power system of conventional generators, it is necessary to take characteristics of wind generators into account.

The unpredictable output of renewable generators makes it more difficult for Transmission System Operator to manage the network congestion due to possible large error in generation prediction. Hence, most TSOs in Europe have chosen to manage the congestion relative to the wind generation separately. The present method is to manage congestion in planning (e.g. day-ahead) by disconnection of generation according to the criteria ―last generation installed, first generation off‖(LIFO). In the LIFO scenario, the last connected generator will be curtailed first. The main deficiency of this approach is that limitation of generation may not be necessary because the day-ahead prediction of wind speed might be inaccurate [1].

As mentioned in the previous chapters, with the development of smart grid, DSM can be considered as a potential mean to support network congestion management and to maximise the system capacity under this circumstance. In this chapter, the efficacy of DSM in form of smart appliances to relieve the congestion in the network is investigated within the IEEE 14 node system. It is followed with measuring the impact of DSM on economic and operational parameters of power system with wind farms.

7.2 Modeling of Wind Generation System

Modeling the overall power system operation and the market behaviors requires the data of wind generation output. From various studies of wind turbine generators, it has been established that there is a non-linear relationship between the power output of wind turbine generator and the wind speed. The relation can be described by the operational parameters of wind turbine generators. Figure 7.1 shows how the power output from a wind turbine generator varies with steady wind speed

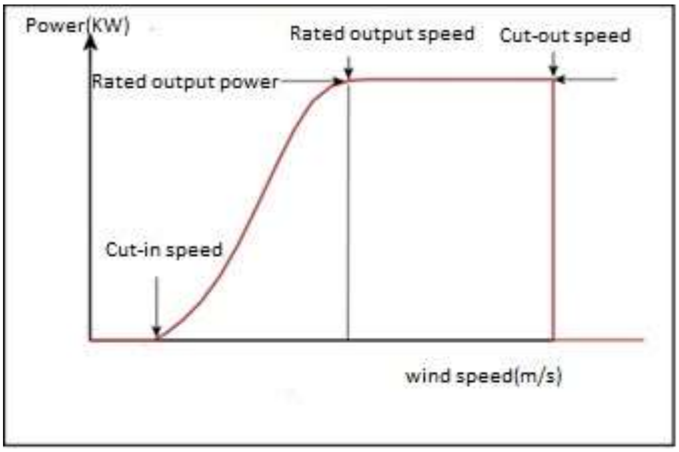

Figure 7.1 Typical wind turbine output curve with wind speed[2]

The cut-in speed is the wind speed at which the turbine first starts to rotate and generate power .The conventional cut-in wind speed is typically between 3m/s and 4m/s.

As the wind speed rises above the cut-in speed, the level of power output rises rapidly as shown in Figure7.1. However, the power output reaches the limit when the wind speed reaches typically somewhere between 12m/s and 17 m/s[2]. This limit to the generator output is called the rated power output and the wind speed at which it is reached is called the rated output wind speed. The design of the turbine is arranged to limit the power to this maximum level even with higher wind speeds.

When the speed increases above the rate output wind speed, the wind forces on the turbine blades continue to increase and there is a large risk of damaging the rotor at some point. To avoid this risk, a braking system is used to stop the rotor rotating.

The wind speed at which the braking system triggers is called the cut-out speed and is usually around 25 m/s.

As shown in Figure 7.1, there is a nonlinear relationship between the power output of the wind turbine generator and the wind speed. The relation can be described by the operational parameters of the wind turbine. The hourly power output can be obtained from the hourly wind speed with the following equations[3]:

$$P_w = \begin{cases} 0 & W_s < V_{ci} \\ (A + B W_s + C W_s^2) P_{wr} & V_{ci} \le W_s < V_r \\ P_{wr} & V_r \le W_s < V_{co} \\ 0 & W_s \ge V_{co} \end{cases} \tag{7.1}$$

where:

W_s = the wind speed

V_{ci} = designed cut-in speed of wind turbine

V_r = designed rated speed of wind turbine

V_{co} = designed cut-out speed of wind turbine

P_{wr} = rating power output of wind turbine

While A, B and C are constant parameters which can be determined using the following equations[3]:

$$A = \frac{1}{(V_{ci} - V_r)^2}\left[V_{ci}(V_{ci} + V_r) - 4 V_{ci} V_r \left(\frac{V_{ci} + V_r}{2V_r} \right)^3 \right] \tag{7.2}$$

$$\frac{1}{(V_{ci} - V_r)^2}\left[4(V_{ci} + V_r)\left(\frac{V_{ci} + V_r}{2V_r} \right)^3 - (3V_{ci} + V_r) \right] \tag{7.3}$$

$$B\square\ (V\ V \qquad)_2\ \square 4(V_{ci}\ \square V_r$$

$$)\square\ 2V_r\square\square\ \square\ \square\square\ _{ci}\square\ _r\square\square \qquad \square$$

$$C\square\ \_\_\_\_\_\_\_(V\ V_{ci}\ \square 1\ _r)_2\ \square\square\square\square 2\ 4\square\ \square\square\square V\ V\_\_\_\_\_\_\_ _{ci}2V\square^r{}_r\ \square\square^{\square}{}_3{}^{\square}\square\square\square$$

(7.4)

7.3 Integrating DSM and Economical Demand Management Index into Congestion Management

The integration of DSM into congestion management method can be illustrated in Figure 7.2.

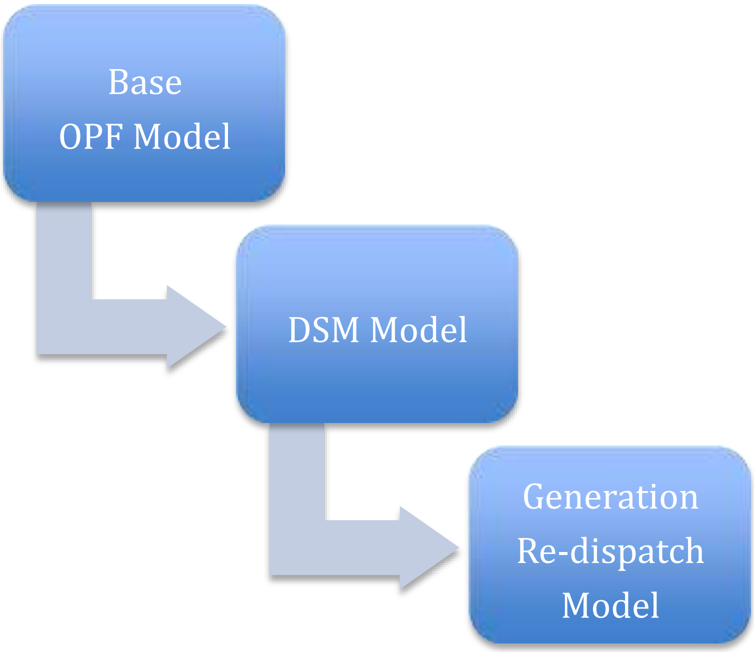

Figure 7.2 Integrating the DSM into Congestion Management

First stage: Base OPF model

In this stage, the objective function is the minimization of total generation cost of the system with the consideration of network constraints. The system operator schedules generating units for each hour of the next day‘s dispatch based on the forecasted load on the next day. The constraints considered are the power-balance between the demand and generation at every time step, the network branches limits and the minimum and maximum limits on power output for each generator. The cheapest generator is dispatched with priority over those with higher costs when there is no congestion in the system. Otherwise the system operator would redispatch the generator output to meet the demand due to the contingency. DC-OPF integrates the power flow calculation and the economic dispatch of generators with the objective function under the equality and inequality constraints of the network operation. The LMP prices are calculated every hour and they vary with the demand and network condition in the time horizon. The objective function can be obtained as below:

$$min \sum_{t\in T} \sum_{i\in N} C_i \left(P_i^g(t)\right) \tag{7.5}$$

where $C^i(P^{ig})$ is the cost function of the non-renewable generator at node i ,the cost of wind generation is assumed zero as it consumes no fossil fuel and the other costs are neglected;

$$\mathrm{C}_i(P_i^g(t) = \frac{1}{2} c_{2i} \left(P_i^g(t)\right)^2 + c_{1i} P_i^g(t) + c_{0i} \tag{7.6}$$

The constraints considered are the power balance between demand and generation, the capacity constraints of transmission lines, and the output limit of the generators.

Second stage: Economic demand management model

If there are contingencies in the system, the system operator can execute demand side management to ensure system reliability and weaken the market power of generators.

There are two main parts in this model. The first part is the calculation of economic demand management index which has been demonstrated in chapter 4 while the second part is load control model (DSM model). With the indication of EDM index, the system operator can choose proper participants and execute the demand side management efficiently. In order to optimize the way in which end users consume electricity, the DSM model which is based on proposed load control formulas in chapter 5 is developed. The adjusted demand profile will be processed to the next stage for the reference of generation re-dispatch.

With the EDM index, the system operator selects proper nodes of consumers to participate in the demand side management and notifies the corresponding distribute network operator or aggregator The distribute network operator, or an aggregator, manages a portfolio of customers who are willing to participate in the DSM programme with specific load control algorithm. The DSM model is presented for simulating the load control strategy of distribute network operator. Here, the load control algorithm is applied in the model to achieve the optimization of maximizing the load reduction during congestion periods.

Third stage: generation re-dispatch model

The generation re-dispatch is also deployed in the proposed mechanism. After adjustment on the demand side, the system operator re-dispatches or curtails the generator units to match the new demand profile with the OPF tools considering network capacity limits and the output of generators. The LMP prices in postcongestion stage are derived from the Optimal Power Flow(OPF) based model.

7.4 Case Studies

7.4.1 Case Study 1: All Appliances Participated in DSM

The modified IEEE-14 node system, as shown in Figure 7.3, is employed for case studies. There are 4 conventional generators respectively; at node 1, 3, 6 and 8. The wind farm is connected to node 2. Table7.1 shows the conventional generators' cost and fuel type. The branch parameters and other system data are not modified as given in the Appendix 1. The transmission limit of each branch is set as infinite when system operates normally. The peak demand of the system is 259 MW and the total generation capacity is 292.4MW. The total conventional plants capacity is 277.4MW while the wind farm has 15MW capacity. In order to evaluate the efficiency of DSM in congestion management, the capacity of transmission line 6-13 is set as 18 MW and the capacity of other branches remain infinite. The load profiles are scaled from the average GB demand data of 2012 which is available on National Grid website[4]. The outputs of the wind farm model in 24 hours, which are depicted in Figure 7.4, are created using the historical wind speed data of Edinburgh area from MET office.

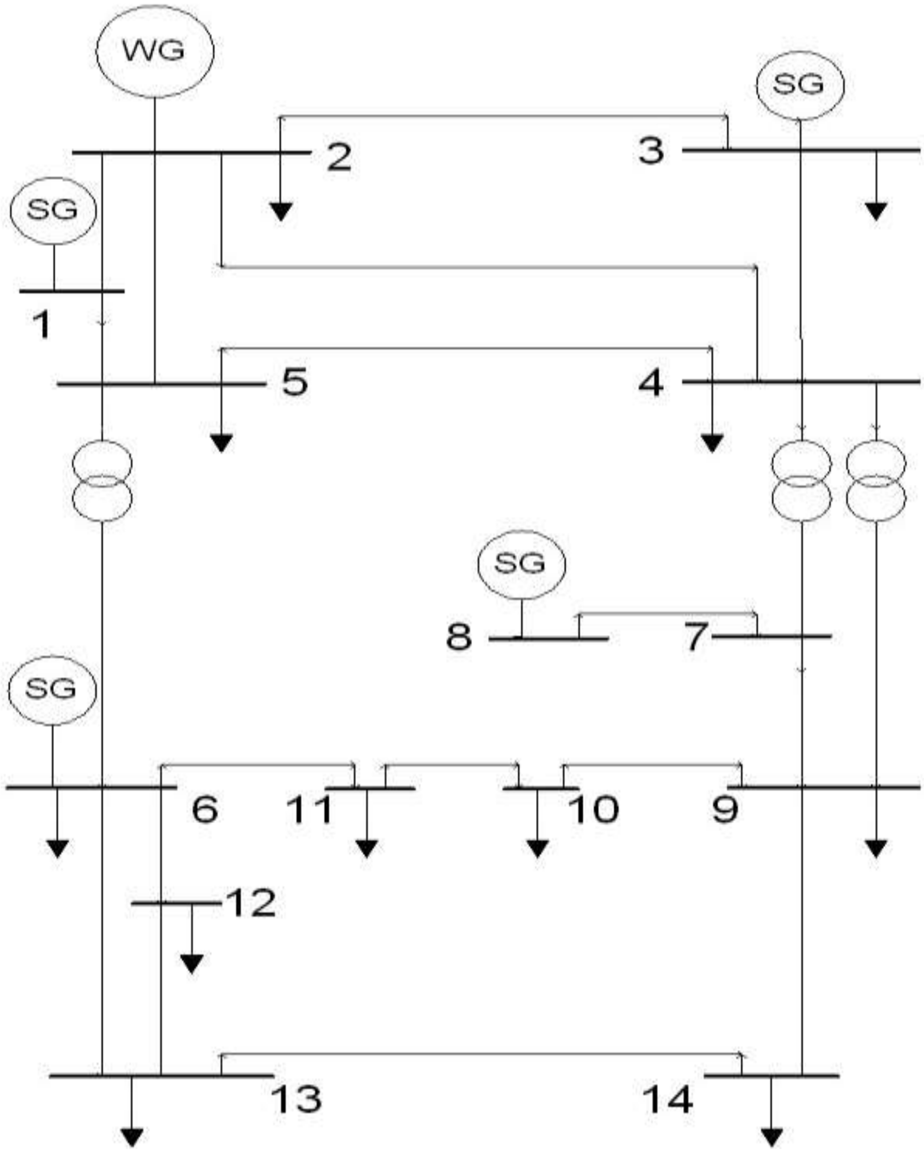

Figure 7.3 Modified IEEE 14 System

Table 7.1 Conventional Generator Parameter

Generator	C_{2i}	C_{1i}	C_{0i}	$P_{\max}$ (MW)	$P_{\min}$ (MW)	Fuel Type
1	0.043	20	0	202.4	0	Gas
3	0.01	40	0	30	0	Coal
6	0.01	40	0	25	0	Gas
8	0.01	80	0	20	0	Coal

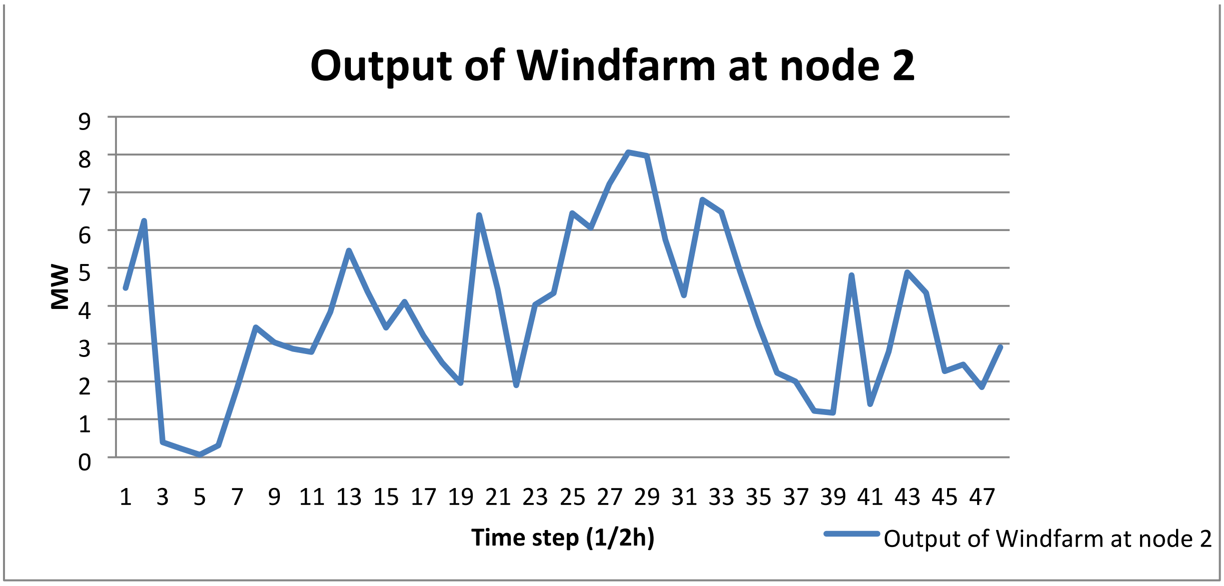

Figure 7.4 Wind farm output

Figure 7.5 shows the LMP prices without DSM under this circumstance and detailed calculation process can be found in Chapter 2.

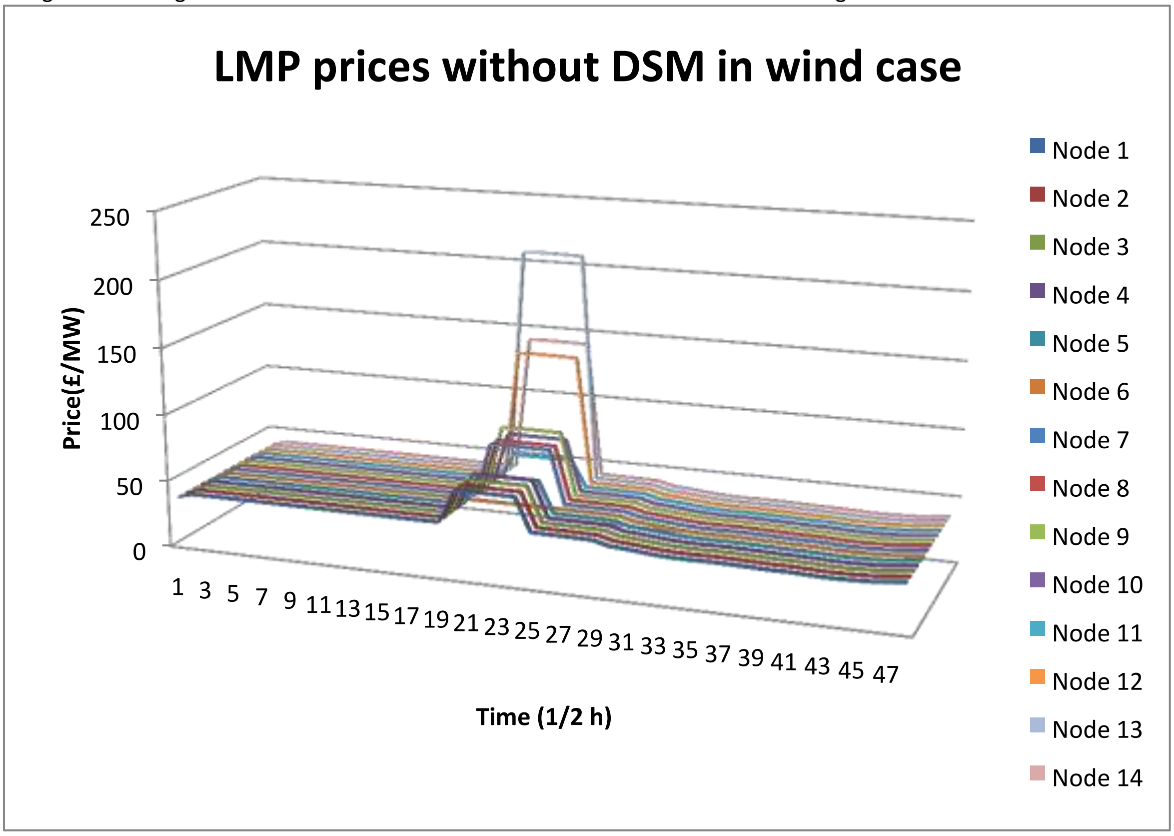

Figure 7.5 LMP prices of all nodes without DSM

The high price spikes in node 12, 13 and 14 were caused by transmission congestion in network at time slot between time-step 20-24. Generally, it can be observed from the results that the penetration of wind generation leads larger price volatility when there are no DSM activities being employed. This can be attributed to the fact that the increasing volatile output of wind generator at node 2 makes the congestion worse in the system. Conventionally, the system operator curtails the output of wind farm directly and thus the wind power is wasted. Hence, it is necessary to introduce the demand side management if optimal operation condition and economic benefits are expected. According to the calculation results of economical load management which are listed in Table 7.2, the execution of load control at node 13 would be the most efficient solution to congestion relief progress.

Table 7.2 Economic Demand Management Index

Node	**S**	**α**	**Is**	**I_F**	**I**
4	0.0091	0	0	0	0
5	0	0	0	0	0
7	0.062	0	0.1023	0	0
9	0.0904	0.8733	0.1503	0	0
10	0.0563	0	0.0926	0	0
11	0	0	0	0	0
12	0.2886	0	0.4859	0	0
13	0.5936	0.2808	1	1	1
14	0.3104	0.4864	0.5318	0.9763	0.5094

The number of smart appliances at node 13 is estimated according to approximate average UK electrical demand data of domestic households and reports of Smart-A projects, which is listed in Table 7.3.

Table 7.3 Numbers of Smart Appliance participated in DSM

Appliance	Washing Machine	Dryer	Dishwasher	Refrigerator	Freezer
Number	20077	11200	5917	21133	8453

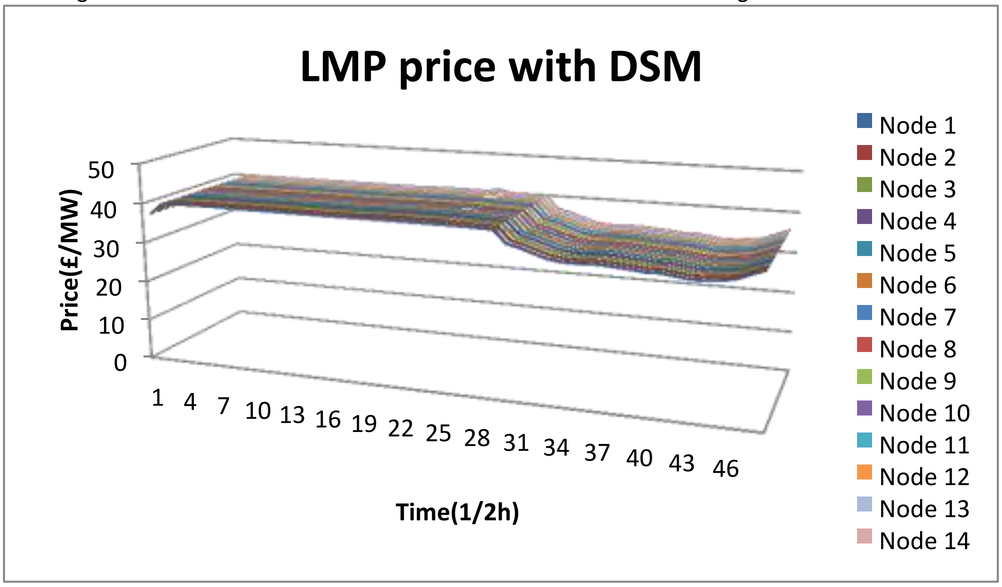

Figure 7.6 LMP prices of all nodes with DSM

It can be observed from Figure 7.6 that the participation of DSM can alleviate the congestion and smoothen the LMP profiles efficiently. The price spikes in the congestion period are shown to be completely removed.

7.4.1.1 Results and Discussion

7.4.1.1.1 Impact on Merchandise Surplus

As mentioned in Chapter 4, the merchandise surplus can be used as an index to evaluate the congestion management. The merchandise surplus is equal to zero when the network experiences no congestion and when there are no losses. However, in practice, the merchandise surplus is usually greater than zero when congestion and losses exist. Therefore, smaller merchandise surplus indicates the more efficient and economical use of power network. With DSM, the value of merchandise surplus among the whole control horizon approaches zero and is much lower than that without DSM as shown in Figure 7.7. This means that congestion is relieved more efficiently with DSM.

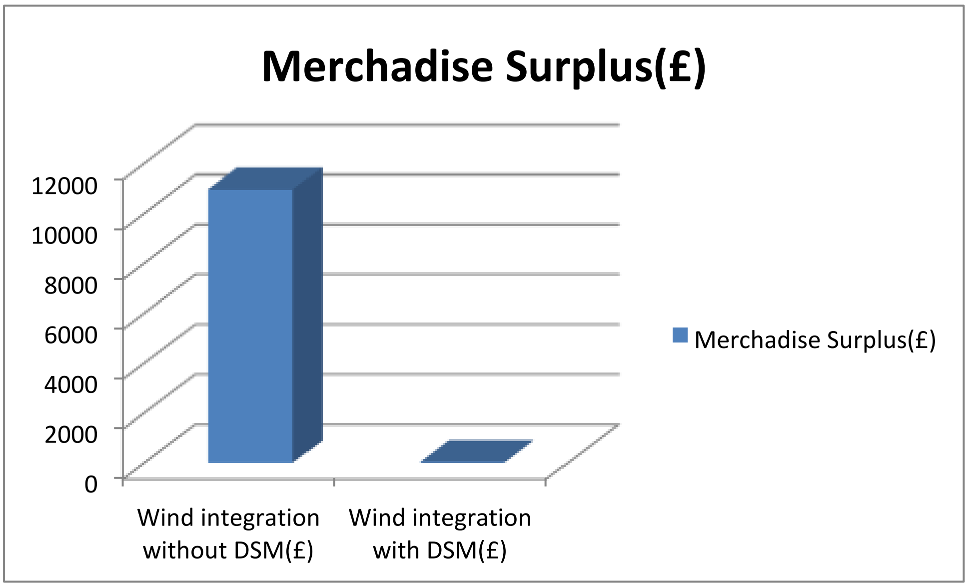

Figure 7.7 Merchandise Surplus of case study 1

7.4.1.1.2 Impact on Production Cost Reduction:

Production cost, which is assumed to be the total running cost of conventional plants, is shown in Figure 7.8. Each generation unit has its own running cost and the total cost is the aggregation of them. A big difference in production cost can be observed when compare between with and without DSM. This is because less demand in the congested period need to be supplied and thus reduces the opportunity to dispatch relatively expensive generators which are supposed to supply load in this period. Therefore, the total production cost is lower.

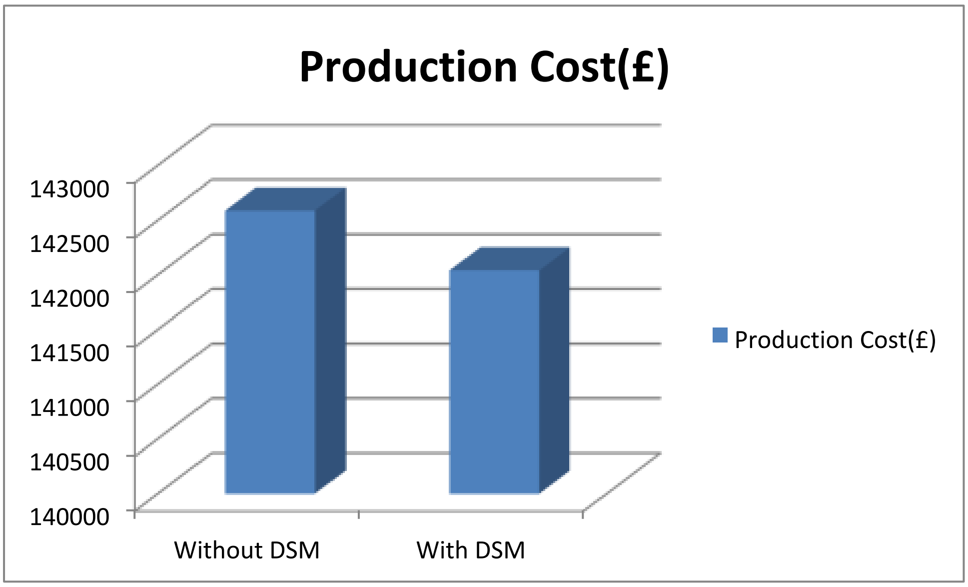

Figure 7.8 Production cost of case study 1

7.4.1.1.3 Impact on Carbon Emission

Total emission in the network comes from conventional fossil fuel plants which spread greenhouse gases into atmosphere. Only CO_2 emissions are studied in this work. Again with DSM, the need for running conventional plants at some points is eliminated and total emission lowered, thereby, decreasing the carbon emission cost as shown in Figure 7.10.

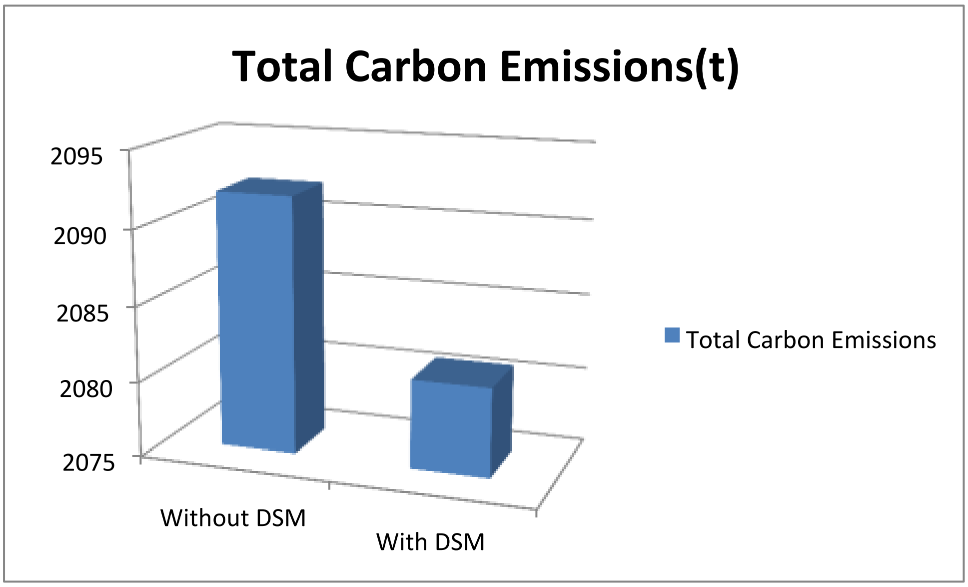

Figure 7.9 Carbon emissions in case study 1

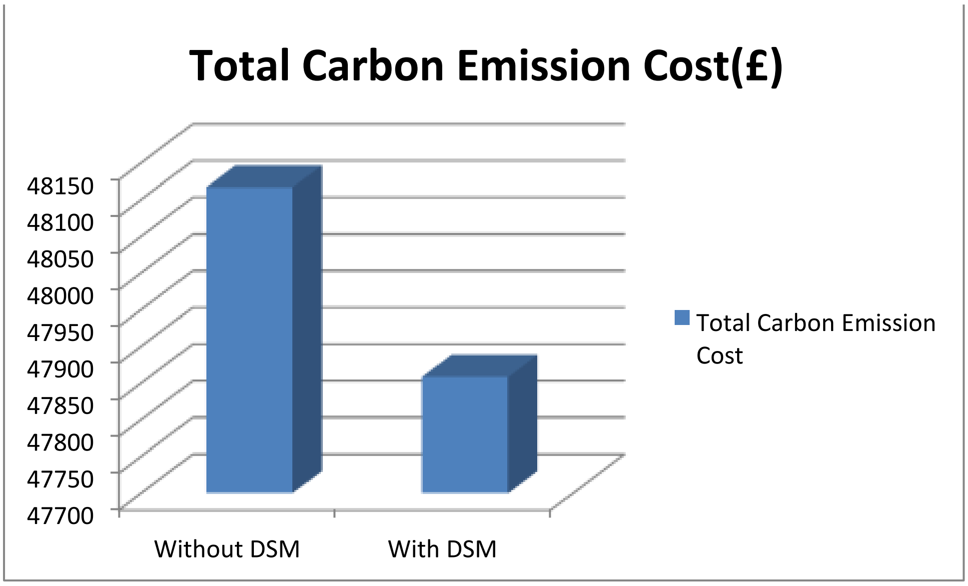

Figure 7.10 Carbone emission cost in case study 1

7.4.1.1.4 Demand Side Management Compensation Payment

To encourage people to participate in DSM programmes, the system operator would provide customers some monetary compensation according to the amount of load adjustment. Those expenses should be taken into account when the financial benefits of DSM participation are investigated. In this study, the DSM price is set from 0£/MW to 100£/MW and this price is considered as the compensation fee paid by the system operators for consumers involved in the demand side management program. The demand profile, both with and without DSM is depicted as Figure 7.11 and the demand variation among the control horizon is shown in Figure 7.12. The cost of DSM can be roughly estimated by multiplying the total demand variation by the DSM price, which is depicted in Figure 7.13.

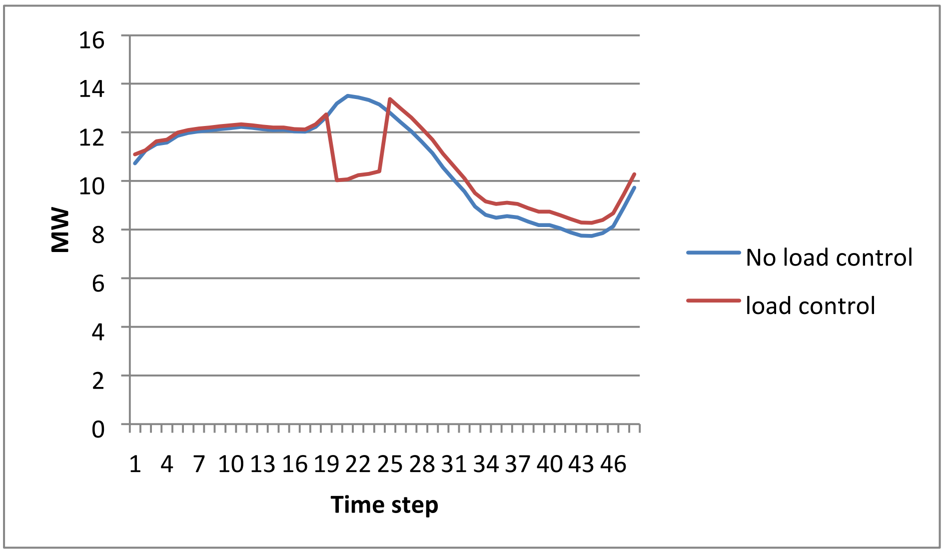

Figure 7.11 Load profile at node 13

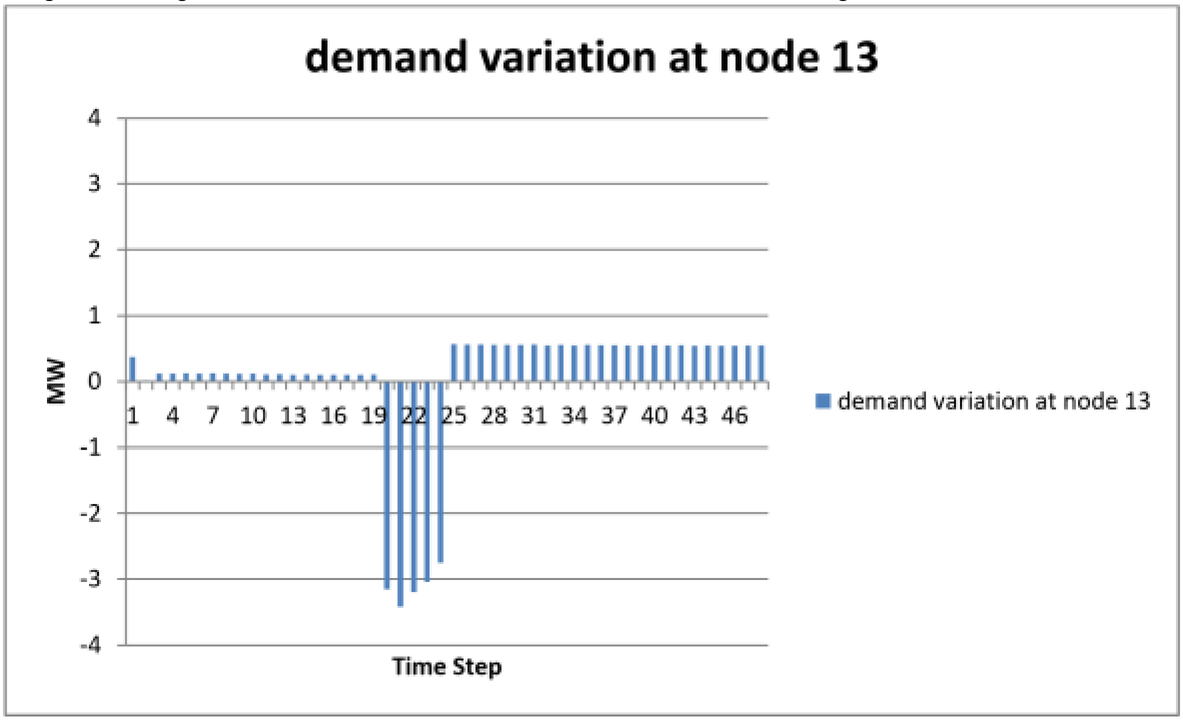

Figure 7.12 Demand variation at node 13

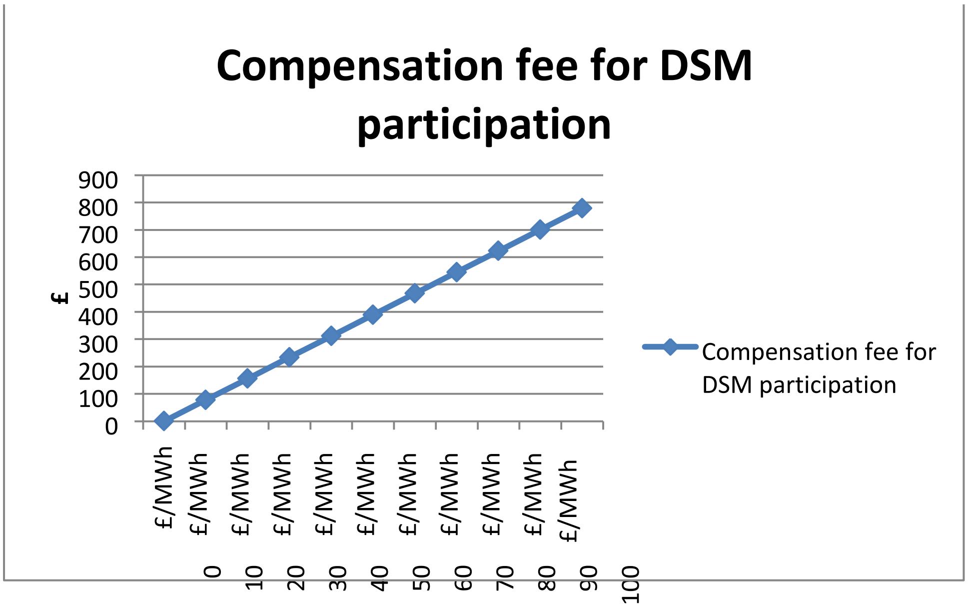

Figure 7.13 Payments for the DSM with different DSM price

It can be observed that increasing the price of DSM will decrease the total operation cost saving down to a point where DSM's contribution is not costeffective. For instance, as listed in Table 7.4, if the DSM price is higher than £80/MW, the total operation cost increased due to the implementation of DSM programme on the user side. In other words, it is more cost-effective for system operators to curtail wind farm output and re-dispatch generators under this circumstance. The negative values of operation cost saving are highlighted with red color in Table 7.4.

Table 7.4

Total operation cost saving considering DSM payment to participants

DSM Price	Total operation cost saving considering DSM payment to participants(£)
0£/MWh	550
10£/MWh	472.2
20£/MWh	394.4
30£/MWh	316.6
40£/MWh	238.8
50£/MWh	161
60£/MWh	83.2
70£/MWh	5.4
80£/MWh	-72.4
90£/MWh	-150.2
100£/MWh	-228

7.4.2 Case Study 2: Different Type of Appliances Participated in Congestion Management

It‘s important to evaluate the potential benefits with the DSM activities of each appliance group. Therefore, the study on the benefits of each appliance is carried out through the following case study. The maximum delayed start time is 12 time steps (6h) for wet appliances while the maximum precool time is 3 time steps (1.5h) for cold appliances. It can be observed that the LMP price at node 13 is most volatile in the congestion period from previous case study, so here, the price volatility at node 13 is evaluated for the sake of simplification .The simulation results of LMP are depicted in Figure 7.14.

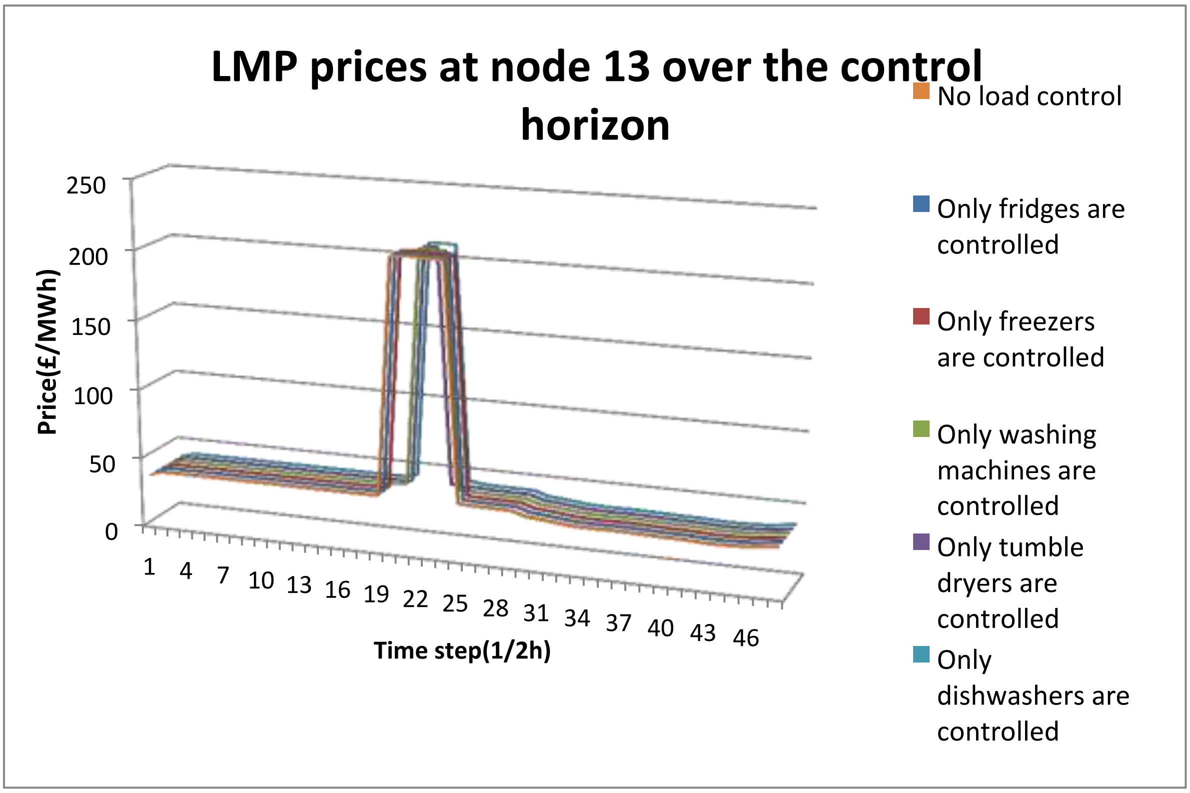

Figure 7.14 LMP prices at node 13 of case study 2

7.4.2.1 Results and Discussion

7.4.2.1.1 Impact on Merchandise Surplus

Figure 7.15 Merchandise Surplus of case study 2

Looking at the results depicted in Figure 7.14 and Figure 7.15, it can be seen that the contribution of wet appliances, i.e. washing machines, dryers and dishwashers load, to congestion relief is relatively remarkable as the high price period decreases significantly with the DSM and merchandise surplus reduces in a large scale. On the other hand, the control over cold appliances is less advantageous since no significant change can be observed in simulation results. The reason for this is that the usage of cold appliances load is relatively even and the allowed pre-cool time is relatively short which narrows the control margin, and therefore its control does not influence price significantly. Wet appliances, especially tumble dryers, are the appliances that provide relatively bigger benefits, offering the biggest amount of control margin at peak time steps and during congested periods.

7.4.2.1.2 Impact on Production Cost

Figure 7.16 depicts the production costs and corresponding reductions under different circumstances. It is observable that load control of washing machines and tumble dryers contribute relatively more to the production cost reduction while freezers contribute the least. This can be attributed to the fact that freezers have relatively narrow control margin, small power consumption per cycle and low penetration level in the domestic sector, therefore the control over them does not influence production cost significantly.

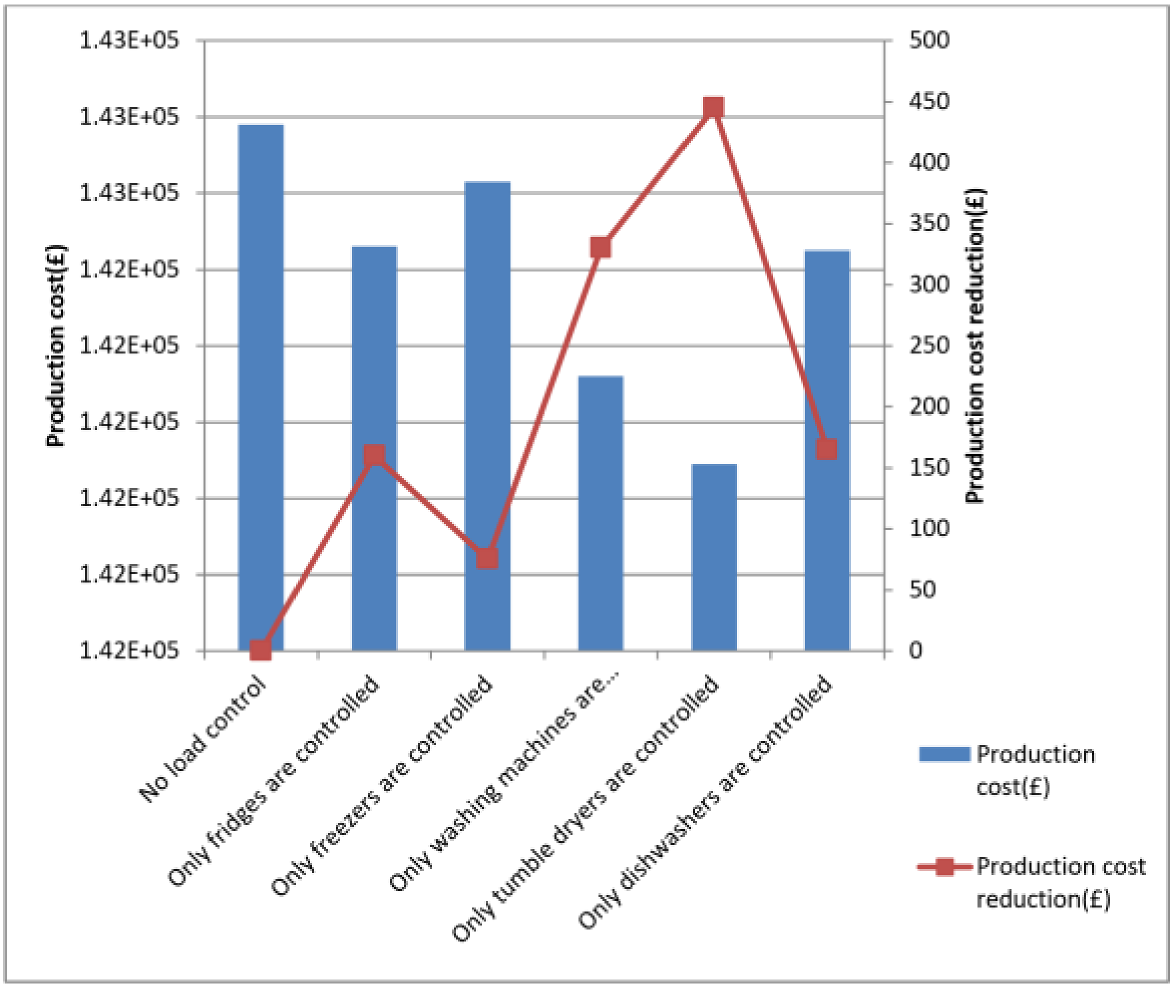

Figure 7.16 Production cost of case study 2

7.4.2.1.3 Impact on Carbon Emission

As shown in Figure 7.17, the load control over appliances will more or less reduce the need for operating thermal plants and thereby reducing the total emissions and corresponding costs.

It is also observable from Figure 7.17 that the highest reduction (in comparison with all scenarios) is achieved when all tumble dryers are controlled. The reason for this is that the total power consumption of tumble dryer is relatively large in peak time, which happens to be the congestion period in this case. Therefore, more demand reduction can be provided by tumble dryers in congestion period and the need to re-dispatch highly pollutant fossil fuel plants is lessen and the total emission decreases subsequently, thereby reducing the carbon emission cost. As shown in Figure 7.18, the cost on carbon emission with respect to each appliance shows the same tendency with the CO_2 emission results, which the lowest CO_2 emission cost is with tumble dryers.

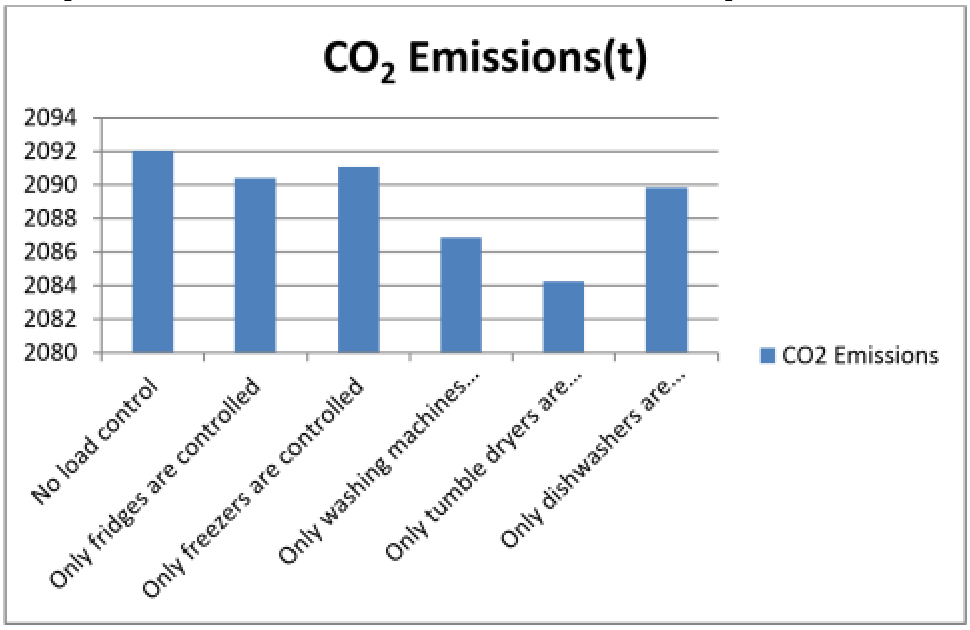

Figure 7.17 Carbon emissions with different appliances

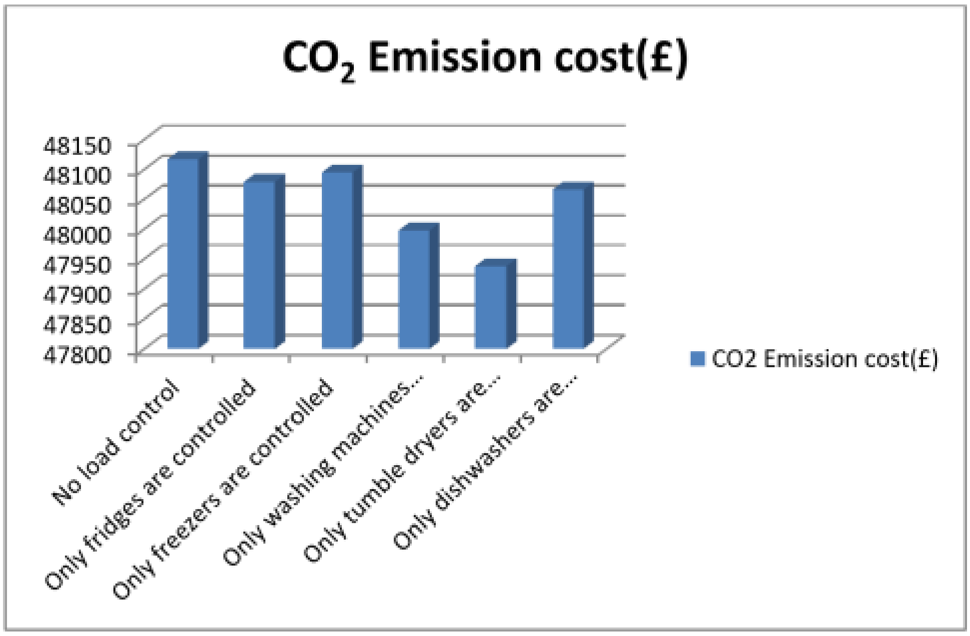

Figure 7.18 Carbon emission cost with different appliances

7.5 Summary

This chapter demonstrates the effect of combining DSM with congestion management on reducing the merchandise surplus and stabilizing the LMP prices where intermittent generation has substantial installed capacity in the power network.

As seen from the simulation results, DSM can also benefit the system by reducing the production costs, smoothing the price profile and lowering the carbon emission level to some extent. However, the degree of these benefits varies with different system operation condition and other factors, such as the DSM price setting.

Furthermore, the importance of each domestic appliance on congestion management has also been investigated. The control over wet appliances would provide relatively larger benefits, as they have bigger participation at congestion period and wider control margin than cold appliances.

References

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Chapter 8 Conclusion and Future Work

8.1 Conclusion

The main objective of this work has been to study the congestion management in liberalised electricity markets from the aspect of demand side and investigate the potential benefit of integrating demand side as an alternative means for enhancing the performance of system and market operation. To this end, a set of indices for optimising the demand participation to relieve congestions in the power system were proposed and integrated into existing congestion management scheme. It was systematically tested on IEEE standard systems. It was demonstrated that the proposed index could be successfully applied to mitigate network congestion problems with increasing market efficiency. Furthermore, a new load control methodology in the form of smart appliances was developed to further demonstrate how demand side management can be executed in the real world. Case studies were carried out to test the effectiveness of the proposed method. Each of chapters in the thesis contributed to the knowledge of topics in a positive and distinctive way.

The first part of the research is to propose a simple but practical index for finding solution to manage the congestion from demand side. The values of the indices are used to allocate optimal load adjustment and determine the amount of demand side participation. After an illustration of the mathematic theory involved, the effectiveness of the proposed index was demonstrated using case studies and were tested on IEEE 14-node and IEEE 30-node systems programmed on the Matlab platform. The code has been verified as correct and the simulation results are reliable. The impacts of economical demand management (EDM) on the LMP spikes and production cost decrement were evaluated. The simulation results showed that the congestion management method with the proposed index could tackle congestion in the power system effectively and economically in the power system. Furthermore, comparing with other exiting methods, the proposed EDM index offers the following advantages:

- Fast calculation based on DCOPF: The index values can be obtained in seconds as the calculation based on DCOPF is simple, robust and with higher speed of convergence. Then, the system operator can have sufficient time to notify the DSM participants and coordinate the resources in power system. Also, this facilitates the demand side participation in electricity market as the system operator and DSM participants have enough time to arrange trading and prepare for real-time operation.
- Compromising economical and physical efficiency of demand adjustment: EDM index not only measures the physical impact of load adjustment on power flow in the congested line but also the economic impact from the user side. It secures the power system operation and minimises the loss of benefit with load adjustment.
- Straightforward Indication: The proposed index is normalised and by comparing the index values of different nodes, the operator can select the DSM participants in an effective and economically desirable manner.

In addition, a new load control methodology that can be employed in the smart grid frame has been developed to further demonstrate how the DSM can be implemented in this thesis. In the thesis, the proposed methodology was illustrated as a generalised technique based on load shifting, which has been mathematically formulated as a linear-constrained quadratic minimization problem. The proposed algorithm allows different control strategies to be applied according to the different attributes of appliances and the methodology is sufficiently general to be implemented in the real world. The validation of the proposed load control algorithm has been demonstrated using different case studies. Comparing with other existing methodologies, the proposed algorithms offer the following advantages:

- Potential to control a wide range of appliances with different control strategies. The proposed algorithm allows control of wet appliances and cold appliances at the same time with different strategies. Thus, the potentials of demand resources are further exploited.

- Direct verification of the implementation of control actions: The proposed DSM architecture facilitates the verification of control actions

  and eliminates the risk in the management over large amount of smart appliances.
- Multiple optimisation options: The proposed algorithm is based on the optimisation principle that allows scheduling of control actions to bring the actual load profile as close as possible to a pre-defined objective profile. Thus, it is flexible enough to use for different purposes by setting different objective load profiles.

Over all, the general conclusions in this work can be summarised as below:

- The integration of active demand side into transmission network management, especially congestion management, can bring enormous benefits not only in the aspect of economic but also improves power system reliability and the environment.
- The proposed EDM index can help system operator to optimise the dispatch of demand side resources in the network to relieve the congestion effectively and economically.
- The proposed smart appliance control methodology can optimise the control behaviours of a wide range of smart appliances according to variant objectives.
- DSM in the form of smart appliances contributes to improving power system operation, reducing relevant costs (annual energy cost saving and deferment of investment in power system) and also decreases carbon emission level.
- The combination of EDM index and smart appliances control can be successfully used to mitigate congestion problem in transmission network with wind integration.

8.2 Future Work

This thesis contributes towards integrating demand side into electricity network congestion management and exploring the demand side control for versatile purposes. However, due to time constraints, there are some issues which have not been investigated in this work. This section highlights several possible expansion and improvement that can be considered for the methodologies proposed in this thesis.

- The proposed EDM index for congestion management is based on DCOPF model. In the simulation, the transmission losses are neglected. Thus, the further study can develop the proposed index on ACOPF base and include the transmission losses in the calculation.
- The proposed load control methodology only considers the control over wet appliances and cold appliances. However, a large scale electrification of heat sector is predicted in the near future. Hence, the thermal load modelling, such as heat pump, HVAC(Heating, Ventilation and Air Conditioning), can be considered to develop the proposed load control algorithm. Also, another direction of future research is to combine the proposed algorithm with the existing thermal load control methodologies for achieving the optimisation of load control in a wider range of appliances.
- Other costs brought about by DSM have not been taken into account, such as the capital cost of DSM investment, network reinforcements for added security and ability to combine with DSM to consumers. In future research, the author suggests considering this cost in the study to draw a more realistic picture of the costs and benefits associated with DSM.
- The impact of DSM on stability of power system should be investigated. As regards to such high level of load which may be disconnected and reconnected within a short period of time, it is important to draw a framework to study the impacts on stability of power system in future research.

- The efficacy of DSM and EDM index to tackle congestion can be tested with case studies under different network conditions, e.g. different wind penetration levels and different congestion scenarios. More conclusions may be drawn from the further study.

- The proposed approaches in this work have been tested on several system simulations. However, more real practical power system testing can be carried out to verify the efficacy of the proposed methods.

Appendix

A. DATA FOR IEEE 14 NODE SYSTEM

The IEEE 14 node system data are obtained from http://www.ee.washington.edu /research/ pstca. The system includes 5 generator nodes,9 load nodes and 20 transmission lines. The one line diagram of the IEEE 14 node system is shown as Figure 4.4. Node data and line data are listed in Tables A.1 and Table A.2 respectively.

Table A.1 Node data for IEEE 14 node system

Node No.	Node Type	Volt Mag	Angle Deg	Generation		Load	
				P_G MW	Q_G MVAR	P_L MW	Q_L MVAR
1	Slack	1.06	0	232.4	-16.9	0	0
2	PV	1.045	-4.98	40	42.4	21.7	12.7
3	PV	1.01	-12.72	0	23.4	94.2	19
4	PQ	1.019	-10.33	0	0	47.8	-3.9
5	PQ	1.02	-8.78	0	0	7.6	1.6
6	PV	1.07	-14.22	0	12.2	11.2	7.5
7	PQ	1.062	-13.37	0	0	0	0
8	PV	1.09	-13.36	0	17.4	0	0
9	PQ	1.056	-14.94	0	0	29.5	16.6
10	PQ	1.051	-15.1	0	0	9	5.8
11	PQ	1.057	-14.79	0	0	3.5	1.8
12	PQ	1.055	-15.07	0	0	6.1	1.6
13	PQ	1.05	-15.16	0	0	13.5	5.8
14	PQ	1.036	-16.04	0	0	14.9	5

Table A. 2
Line data for IEEE 14 node system

Line Number	From Node	To Node	Resistance(p.u)	Reactance(p.u)	Line Charging Susceptance(p.u)	Tap ratio
1	1	2	0.01938	0.05917	0.0528	1
2	1	5	0.05403	0.22304	0.0492	1
3	2	3	0.4699	0.19797	0.0438	1
4	2	4	0.05811	0.17632	0.0374	1
5	2	5	0.05695	0.17388	0.034	1
6	3	4	0.06701	0.17103	0.0346	1
7	4	5	0.01335	0.04211	0.0128	1
8	4	7	0	0.20912	0	0.978
9	4	9	0	0.55618	0	0.969
10	5	6	0	0.25202	0	0.932
11	6	11	0.09498	0.1989	0	1
12	6	12	0.12291	0.25581	0	1
13	6	13	0.06615	0.13027	0	1
14	7	8	0	0.17615	0	1
15	7	9	0	0.11001	0	1
16	9	10	0.03181	0.0845	0	1
17	9	14	0.12711	0.27038	0	1
18	10	11	0.08205	0.19207	0	1
19	12	13	0.022092	0.19988	0	1
20	13	14	0.17093	0.34802	0	1

B. DATA FOR IEEE 30 NODE SYSTEM

This IEEE 30 node system data is obtained from http://www.ee.washington.edu/ research/ pstca. The single line diagram is shown in Figure 4.8. The system contains 6 generator nodes, 24 load nodes and 41 transmission lines. The node data and line data are tabulated in Table B.1 and Table B.2 respectively.

Table B.1 Node data for IEEE 30 node system

Node No.	Node Type	Volt Mag	Angle Deg	Generation		Load	
				P_G(MW)	Q_G(MVAR)	P_L(MW)	Q_L(MV)
1	Slack	1.06	0	260.2	-16.1	0	0
2	PV	1.043	0	40	50	21.7	12.7
3	PQ	1	0	0	0	2.4	1.2
4	PQ	1.06	0	0	0	7.6	1.6
5	PV	1.01	0	0	37	94.2	19
6	PQ	1	0	0	0	0	0
7	PQ	1	0	0	0	22.8	10.9
8	PV	1.01	0	0	37.3	30	30
9	PQ	1	0	0	0	0.00	0.00
10	PQ	1	0	0	0	5.8	2
11	PV	1.082	0	0	16.2	0.00	0.00
12	PQ	1	0	0	0	11.2	7.5
13	PV	1.071	0	0	10.6	0	0
14	PQ	1	0	0	0	6.2	1.6
15	PQ	1	0	0	0	8.2	2.5
16	PQ	1	0	0	0	3.5	1.8
17	PQ	1	0	0	0	9.0	5.8
18	PQ	1	0	0	0	3.2	0.9
19	PQ	1	0	0	0	9.5	3.4
20	PQ	1	0	0	0	2.2	0.7
21	PQ	1	0	0	0	17.5	11.2
22	PQ	1	0	0	0	0	0

23	PQ	1	0	0	0	3.2	1.6
24	PQ	1	0	0	0	8.7	6.7
25	PQ	1	0	0	0	0	0
26	PQ	1	0	0	0	3.5	2.3
27	PQ	1	0	0	0	0	0
28	PQ	1	0	0	0	0	0
29	PQ	1	0	0	0	2.4	0.9
30	PQ	1	0	0	0	10.6	1.9

Table B.2
Line data for IEEE 30 node system

Line Number	From node	To node	R (P.U)	X (P.U)	B/2 (P.U)	Tap Ratio
1	1	2	0.0192	0.0575	0.0264	1
2	1	3	0.0452	0.1852	0.0204	1
3	2	4	0.057	0.1737	0.0184	1
4	3	4	0.0132	0.0379	0.0042	1
5	2	5	0.0472	0.1983	0.0209	1
6	2	6	0.0581	0.1763	0.0187	1
7	4	6	0.0119	0.0414	0.0045	1
8	5	7	0.046	0.116	0.0102	1
9	6	7	0.0267	0.082	0.0085	1
10	6	8	0.012	0.042	0.0045	1
11	6	9	0	0.208	0	0.978
12	6	10	0	0.556	0	0.969
13	9	11	0	0.208	0	1
14	9	10	0	0.11	0	1
15	4	12	0	0.256	0	0.932
16	12	13	0	0.14	0	1
17	12	14	0.1231	0.2559	0	1
18	12	15	0.0662	0.1304	0	1
19	12	16	0.0945	0.1987	0	1
20	14	15	0.221	0.1997	0	1
21	16	17	0.0824	0.1923	0	1
22	15	18	0.1073	0.2185	0	1
23	18	19	0.0639	0.1292	0	1
24	19	20	0.034	0.068	0	1
25	10	20	0.0936	0.209	0	1
26	10	17	0.0324	0.0845	0	1
27	10	21	0.0348	0.0749	0	1
28	10	22	0.0727	0.1499	0	1
29	21	22	0.0116	0.0236	0	1
30	15	23	0.1	0.202	0	1
31	22	24	0.115	0.179	0	1

32	23	24	0.132	0.27	0	1
33	24	25	0.1885	0.3292	0	1
34	25	26	0.2544	0.38	0	1
35	25	27	0.1093	0.2087	0	1
36	28	27	0	0.396	0	0.968
37	27	29	0.2198	0.4153	0	1
38	27	30	0.3202	0.6027	0	1
39	29	30	0.2399	0.4533	0	1
40	8	28	0.0636	0.2	0.0214	1
41	6	28	0.0169	0.0599	0.065	1