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Domestic Demand Response to Increase the Value of Wind Power

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Domestic Demand Response to Increase the Value of Wind Power

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Summary

This thesis describes a new method to evaluate the value of wind power combined with domestic demand response. The thesis gives a brief overview of current domestic demand management programmes, and highlights the demand response and its current application. Such technology has conventionally been used for different purposes, such as frequency regulation, and to minimize the spot electricity prices in the market. The aim is to show whether such technology may become useful to make the renewables, and in particular wind power more interesting for investors.

An assessment framework based on generation scheduling is developed to quantify the value of wind power. A further important aspect of value of wind power is the impact of intermittency on overall reliability of the system. This necessitates increasing the spinning reserve level which will increase the production cost. The changes in the spinning reserve level has been investigated in this thesis and it has been shown that how different forecasting errors may change the overall value of a windfarm over its lifetime.

One of the most important aspects of a system containing demand response, is the availability of demand response. A load modelling package is developed to show the potential for demand response in a real system from domestic sector.

With every increasing the concerns with regard to future of generation mix in Britain, this work has proposed over 72 scenarios for the future of generation mix in Britain and the impact of demand response to increase the value of wind power in 2020 has been investigated. The assessment framework is enhanced by showing that how the value of wind power combined with domestic demand response may change by changes in emission price, and cost of demand response. This will show the degree of feasibility of such system in which demand response is treated like a commodity.

List of Abbreviations

CCGT .... **Closed Cycle Gas Turbine**

CHP .... **Combined Heat and Power**

CO_2 .... **Carbon** Dioxide

CCS .... **Carbon** Capture and Storage

DSM .... **Demand Side Management**

GB .... **Great** Britain

GW .... Giga Watt

IGCC .... **Integrated Gasification Combined Cycle**

kW .... **Kilo** Watt

LoL .... **Loss of Load**

MW .... Mega Watt

NO_x .... **Nitrogen Oxides**

OCGT .... **Open Cycle Gas Turbine**

RTP .... **Real Time Pricing**

SO_x .... **Sulphur** Oxide

SBP .... **Syetem Buy Price**

SSP .... **Syetem Sell Price**

SoS .... **Security** of Supply

ToU .... **Time of Use**

TW .... **Terawatt**

UK .... **United Kingdom**

$C(c,e,s)$ .... **Objective function (cost, emission and security)**

i .... **Number of generation unit**

p_i .... **Scheduled power for unit *i***

p_l ....**Power losses in the network**

D ....**Demand**

p_r .... **Power Reserve**

S .... **Security violation**

αs ....**Scaling security factor**

αc ....**Scaling cost factor**

αe ....**Scaling emission factor**

τs ....**Boolean variable for security**

τc .... **Boolean variable for production cost**

τe ....**Boolean variable for emission**

FCi .... **Fuel-cost**

MCi ....**Maintenance-cost**

STi ....**Start-up cost**

SDi ....**Shut-down cost**

BMi .... **Base Maintenance cost**

IMi .... **Incremenmtal cost**

α_i, β_i, C .... **Generator's fuel cost coefficients**

TSi ....**Turbine Start-up cost**

BSi .... **Boiler start-up cost**

MS_i .... **Start-up maintenance cost**

τc .... **Boolean variable for production cost**

τe .... **Boolean variable for emission**

D_i .... **Number of hours down**

AS_i .... **Boiler cool down coefficient**

K .... **Incremental shutdown cost**

α , β , γ , δ , ε .... **Emission coefficients**

S_v .... **Voltage security violation**

S_g .... **Generator reactive power security violation**

S_b .... **branch Power flow security violation**

τv .... **Voltage Boolean variable**

τb .... **Branch flow Boolean variable**

τg .... **Generator re-power Boolean variable**

$CSPP_i$ .... **Capacity Limit of unit *i* to provide spinning reserve**

$CNPP_i$ .... **Capacity Limit of unit *i* to provide negative reserve**

SP_i .... **Maximum Contribution of unit *i* to spinning reserve**

NP_i .... **Maximum Contribution of unit *i* to negative reserve**

In this thesis the term “Demand Response” is used for response of demand to a signal such as price or wind power output in “Real Time” and “Dynamically”.

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1. Introduction

1.1 Research Motivation

Water and energy are the primary drivers for human life and world development. Therefore, the importance of security of supply of these primary life support resources can not be ignored. The UK has adequate water resources to maintain the security of water supply. However the concept is different for energy, mainly heating and power. The country has moved from relatively self-sufficiency in energy to the position of major net importer, and the current high international energy prices and recent high-profile supply interruptions, have brought the risks inherent in this position into very sharp focus.

Security of supply of energy is currently a major issue for the UK's electricity sector since the majority of the fuels to generate electricity such as coal and gas are being imported**.** Lack of storage facilities also worsens this problem as it makes the price of generating electricity sensitive to wholesale energy prices. Hence, the government has placed the issue of security of supply at the heart of its ongoing review of national energy policy. Classically, in the electricity industry, security of supply has been maintained by securing enough generation capacities with diverse fuel inputs. The Oil crisis in 1970's and the global fear of major disturbances in fossil-fuel supply as a result of it, the difficulties dealing with uneconomic deep-pit coal extraction in the UK, and became a trigger to study and work on alternative sources of meeting the increasing demand for energy and reduce the dependency on fossil fuels to minimize the risks for security of supply.

More recently, concern over the potential impact of global warming is forcing greater changes. A 'World Summit' was held at Rio de Janeiro, Brazil in 1992 at which the United Nations Framework Convention of Climate Change (UNFCCC) was set up. It was followed by a series of intensive global negotiations in which more than 160 nations took part, culminating in the Kyoto Protocol in 1997. Under this agreement, the developed nations, apart from USA, committed themselves to an average reduction of 5.2% from 1990 levels in six greenhouse gases[1] over the period 2008 to 2012. The European Union has agreed to an overall reduction of 8% within its member states. In practice, this will be achieved through agreed targets per country, with the UK agreeing a reduction target of 12.5%. In addition, the UK Government has a manifesto commitment to reducing UK CO_2 emissions

[1] These include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6).

by 20% and 34% from 1990 levels by 2010 and 2020 respectively. The long term objective is to reduce carbon emissions to 60% by 2050.

Renewable energy sources can provide clean and sustainable energy for the energy sector. Since there are different types of renewables, more or less available in all the countries, deriving the energy from renewables is possible for all power sectors. In the UK, for example a government target has been set to aim to achieve 10% of electricity generation from renewable resources by 2010 and 20% by 2020.

However a major issue in integrating the renewable sources (in particular wind power) is their intermittent and unpredictable supply. In order to use it, it has to be backed up by other non-intermittent generation sources or energy storage units. Several methods have been considered to achieve a smoother output from a wind power plant such as backing up the renewables with conventional plant, introducing new storage devices to avoid utilizing conventional plant to back up renewable plant, etc. But they are all too expensive or inefficient options to use on a large scale. This makes the renewable sources expensive to operate, decreases their revenue, and makes them unattractive for investors.

After the arised 1970's the oil crisis, one of the programmes set up to better control or manage energy consumption was Demand Side Management (DSM). DSM programmes generally involve consumers changing their energy use habits and using energy-efficient appliances, equipment, and buildings. Dynamic demand management in which consumers can respond to different signals such as price in real time is being exercised in many power systems. Current dynamic demand management programmes in the GB power system include consumer's response to price of electricity known as Real Time Pricing (RTP), frequency deviations known as Frequency Response (FR), or in very limited scale to the need for reserve in the system such as Short Term Operating Reserve (STOR) or Fast Reserve (FR).

1.2 Problem Statement and Objectives

The electricity industry has been formed on the assumption of unresponsiveness and inelastic demand particularly in the short-term. The resulting development of the electrical power system took into account this assumption as nearly all control methods, and monitoring mechanisms were implemented on the supply side. This results in the need for matching the supply side with demand side to balance the demand and supply. As a result, the market structure and physical nature of the system excludes active and real-time participation by consumers; particularly domestic consumers.

Although electricity demand, in all sectors is elastic, in long-term; the higher the price of electricity is, the lower the consumption will be. However domestic electricity consumers do not have the opportunity to respond to changes in electricity prices due to a lack of communication between consumers and utilities; resulting in lack of short-term and real-time elasticity. Electricity spot markets generally determine prices by the hour. Consumers, in contrast, are charged based on their aggregated monthly usage by a flat rate tariff. The hourly prices are mapped to an estimated aggregate demand profile for various types of consumers. The methodologies for determining the load profiles of consumers are imprecise. Yet all customers are required to pay based upon the estimated profile, regardless of how poorly it corresponds to their actual usage, even Time of Use (ToU) pricing methods can just shift the consumption from peak period to off-peak hours and it is unable to respond to price variations in the market in real-time.

Increasing the penetration of renewable power generation in the system will increase the need for reserve, and back-up power from non-intermittent sources. These two factors will increase the price of electricity generation up to a point which may make the renewables cost ineffective. To maximize the benefits of renewables, having a firm and non intermittent power output is needed which has led to designing many hybrid systems.

In DSM programmes which involve direct load control, reductions in energy demand at the end user's premises can release electricity generation, transmission and distribution capacity, for a short period until supplying the reduced demand can be met efficiently and securely. In fact demand provides negative capacity to the system, which can be used at anytime required. Currently large loads; greater than 3MW are providing such negative capacity for frequency regulation purposes, and over 50MW loads can participate in providing FR and STOR.

The domestic sector can also provide such capacity if aggregated and have the additional benefit that it is widely available in the system in contrast with large industrial loads which are located in certain areas. Furthermore, by increasing the penetration of renewables, domestic demand response can provide the back-up power for power deficits of intermittent generation resulting in higher value for renewables. Domestic demand in the GB power system has not been established yet, due to lack of knowledge regarding the domestic loads and their aggregated effect, lack of precise analysis on the benefits which could be derived from domestic demand response in comparison with the price that has to be paid to maintain domestic demand response.

This project aims to find a solution to provide demand response from the domestic sector and evaluate the impact of domestic loads to respond to the wind power variations to increase the value of wind power. Therefore key objectives are:

- To quantify the responsiveness level in the domestic sector available to participate in dynamic demand management;
- To design an algorithm to facilitate participation of the domestic sector in dynamic demand management;
- To address the benefits such as reduced production cost, reduced emissions, and increased value of wind power by the participating domestic sector in dynamic demand management, and
- To assess the feasibility of using dynamic demand management with different incentive levels for the participants.

1.2 Contributions

The main contributions of this work are as follows:

- To communicate and discuss the various benefits of the successful implementation of demand response;
- To develop a deeper understanding of the impact of increasing the wind power penetration on the system in terms of operational characteristics such as production cost and emissions;
- To show the need for extra spinning reserve level associated with the wind power penetration in the system which is required to maintain the same level of reliability; and the impact of extra spinning reserve level on value of wind power;
- To present a framework for studying the nature of loads and the potential of the domestic demand to become responsive;
- To demonstrate the potential of the domestic demand response to increase the value of wind power;
- To show the feasibility of using domestic demand response with different incentive levels;
- To show the impact of different emission prices on the feasibility of using various levels of domestic demand response.

1.3 Structure of the Document

The organization for this thesis is now discussed. Chapter 2 first reviews sustainability in the current energy environment, and the need for such system and different means of providing a sustainable electrical energy supply system, and the implications for sustainability legislations in the UK. The barriers to integrate renewable sources are also studied along with DSM programmes, including their history, objectives, and different types of DSM programmes are followed by their limitations in a system to mitigate the intermittency issues of renewables. In chapter 3 the value of wind power is explained and an assessment framework based on generation scheduling problem is designed to assess the value of wind power at different locations in the grid. It will be shown that in order to assess the true value of wind power, it is necessary to consider the increased level of spinning reserve requirement due to intermittent generation in the system. In chapter 4, a probabilistic spinning reserve calculation tool is designed and shows the impact of different wind penetration levels, and different forecasting horizons, on the required spinning reserve level. In chapter 5, the feasibility of demand response is assessed through taking into account different prices for demand response, and different contribution levels of demand response. Chapter 6 details the load modelling in domestic sector in order to study the responsiveness level among domestic consumers in an area with some known information such as total population and different types of consumers. Previous methods of studying the electrical load profile are reviewed and it is shown that the proposed method can help in studying the degree of responsiveness among domestic appliances by modelling the end-use appliances through bottom-up load modelling. Chapter 7 proposes 72 hypotheses in a form of 6 main scenarios, to reflect the future of generation mix in the GB power system in 2020. The results in this section show the impact of different parameters such as location and capacity of windfarms, different penetration of nuclear power and demand growth on production costs, greenhouse gas emissions, spinning reserve requirement and network losses. In chapter 8 the impact of demand response in the GB power system is investigated. It is shown that how demand response can increase the efficiency of power generation, reduce the production costs and emissions, and increase the value of wind. It is also shown how with different carbon prices in the future, the added value of wind due to demand response may change

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Chapter 2 .Sustainability in the Electricity Industry

In this chapter the concept of sustainability in the electricity industry is studied through explaining the importance of sustainability and need for sustainable energy, and sustainability legislations in the UK with regard to the process of electricity generation and consumption. Different tools for achieving a sustainable process on the generation side including various forms of renewable sources are introduced, and the measures which have been taken in demand side known as demand side management programmes, are also explained.

2.1 Need for Sustainable Energy

Energy is vital to human development and it is impossible to for example operate a factory, run a shop, deliver goods to consumers or grow crops without some form of energy. Access to modern energy services not only contributes to economic growth and household incomes but also to the improved quality of life that comes with better education and health services. Unless access to energy is improved, many of the world's poorest countries will remain trapped in a circle of poverty, social instability and under development. If we are to significantly improve access to energy worldwide and maintain a secure energy system all forms of energy will be needed. This includes coal, gas, oil, nuclear, hydro and renewables.

Energy is essential for development and what we mean by sustainable development according to Brundtland Commission (1987) is "development that meets the needs of the present generation without compromising the ability of future generations to meet their own needs". In the context of sustainable development, there are three domains which interact with each other and any decision based on sustainability issues covers these three domains [1-2]:

1. **environment:** atmosphere, hydrosphere, land, biota, minerals;
2. **society:** population, lifestyle, culture, social; and
3. **economy:** agriculture**,** households**,** industry**,** transport, services

And no sustainable development plan is sustainable, unless it does not affect the three mentioned domains in long term. The implication is that unsustainable production and consumption by today's society will degrade the environmental, social, and economic basis for tomorrow's society, whereas sustainability involves ensuring that future generations will have the means to achieve a quality of life equal to or better than today's.

Over the next 30 years, it is estimated that global energy demand will increase by almost 60% [3]. Two thirds of the increase will come from developing countries – by 2030 they will account for almost half of total energy demand. However, many of the world's poorest people will still be deprived of modern energy in 30 years time. Electrification rate in developing countries is expected to rise from 66% in 2002 to 78% in 2030 but the total number of people without electricity will fall only slightly, from 1.6 billion to just under 1.4 billion in 2030 due to population growth [4].

The process of production and consumption of electricity is converting a form of energy, which could be either fossil fuel or non-fossil fuel, to a new form, and transporting the electricity to end use consumers where all electrical loads are located. Most of the energy sources which electricity is being generated from are fossil fuels; such as coal, oil and gas with the availability of abundant, affordable and geographically disperse but limited reserves. Fossil fuels are able to provide affordable energy worldwide i.e. 40% of total energy comes from coal and 24% of total electricity being consumed in the world is generated from coal. Coal, like all other sources of energy, has a number of environmental impacts, from both coal mining and coal use. Coal mining raises a number of environmental challenges, including soil erosion, dust, noise and water pollution, and impacts on local biodiversity and using coal involves spreading greenhouse gas[1] (GHG) emissions into the atmosphere. Figure 2.1 shows the CO_2 emissions produced by different type of plants which use fossil fuels. There are other issues associated with using fossil fuels; long term and short term supply; at current production levels, proven coal reserves are estimated to last 147 years. In contrast, proven oil and gas reserves are equivalent to around 41 and 63 years respectively at current production levels [5]. Over 68% of oil and 67% of gas reserves are concentrated in the Middle East and Russia and with starting the oil crisis in 1970s and current political issues in that area causes more concerns in terms of long-term security or resource availability; and short-term security associated with supply disruptions of the primary fuel or of the electricity generated.

[1] The six main greenhouse gases are carbon dioxide(CO2), nitrous oxide(N2O), sulphur oxide (SO2), methane (CH4), hydro-fluorocarbons (HFCs), sulphur hexafluoride (SF6) and per-fluorocarbons(PFCs).

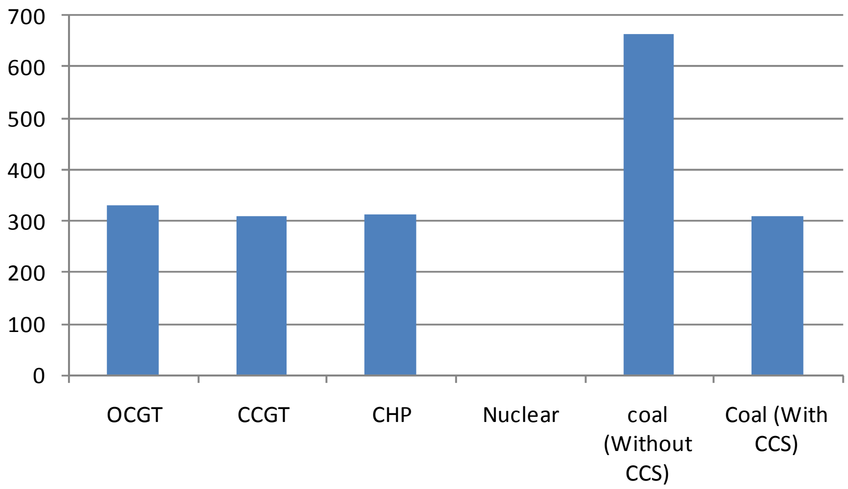


Fig. 2.1. CO_2 emission produced by power plants (Kg/MWh) during power generation [47]

Generation of electricity is not the only side of the process of using providing the electricity which is can not be always sustainable, the transmission, distribution and consumption are nor perfect and cause huge amount of energy losses in transmission lines, and network components, and with different consumption patterns among consumers with some inefficient appliances; hence even more energy must be transformed in the form of electricity to meet demand. It results in an unsustainable cycle which could even deprive many people of electricity at the moment as well in the future. Figure 2.2 shows the number of people without electricity in developing countries [5].

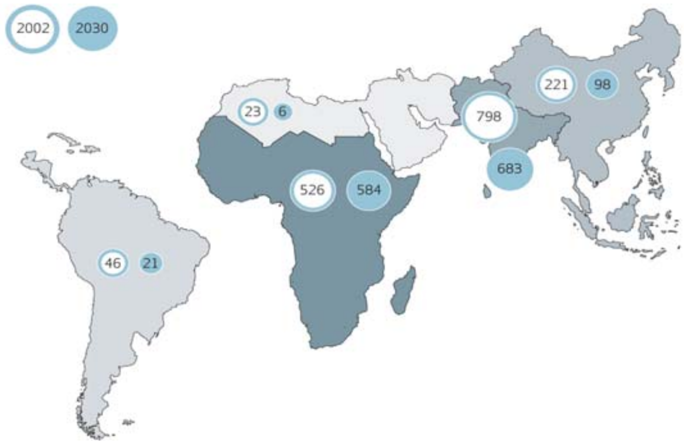


Fig. 2.2. Number of people without electricity in developing countries (in million) [5]

To tackle the previously mentioned problems which all result from operating an unsustainable cycle of electricity generation, most of the countries in the world have some plans to alter their production, transmission and consumption patterns in the future. Implementing renewable sources as significant in production levels (For every 1GW of fossil fuel fired electricity generation capacity displaced by an equivalent amount of renewable electricity, carbon emissions would be around 0.7MtC to 1.5MtC lower [6]) or substituting power lines with new system such as HVDC to reduce the losses in transmission level and wide Demand Side Management (DSM) programmes such as energy conservation to change the consumption pattern are those programmes which could benefit the energy industry and make a more sustainable cycle of generating and using the electricity.

2.2 Sustainable Energy Legislations in the UK

The Kyoto Protocol is perhaps one of the most famous international agreements set by United Nation to tackle the climate changes. The European Union Emission Trading Scheme (EU ETS) is the largest multi-national, greenhouse gas emissions trading scheme in the world and is a main pillar of EU climate policy. In addition to these policies and regulations each country depending on its situation and development plans has unique plans to reduce emissions, depending on the situation of the country in terms of energy level (purely consumer or producer). The UK is currently considered both an energy producer and consumer, however when North Sea oil and gas resources are exhausted; UK will become a pure importer of fossil fuels from other countries.

The latest version of the Energy White paper published by the Department for Business, Enterprise and Regulatory Reform[2] in 2007 gives the future plans of the UK energy sector to have a sustainable energy cycle. It sets out four energy policy goal [7]:

1. To put the country on a path to cutting the UK's carbon dioxide emissions; the main contributor to global warming by some 60% by about 2050, with real progress by 2020;
2. To maintain the reliability of energy supplies;
3. To promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity; and
4. To ensure that every home is adequately and affordably heated to reduce the issue of fuel poverty.

Part 1 and 2 of these four policy goals directly suggested that more renewables will be used in the electricity industry as they are key means of tackling environmental issues and mitigating the reliability issues resulting from relying on fossil fuels to generate electricity. The current legislation in terms of renewables is to see renewables growth as a proportion of the electricity supply to 10% by 2010, with an aspiration for this level to double by 2020.

[2] Department for Business, Enterprise and Regulatory Reform (DBRR) is formerly known as Department of Trade and Industry (DTI)

By the end of year 2005 4.3% of total electricity had been generated in the UK was coming from renewables. Figure 2.3 shows the 2006 UK electricity generation mix in percentage of installed MW capacity. Figure 2.4 shows the 2006 UK electricity generation mix in percentage of generated MWh from different fuel sources.

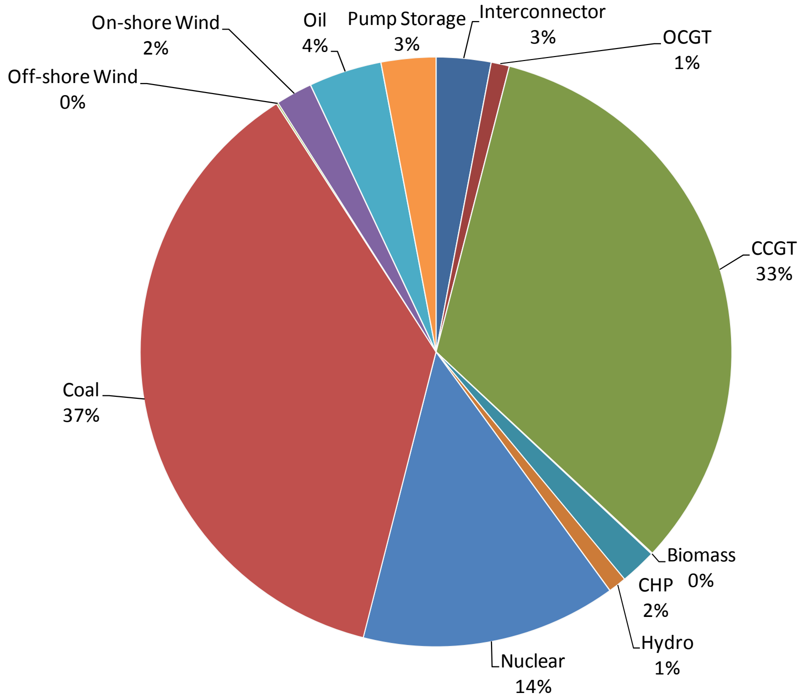


Fig 2.3. Electricity generation mix in the GB power system (MW installed capacity) [7]

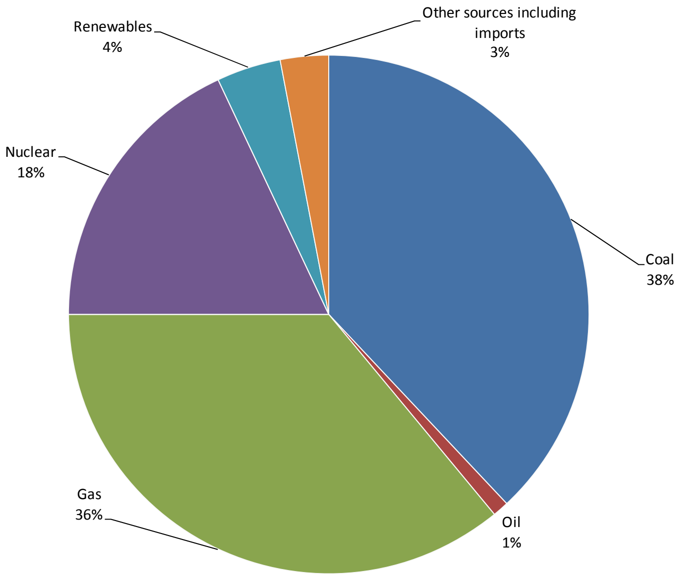


Fig. 2.4. UK electricity generated from different fuels in 2008 (MWh) [7]

The UK's total generation capacity is about 76GW with annual consumption of about 350TWh (terawatt hours) and winter peak demand of about 60GW. This level of capacity is roughly 20% higher than the expected level of peak demand [8]. The composition of the UK's existing generation mix is largely a result of the considerable number of new gas-fired power stations built during the second half of the 1990s known as the "dash for gas" when the economics of new gas power stations were particularly compelling. In 1990s when the electricity market in the UK became privatized, and because of competition between generation companies, consumers could benefit from lower electricity prices due to the excess of generation capacity. Consequently, few new power stations have been built during the early to mid-2000s. The pressure to close conventional power stations because of environmental impact is resulting from EU legislations known as "Large Combustion Plant Directive" (LCPD), which aims to reduce sulphur dioxide (SO_2) and nitrogen oxide (N_2O) emissions and dust from all combustion power plants with a thermal output of greater than 50 MW [9]. Current generation mix in the UK indicates one third of the UK's total carbon emission or 47 MtC per year. New combustion plant must meet the Emission Limit Values (ELVs) given in the LCPD. For 'existing' plants (i.e. those in operation pre-1987), Member States can choose to meet the obligations by either complying with ELVs for NOx, SO2, and particles or Operating within a 'National Plan'. That would set an annual national level of emissions calculated by applying the ELV approach to existing plants, on the basis of those plants' average actual operating hours, fuel used and thermal input, over the 5 years to 2000 [10].

By closing some conventional plants due to public and environmental concerns other sources of electricity generation will participate more in this process. Despite the fact that the current legislation obliges generating 10% of total electricity from renewables but because of infrastructure issues in the UK power system it is estimated that by 2016 only 8% of total electricity generation mix will come from renewables. Figure 2.5 shows an estimation of the UK electricity generation mix by 2016 [11-12].

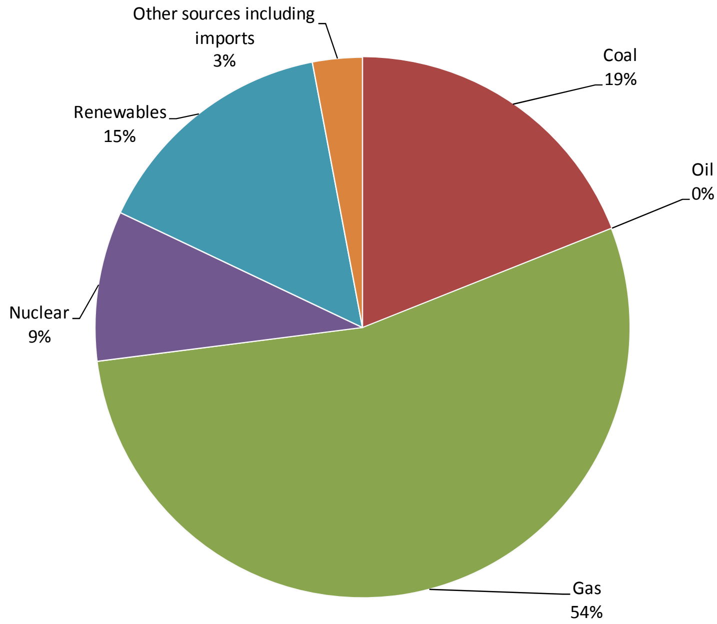


Fig. 2.5. UK electricity generation mix by 2016[3] (electrical energy produced) [11-12]

2.3 Renewable Energy Sources in the UK

Several sources of energy are known as renewable energies. In 2008, over 19.6TWh of electrical energy was generated from renewable sources.

Renewables in general have the following characteristics:

1. Clean environmentally-friendly; no direct emission from them;
2. High pay-back ratio ($\frac{Energy\ produced}{Energy\ Consumed\ to\ produce\ Energy}$) ;
3. Almost unlimited and free source of energy available;
4. Location dependency;
5. Intermittent nature (particularly for wind);
6. Some types of renewables have energy storage capacity;
7. Shorter time to build in comparison with conventional plants.

[3] There are different scenarios for the future of the UK generation mix. This graph is based on the assumption of economy growth.

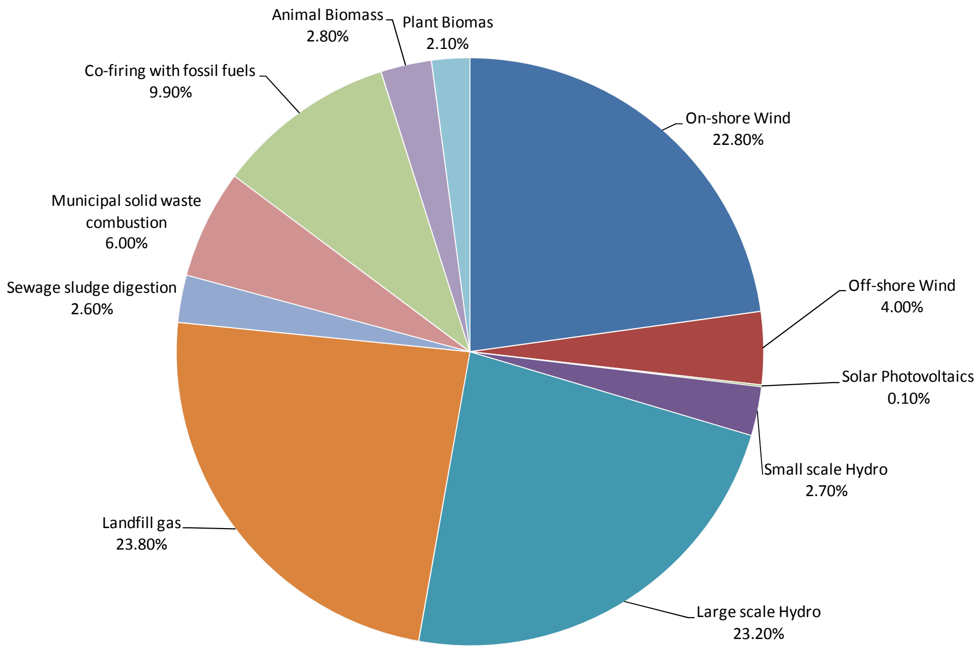


Fig. 2.6. Make up of renewable electricity generation in the UK in 2008 (in percentage of total 19.6TWh) [7]

2.3.1 Hydro:

Hydropower makes use of the energy from moving water, usually by channelling water at high pressure from the top to the bottom of a dam or by making use of river flows to drive an electricity generator. The energy is obtained from the sun, which evaporates water from the sea and deposits it over land, giving it potential energy in the form of height. Although large-scale hydro using dams is still being developed around the world, UK developments will focus on small-scale, 'run of river' projects due to their lower environmental impact and smaller spatial requirement.

Hydropower is the world's No.1 source of renewable energy and produces approximately 17% of the world's electricity and approximately 40% of the UK's renewable energy is provided by hydropower. Hydro beats all other electricity generating technologies with a pay-back ratio of 300; this is ten times more than oil-fired power stations and is the only type of carbon-free renewables which could be stored [13]. Another advantage of hydro units is deregulated market is their operational characteristics which gives them more opportunities, as they have a very low inter-temporal[4] cost [14].

[4] Inter-temporal costs included start up/shut down cost and ramping cost.

The issues with regard to hydro units include hazard to wild life posed by hydroelectricity which is the interference with the natural habitat of flora and fauna particularly migratory fish, fear of dam burst, and visual impacts.

2.3.2 Tidal and Wave:

Despite very large resources, tidal energy has not been successfully exploited on a wide scale. Tidal produced electricity is generated by making use of tidal water flows. It can be done by constructing a tidal barrage in an estuary and operating this like a conventional hydro dam – however, the environmental impacts are often prohibitive. Alternatively, turbines can be placed underwater in the tidal stream – these produce power from both in and out flows. Other variations are also possible. Tidal power is gaining increased interest in the UK, with a number of projects at demonstration and testing stage.

Waves transmit large volumes of energy from windy conditions far out to sea to the shore. Here the energy can be used to generate electricity and a variety of technologies are being developed to do this. The potential of wave energy in the UK is large due to our extensive coastline.

The Severn Estuary in Bristol Channel could provide 4.4% of the UK electricity supply (17TWh) from the second greatest tidal range resource in the world, generating electricity for over 120 years regardless of environmental impacts[5] which are barriers against development of this project. One of the advantages of tidal power for the UK is that it is distributed almost evenly geographically [15].

2.3.3 Wind:

Wind energy is widely dispersed. It is greatest in high latitude locations and has been used for centuries in windmills of various forms for grinding grain or pumping water. Modern wind turbines are available for both large and small scale electricity generation, and huge technological advances have been seen over the past 20 years.

As UK is one of the windiest countries in Europe a high proportion of electricity could be generated through wind. Together, wind, wave and tidal power could supply 21% of the country's projected electricity supplies by 2020, resulting in over £16 billion of investment in the UK project life cycle [16]. Because UK is an island, access to off shore wind farms which are located somewhere in the middle of water where wind energy level is higher

[5] It is estimated that developing Severn Estuary project may lead to loss of up to 75% of the existing inter tidal habitats, which are internationally protected [15].

than on shore, it can benefit from high energy available to be achieved from offshore wind farms as well. Currently 3679.39 MW installed wind capacity exist in the UK, this capacity will reduce the CO_2, SO_2 and NO_x emissions 4157858, 96694 and 29008 tonnes per annum. 3081.2 MW of this capacity comes from 208 onshore windfarms and 498.2 MW from 8 offshore windfarms [16]. Figure 2.7 shows the all windfarms located onshore and offshore in the UK.

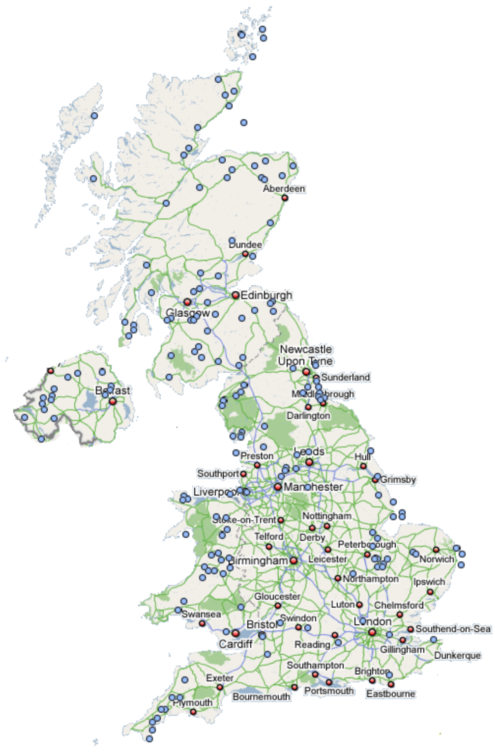


Fig. 2.7. Windfarms location in the UK in 2008 [16].

However there are some problems associated with windfarms; a single large coal-fired power station occupies about 1 square km of land, whereas a wind farm of equivalent output would measure over 500 sq. km Noise, visual intrusion, hazards to wildlife and interference with TV, radio and radar are drawbacks of having windfarms in the society.

2.3.4 Biomass:

There are three types of indigenous biomass fuel:

1. Forestry materials, where the fuel is a by product of other forestry activities;
2. Energy crops, such as Short Rotation Coppice (SRC) willow or miscanthus, where the crop is grown specifically for energy generation purposes; and
3. Agricultural residues, such as straw or chicken litter.

Biomass can also be imported, mainly in the form of pelleted sawdust which is already an internationally traded commodity. Biomass fuels likewise water can also be stored and have energy storage capacity. Alsobiomass fuels are being considered and used for Renewable-Combined Heat and Power (RCHP) systems [17]. Using biomass fuels in particular wood has both negative and positive impacts on environment. Quantifying the benefits for environment is hard in the UK but with the experience of countries such as Austria and Sweden shows that net impact will be positive [18].

2.3.5. Solar Power

Sunlight is the world's largest energy source (170,000TWth) and the amount that can be easily accessed with current existing technologies exceeds the world's primary energy consumption. Different technologies have been developed up to now in order to utilize solar power. They include Photovoltaic (PV), Solar Thermal Electric (STE), Passive Solar Design, and Active Solar.

Solar PV uses solar cells, usually made from silicon to produce electricity directly from sunlight. The technology is currently quite expensive, although solar PV costs have fallen dramatically over time and further falls and technological improvements should be possible. Direct sunlight is not necessary and the cells can produce electricity even during cloudy conditions (at a reduced rate). Future applications for solar PV in the UK are likely to centre on building integrated solutions, such as cladding and roofing.

The main use of solar power is not limited to just generating the electricity; those places where solar panels are installed can benefit from water heating through solar power as solar panels can be fitted to absorb heat from the Sun; the technology called Solar-thermal and has been used primarily for domestic purposes, although industrial and commercial applications also exist. Solar thermal is exploited extensively in countries such as Cyprus and China, but so far has had limited penetration in the UK. It is now being given more encouragement. A solar thermal collector can provide around 60% of a household's hot water requirement over the year in UK conditions [19].

2.3.6. Geothermal

There are two main use of geothermal energy; geothermal heat pump for heating the buildings and electricity production. For electricity production; as aquifers does occur naturally in the UK the only possible way to produce electricity from geothermal energy is a technology called "Hot Dry Rock" where two holes with about 10km deep is drilled into the earth's crust the rock structure between them is fractured, then cool water is pumped down one hole and hot water extracted from the other. The temperature difference is then used to drive a steam turbine, as in conventional power stations, although, in view of the relatively low temperature differentials, a fluid other than steam would probably be used. In the UK, Cornwall contains much of the theoretical potential geothermal energy resource.

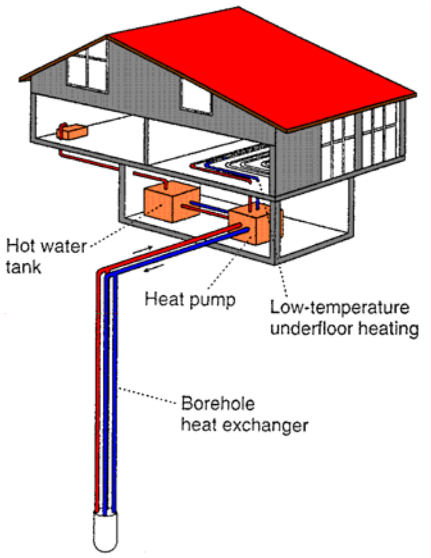


Fig. 2.8. The geothermal heat pump.

2.4 Barriers to Implementing Renewable Power

Implementing renewables into the current network involves some studies to assess whether or not the network has enough capacity to accommodate new source of power. Besides, huge investment in building new plant is needed to satisfy the increasing demand for electricity. In principle this demand could be met by any source of power; either renewable or non-renewable. When the decision for choosing renewable plant because of its advantages over conventional plants is considered, the intermittent nature of renewables makes it very difficult to direct the investment straight away to choose renewables. Extra power in the power system needs to be always available to be dispatched from different locations due to demand uncertainty and for contingencies. This concept needs to be expanded when renewable are added into the system; extra power needs to be available for dispatching also in case of loss of output power from intermittent plant. This forces the network planners to always backup intermittent plant with other sources such as power storage.

This is not the only problem with regarding to renewables, as mentioned before network needs to be expanded to accommodate more power. However one of the advantages of embedded generation is to reduce the power flow in branches by serving the local demand. Renewables because of their dependency on the availability of natural sources of energy must be installed in specific locations which could be either far from existing transmission lines and the current network power transportation components may not be able to accommodate extra power. Investment in expanding the network may be difficult to justify as network planner can not guarantee the utilization level of proposed network by renewable plant because of renewable output variability. There are therefore some barriers to increasing the penetration of renewables [20- 23]:

2.4.1. Technical Issues:

Renewable power generation when compared with conventional power generation has a greater dependency on specific locations where the main source of energy is available. In the case of wind power, windfarms must be installed in the windy regions to maximize the energy output of the windfarm. The transmission access to these locations may be restricted and therefore extracting the energy output of renewables is an issue which may be a barrier for increasing the penetration renewables.

Transmission and busbar limited capacity (due to power flow limit, fault current growth, and voltage rise) of existing transmission and distribution assets may require further reinforcement if renewables are to be connected to existing nodes. Such reinforcement due to increasing the intermittent generation, incurs additional costs especially in terms of the connection cost for use of system and may lead to a renewable project being uneconomic.

Another important issue with regard to intermittency of renewables is the need for the back-up power. To compensate for the power output variations of renewables in particular wind power, conventional plants must always be available on stand-by to compensate for such fluctuations. This has a drawback in efficiency of conventional plants.

2.4.2. Market issues:

Renewable plant usually has zero fuel cost and zero emissions, therefore when bidding in the market its power output will always be dispatched. This can result in reducing the exercising the market by large power generation companies. However, intermittency and diffuse nature of wind power makes it very difficult to participate in the electricity Market without a back-up power which is usually a conventional source.

These issues will persuade the renewables industry to look for more advanced technologies to eliminate the problems associated with installing more renewable power.

2.5. Demand Side Management

In early 1970's at the beginning of the energy crisis most nations realized how reliant on fossil fuels they were c and this level of dependency on such unsecure sources of fossil fuels which are mostly imported from other countries, will make their economy and social welfare vulnerable. In energy terms there was not a well established programme or policy at even national level to reduce the dependency on fossil fuels. The solution to this issue was to some extent known; using other sources of energy such as renewables or managing the consumption pattern. Both these two options have been very seriously considered and studied but for different purposes; first for to switch to renewable energies for generation and second option is to switch to different mode of consumption in demand side.

Demand Side Management (DSM) has a number of potential benefits to utilities, including reduced costs of electricity, increased security of supply at times of network stress, deferred network investment, and simplified outage management. In addition, DSM can also deliver important non-financial benefits, such as carbon savings, through reduced reliance on more polluting generating plant and increased energy efficiency as customers become more aware of their usage patterns. As demand for electricity is indirect, consumers actually demand the services provided by the electricity rather than the electricity itself. Controlling energy based demand can allow for increased efficiency by reducing peak loads without loss of end use service quality. Therefore DSM programmes have been widely focused on how to manage the consumption pattern of electrical appliances by minimizing the negative impact on consumers [24].

2.5.1 DSM Objectives

The demand side in an electricity network consists of different types of consumers; domestic, commercial, industrial. Many nations have electrified aspects of their agriculture and transportation and these two sectors are also included in demand side. Each one has some specific type of loads with different time activation (load profile) which makes a diversity of load categories in the network.

Reliability of electrical networks is the most important aspect of most works which have been done in this field and as it depends to two major factor; security and supply adequacy; supplying these loads is very important in order to increase the reliability. Some of the loads are categorised as critical loads which must be supplied with minimum interruption as any interruption may lead to severe costs on safety consequences and safety risks.

However meeting these criteria as well as running the system efficiently without participation of demand is almost impossible. This method of controling and managing the electricity utilization is known as demand side management (DSM). DSM includes a broad range of tools for changing electricity load shape, for reasons which include the following [25]:

1. Reducing price volatility/flattening spot prices;
2. Improving system reliability and reducing the risk of black-outs;
3. Reducing network congestion;
4. Delaying construction of additional generation, and/or grid and network upgrading;
5. Reducing greenhouse gas emissions;
6. Improving market efficiency by enhancing consumers' ability to respond to changing prices; and
7. Energy conservation through both behavioural and operational changes.

Demand side management consists of different ways to change the electricity consumption pattern in all sectors; commercial, domestic, industrial, transport sector etc. Most load based DSM programmes aim to achieve goals such as peak clipping, strategic conservation, strategic load growth, valley filling, load shifting and flexible load shape as illustrated in fig. 2.9.

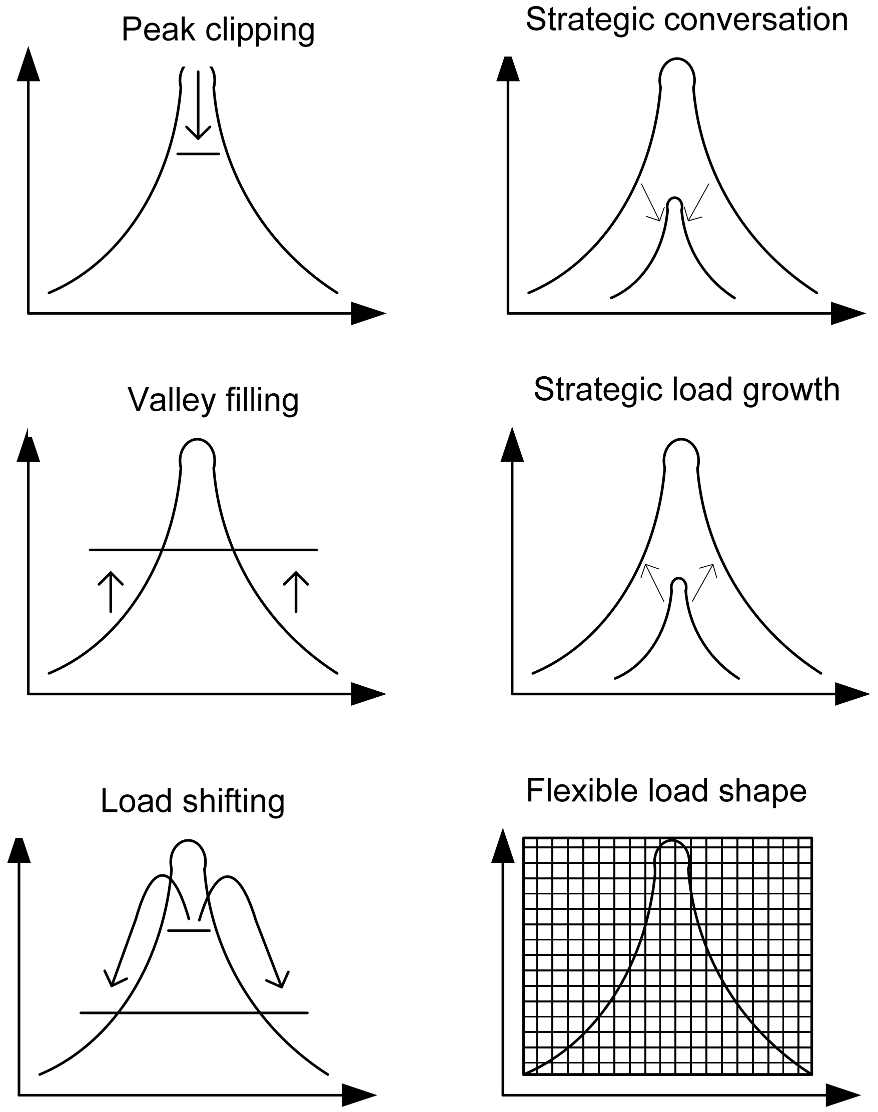


Fig. 2.9 Demand side management addresses all the basic load-shape objectives

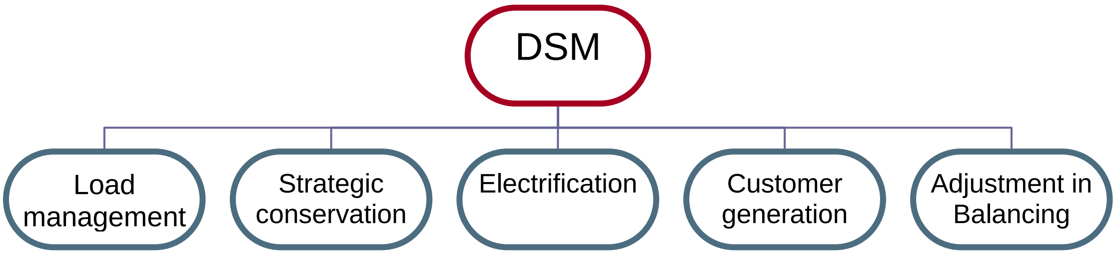
1. Peak clipping – reducing the demand during short usage peaks;
2. Valley filling – increasing the demand during the off-peak period;
3. Load Shifting - combines the benefits of peak clipping and valley filling by moving existing loads from on-peak hours to off-peak hours;
4. Strategic conservation – decreasing the overall load demand by increasing the efficiency of energy use;
5. Strategic load growth - increased electric energy use either to replace inefficient fossil-fuel equipment or to improve customer productivity and quality of life; and
6. Flexible load shape – specific contracts with possibilities to flexibly control customers' equipment

Apart from the technical and economic advantages of implementing the DSM programs, the environmental effect of DSM is also important and must be taken into account. The Kyoto protocol is one of the agreements that requires most countries to reduce their CO_2 emissions. Those power plants which need to burn fossil fuels to generate electricity are of the major sources of air pollution. By reducing the need to build new plant by supplying loads from emission-free sources like wind as well as promoting new emission reduction policies such as "Emission Cap and Trade" will allow the Kyoto protocol to be achieved.

Renewable energies have an intermittent nature therefore utilities can not rely solely on them without having the backup from a non-intermittent source. DSM programs will help the utilities to supply more loads from intermittent generation especially if some energy storage devices can be included in the system, even at consumer level.

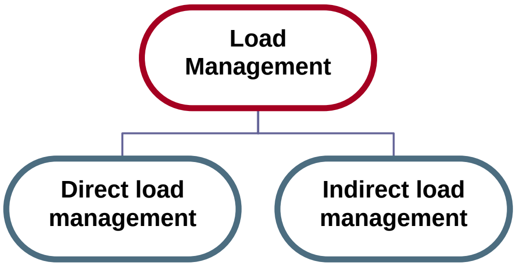
2.5.2 DSM Methods:

DSM programs provide cost incentives to consumers for over some control of when energy is supplied to the distributer which allows better and more effective utilization of generation resources. Most analyses of electric power systems (both economic and technical) assume that demand is highly inelastic. This is based on experience from the regulated industry where the system was designed to meet demand, costs are socialized, and prices are time invariant.



2.5.2.1 Load management

Load management (LM) is one of the DSM method which aims to control the actual load either directly or indirectly. It is better known than any other DSM Method. The advantage of LM is to mitigate cost of peak power and adding capacity to the network, in other words the principles of LM is that the consumer profits by scheduling more and more consumption to off-peak periods. Load management (LM) can be done in two ways: Direct load control i.e. switching on/off different loads by using artificial intelligence devices, and Indirect load control i.e. changing the tariff according to time/day



2.5.2.1.1 Direct Load Management [26-27]:

These methods directly control the load; either by restricting its consumption such as using switchover meters, or backing up the loads with energy storage devices such as batteries to supply demand if the power in the network is not enough to meet the load. The methods which have been studied included:

1. ripple controllers;
2. switchover meters;
3. voltage reduction;
4. using batteries to supply electricity especially in peak hours;
5. using storage devices (heat and cool); and
6. Using artificial intelligence to control some loads, i.e. lightning which can be controlled by lightening sensors like a photocell or motion cell.

2.5.2.1.2 Indirect Load Management [28-29]:

Indirect load control usually works by setting up a scheme aim to persuade consumers to control their power consumption. This control could be maintained by either offering an incentive programme or an obligatory. They include:

1. Setting up new and various tariffs; i.e. Economy 7 and Economy 10 in the UK and G12 in Poland;
2. Performing different programmes such as heat storage and electrical energy storage;
3. Setting up a minimum standards of efficiency for electrical appliances and;
4. Setting up cost penalties for consumers who consume more power than expected.

2.5.2.2. Strategic Conservation:

By improving energy conservation a noticeable amount of load can be reduced. Strategic conservation methods are usually long-term schemes which authorities set in order to reduce the energy losses and often involve some educational programmes to inform the public about governments strategies on energy saving.

Improving the energy efficiency level of appliances in the domestic sector, or promoting energy saving light bulbs along with incentivising them are good examples of strategic conversion schemes. Figure 2.10 shows the popularity of different strategic conversion techniques among end-use consumers.

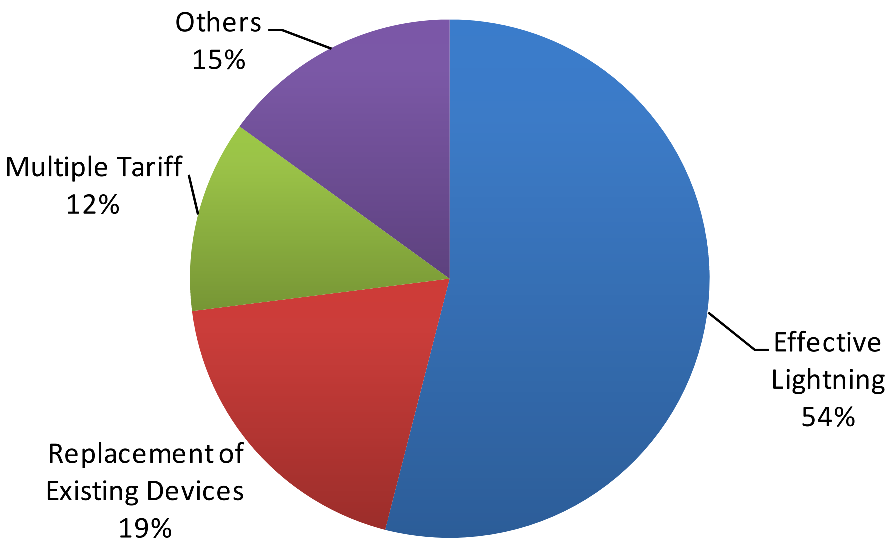


Fig. 2.10 Options to increase effectiveness of energy consumption chosen by consumers [30].

Strategic energy conservation programmes for commercial and industrial sectors are often mandatory, or by setting penalties and incentives such as reducing the fixed charge component in an electricity bill oblige the industries to improve or change their electrical appliances to better consume the energy. These programmes often involve substantial investment in performing this improvement and the benefits of that saving must be clear for the consumer to go ahead. These programmes include [30]:

1. Replace inefficient motors;
2. Change lighting system;
3. Use gas heaters instead of electric heaters;
4. Correcting the power factor; and
5. Improving manufacturing process.

2.5.2.3. Electrification:

Electrification is another aspect of DSM. Because of the diversity of consumers and loads connected to the network it is very important to have a combination of different consumers with different load patterns. This will result in having a less volatile, flatter demand curve which reduces the peak load demand. Although the base load will increase this may be supplied by more base load power plants which are usually cheaper to run in comparison with peaker units. Also electrification increases the revenue for the utilities but does required them invest supply more loads because of load diversity. For instance, if there are 10 houses, each with 10kW peak, only about 10,000kW needs to be reserved due to load diversity.

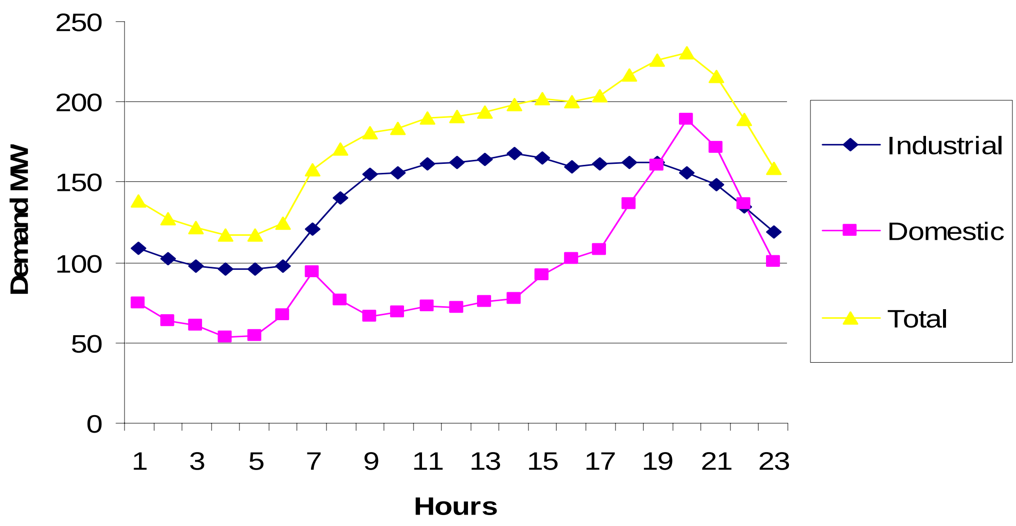


Fig. 2.11 Two types of demand patterns and their aggregated effect.

2.5.2.4. Customer Generation (Standby Generation):

Generation of electricity using customer-owned equipment on a customer's premises intended to primarily offset a customer's electricity use and sell the surplus to the national grid. In general customer generation (on-site generation) has the following benefits:

1. "Back-up" or emergency generation designed to be used during utility power outages;
2. "Co-generation," or combined heat and power applications, used by customers that have consistently high need for steam or another form of thermal energy;
3. Generation to be used during "peak demand," when it may be less costly to operate a generator than to buy power from customers;
4. "Environmentally friendly" generation used by customers who want to reduce pollution;
5. Generation to be used to improve reliability or power quality when operational needs exceed the level of service that a utility can provide.

The following forms of electricity generation have been considered for customer generation [31]:

1. Photovoltaic (solar) panels ;
2. Small scale hydro;
3. Combined heat and power;
4. Biomass such as pig waste; and
5. Small scale wind.

Micro-generation will be one of the best options for the UK in 2050 both in terms of amount of load which can be supplied by micro generation (estimated 9% of total UK electricity requirements). This will reduce domestic sector CO_2 by 3%; because of the efficiency of providing near the point of consumption which reduces the losses in transmission of gas and electricity. Micro-generation units can be either standalone or grid-connected. The second form; grid-connected is more likely to be used in the UK. This concept is now known as micro-grids. In literature micro-grid is a small power supply network to provide energy for a small community.

In 2004, 82000 micro-generation units were installed in the UK and very currently in 2007 it was estimated that if consumers could generate around 2000kWh per year the surplus electricity likely to be generated would pay for the cost of the meter.

2.5.2.5. Adjustment in Electricity Market

In the UK, One of the key selling points for the development of the New Electricity Trading Arrangements[6] (NETA) was the introduction of a two-sided market where an appropriate level of supply and demand interaction would take place. The interaction between supply and demand will take place in the future markets and in the balancing mechanism, where participants could elect to offer services directly to the system operator. Supply and demand in this market set the price and price changes time to time [32].

Electricity utilities at each scheduling period must balance the demand and supply in the system. The balancing mechanism in a deregulated energy market can be done through either supplying more electricity or reducing the demand. Currently the Short Term Operating Reserve (STOR) can be provided by contracting the deferrable loads. This

[6] In April 2005 the NETA arrangements were extended to include Scotland leading to a UK wide market. These new arrangements are called BETTA (British Electricity Transmission and Trading Arrangements).

scheme that requires a bulk load (minimum 3MW) becomes available in less than 240 minutes for a minimum duration of 2 hours upon instruction by National Grid [33].
The government report on the response to Clause 18 of the Climate Change and Sustainable Energy Act in August 2007 has considered other options such as dynamic demand for balancing services.

Because of the competition in a deregulated electricity market which will result in cheaper electricity and also security of supply to loads, electricity companies have a wide range of programmes to involve consumers in the balancing mechanism. For example, load may play the role of negative demand whenever meeting the total loads could be uneconomical or would reduce the security of the power system.

2.5.3. Issues with DSM Programmes:

A key issue in DSM is the recovery of costs and lost revenues resulting from intervention in the customers' end-use of electricity. As DSM programmes aim to reduce the need for generation capacity they are considered in Least Cost Planning (LCP) strategies in which the cheapest overall cost of delivering energy services is assessed. In some circumstances it can be shown that it is cheaper to save energy in end-use than to generate the equivalent energy. When energy efficiency is improved, the electricity company avoids fuel consumption in generation, avoids utilizing expensive units to meet the peak demand, network losses and some administration charges, and may also avoid costly network or generation reinforcement.

However, an electricity company that introduces energy efficiency measures will lose some revenue, so that energy efficiency and generation cannot be considered on equal terms. In this case to make the DSM justifiable the network planners extend the LCP to associated benefits which could be derived from DSM; such as reduction in environmental pollutants and avoided cost of reinforcement of the network. When considering these external benefits those strategies which were not cost-effective by LCP may become more justifiable. In fact a new strategy known as Integrated Resource Planning (IRP) has been developed which considers associated benefits of DSM for the electricity company [34]. For example, in the US the peak load can be lowered 30,000MW nationally and by reducing this amount of peak load, society could avoid the burning of 680 billion cubic feet of gas (BCF) of gas per year and could avoid producing 31,000 tons of NOx emissions [35].
Reliability of the network is also an important objective which can be achieved by implementing the DSM programmes. DSM programmes can help to meet both reliability

parameters (security and adequacy) by providing available resource from demand, and more flexible energy consumption pattern.

Performing most of the DSM programmes usually are costly and the benefits resulting from it should be quantified well in advance before starting any project relating to it. Communication is one of the most essential requirements especially in direct load management and can increase the cost of introducing DSM to a network [36]. Most of these programmes only have a long-term benefit for both the network and consumers. In a deregulated electricity market where competitiveness can reduce the cost, demand side management programmes are often offered to reduce the cost of tariff.

2.5.4 Current DSM methods Limitations

There are market related and technical issues in current DSM programmes. Firstly from the market's point of view, current DSM programmes aim to manage the load by either smoothing the load curve or if necessary reducing the demand to make the most efficient use of energy resources. In fact the assumption is made on the supply side nothing is going to be volatile which demand is supposed to respond to it. This assumption was true before the deregulation of electricity market, but now electricity is being traded over time at a different price. So far one of the drawbacks of current DSM methods is their inability to mitigate electricity spot prices.

Figure 2.12 shows the System Buy Price (SBP); which is the price paid by suppliers and generators. As we can see at the time of system peak SBP increases. However, in terms of domestic consumers billing, they are charged at a flat rate, regardless of all these price fluctuations [37].

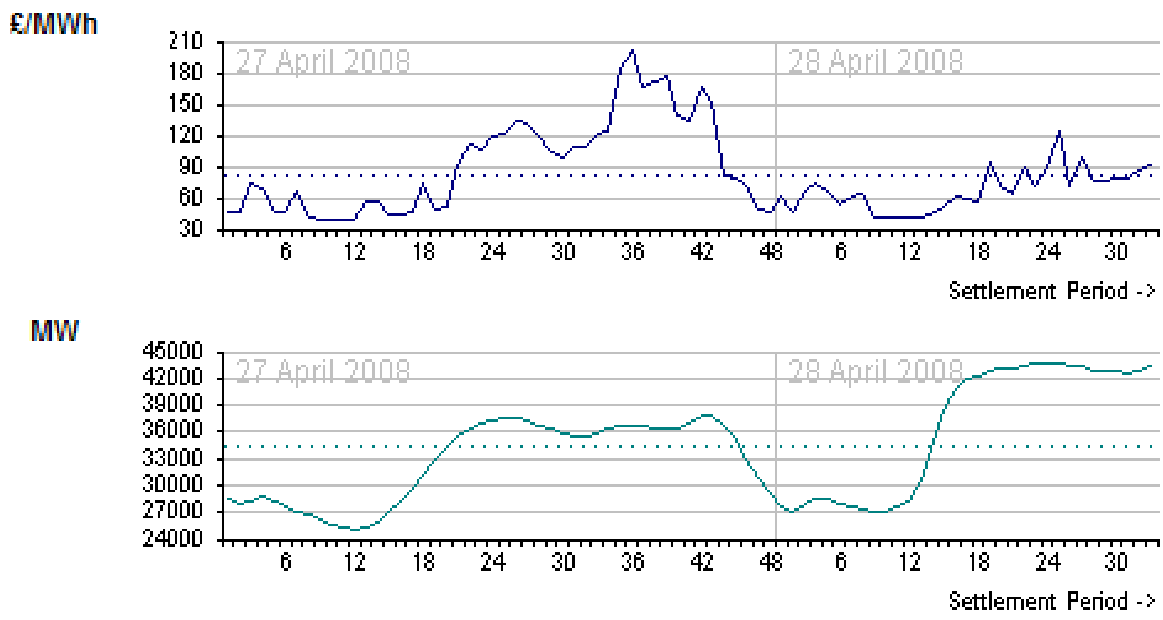


Fig. 2.12. System Buy Price (SBP) and electricity demand [37]

Secondly if technical issues are considered it must be noted that in any power system power balance must be maintained on a cycle-by-cycle basis. Extra cost has always been imposed by utilities because of error in demand forecasting, which has never been 100% accurately predicted. Future electricity networks tend to have more penetration of renewables and in renewable networks this uncertainty is further pushed by intermittency in the power output of renewable units.

There are several solutions to mitigate intermittency issues; but current DSM programmes will not mitigate this issue as none of them has the ability to respond dynamically to power fluctuations, i.e. if we consider demand shifting; it aims to shift the load to reduce the peak demand but in an intermittent system there is no guarantee that even by shifting the demand to off-peak hours it could be securely supplied.

The possible way to implement DSM in future power systems is to have the technology to enable demand to respond to these fluctuations in power delivery and spot prices. At the moment the methodology available to make use of demand response requires huge bulk load with considerable amount of commitment. The current methods in fact do not consider aggregated effect of small loads.

Currently the only technology available to do this is Tele-switching the load through radio transmitters, telephone line, TV, internet or well established ripple controllers. Smart-metering scheme in the UK aim to mitigate some of these issues in particular market issues where consumers will be billed remotely and depending on the time of consumption. Smart meters are not designed to provide the facilities to mitigate the intermittency in supplying power in the network, but as they provide bilateral communication between the system and loads this facility could be added to them.

2.5.5 Demand Response:

This section summarizes dynamic demand response (DR) resources, types and design principles for gaining customer participation, and creating customer and market value for demand response resources. Since this technology is being employed by many utilities across the world, a summary thet extent of demand response application in different countries is also presented as well as emphasis on utilization of demand response in the GB power system.

2.5.5.1 Definition of Demand Response

The United States Federal Energy Regulatory Commission has suggested a definition for responsive demand: “Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized”. This definition only covers the economy based products of demand response, whilst demand response has far more important aspects which can not be defined by such definition. Therefore in this thesis demand response in the electricity industry is defined as a ***technology which enables loads to respond to the supply, transmission and distribution side***. Demand response includes ***direct load control*** such as residential air conditioners, partial or curtailable load reductions, and complete load interruptions. It also includes ***indirect load control***, known as dynamic price response includes Real-Time Pricing (RTP), Coincident Peak Pricing (COP) or known as Critical Peak Pricing (CPP), and demand bidding or buyback programs [38].

Figure 2.13 shows the demand response’s architecture. It is observable from this figure that demand may respond to different signals, such as market activities, information sent by system operator regarding the balance of supply-demand and operation condition of transmission system, information sent by distribution system operator regarding the distribution system condition, or even to power output of an on-site generator such as wind turbine.

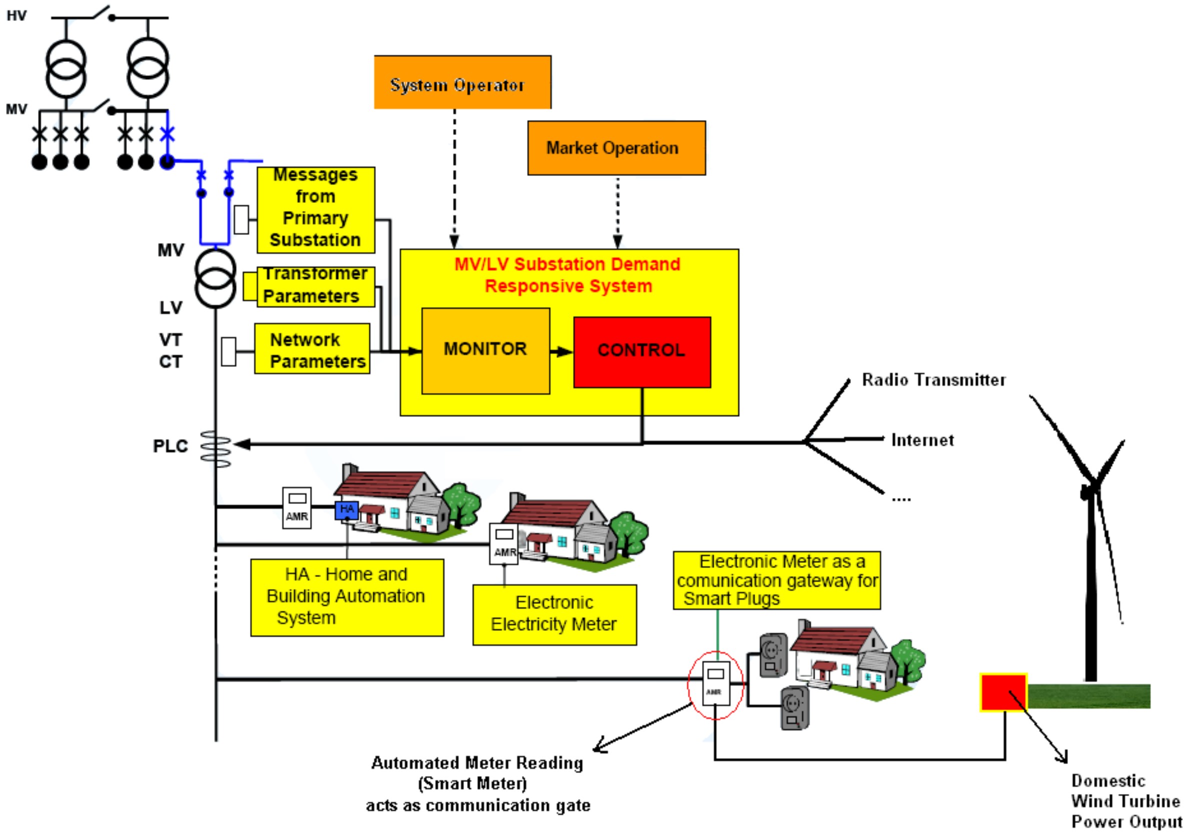


Fig. 2.13 Architecture of demand response [48]

Those loads which will be used as a resource in a demand response programme, will be connected to the main grid through a module which will detect the signals received from the sender module. This will disconnect the load from the grid, and after either a certain time period, or after the re-connect signal is received, the load is again connected. Figure 2.14 shows the domestic demand response's module installed on a washing machine.

Fig. 2.14 Domestic demand response module installed on a washing machine

Demand response benefits primarily as resource savings that improves the efficiency of electricity generation and supply. The benefits of demand response can be classified in terms of whether they accrue directly to participants or to some or all groups of electricity consumers [38]. These benefits include:

1. Consumer electricity-bill savings: reduced electricity bill and incentives earned by customers that adjust load in response to current supply costs or other incentives.
2. Bills savings for other customers: reduced market price volatility and lower wholesale market prices that result from demand response translate into reduced supply costs to retailers and eventually make their way to almost all retail customers as bill savings.
3. Reliability benefits: reductions in the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.
4. Market performance: demand response acts as a deterrent to the exercise of market power by generators;
5. Improved choice: customers have more options for managing their electricity costs; and
6. System security: system operators are provided with more flexible resources to meet contingencies.

2.5.5.2 Applications of Demand Response

The purpose of demand response is to provide the means of providing some response from the demand side to supply side and this is used for different purposes, but in general they can be classified into two main groups: economy, and reliability purposes [39, 40].

2.5.5.2.1 Economy Based Products

Economy based products are usually offered by electricity suppliers, and they are mainly voluntary, and not regulatory. Economy based products measure the consumer's electricity production dynamically, and the price they offer is neither flat rate, nor a fixed price depending on time of use in a period. It is basically a price which changes dynamically. These tariffs mainly reflects the actually price of electricity in the wholesale market.

The benefits of economy based products of demand response is illustrated using figure 2.15 which shows the changes in supply price for different demand levels. The price of electricity at different demand levels, and at different times is different. But changes in the price of electricity are always influenced by changes in demand level, and the higher the demand is, the higher the price of electricity will be observed in supply side. This is due to change in the generation dispatch pattern which increases the cost of electricity generation. In figure 2.15 it is observable that price C1 is seen when demand is D1. A typical dynamic demand response programme monitors the changes in demand from D2 to D1, and at the same time, bills the consumer depending on the price which is observable in supply side. A consumer may choose to have a control mechanism to limit its consumption (does not let the demand reaches to D1) if the price of electricity generation increases.

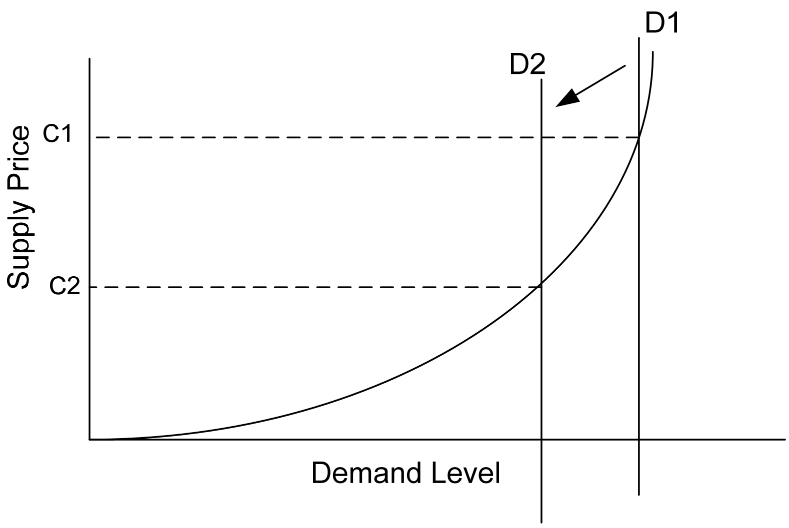


Figure 2.15 Demand level versus supply price

The benefit for both consumer and supplier will result in a different cost between the price C1 and C2 which may be shared between supplier and consumer. Consumers will benefit either through receiving payment for the duration that they have been disconnected and the capacity they had made available, or through savings made on not paying higher price for the electricity.

2.5.5.2.2 Reliability Based Products

Demand Response may also be used as a reliability resource in the system. Reliability based products unlike economy based products are usually mandatory, that is, the contract incorporates the requirement that the demand response resource be made available upon request. Reliability products may be used for different purposes such as; frequency regulation, balancing services, spinning reserve and operating reserve, and reliability margin reserve.

2.5.5.3. Current Use of Demand Response

2.5.5.3.1. North-America (USA and Canada):

As of 2007, the North American Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) include the Alberta Electric System Operator (AESO); California Independent System Operator Corporation (CAISO); Electricity Reliability Council of Texas (ERCOT); Ontario's Independent Electricity System Operator (IESO); Midwest Independent System Operator (MISO), ISO New England (ISO-NE); New Brunswick System Operator (NBSO); New York Independent System Operator (NYISO); PJM Interconnection (PJM); and Southwest Power Pool (SPP). The map of ISOs and RTOs is shown in figure 2.16.

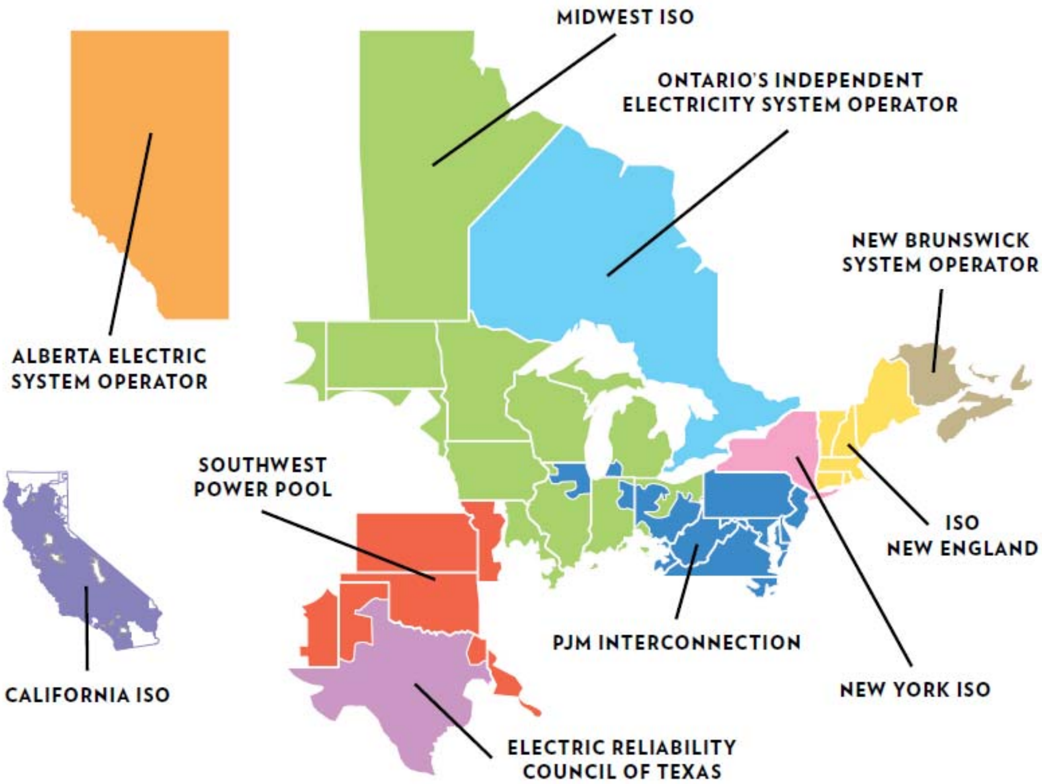


Figure 2.16 Map of North America's (ISOs) and (RTOs)

Demand response in the 10 North American ISO and RTO markets serves several critical roles in the management of the regional power grids. Almost all RTOs and ISOs offer demand response packages to eligible consumers (depending on type and size). More than 23,000 (MW) of demand response are now participating in North American ISO and RTO markets, representing 4.5% of their combined electricity demand. Researchers have found that demand response of about 5% to 15% of peak demand should result in an efficient balance between building new supply resources and reducing demand. A summary of current programmes offered by them include [41]:

- Southern California Edison (SCE) offers a range of demand response products including:
    - Capacity Biding Programme (CBP) which is a flexible bidding program where participants are paid a monthly incentive to reduce load to a pre-determined amount during CBP events with day-of or day-ahead notification. Customers may also participate through an aggregator.
    - Demand Bidding Program (DBP) which is a voluntary internet-based bidding program that offers bill credits with no penalties for reducing power when a DBP event is called with day-of or day-ahead notification.

  - Real Time Pricing (RTP) in which participants are billed for the electricity they consume based on hourly prices driven by temperature. Participants may choose to make adjustments in their electricity usage based on the hourly prices within different temperature ranges (i.e. Extremely Hot, Very Hot, Hot, Moderate, Mild Summer Temperatures, High Cost/Low Cost Winter).
  - Agricultural and Pumping Interruptible (API) which is offered to agricultural and pumping stations and is an Interruptible rate that offers a monthly credit to customers who allow SCE to temporarily interrupt electric service to their pumping equipment.
  - Time-of-Use Base Interruptible Program (TOU-BIP) which is a program for customers who can reduce their electrical usage to a pre-determined amount, also called the Firm Service Level (FSL), within 15- or 30-minutes of notice. In return, customers receive a monthly capacity credit. Customers may also participate through an aggregator.

- San Diego Gas & Electric offers demand response in the form of RTP, Emergency Demand Response Program, and day-ahead option (for balancing purposes) to all consumers.

- ISO New England offers demand response in the form of RTP, and day ahead response for customers with the peak demand of over 200kW.

- The New York Independent System Operator (NYISO) has two demand response programmes: the Emergency Demand Response Program (EDRP) and ICAP Special Case Resources (SCR) program. Both programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid.
  - The Emergency Demand Response Programme (EDRP) is designed to reduce power usage through the voluntary shutting down of businesses and large power users. Companies, mostly industrial and commercial, sign up to take part in the EDRP. The companies are paid by the NYISO for reducing energy consumption when asked to do so by the NYISO.
  - Special Case Resources is a programme designed to reduce power usage through the shutting down of businesses and large power users. Companies, mostly industrial and commercial, sign up to become SCRs. The companies must, as part of their agreement, curtail power usage, usually by shutting down when

asked by the NYISO. In exchange, they are paid in advance for agreeing to cut power usage upon request.

2.5.5.3.2. France: ERDF, a subsidiary of EDF, and the largest electricity distribution network in the European Union; deals with 33 million customers in France. ERDF introduced an optional tariff called “Tempo” for domestic customers with over 9kW peak demand, with prices that vary according to the time of day and year [42]. It colour codes days according to price (blue for low, white for medium and red for high) and each evening, a customer display unit indicates the “colour” of the following day, usually linked to the weather. Customers can then reduce their consumption on the highly priced days and ERDF can reduce peak demand (it was originally devised as a load-shifting scheme). The system also allows customers to take savings made during one period as increased comfort in others, without increasing their overall spending make it simpler.

Tempo pricing scheme has not yet been very popular among small domestic consumers, as it can only benefit large domestic households with peak over 9kW (large domestic consumers). This is due to high standing charge and small domestic consumers who may not be able to shift/curtail their consumption may even end up paying more. (37% of French households are estimated to have peak demand lower than 3kW) therefore ERDF’s tempo program has only 120,000 residential customers. Different tariffs are now introduced for participating consumers. Time of Use (TOU) is a new tariff, which measures the consumers’ consumption in real time and charges the consumers depending on time of consumption.

2.5.5.3.3. Italy: There is a large distributor (ENEL) and many medium-sized distributors owned by Municipalities (Rome, Milan, Turin, Brescia, Parma, Verona, Trieste, Bologna, etc), and a lot of small local distributors. Demand response in the form of RTP is available for consumers with peak capacity of over 12kW [43].

2.5.5.3.4. Great Britain: National Grid (NG) is the transmission network owner in England and Wales and system operator for Great Britain. Demand response is provided by NG for frequency regulation and Short-Term Operating Reserve (STOR) in which only participants who can provide over 3MW available to NG are eligible to participate. Demand response has also been used for Fast Reserve only participant who can provide minimum 50MW available to the network are eligible to participate [44]. Participants are paid an availability payment (£/MW/h) and utilization payment (£/MWh) [45].

2.5.5.4. Domestic Demand Response in GB Power System:

Although in many other utilities domestic loads have the potential for becoming responsive and participate in a range of demand response programmes (mainly RTP), but in the GB power system, domestic demand response has not yet been offered to domestic consumers. In December 2008, it was announced that a pilot project aims to study the impact of domestic demand response (provided through refrigerators) only on environment [46].

2.6 Chapter Summary

With increasing the concerns about energy security and global warming, the subject of sustainability is being credited more than ever. Within the context of the electricity industry, sustainability has different aspects; from generation to consumption and a sustainable system aims to make this cycle sustainable.

This chapter provided a summary of current legislations in the UK to transform the process of electricity generation and consumption to a more sustainable process. Several different types of renewables were discussed in this chapter, and it was highlighted that wind power is the most promising type of renewable electricity generation for the UK since wind energy has high level of availability in different parts of this country. Installing new renewable plants is subject to availability of source of energy and capability of the network to accommodate extra power. Such criteria do not make them easy to penetrate into the current electricity systems.

Demand Side Management programmes rely on two main aspects; technology based methods which directly control the demand, and behavioural programmes which by education and setting up programmes aim to indirectly make the consumers control their electricity demand. Several types of demand side management programmes were discussed in this chapter, and it was shown how current programmes are unable to mitigate the issues that act as barriers to integrate renewables. Demand response was also highlighted and current applications and users of demand response in different power systems were introduced. It was shown how in the GB power system demand response is being used as a resource by the network operator.

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Chapter 3. Economic Assessment of Value of Wind Power

Availability of wind energy which is different at different locations primarily determines the appropriate location for installing windfarms. However grid-location of windfarms must always be considered in an attempt to accurately quantify the benefits which can be achieved from windfarms during their lifetime operation to the supply network. The value of windfarms is significantly affected by their penetration and concentration, and is further affected by their location within a network. This is because the location and penetration-level of wind generation will result in significant impact on power-flow distribution across the network. The objective of this chapter is to measure the impact of grid-location of windfarms on economic and operational parameters of power system in the lifetime of a windfarm project. This chapter first develops an assessment tool to quantify the economic and operational impact of wind power in the grid. This is followed by developing different scenarios in which different penetrations of wind power are installed at different locations in the grid, and it is demonstrated how the value of wind is affected by location and network constraints.

3.1 Definition of Value of Wind Power

Wind energy is developing in almost all European countries, leading the global market with 48,545 MW of installed capacity at the end of 2006, representing 65% of the world's total installed capacity. In 2006, wind capacity in Europe grew by 19%, producing approximately 100 TWh of electricity, equal to 3.3% of total EU electricity consumption in an average wind year [1]. Key drivers of this growth-rate are climate change and increasing the security of energy supply. In the UK, government has set out a statutory commitment to cut CO_2 emissions by 60% from 1990 levels by 2050. The key element to achieve this target is displacing conventional plants with renewable energy plants, as almost 30% of total CO_2 emissions come from electric power stations. Currently more than 2.4 GW_e of wind power has been installed in the UK, with annual CO_2 reduction of 5,439,775 tonnes [2].

Windfarms have the capability to displace some conventional plants, considering intermittency and the current level of installed wind capacity (around 6%), the displacement level is limited to 35% of total installed capacity. This level is lower in higher penetration of wind generation as other issues such as balancing between demand and power may limit it down to 20% if wind has 20% penetration level [2].

Replacing the conventional plants with wind power generation plants, results in fuel-cost saving and emission reduction which may be quantified using the “Value of Wind”. Value of the wind can be assessed in very different ways with varying degrees of sophistication. It could be simply defined as just the amount of the energy which could be produced from a wind generator, nonetheless this is not necessarily an ideal definition as it neglects additional costs imposed by the variability of wind power [3]. Reference [4] presents two definitions for the value of wind with regard to intermittency. First it is the avoided cost of thermal power generators when using wind power. These are the operation costs (mainly fuel-costs) of thermal power stations as well as the fuel saved in electric boilers. The second definition is much wider, it includes all socio-economic effects of integrating wind compared with non-wind cases. For this, the socio-economic surplus (sum of consumer and producer surplus) has to be calculated. When looking at the differences in the socio-economic surplus between reference and wind cases the value of wind to the whole market is derived. Higher values of wind will result in a more economic system, reducing the payback period of capital cost required to build the windfarm, and creating a less polluted environment. Reference [5] evaluates the net benefit of wind in terms of the added capacity, reduced emission and fuel saving considering the growth rate of wind over the next decades. It also shows the sensitivity of value of wind power to changes in fuel price and emission trade costs. Reference [6] has conducted the same study in order to evaluate the value of wind in terms of emission and fuel-cost reduction while considering the effect of wind prediction based on the Dutch system which has a large amount of combined heat and power (CHP), which will result in high reserve for wind. CHP, unlike wind does not have stochastic pattern as is it controllable. Their work also shows the amount of wasted wind in different wind penetrations because of low demand, and it concludes that there are no ramp rate problems regarding wind penetration.

Value of wind is reduced by the fact that wind power is not steady; it is intermittent and highly variable so that the wind generator output will often deviate from the committed level. In order to increase the value of wind previous researches proposed several solutions. Reference [7] suggests integration of hydroelectric generation mixed with wind generation because both have a stochastic pattern (hydro is more controllable though). This method tends to increase the value of renewables instead of backing up wind plants with non-renewable units. References [7], [8] address the role of storage devices to mitigate the intermittency and ease the integration of wind energy and increase the value of non-fossil fuel plants. References [9], [10] emphasise the importance of an accurate wind prediction to increase the value of wind.

One of the most influential factors in increasing or decreasing the value of wind, is the network capability to accommodate, and transport the power coming from windfarms. The network's capability to carry power varies significantly from one place to another, thus for the same windfarm, total energy supplied from wind power at different locations could differ considerably [11]. Reference [12] has presented a method similar to the optimal power-flow method with a difference where the new method considers minimizing total losses depending on the amount of injected power through renewables to determine the optimum location of resources in distribution planning. Reference [13] has also aimed to find the optimum location of windfarms in order to increase the benefits which could be achieved from wind power, with respect to minimizing the transmission lines' losses by considering both active and reactive power losses and proposes an algorithm for voltage scheduling in order to reduce the losses.

To summarise, all previous researches in evaluating the value of wind did not consider the detailed network modelling and thus the network constraints, and the impact of those constraints on the net benefit of wind power. It is shown in this chapter that only considering network losses as the only tool to find the optimal location of distributed generators does not always result in making the maximum profit from wind power. This chapter presents a framework that evaluates the value of windfarm in terms of fuel-cost saving and emission reduction, while considering the impact to the network for different penetration levels installed at different locations in the grid. Various levels of wind power penetration have been simulated in remote areas, close to load centres, and at transmission level. This chapter describes the impact of grid locations of a windfarm on network losses, production cost, emissions, security of the system, and hence the value of wind.

3.2 Value of Wind Power Parameters

Electricity generation through any source of energy has two major costs: capital costs which includes the cost of building the power plant and connecting it to the grid including any network reinforcement; and running costs such as buying fuel, maintenance, operation and carbon-capturing. Before building a plant the cost-effectiveness analysis must be performed in order to quantify the payback period and revenue which will be made in the lifetime operation of the plant.

The capital costs associated with windfarms mainly depend on the location where the construction is to be done. Commercial on-shore windfarms have lower capital cost around £800/KW_e in comparison with off-shore windfarms, which cost around £1330/KW_e to be built [14].

Electricity production through wind is not currently the cheapest form of electricity generation. At present, each unit of electricity generated by on-shore and off-shore windfarms costs around 3.5p/kWh, and 5.6p/kWh respectively [14]. Although windfarms have “zero fuel-cost” but because of their low load factor, the amount of energy they can produce in their lifetime is lower than in conventional plants. Table 3.1 shows the load factor of different types of power plant [15].

TABLE 3.1.
Load Factor of Different Power Plants [15]

Type of Plant	Load Factor	Type of Plant	Load Factor
Sewage Gas	90%	Waste Combustion	60-90%
Landfill Gas	70-90%	Hydro	30-50%
Combined Cycle Gas Turbine (CCGT)	70-85%	Combined Heat and Power (CHP)	70-90%
Coal	65-85%	Farmyard Waste	90%
Nuclear Power	65-85%	Energy Crops	85%
Wave Power	25%	Wind	25-40%

Therefore while deciding to displace cheaper generation units with windfarms, estimation of the benefits which could be translated to cost, is important in order to evaluate the cost-effectiveness of a project. The benefits associated with wind power are as follows:

3.2.1. Fuel-Cost Saving of Conventional Plants through Wind Power:

Different fuel-costs are associated with different power generation technologies; fuel-cost is zero for wind, hydro, wave and solar, it is positive for oil, gas, coal and nuclear plants and it is negative for technologies which generate the electricity from waste.

Fossil fuel must be supplied to conventional plants, to generate the electricity. Generating the electricity from wind will result in less operating the conventional plants, and therefore saving on cost of fossil fuels. As fossil fuels have volatile price, the amount of saving depends on the fuel price at the time of operating the windfarm. By increasing the wind power penetration this saving considerably decreases because of intermittency of wind, resulting in more frequent start-up of conventional plants which leads to higher operation cost [16].

3.2.2. Emission Reduction:

As power production through wind has zero emissions therefore the equivalent cost of emission reduced by wind power must be included in evaluating the value of windfarm.

Major types of emission to air which are usually being displaced by wind power include: CO_2 emissions; NO_x and SO_x emissions. The amount of displaced emission is translated to price and is added on the value which is given to wind because of saving on fuel-cost. A terminology known as “Social Cost of Carbon” in the UK currently determines the cost of CO_2 emission [17]. The social cost of carbon (SCC) measures the full global cost today of an incremental unit of carbon (or equivalent amount of other greenhouse gases) emitted now, summing the full global cost of the damage it imposes over the whole of its time in the atmosphere. The SCC signals how much society should, in theory, be willing to pay now, to avoid the future damage caused by incremental carbon emissions. Currently SCC in 2007 is £27 per tonne of CO_2.

3.2.3. Added Capacity:

Reliability in power system depends on two major parameters: security; and adequacy of power. By adding generation capacity through windfarms into the system, one condition of having a reliable system is met. This also mitigates issues such as security of supply which concerns relying on the power from conventional plants which are dependent on abundant fossil fuels but with limited reserve.

3.2.4. Saving on Capital Cost of Building Other Plants:

Another advantage of increasing the penetration of wind power in the system, is to lessen the need for building new conventional plants. This will result in saving on the capital costs of building new conventional plants. The capital costs, per unit output of wind power are normally lower than comparable costs for thermal stations and very much lower than hydroelectric plants. This is due to the cost of the extensive civil-engineering works involved and to the very long periods of construction of projects such as hydroelectric plants and thermal units, during which costs are incurred and interest has to be paid, without receipt of any compensating income. Table 3.2 shows the different capital cost of conventional and windfarms [14].

TABLE 3.2.
Capital Cost of Power Plants (2008) [14]

Type of Plant	Capital cost, £/kW
Gas (combined cycle)	400
Coal (pulverised fuel)	800
Coal-IGCC with CCS	1600
Nuclear	1770
Wind--onshore	800
Wind--offshore	1330

Besides, shorter construction time of windfarms than many types of conventional plants will reduce the “planning margin” requirement for installed capacity over maximum demand.

Wind power has a capacity credit, and the capacity credit is around the mean wind power output for small penetrations of wind power in the grid, and drops to a value near the minimum wind power generation for larger penetrations. This is because of the intermittency of wind, a windfarm with “a” MW capacity does not displace “a” MW conventional plant and this level of displacement varies in different power systems [18], [19].

3.2.5. Embedded Generation Benefits:

A small percentage of the energy transferred across the network is lost, due to physical processes such as [20]:

1. Resistive losses in cables 61% of total losses;
2. Fixed losses: 18% of total losses(consists of corona and iron losses can be around 24% of total losses in adverse weather);
3. Substation transformer heating losses: 10% of total losses; and
4. Generator transformer heating losses: 11% of total energy loss.

If windfarms are integrated into the power system at distribution level, then the additional benefit of this integration will be reducing the power-flow across the network, resulting in both real and reactive power loss reduction across the network. The calculation of these benefits is a complex issue and they vary both regionally and locally. However, these benefits may result in costs if penetration of wind energy in remote regions requires network reinforcements [20].

3.3. Assessment Framework of the Value of Wind Power

A long term generation scheduling process, combined with a reserve calculation tool is developed and implemented. The reserve calculation tool is used to determine the reserve requirement with regard to wind forecasting errors. The generation scheduling without wind is performed to determine the base-case and while the windfarms’ location and penetration are different for each scenario the objectives are:

1. To determine the optimal wind penetration level,
2. To study the location of windfarms and determine the best location in the grid which enhances the economical and operational values of integrating windfarms.

This methodology can be applied to other non-conventional energy sources. The proposed methodology consists of the following four steps:

1. Generation mix planning;
2. Hourly generation scheduling;
3. Production cost, emissions, security indices, capacity displacement, energy value; and
4. Lifetime value of wind.

In an attempt to evaluate the value of wind at different locations and with different penetrations, the simulations are performed with and without wind. By performing unit-commitment in the no-wind case, production cost, total CO_2 and NO_x emissions, as well as security violation index have been evaluated as a benchmark. Then by increasing windfarms installed capacity and moving certain amount of penetration at each scenario in different locations of the network those parameters have been re-evaluated. Windfarms for each scenario were located at different busbars; in transmission level and distribution level, close to generation units and close to the load. Fig. 3.1 shows the algorithm of calculating the value of wind for one year, and the lifetime value of wind.

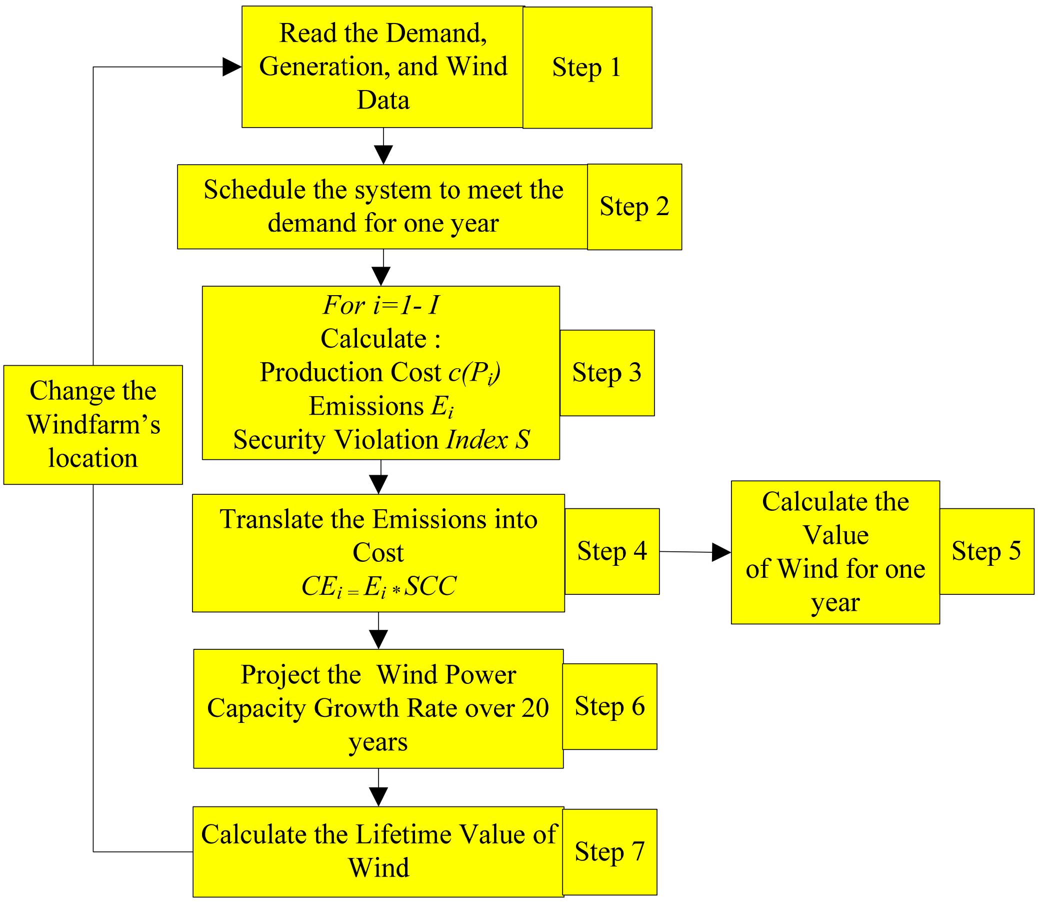

Fig. 3.1. The algorithm of calculating the value of wind.

3.4 Step 1: Input Data:

3.4.1. Network:

The IEEE 30-busbar system was chosen for our study. The system consists of 8 conventional plants; 4 coal fired plants, 4 open cycle gas fired and a windfarm. Fig. 3.3 shows the IEEE 30 busbar test system [28].

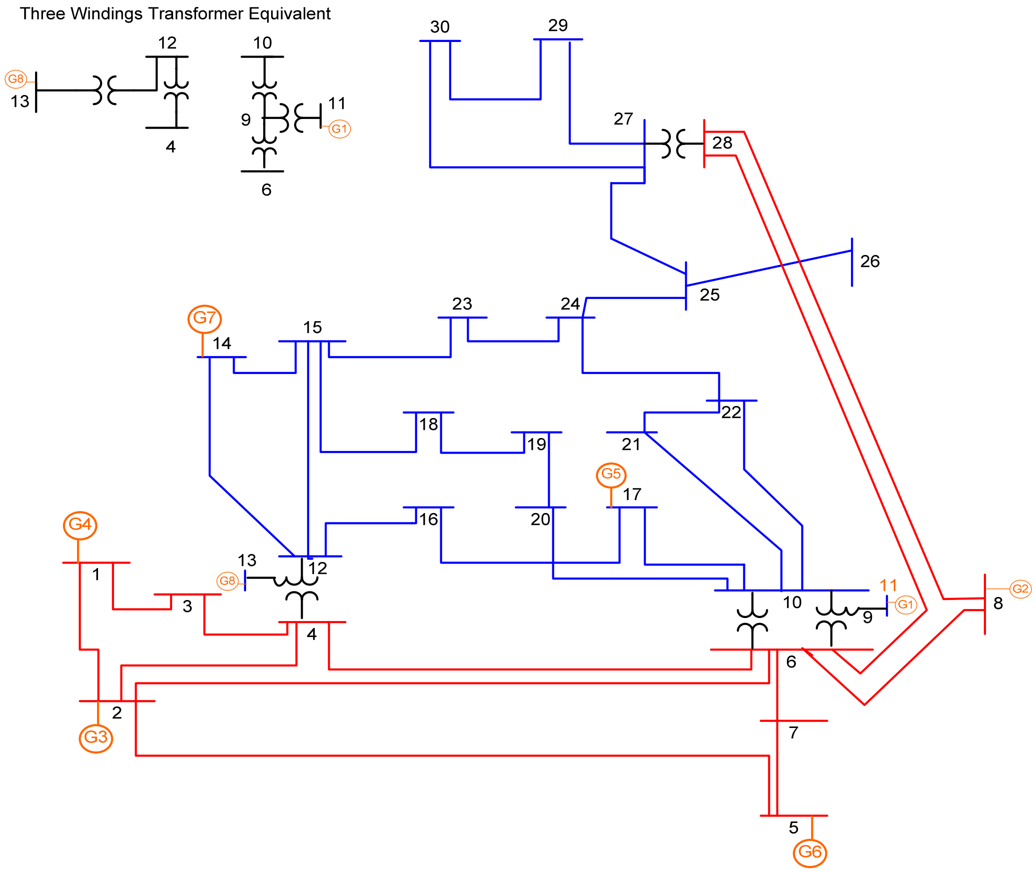

Fig.3.2. The IEEE 30 busbar used as test system [28].

3.4.2 Demand Data:

The demand data including the load profile is derived from [28] for the entire unit-commitment horizon - one year. The peak demand is 283.4 MW and minimum demand is 97.3MW. Fig. 3.4 shows the load duration curve for our study.

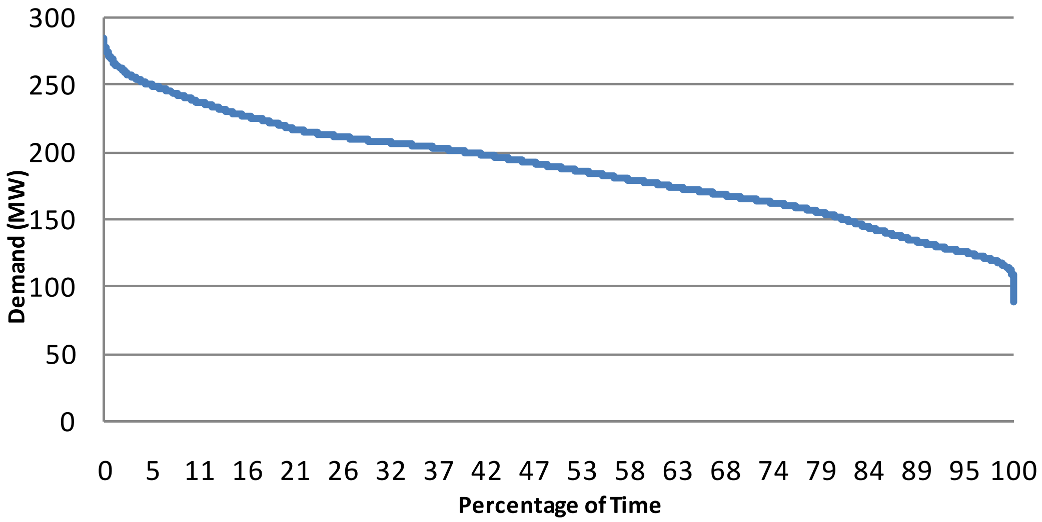

Fig. 3.3. Annual load duration curve [28].

3.4.3. Generators Data:

As the purpose of this study is to evaluate the value of wind in a system with conventional plants, the generator's fuel coefficients have been taken from [29] for coal and gas plants. Generation fuel-cost coefficients and characteristics are shown in Table 3.3 & 3.4 respectively.

TABLE 3.3

Generators' Fuel-cost Coefficients [29]

Unit Type (No)	*a*	*b*	*c*
Gas (1)	0.02	1.2	80
Gas (2)	0.01	0.8	50
Gas (3)	0.06	4.5	60
Gas (4)	0.01	0.4	55
Coal (5)	0.06	5.2	23
Coal (6)	0.05	2.2	22
Coal (7)	0.05	3.0	30
Coal (8)	0.04	1.8	44

TABLE 3.4.
OTHER GENERATORS CHARACTERISTICS[29]

Unit	Min Up Time	Min Down Time	Ramp rate	P_{min}	P_{max}	Busbar No.
1	1	1	3	5	35	11
2	1	1	4	10	45	8
3	2	1	3	8	40	2
4	1	2	4	10	60	1
5	3	2	6	5	25	17
6	4	2	6	5	80	5
7	2	3	7	5	35	14
8	3	2	7	5	30	13

3.4.4. Windfarm Data:

Wind speed data have been obtained from the United Kingdom Meteorological Office (UK-Met Office) for a period of one year. The data concerns hourly wind speed with a resolution of 0.1 m/s for South west of the UK. As one of the objectives of this research is to assess the effect of different penetrations on the value of wind, the capacity of the added windfarms will be varied. It has been assumed that the windfarms consist of different numbers of identical wind turbines; each with 600kW capacity. The wind turbine power curve is shown in Fig. 3.5.

The load factor of the windfarm considered in this study is 27% in which its capacity is different for each case as shown in table 3.5. The selection of busbars where windfarms are to be installed for each scenario is as follows: a scenario in which the windfarm is located at transmission level (bus no. 5), or else at distribution level close to loads center (bus no. 19), then in remote areas where demand is high (bus no. 30) or where the demand is relatively low (bus no. 26).

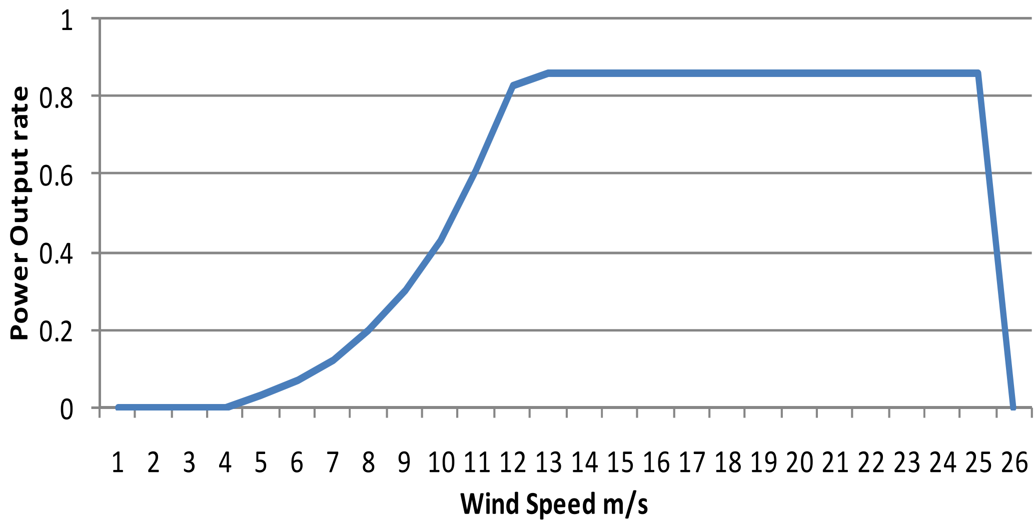

Fig. 3.4. Wind energy conversion characteristic of the considered wind turbines.

3.5. Step 2: Generation scheduling problem:

Variable costs are dependent on the operation pattern of generators. Several technical factors must be taken into account to determine the best operation pattern of a set of generators in a system. This is defined in Generation Scheduling Problem. Generation scheduling problem is an optimization problem which is defined in the following section. Generation units in any power systems are scheduled to deliver required amount of power to be consumed by end-use loads. The problem of finding the best operational level of each generation unit, in terms of fuel cost and emission level, to serve the load is called generation scheduling:

$$Min \quad \chi(c,e) = (\sum_{i=1}^{N}[c(P_i) + e(P_i)]) \tag{3-1}$$

where $\chi(c,e)$ is generation scheduling function consists of two main elements of *c* which is the cost function, and *e* which represents the emission function, for power output of P_i for set of *N* generators.

Generation Scheduling is an optimisation problem which must be solved in order to find a solution for any given system. Since this problem includes many constraints which must be taken into account, it requires an optimisation method (solver). In this chapter Dynamic Programming approach has been used in order to solve this problem [16].

3.5.1. Production cost; $c(P_i)$:

Different electricity generation technologies exist in power systems; the most common ones include thermal plants, hydro-electric generation and windfarms. Each can be represented in generation scheduling with a cost function. The production cost of a power system consisting of *i* generators each with individual production cost $c(P_i)$ expressed mainly as a function of its real power output P_i can be modelled of fuel-cost, start-up cost, shut-down cost:

$$c(P_i) = FC_i(P_i) + ST_i(P_i) + SD_i(P_i) \tag{3-2}$$

Thermal plants have a quadratic fuel cost function as shown in (5):

$$FC_i(P_{it})=a_i \times P_{it}^2+b_i \times .P_{it}+c_i \tag{3-3}$$

where FCi is fuel cost of generator *i* having power output of P_{it} in (MW), and a_i, b_i, c_i are generator's fuel cost coefficients.

-Start-up cost:

$$ST_i = TS_i + [1 - e^{(D_i / AS_i)}] \times BS_i \tag{3-4}$$

-Shut-down cost:

$$SD_{it}=K \times P_i \tag{3-5}$$

3.5.2. Emissions:

Some of the pollutants produced by conventional plants in large quantities are: Sulphur Dioxide SO_2, Carbon Dioxide CO_2, Nitrogen Oxides NO_x and Hydrocarbons. Coal fired plants also produce fly ash and metal traces. NO_x and CO_2 emissions are highly nonlinear in *P* and are difficult to model. This chapter adopts the commonly used [21] second-order polynomial function with the exponential part to represent the NO_x emissions function. Similar expressions are also used for CO_2 and particulate emissions. Total emission in this chapter is represented by NO_x and CO_2 and is a function of power outputs, expressed by:

$$e_{ij}(P_i) = \alpha_{ij}.P_i^2 + \beta_{ij}P_i + \gamma_{ij} + \delta_{ij}.e^{\varepsilon_{ij}.P_i} \tag{3.6}$$

The total emission from each unit E_i can be calculated as the sum of individual pollutants.

$$E_i = \sum_{j=1}^{J} e_{ij} \tag{3.7}$$

Where *j* is total number of pollutants considered in a dispatch.

3.5.3. Security:

The Security function consists of three main objectives; the sum of voltage deviations at busbars, apparent power-flow violations in branches and reactive power limit violation generated by generation units:

$$S = \tau_v.S_v + \tau_b.S_b + \tau_g.S_g \tag{3.8}$$

- Voltage Security Violation

This is a term which deals with the voltage at bus bars which must always remain between a minimum and maximum limit at all generation scheduling blocks.

- Apparent Power-flow

Apparent flow (complex power; $S = P + jQ$) in transmission lines is one of the constraints which sometimes cause de-committing a unit or keeping its output up to certain level as transmission lines are running up to their maximum capacity; a term which is known as transmission congestion.

- Reactive Power generated by units

In power system, voltage collapse usually happens when the reactive power is not enough to meet inductive loads such as induction motors etc. Generation units, despite the fact that they require reactive power to generate active power (if induction generators are considered), have also a limited capability for generating a certain amount of reactive power and exceeding this limit will reduce the security of the system. For a given generator shaft power, its reactive output is limited by either field or armature winding heating. These thermal capabilities impose limitations on the generator reactive power capability, which is normally represented by synchronous generator capability curves, as shown in Fig. 3.2 [34].

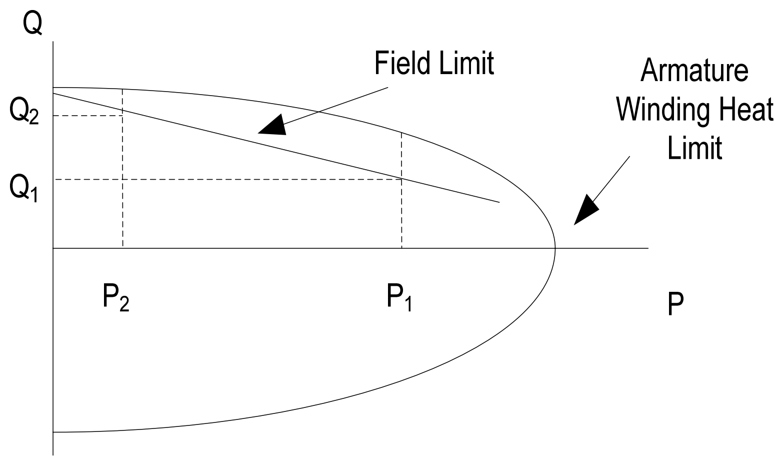

Fig. 3.5. Synchronous generator's generation capability curve [34].

Security violation indices are calculated by following equations:

$$s_v = \sum_{m=1}^{M} (\left|V_m^{ideal} - V_m\right| - V_m^{\partial})^2 \ if \ (V_m^{ideal} - V_m) > V_m^{\partial} \tag{3.9}$$

$$s_b = \sum_{k=1}^{K} (\left|S_k^{\max} - S_k\right| - S_k^{\partial})^2 \ if \ (S_k^{\max} - S_k) > S_k^{\partial} \tag{3.10}$$

$$s_g = \sum_{i=1}^{I} (\left|Q_i^{\max} - Q_i\right| - Q_i^{\partial})^2 \ if \ (Q_i^{\max} - Q_i) > Q_i^{\partial} \tag{3.11}$$

where *m, k* and *i* are the numbers of bus bars, branches and generating units respectively. V_m , S_k and Q_i are voltage at bus *i*, apparent power-flow in branch *k* and reactive power generated by unit *i*. The *ideal* superscript denotes the desired value of the respective variable and the *max* superscript denotes the rated value while the ∂ superscript denotes the tolerance allowed for the variable, which is the maximum deviation allowed from the desired or rated value [16].

3.5.4. Generation Scheduling with Wind Power:

Wind power provides a degree of sophistication over the generation scheduling problem by incorporating the effects of limited predictability and variability. Inaccuracies in wind forecasting, necessitates the use of extra system reserve. To counter these problems, some windfarms may be combined with diesel generators or energy storage units such as those hybrid systems shown in [15], [22]. Another routine is to use conventional plant, such as open cycle gas turbine (OCGT) units, to provide additional reserve but this will inevitably limit the competitiveness of wind power.

Wind power in the generation scheduling and economic dispatch problem is usually given priority dispatch because of zero fuel-cost and green energy certificate carrier. In this case providing the wind is blowing and wind units are operating, thermal units can operate in their lower output levels in order to be available to ramp up or down to accommodate the variability of the wind which may lead to inefficient use of conventional plant. There may also be an increase in the number of start-ups and shut-downs of other units as system operators attempt to coordinate the following of the fluctuating load throughout the day and the variable output of the wind generation [16].

In this chapter wind is modelled as “negative load” Therefore, load demand is reduced by the forecast wind power producing a new load demand. This new load demand is then used in the economic dispatch process.

3.5.5. Generation Scheduling Constraints:

3.5.5.1. Crew constraint:

With thermal power plants, particularly starting up and shutting down generation units needs a certain number of crews to operate and sometimes because of lack of crews it is impossible to start up or shut down more than one unit at a time.

3.5.5.2. Minimum up and down time:

In some power plants i.e. nuclear, hydrothermal etc., because of economic efficiency and technical constraints it is impossible to shut down a unit before the minimal required in-duty period is reached; again once a unit is turned off it may be impossible to start it up and bring it back to the system before a certain minimum number of off-duty hours is reached. These units have different characteristics from “*Peaker*” units; for instance gas turbine units which are not usually subject to a minimum up and down time and can start up and supply peak demand and shut down straight after peak period with a minimal cost.

3.5.5.3. Generator Ramping Up and Down Rate:

The ability to increase (or decrease) the output power of a generator over a certain time of period is called *Ramping Rate.* Generation units with different capacity will have different ramping rates and they must be considered in generation scheduling to ensure the safe operation of generation plant due to electricity demand variability.

3.5.5.4. Reliability Must Run Units (RMR):

In the power system, generation units that the system operator determines are required to be on-line (at certain times) to meet applicable reliability criteria requirements [23], such as voltage support or during system maintenances are known as Must Run units. Besides, some units are required to be on-line due to other reasons apart from generating the electricity; such as hydro-units which may need to operate due to delivering water for agriculture.

3.5.5.5. Generator output limits

Generation units must be scheduled to operate within their maximum and minimum rated output in terms of both active and reactive power:

$$PG_i(\min) \leq PG_i \leq PG_i(\max) \qquad QG_i(\min) \leq QG_i \leq QG_i(\max) \tag{3.12}$$

3.5.5.6. Spinning Reserve and Negative Reserve:

-Spinning Reserve:

Available generation capacity in the system must be greater than load demand, network losses and required spinning reserve. Spinning reserve is the amount of power always available to be dispatched in the system to meet sudden demand increase or being used in minor contingencies.

$$\sum_{i=1}^{I} Pi \geq demand + network \quad losses + spinning \quad reserve \tag{3.13}$$

$$\sum_{i=1}^{I} (CSPP_i - P_i, SP_i) \geq spinning \quad reserve \tag{3.14}$$

-Negative Reserve Requirement

Negative reserve is to make sure at each scheduling period there are sufficient generation units in the system which are running at certain amount and higher than their “minimum generation limits”. This is to allow their output to be reduced in cases where demand is lower than it was forecasted [24]. Negative reserve in the systems with high penetration of wind power is an important subject which has to be maintained particularly when wind power is also higher than it was forecasted. If not, then to avoid power surplus, wind power curtailment occurs.

$$\sum_{i=1}^{I} (CNPP_i - P_i, NP_i) \geq Negative \quad reserve \tag{3.15}$$

Equation 3.15 indicates the constraint imposed by the negative reserve requirement, which requires in the system enough generation capacity to be scheduled in a way to provide enough negative reserve required for wind power.

3.5.5.7. Additional Reserve Requirement for Wind Power:

So far, the additional reserve requirement has not been considered for the wind power and total system reserve is calculated deterministically. In reality, the reserve requirement must change with changes in the penetration of intermittent generation to maintain the same level of reliability [25-27].

In order to maintain negative reserve, total forecasting error in the system must be considered. While wind forecasting error is considered as the main objective, demand forecasting error is assumed to be zero for the sake of simplicity, and negative reserve has been maintained by taking into account ramp-down of generators in a way that at each scheduling period, generators can reduce their output down to maximum error in forecasted wind power at that period. To ensure that the scheduled generations during period *t* provide spinning reserve and negative reserve, the following constraints have been enforced in the generation scheduling problem at each scheduling period:

$$\sum_{i=1}^{I} CSPP = \min\ [\ (P_i^{\max} - P_i\ )],\ \ (Ramp_i^{up}\ )] \tag{3.16}$$

$$\sum_{i=1}^{I} CNPP = \min\ [\ (P_i^{\min} - P_i\ )],\ \ (Ramp_i^{down}\ )] \tag{3.17}$$

where $P_i^{\max}$ and $P_i^{\min}$ are maximum and minimum feasible operation for unit *i* respectively.

3.6. Step 3: Results and Discussion

3.6.1. Reduction in Network Losses:

As mentioned in section III, one of the benefits of distributed generators is their impact of reducing the network losses. The calculated losses in this study are only “resistive losses in cables”. Considering the DC power-flow model [31], it is possible to estimate the losses for the scheduling period of *T* by:

$$Losses = \sum_{t=1}^{T} (\sum_{l=1}^{L} Rs_l \times F_{l,t}^2) \tag{3.18}$$

The total network losses for computed busbars are plotted in fig. 3.6. Total energy loss across the branches in scenario 1 is around 2.7% of the total generated energy. As more wind capacity is added to the system, total system losses tend to decline. This reduction varies between different nodes. Node 30, which is a remote node with around 10.6 MW load tends to benefit the system more in terms of power loss reduction compare with other nodes. This is due to reduction in power-flow across the branches to supply the demand at this node. This situation is different for node 5, in which by increasing the wind penetration, total energy losses tend to reduce slightly although around 94 MW load is located at this node. In this node an 80 MW coal plant has already been installed and due to economic characteristics of coal plants (cheap to run), in the scheduling problem, this plant is operated most of the time and supplies the demand at this node and the surplus of load has to be supplied through other plants.

By installing the windfarm at this node, although the total losses will be reduced, this reduction will be limited in the case of high penetration of wind power as the power generated from wind has to be supplied to other nodes and results in increasing the power-flow across the branches.

TABLE 3.5.

SCENARIO CASES EXPLAINED

Case no.	Wind Power Penetration	Installed Wind Capacity (MW)
1 (base case)	0%	0
2	3%	10
3	4.7%	16
4	7%	26
5	8.4%	30
6	10%	35

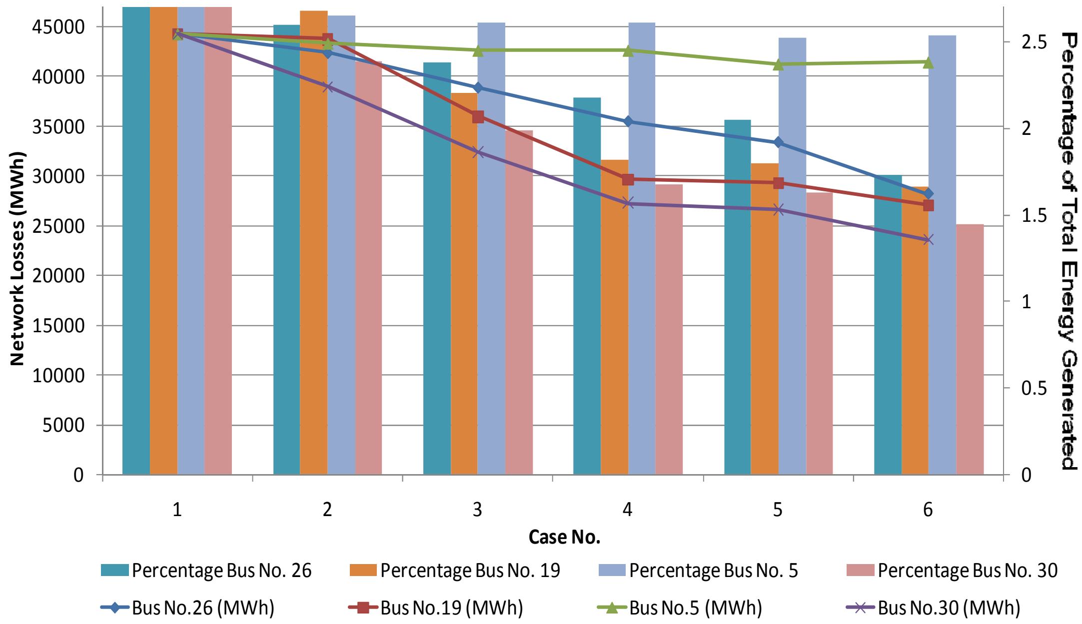

Fig. 3.6. Network losses in MWh, and in percentage of total energy.

3.6.2. Production Cost Saving

Total production cost which is the sum of total running cost of conventional plants for each case is shown in Fig. 3.7. In case no. 1 when there is no wind power in the system highest production cost is observable, since only conventional plants are to supply the demand. Because no operational cost is associated with windfarms, by adding more wind capacity to the system, production cost tends to drop. As can be observed, the degree of reduction in production cost in each scenario is different for different locations where the windfarms is installed. In case no. 2 where only 10MW wind capacity is added to the system nodes 26 and 30 face the lower production cost (higher saving). This is because these nodes are remote nodes and in the base case it was required that power to be transported from other nodes to supply these nodes. That involved higher losses and in some cases changes in dispatch pattern, which involved a number of start-ups and shut-downs which increase the cost.

By installing 10MW of wind at these nodes, higher efficiency, and a saving on production cost is achieved. But when looking at higher penetrations of wind power, it can be seen that wind capacity added to the system at nodes 5 and 19 will result in higher savings. For node no. 19, since it is located at the distribution level and close to other nodes. By installing higher penetrations of wind power, this node and other neighbourhood nodes will be supplied mainly by wind power, and it will minimize the power losses. For bus no. 5, since this bus has the highest load level with a peak demand of 94.2MW, the higher the penetration of wind is, the higher the savings will that result. However an 80MW coal fired plant is installed at this node and the power generated from both this power station and windfarm has to be transported to other nodes, it does not reduce the power losses which are usually high at distribution level. The total saving is only achieved through savings on the coal fire station's the fuel.

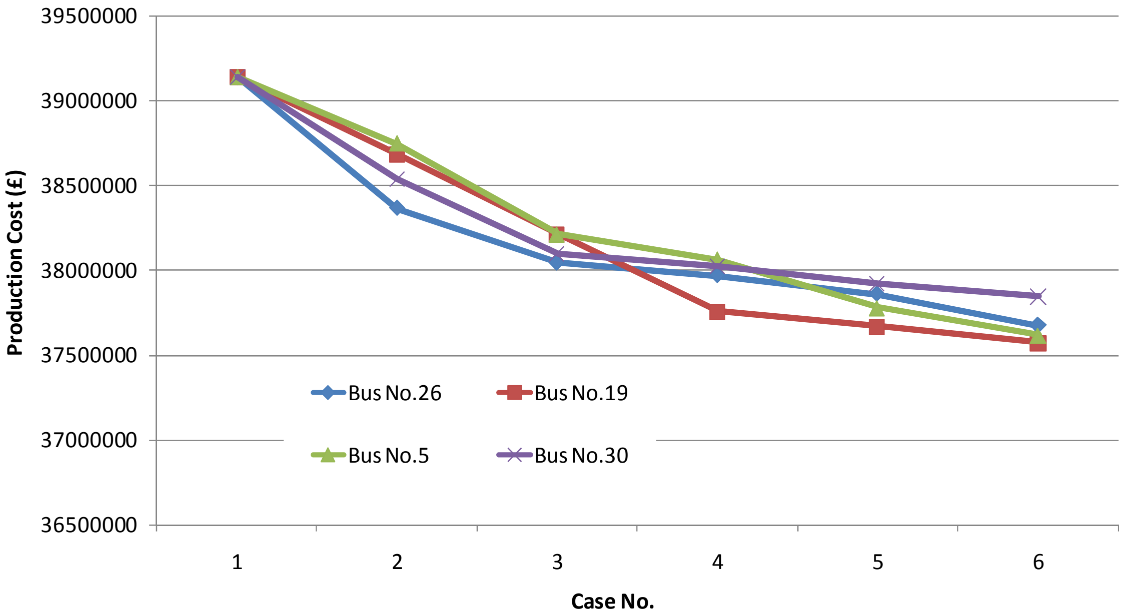

Fig. 3.7. Total production cost.

3.6.3. Emission Saving:

Total emission in the network comes from conventional plants and only NO_x and CO_2 emissions are considered in this study. Because wind power has an intermittent nature and its behaviour is dictated by short-run and long-term climatic conditions. Daily demand level varies at different hours of the day and it is being supplied by different generation technologies, resulting in different levels of emission during the day [32]. Therefore the amount of emission reduced by wind depends on level of wind power and demand. The long-term effect of wind power in the network is considered by giving priority dispatch to wind power. It means that for every MWh of wind generation produced at a certain hour during the day, it is assumed that there will be another MWh of power production that will be backed off from conventional plants at that particular hour or demand level.

By increasing the wind penetration and locating the windfarms in different locations, total emissions against various wind penetration levels are calculated. The results are shown in Figs. 3.8 and 3.9. In general by increasing the wind penetration, it is expected to see a reduction in emission levels because of the energy produced by conventional plants being displaced by wind power. This reduction level varies at different locations where the windfarm is installed because of the network's impact.

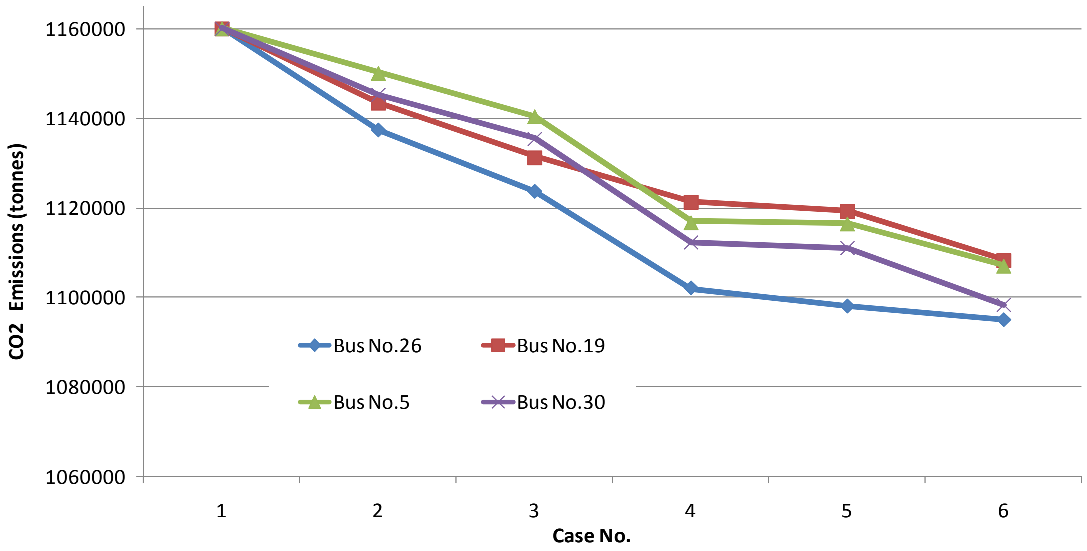

Fig. 3.8. Total CO_2 emission.

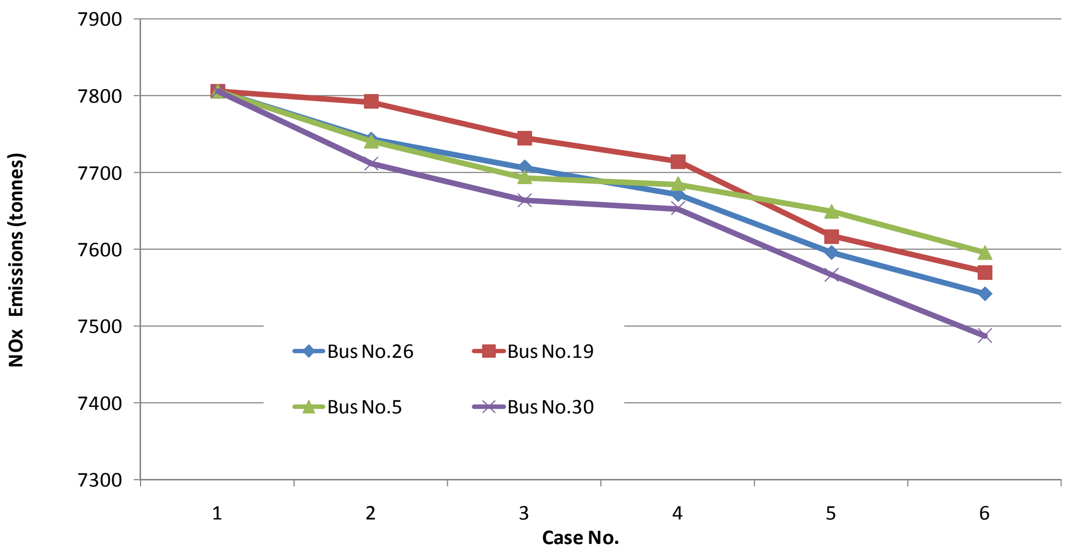

Fig. 3.9. Total NO_x emission.

3.6.4. Impact on Security:

Security constraints are either MW-related or Voltage/MVar related:

1. lines mw or MVA flow rating;
2. power-flow limits (MW flow limit);
3. voltage limits at busbars;
4. reactive power of generators; and
5. transformer tap-changer positions (MVAR).

One of the key constraints in locating windfarms in the grid is network limitations in accommodating and transferring power on branches. Therefore one of our objectives is considering thermal limits of transmission lines. Another objective is the amount of reactive power from generation units to maintain voltage profiles. System operators in the world have different criteria to allow voltage deviations. In the UK, under normal system conditions, both peak or off peak load conditions, the voltages need to be maintained between 94% and 106% of the nominal value.

In our study the aim is to lessen the security objectives as well as minimizing the fuel-cost and emissions of thermal plants. Each security objective has a minimum and maximum allowed amount of deviation, and the aim is to minimize these deviations, such as the maximum and minimum allowed voltage at each busbar. It must be noted that these values will change at each scheduling session and the final security violation index is the total amount of the security violation indices for the scheduling horizon in our simulation the scheduling horizon; 8760 hours or one year.

It can be observed from Fig. 3.10 that when the windfarm is connected to busbar no.5 the security violation increases by increasing the wind penetration unlike other cases. The reason for that is that by installing windfarm at busbar no.5 voltage on other buses will deviate more from their nominal value. One reason behind increasing the total security violation index for a scenario in which windfarm is installed at bus no. 5 is its impact on voltage profile of other busbars which is investigated in fig. 3.11. Installing the windfarm at this busbar results in a worse voltage profile at other busbars with higher deviations, while at other busbars increasing the wind power penetration minimizes the voltage deviation and improves the voltage profile in all busbars.

Fig. 3.12 and 3.13 compare two different cases when windfarm is connected to busbar no.30 and no.5. Fig. 3.12 shows that by installing windfarm in busbar no. 30 and by increasing the wind power penetration, voltage deviation tends to be minimized, resulting in increased overall security of the network. However as it can be observed from Fig. 3.13, by installing the windfarm in busbar no. 5 because the busbar itself is a weak busbar, the voltage rise happens at this busbar by increasing the wind penetration and voltage at other parts of the network also deviates more which will result in a less secure network.

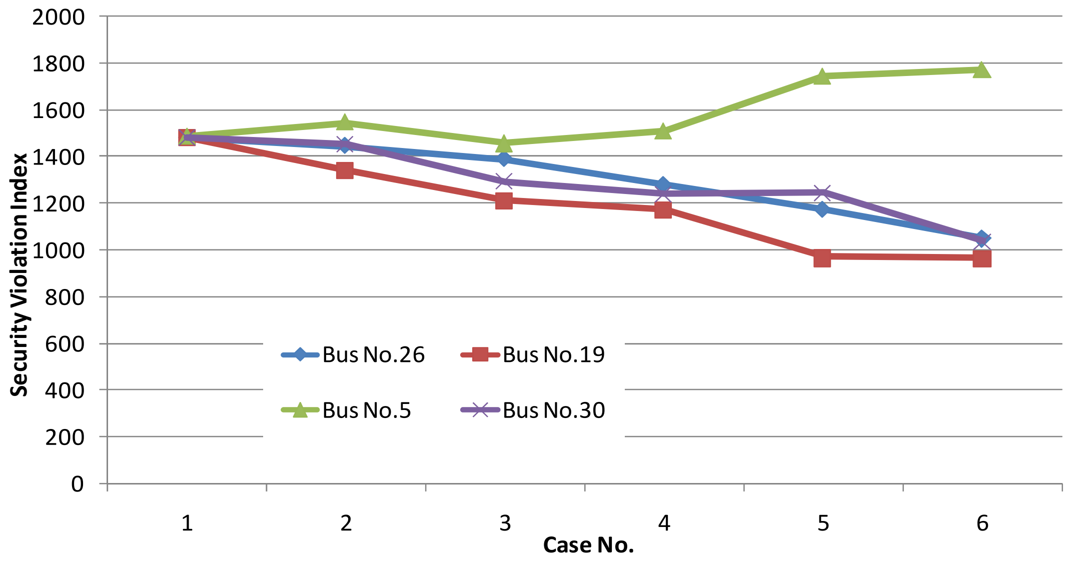

Fig..3.10. Security violation index.

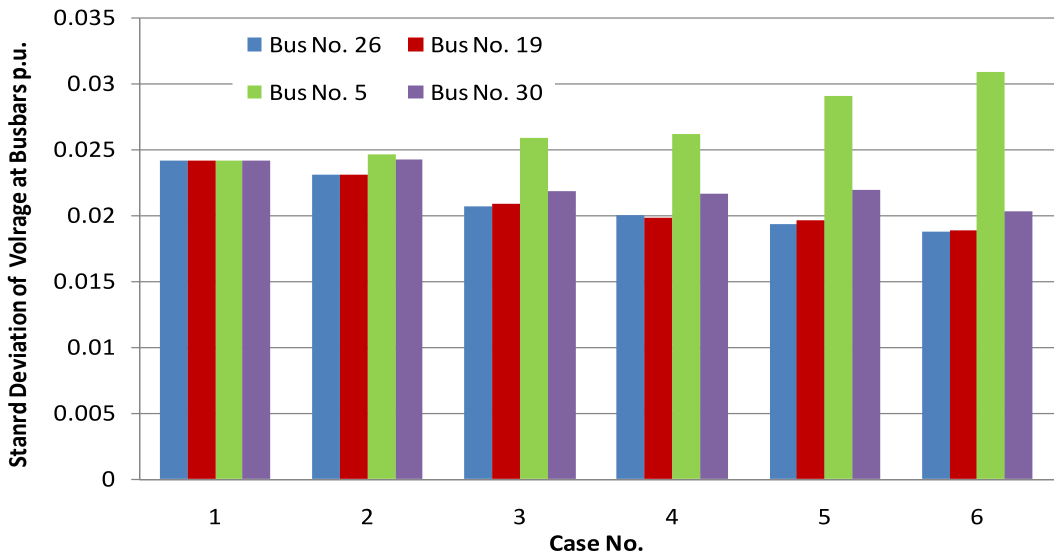

Fig. .311. Standard Deviation of Voltage at Busbars for different cases.

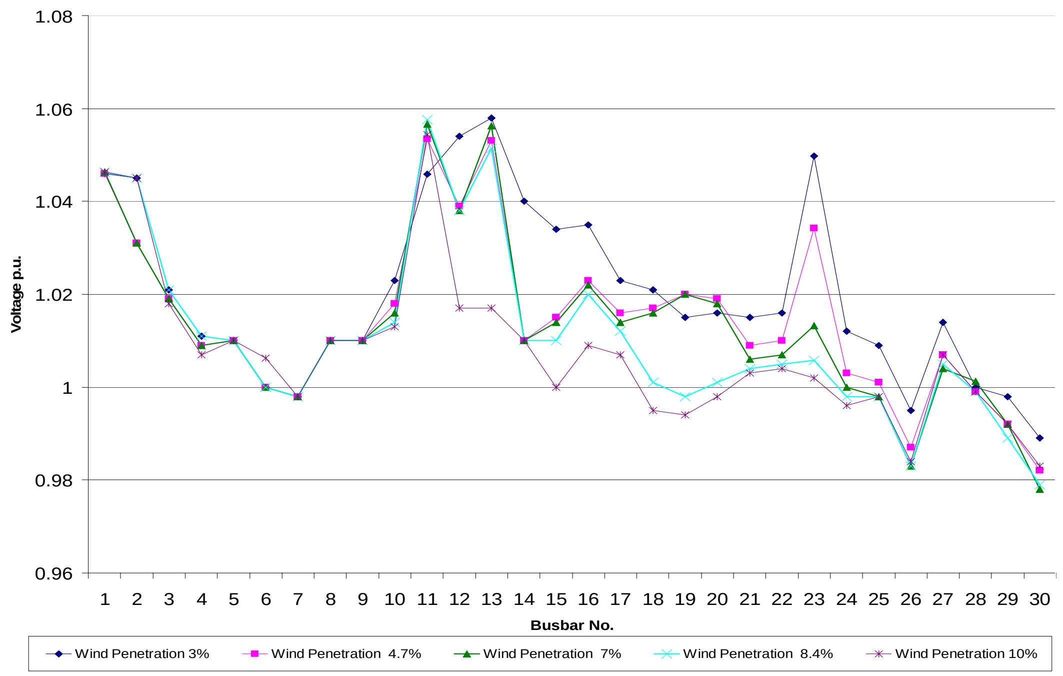

Fig. 3.12. Busbar voltage deviation when windfarm is installed at busbar no. 30

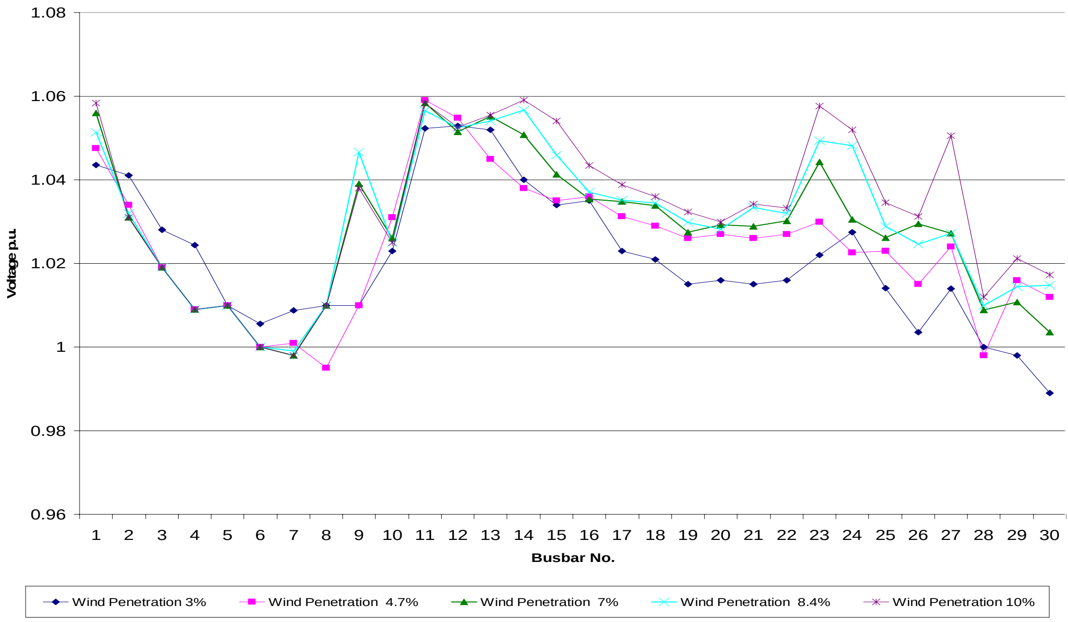

Fig. 3.13. Busbar voltage deviation when windfarm is installed at busbar no. 5

3.7 Step 4: Translating Emission Level to Cost:

To calculate value of wind at each location, the benefits associated with wind needs to be considered. The value is based on the fuel-cost saving of wind as well as cost savings from emission. To translate the emission levels to cost, the CO_2 emissions (and CO_2 equivalent of NO_x) is multiplied by SCC, to derive the £/tonne cost equivalent of emission [33].

3.8. Step 5: Value of Wind Power:

Fig. 3.14 shows the value of wind in the system for different penetration at various locations over a year. The value of wind is reduced by increasing the wind penetration shown in graph, wind in the system may result in utilizing thermal plants in their lower output rate which is not usually the efficient mode of operation of a conventional plant. Another impact of increasing wind penetration is more frequent shut-down and start-up of thermal units which causes increasing the cost of thermal plants. Equation (3.19) shows the calculation method of the value of wind, where *C* is the total production cost and emission cost for each scenario.

$$Value\ of\ Wind = \frac{C(No\ wind) - C(with\ wind)}{P(Wind)} \ \text{£}/_{MW}\ /\ Year \qquad (3.19)$$

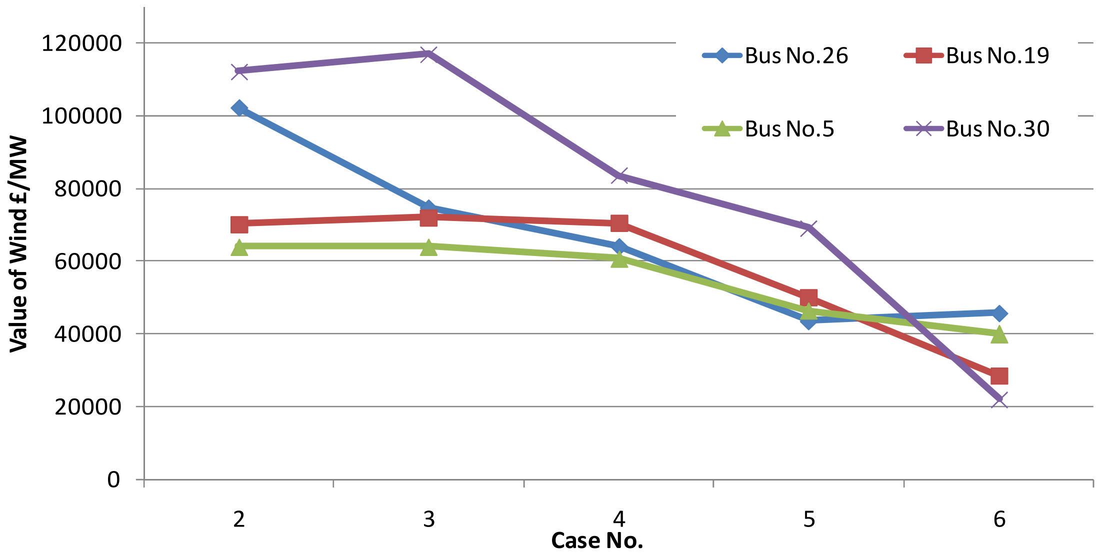

Fig. 3. 14. Annual value of wind for different cases.

3.9 Step 6: Projection of Wind Power Penetration Over 20 Years:

As increasing the wind power penetration occurs over a time scale of a few years, the value per MW of wind tends to decrease during the time. It is supposed that in 2010 there is 10MW installed wind capacity in the network. If the target for wind power over the next 20 years is reaching the 35MW installed wind capacity by 2030 by a constant growth rate, over these 20 years at different times there is different penetration level of wind in the network. If wind power is to reach a capacity of "*Cl*", and the current capacity is "*Dl*", then the number of years *n* it takes to grow from "*Dl*" to for a given growth rate "*r*" can be determined from (3.25):

$$Cl = Dl \times (1 + r)^n \qquad (3.20)$$

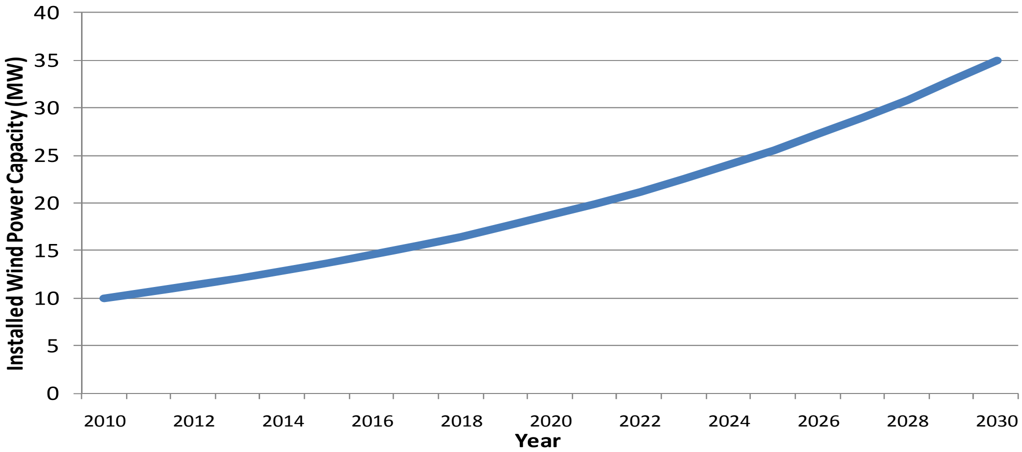

Fig. 3. 15. Wind power capacity growth rate over 20 years.

TABLE 3.6.

WIND PENETRATION AND CAPACITY IN 20 YEARS

Year	Installed Capacity (MW)	Penetration %
2010	10	3%
2015	13.67	4.10%
2020	18.70	5.60%
2025	25.50	7.70%
2030	35.00	10%

Fig. 3.15 and table 3.6 show the wind power installed capacity over a period of 20 years from 2010 to 2030. The break-even point in studying the life time value of wind is defined as the point where the total revenue in the present value received from operating the windfarm within the grid equals the capital cost associated with the windfarm. Fig. 3.16 shows the value of a 10MW windfarm over its life time when the level of wind penetration is continuously increasing.

3.10 Step 7: Lifetime Value of Wind Power:

In order to calculate the payback period, it is necessary to calculate the value of wind power over windfarm's lifetime. The cost of capital is often used as the discount rate; the rate at which the projected value of wind power will be discounted to give a present value. To calculate the present value of wind power for each year, knowledge of the future discount rate is required. Since this value changes over time, in this paper the historic interest rate in the UK is used, and the average interest rate of 6% represents the average interest rate in the past 20 years and is assumed to calculate the value of wind each year [35].

Therefore:

$$FV_n = DPV \times (1+k)^n \quad (3.21)$$

$$Total\ revenue = \sum_{n=0}^{N} FV_n \quad (3.22)$$

From Fig. 3.17 (numeric results are attached in appendix (B) it is observable that location of a windfarm can significantly affect on the actual profit generated by wind power. These benefits have been translated into the revenue produced by wind through supplying the demand. It is shown that the shortest pay-back period for a 10MW windfarm by considering fuel-cost and emission saving can be achieved by installing the windfarm at busbar no. 19. This lies between 7 and 9 years after starting the operation of this windfarm where the total revenue will cover the capital cost. Any revenue produced after this point is considered as the profit gained from this windfarm. The worst scenario is when the windfarm is installed at busbar no. 5 in which the pay-back period is almost 20 years which is equal to almost the lifetime of wind.

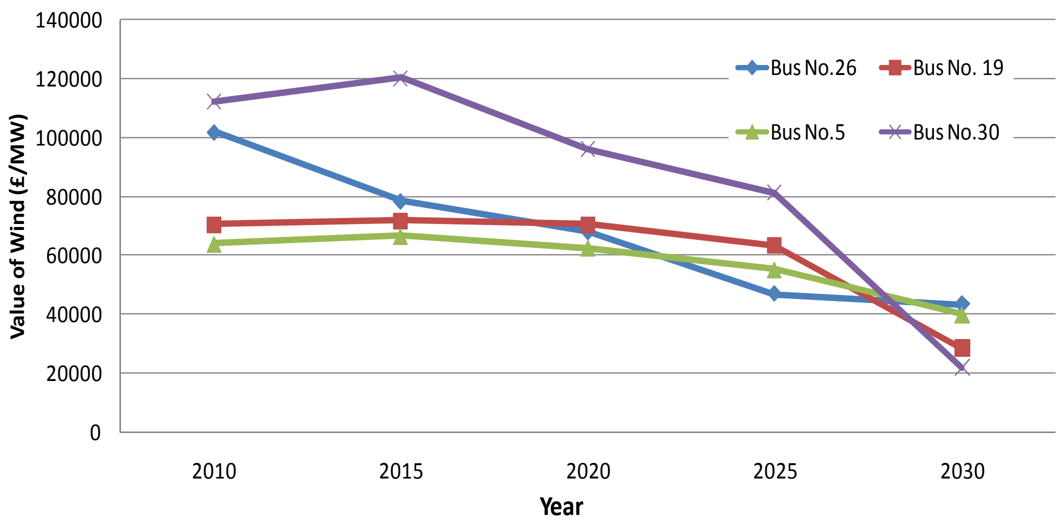

Fig. 3.16. Value of wind over 20 Year.

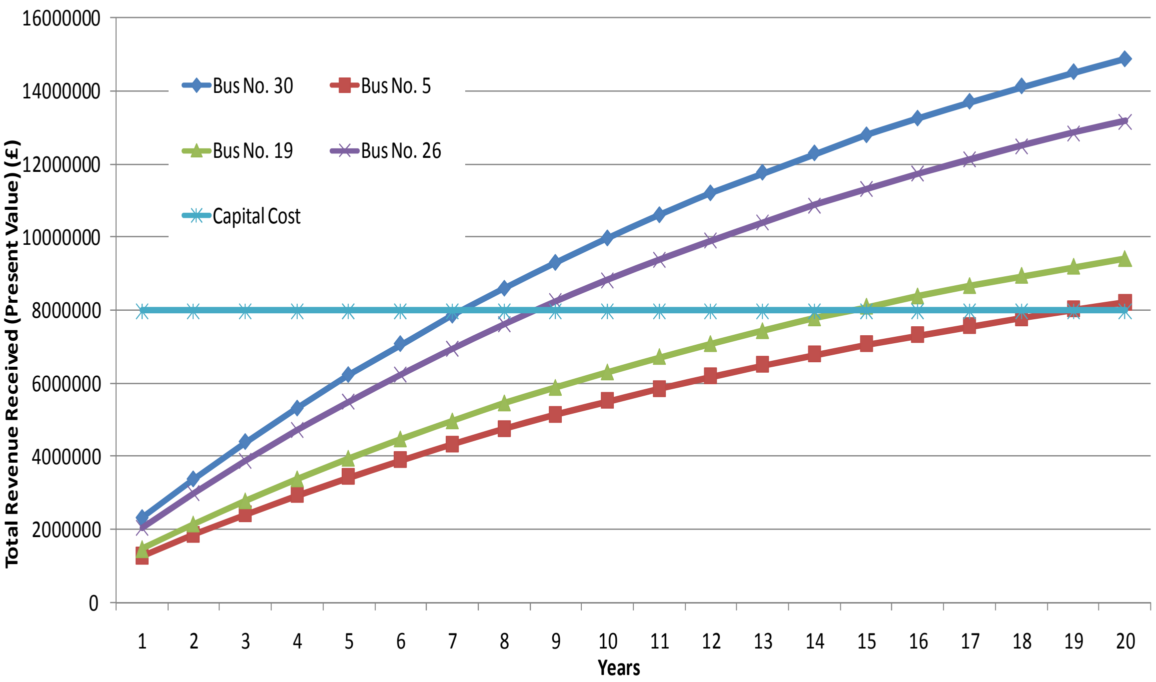

Fig. 3.17. Break-even predicted for the windfarm.

3.11 Chapter Summary

This chapter investigated how the benefit of wind generation related with the location of windfarms and the level of penetration. The value of wind power drives from reducing the fuel-cost of conventional plants and reducing their emission pollutants. The value of wind may also increase by different generation mixes in the network, such as an increase in gas-fired units and a reduction in coal-fired units. In this case further reduced emissions arise due to increasing wind penetration.

The main findings of this chapter include:

- Traditionally, only network energy losses have been considered as a measure to find the optimum location; lower losses indicate a better location provided appropriate availability of wind energy exists. Generally, energy losses can be reduced in the network by installing windfarms next to the load centres. They will reduce supply requirements from more distant resources, thereby by reducing transmission losses which are effectively wasted supply.

  But it was shown that although the overall network losses are different for different grid-location of windfarms, it should not be solely used as an indicator for suitability of the grid-location. When the aim is to find the best location, the impact of the location depends on where the windfarm is installed relation to the electricity generation side must also be taken into account. These effects include:

  - The impact on total number of shut-down and start-up of conventional plants due to change in the dispatch pattern.
  - The impact on marginal cost of electricity generated by conventional plants whilst the location of windfarms may change the power dispatch, hence changing the total production cost.
- The grid location of windfarms has an impact on the payback period of the capital costs invested to build the windfarms. Capital costs can be recovered over different time scales; therefore the amount of profit that can be made after the break-even point depends on the location of the windfarm. Hence, the benefit of windfarms must be studied in different time horizons:
  - In the short-term by placing the windfarms at appropriate locations in the grid, the day-to-day running of power system will be with less deviation of security parameters and these parameters have an impact on reliability of the system.
  - Long-term benefits included the ability of the current network to supply increasing demand without network re-enforcement. The degree of these benefits significantly varies from location to location where a windfarm is connected to.

3.12 References

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Chapter 4. Impact of Spinning Reserve on Value of Wind Power

In order to study the true value of wind power, the additional spinning reserve requirement due to increasing the value of wind power in the system must be studied as was discussed in the previous chapter. This chapter first studies the impact of increasing the need for spinning reserve as a result of intermittent generation. A probabilistic spinning reserve calculation is developed to calculate the level of spinning reserve needed in a system with intermittent generation to maintain the same level of reliability.

4.1. Spinning Reserve's Role in Value of Wind Power

Intermittency and the varying pattern of wind power creates difficulty in utilizing it in the same way as conventional plants. This has an impact on the reliability of power system and necessitates subsequent changes in conventional methods of operating the power system such as providing additional reserve to cater for variations in wind power output. Providing additional power reserve will increase the trading cost of wind power and reduce its value down to a level which may make the use of wind power uneconomic. Probabilistic approaches have been considered for spinning reserve calculations because they reflect the random behaviour of system components and are consistent with operating risk levels since they provide a realistic evaluation of the risk by incorporating the stochastic nature of system components. In this chapter, the effect of different levels of spinning reserve on the value of wind power is investigated.

One of the major factors in the assessment of value of a windfarm is to calculate the additional spinning reserve requirement due to the existence of intermittent power generation source in the system. The extra reserve has to be calculated accurately in order to calculate the value of wind power with less uncertainty. The methodology to calculate the spinning reserve presented in this paper is factored into the assessment framework [7] in calculating the value of wind. It compares different approaches in calculating spinning reserve (deterministic /probabilistic), the resulting differences in the level of spinning reserve and their impact on value of wind. The changes in value of wind arise from changes in the production cost and efficiency of power plants when spinning reserve level reflects the unpredictability of intermittent generation.

4.2 Spinning Reserve Requirement for Wind Power

Scheduling sufficient level of spinning reserve in a power system is required to maintain enough available generation capacity which may be at risk due to generator outage, load and wind forecasting error. Several methods have been used in the past to indicate the required level of reserve. Deterministic criteria are implemented by most market operators to decide the required amount of spinning reserve. A certain percent of the hourly-load or capacity of the largest on-line unit is normally used as the spinning reserve requirement [1]. Since the intrinsic reliability of each scheduled generator, demand and wind pattern all have a stochastic pattern, the problem with deterministic approaches is that they do not take into account the stochastic nature of the problem. Therefore probabilistic approaches have been developed for calculating the spinning reserve [2- 4].

In order to calculate the spinning reserve using probabilistic approaches, it is essential to derive the total system risk which indicates the probability of not being able to serve certain amount of demand due to component failure. This can be done through the calculation of a Capacity Outage Probability Table (COPT). The information obtained from COPT indicates the risk of losing certain level of demand due to failure of a single or multiple generators. Load and wind forecasting errors can also be integrated in this to also show the demand loss not only due to not having sufficient capacity to serve the demand but also due to unpredicted deviation of wind power and sudden demand changes. Method presented in [5] has taken into account the wind and demand forecasting errors and show the spinning reserve requirement with increasing wind penetrations. Once the risk level of a system at different load levels is found, the system operator must contract enough generation capacity which can be made available within certain time to cater for these risks. The level of required capacity is determined by system reliability standards; i.e. not more than 8 hours/year Loss of Load Expectation (LOLE) in Northern Ireland is set of EirGrid [6] or availability of 99.9% which is widely acceptable in the Great Britain power system set by National Grid [7].

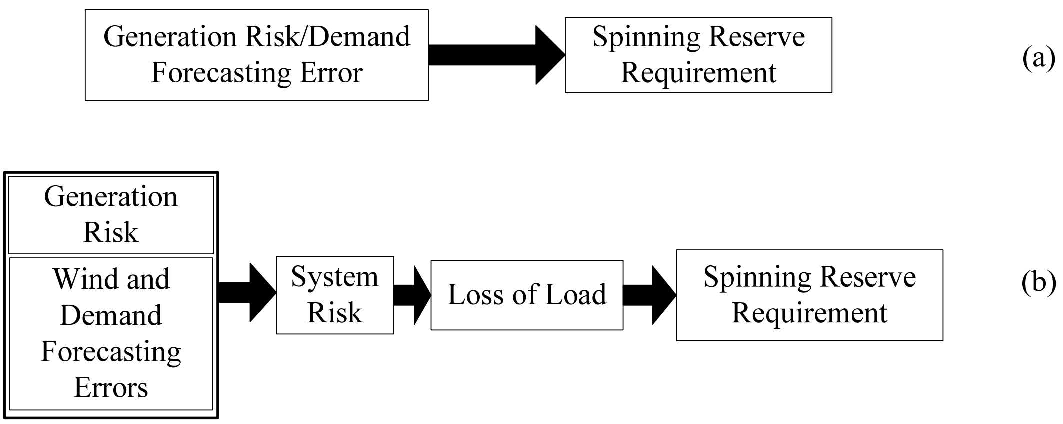

Fig 4.1. (a) Direct Estimation of Spinning Reserve from Generation Risk,
(b) Estimation of Spinning Reserve from loss of load resulting from total system risk.

Finding the right level of reserve which corresponds to acceptable reliability level, while considering economical aspects is the main task in calculating the spinning reserve through probabilistic methods. This was first considered in [12] by considering generator failure rate. The spinning reserve requirement was adjusted in order to maintain the required level of reliability at all scheduling periods. In this method shown in figure 4.1.a, generation risk directly determines the level of spinning reserve requirement which is calculated in this paper through committing enough units to provide an acceptable level of reliability.

In [8] probabilistic reserve calculation based on statistical approximations is developed. This method finds the approximate level of spinning reserve which corresponds to appropriate LOLP. The problem with this approach is the selection of an appropriate risk criterion and lack of a tool to quantify the socioeconomic cost of outages because it measures only the probability that the load exceeds the generating capacity but does not quantify the extent of the disconnections that might result from such deficits.

A cost benefit approach is presented in [12]. This approach consists in post-processing the unit commitment schedule to compute the level of risk of consumer disconnection at each hour. It first gets estimation for spinning reserve level and if this risk is not within a certain range of a pre-specified target for some periods, the SR requirement is adjusted for these periods and the UC is run again. Then in order to optimize the level of spinning reserve, the Value of Lost Load (VOLL) is compared with the cost of providing spinning reserve and the optimal level is determined once cost associated with providing a level of spinning reserve is equal to value of lost load. This method is suitable to quantify the required level of spinning reserve. However the optimization tool requires information regarding the VOLL, which is extremely difficult to obtain without conducting surveys and makes it difficult to apply this model to any power system. In [9], a method estimating spinning reserve based on LOLP and Expected Energy Not Supplied (EENS) is developed to optimize the required level of spinning reserve. In this approach not only the spinning reserve must satisfy the LOLP, but also by imposing the second constrain, EENS, the appropriate level of reserve is quantified. In [13] a similar method based on LOLP and Expected Load Not Supplied (ELNS) is developed for calculating spinning reserve. The problem with both methods in [12] and [13] is the arbitrary selection of reliability metrics, and these methods only considered limited number of outages; two in these methods. Besides, since the spinning reserve is to cater for not only the generation outages, but also system forecasting errors, these two methods are unable to assess the sensitivity of the spinning reserve level to system forecasting errors.

In this chapter a probabilistic spinning reserve scheduling is developed. Then by using a security approach model; shown in figure 4.1.b ,which represents the risk index of each operating state for each generation scheduling block, and by comparing state's capacity risk index and ELNS to reference risk index determined by system operator, the level of spinning reserve is quantified. The security function approach is a method which indicates the total risk of the system and allows setting the maximum tolerateable risk. The benefits of this method include applicability of this method to any power system where generation risk is different hence the reliability metrics' standards may differ, ability to both quantify the LOLP, ELNS and EENS to quantify the socioeconomic costs associated with spinning reserve. As well as assessing the sensitivity of the spinning reserve level to system forecasting errors. The last one is particularly a matter of interest since with increasing the intermittent generation sources in power system the issue of spinning reserve quantification is becoming more and more important.

4.3. Security Function Approach

4.3.1. Security Function Index

The security function approach was first proposed in 1970 [10], the primary principle is quantifying the total system's risk and aiming for keeping the risk below the maximum tolerateable risk. Security function index $S(t)$ is defined by (4.1):

$$S(t) = \sum_i^I \rho_i(t) q_i(t) \tag{4.1}$$

where $\rho_i(t)$ is the probability that the system is in operative state i at time t, and $q_i(t)$ is the probability that state i constitutes a system failure at time t. An operative state is a particular operating configuration of the system consisting of certain generators running, certain generators unavailable, and certain generators on standby. Since in generation scheduling the state of generation units changes from time to time to meet the economic, environmental and constraints of the system, the operating state's probability, $\rho_i(t)$ will also change. Therefore the application of this method requires calculation of $\rho_i(t)$ for all possible states in the system. In has also been mentioned in [10] that to estimate the states' probability, the calculations must also be extended to other components than generation units; i.e. transmission lines availability at time t.

To quantify the total system risk resulting from the by failure rate of power plants and its impact on security function, it is assumed that the probability of generation failure is independent from failure rate of other components such as transmission lines etc. and it is the only failure which spinning reserve must be catered for. Therefore:

$$\rho_i(t) = \rho_i^G(t) \tag{4.2}$$

By making this assumption while the size of state i is reduced, and $q_i(t)$ can also be considered as a binary number (κ_t), which is 1 when $\rho_i^G(t)$ results in loss of load, and 0 if no loss of load occurs. Consequently:

$$S(t) = \sum_i^I \kappa_t \rho_i^G(t) \tag{4.3}$$

where $\rho_i^G(t)$ is the state probability related to generation units which can be calculated for each scheduling period. State's probability of failure $\rho_i^G(t)$ depends on failure rate of individual generation units.

4.3.2. Generator's Risk Evaluation

A basic generating unit parameter used in creating the COPT is the Forced Outage Rate (FOR). This parameter provides an estimate of the probability of a unit being out of service (due to a failure) at some distant time in the future. A two-state generating unit model is shown in fig 4.2, and the FOR is given by (4.4):

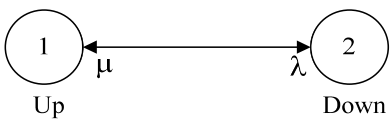

Fig 4.2. Two State Model of a Generator

$$FOR = \frac{\lambda}{\lambda + \mu} \tag{4.4}$$

Where Where:

λ is the failure rate of the generating unit (failure/year)

μ is the repair rate of the generating unit. (repair/ year)

The FOR indicates the failure rate of a generator in the steady state sometime in the future and is not time dependent. The Outage Replacement Rate (ORR) is the failure rate parameter which is a function of time. Time in short-term assessment of generators' reliability is called Lead Time, or the time after failure of a generator which no other unit can be brought up online, or in fact the shortest start-up of a unit which can be brought up online [1]. Therefore:

$$\upsilon = \frac{\lambda}{\lambda+\mu} - \frac{\lambda}{\lambda+\mu} e^{-(\lambda+\mu)T} \tag{4.5}$$

where υ is the ORR, and T is the lead time. In a large power system containing fast start units with start-up time of less than 1 hour, and considering the fact that in the lead time no repair can be made to bring the failed unit back to operation, then:

$$\upsilon = \lambda T \tag{4.6}$$

Therefore

$$\rho_i^G(t) = \upsilon_1^g \prod_{\substack{n \\ n\neq 1}}^{N} (1-\upsilon_n^g) + \upsilon_2^g \prod_{\substack{n \\ n\neq 2}}^{N} (1-\upsilon_n^g) + \ldots\ldots \tag{4.7}$$

where *N* is total number of generation units which are operating to serve the demand. Since the capacity of generation units in the system is different and each generator's output is a certain (but likely to be different) level, therefore the failure rate of each state form *N* generators can also be shown in a way that their failure will result in loss of load. This is shown in figure 4.3.

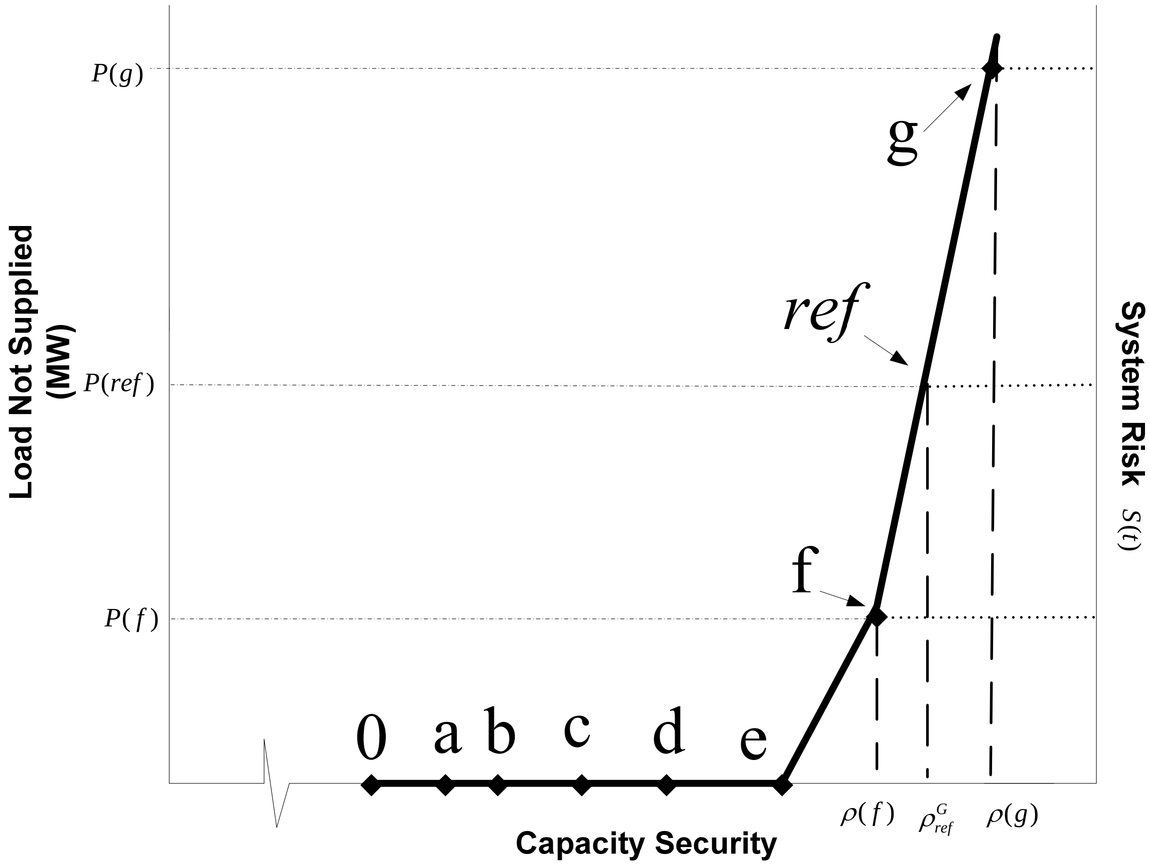

Fig 4.3. System risk $S(t)$ and magnitude of loss of load for N generators.

Figure2 shows the system risk at state (i) from *N* generation units which are operating in the system to serve the total demand. Point (0) shows when all generation units at time (t) are available, therefore:

$$\rho_{(0)}^{G} = \prod_{n}^{N} (1 - \upsilon_{n}^{G}) \tag{4.8}$$

and

$$P_{(0)} = \sum_{n=1}^{N} P_n \tag{4.9}$$

Points (a-e) on this graph show the region on the capacity risk function where losing certain capacities i.e. “a” Megawatts, will not result in loss of load:

$$\sum_{\substack{n=1 \\ n \neq a-e}}^{N} P_n - P_{a-e} \geq P_{demand} \tag{4.10}$$

and

$$\rho_{a}^{G} = \upsilon_{a}^{G} \prod_{\substack{n=1 \\ n \neq a}}^{N} (1 - \upsilon_{n}^{G}) + \rho_{(0)}^{G},$$

$$\rho_b^G = \upsilon_b^G \prod_{\substack{n=1 \\ n \neq b}}^{N} (1-\upsilon_n^G) + \sum_{n=0}^{a} \rho_n^G \ ,$$

$$\rho_c^G = \upsilon_c^G \prod_{\substack{n=1 \\ n \neq c}}^{N} (1-\upsilon_n^G) + \sum_{n=0}^{b} \rho_n^G \quad ,\ldots \tag{4.11}$$

Point (f) shows on the x axis, is the risk index of the system in which losing the capacity (f) will result in loss of load. The risk of the system and the magnitude of the loss of load are $\rho(f)$ and $P(f)$ respectively. Point (g) on the x axis shows the capacity risk $\rho(g)$, where losing the capacity (g) which is greater than capacity (f) will result in loss of load with the magnitude of $P(g)$.

$$\sum_{\substack{n=1 \\ n \neq f}}^{N} P_n - \sum_{n=f}^{e} P_n \langle \ P_{demand} \tag{4.12}$$

and

$$\rho_f^G = \upsilon_f^G \prod_{\substack{n=1 \\ n \neq f}}^{N} (1-\upsilon_n^G) + \sum_{n=0}^{e} \rho_n^G \tag{4.13}$$

As can be observed from figure 4.2, the system risk is higher when capacity (g) is lost compared with the situation where capacity (f) is lost, so the magnitude of loss of load. In power systems, system operators determine the maximum capacity risk which can be tolerated. The maximum allowed capacity risk resulting from generation units is called ρ_{ref}^G. Therefore spinning reserve is required for probabilities which result in loss of load (κ_t =1), but the level of reserve can be optimized subject to meet the condition (4.14):

$$\rho\,_n^G(t)_{new} = \rho_{ref}^G \tag{4.14}$$

where $\rho\,_n^G(t)_{new}$ is the system risk when spinning reserve is provided to cover the loss of load caused by failures with probabilities below and equal to ρ_{ref}^G. Accordingly, once the system risk is found for certain load level, in order to estimate the spinning reserve requirement, by using the system risk function, the probability of ρ_{ref}^G has to pointed and the corresponding loss of load level $P(ref)$ is the spinning reserve requirement.

4.3.3. Spinning Reserve Level Estimation from System Risk

It is reasonable to assume that the system risk function, from point (f) to point (g) is a first-degree polynomial function of one variable. This assumption is correct because no other capacities can be lost as a result of an outage (only full outage of a generation units is considered in this paper). Therefore the relationship between capacity risk and system risk for the capacities (f) to (g) is written in (4.15). Once the system risk function is found, it is easy to find the loss of load function. Loss of load function is also a function of capacity risk and since in this method we have only considered the generator capacity outage as a risk in the system, it can be another way of representing total system risk in megawatt of load which is lost due to losing certain level of capacity. Hence:

$$S(t) = \kappa_t \alpha_t p_n^G(t) + \beta_t, \quad \text{n= (f) to (g)} \tag{4.15}$$

and

$$LOL_i(t) = P_{demand} - \sum_{n=1}^{n} P_n \tag{4.16}$$

then

$$ELNS_i(t) = \kappa_t \alpha_t p_n^G(t) + \beta_t, \quad \text{n= (f) to (g)} \tag{4.17}$$

where κ_t is a binary number which is 1 when $\rho_n^G(t)$ results in loss of load, α_t and β_t are security function coefficients and must be calculated. Therefore the spinning reserve requirement to satisfy the capacity risk index can be calculated from (4.18):

$$SR_i(t) = [ELNS_i(t), \rho_{ref}^G] = \kappa_t \alpha_t \rho_n^G(t)_{new} + \beta_t \tag{4.18}$$

From (4.18) the required spinning reserve for state (i) can be calculated. This spinning reserve level (in Megawatts) satisfies the system risk standard and compensates for all loss of loads occurs as a results of capacity outages equal and below the capacity outage risk standard.

4.4 Impact of System Forecasting Errors

4.4.1 Wind and Demand Forecasting Error:

Spinning reserve is required not only for capacity deficits resulting form generation unit outage, but also to cater for wind and demand forecasting errors. Wind and demand forecasting errors have an impact on the level of spinning reserve requirement, and the more accurate the forecasting is, the less spinning reserve is required to cater for these forecasting errors. Since these two errors are independent from each other and in order to have a generalized error to represent the total system error, then total system error can be given by (4.19):

$$\sigma = \sqrt{\sigma_{wind}^{2} + \sigma_{demand}^{2}} \tag{4.19}$$

where σ_{wind} and σ_{demand} are wind and demand forecasting "Percentage Relative Errors" respectively. Percentage relative errors can be transformed to "Absolute Errors" to show the magnitude of error which must be used in system risk index function using (4.20):

$$\sigma_a = \frac{\sigma_r(\%) \times 100}{x} \tag{4.20}$$

where σ_a is absolute error, $\sigma_r(\%)$ is the percentage relative error, and x is the measured value which in our study is real-time demand and wind. The consumers' demand pattern has a highly repetitive nature of the daily load profile; and demand forecasting errors are not especially sensitive to the forecast horizon and are usually proportional to the size of the load at any given hour. But since wind forecasting error depends on the forecasting time horizon; closer to the scheduling time, less forecasting error will result. Therefore the impact of forecasting horizon must also be considered to determine the right level of wind forecasting error.

4.4.2 Spinning Reserve's Sensitivity to Forecasting Errors:

The aim is to quantify the sensitivity of the method which was presented in (4.18) to total system error. The element used in (4.18) to calculate the spinning reserve is dependent to two main factors:

1) Generation Capacity; and
2) Demand.

Since wind power comes from a generation source, it has the same characteristics as other generation sources such as outage rate as well as a new element associated with wind power which is its forecasting error. In order to make the calculations easier to implement, the wind is modeled as negative load and subtracted from demand, therefore the sensitivity is assessed to only one element; which it is called in this paper "new demand".

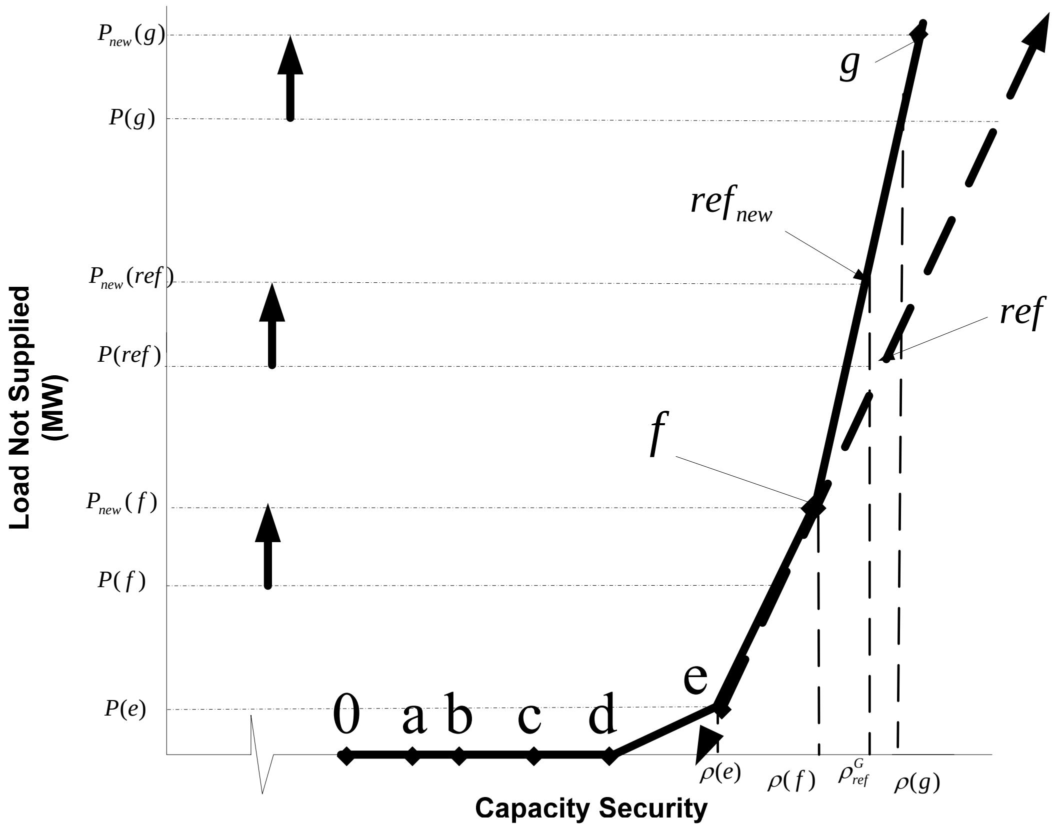

Fig 4.4. The magnitude of loss of load resulted by N generators by considering system forecasting errors.

Figure 4.4 shows the capacity risk of the system similar to figure 4.3. But in this graph there are two line patterns; the line with arrow at both ends, shows the previous ELNS function where no forecasting error was present. It is observable that required spinning reserve level corresponding to appropriate level of risk is shown at point “ref”. The single line shows the ELNS function by considering forecasting errors which will result in higher levels of ELNS with losing same capacities. In previous section capacity (e) would not result in any deficit to cause loss of load, but when system forecasting errors are taken into account, losing the capacity (e) will result in some loss of load; $P(e)$. In order to perform the sensitivity analysis, demand is modeled at each time interval, and wind is also modeled based on the forecasted level, and according to the wind forecasting horizon total demand ‘s variations is used to assess the spinning reserve’s sensitivity to the system errors.

$$P_{demand}^{new}(t) = P_{demand}(t) - P_{wind}(t) \tag{4.21}$$

where $P_{demand}^{new}(t)$ is new system demand $P_{demand}(t)$, minus total wind level $P_{wind}(t)$ at time (t) in megawatts. In (4.18) κ_t is 1 whenever losing the capacity (n) results in loss of load. Then by performing the sensitivity analysis to changes in $P_{demand}^{new}(t)$, the changes in required level of spinning reserve is quantified. Consequently:

$$\frac{\partial SR_i(t)}{\partial P_{demand}^{new}(t)} = \frac{\partial ELNS_i(t)}{\partial P_{demand}^{new}(t)}$$

$$= \frac{\partial \alpha_t p_n^G(t)}{\partial P_{demand}^{new}(t)} + \frac{\partial \beta_t}{\partial P_{demand}^{new}(t)}, \quad (\kappa_t = 1) \tag{4.22}$$

Therefore it is essential to quantify the sensitivity of the polynomial function which represents the system risk function to “new demand variations” $\partial P_{demand}^{new}(t)$.

4.5 Numerical Simulation

4.5.1. Combining Spinning Reserve Evaluation and Value of Wind Power Assessment

The proposed method is applied on IEEE 30 busbar network with 8 thermal generators [14]. Conventional generators’ outage rates are taken from [15]. A generation scheduling program was initially developed in C++ and solved with dynamic programming, to evaluate the total generation cost and emission level, for a given demand, set generators and network data. This has been modified in this chapter to include probabilistic spinning reserve assessment, and calculate the value of wind power. The algorithm for calculating the value of wind power is presented in fig. 4.5. The algorithm of calculating the value of wind power is similar to the developed algorithm in chapter 3. The only difference is that in the new algorithm in this chapter generators’ outage rate data must be fed into the simulation process as well as other input data. Besides, before running the generation scheduling, the required level of spinning reserve must be calculated; using the developed method in this chapter.

Different scenarios are considered; the first scenario in which only conventional plants are to supply the demand and spinning reserve is quantified as a base case while respecting the impact of demand forecasting error. In this case total production cost is also calculated to be used as a benchmark for value of wind calculation. As increase in the wind power penetration occurs in a time horizon of few years, the value per MW of wind tends to decrease during the time. It is supposed that in 2010 there is 10MW installed wind capacity in the network. If the target for wind power over the next 20 years is reaching the

35MW installed wind capacity by 2030 by a constant growth rate, over these 20 years at different times there is different penetration level of wind in the network. If wind power is to reach a capacity of “Cl”, and the current capacity is “Dl”, then the number of years n it takes to grow from “Dl” to for a given growth rate “r” can be determined from (4.23):

$$Cl = Dl \times (1 + r)^n \tag{4.23}$$

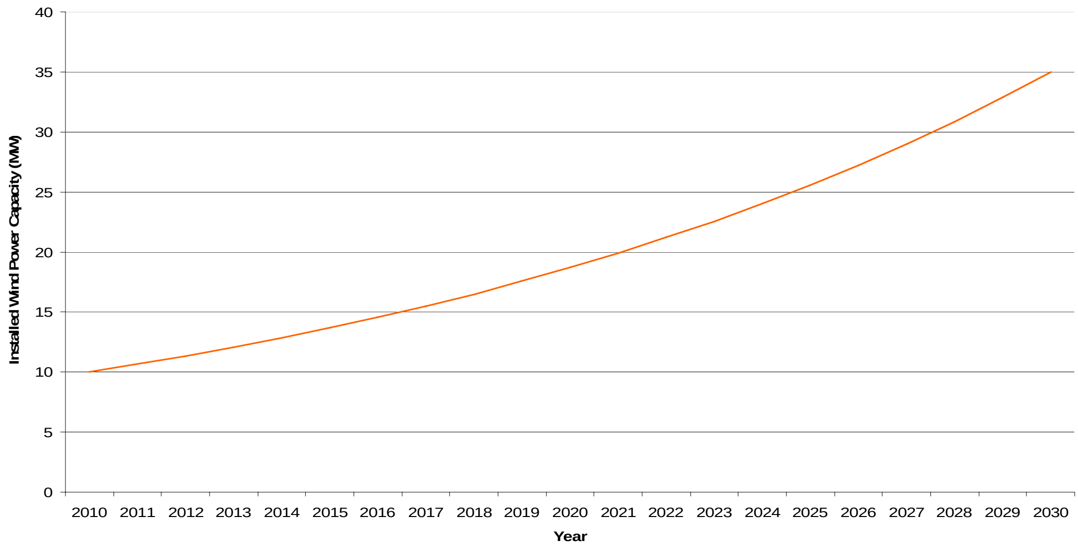

Fig. 4.6. Wind power capacity growth rate over 20 years.

Break-even point in studying the life time value of wind is defined as the point where total revenue in present value of revenue received from the energy sell from the windfarm equals to the capital cost associated with the windfarm. Equation (24) shows the calculation method of value of wind, where *C* is total production cost and emission cost for each scenario.

$$Value\,of\,Wind = \frac{C(No\,wind) - C(with\,wind)}{P(Wind)} \;\; £/MW/Year \tag{4.24}$$

where C is the total operational cost of the system to meet the forecasted demand including production cost and emission penalties in £, and P is the installed capacity of wind power in MW. In fact, the total cost of each scenario 2 in which wind power exists is subtracted from scenarios 1 which only contains thermal plants, and divided by total wind power capacity which exists over the lifetime of a 10MW windfarms according to fig 4.6 .

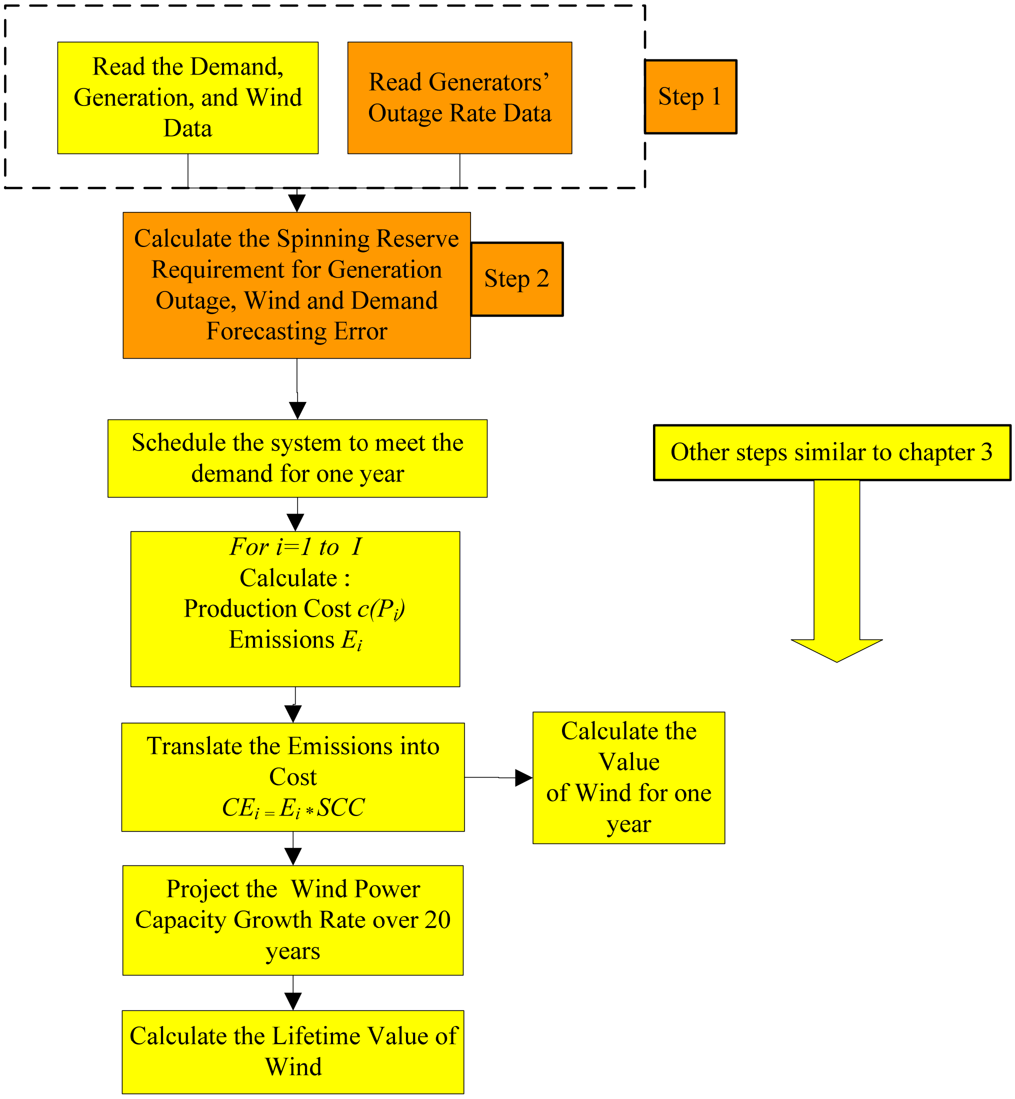

Fig. 4.5. The Algorithm of Calculating the Value of Wind Power while Considering the Impact of Additional Spinning Reserve Requirement

4.5.2. Step 1: Generator and Demand Data:

In the test system, the total conventional generation capacity is 350MW and peak demand is 293MW. Table 4.1 shows the capacity and failure rate generators' data and peak demand.

TABLE 4.1
Generators' Capacity and failure Rate and Peak Demand [6 & 7]

Unit No	Unit Type	Failure Rate ; λ	Installed Capacity (MW)
1	Coal	0.4	35
2	Coal	0.3	45
3	Coal	0.4	40
4	Coal	0.4	80
5	Gas	0.2	25
6	Gas	0.2	60
7	Gas	0.2	35
8	Gas	0.2	30

Peak Demand (MW)	293

4.5.3. Wind Data:

The most important characteristic of wind power is its fluctuations. For optimized power plant scheduling and power balancing, an accurate forecast of the wind power generation for the whole control area is needed. The relevant time horizon depends on the technical and regulatory framework; such as the types of conventional power plants in the system and in deregulated markets the bilateral markets and the trading gate closure times. The current practice in the GB power system is to forecast the wind on day ahead, 8 hours ahead, 4 hours ahead, and 2 hours ahead where an accurate wind speed will be forecasted. Figure 6 shows the wind forecast relative error at different time horizons based on the study which was conducted before [11].

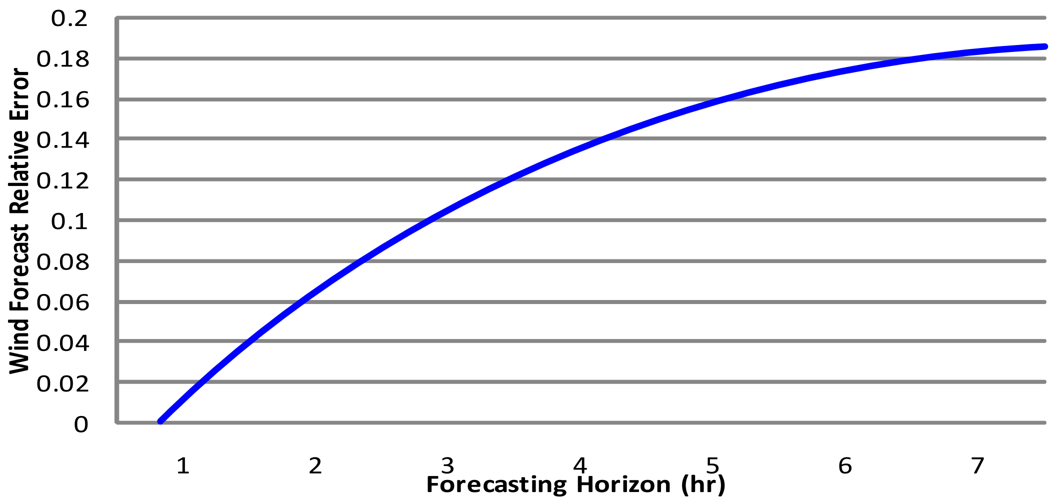

Fig. 4.7. Wind Forecast Relative Error at different time horizons [11]

4.6. Step 2: Calculation of Spinning Reserve Level and Value of Wind Power

Results presented in this section include spinning reserve level for different wind penetrations, and the value of wind over its lifetime. The spinning reserve calculation is based on the probabilistic approach described in section III, taking into account of generation failure, generation shortfalls, demand and wind forecasting errors. Results highlight the impact of wind forecasting error on both required spinning reserve level and value of wind power.

4.6.1. Spinning Reserve Level

4.6.1.1. Scenario 1 (impact of load forecasting error):

In this section, spinning reserve is only scheduled to cater for generation deficits resulting from generation outage and load forecasting error. The impact of load forecasting error is significant on the level of reserve requirement; without any load forecasting error the LOLP is 5.2% with EENS equal to 5.62MWh. Both LOLP and EENS increase while load forecasting error is considered they will be as high as 6.91% and 6.61MWh for LOLP and EENS respectively. This will determine the level of reserve requirement to compensate for these errors. This is shown in fig. 8.

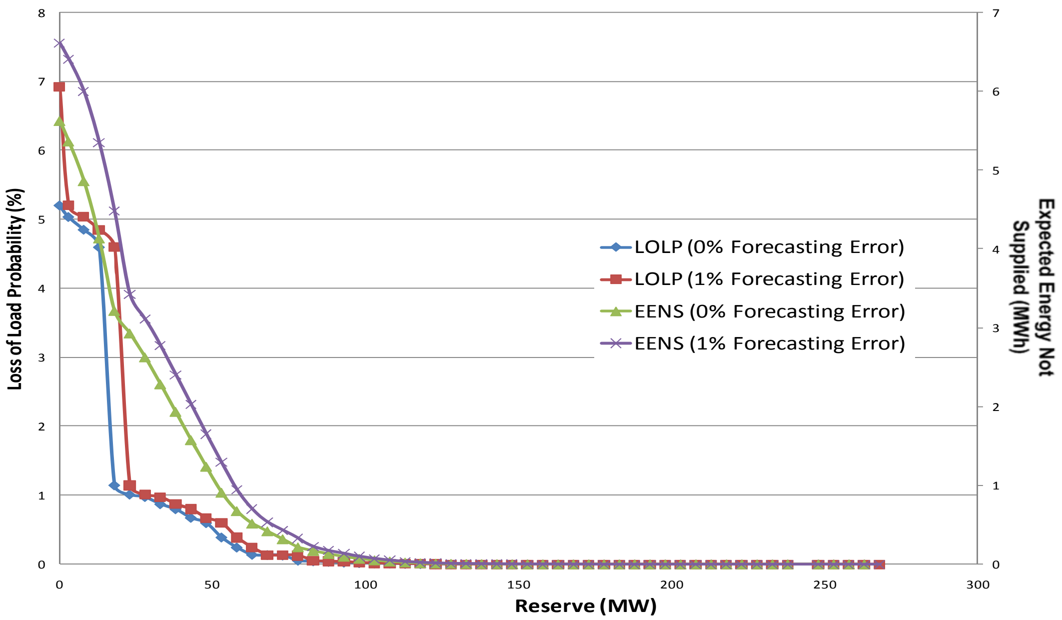

Fig. 4.8. EENS, LOLP VS Power reserve.

4.6.1.2. Scenario 2 (impact of load and wind forecasting errors):

In this scenario, spinning reserve must be provided to cater for both demand and wind forecasting errors. Demand forecasting error is assumed to be 1% for scenario 2, wind forecasting error varies for different cases.

The uncertainty level increases by increasing the wind penetration on the system which requires scheduling higher level of spinning reserve. Figure 4.9-4.11 confirm that this is the case. It is observable from fig. 4.9 that EENS level has low sensitivity to increasing the forecasting error, but as it is shown in fig. 10 when wind capacity in the system has reached 20MW, EENS becomes more sensitive to forecasting horizon which corresponds the forecasting error. In fig. 11, the magnitude of EENS is highly sensitive to forecasting error; resulting in higher level of spinning reserve requirement.

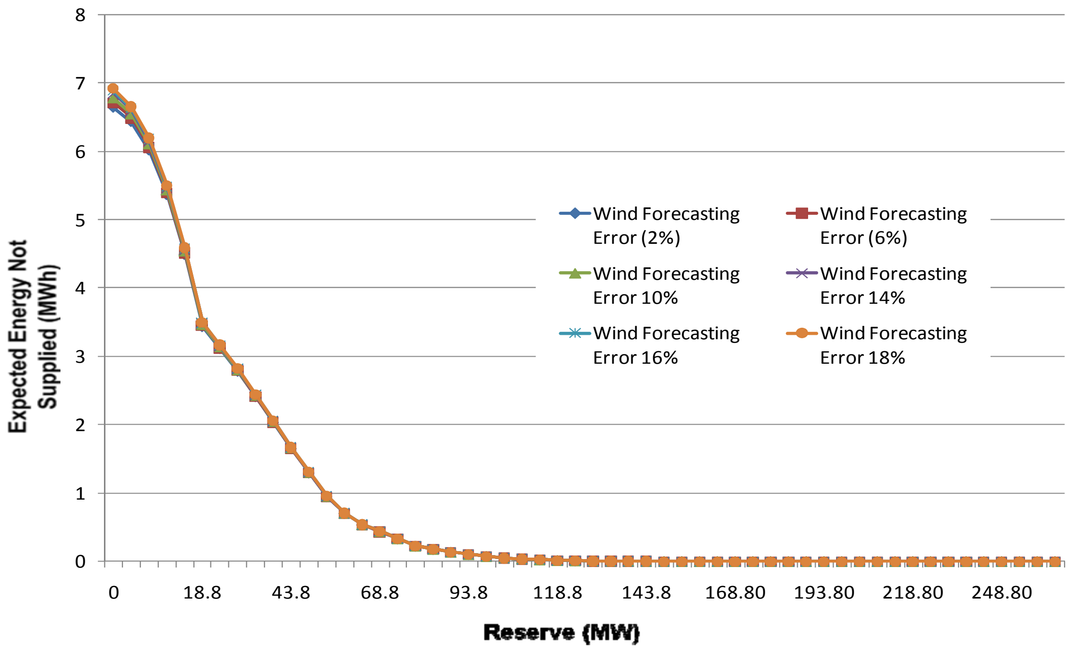

Fig. 4.9. EENS VS Power reserve for wind capacity of 5MW.

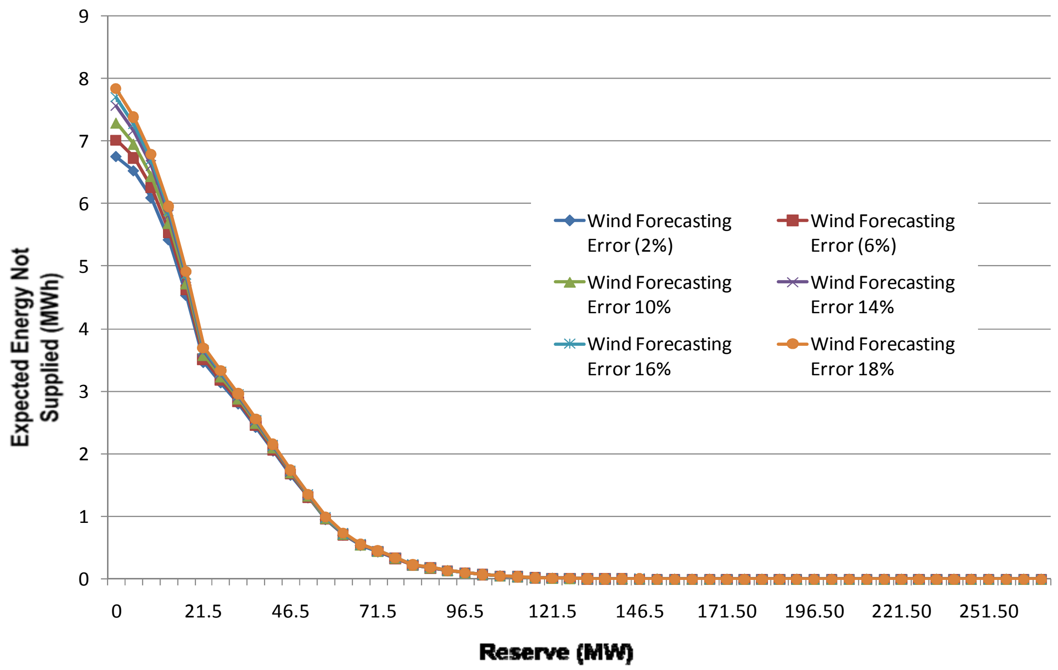

Fig. 4.10. EENS VS Power reserve for wind capacity of 20MW.

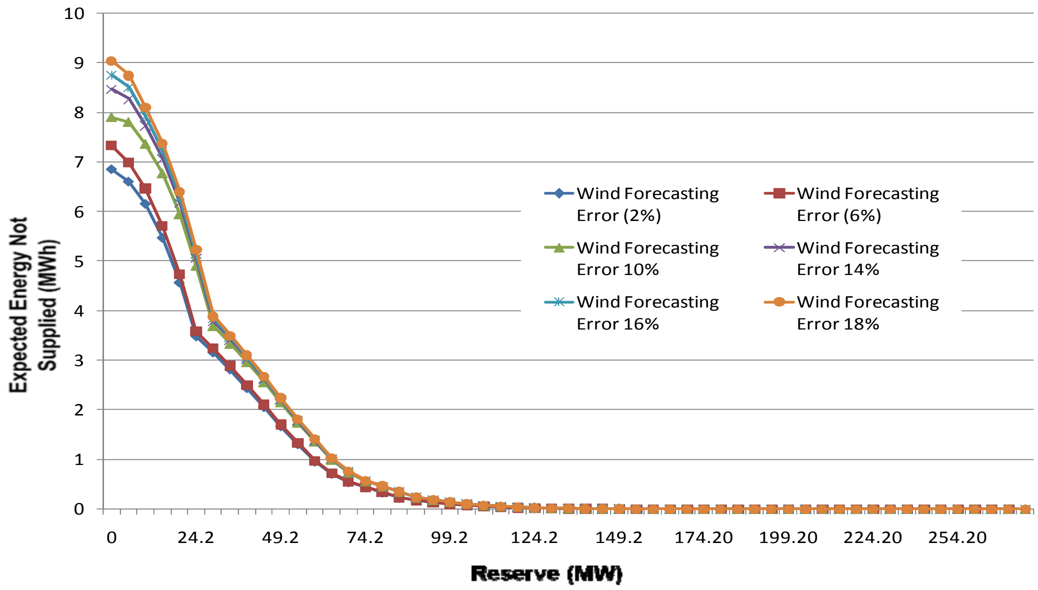

Fig. 4.11. EENS VS Power reserve for wind capacity of 35MW.

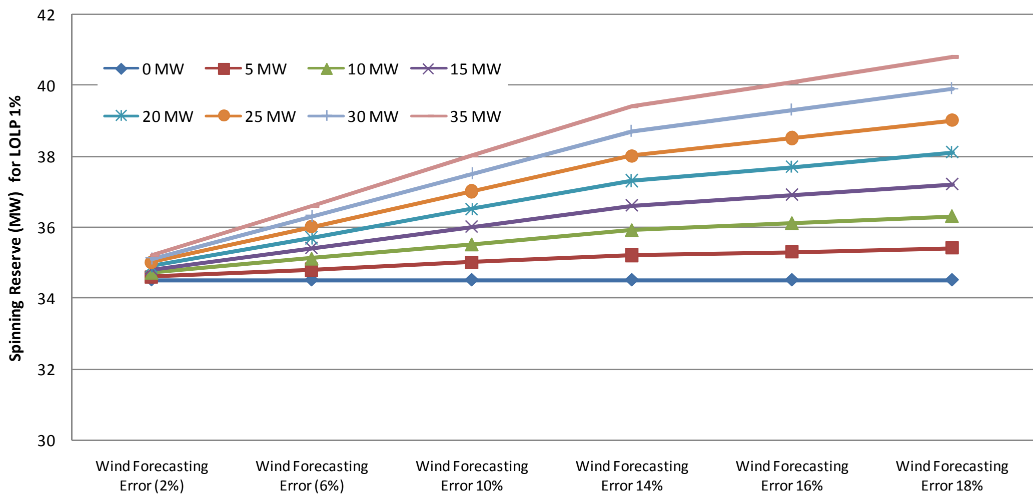

Fig. 4.12. Power reserve for various wind capacities with different forecasting error

4.6.2. Step 3: Impact on Value of Wind Power:

Value of wind power is calculated using scenario 1 as a benchmark, in which only thermal generators exist to show the benefits of wind power in terms of saving on fuel cost, and on emission levels of thermal plants. Different levels of spinning reserve have an impact on total costs of the system, and hence the value of wind is affected by the spinning reserve requirement level. Fig. 13 shows the value of wind using deterministic (the blue graph) and probabilistic approaches. The deterministic approach assigns the level of spinning reserve in relation to the level of demand, but has no bearing to the wind penetration level. Due to the lack of consideration of the latter, the calculated spinning reserve level will be lower. Using the probabilistic approach which reflects the additional risk level from intermittent wind generation, the system will result in higher spinning reserve levels which increases the total costs and reduces the value of wind power. It is shown in fig. 4.13 that wind forecasting has an impact on value of wind power. Higher accuracy in forecasting the wind, results in lower spinning reserve requirement, and hence reduced total system costs and higher value of wind power.

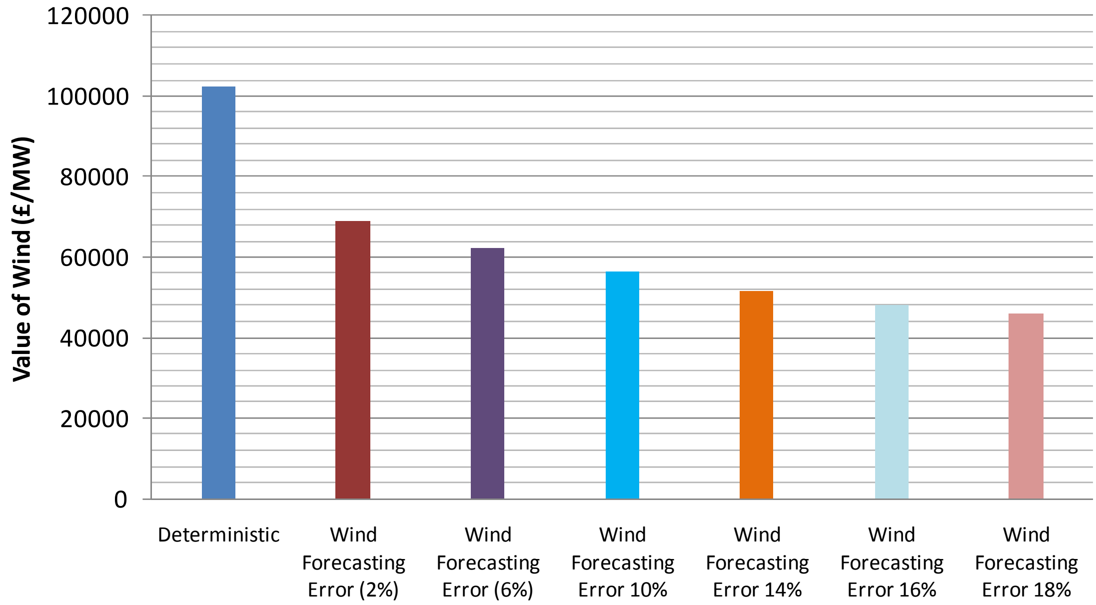

Fig. 4.13. Value of Wind with different Spinning Reserves

The break-even point in studying the life-time value of wind is defined as the point where the total revenue from wind energy sell in present value received, equals to the capital cost associated with the installation, maintenance and operation of windfarm. Fig 4.14 shows the value of a 10MW windfarm over its life-time when the level of wind penetration is continuously increasing based on the growth rate projected in fig 4. 6. Fig 4.14 shows the break-even point predicted for this 10MW windfarm installed at different locations, while the benefits of wind included fossil fuel-cost saving as well as reducing the CO_2 emissions. From fig 4.14 it is observable that spinning reserve calculation method can significantly affect on the actual profit generated by wind power. These benefits have been translated into the revenue produced by wind through supplying the demand. It is also obvious that by increasing the forecasting horizon, the lifetime value of wind reduces, and more time would be required to recover the capital cost.

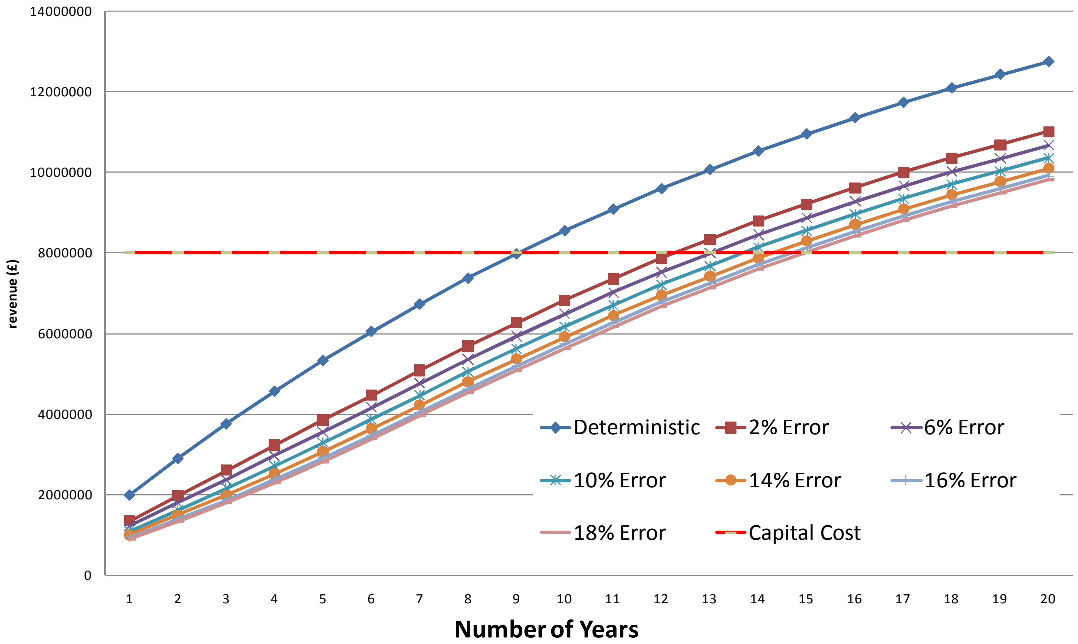

Fig 4.14. Break-even predicted for the Windfarm with Different Spinning Reserve Calculation Methods

Increasing the spinning reserve requirement increases the total cost of the system due to increasing the number of start-up and shut-down, and increase in marginal fuel cost of some generators due to not operating in their best operating range.

4.6.3. Impact on Operation of Generators

4.6.3.1. Increasing the number of start-up and shut-down:

We considered operating constraints and start-up and shut-down costs that typically appear in the unit commitment problem. Available generation capacity at each scheduling period must be equal to demand, losses and spinning reserve. Sometimes due to generator, or network constraints, it is required to shut-down a thermal unit, or start-up another plant to meet this constraint. By doing so, additional costs are incurred. Our results show that by increasing spinning reserve requirement, the number of start-ups and shut-down of generators increases as it is show in fig 4. 15. It shows that in lower spinning reserve levels (which was derived using deterministic approach), the number of star-up and shut-down of generators is lower. Increasing the forecasting horizon will increase the spinning reserve requirement which results in higher number of start-up and shut-down.

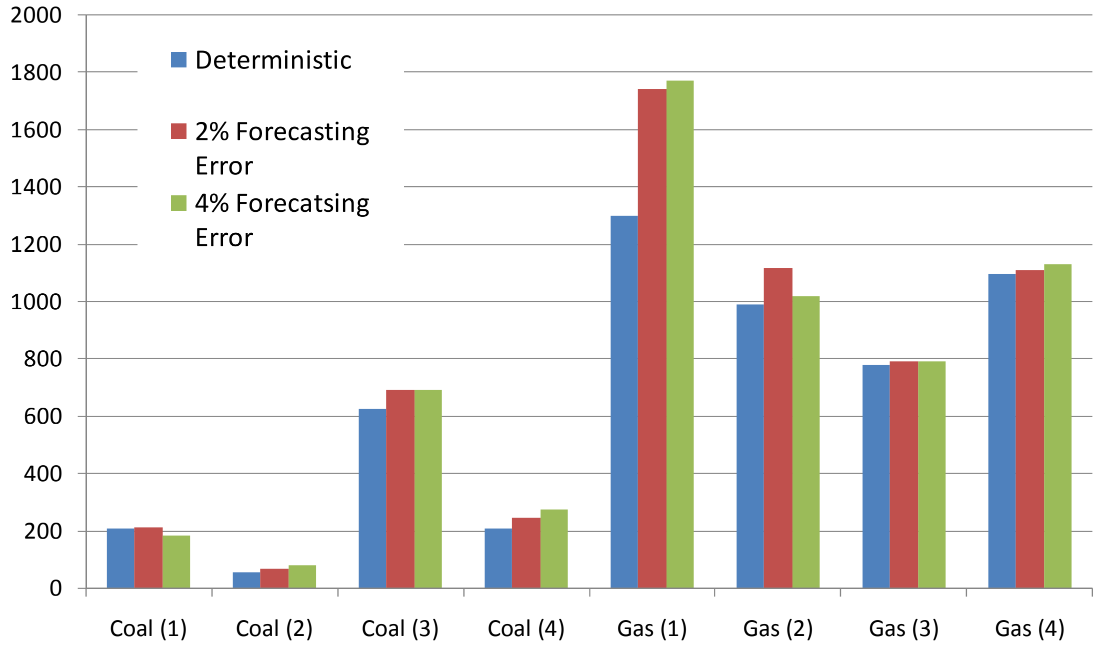

Fig 4.15. Number of Start-up and Shut-down of Thermal Plants.

4.6.3.2. Increase in marginal fuel cost and emission level

Available capacity to maintain spinning reserve is provided through power plant operating at a reduced load to meet spinning reserve requirements, or plants which can be brought up online with a short instruction such as pump-hydro, or interruptible loads. In this study only thermal plants are used as sources of providing the spinning reserve. Thermal plants usually have higher efficiency and lower emission output per MW when they are being operated at their maximum output. Lower marginal fuel cost is achieved if thermal plants operate at their higher capacities as is shown in the CO_2 output and fuel cost curve of thermal plants used in this paper in fig 4.16 and 4.17 respectively.

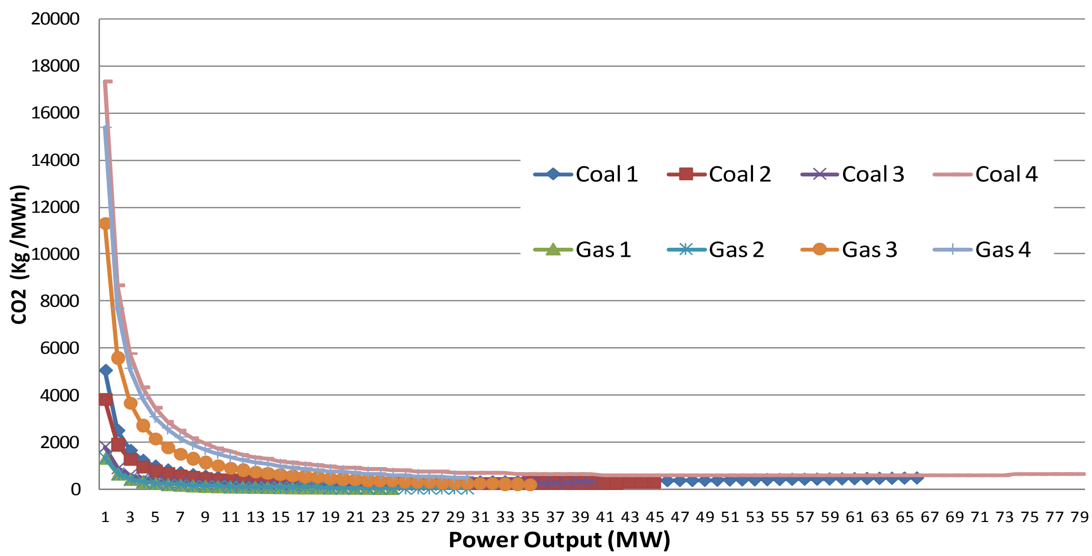

Fig 4. 16. CO_2 output curve of power plants

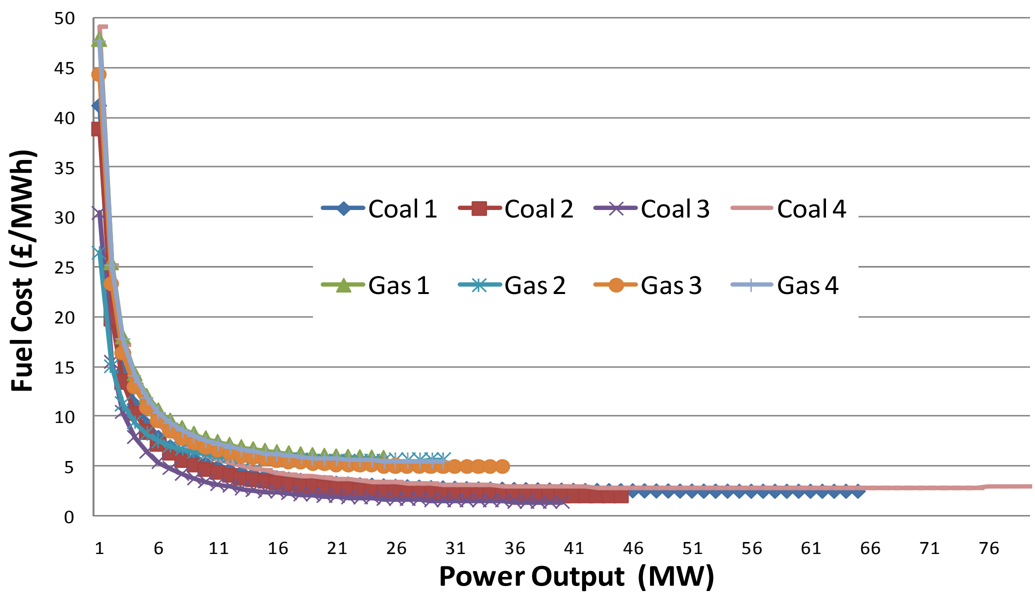

Fig 4. 17. Fuel cost curve of power plants

To maintain the spinning reserve power plants operating at a reduced loading will have higher marginal fuel cost and CO_2 output level. Comparing two cases of operation of one of the gas fired plants for 168 hours shown in fig 4. 18 and 19; where wind forecasting error is 2% and 10% respectively, shows that increasing the reserve requirement due to higher wind forecasting error results in higher marginal fuel cost of thermal plants.

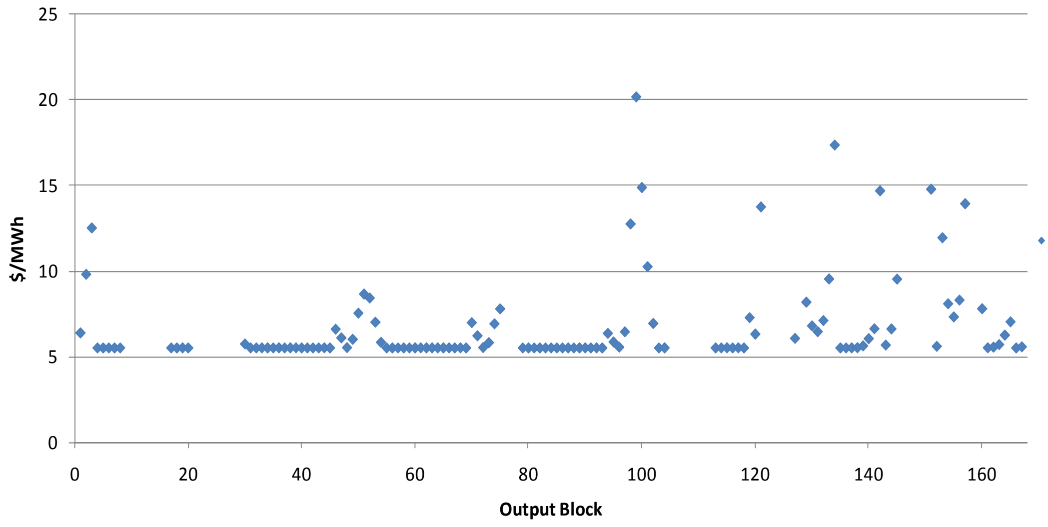

Fig 4. 18. Marginal Fuel Cost of Gas (4) plant with 2% Wind Forecasting Error

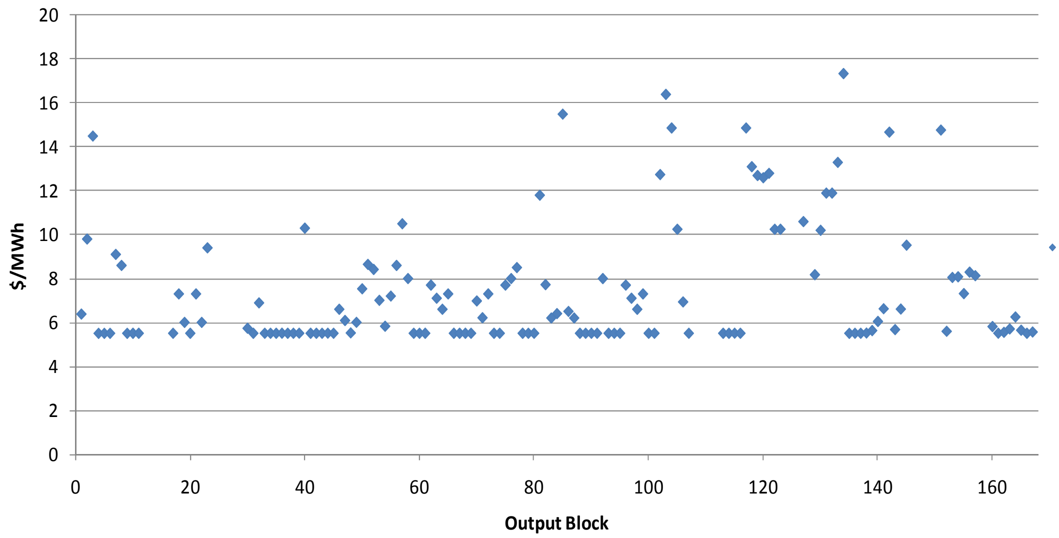

Fig 4.19. Marginal Fuel Cost of Gas (4) plant with 10% Wind Forecasting Error

4.7 Chapter Summary

While increasing the wind power penetration in power systems across the world is matter of interest due to benefits associated with utilizing wind power, but intermittency of wind power create difficulty in utilizing the wind power in a same way as conventional plants. Such nature has impact on reliability of power system and necessitates subsequent changes in conventional methods of operating the power system such as providing additional spinning reserve to cater for variations in wind power output. Providing additional spinning reserve may increase the trading cost of wind power and reduce its values down to a level which may make it less viable. The main findings of this chapter include:

- A methodology to calculate the spinning reserve for a given system with intermittent generation is developed. This calculations based on this method reflects the actual risk on the system imposed by:
    - Demand forecasting error;
    - Wind forecasting error; and
    - Conventional generators outage rate.

  and the benefits of this method include:
- Different levels of spinning reserve requirement have impact on the life-time value of wind power. This is mainly due to changes in the operation pattern of thermal generators by changing their efficiency level (the higher the spinning reserve requirement, the lower the efficiency of thermal plants). Changes in the marginal fuel cost, and emission output of thermal plants are two important elements which change the overall cost in the system.

4.8 References:

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Chapter 5. Increasing the Value of Wind Power with Demand Response

In this chapter an algorithm is presented to increase the value of wind power with demand response. Demand response is used to reduce the power output fluctuations of wind power, and reduce the need for back-up power from non-renewable sources. The savings made will increase the value of wind power. These savings are resulted from reduced fuel cost of conventional plants, and emission output since the overall efficiency of power generation will be increased whilst wind power output is less fluctuating and more steady. It is also shown that the degree of benefits of demand response depends on the price which has to be paid for the demand to respond to wind power output.

5.1 Impact of Demand Side Management Programmes:

In this section the benefits of current domestic demand side management programmes (excluding demand response) in terms of saving on operational costs, emissions and increasing the security of the system are shown. As mentioned in chapter 2, shifting the demand has been considered in many countries in the world as one of the DSM programmes in order to reduce the total peak demand. This programme consists of some technical and regulatory incentives which facilitate shifting a proportion of demand from peak hours to off-peak hours. This will improve utilization of existing generation and transmission capacity, and by reducing the system peak, it will result in a more secure and reliable network. Figure 5.1 shows a typical demand curve for the GB power system [1], with two peaks which usually happens at morning and in the evening. By shifting a proportion of load which consumes power from these two periods to off peak periods, the above benefits will result.

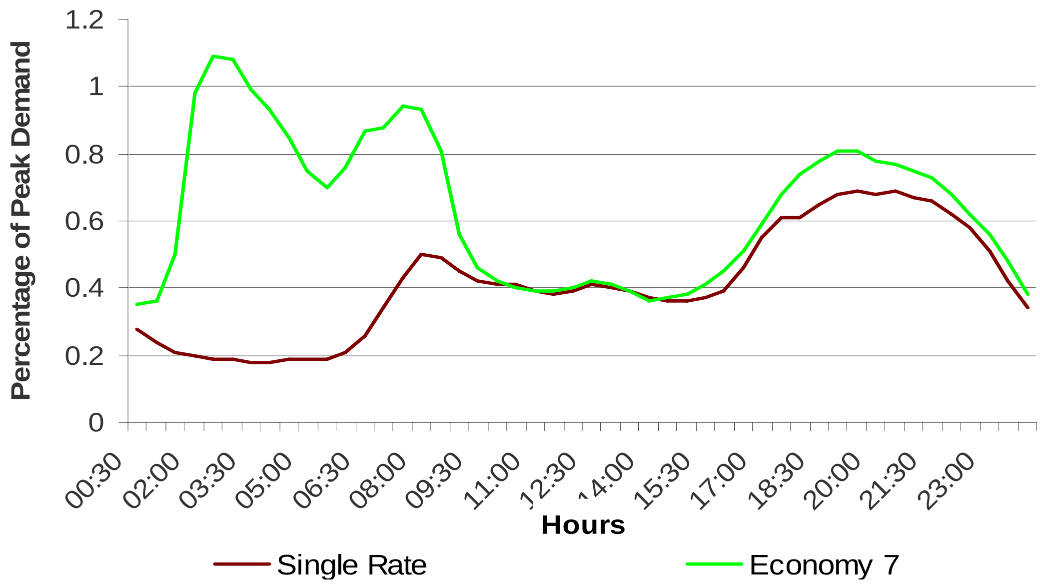


Fig. 5.1 Different Domestic Power Consumption Patterns [1]

Total load in the system is 283.4MW. It has been assumed that 80MW of total load is domestic and 16% of total domestic load is committed to Economy 7[1]. Load profiles represent the UK domestic load profiles and have been derived from Elexon co [1].

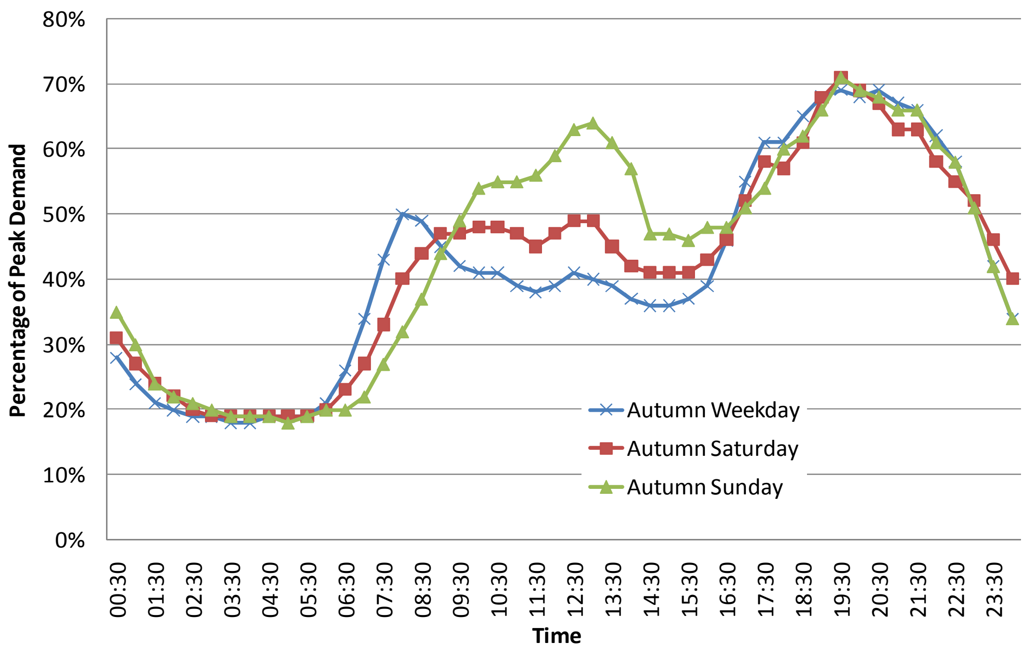


Fig. 5.2 Single rate Load profile [1]

1 Currently (2009) in the UK 16% of domestic consumers who are supplied by major suppliers are participating in Economy 7 scheme which led to an increased domestic night time load giving a more balanced use of the electricity network across the day. More recently there has been a preference for gas central heating rather than electric heating, which has meant that many customers who are on Economy 7 tariffs no longer have a large night time load.

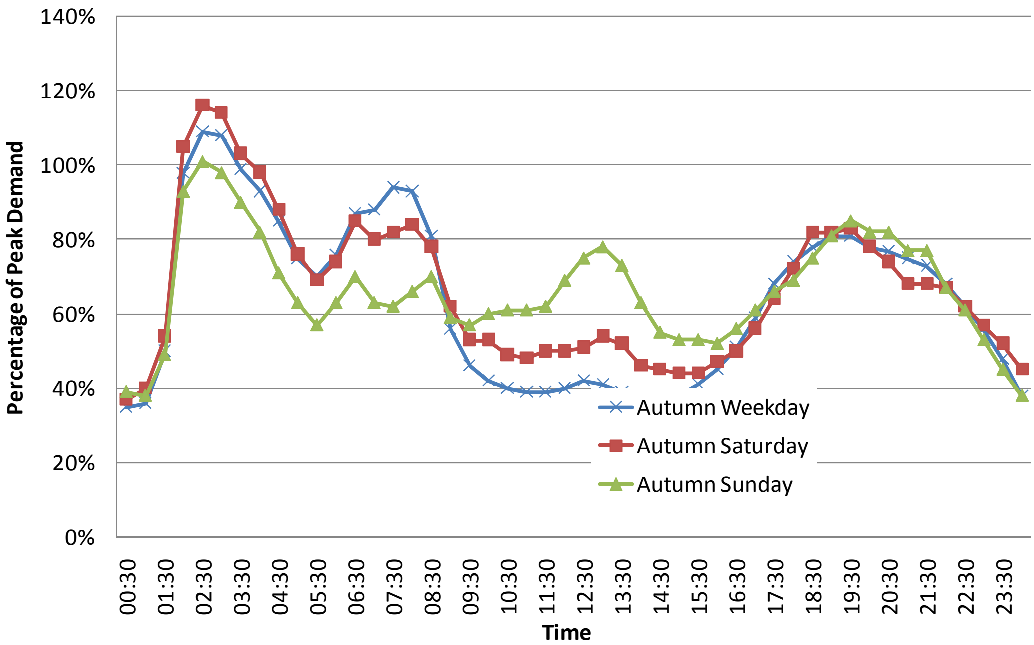


Fig. 5.3 Economy 7 load profile [1]

5.1.1. Production Cost Savings:

The total generation cost; which is the total running cost of conventional plant, significantly differs in the presence of demand shifting. Without shifting the demand as total peak of the system is higher, it required gas units to provide extra power to for short period of time to serve the loads. These units are very expensive to run and the difference in cost at each case is mainly because of reducing the need for running these units. Table 5.1 shows the result of our simulation for each case. We have considered several cases; first when there is no demand side management program implemented and the results show generation cost is £38,533,600. By having 16% multi-tariff demand, the generation cost will be reduced by 1.3% down to £38,032,663. 1.3% drop in production cost in a network with total 283.4 MW demand may not be noticeable but in a real network this reduction is significant.

5.1.2. Emission Reduction:

Emissions which all come from conventional units are calculated in this simulation. As expected in the worst scenario where there is no demand management in the network, the highest level of emission is seen. Demand side managements significantly reduce the emissions as is seen in table below, 5862 tones of CO_2 emissions could be reduced just by multi tariff demand. This is due to less operation of power plants at the time of system peak to meet the demand. These plants (usually OCGT) are thermal plants which emit environmental pollutants and by reducing the peak demand the operation of such pollutant plants will also be minimized.

Table 5.1.
Comparison between Different Cases

Case	Production Cost £	Security *Index*	Emission *Tonnes*
Single rate	£38533600	1456	1145300
16% Domestic Economy 7	£38332663	1394.8	1139438

5.1.3. Impact on Security:

As mentioned before, the security violation index takes into account three factors; the voltage in busbars, reactive power of generators and active power flow over transmission lines. if any of these factors varies outside prescribed limits, it makes the unit commitment and economic dispatch decisions unacceptable. Even under the limits these objectives may violate from their nominal points. We have allowed voltage on busbars to be considered if they are between 1.06pu and 0.94pu of the nominal value. Finally by considering the loading level of transmission lines, voltage on busbars and generators maximum reactive power the security violation indices have been calculated and the total security violation index is the sum of these indices. It is clear according to eq.3.14-3.16 in section 3.3.2.3 that smaller security index represents more secure network. For security constrained unit commitment usually pre contingency and post contingency analysis also add up on top of the security index. The results for security index show it is 1456. By having 16% multi-tariff demand, it will be down to 1394.8.

5.1.4. Value of wind Power:

By increasing the wind penetration as the power injected to the network through wind will reduce the need for running conventional plants, therefore total production cost is cheaper in general with increasing the wind penetration. However this is not always the case as network constraints such as busbar voltage rise where windfarms are installed, and the unit commitment decisions may change and total production may increase. On the other hand with increasing the wind penetrations the need for back-up power may also increases. This increase may happen at certain penetration levels where demand still needs to be met by other plants or at certain locations where transmission system connected to the network is not able to transport the power that comes from renewables. By shifting the demand, total peak of the system will drop; therefore issues such as the transmission congestion because of overloading branches may happen less.

Table 5.2 shows the value of wind power in two different cases. In the previous section the value of wind power for a system with 16% demand with economy 7 tariff compared with total demand with single rate profile has increased by 21%. This shows the contribution demand side management in increasing the value of wind power.

Table 5.2
Value of Wind Power for Different Cases

Case	Value of Wind £/MW/Year
Single Rate with 10% Wind Penetration	£112154.85
16% Economy 7 with 10% Wind	£136,547.02

5.2 Current Benefits of Demand Response

Although electricity generated by windfarms remains too expensive to compete with thermal power sources in most grid-connected applications, there is a growing niche of environmentally-friendly applications which will expand as the cost of windfarm power falls. As more wind power is added to the current system, the desirable mode of operation is to have dispatchable power, not only wind power works as a fuel saver. Intermittency of wind requires combining windfarms with non-intermittent sources such as diesel, or gas-fired plant to compensate for wind's intermittency. Demand response is the largest underutilized resource in the UK. Demand response provides a number of opportunities for improving the planning and operation of power system. With current demand response methods, several objectives have been achieved. Those objectives include:

- Reducing price volatility/flattening spot prices;
- Improving system security and reducing the risk of black-outs;
- Reducing network congestion;
- Delaying construction of additional generation, and/or grid and network upgrading (network reinforcement deferral);
- Reducing greenhouse gas emissions;
- Improving market efficiency by enhancing consumers' ability to respond to changing Prices.

The rest of this chapter studies the economic viability of combining windfarms with demand response to compensate for fluctuations in wind power output. An assessment framework is developed in this chapter based on generation scheduling to assess the demand response benefits both in terms of operation of windfarms, and as a reliability resource to provide additional spinning reserve requirement for wind power.

5.3 Supply Cost & Demand Response in a System with Wind Power:

The continuous balance between demand and supply has conventionally been maintained by generators which respond to demand variations. Deregulation has provided the opportunity for demand to change this pattern by responding to generation side once instructed through different signals, such as a price signal whenever the marginal price of electricity is increasing; known as price responsive demand or sensitive to frequency deviations for frequency regulation purposes.

Price responsive demand as shown in fig. 5.4, reduces the marginal cost of the electricity production; or in fact the price that will be seen in the market. Two demand curves D1 and D2, represent the original demand level, and the reduced demand due to demand response respectively.

Since different generation technologies provide the different levels of power to supply the demand, the marginal cost of electricity depends on the cost of electricity generation from different sources. Power Plants which have lower production cost supply the base-load, therefore increasing the base-load is desirable for efficient operation of power system. This is usually done through non-dynamic demand response (such as economy 7 scheme) which shifts the demand from peak periods, to off-peak periods.

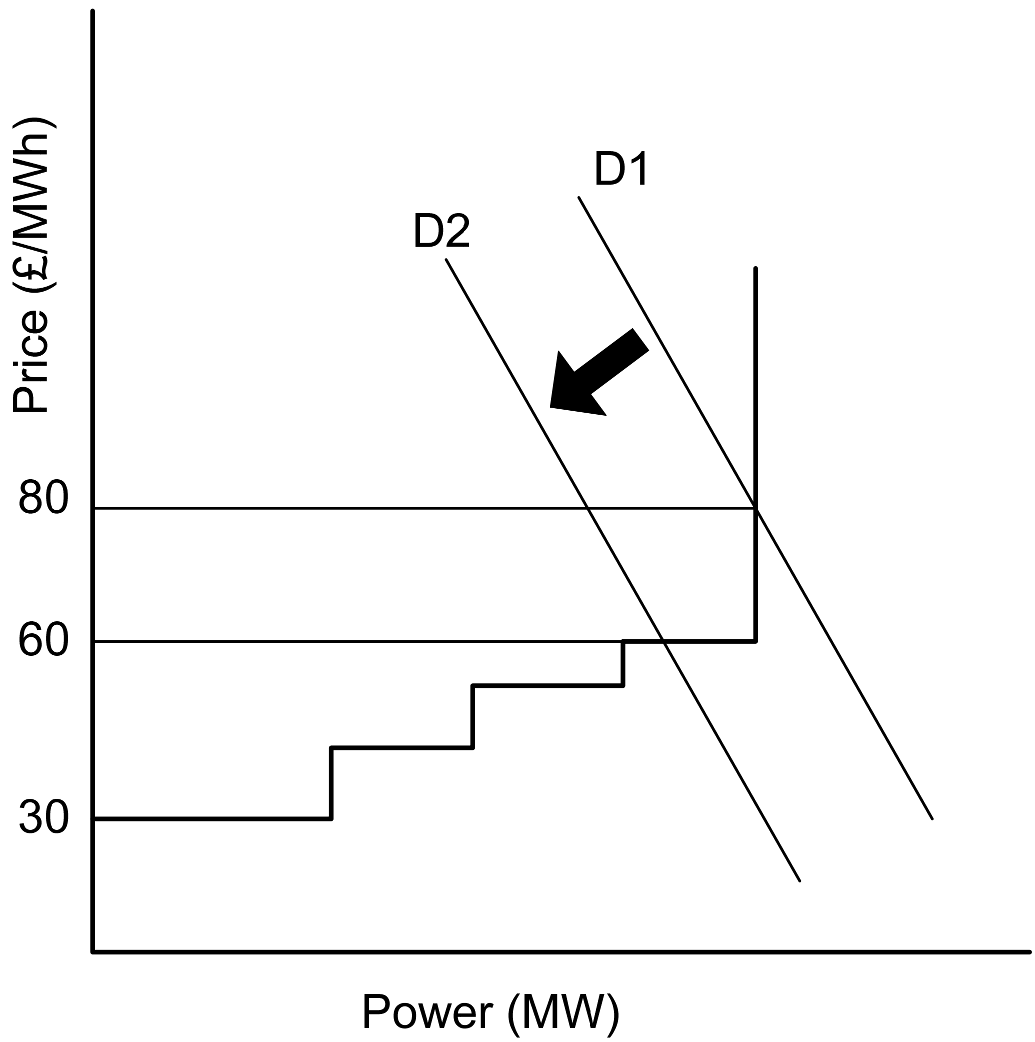


Fig. 5.4. Marginal Cost of Electricity for different compensation levels of demand response

5.3.1 Cost of Providing Wind Power

Windfarms have zero fuel cost, and are represented by (5.1):

$$(P_{wit}) = \frac{1}{2}\eta\,(A \times C_p \times V_t^{\,3} \times N_g \times N_b) \tag{5.1}$$

where P_{wit} is power output of wind turbine in (MW),

η is air density,

A is the rotor swept area exposed to the wind (m^2),

C_p is coefficient of performance,

V_t is wind speed in kilometers/hr at time *t* represented by a time-series,

N_g and N_b are generator and gearbox/bearings efficiency respectively.

Increasing the wind penetration in the system has two impacts on marginal price of electricity. Firstly since wind has zero fuel cost, at the time of system peak it can reduce the marginal price of electricity generation only if wind is blowing and no other constraints are to dispatch the electricity generated from windfarms. It is shown in fig. 5.5 that wind power's presence in the system will move the graph to the right and increases the ***base-load generation***.

On the other hand, it may increase the marginal price by putting additional burden on the system operator to provide back-up power for deviations in the output of windfarms, and spinning reserve. Therefore increasing the base-load power will not always be achieved at the same level of the injected wind power into the system and trading cost of wind power includes mainly the cost of providing additional reserve for wind power which is the cost of additional spinning reserve requirement for wind power. Hybrid windfarms which have dispatchable power, cost of back-up power (either through storing the electrical energy or from a non-intermittent source) in case of a hybrid windfarm:

$$C(P_{wit}) = C(SR) \times \frac{\partial SR}{\partial P_{wi}} + C(BP_{wit}) \tag{5.2}$$

where $C(P_{wit})$ is trading cost of wind power,

$C(SR)$ is the cost of spinning reserve in (£),

$\frac{\partial SR}{\partial P_{wi}}$ is the increased level of spinning reserve due to wind power , and

$C(BP_{wit})$ is the cost of back-up power in (£).

5.3.2 Cost of Demand Response

Demand; D_t is made of controllable and non-controllable loads and both have to be forecasted. Demand is usually represented by time-series for the whole generation scheduling horizon. Demand response participants are usually paid an ***availability payment*** based on the capacity they make available (£/MW), and ***utilization payment*** which depends on the energy provided through demand response (£/MWh). Therefore the cost function representing demand response can be written as:

$$C(DR_i) = \mu_i . DR_i + \tau_i .(DR_{it} \times t) \tag{5.3}$$

where $C(DR)$ is cost function of demand response (£/MWh),

DR_i is capacity provided by customer group *i* ,

DR_{it} is total capacity utilized at time *t* , and

μ_i and τ_i are payment for customer group *i* in (£).

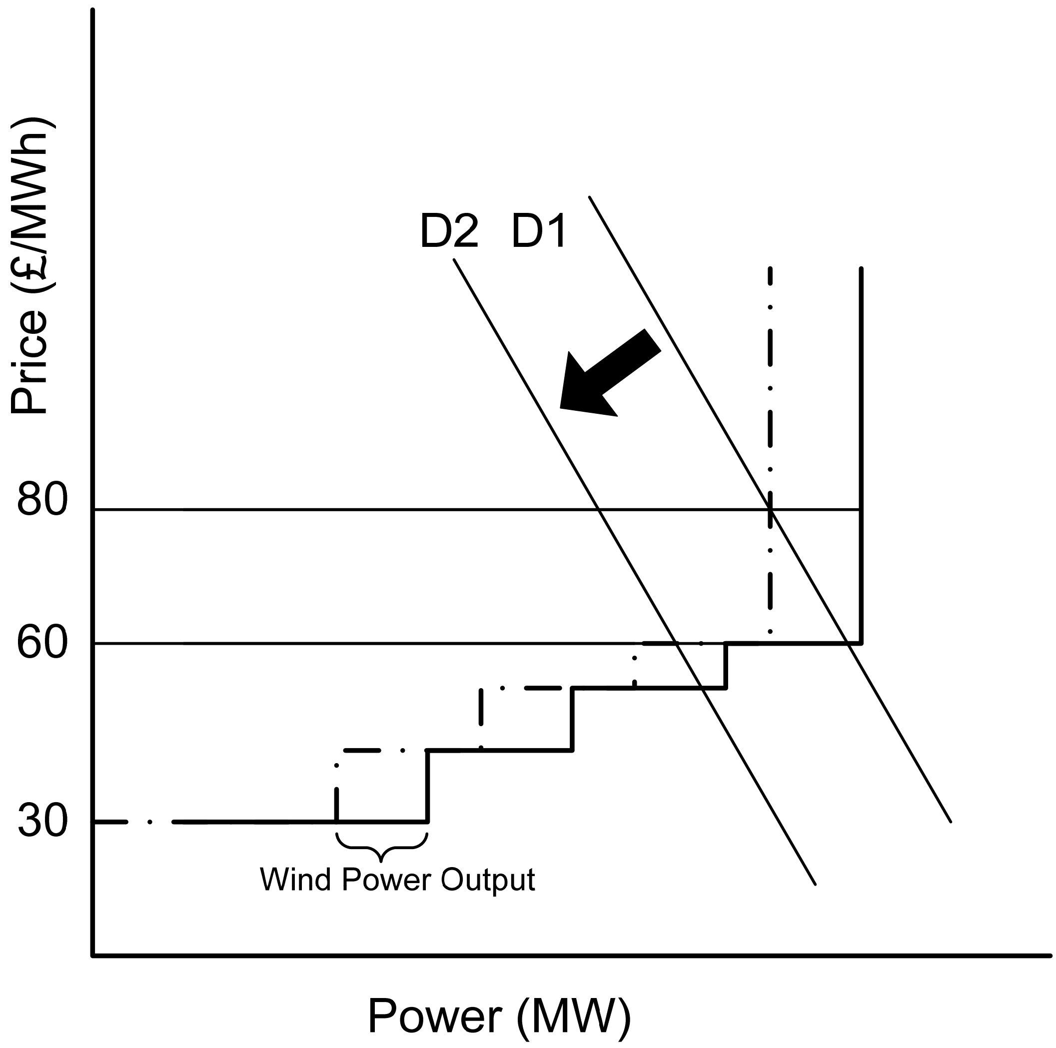


Fig. 5.5. Marginal Cost of Electricity for different compensation levels of demand response in presence of wind power

A demand response system integrated with windfarm system can compensate for fluctuations in the power output of the wind turbine and raise the fuel saving potential. Such system must have response to wind power's fluctuations therefore total electricity production cost from a windfarm can be written as:

$$C(P_{wit}, DR) = C(P_{wit}) + C(DR_i, U_{it}) \tag{5.4}$$

$$C(P_{wit}, DR) = C(P_{wit}) + \mu_i.DR_i + \tau_i.(DR_{it} \times t)U_{it} \tag{5.5}$$

the binary number U_{it} is “1” whenever respond to wind’s fluctuation is required. Therefore cost of demand which is contracted by windfarm’s operator has to be paid availability fee and utilization fee whenever response to wind power output is required. Since demand response can also participate in spinning reserve market, therefore cost of additional spinning reserve due to increasing the wind power can also be assessed with demand response.

5.3.3 Total Cost Function for a System Including Demand Response:

Therefore the total running cost for a system including demand response then can be written as:

$$\sum_{i=1}^{I}(FC_i(P_i)+ST_i(P_i)+SD_i(P_i))\sum_{t=1}^{T}U_{it}+C(P_{wit})+C(DR_i) \tag{5.6}$$

The revenue that a generator will make over its lifetime must be equal to total variable cost and capital cost, plus a profit for the generator owner. The equation (5.6) is the main objective function used in this paper to study the impact of demand response on the value of wind power. It includes the running costs associated with the thermal plants, cost of providing the wind power, and cost of demand response.

5.4 Methodology of Increasing the Value of Wind Power with Demand Response:

The methodology used to investigate the role of demand response to increase the value of wind is shown in the algorithm of figure 5.6. Demand and wind data are forecasted, and responsiveness level is assessed. Thermal generators are scheduled to supply the demand and wind is modelled as negative load. The aim is to achieve firm power output from the windfarm studied, therefore demand will respond to wind power whenever it drops below its net capacity. Since the aim of demand response is only shifting the demand, therefore the amount of demand reduced to compensate for wind power fluctuations will be re-connected after 1 hr. Cost associated with demand response varies for different scenarios to show the degree of feasibility of demand response to increase the value of wind power. As a base case demand was considered with zero responsiveness level. Then by introducing the responsive demand results were compared to the base case in order to quantify the benefits of responsive demand. Our study objective included:

- Fuel cost of thermal plants and spinning reserve cost;

- CO_2 emission of thermal plants; and
- Value of wind power.

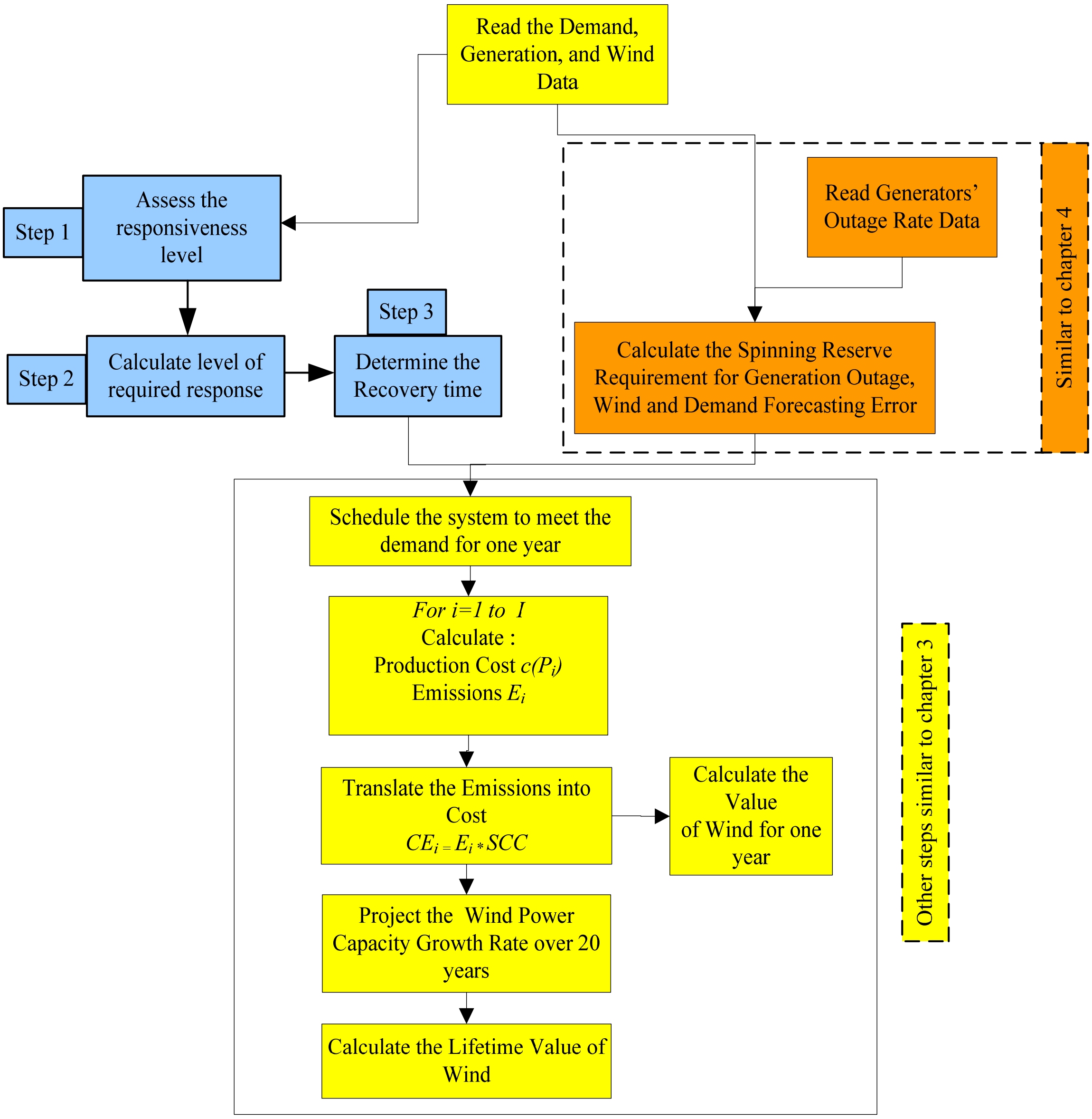


Fig. 5.6. The Algorithm of Calculating the Value of Wind Power with Demand Response

5.4.1. Step 1: Assessing Responsiveness Level

In order to design a system to enable demand responds to wind power fluctuations, it is essential to have the knowledge of available demand response level. The available demand response is the proportion of demand which can be disconnected in order to compensate for wind power deficits. In this chapter it is assumed that there is sufficient demand response level up to 100% compensation level for wind power. This will then be further investigated in chapter 6 in which the potential for demand response will be studied.

5.4.2. Step 2: Calculation of Required Responsiveness Level:

Calculation of level of required responsive demand depends on the level of compensation. In order word, it is important to determine how much wind power fluctuation has to be minimized (through increasing the level of demand response). In order to study the impact of different demand response levels on value of wind power, the compensation level from 0% (no demand response) to 100% (a firm wind power output) is considered in this chapter.

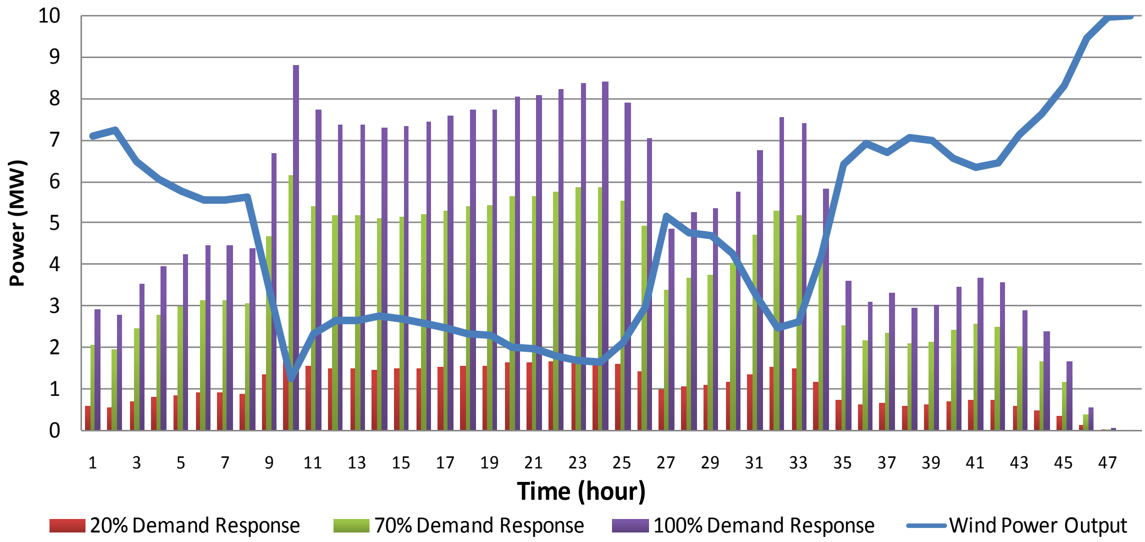


Fig. 5.7. Wind power output for a typical 48-hour period
and different levels of demand response.

5.4.3. Step 3: Determination of Recovery time:

Any load which is disconnected from the system has to be recovered within certain time. This will ensure that all loads will be supplied and only demand will be shifted to benefit the revenue earned by a windfarm. In this thesis a recovery time of 1hour is set for all loads which are being disconnected.

5.5. Benefits from Demand Response

5.5.1. Economic Demand Response:

Wind power is usually given priority dispatch (due to green energy certificate which will be achieved from wind power). Therefore, as long as there is no constraint to extract the power from windfarm, wind power output will be dispatched. Whenever the power output of the windfarm drops, demand respond will respond to it. The savings which can be made from this combination varies over time and depends on marginal cost of electricity generated from thermal plants, and marginal emissions. Since loads which are shed to compensate for wind power variations must be paid, therefore a cost-benefit assessment model is developed to investigate different prices offered by demand response, and different compensation levels to wind power output.

The payment for demand response is based upon the actual response energy provided in the generation scheduling window in (£/MWh). This price varies so the impact of demand response and the degree of feasibleness can be studied.
Once the required economic demand response is assessed, and scheduled to be curtailed, then it has been assumed that same level of demand will have to be recovered in the next generation scheduling block; therefore the curtailment time for each group of loads is limited to half an hour. Therefore:

$$D_t^{'} = D_t - (DR_t) + (DR_{t-1}) \tag{5.7}$$

where $D_t^{'}$ is the new demand which has to be scheduled at time t,

D_t is the forecasted demand,

DR_t is required demand response at time t, and

DR_{t-1} is the curtailed demand response at previous scheduling block.

5.5.2. Reliability Demand Response:

Reliability demand response is provided for additional spinning reserve requirement for wind power. Increased level of spinning reserve is assessed for wind power, and only for increased level of spinning reserve requirement, demand response is contracted. The payment for this service is usually based on number of hours demand is available and again this fee varies to see the impact of different prices for spinning reserve from demand response.

Therefore the spinning reserve requirement for each scheduling block will only be the required spinning reserve for generation outages and demand forecasting error. Figure 5.8 shows the increasing level of spinning reserve due to increasing the wind power in the system based on probabilistic approach to calculate the spinning reserve similar to what was proposed in previous chapter.

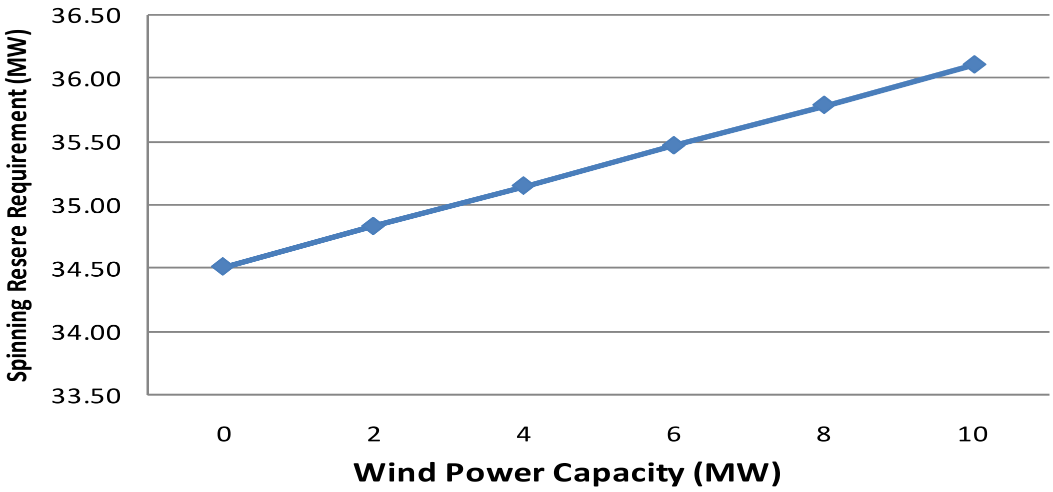


Fig. 5.8. Spinning Reserve Requirement for Wind Power.

5.6. Results and Discussions :

5.6.1. Production Cost:

Total generation cost, which is total running cost of thermal plants, is assessed on different demand response utilization prices, with different compensation levels for wind power deficits. Since demand response participants must be paid in order to compensate for wind power deficits, more energy required for wind power deviations, more revenue will be lost. At the same time, more energy derived from wind power (hybrid wind power-demand response) will reduce the fuel cost of thermal plants.

It is observable from fig. 5.9 that at low demand response prices, increasing the compensation level from demand response will reduce the total production cost. This is because the energy required to change the fluctuating wind power profile to a firmer output profile can be achieved at lower price. Therefore higher the compensation level is, lower the production cost will result as marginal demand response price is cheaper than marginal production cost of thermal plants which were required to supply the demand in presence of a fluctuating with power. The saving made is mainly due to reduced start-up and shut-down costs of thermal plants which is achieved due to less fluctuation of power derived from wind-demand response hybrid model.

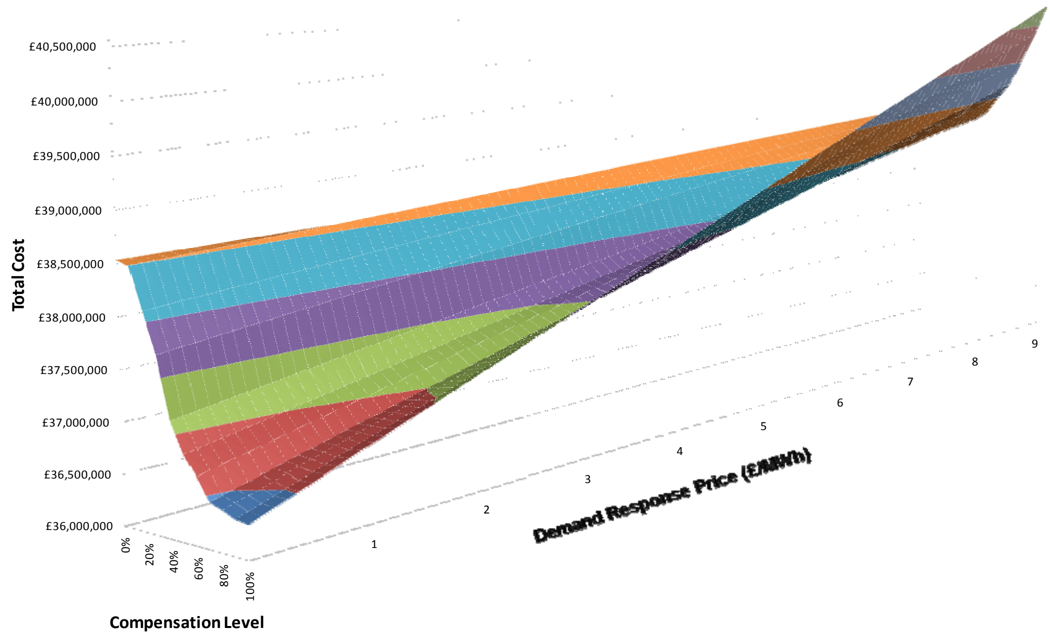


Fig. 5.9. Production Cost for different Compensation Levels & Demand Response Prices.

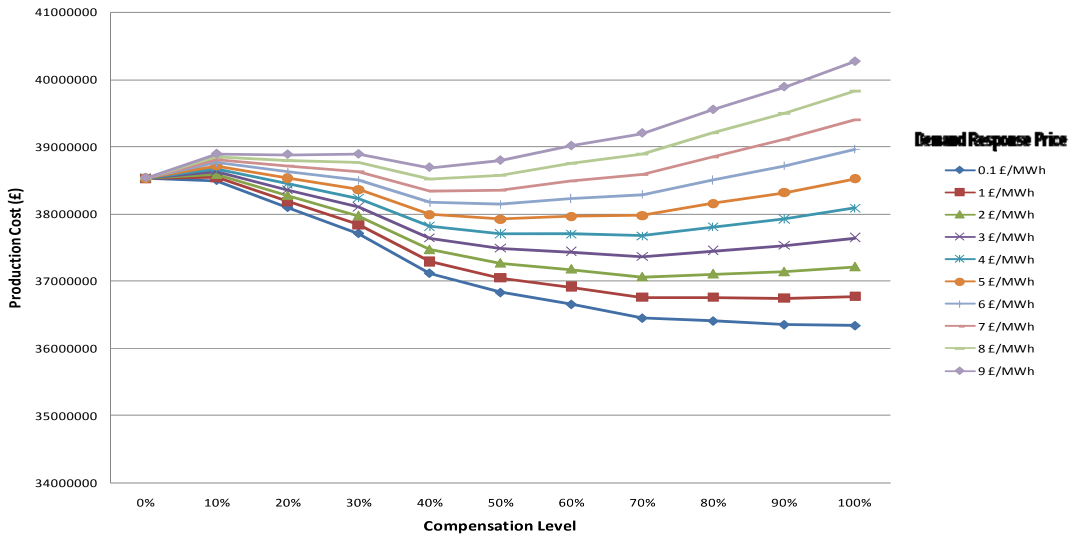


Fig. 5.10. Snapshot of Production Cost for different Compensation Levels & Demand Response Prices.

It is also observable from fig. 5.9 and 5.10 that at low compensation levels (i.e. 10%) no saving can be made even at low prices for demand response. This is because at compensation levels (in this study less than 10%), wind power is still a fluctuating source, which requires thermal plants as a backup. This is shown in fig. 5.11 in which power duration curve of the windfarm with different compensation levels of demand response is presented.

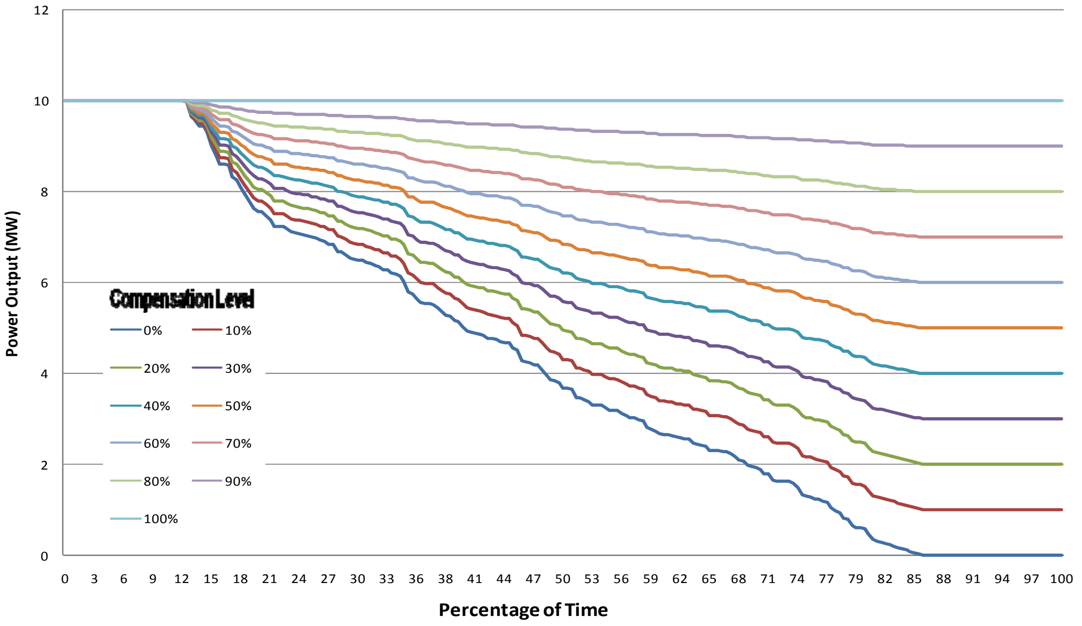


Fig. 5.11. Wind Power Output Duration Curve.

It can be seen that at low compensation levels, wind power is still a very fluctuating source and thermal plants must regularly start-up and shut-down to balance the demand-supply which will result in increasing the marginal cost of power generation by thermal plants as shown in fig. 5.12.

Increasing the compensation level will change the wind power profile to a less intermittent and firm profile which requires less back-up from other thermal plants.

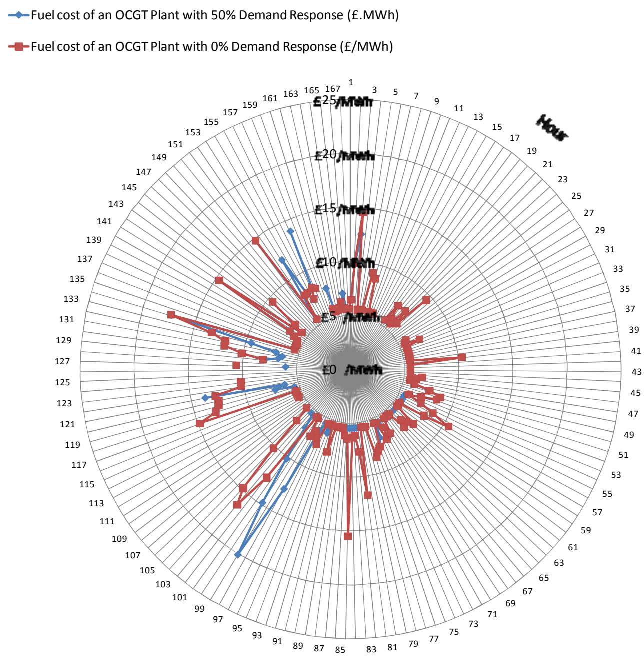


Fig. 5.12. Marginal Cost of Power Generation by a Gas Fired Plant with and without demand response compensation.

5.6.2. Emission Level:

Wind Power, as a clean source of power has no output emissions. Supplying demand with wind power will reduce the need for operating the thermal plants which reduces the total emissions significantly as shown in fig. 5.13. By increasing the total energy provided by the hybrid wind-demand response model studied in this paper, thermal plants tend to reduce their output, therefore total emissions resulted from them will be lower at higher compensation levels. It is also observable from fig. 5.13 that the highest reduction rate compare with all cases, in which demand response compensates for wind power fluctuations, is achieved when 100% compensation level is maintained.

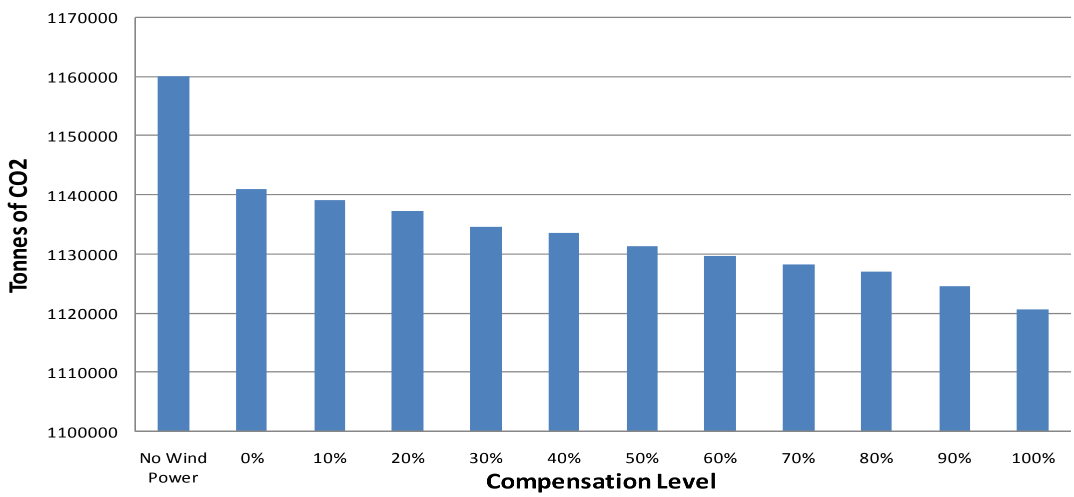


Fig. 5.13. Total CO_2 Emissions.

In this case, a firm wind power will not only reduce the operation hours of thermal plants and total start-up & shut-downs, but also increases the efficiency of electricity generation by thermal plants, which in turn results in reduced marginal emission output of them. Marginal emission output of conventional plants, as is shown in chapter 3 is a second order polynomial function of power output and thermal plants (particularly gas fired plants) have lower marginal emission output if they are operated at their maximum output, instead operating at lower output levels. If thermals plants are to back-up wind power, they may either be operated partially loaded and then will have higher marginal emission output, or those plants which have a short minimum up/down time will be used to provide extra power needed to compensate for wind power which again, results in higher marginal output emission since the plants will not be fully loaded.

5.6.3. Impact on Spinning Reserve:

Responsive demand providing spinning reserve is a financially attractive way to provide system response to contingencies. It has both technical and financial benefits, and in this chapter the financial benefit of such scheme is investigated. Generation units which must maintain the required spinning reserve are to be partially loaded, and this reduces the efficiency of electricity generation, since marginal fuel cost and emission of thermal generators are lower if they are fully loaded. As shown in fig. 5.14, spinning reserve level increases by increasing the wind power capacity in the system. This is due to higher uncertainty level in the system as a result of wind forecasting error which was assumed to be 16% representing wind forecast for 5-6 hours ahead.

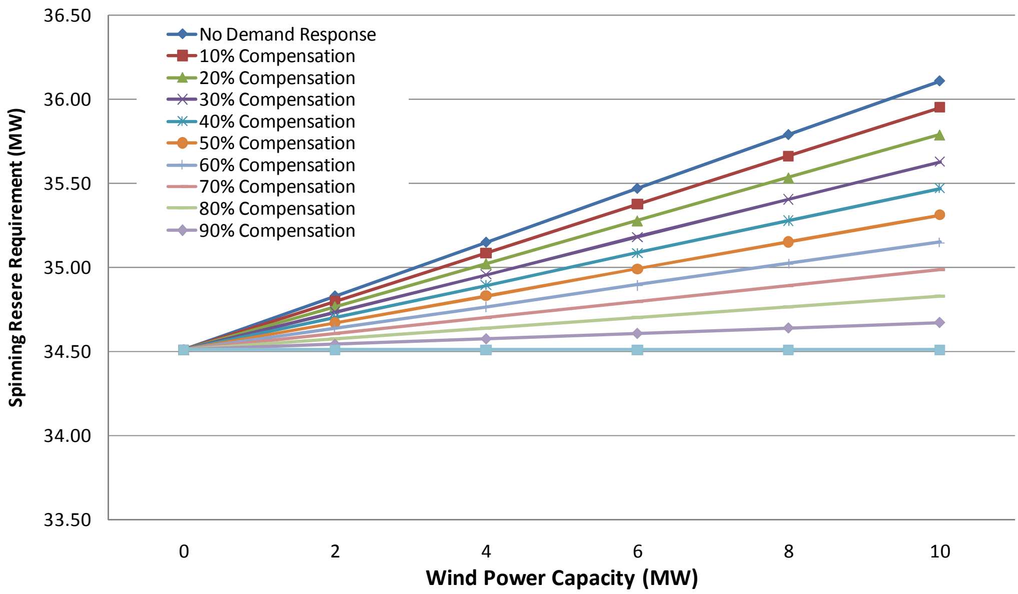


Fig. 5.14. Spinning Reserve Requirement for Wind Power with different demand response compensation levels. .

The results show that if all this increased level is to be maintained by generators, the spinning reserve cost increases by 4.63% which is due to need for allocating more available generation capacity for spinning reserve. If the entire extra spinning reserve requirement is to be provided by demand response, then a maximum of 1.6MW of demand response must be contracted and paid for 8760 hours of being available. It must be noted that the spinning reserve requirement is much lower when demand level is lower and the graph in fig. 5.15 shows the spinning reserve requirement at the time of system peak. The reduction in spinning reserve cost depends on the contribution level of the demand response and the availability fee paid to the demand, the higher the contribution level and lower the availability fee is, the lower the spinning cost and vice versa.

In fig. 5.15 the total spinning reserve cost verses different contribution levels of demand response to maintain the extra spinning reserve required for wind power is shown for different demand response availability prices. In 100% demand response contribution and when the availability price of demand response is zero, total spinning reserve cost which is £568,930.69 is only for generation outages and demand forecasting error which is assumed to be 1%. Reduction in demand response contribution to maintain the extra spinning reserve required for wind power, increases the total spinning reserve cost as some generators must also maintain the spinning reserve for wind power which increases the production cost. When demand response's contribution is 0%, all the extra spinning reserve for wind must be maintained by generators.

Increasing the price of demand response will increase the total spinning reserve cost up to a point where demand response's contribution is not cost-effective. As shown in fig. 5.15 if the availability price paid for demand response is higher than £2/MW/h, the spinning reserve cost reduces by reduction in the contribution level of demand response, or in other word, it is more cost-effective for generators to maintain the total spinning reserve required.

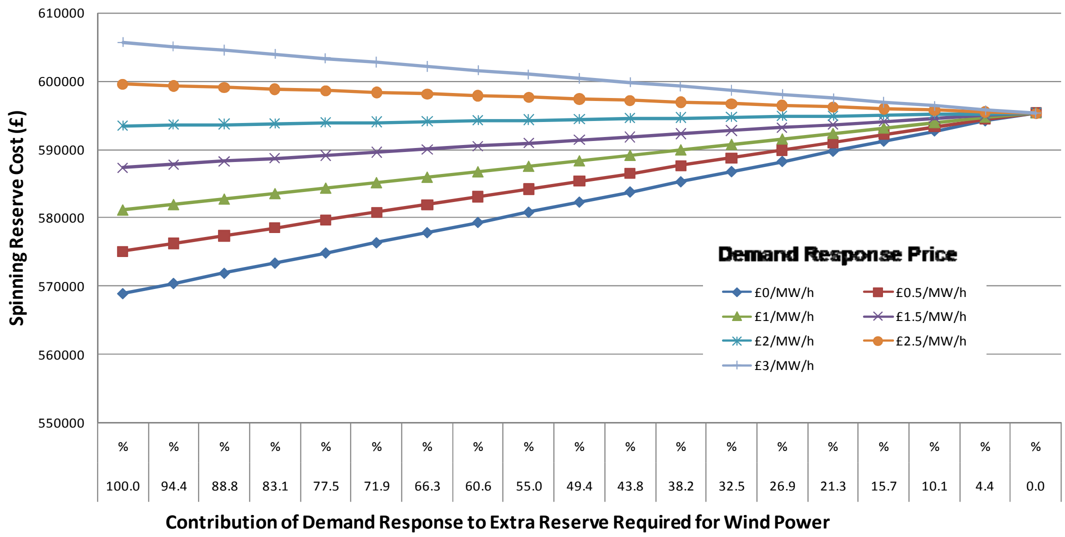


Fig. 5.15. Spinning Reserve Cost with Demand Response.

5.6.4. Value of Wind Power:

The value of wind power for each different scenario in which demand response's contribution is different with different prices, is shown in table 5.3. The value of wind power, at low demand response prices increases by increasing the compensation level. This is due to savings which can be made on fuel cost of conventional plants. The value of wind power in case of no contribution from demand response is 112,154.8 £/MW/Year. This value tends to increase when demand response is compensating for wind power fluctuations. However, by increasing the price paid for demand response, the value of wind power tends to reduces until the point that if the demand response's price is higher than £9/MWh, at high compensation levels, this results in negative value for wind power.

Obviousely cost saving on fuel cost of conventional plants and emissions penalties is made. However, since the price which has to be paid for demand response to compensate for wind power deficits is so high in a year of generation scheduling. Therefore the owner of the windfarm will not only make any revenue, but also loses some money for compensation purposes as illustrated in fig. 5.16 & 5.17. It is shown that if the savings on fuel cost of thermal plants and emission penalties are higher than the price which has to be paid for the certain levels of demand response, then higher value of wind power will result compare with the case where no demand response is integrated with wind power.

Table 5.3.Value of Wind Power (£/MW/Year) for
Different Compensation Levels & Demand Response Prices

Compensation Level / Demand Response Price	0%	20%	70%	100%
0£/MWh	112155	165871	354994	386776
1£/MWh	112155	157135	324420	343099
2£/MWh	112155	148400	293846	299422
3£/MWh	112155	139664	263272	255745
4£/MWh	112155	130929	232698	212068
5£/MWh	112155	122194	202124	168390
6£/MWh	112155	113458	171550	124713
7£/MWh	112155	104723	140976	81036
8£/MWh	112155	95987	110402	37359
9£/MWh	112155	87252	79829	-6318
10£/MWh	112155	78517	49255	-49995
11£/MWh	112155	69781	18681	-93672
12£/MWh	112155	61046	-11893	-137349
13£/MWh	112155	52310	-42467	-181026

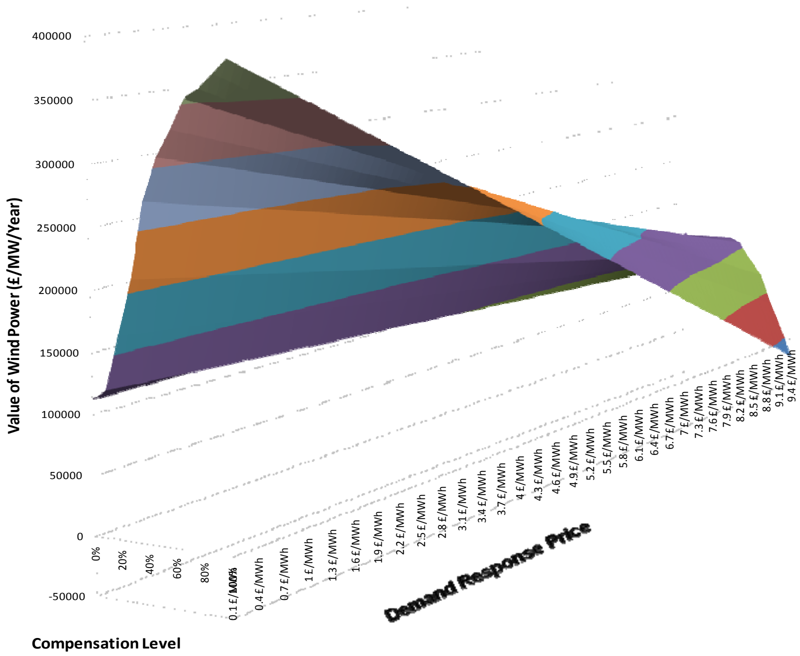


Fig.5.16. Value of Wind Power for different Compensation Levels & Demand Response Prices.

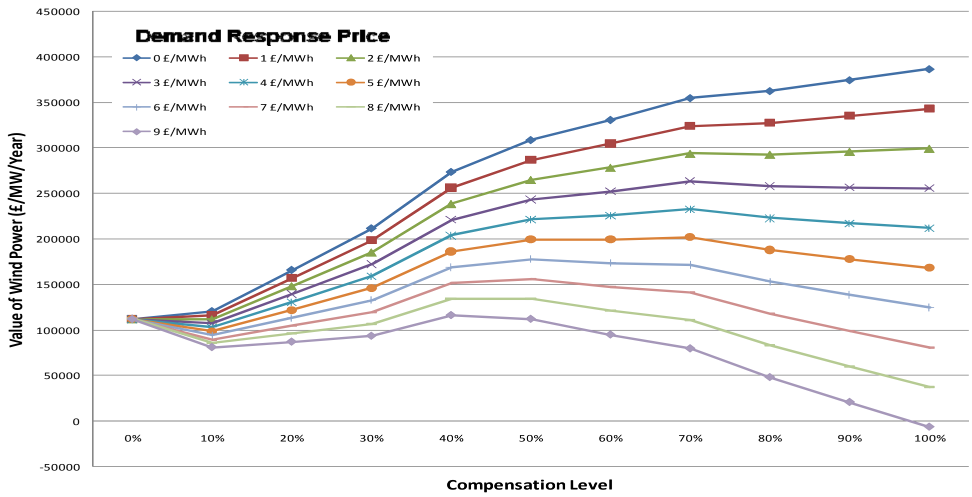


Fig. 5.17. Snapshot of Value of Wind Power for different Compensation Levels & Demand Response Prices.

5.6.5. Lifetime Value of Wind Power:

It is shown in fig. 5.18 in which the demand response's price is £0/MWh, that the lowest payback period will be achieved in less than two years. If 100% compensation level is maintained through demand response, compare with a scenario in which no demand response is contracted which the payback period is between 9-10 year.

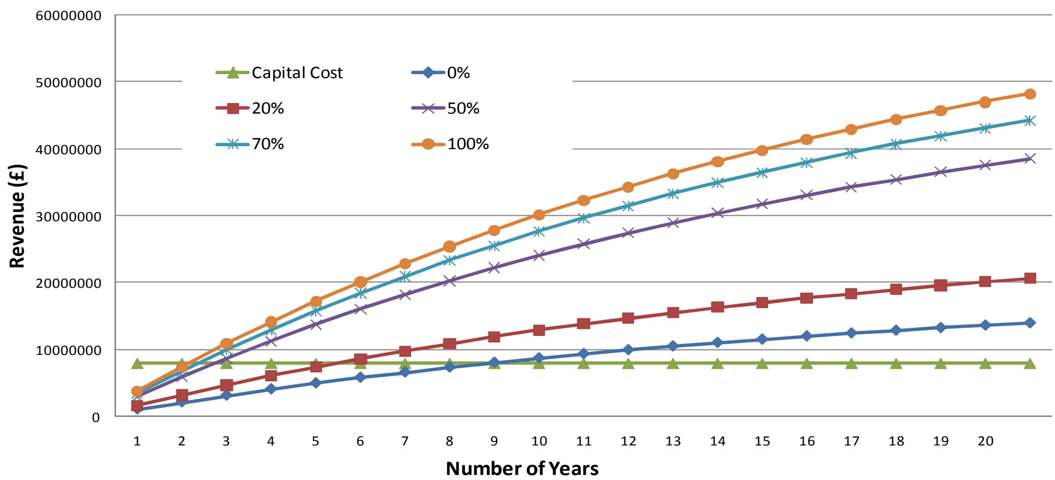


Fig. 5.18. Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £0/MWh.

By increasing the price of demand response, higher compensation levels tend to delay the payback period, as shown in fig. 5.19-5.23. It is also observable from these figures that sometimes, i.e. in fig. 5. 21, different compensations levels (70% and 100%) both result in the same payback period. This is because in higher compensation level, although more savings will be achieved from fuel cost and emission penalties of thermal plants, a higher price has to be paid to maintain such level of compensation which is equal to lower compensation level which lower savings, and lower fee has to be paid to maintain the demand response compensation.

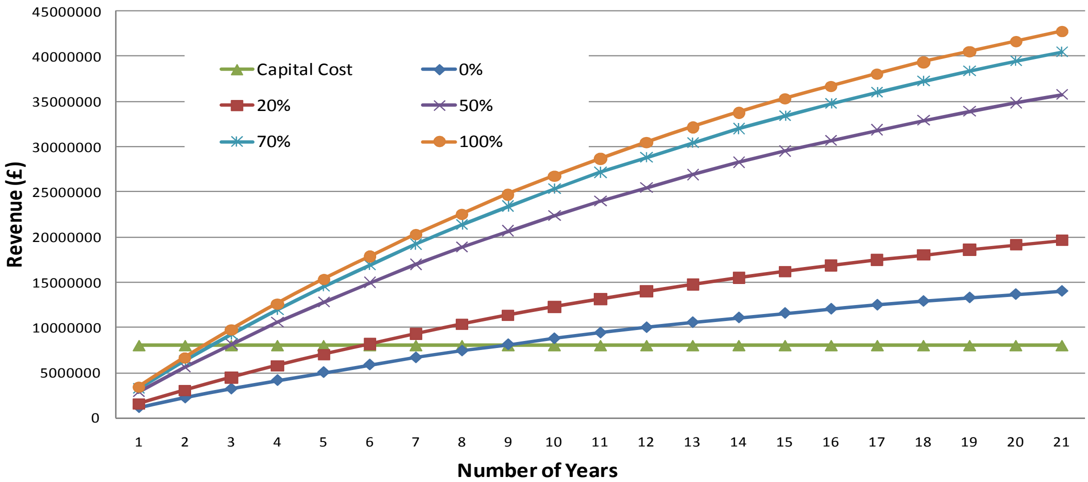


Fig. 5.19. Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £1/MWh.

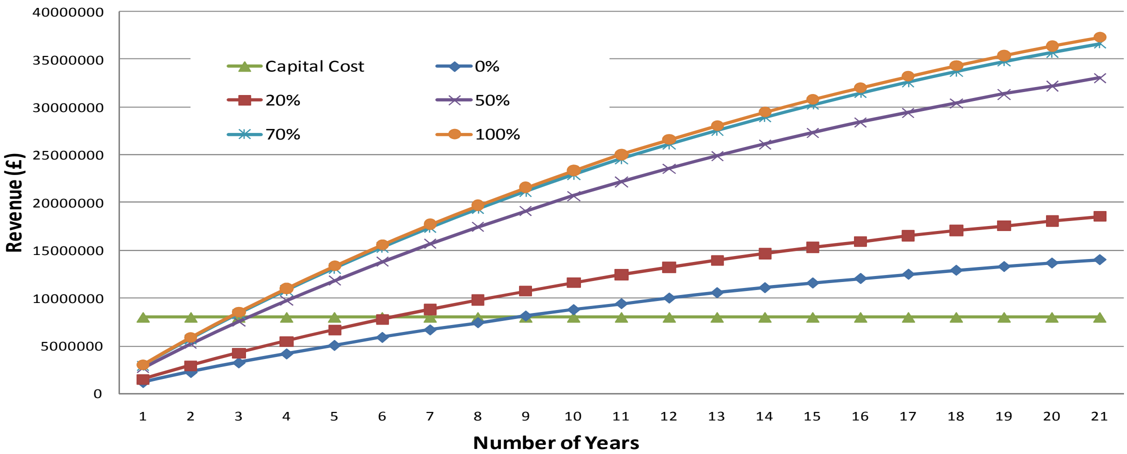


Fig. 5.20 Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £2/MWh.

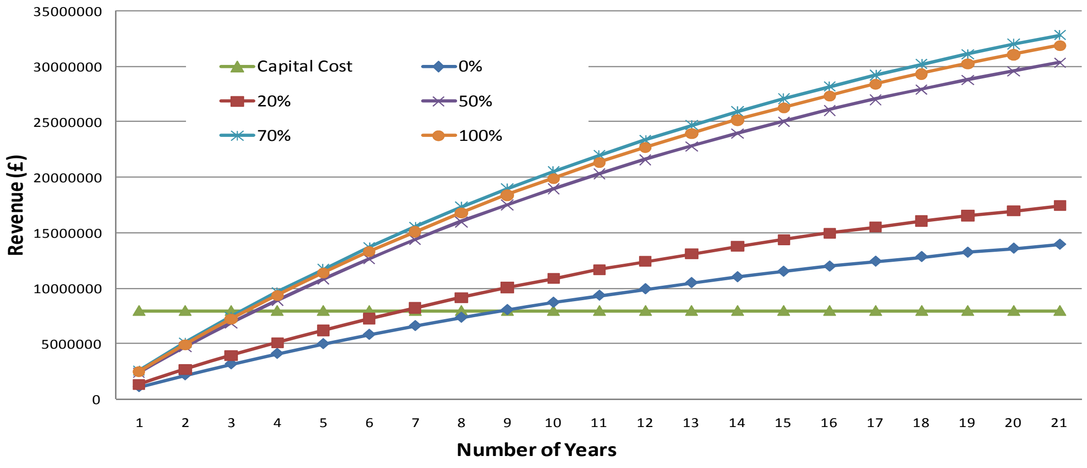


Fig. 5.21 Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £3/MWh.

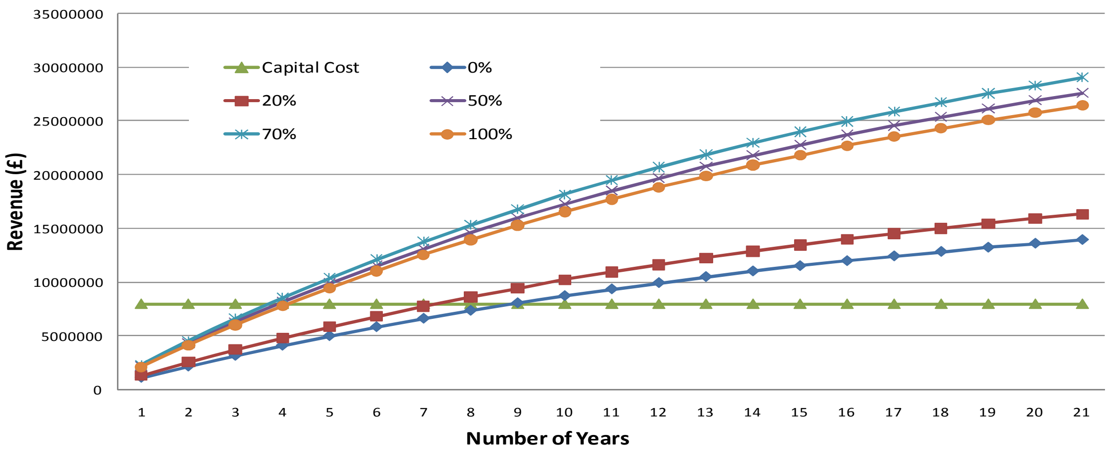


Fig. 5.22. Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £4/MWh.

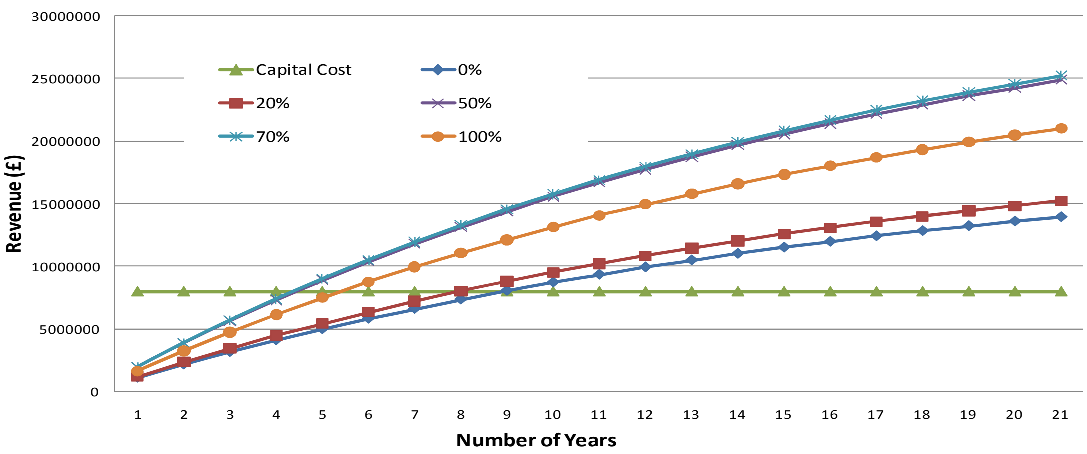


Fig. 5.23. Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £5/MWh.

When the price of demand response is over £6/MWh, the contribution of higher levels of demand response in expediting the payback period for a windfarm is actually negative. It means that due to the price which has to be paid to have certain levels of compensation levels, this will increase the total costs over the lifetime of a windfarm and delays the payback period. But still, at lower compensation levels contribution of demand response is to reduce the payback period as shown in fig. 5. 24.

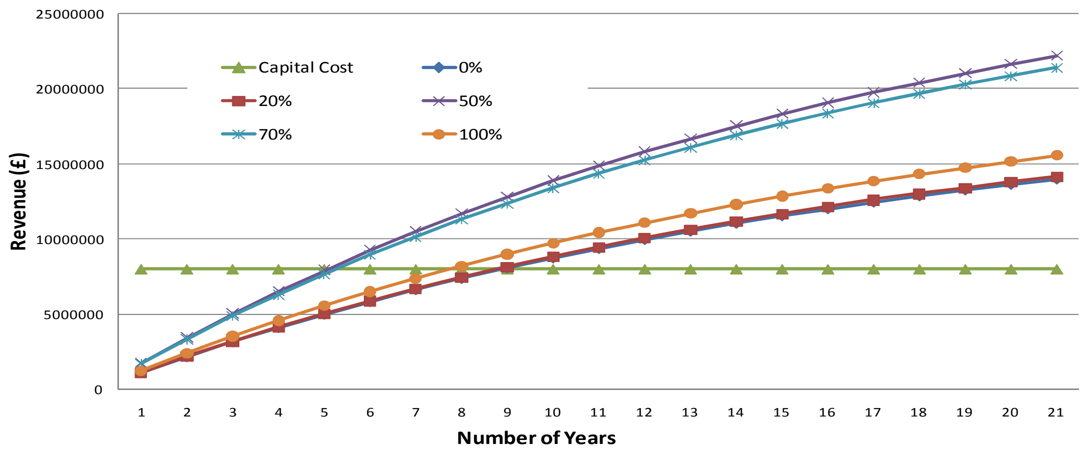


Fig. 5.24. Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £6/MWh.

If the price of demand response is higher than £7/MWh, higher compensation levels tend to delay the payback period even compared with a case where no compensation from demand response exists as shown in fig. 5.25. However, if an optimal level of compensation level for such price is maintained, then there is still chance for demand response to expedite the payback period of a windfarm as shown in fig. 5. 25 and 5.26.

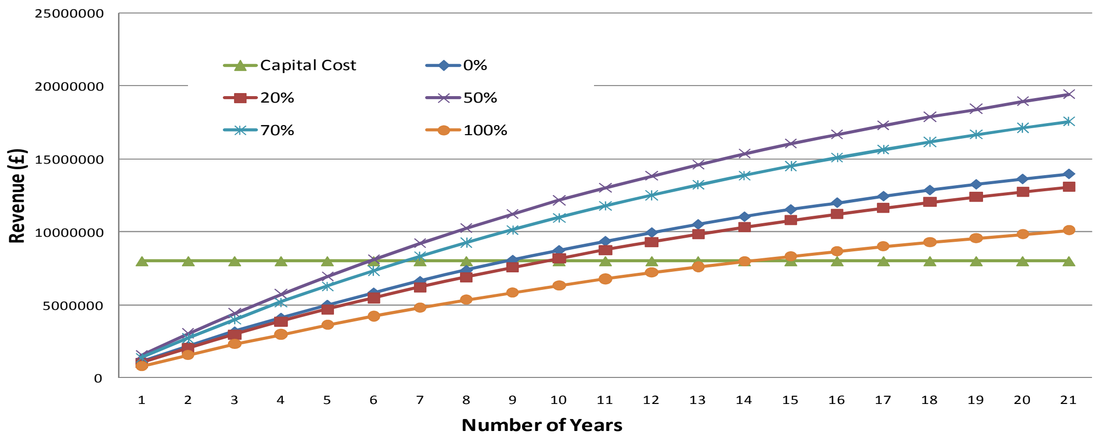


Fig. 5.25. Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £7/MWh.

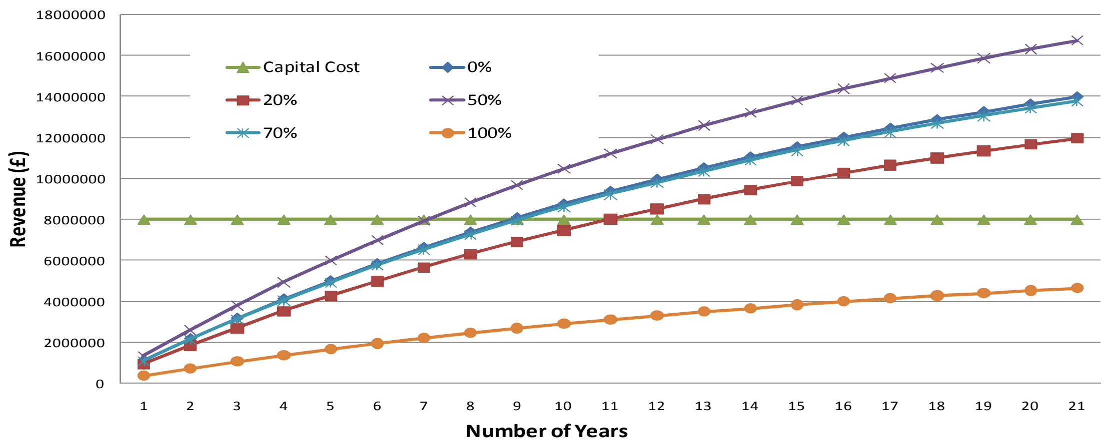


Fig. 5.26. Break-even predicted for the hybrid windfarm for different compensation levels of demand response when the price of demand response is £8/MWh.

5.7. Limitation of this Model for a Large System

In this chapter, an assumption was made that enough demand response is always available to respond to wind power variations. Making such assumption for a large and real power system is not always correct, since availability of demand response is limited at different hours and it is an important factor which must be taken into account.

Demand response availability depends on the proportion of total demand, which is contributed by specific types of appliances which can become responsive. Considering the random operation behaviour of different appliances, quantifying the demand response level is one of the biggest challenges which will be discussed in the next chapter.

5.8. Chapter Summary

Considerable worldwide interest in the potential of demand-side management techniques has the potential of reducing balancing costs for system operators and so, as a side effect, reducing the additional costs of intermittent renewables as well as reducing the emissions. Currently there is considerable interest in exploring the possibilities of high penetrations of wind energy into electricity networks and mitigating the barriers to increase the wind penetration. This chapter demonstrates the effect of combining demand response with wind power on reducing the cost, and emissions where intermittent generation has substantial installed generation capacity in the system.

The main results of this chapter include:

- DSM programmes van benefit the system by reducing the fuel costs and emission levels. In a system with intermittent generator, DSM programmes (non-dynamic) may increase the value of wind power by reducing the thermal generators' cost and increasing the cost-savings through windfarms. The results show that 21% increase in the value of wind power may be achieved just by shifting about 16% of loads from peak to off-peak periods.
- Dynamic DSM programmes (demand response) will further increase the value of wind power through:
    - Reducing the need for additional spinning reserve for wind power;
    - Reducing the variability of wind power which:
        - Increase energy share of wind power;
        - Reduces the number of start-up and shut-down of thermal plants;
        - Increases the efficiency of power generation which will reduce the cost and emissions.
    - The results suggest that cost savings about £150,000/MW demand response may be achieved. This excludes the costs associated with demand response (such as cost of implantation, etc.).
- The impact of demand response on value of wind power was studied, and the result suggest that demand response may expedite the payback period for a windfarm from 10-12 years down to 2-3 years if 100% demand response can be maintained. The expedition in breakeven point will be limited when cost of demand response is taken into account, and in fact high compensation levels may not be feasible.
- The results indicate that if the cost of demand response is taken into account, the degree of feasibility of this technology with regard to value of wind power will be limited to demand response prices up to £6/MWh.

5.9. References

[1] Load profile (used for balancing market) www.elexon.co.uk

Chapter 6. Assessment Framework of Responsiveness Level in Domestic Sector

In order to combine the wind power and domestic demand response, it is essential to study the load profile of different appliances in domestic sector. Therefore to complete our assessment framework of studying the value of wind power combined with demand response, the load profile of different appliances is studied and a demand response evaluation package is developed to study the potential for demand response at different locations in the grid. This chapter first investigates the previous methods of estimating the load profile particularly in the domestic sector; different techniques and the application of current methods are presented, and then by proposing a method which is based on the probability of different appliances being used by different types of customer, total load profile for E&W is estimated. Then by distinguishing between those appliances which are able to become responsive, total domestic demand response potential is calculated.

6.1 Demand Response from Domestic Loads

Uncertainty and variability are inherent to electric power systems; demand rapidly changes and since there is limited control mechanism on it, this could threaten grid integrity and stability. Besides, maintaining the security of supply is becoming an increasingly strategic issue considering both volatility of wholesale energy prices, and limited facilities for electricity generation, transmission and distribution which has resulted in suppliers becoming unable to fulfil their contractual obligations.

Demand has been participating in improving the economy, security and reliability of energy industry as well as eliminating the negative environmental impacts since the beginning of introducing Demand Side Management (DSM) programs in the early 1970s as explained in chapter 2. Demand in the domestic sector is the aggregated power consumption of households. Domestic Demand Response (DDR) is still the largest underutilized resource in the power system. Since the new schemes introduced by network operators and electricity supply companies allow small loads to be aggregated and provide the same capacity of a large industrial load, attention has been focused on DDR more than ever.

The fundamental problem in employing DDR is not having sufficient information about the power consumption pattern of small domestic loads. This chapter aims to investigate the methods that have been used in the past to model the electrical load profile in domestic sector, and explain the limitations of the current methods to be used for modelling the individual appliances for demand side management purposes, and to propose a model which can satisfy us in studying the load profile of domestic sector in order to perform various demand side management experiments.

To evaluate the amount of load which could become responsive it is important to know the load profile of the proposed consumer. If loads are to become responsive like load shifting programs the overall satisfaction of consumers should not be affected. Therefore only those loads may become responsive which have more elastic and may be shed in response to a network operator signal or even autonomously by detecting the network variations.

6.2 Load Profile in Domestic Sector

6.2.1 Definition of Load

Load can be defined in several ways depending on the requirements of the applications. The most important specifications of load data are [1]:

1. System location (customer site): Load is located in a specific location within the grid;
2. Customer class: Loads are divided into industrial, commercial, domestic, agriculture and services;
3. Time: load level within a system varies depending on time of year, day of week and time of day;
4. Dimension: kW and $\cos\phi$.

6.2.2. Load profile:

Load Profiles shows the electricity consumption pattern by a group of consumers. A load profile gives the Half-Hourly which is known as “Settlement Period” shape of usage across a day (Settlement Day). Apart from the pattern of electricity consumption, other information could be derived from load profile of individual or a group of customers. This includes:

1. Peak load values;
2. Minimum load values;
3. Total load which could be shifted from peak to off-peak periods;

6.2.3. Impact of Different Factors on Electricity Load Profile:

6.2.3.1 Customer factor:

The amount of energy consumed is very dependent upon the attitude and awareness of the energy customers. The consumption pattern in different building types, like households, schools and office buildings, is usually unique for that particular building. Therefore customer influence differs depending on what kind of buildings they spend their time in. Consumers will have less influence in a building with automatic control than they will have in a manually controlled building. Awareness and attitudes towards energy consumption are more evident in household consumption than in situations where many people may simultaneously have an influence on energy use, such as in office buildings. Programs which are designed to control the energy consumption of electrical appliances, such as shifting the energy consumption from peak periods to off-peak period have also impact on load profile and can be included as part of the customer factor.

6.2.3.2. Weather factor:

Different climatic parameters influence the load and energy demand such as temperature level versus space heating, ventilation and cooling; wind speed and direction versus space heating and ventilation; solar irradiance vs. cooling and lighting; hours of daylight versus lighting and cloud layer vs. space heating. The climate changes from place to place as well as on a yearly basis, making the generation of a common representation of the normal climate into a challenging task at any given location.

6.2.3.3. Time factor:

The amount of load within a system varies with the time depending on human activities and other events which may increase or decrease the utilization of electrical loads.

6.2.3.4. Other Electric Loads (Coincidence Factor):

Some electric loads are influenced by each other; e.g. operating one type of load may result in shutting down another one or necessitate operating another load at the same time. For example cooker use may correlate with kitchen light and extraction.

6.2.4. Available Data to Model Load Profile:

To model a customer's load profile we need to have some information about them. Preferably, this information should indicate the consumption pattern of the customer during the study period. However this requires installing a electricity meter at the point of consumption for every customer who is able to record the consumption level at interval points. Some customers (usually non-domestic customers) have such meters but in the domestic sector, so far not all the customers have benefited from such meters.

In the domestic sector, the electricity meters usually record the energy consumption of a customer during a specific period. Therefore, the kWh energy consumption is one of the available data which is being used to model the customers load profile. These customers are billed on a tariff called Increasing Block Tariff (IBT). IBT sets a cheaper tariff for the first A kWh consumption and then a different tariff for anything the consumer used above the first A kWh. In some countries the second tariff is higher (to encourage people to save the energy) and in some countries it is cheaper (to encourage the people to utilize electrical appliances). Flat rate billing is also accepted in many countries such as UK.

The number of people living in each household, their occupation and number of houses in each area as well as weather data may be known and can be used to model a customer or a group of customers.

6.3. Modelling techniques used for Load Profiling

Several methods are used to model the energy consumption at different sectors; they can be divided into three main groups [8]:

- Statistical analyses;
- Energy simulation programs;
- Intelligent computer systems.

6.3.1. Statistical Analysis:

The statistical analyses method of load profiling and energy estimation is based on large amounts of measured energy consumption data. The probability sample must have a high level of statistical data in order to meet the accuracy requirements of the planners. Load profiling is mainly based on linear, or multiple regression analysis. A regression analysis indicates the mathematical correlation between different variables. This analysis also gives an indication of the quality of the correlation between various energy consumption measures and climatic parameters, such as load and temperature outside. The representation of weather and socio-economical factors is very important in terms of load profiling. Customer behaviour such as their income, occupancy and working pattern, numbers of household's occupants etc. all have impact on the load profile of a particular household.

Werner in [2] used multiple linear regression analyses on the total district heat consumption for six different district heating companies in Sweden for heat load estimations. The focus was on the aggregated daily load level and the model was developed based on outdoor temperature, wind velocity, solar radiation, hot tap water supply, heat losses in the distribution network, as well as additional workday load.

The Energy-Signature method has been used in [3]. The method is based on linear regression analysis of heat consumption versus outdoor temperature, on a daily, weekly and monthly basis. The daily district heat consumption versus daily mean temperature, along with the daily utilization time, was applied to estimate the building's design heat load on an hourly basis. It has analyzed district heating measurements of 50 buildings, including large and small apartment blocks, office buildings, and retirement homes. The average heat load profiles for the various building categories were estimated for February 1991. The maximum specific heat load, both measured and corrected using energy-signature and utilization time, was presented for all buildings analyzed.

The Conditional Demand Analysis (CDA) has also been based on regression analysis, with the regression level on the end-use, not the total energy demand [4]. Different appliances (electrical equipment, cooling and heating devices) at the customer level were summed to estimate the total energy demand for each particular customer. Energy consumption, electrical appliances, demographic features, energy market prices and weather data are necessary when applying the CDA method. The method alone was relatively inexpensive, but resulted in less precise estimates for the different end-uses.

Multiple regression analyses is applied to estimate household demand for electricity in all electric buildings with direct load control in [5]. The load data analyzed were based on hourly measurements of residential dwellings' electricity consumption during a six-month period. All measured buildings had installed load control technology. The model incorporated variables such as electricity price, daylight, outdoor temperature, and wind speed, as well as several dummy variables representing hours, type of day, day of week, and month of year, among others.

Probability distribution functions have been used for load estimations in order to calculate expected values and standard deviations [6]. This model is based on probability distribution functions such as the normal distribution for high load hours and lognormal distribution for low load hours in order to derive load profiles for all electric buildings. Altogether 46 different load profiles were developed for various customer categories, and the model predicts the average hourly electricity load and standard deviation divided into month, day type and hour. In [7] the probability distribution approach was also used in order to estimate load profiles for residential, commercial and industrial customers, in which the electricity consumption data was assumed to be temperature-independent in all electric buildings.

6.3.2. Energy Simulation Programs:

Energy simulation programs are mainly based on two different modelling techniques; the response function method (an analytical method) and the numerical method. Response function methods solve linear differential equations that include time invariant parameters, while numerical methods use non-linear, time varying equation systems. Even though programs based on the response function method are easier to validate in most cases, the numerical methods are preferred because they can solve the equations simultaneously, handle complex flow path interactions and accommodate time varying system parameters [9].

The primary numerical method is a nodal network representation of the building. This means that the whole building, or one specific room, is divided into segments where each segment is represented by one node. Energy conservation equations are developed for each node and the entire nodal network is solved simultaneously. Many simulation programs are based on the nodal network model, but the differences lie in the solution techniques [9].

6.3.3. Artificial Intelligent Systems:

The last methodology for load modelling and energy estimations presented here is artificial intelligence, where the systems consist of expert systems and artificial neural networks. Expert systems "make decisions" based on an interpretation of data and a selection among alternatives. Neural networks are trained in relation to a set of data until the network recognizes the patterns presented. The artificial neural network may then make predictions based on new patterns [10]. The latter system is the most suited for load modelling and energy estimations because it is able to handle incomplete data which might result from measured energy data and climatic parameters. Neural networks can also solve non-linear problems as well as "…exhibit robustness and fault tolerance" [10]. Artificial neural networks were applied to identify different electricity load profiles in New Zealand homes [11]. A pattern recognition probabilistic neural network (PNN) algorithm was used to classify electricity load profiles based on a large number of electricity measurements.

An example of an energy estimation method based on intelligent computer systems for the prediction of energy demand in Canadian households, called the Neural Network method (NN), has been presented by Aydinalp [4]. The NN model estimates end-use energy consumption in buildings based on three networks; a hot tap water consumption network, a space heating network, and an appliance, lighting, and space cooling network. This last network included 55 input units alone.

6.4. Proposed Methodology

6.4.1. Algorithm Description

The general equation to calculate the total daily power demand that is applicable to all end-use appliances is:

$$\sum_{i=1}^{I} Di_t = \sum_{i=1}^{I} N_i \times C_i \times Fn_t \qquad (6.1)$$

$$E_i = \alpha . \sum_{t=0:00}^{t=23:59} Di_t \qquad (6.2)$$

where:

Di_t is total power required by component *i* at time *t*;

N_i is the number of appliances of type *i* ;

C_i is load type *i* energy consumption (watt);

Fi_t is the fraction of the connected load of type *i* in at time *t* ;

E_i is the daily energy consumption of load type *i*.

As Fi_t in particular for domestic sector depend on type of day (weekday, Saturday, Sunday) another coefficient"α" needs to be multiplied to the equation (6.2) in order to differentiate the energy consumption of each appliance in different days. Besides, N_i which represents the number of appliances of type i depends of socio-economic situation of each household. Therefore a comprehensive aggregated demand requires considering these modules as well.

Each household is modeled by a set of different appliances connected in parallel and fed by the main feeder as shown in fig 6. 1. Each appliance is connected by a switch which consumes energy when the switch is close and will be disconnected when the switch is open. Therefore operation of each appliance is dependent on probability of the switch connected to it to be open or close.

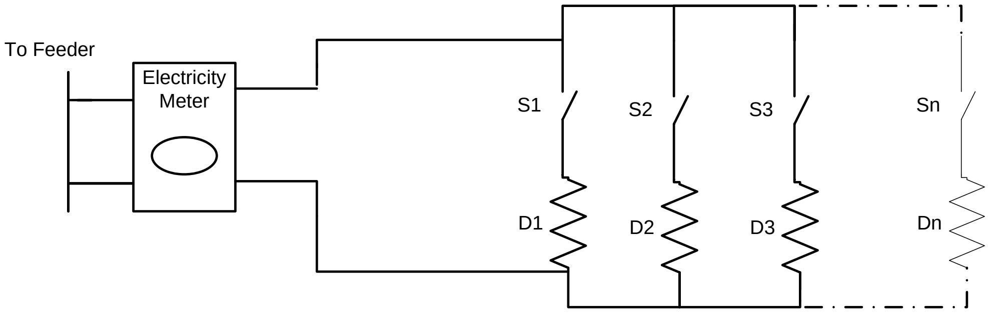


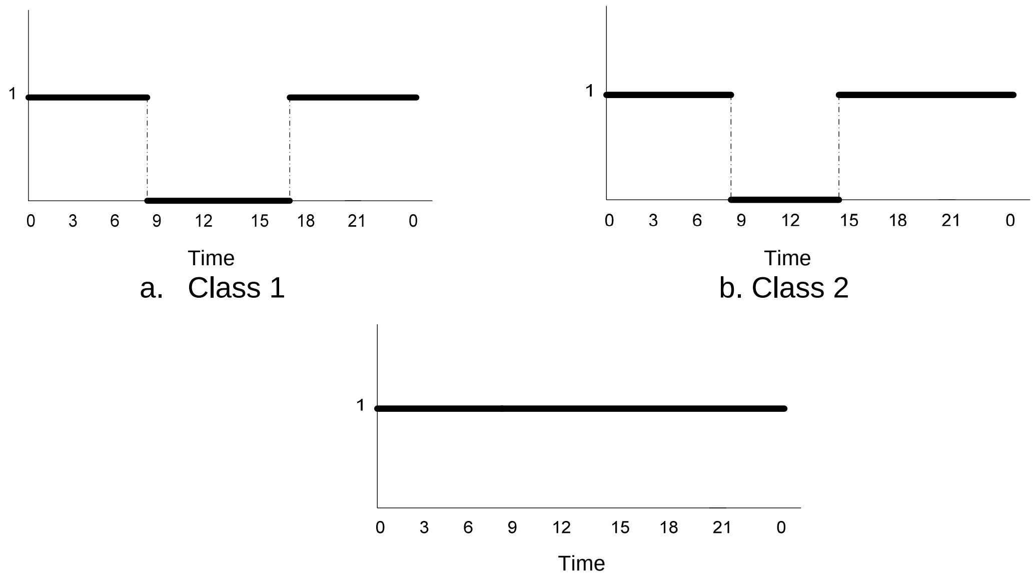
Fig 6.1. Simple Model of Appliances in a House.

The simple equation which denotes the probability that each switch is open or closed is shown in (6.4):

$$\rho_s = \sum_{c=1}^{C} \sum_{t=:0:00}^{23:49} \tau_{c,t} \times \rho_{c,t} \qquad (6.3)$$

where ρ_s is the probability of switch s to be closed, , $\tau_{c,t}$ is a binary variable which is 1 when the customer type C which has influence on the operation of appliance is at home at time *t* , and $\rho_{c,t}$ is the probability of operation of appliance type *s* by customer type c, at time t. Therefore ρ_s is zero when $\tau_{c,t}$ is zero, and is equal to the value of $\rho_{c,t}$ when $\tau_{c,t}$ is 1.

There is an exception for fridge-freezers as occupancy of the consumer does not have any impact on operation of this type of appliance; ignoring the impact of opening-closing the fridge-freezer's door and ρ_s is a constant number throughout the day for this type of appliance. The value of $\tau_{c,t}$ for different households is shown in fig 6. 2. Single households are assumed to have $\tau_{c,t}$ similar to class 1, two adults, and two adults with children class 2, and other households are assumed to have an occupancy pattern similar to class 3.



a. Class 1 b. Class 2

c. Class 3

Fig 6.2. Different Occupancy Pattern Classes

After entering the input data, by generating the random variables depending on number of households in each class, and sorting them depending on the outcome of the generated variable that fits into which probability band, the total number of start-ups of appliance n will be derived. Then by considering different load profiles of each appliance which dictate different duration of operations, the load profile of each appliance starting at its start-up point will be derived. After all by aggregating the different load profiles the total load profile of each appliance from the starting point which is its start-up point will be derived. This algorithm will be looped and continued until all different appliances for all different classes of consumers are being modelled, and at the end by aggregating the different consumers' load profiles total load profile of this area will be presented.

Figure 6.3 shows the flowchart of the proposed algorithm to model the load profile. In our study 13 main types of appliances in the domestic sector are modelled, as well as considering other appliances as miscellaneous appliances. For each appliance, the ownership rate of that appliance is considered, i.e. the ownership rate of microwave oven in the domestic sector of the UK is 75%. It means that in an area with 100 households, 75 households will own a microwave oven. It was assumed that the ownership rate of different appliances is the same for all different type of consumers.

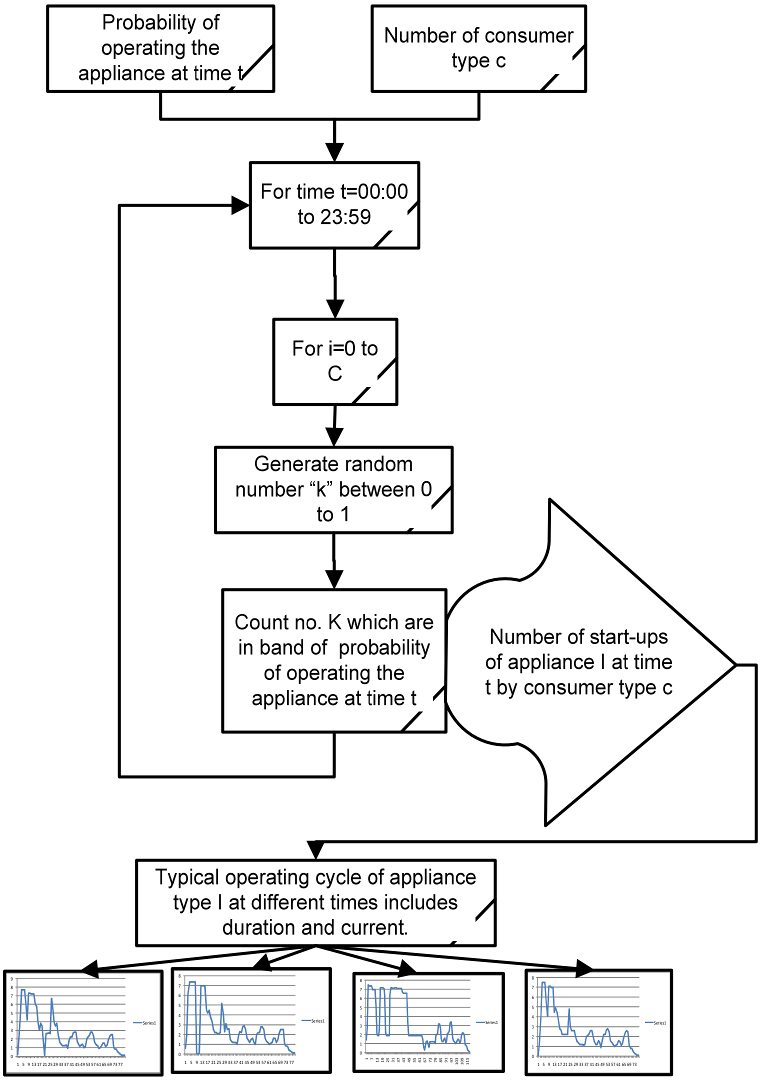


Fig 6.3. The Algorithm of Load Profiling

6.4.2. Input Data:

In order to perform such simulations the initial input data which were available and used in this study includes the factorslisted in the following sections:

6.4.2.1. Type of Consumer (Including number of consumers, different class, etc.)

The total number of households, in England and Wales were considered for this study, including type of household. From census data, households in E&W are divided into seven main groups: single adult, single pensioner, two adults, two pensioners, two adult with children, two adult and one pensioner, and three adults. The total number of consumers is derived from census data; office of national statistics [12] and the households stock of E&W is shown in fig 6. 4.

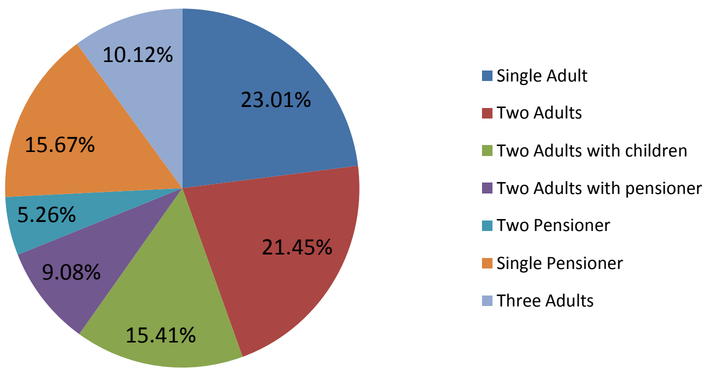


Fig 6.4. Hosuehold Stock in E&W [12].

6.4.2.2. Type of Appliance:

Table 1 shows the different types of appliance in the domestic sector [13]. These are the main group of domestic appliances depending on their application. Among these types of appliances only washing machine, dryer, and dishwasher from wet appliance, fridge and freezer from cold appliances, TV and multimedia player from brown appliances, iron, PC from miscellaneous appliances, microwave oven, cooker and kettle from cooking appliances are modelled in this research.

Table 6.1. List of Domestic Appliances

Type	Members
Cold Appliances	Refrigerators: one door refrigerators with or without frozen compartment, fridge-freezers: two door combination refrigerators ,Upright freezers, chest freezers
Wet Appliances	Washing machines: any automatic washing machine including the washing cycle of washer-dryers, Tumble dryers: all types of dryers including the drying cycle of washer-dryers, dishwashers
Cooking Appliances	Electric ovens: including grills Electric hobs Microwaves: includes combination microwave/grill/convection ovens Electric kettles: includes all types of electric kettle Mixer (Hand mixer or Stand-up mixer) Hot drinks makers: coffee and tea makers, Sandwich toasters Pop-up toasters Deep fat fryers, Electric frying pans Slow cookers Cooker hoods Food preparation appliances: mixers, blenders, processors, whisks etc.
Lighting	Incandescent & Fluorescent strip.

Appliances	
Brown Appliances	Televisions, VCRs (video cassette recorders), Non-portable audio equipment: hi-fi systems, record players etc Satellite control boxes for TVs, cable control boxes for TVs, Portable audio equipment: Cassette recorders, radios, clock radios, X-boxes (games etc.)
Miscellaneous Appliances	Irons: steam irons and dry irons vacuum cleaners DIY equipment: drills, torches, battery chargers, Garden equipment: lawn mowers, trimmers, hedge trimmers, Other home care equipment: sewing machines, floor polishers, lights on extension cords, Hair styling equipment: hair dryers, curling tongs Small personal care appliances: electric toothbrushes, electric razors, Electric towel rails, Electric blankets Electric instantaneous showers, Central heating pumps, Personal computers, Computer printers (LaserJet or Facsimile machines Answering machines Other office equipment: slide projectors, electric typewriters etc.

6.4.2.3. Ownership Level:

The study done by Mansouri [13] has evaluated the factors such as ownership level of different appliances in the domestic sector of the UK as shown in fig 6. 5. In our simulation it was assumed that the ownership rate of different domestic appliances is the same for different types of consumers and same for different locations.

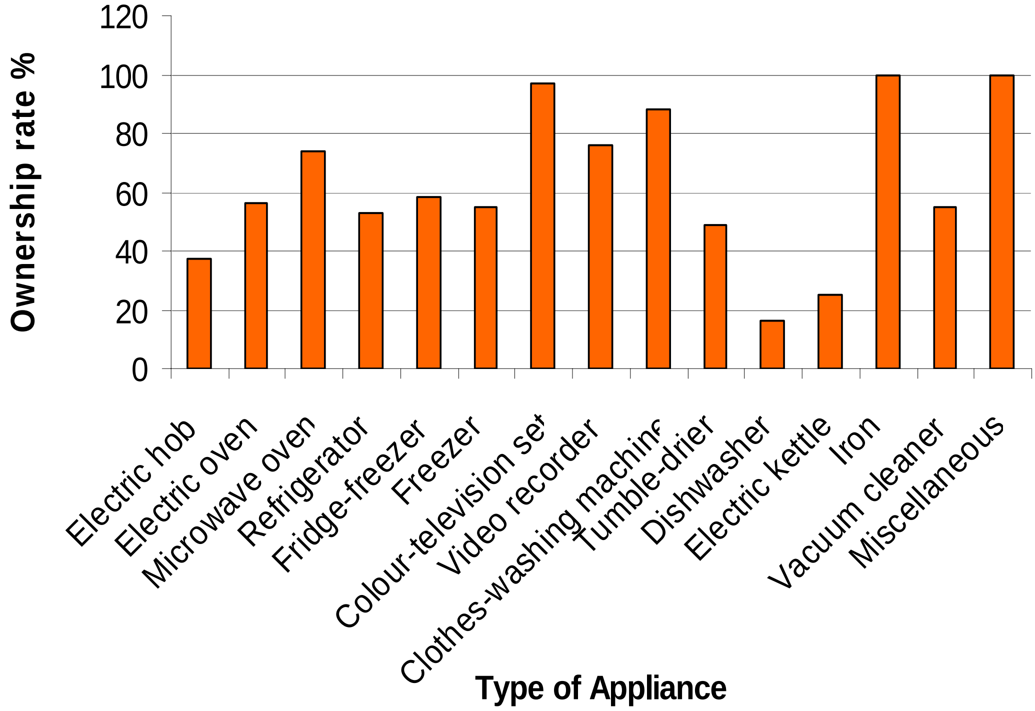


Fig 6.5: Ownership rate of domestic appliances [13]

6.4.2.4. Probability of Operating Each Appliance:

Number of operations for different classes of consumers is defined by a probability distribution function. The probability distribution of a discrete random variable of X which defines the total number of operation of an appliance is a function which gives the probability $\rho(x_i)$ that the random variable X equals (x_i). For each value xi:

$$\rho(x_i) = \rho(X = x_i) \tag{6.4}$$

Therefore for each appliance, owned by a group of households, a probability distribution function is defined to show the approximate probability of operation of that particular appliance, for the period of time. Fig 6.6 shows the approximate probability of operating an oven in a single adult household for a period between 17:00-22:00.

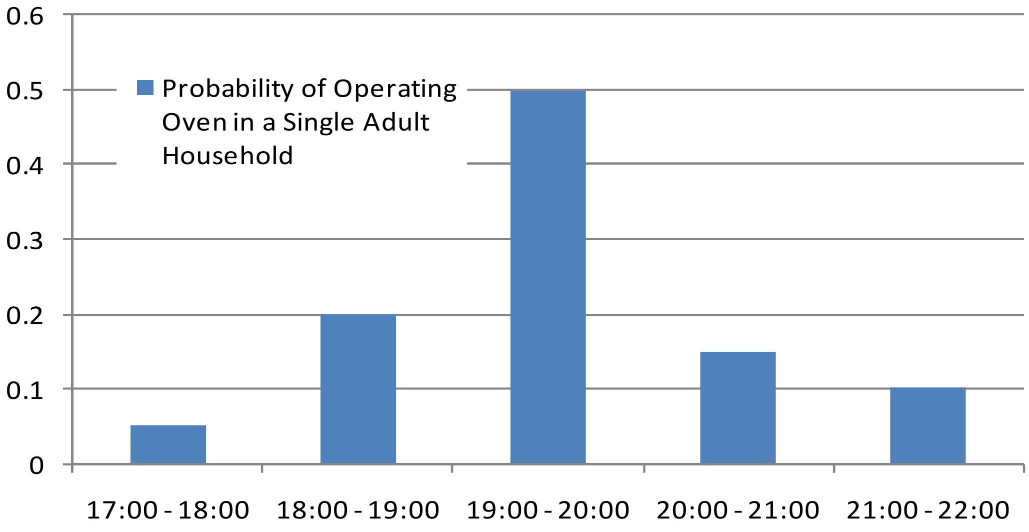


Fig 6.6. Probability of Operation of Appliance.

6.4.2.5. Typical Operation Patterns for Each Appliance:

An assumption which was made here that appliances' consumption pattern is limited to only four profiles for each appliance. Figure 6.7 shows an example of different profiles which were considered for washing machine.

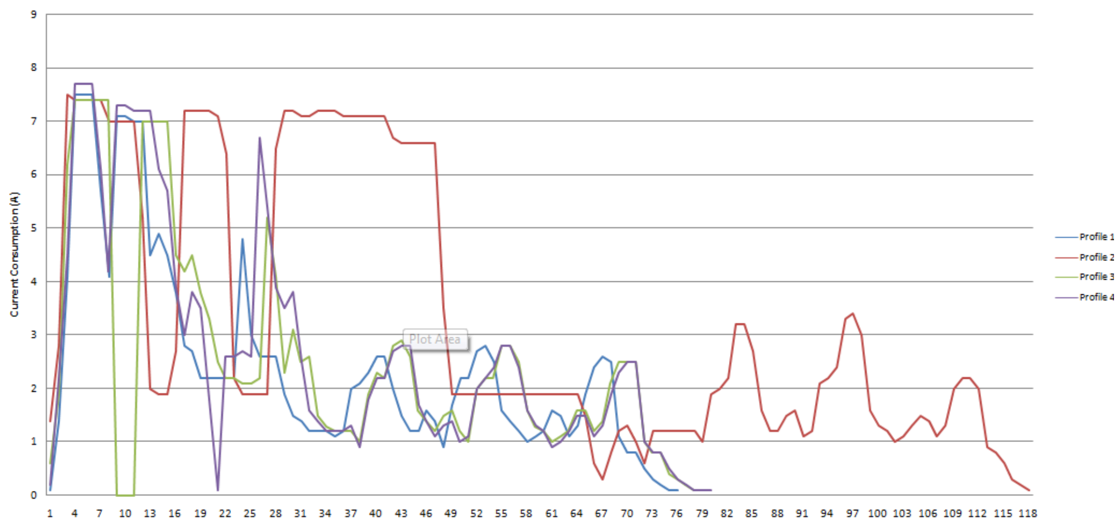


Fig 6.7. Different Load Profiles of Washing Machine

6.4.2.6. Energy Management Programme (Economy 7):

In the UK; Economy 7 is the well-known scheme for domestic consumers and it gives 7 hours continuous low tariff power [mostly overnight] to consumers. Another scheme is called Economy 10 in which 10 hours low tariff is split between day and night time; usually 2 hours in the morning, 3 hours in the afternoon and 5 hours overnight. In 2008 16% of total domestic consumers were committed to Economy 7 tariff; this is equal to 27% of total electrical energy consumed in domestic sector. The commitment level varies across the country but in general consumers save money through reducing their consumption during the day and shifting their demand to off-peak hours. Figure 6.8 and 6.9 show different types of domestic load profile for the autumn season in the UK.

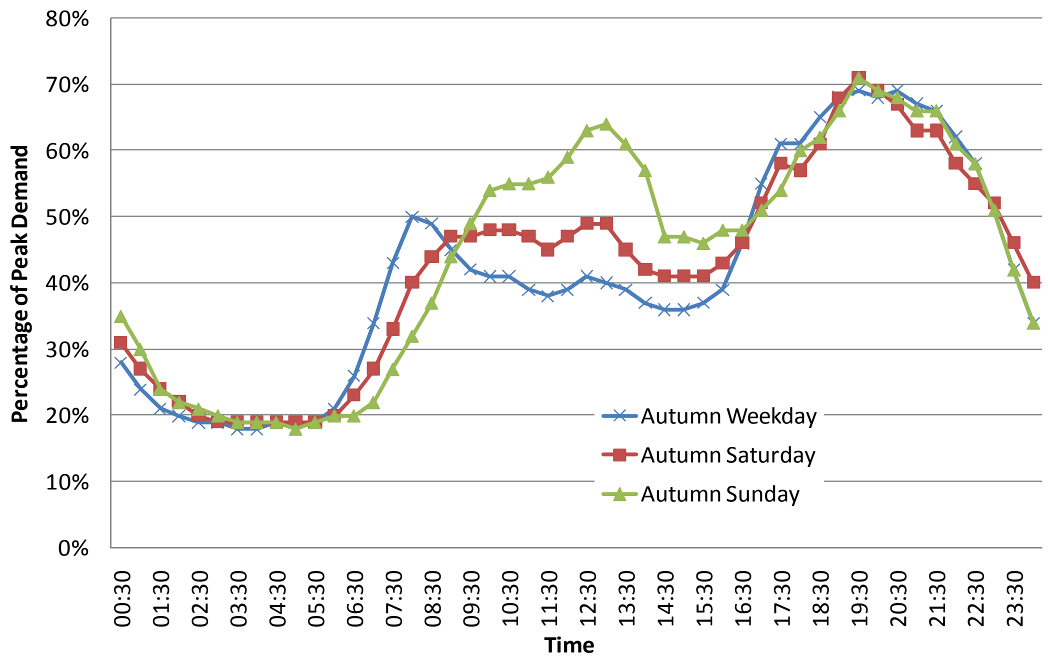


Fig 6.8. Domestic non-Restricted Load Profile

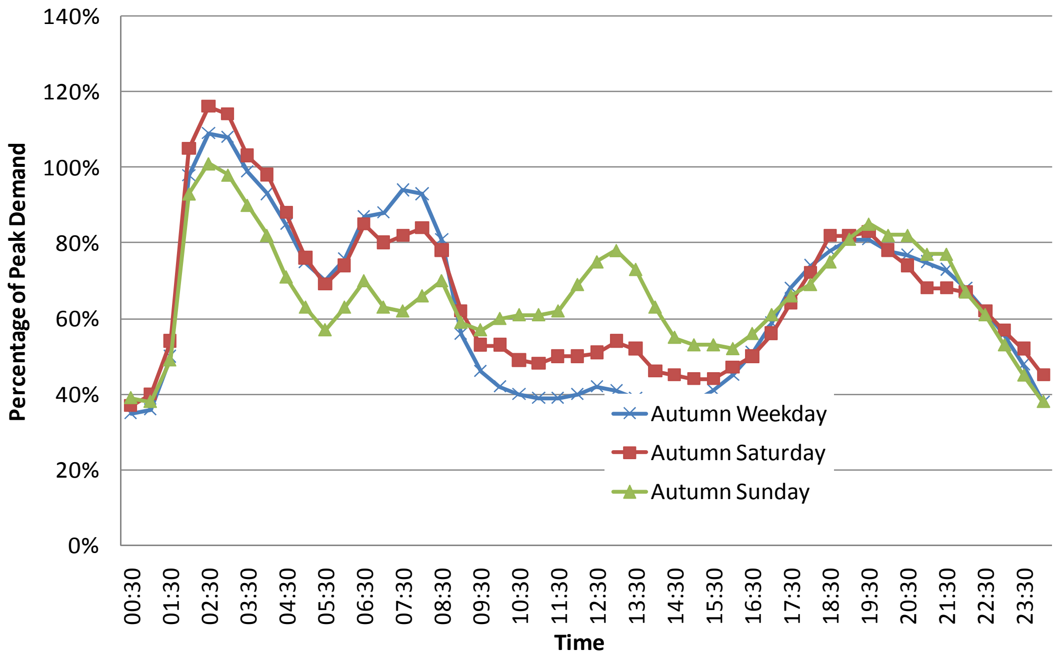


Fig 6.9. Domestic Economy 7 Load Profile

If those consumers who are committed to economy 7 tariff alter their consumption pattern in order to maximize their saving, this will have an impact on demand modelling. Therefore this has been taken into account by distinguishing the probability of operation of some appliances (washing machine, dryer, and dishwasher) for 16% of total domestic consumers in England and Wales.

6.5. Results and Discussions:

6.5.1 Total Demand:

Total demand for a typical weekday is generated using the algorithm in fig 6.8 and it is shown in fig 6.10. By observing the total demand profile which is aggregated of load profiles of individual appliances, it is noticeable that the total demand has a peak in the morning, in the afternoon and the highest peak in the evening. A typical domestic load profile consists of a mixture of consumers will have the same pattern. Different appliances contribute in different peaks on the load profile of a household or an area, in particular lighting and heating appliances which are not modelled in this exercise. It is because these two types of appliances do not necessarily have correlation with type of household, and in fact they are significantly dependent on the size of the properties. This information at the time of simulation was not available therefore in order to not making a wrong assumption, lighting and heating electrical loads are not modelled.

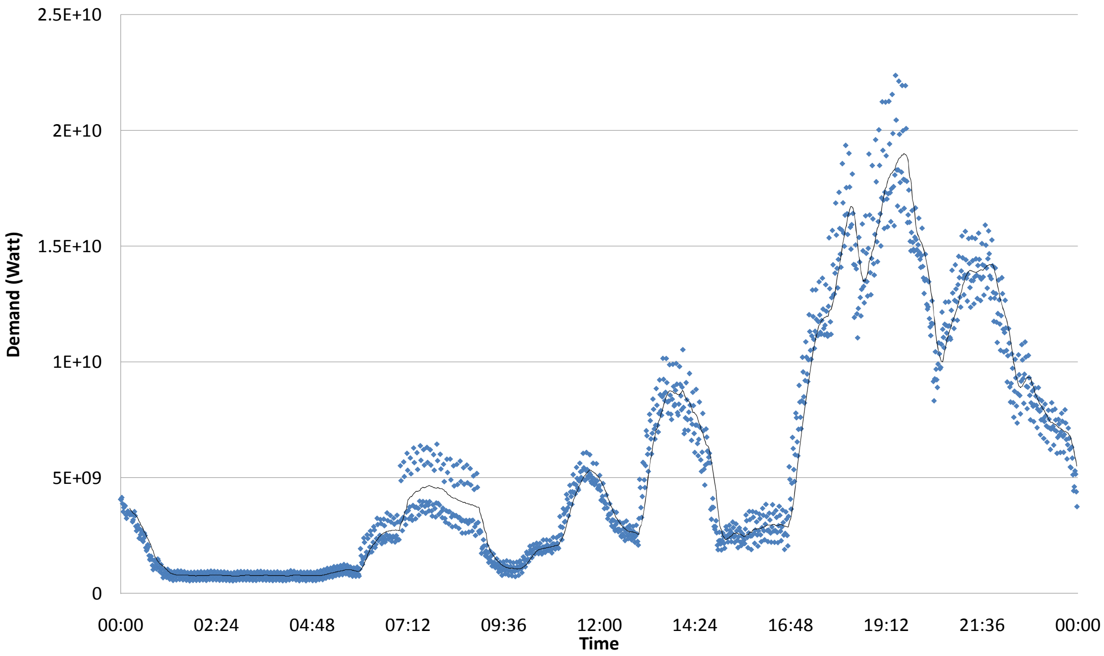


Fig 6.10. Total load profile excluding heating and lighting.

6.5.1.1. Morning peak:

The morning peak is due to operating such appliances as kettles, cookers and electric showers in order to get ready for starting a day. As the area which was studied consists of a mixture of different consumers, their aggregated consumption of electricity by different appliances will create the peak demand in the morning. Different types of consumer will have a different effect, but in general as we assumed that all consumers may operate for example their kettles in the morning (ownership level of kettle was assumed 100%) therefore the morning peak is resulted from operating the appliances such as kettle, electric shower and cooker. Figure 6.11 and 6.12 show the typical consumption pattern of a two adult and single adult house where both have single morning peak. When these profiles are aggregated and because the occurrence of this peak is assumed to be random, then such morning peak in fig 6.12 will be resulted.

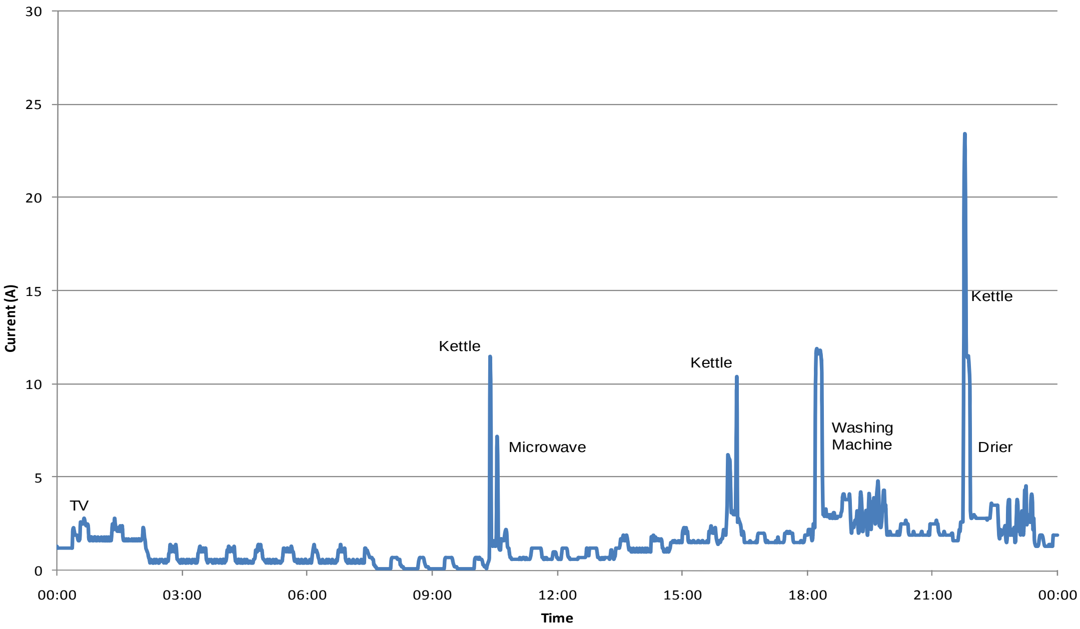


Fig 6.11. Load profile of a two adult household

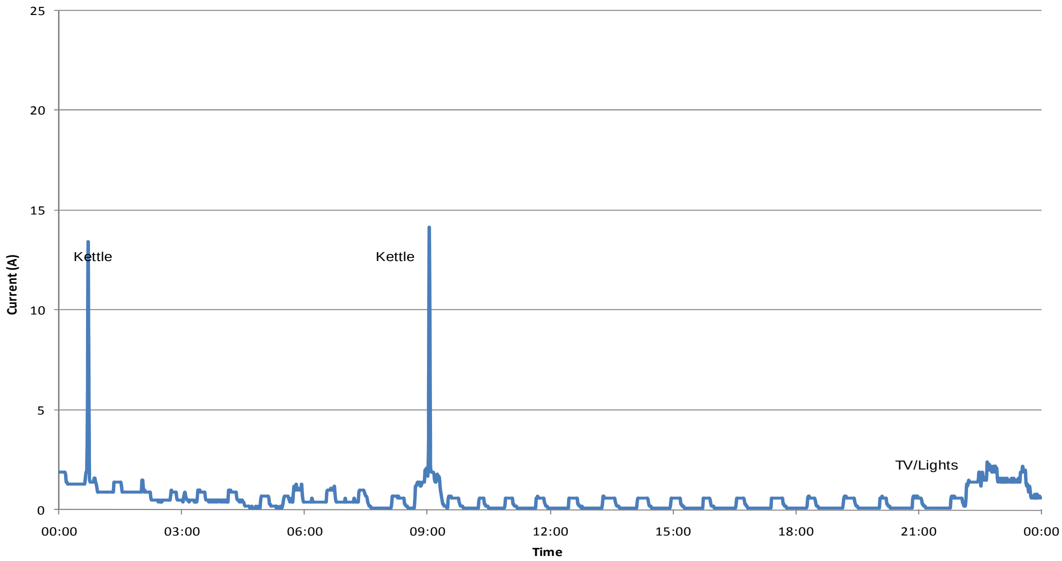


Fig 6.12. Load profile of a single adult household

6.5.1.2. Afternoon Peak

Afternoon peak in domestic sector is resulted from operating the domestic appliances by those households who are usually at home during the day. In our simulation occupancy pattern for single and multiple pensioner households, multiple adult with children households were considered to be morning-day-night occupancy. It means that these households consume electricity during the day. Figure 6.13 and 6.14 show the load profile of a two adult with dependents and two pensioner households where both have an afternoon peak.

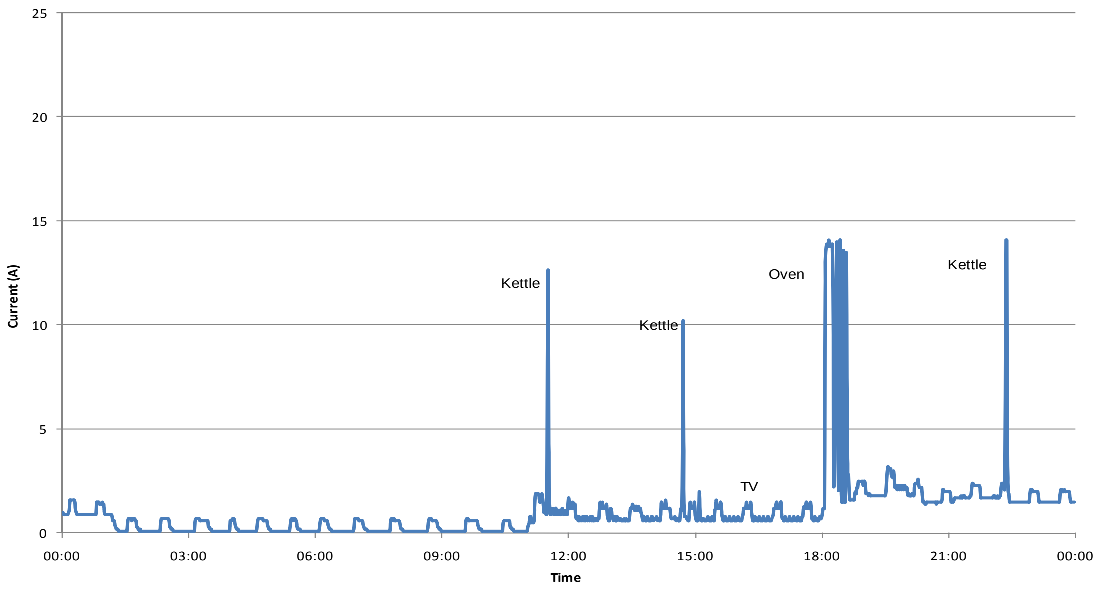


Fig 6.13. Load profile of a two adult with dependent household

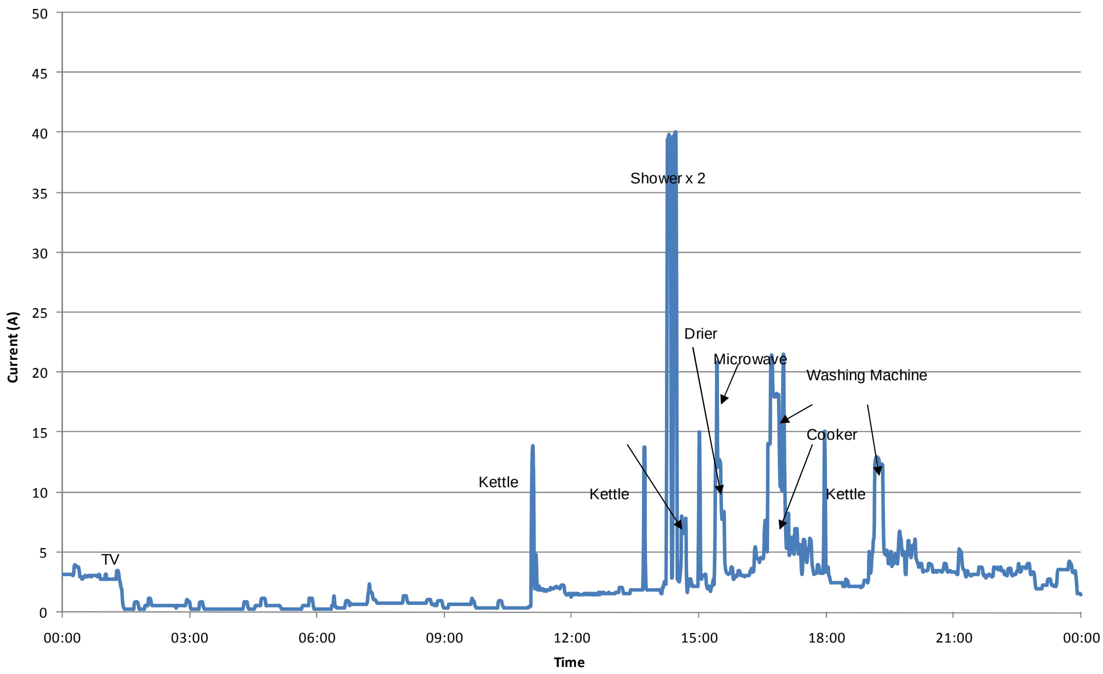


Fig 6.14. Load profile of a two pensioner household

6.5.1.3. Evening Peak:

the evening peak which is usually the highest peak both in the domestic sector and in national level mainly resulted from the lighting load. Street lighting and domestic lighting both contribute to the high level of the evening peak. In the domestic sector other appliances such as TV, cooker, oven, microwave, dishwasher and drier tend to be operated over the evening hours. Therefore, the peak in the domestic sector is an aggregated effect of operating several appliances.

In our study, due to unavailability of data about houses we did not model the lighting loads. Hence, the evening peak in fig 6.14 is produced by other appliances in all types of households.

6.5.1.4. Overall Pattern:

The total pattern was studied separately over different periods. The overall pattern is also comparable with other domestic areas. It is important to note that in our studied area where over 45% of households have day occupancy the afternoon peak is noticeable. A typical load profile of a domestic area shown in fig 6.15, such peaks and valleys are observable. ***The valley in our result is higher due to not simulating the heating and lighting loads*.**

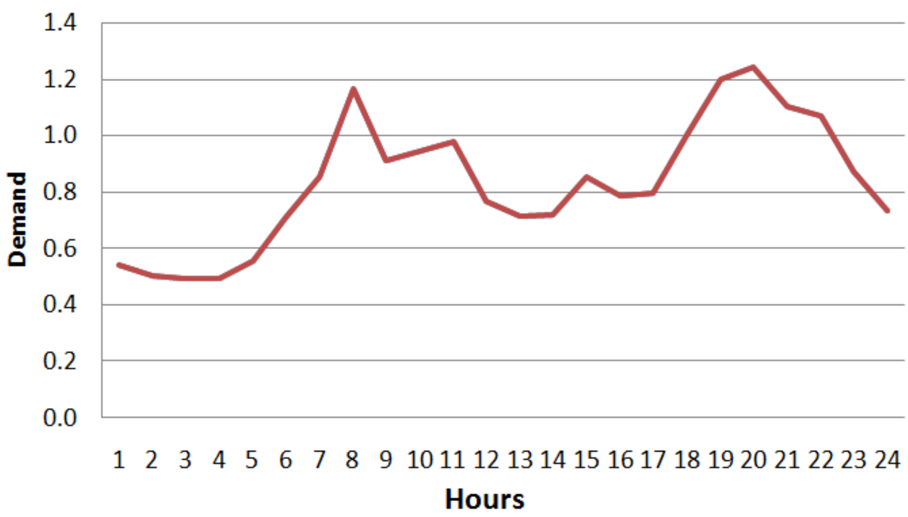


Fig 6.15. Load profile of a domestic area

Besides, each appliance has different power consumption rate. In the UK (and in most of the other countries) domestic appliances depending on their average power consumption are classified into different groups. A to G, where A is the most energy efficient type of that appliance, and F is the most energy consuming type. The total energy consumption of a chest-freezer in UK-MARKAL [14, 15] model is between 188.06kWh/annum to 488.89kWh/annum. Our results shows that a typical fridge-freezer in the domestic sector will consume 251.85kWh which is something between the most energy efficient and the most energy consuming type of fridge-freezer.

6.5.2. Responsiveness Level:

Different types of appliances have the potential of becoming responsive. And, if demand response if to be provided from the domestic sector, it should not cause inconvenience for customers. Only appliances with an operation mode which is passive (like fridge) are capable of becoming responsive; and unlike a TV for which any interruption in power results in overall dissatisfaction of consumers. Therefore in this exercise fridge and freezer, washing machine, drier and dishwasher are the appliances which are considered to become responsive. Another important factor when considering the capability of a type of appliance to become responsive is the impact of the supply interruption period on the service being provided. Fridge-freezer is an appliance which is intended to keep the temperature down below a certain levels in order to keep the contents fresh and harmless. Figure 6.16 shows the changes in fridge and freezer's temperature on cyclic operation of the fridge.

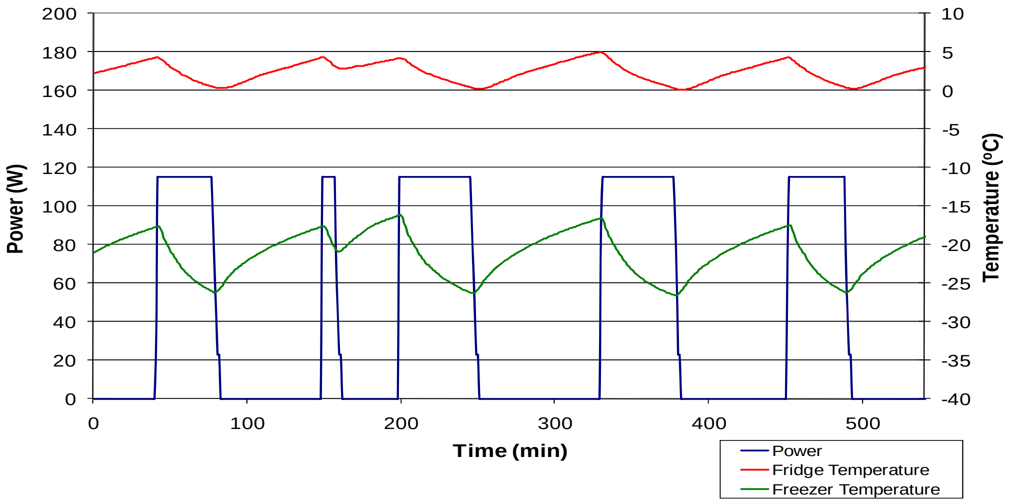


Fig 6.16. Temperature changes in cyclic operation of fridge-freezer [16].

The maximum allowed temperature for domestic fridges is 8 °C. This means that in normal operation pattern, the inside temperature of a fridge must remain between 2-8 between the range of +2°C and +8°C. Current legislations regarding power cuts gives the consumers the right to ask for compensation for the damage caused by a power cut above a maximum of two hours. This is investigated by observing fig 6.17 which shows the increase in the temperature of a fridge and freezer after switching off considering the temperature at the time of power cut was at its maximum level. It shows that the temperature of +8°C which results around 130 minutes after the fridge was switched off. Therefore if the supply interruption lasts for more than 130 minutes, the contents inside the fridge may start going off.

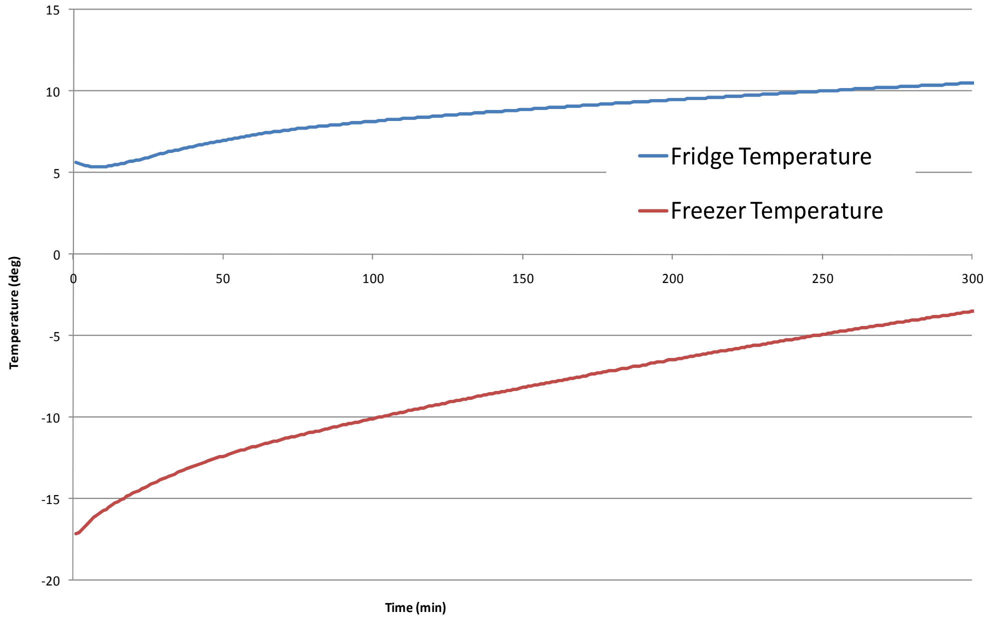


Fig 6.17. Fridge and freezer temperature after switch off [16].

Another important conclusion is that demand response provided by fridges can be available up to 130 minutes without causing any damage to the fridge and freezer's contents. Total demand response's potential from domestic sector maintained by fridge and freezers, washing machines, dryers, and dishwashers are shown in fig 6.18.

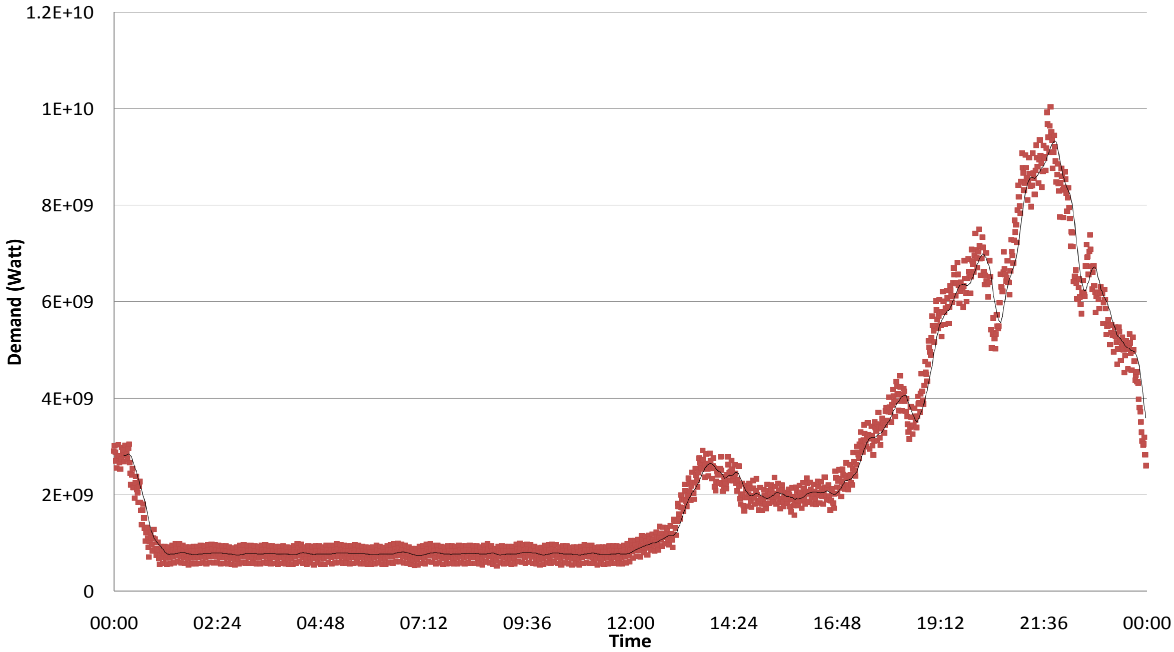


Fig 6.18. Total Demand Response's potential.

It is observable from fig 6.18 that availability demand response varies during a typical day, in the evenings and when consumers tend to use their appliances, such availability is larger compare with early hours of morning when only fridges and freezers are the only sources of maintaining the demand response. The minimum and maximum available responsive demand is around 1GW and 10GW respectively. By using the total electrical heating loads during the winter period, which is also suitable for making responsive, therefore this value could even be higher.

6.6 Chapter Summary

Responsive demand is currently providing variety of services for power systems. Demand response as a product is either utilized as a reliability based product, or for economical purposes. In both cases, information regarding the concentration, location and capacity of available demand response is required.

This chapter investigated the potential for demand response in the domestic sector of England and Wales. The technique used in this chapter to generate the load profile of domestic household' appliances was based on the probability of operating different appliances by different groups of consumer. Since the availability of data for any statistical analysis is an essential factor, and because the data required in this technique is widely available for different locations in England and Wales, this technique can be used to assess the potential of demand in a location to become responsive. It was shown that the domestic demand response's potential is different throughout the day since the consumption pattern of different appliances is different. It was shown that fridge-freezers which compose the base load in the domestic sector have the potential of becoming responsive since interruptions of up to nearly two hours may not jeopardize the service provided by fridge-freezers.

6.7 References

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Chapter 7. Changes in Generation Mix of the GB Power System in 2020

In this chapter a summary of current state of generation mix in the GB power system is presented. This is followed by studying the impact of various legislation such as LCPD, government's renewable target, and nuclear power decommissioning which work as a driver, and will shape the future generation mix. By considering these drivers for change, and under different socio-economic climates, six main scenarios have been developed. This enables us to study the impact of different locations for wind power to be studied as well as the effect of different installed capacities of nuclear power in each case.

7. 1 Current State:

Current GB generation mix is split into one-third gas, one-third coal and one-third for other fuel types such as nuclear and renewables (including Hydro) as shown in figure 7.1 [1].

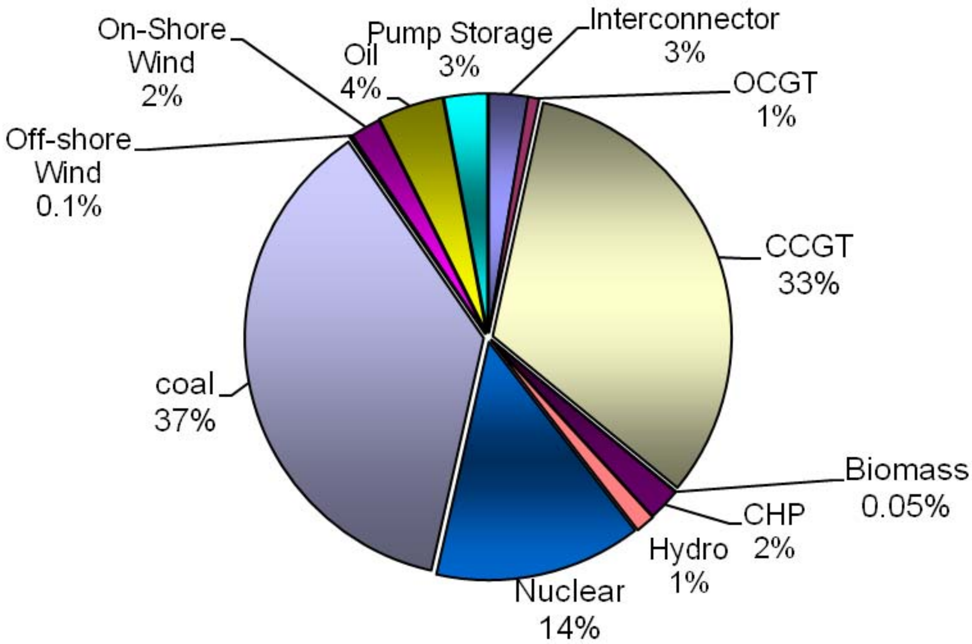

Fig. 7.1. Generation mix in the GB (2008) in percentage of total capacity (78GW) [1]

The electrical energy production reflects these same proportions, apart from the fact that nuclear is far more dominant in the 'other' category. Generation capacity in 2008 is about 78GW in which 11GW of it is nuclear power. Current capacity of nuclear power supplied about 20% of total electrical energy which results in about 34,000,000 tonnes of CO_2 being saved through utilizing nuclear power as shown in figure 7.2.

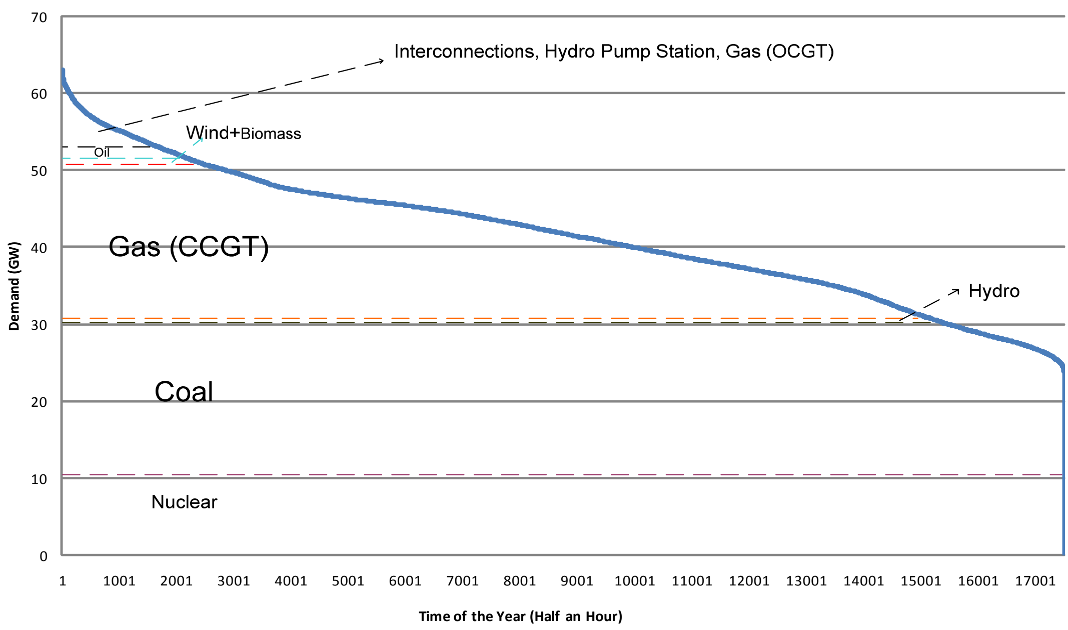

Fig. 7.2. Load Duration Curve and Energy Share of Different Generation Types (2008) [1]

The prospects for building new nuclear plants remain almost as dim now as they have been since 1990 until January 2008. The economic advantage of gas-firing over nuclear was so strong that there was no credible tax regime - penalizing fossil fuels - that could make up much of the economic and financial gap between the technologies [2].

In January 2008 when the government published the White Paper on Nuclear Power, it strongly supported building new nuclear power capacities by encouraging the private sector to build new capacities. In April 2009, the government announced 11 sites for new nuclear rector, making nuclear power back to the central stage.

7.2 Main Drivers for Change in Generation Mix:

A major challenge for the electricity industry is the fact that in the coming years many coal-fired and nuclear power stations are due to close. Significant new investment in generating capacity is needed to replace them. At present, the Department for Business, Enterprise and Regulatory Reform (BERR) is aware of around 18 GW of potentially new conventional generation capacity that is at various stages of development, over 90% of which will be gas-fired.

7.2.1. Impact of Large Combustion Plant Directive (LCPD) [3] and Security of Supply:

From 2008, GB coal- and oil-fired power stations have been governed by the Large Combustion Plant Directive (LCPD). This sets new limits on the amounts of sulphur dioxide (SO_x), nitrous oxides (NO_x) and dust power stations can emit. It is expected that around 12GW of coal and oil-fired generation will be decommissioned by 2015-16 as a result of the EU's Large Combustion Plant Directive (LCPD).

One of the main factors being considered in the energy market in 2007-08, that was highlighted in government's energy white paper published in 2007 was "future supply security". The government and numerous analysts pointed to a supply gap by the middle of the next decade. It is not yet clear how this gap should be best filled

.

From a security of supply perspective, gas still presents potential problems. Now a net importer of gas, Britain is dependent on external markets for its gas supply security. And, with Britain having gas storage for just 5% of its consumption, compared to around 20% in Germany and 16% in France, it is arguably more import-dependent than other member states[1].

Unlike gas, coal does not present any security risks, with Australia and South Africa being secure sources of supply, while the US is also seeing resurgence in coal supply to Europe. The major problem with coal is environmental. With around twice the carbon content of gas, and with existing boiler technology less efficient than that of gas boilers, coal plant produces significantly more carbon dioxide emissions than other generation methods.

The coal solution is a two-stage process. The first ideally involves the Government supporting supercritical boilers that increase the efficiency of coal-fired plant from around 38% at present to nearer 45%, with a consequent reduction in emissions. The second stage is expediting the commercial development of CCS technology which can remove up to 90% of carbon dioxide emissions produced from generation facilities.

[1] To this end, Britain has sought to align itself with Norway for its gas imports, with the government stressing the importance of this relationship at the official opening of the Ormen Lange field last October. It was right to do so. While Russia has never failed to deliver on a supply contract to date, recent reports suggest Russia may not be a reliable exporter of gas to Europe in the future. If this proves to be the case then there will be more competition for other gas supply sources, including Norway.

Yet, even if the new nuclear programme proceeds, unless it is changed from a like-for-like replacement programme to an increased capacity programme the long-term supply security benefit will likely be limited.

Through investing in new clean coal generation capacity, combined with like-for-like new nuclear replacement to provide around 20% of supply, and for renewables to ramped up to provide 20% of supply, will Britain effectively fill its energy gap and reduce emissions. This will result in a balanced generation mix.

7.2.2. Nuclear Power Plants Closure

Total installed capacity of Nuclear Power plants at the end of 2008 is about 11GW. Around 7.4 GW of nuclear power plant will have closed by 2020 as stations come to the end of their operating lives as shown in figure 7.3 [4-6].

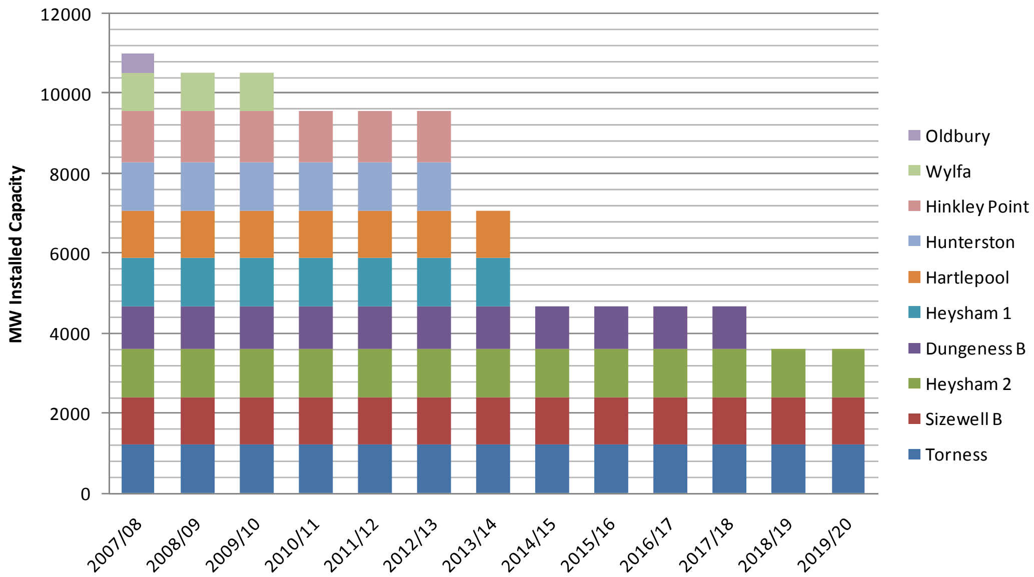

Fig. 7.3. Nuclear Power Stations' Closure [4].

The UK Government supports a like-for-like replacement of existing nuclear capacity as it is decommissioned. With regard to possible location of new Nuclear power stations; if any, they will be installed at existing locations where nuclear power stations exist as shown in figure 7.4.

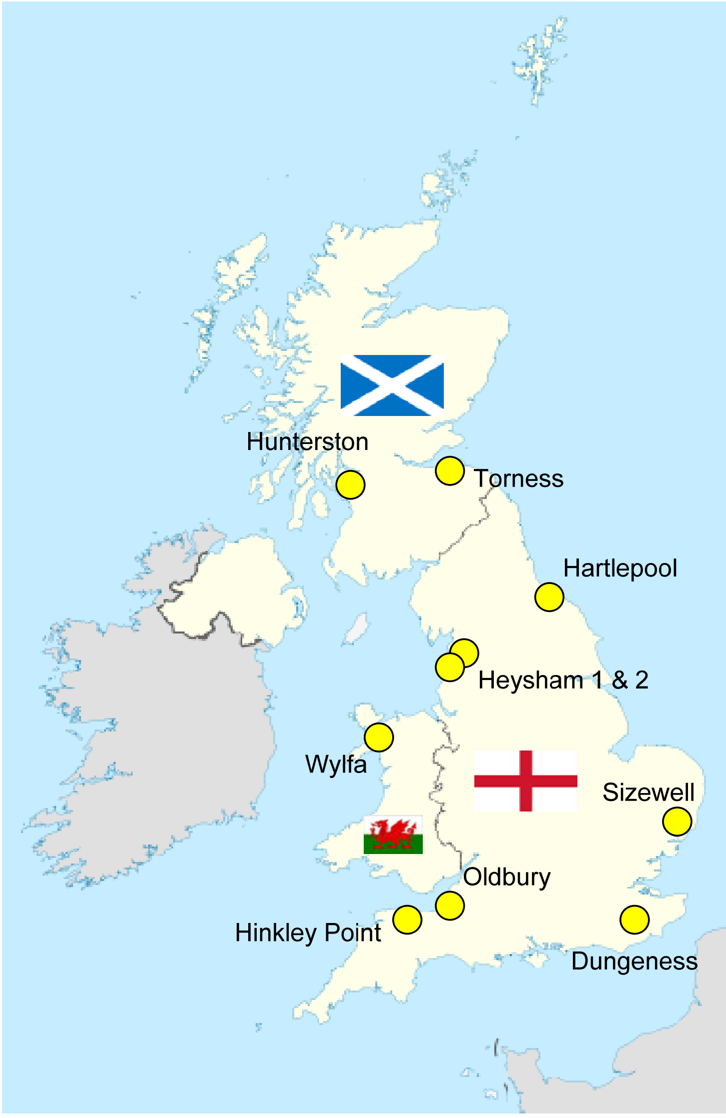

Fig 7.4.Map of Nuclear Power Stations in the UK [5].

7.3 Uncertainties and Future Scenarios

7.3.1. Main Scenarios

There are several factors such as economic, environmental and regulatory that have an impact on the future of electricity generation and consumption. Ault. *Et al* has presented number of technologies which are likely to be important to the development of the electricity network in the GB power system over the coming decades under different scenarios [7]. The authors by considering the impact of a strong economy or in contrast weak economy, or supporting the drivers for saving the energy and environment and so on, have proposed different scenarios with different types of generation with different capacities. In this chapter the work has extended the four main scenarios proposed by Ault in order to develop different sets of meaningful future generation mix. The four main scenarios proposed by Ault are:

7.3.1.1 Business as Usual (Scenario 1):

Scenario1 in which it is likely to follow the same trend both in terms of demand growth and generation capacity growth while considering government's targets (20% of energy supplied from renewables) and closing down some nuclear power stations by 2020. The peak demand's will grow by 1.3% and it reaches 72GW, and in order to supply 20% energy from renewables the capacity between 22-26GW of wind power will be required.

7.3.1.2 Strong Economy (Scenario 2):

Scenario 2; where it was assumed that economy's growth and drivers for saving the environment will result in 2% annual demand growth, and demand will reach 79.73GW where total energy will be 459TWh and between 34-37GW of wind power will be required to supply the government's renewable energy target.

7.3.1.3 Economy Downturn (Scenarios 3.1 & 3.2):

In the case of economic downturn in which the severity is unknown, two scenarios are developed. In order to supply certain amount of energy from renewables total capacity of wind power between 22-24 GW will be required for scenarios 3.1 and 3.2 respectively.:

3.1. In scenario 3.1 it is expected that demand will grow but this growth rate is limited to 0.5%, where peak demand will only reach 64.71GW.

3.2. Another scenario in which the economic downturn is severer is scenario 3.2 in which demand growth will be negative and will reduce by -0.5% which results in a total peak demand of 57GW.

7.3.1.4 Ultra Green (Scenarios 4.1& 4.2):

In this scenario, two main objectives are considered. First demand reduction which result in reduced peak demand, and increasing the drivers for green energies.

4.1. Scenario 4.1 in which more attention is made on green electricity generation, and reducing the energy demand, corresponds to a peak demand of 54GW.

4.2. In Scenario 4.2, demand reduction has not been given much priority and only electricity generation technologies are to be renewable, but still demand growth is limited to 0.9% which corresponds to 68.36GW.

7.3.2. Generation Mix for Each Scenario:

New investment to build additional generation capacity should only be made when there is a need for capacity – to replace existing capacity upon retirement and/or to meet demand growth. In general, there are three possibilities where it would be economic to add new capacity:

1) When existing capacity is retired. Assuming that there is a capacity balance prior to retirement, failure to replace existing plant upon retirement would lead to capacity imbalance.

2) As demand grows, there is a need for investment in new generation in order to maintain capacity balance.

3) When the energy policy encourages certain types of generation technologies that are currently absent or in a small proportion

To develop a more detailed energy mix within each scenario, first demand growth for each scenario was considered in 2020 and total energy which must be supplied from different types of plant. Then by taking into account the government's target to provide 20% of energy from renewables, total energy share of renewable plants was derived as shown in figure 7.5.

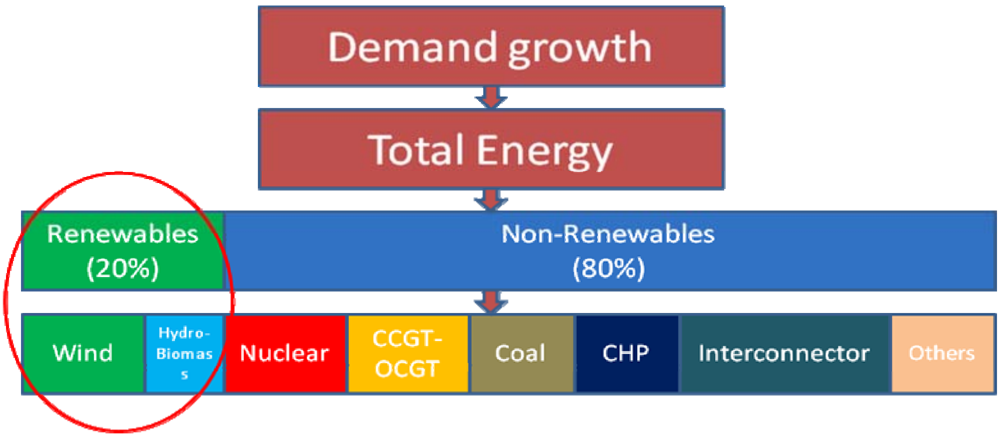

Fig. 7.5. Calculation of total energy for each scenario

Since the majority of the renewable sources in the GB power system are hydro, wind and biomass, and because the prospects of increasing the installed capacity of other renewable plants than wind is not very promising, the total required wind energy to supply the proportion of renewable energy target was derived for each scenario. Considering wind's capacity factor is different at different locations, for each scenario the required level of installed capacity of wind is affected by two main factors:

1. Windfarm's location at North or South
2. Windfarms's location at off-shore or on-shore.

In figure 7.6 the calculation of total renewable energy for each scenario from demand growth rate is shown, while demand growth rate is different for each main scenario, therefore the total renewable energy which is required to supply such a demand is different for each scenario.

	1 Continuing Prosperity	2 Strong Optimism	3 Economic Downturn	4 Green Plus
Growth Rate	+1.3%	+2%	+-0.5%	+-0.9%
Peak Demand	72 GW	79.73 GW	64.71 GW 57 GW	68.36 GW 54 GW
Energy	437 TWh	459 TWh	372 TWh 329 TWh	393.5 TWh 311.1 TWh
	87.4 | 349.6	91.8 | 367.2	74.4 65.8 | 297.6 263.2	78.4 62.2 | 314.8 248.8

Fig. 7.6. Calculation of total renewable energy for each scenario from demand growth rate.

In figure 7.7 it is shown how 20% renewable energy contribution can be translated to installed capacity of renewable plants. Since the potential sites for hydro plants have all already been utilized, therefore the majority of this 20% contribution must come from by wind and biomass.

	Continuing Prosperity	Strong Optimism	Economic Downturn	Green Plus
20% Renewable	87.4	91.8	74.4 65.8	78.4 62.2
Wind Energy	74.29 TWh	78 TWh	63.24 TWh 55.9 TWh	67 TWh 52.87 TWh
Wind Capacity	22-26 GW	34-37 GW	20-24 GW	23-26 GW

Fig. 7.7. Calculation of total Installed capacity of wind for each scenario.

The prospects for biomass is still unclear and literatures suggests that there will not be huge potential for biomass plants at least by 2020 due to risks associated with biomass [8]. Therefore as it can be seen in figures 7.7 and 7.8 the total installed capacity of wind power depending on their location. Figure 7.9 and table 7.10 are the summary of the future proposed scenarios.

	Continuing Prosperity	Strong Optimism	Economic Downturn	Green Plus
Wind Capacity	22-26 GW	34-37 GW	20-24 GW	23-26 GW
Wind Location	South or North	South or North	South or North	South or North
	Onshore-Offshore	Onshore-Offshore	Onshore-Offshore	Onshore-Offshore

Fig. 7.8. Location of Windfarms for each scenario.

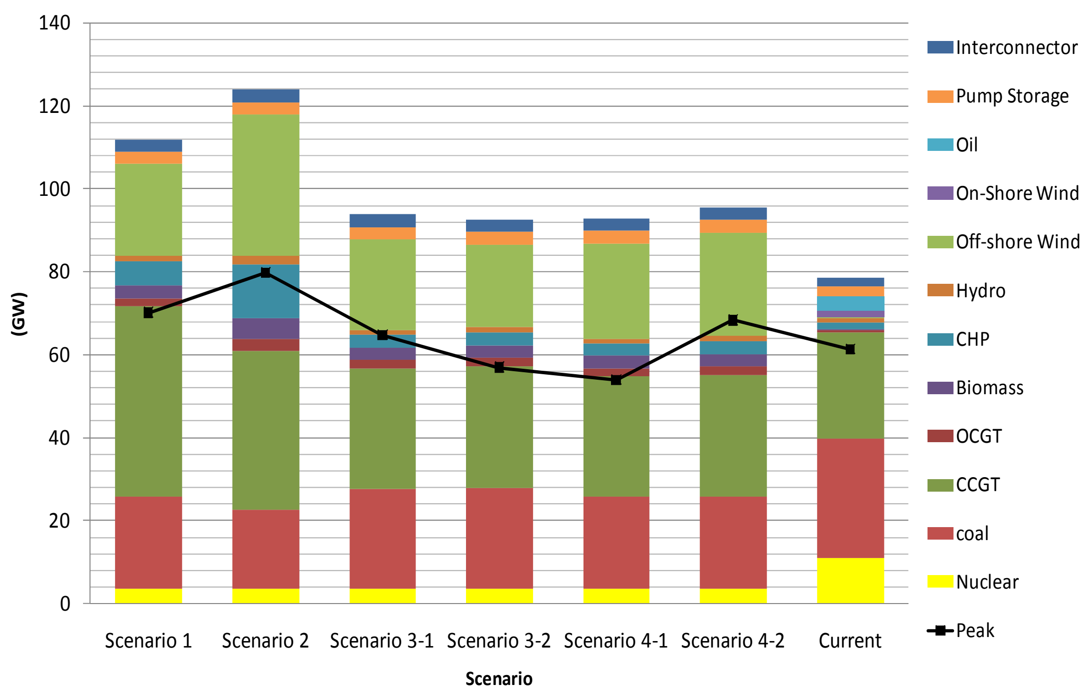

Fig. 7.9. Generation Mix, Peak Demand and Generation Margin for different scenarios

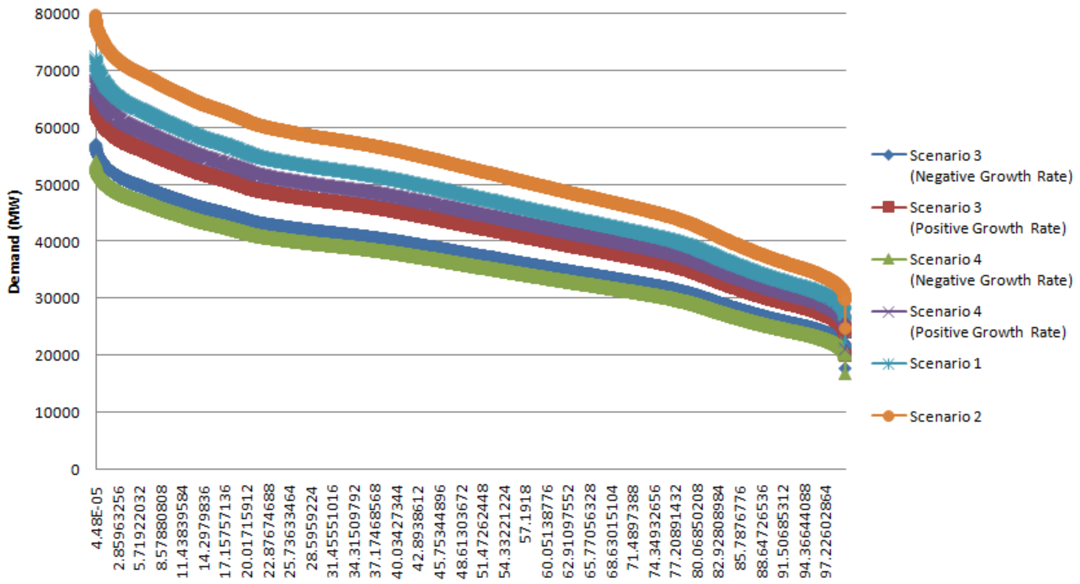

Fig. 7.10. Load Duration Curve for different scenarios.

Table 7.1Capacities of Generation Technologies in different Scenarios and Associated Peak Demand in GW

<table>
<tr><th></th><th>Scenario 1</th><th>Scenario 2</th><th>Scenario 3-1</th><th>Scenario 3-2</th><th>Scenario 4-1</th><th>Scenario 4-2</th><th>Current</th></tr>
<tr><td>Interconnector</td><td>3</td><td>3</td><td>3</td><td>3</td><td>3</td><td>3</td><td>7.07</td></tr>
<tr><td>OCGT</td><td>1.8</td><td>3</td><td>2</td><td>2</td><td>2</td><td>2</td><td>0.59</td></tr>
<tr><td>CCGT</td><td>46</td><td>38</td><td>29</td><td>29</td><td>29</td><td>29</td><td>25.53</td></tr>
<tr><td>Biomass</td><td>3</td><td>5</td><td>3</td><td>3</td><td>3</td><td>3</td><td>0.05</td></tr>
<tr><td>CHP</td><td>6</td><td>13</td><td>3</td><td>3</td><td>3</td><td>3</td><td>1.73</td></tr>
<tr><td>Hydro</td><td>1.3</td><td>2</td><td>1</td><td>1</td><td>1</td><td>1</td><td>1.03</td></tr>
<tr><td>Nuclear</td><td>3.8</td><td>3.8</td><td>3.8</td><td>3.8</td><td>3.8</td><td>3.8</td><td>11.01</td></tr>
<tr><td>coal</td><td>22</td><td>19</td><td>24</td><td>24</td><td>22</td><td>22</td><td>28.91</td></tr>
<tr><td>Off-shore Wind</td><td rowspan="2">22</td><td rowspan="2">34</td><td rowspan="2">22</td><td rowspan="2">20</td><td rowspan="2">23</td><td rowspan="2">25</td><td>0.14</td></tr>
<tr><td>On-Shore Wind</td><td>1.60</td></tr>
<tr><td>Oil</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>3.50</td></tr>
<tr><td>Pump Storage</td><td>3</td><td>3</td><td>3</td><td>3</td><td>3</td><td>3</td><td>7.30</td></tr>
<tr><td>Total</td><td>111.9</td><td>123.8</td><td>93.8</td><td>97.6</td><td>97.8</td><td>95.5</td><td>78.4</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Peak</td><td>70.14</td><td>79.73</td><td>64.71</td><td>57</td><td>54</td><td>68.36</td><td>61.30</td></tr>
</table>

7.3.3. Developing Sub-Scenarios (Windfarms' Location)

Another important factor considered in this project is the location and type of wind power for each scenario. Therefore the impact of location of windfarms can also be studied. Table 7.2 and figure 7.11 show the total installed capacity of wind power at different locations in percentage of targeted wind power. But the final table which shows the average production cost has included all sub-scenarios.

Table 7.2 Sub-scenarios explained.

	North		South	
	On-Shore	Off-shore	On-Shore	Off-shore
Sub Scenario 1	16%	24%	24%	36%
Sub Scenario 2	24%	16%	36%	24%
Sub Scenario 3	24%	36%	16%	24%
Sub Scenario 4	24%	36%	24%	16%

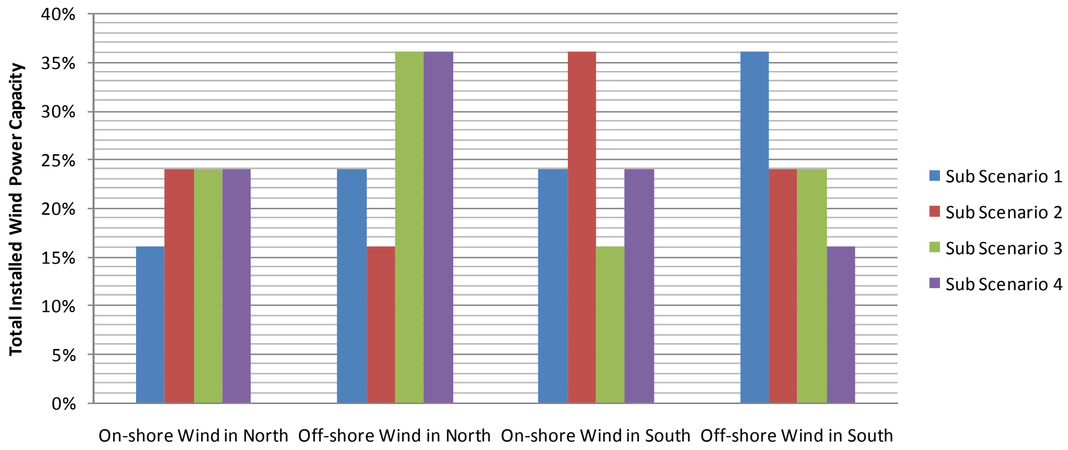

Fig. 7.11. Wind Power in percentage of total installed capacity at different locations.

Therefore for each scenario a different level of installed capacity of wind depending on the location of windfarms is required. Therefore some

7.3.4. Developing Cases (Nuclear Power Plants Replacement)

Since there are many uncertainties regarding replacement of decommissioned nuclear power stations, three cases are developed in order to take into account the replacement rate of nuclear power stations:

1. Case 1: No Nuclear Power station will be built and only decommissioning of nuclear power will be considered (base case of all scenarios).
2. Case 2: By 2020, half of the total capacity of nuclear power stations which are decommissioned will be replaced by new capacities in the same locations.
3. Case 3: By 2020 total capacity of nuclear power stations which are decommissioned will be replaced by new capacities in the same locations.

This helps to study the role which nuclear power has in each scenario. The process of building our generation mix hypothesis is explained in the diagram below. Each main scenario will be studied through four sub-scenarios which represent the location of windfarms, and each sub-scenario will be studied through three cases for nuclear power replacement. In total 72 generation mix hypotheses were studied.

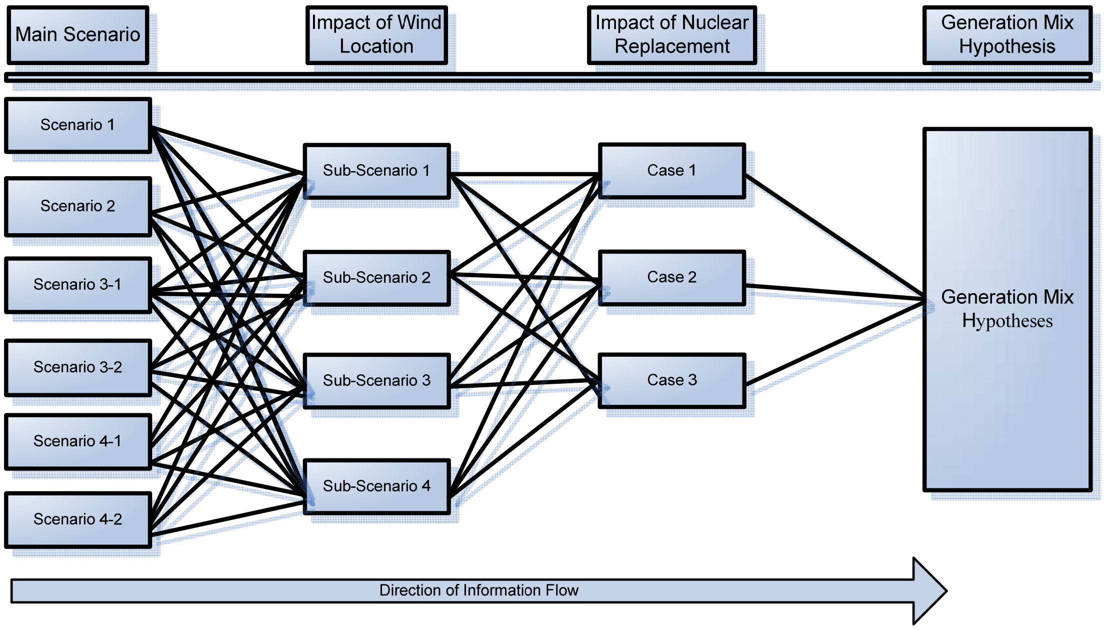

Fig. 7.12 Algorithm of Generating Different Hypotheses.

7.4 Test System (The GB Network)

To assess the optimal energy mix for 2020, a reduced GB power system is reduced, generation and demand are located in reduced network and the reduced model is validated by checking the power flows in the main branches compare with the actual network. This along with relevant data and information is presented in this chapter.

7.4.1. Network Model:

By the end of 2008/09 the power system in GB will be made up of 167 large power stations, the 400kV and 275kV transmission system (and 132kV transmission system in Scotland) and 14 distribution systems. The existing system consists of 681 nodes, and 1145 branches [9].

In order to perform our studies, we have reduced the existing system down to 53 nodes, and 62 lines and the power flows were compared and validated with the original system. To reduce the current system down to 53 nodes, we started from low voltage nodes and transferred loads, generation and reactive shunts compensators to higher voltage nodes. While reducing the system, “T”eed or higher meshed nodes were not reduced. The system was reduced to a 29-node system to represent England and Wales (E&W)

including 33 lines, 21 transformers and 20 reactive shunt compensators. Then in order to include the nodes in Scotland we reduced the system in Scotland, and connected the reduced E&W system to the reduced system in Scotland by considering existing “interconnectors” between E&W network to Scotland. The power-flow results are shown in figure 7.13 along with the reduced GB network in figure 7.14. Tables 7.3 and 7.4 show the name of the nodes, and total generation and demand lumped into these nodes respectively.

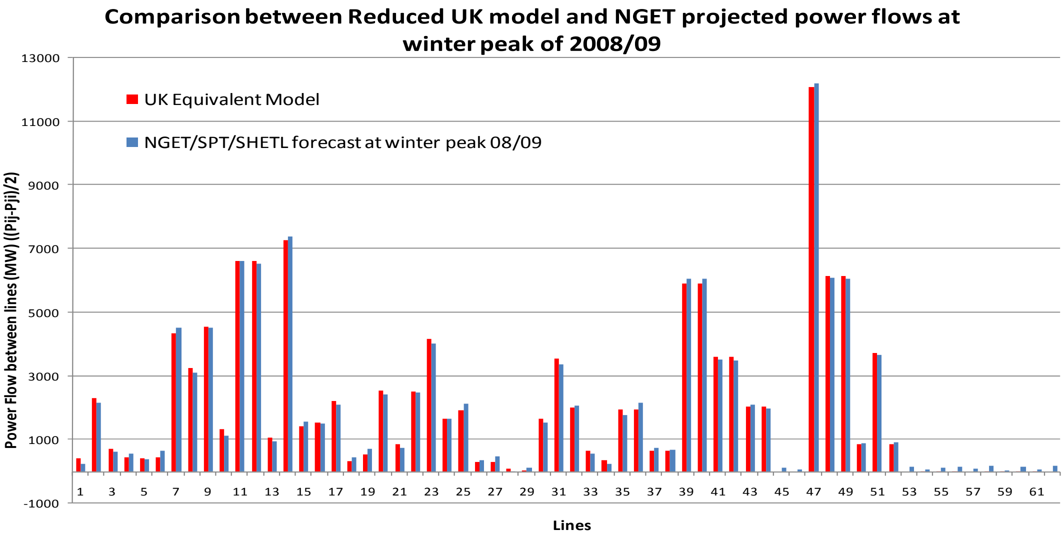

Fig. 7.13. Power-Flow across the Branches for Reduced and Original GB Network.

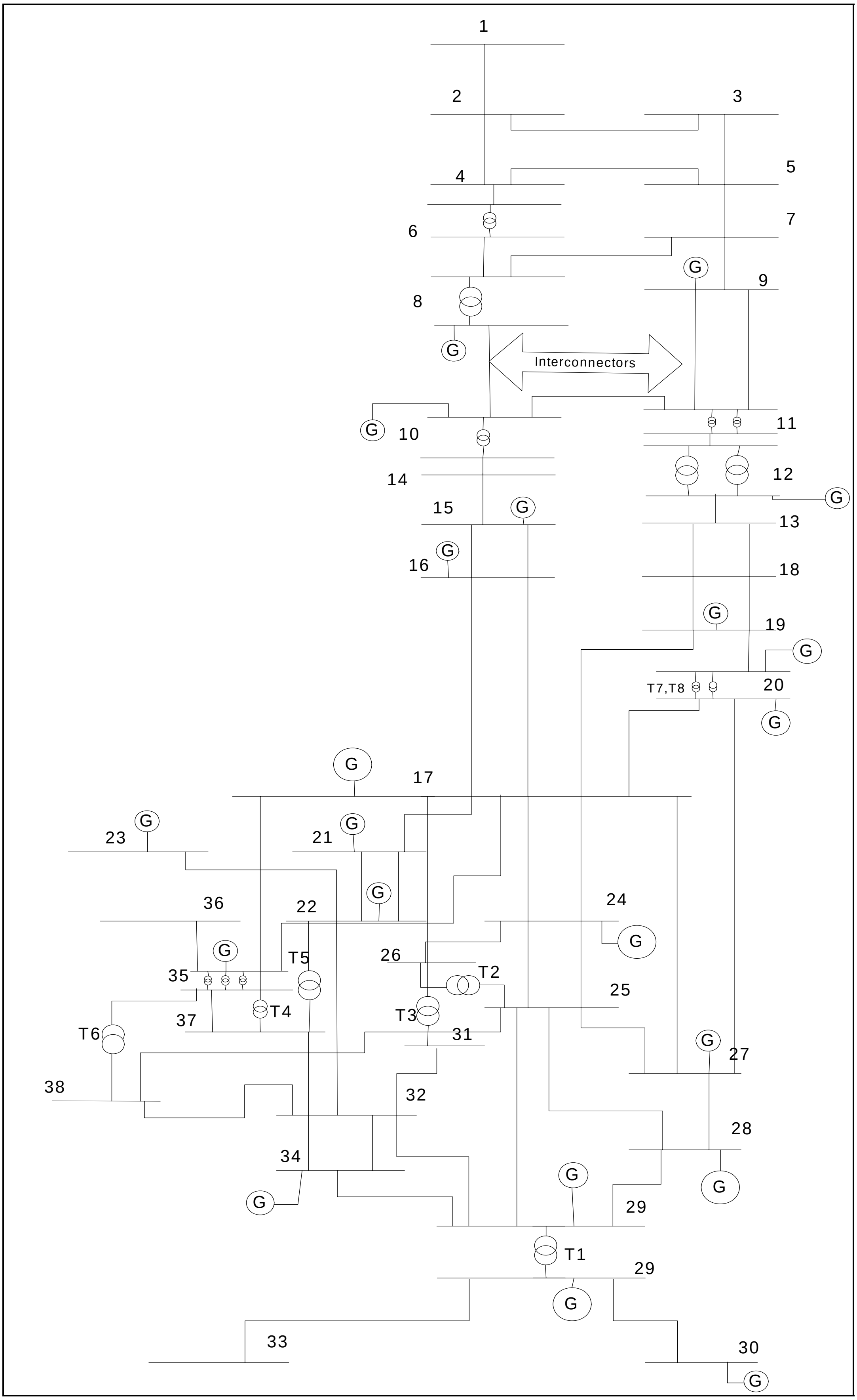

Fig. 7.14. The reduced GB Transmission System

TABLE 7.3
Reduced Network Explained

Node No.	Node Name	Node No.	Node Name
1	Dounreay	20	Willington
2	Beauly	21	Rugeley
3	Kintroe	22	Ironbridge
4	Errochty	23	Legacy
5	Tealing	24	Bustleholm
6	Inverkip	25	Hamshall
7	Longannet	26	Nechells
8	Strathaven	27	Coventry
9	Cockenzie	28	Berkswell
10	Harker	29	Feckenham
11	StellaWest	30	Cowley
12	Norton	31	Oldburry
13	Creyke Beck	32	Kitwell
14	Penwortham	33	Melksham
15	Daines	34	Bishops Wood
16	Cellerhead	35	Bushbury
17	Drakelow	36	Willenhall
18	Cottam	37	Penn
19	Ractliffe	38	Ocker Hill

TABLE 7.4
Peak Load and Installed Generation Capacity at each Node in the Reduced Network

Node Name	Peak Load		Generation Capacity	
	P	Q	P	Q
Berkswell	2593	1179	0	1931
Bishops wood	2999	1349	0	3862
Bushbury	1577558	661	0	1287
Bustleholm	2592	841	0	215
Cellerhead	4832	2077	0	3218
Cockenzie	0	0	0	0
Coventry	337532	1316	0	1931
Cowley	13062	118	18495	18237
Creyke Beck	0	0	5009	5367677
Daines	848	0	2339	2682
Drakelow	1075	4047507	0	1609
Feckenham	1390	5896081	0	3218
Hamshall	2968	1102462	0	0
Harker	0	0	17389	17389
Ironbridge	2267	851	1034	1073
Kitwell	2550	828	0	0
Legacy	605	0	0	9977
Melksham	6002	-659	9146	8908543
Nechells	2921	1395	0	0
Norton	0	0	3360	0
Ocker Hill	8680308	436	0	0
Oldburry	758	345	0	0
Penn	2062	907	13674	13946
Ractliffe	887	330	554253	5471
Rugeley	1248	525	1092	1180
StellaWest	0	0	451	451
Willenhall	787	332	0	0
Willington	2982	1332	467	2038

7.4.2. Current Location of Power Plants:

Currently there are over 150 power stations in the GB system providing 78GW of installed capacity. To project the future scenarios when capacity, type and location of generation units are different, several literature sources were studied and the predicted location and capacity of each plant was derived from those literature sources. The generation emission and fuel cost coefficients were also derived from several references [10 and 11] and were modified according to another reference [12] in order to reflect the actual marginal cost, and emissions of different types of power generation. In order to study the impact of these generators at current state on our reduced model, the generator plants are lumped to specific nodes (depending on the location of the plant) as shown in fig. 7.15.

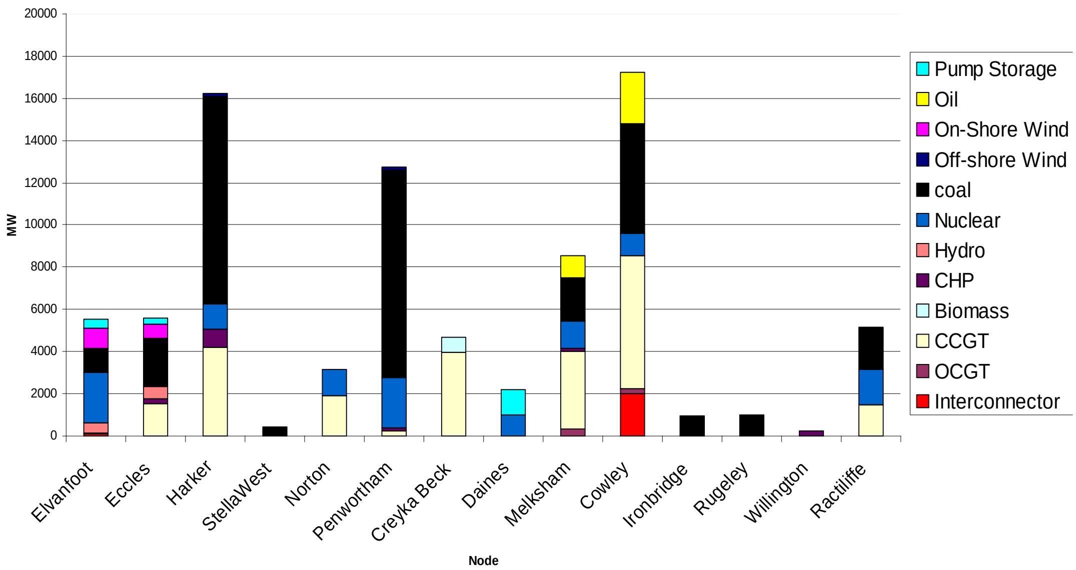

Fig. 7.15. Lumped Generation Capacity (current scenario) in reduced model.

7.4.3 Location and Capacity of Power Plants in Future Scenarios:

The information regarding the power plants' capacity at each location is presented in tables 7.5-7.10. It can be seen from these tables that different generation technologies have different capacities in each scenario. In some nodes, the size of a generation type is very large i.e. 12.43GW CCGT connected to Cowley. This is because on the reduced network, this node represents total generation capacity connected to several nodes which are all lumped to this node.

Table 7.5. Location of Power Plants for Scenario 1.

	Strath aven	cocke nzie	Har ker	Stella West	Nort on	Penwor tham	Creyka Beck	Dai nes	Melks ham	Cow ley	Ironbri dge	Rug eley	Willin gton	Racti liffe
Intercon-nector	116	0	0	0	0	0	0	0	0	2884	0	0	0	116
OCGT	0	31	0	0	0	0	0	0	1024	746	0	0	0	0
CCGT	0	3013	8263	0	3806	453	7810	0	7278	1243 9	0	0	0	0
Biomass	177	0	0	0	0	0	2823	0	0	0	0	0	0	177
CHP	0	916	3140	0	0	557	0	0	568	0	0	0	819	0
Hydro	600	700	0	0	0	0	0	0	0	0	0	0	0	600
Nuclear	750	0	374	0	376	749	0	305	393	336	0	0	0	750
coal	730	1459	6215	266	0	6215	0	0	1301	3279	610	645	0	730

Off-shore Wind	22-26GW (location varies depending on the sub-scenarios)													
On-Shore Wind														
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pump Storage	680	464	0	0	0	0	0	1856	0	0	0	0	0	680

Table 7.6. Location of Power Plants for Scenario 2.

	Strath aven	cocke nzie	Har ker	Stella West	Nort on	Penwor tham	Creyka Beck	Dai nes	Melks ham	Cow ley	Ironbri dge	Rug eley	Willin gton	Racti liffe
Intercon-nector	116	0	0	0	0	0	0	0	0	2884	0	0	0	116
OCGT	0	51	0	0	0	0	0	0	1706	1243	0	0	0	0
CCGT	0	2489	6826	0	3144	374	6452	0	6012	10275	0	0	0	0
Biomass	295	0	0	0	0	0	4705	0	0	0	0	0	0	295
CHP	0	1985	6804	0	0	1207	0	0	1230	0	0	0	1775	0
Hydro	923	1077	0	0	0	0	0	0	0	0	0	0	0	923
Nuclear	750	0	374	0	376	749	0	305	393	336	0	0	0	750
coal	630	1260	5368	230	0	5368	0	0	1124	2831	527	557	0	630
Off-shore Wind	32-34GW (location varies depending on the sub-scenarios)													
On-Shore Wind														
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pump Storage	680	464	0	0	0	0	0	1856	0	0	0	0	0	680

Table 7.7. Location of Power Plants for Scenario 3-1.

	Strath aven	cocke nzie	Har ker	Stella West	Nort on	Penwor tham	Creyka Beck	Dai nes	Melks ham	Cow ley	Ironbri dge	Rug eley	Willin gton	Racti liffe
Intercon-nector	116	0	0	0	0	0	0	0	0	2884	0	0	116	0
OCGT	0	34	0	0	0	0	0	0	1137	829	0	0	0	34
CCGT	0	1900	5209	0	2400	285	4924	0	4588	7842	0	0	0	1900
Biomass	177	0	0	0	0	0	2823	0	0	0	0	0	177	0
CHP	0	458	1570	0	0	278	0	0	284	0	0	0	0	458
Hydro	461	539	0	0	0	0	0	0	0	0	0	0	461	539
Nuclear	750	0	374	0	376	749	0	305	393	336	0	0	750	0
coal	796	1592	6780	290	0	6780	0	0	1420	3577	666	703	796	1592
Off-shore Wind	20--24GW (location varies depending on the sub-scenarios)													
On-Shore Wind														
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pump Storage	680	464	0	0	0	0	0	1856	0	0	0	0	680	464

Table 7.8. Location of Power Plants for Scenario 3-2.

	Strath aven	cocke nzie	Har ker	Stella West	Nort on	Penwor tham	Creyka Beck	Dai nes	Melks ham	Cow ley	Ironbri dge	Rug eley	Willin gton	Racti liffe
Intercon-nector	116	0	0	0	0	0	0	0	0	2884	0	0	0	0
OCGT	0	37	0	0	0	0	0	0	1251	912	0	0	0	0
CCGT	0	1913	5245	0	2416	287	4958	0	4620	7896	0	0	0	1865
Biomass	177	0	0	0	0	0	2823	0	0	0	0	0	0	0
CHP	0	458	1570	0	0	278	0	0	284	0	0	0	410	0
Hydro	600	700	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	750	0	374	0	376	749	0	305	393	336	0	0	0	517
coal	799	1598	6808	291	0	6808	0	0	1426	3592	669	706	0	1402
Off-shore Wind	32-34GW (location varies depending on the sub-scenarios)													
On-Shore Wind														
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pump Storage	680	464	0	0	0	0	0	1856	0	0	0	0	0	0

Table 7.9. Location of Power Plants for Scenario 4-1.

	Strath aven	cocke nzie	Har ker	Stella West	Nort on	Penwor tham	Creyka Beck	Dai nes	Melks ham	Cow ley	Ironbri dge	Rug eley	Willin gton	Racti liffe
Intercon-nector	116	0	0	0	0	0	0	0	0	2884	0	0	0	0
OCGT	0	34	0	0	0	0	0	0	1137	829	0	0	0	0
CCGT	0	1900	5209	0	2400	285	4924	0	4588	7842	0	0	0	1852
Biomass	177	0	0	0	0	0	2823	0	0	0	0	0	0	0
CHP	0	458	1570	0	0	278	0	0	284	0	0	0	410	0
Hydro	461	539	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	750	0	374	0	376	749	0	305	393	336	0	0	0	517
coal	730	1459	6215	266	0	6215	0	0	1301	3279	610	645	0	1280
Off-shore Wind	23-26GW (location varies depending on the sub-scenarios)													
On-Shore Wind														
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pump	680	464	0	0	0	0	0	1856	0	0	0	0	0	0

Storage														

Table 7.10. Location of Power Plants for Scenario 4-2.

	Strath aven	cocke nzie	Har ker	Stella West	Nort on	Penwor tham	Creyka Beck	Dai nes	Melks ham	Cow ley	Ironbri dge	Rug eley	Willin gton	Racti liffe
Intercon-nector	116	0	0	0	0	0	0	0	0	2884	0	0	0	0
OCGT	0	37	0	0	0	0	0	0	1251	912	0	0	0	0
CCGT	0	1913	5245	0	2416	287	4958	0	4620	7896	0	0	0	1865
Biomass	177	0	0	0	0	0	2823	0	0	0	0	0	0	0
CHP	0	458	1570	0	0	278	0	0	284	0	0	0	410	0
Hydro	600	700	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	750	0	374	0	376	749	0	305	393	336	0	0	0	517
coal	730	1459	6215	266	0	6215	0	0	1301	3279	610	645	0	1280
Off-shore Wind	23-26GW (location varies depending on the sub-scenarios)													
On-Shore Wind														
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pump Storage	680	464	0	0	0	0	0	1856	0	0	0	0	0	0

Generators' data include their production cost and total emissions. The generators' fuel cost function is defined by a set of quadratic equations as shown in chapter 3, section 2.1 and same for emission function which is defined by the equations shown in 3.2.2. The fuel cost and CO_2 coefficients used for the GB power system are included in appendix A. In order to validate the coefficients used in this section, the production cost and total emission output of different plants were compared with references [12& 13] which shows they conform to suggested average production cost and emission output of different types of power plants as shown in fig. 7.16 and 7.17.

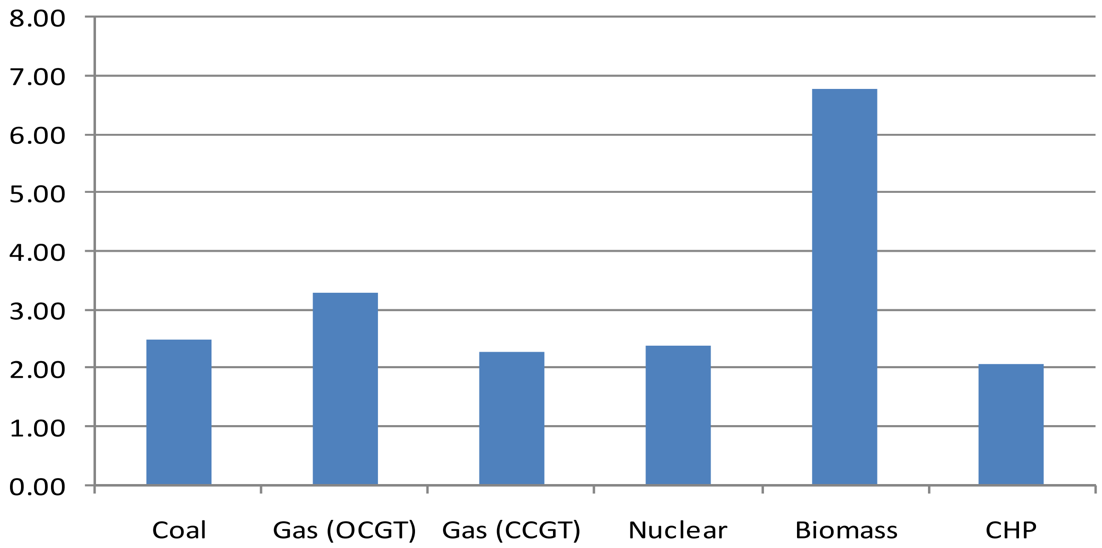

Fig. 7.16. Production cost of different generation technologies (p/KWh) [12& 13]

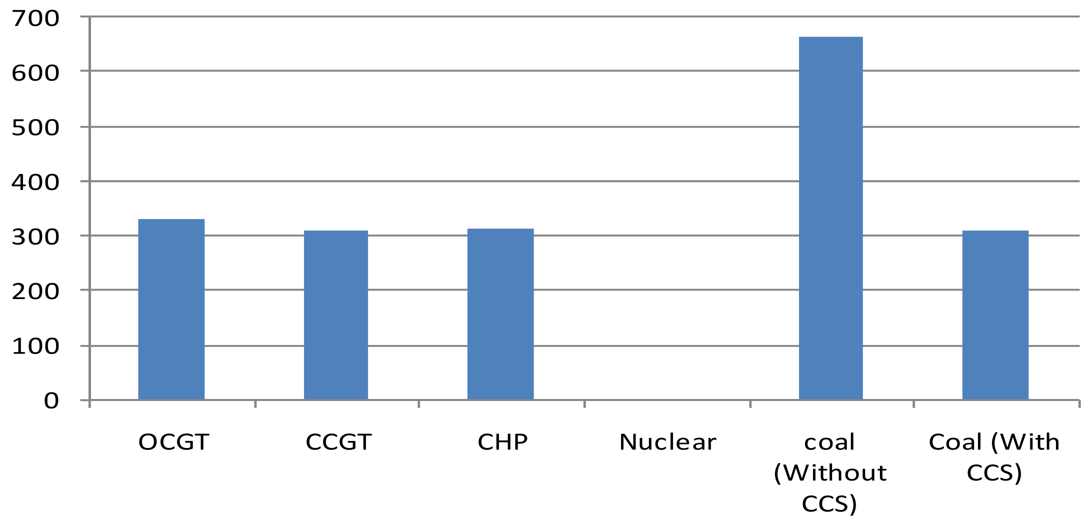

Fig. 7.17. Emission (CO2) produced by different generation types (Kg/MWh) [12 &13]

7.4.4. Demand Data:

Locational demand growth are derived from national grid's seven year statement, where the future nodal demand growth are forecasted for the next 7 years was used to project the demand growth for each scenario for 2020 [14]. It is assumed that load profile (pattern) for all four scenarios are similar to the current load profile of the GB system as shown in fig. 7.18.

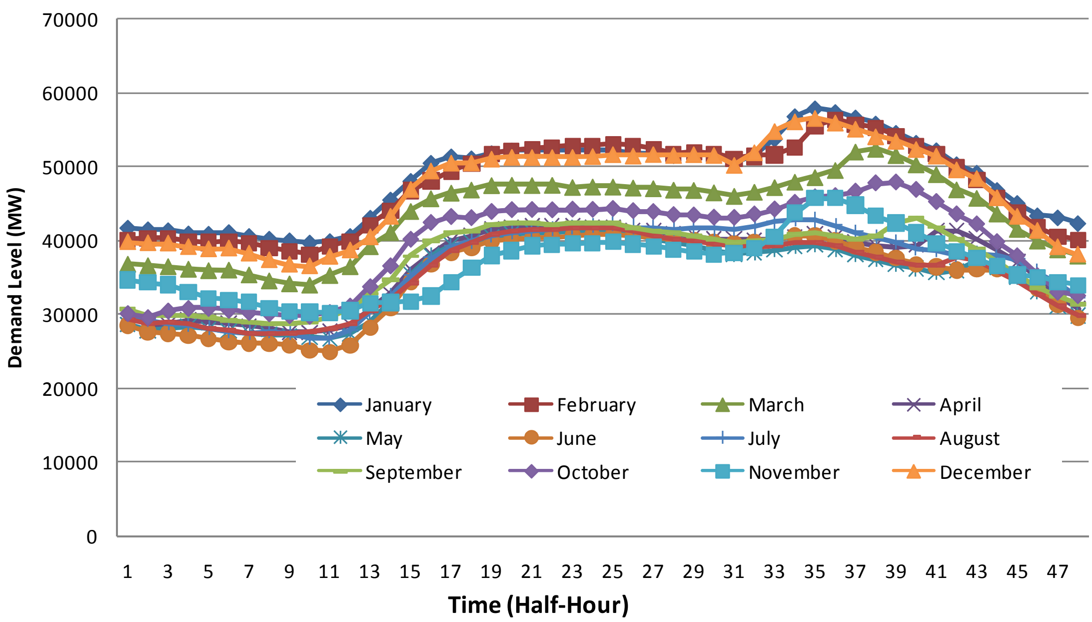

Fig. 7.18. Typical Load Profiles for Different Months in the GB System [14]

7.4.5. Wind Data:

In order to describe the variation of wind speeds at different locations and use different wind data for different wind-farms installed at different locations. In GB, the windiest locations are those that are situated closer to the shores and mountains. Coastal winds have less exposure to the drag and mountains can cause the wind to blow faster as the air mass is forced to travel over or around the mountain. In the GB, up north in Scotland and closer to coats, the wind potential is greater. The GB wind map is shown in fig. 7.19.

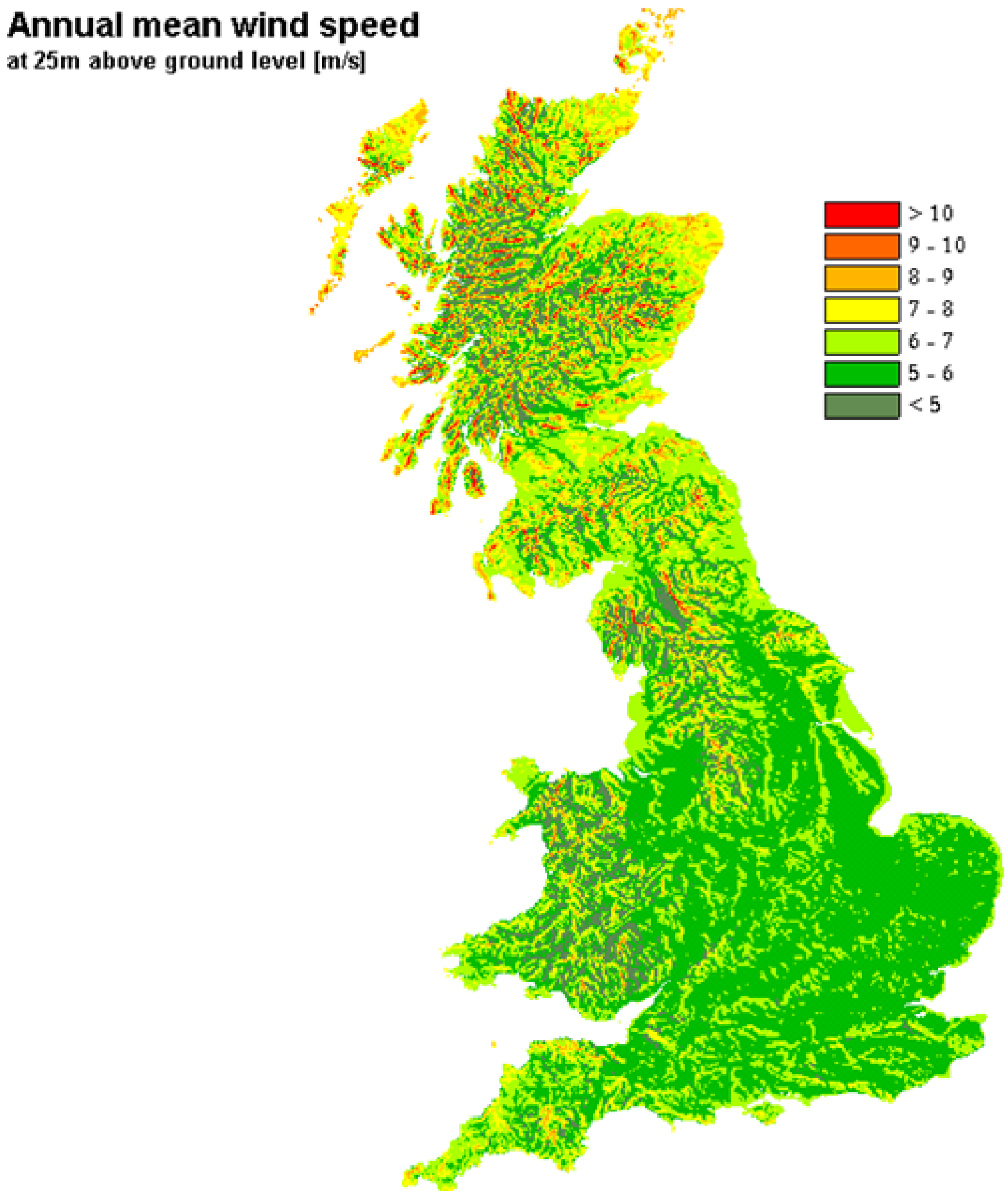

Fig.7.19. GB wind Map [15].

The wind variation for a typical site is usually described using the so-called Weibull distribution. The Weibull distribution describes the probability of the wind speed blowing at specific speed and it is usually measured annually for each site. Figures 7.20-7.22 show different Weibull distributions for South, North and off-shore respectively [15].

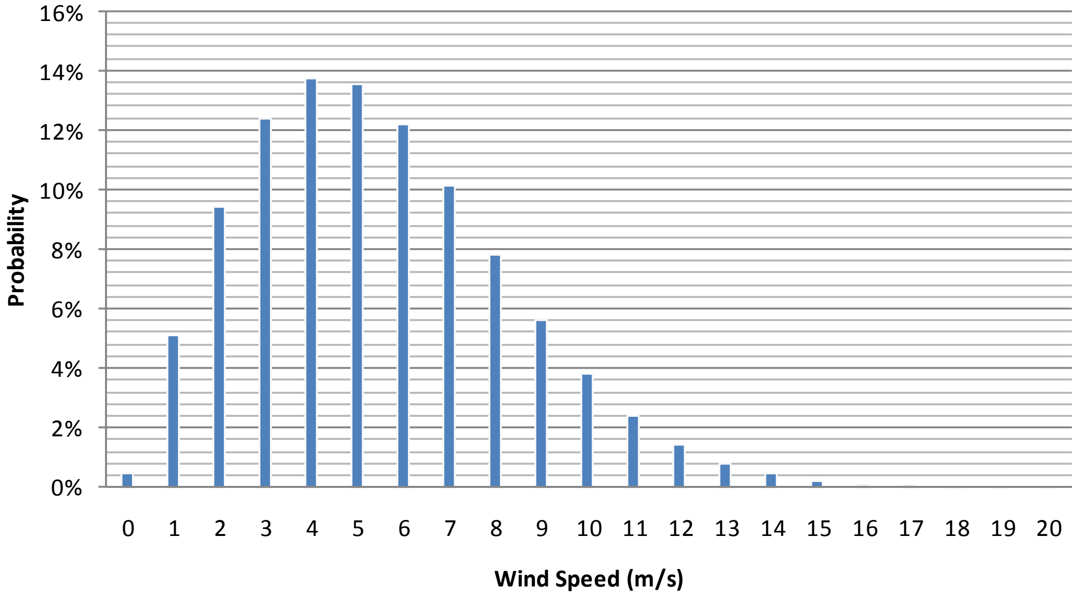

Fig. 7.20. Weibull distributions for Wind Speed in South of GB Network

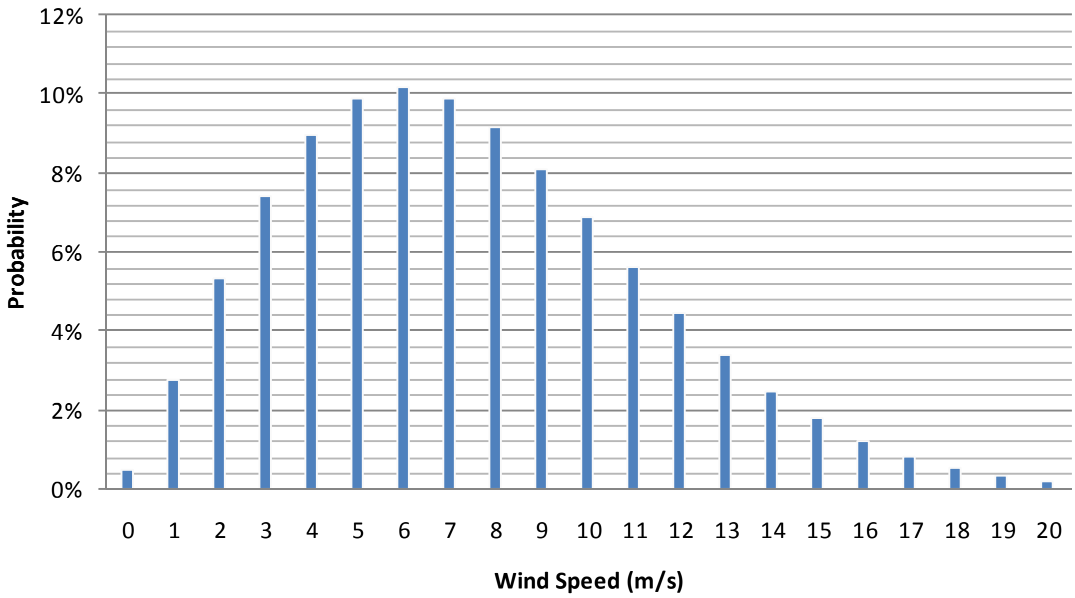

Fig. 7.21. Weibull distributions for Wind Speed in North of GB Network

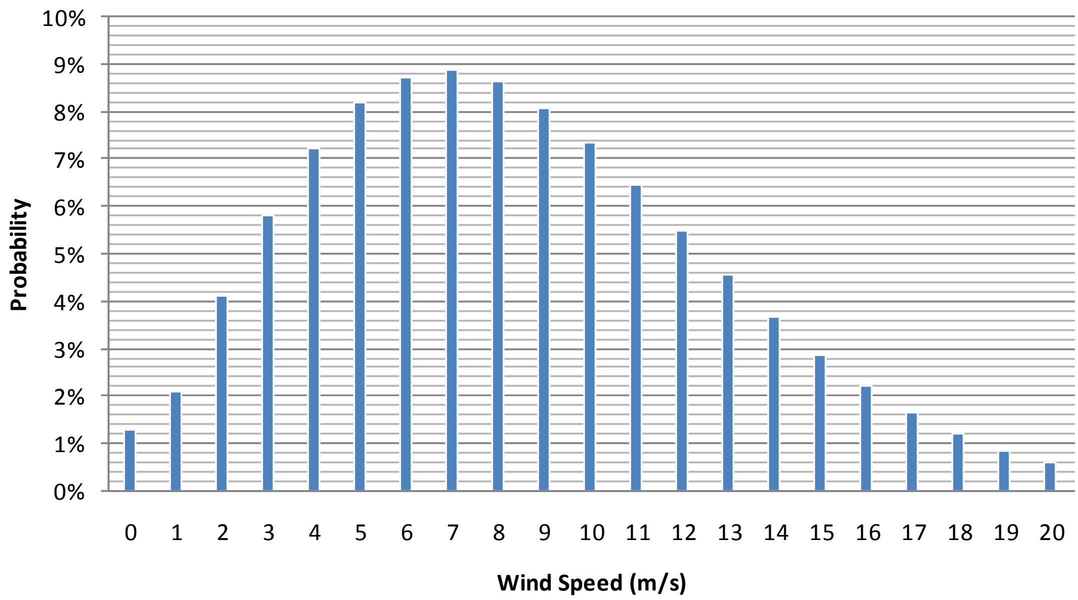

Fig. 7.22. Weibull distributions for Wind Speed in off-shore of GB Network

7.5 Results and Discussions

7.5.1. Presentation of Results

This chapter proposed 72 hypotheses which are analyzed. Since such a high number of hypotheses gives a large number of outputs, it makes it extremely difficult to show the outputs in a conventional way (by simply using an independent variable versus a dependent variable) to understand and lead to a final result. Besides, results in this chapter are dependent to each other, i.e. it is not feasible to show the results for case no. 1 without including all different sub-scenarios. The full dispatch results are attached in appendix B.

Box plots or box-whisker plots give a good graphical image of the concentration of the data. They also show how far from most of the data the extreme values are. Since in this chapter it is desirable to compare the output parameters for different scenarios with each other, using the box plot is the most appropriate form of presenting the results.

The box plot as shown in fig. 7.23 is constructed from five values:

- The smallest value;
- The largest value;
- The first quartile;
- The third quartile; and
- The median.

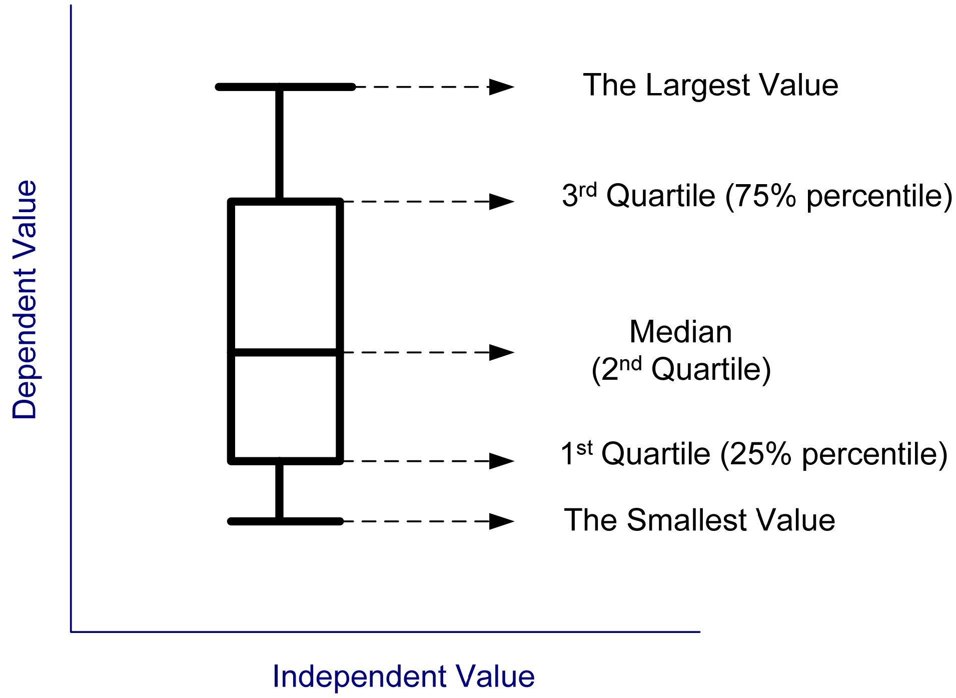

Fig.7.23. A Box Plot and its Components to Show the Results

7.5.2. Effect of Wind Power:

7.5.2.1. Effect of Location of Windfarms:

7.5.2.1.1. Impact on Production Cost:

In fig. 7.24, regardless of in which scenario, or which level of nuclear power plant exists in the systems, the production cost for different locations of wind power is shown. On average, sub-scenario 1 shows the cheapest production cost, which corresponds to a situation where more wind power is connected to South part of the GB system, and windfarms are mainly off-shore. The most expensive will result, when the majority of windfarms are connected to North, and they are mainly on-shore and have lower load factor.

The difference in production cost observed in sub scenarios is mainly due to different generation mixes which exists under different scenarios. i.e. in sub-scenario1 of scenario 1, three different cases of nuclear power penetration exist which result in production cost between £22.2 to £22.9/MWh. Similar cases for scenario 2 result in production costs in a different range of £19.23 to £21.03/MWh. Other generation technologies such as coal, gas and other types of renewable have different penetration level, and production cost. Thus, a range of production costs are observed for each sub-scenario.

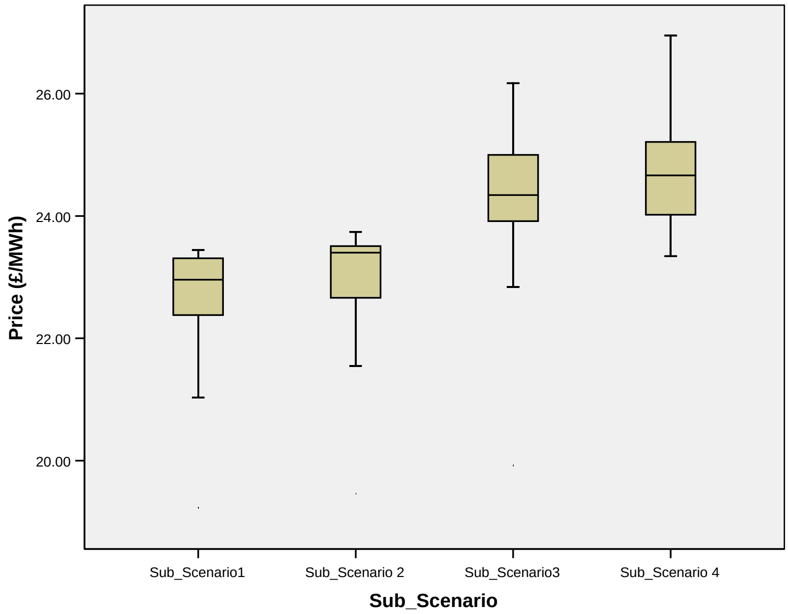

Fig. 7.24 Production Cost for Different Sub-scenarios representing windfarms' location

7.5.2.1.2. Impact on Emission Level:

A similar result is observable for the average emission level for different locations where windfarms are connected. Since windfarms connected to South will have a higher load factor particularly if they are off-shore, they will displace pollutant conventional plants at various levels. The highest and lowest displacement level will result in sub-scenario 1 and 4 respectively, which corresponds to the lowest and highest emission levels as shown in fig. 7.25.

Similar to production cost; for each sub-scenario a range of emission outputs are observed. The difference in emission level observed in sub scenarios is mainly due to different generation mixes which exists under different scenarios. i.e. in sub-scenario1 of scenario 1, three different cases of nuclear power penetration exist which result in emission level between 283kg/MWh to 314kg/MWh. This is also because different sets of generation mix under each scenario exist. The impact of wind power in displacing some emissions from conventional plants depends on the what type of emission-free plants exists in the system so wind power can reduce their operation time, hence reducing the emissions.

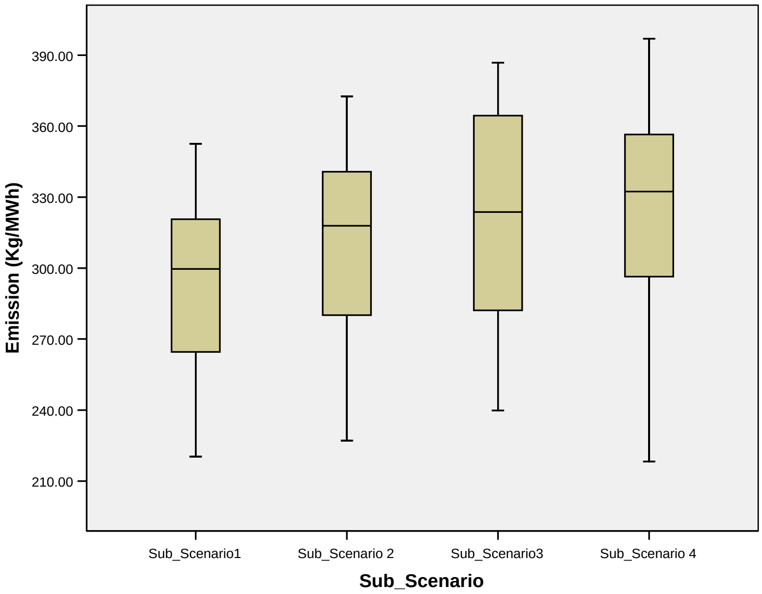

Fig. 7.25 Emission level for Different Sub-scenarios representing windfarms' location.

7.5.2.1.3. Impact on Network Losses:

In future generation mix scenarios, with any load level, since the density of load is higher in England, the most appropriate location to connect the windfarms to the system is South. This will result in reduced power losses across the network, reduced bottleneck in the interconnector between England and Scotland which reduces the contribution of wind power as shown in fig. 7.26.

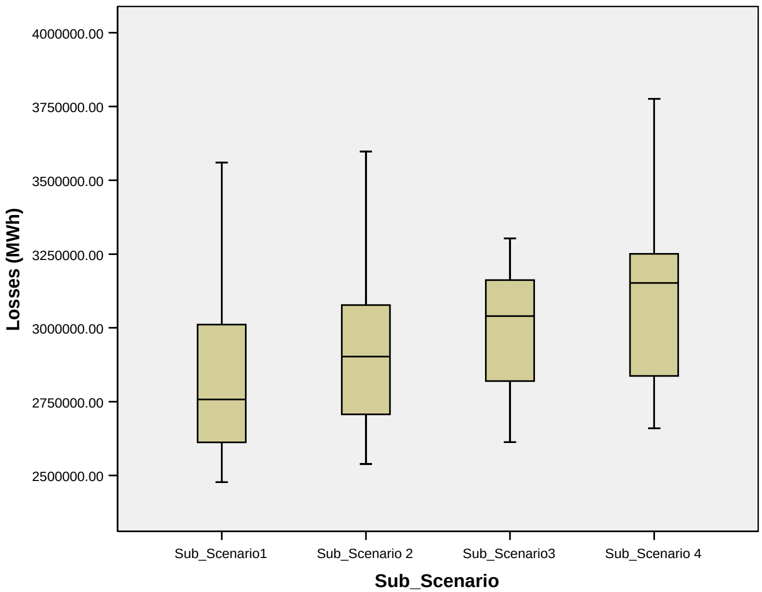

Fig. 7.26 Network Losses for Different Sub-scenarios representing windfarms' location.

It is observable from fig. 7.26 that the maximum network losses seen in sub scenario 3 is the lowest observed number compared with other sub scenarios, although the average losses in this sub scenario is higher compared with sub scenario 1 and 2. In sub scenario 3 the majority of windfarms are installed at North, and mainly off-shore. This means that the losses due to network constraint will be seen as the energy produced by windfarms may not used locally and has to be transported to other parts of the network to feed the demand. Since the way that the results are shown is by using box-plot, and in doing so the maximum and minimum observed results are shown by considering 95% confidence level, the maximum network losses for this sub scenario is only shown by this confidence level and the actual losses due to high difference are omitted.

As shown in fig. 7.27, the actual network losses (directly observed from results) will be the highest for scenario 2, in which demand growth is assumed to be the highest, and the wind power will have the capacity as high as 34GW. This will result in very high level of network losses as wind power in other scenarios have much lower capacity; between 20-26GW.

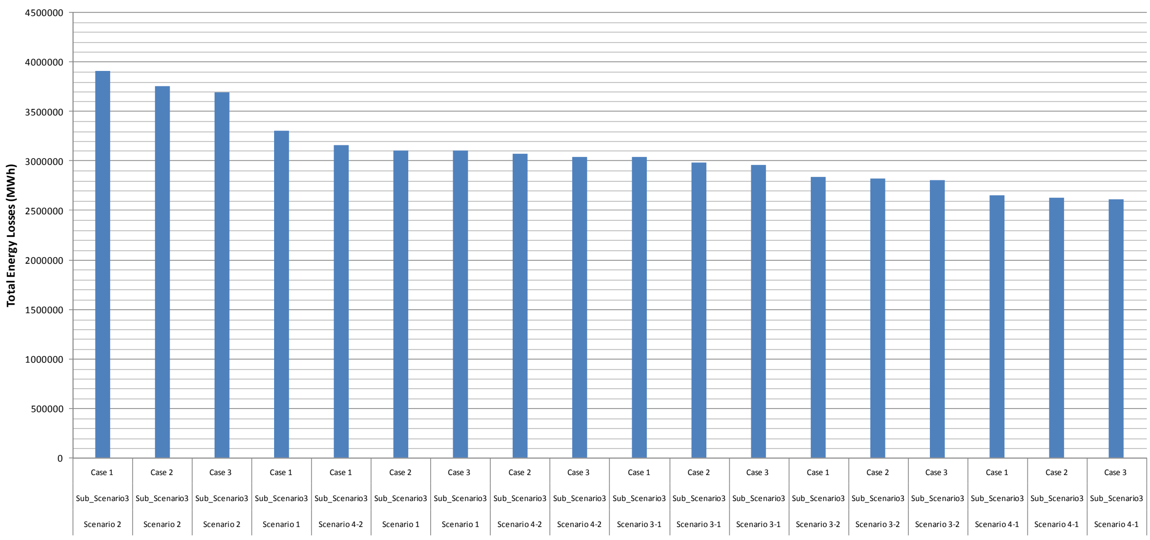

Fig. 7.27 Actual Network Losses Sub Scenario 3.

7.5.2.2. Effect of Wind Power Penetration:

7.5.2.2.1 Impact on Production Cost:

The impact of windfarm capacity on total production cost is reducing the production cost due to supplying the demand with a zero fuel power generation source. It is shown in fig. 7.28 that the lowest production cost will result when wind power has the highest penetration level; in scenario 2.

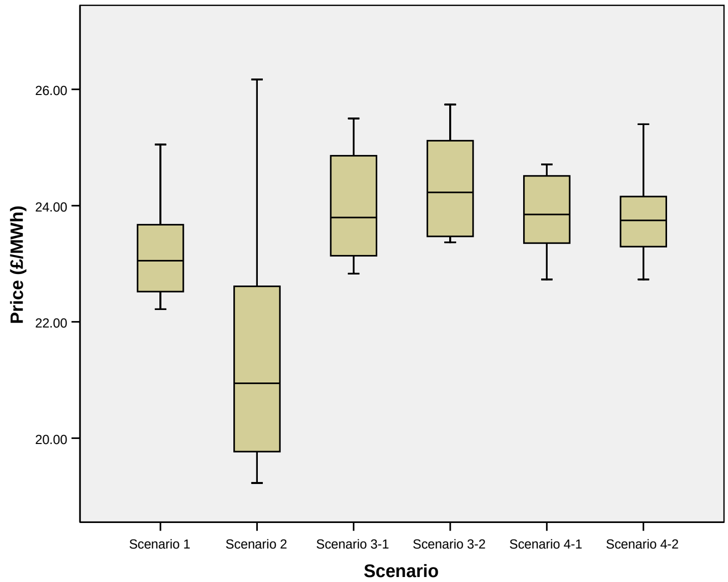

Fig. 7.28 Production Cost for Different Scenarios representing windfarms' Capacity.

It is observable from fig. 7.28 that the difference seen in production cost of scenario 2 is the highest compared with other scenarios. By investigating this more as shown in fig. 7.29, the highest production cost is observable for a case in which wind power is mainly on-shore and installed at North, whilst the penetration of nuclear power is also the lowest. In this scenario due to very high level of demand, the production cost is very sensitive to wind power location, and nuclear power penetration level. As illustrated in fig. 7.29 first three very high production costs are observed for when wind power is installed at North, and nuclear power penetration is the lowest (particularly for the first two high production costs).

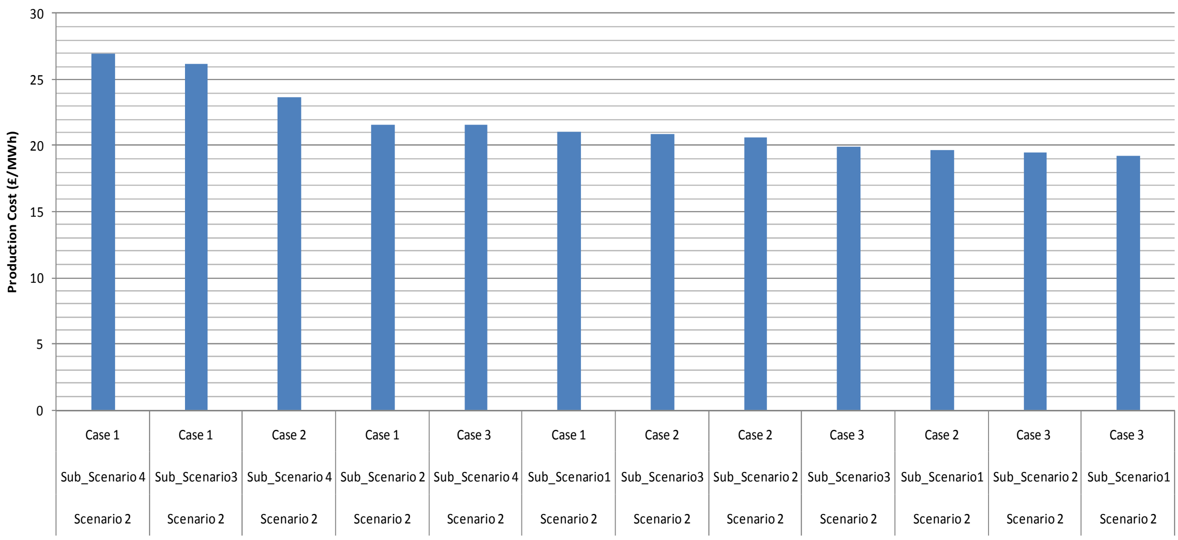

Fig. 7.29 Production Cost for Scenario 2.

7.5.2.2.2 Impact on Emission Level:

It is shown in fig. 7.30 that higher wind power in the system will result in lower emission level. Higher volumes of energy will be supplied from clean sources, thus reducing the need for operating more polluting conventional plant.

It is observable from this graph that in each scenario the emission varies depending on the level of wind capacity exists in the scenario. i.e. in scenario 2 since there are over 30GW of wind capacity installed, therefore the lowest level of emission is observable. However by doing my investigation in all different scenarios and sub-scenarios it becomes obvious that the level of emission is not just dependent on the level of wind power.

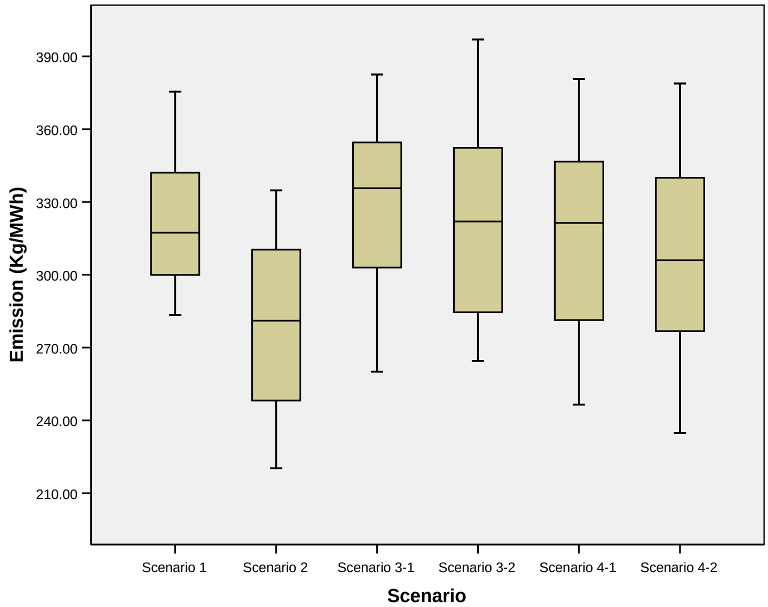

Fig. 7.30 Emission Level for Different Scenarios representing windfarms' Capacity.

In fig. 7.31 it is shown the level of emissions versus wind power capacity. It is clear from this graph that when wind power capacity equals 22GW, the average emission level increases compared with the case when wind power capacity is 20GW. This is due to the changes in the generation mix observed in different scenarios. Wind power capacity of 22GW is observable in scenarios 1 and 3-1. In both scenarios coal and CCGT plants have higher installed capacity compared with other scenarios.

Demand level is also high in these two scenarios compared with others with an exception in scenario 2. Therefore high energy required by loads, and the nature of generation mix in these two scenarios results in high level of emissions from conventional plants.

This allows drawing the following conclusion that to reduce the environmental impact of electricity generation, increasing the capacity of renewables is not solely enough. It is important to employ other measure such as demand side management to control the demand, and consider the impact of other non-renewable plants on the produced emission as a result of electricity generation.

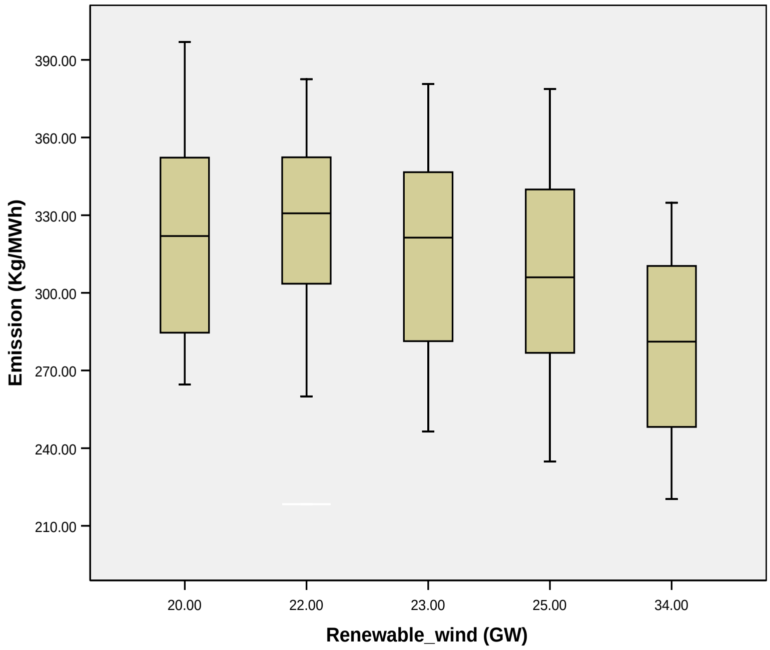

Fig. 7.31 Emission Level for Different windfarms' Capacity.

7.5.3 Effect of Nuclear Power:

7.5.3.1 Impact on Production Cost:

The UK government supports a like-for-like replacement of existing nuclear capacity when it is decommissioned. Since the replacement level is still uncertain, three main cases for nuclear power were investigated; where no nuclear plant is replaced, half of them are replaced and all decommissioned nuclear power plants are replaced with new plants.

The benefits associated with having nuclear power in a system with significant wind penetration will also be the reduced production cost which is mainly the impact of reduced spinning reserve requirement as well as cheaper production cost of nuclear power stations. It is shown in fig. 7.32 that by replacing 50% of total decommissioned nuclear power plants, production cost will be reduced on average by 3.5%. This reduction will be continued if 100% of decommissioned nuclear power plants are replaced by new capacities, but by only 1.9% compared with the previous case.

This is because in practice, nuclear power due to its low emission output will have priority on dispatch on more pollutant plants such as coal. If more coal power is not dispatched due to nuclear power in the system, other plants such as gas fired plants will have higher load factor which also have higher marginal production cost.

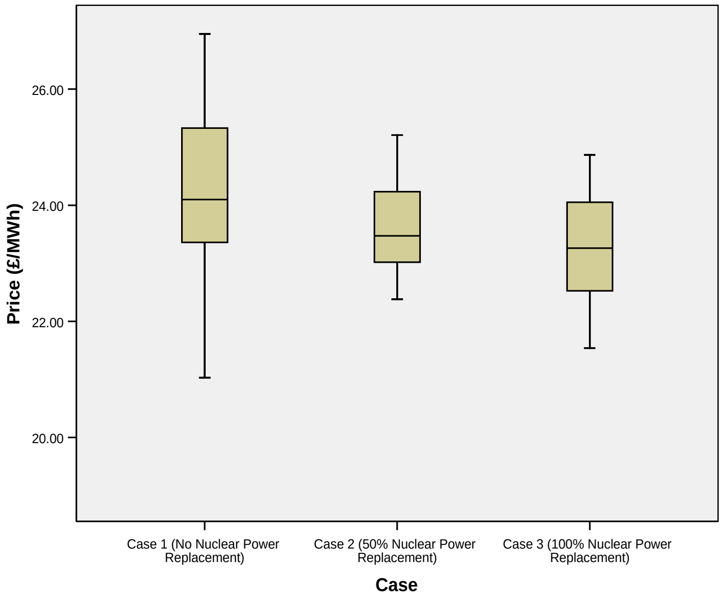

Fig. 7.32 Product Cost for Different Cases representing Nuclear Power's Capacity.

7.5.3.2 Impact on Emission Level:

The results suggested that nuclear power because of its low CO_2 output which does not impose any restrictions on the number of hours which it can operate and due to nature of nuclear power plants which are base-load plants, they will operate most of the times and will mainly result in reduced emission level. While the impact of increasing the nuclear power penetration from 50% to 100% replacement level on production cost is lower compared with no nuclear power capacity to 50% replacement, but the impact on emission level is significant. It is shown in fig. 7.33 that by replacing the full decommissioned capacity, in all scenarios and sub-scenarios the average emission level will be reduced by 25% compared with case 1.

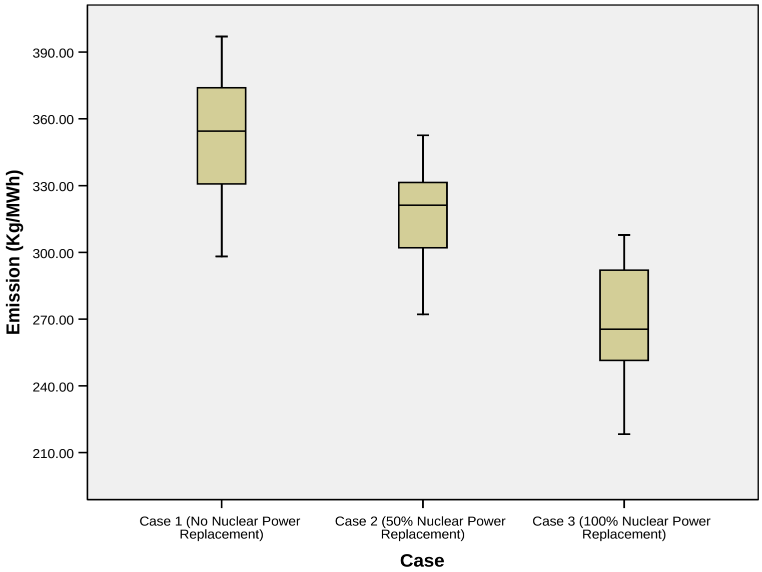

Fig. 7.33 Emission Level for Different Cases representing Nuclear Power's Capacity.

7.5.3.3. Impact on Network Losses:

As shown in fig. 7.34 that the impact of nuclear power capacity replacement on the network losses is insignificant. Since the location where nuclear power plants will be replaced is near the location where coal fired plants (which will be displaced in power dispatch). A careful observation in fig. 7.34 makes it clear that apart from reduction in the average network losses by increasing the nuclear power penetration, the range of network losses for all scenarios and sub-scenarios will also be minimized by increasing the nuclear power penetration. The reduction in the range of network losses for each case is very important since it allows drawing the following conclusion that by increasing the nuclear power penetration, no matter what socio-economic policy is being applied to the electricity industry, the network losses are likely to be minimized.

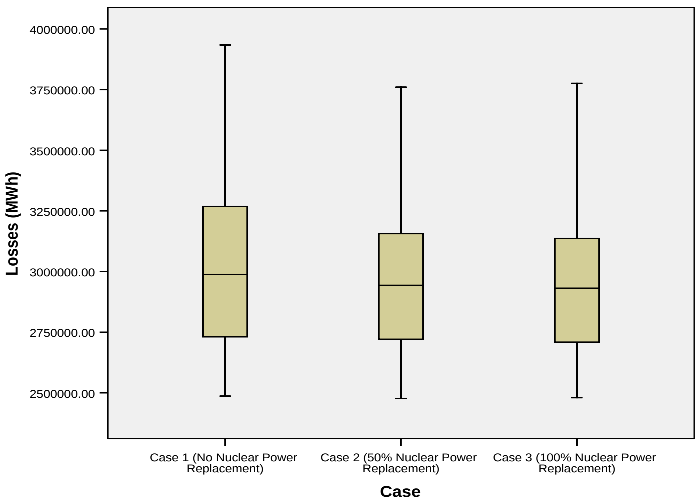

Fig. 7.34 Network Losses for Different Cases representing Nuclear Power's Capacity.

7.5.3.4 Impact on Spinning Reserve Level:

Another major impact of added capacities of nuclear power stations is their contribution on spinning reserve requirement. This is because of higher reliability (lower outage rate) which contributes to overall reliability of the generation capacity and reduces the need for spinning reserve level. It is shown in fig. 7.35 that while the spinning reserve level for different scenarios depends on demand level and wind power penetration level, but generally added capacities of nuclear power reduces the need for spinning reserve level. By replacing 50% of displaced nuclear power plants, the spinning reserve level will be reduced by 4%. If all the decommissioned displaced capacities of nuclear power are to be replaced by new capacities, then the spinning reserve level will be reduced by 8% compared with the base case.

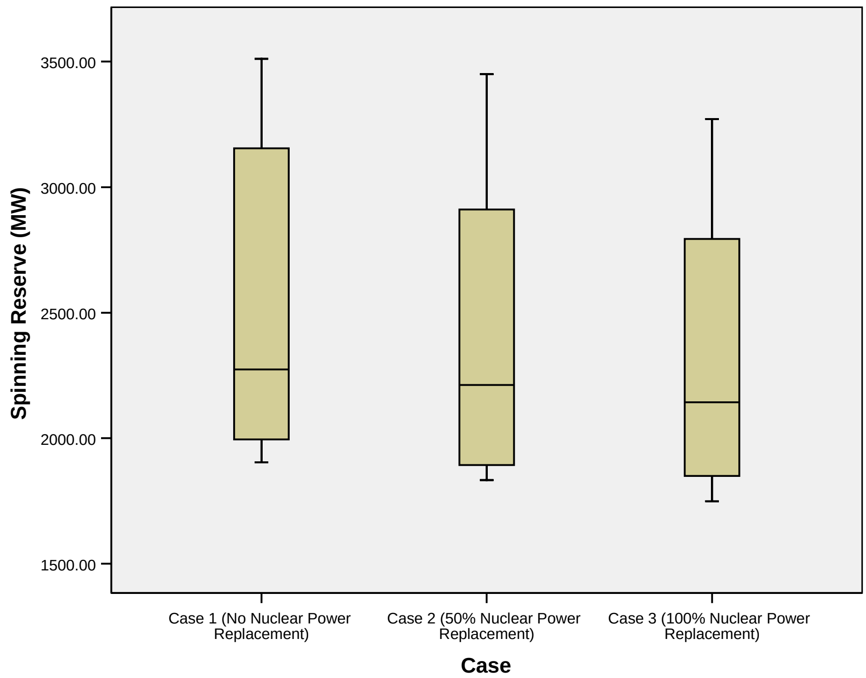

Fig. 7.35 Spinning Reserve Level for Different Cases representing Nuclear Power's Capacity.

7.6 Optimal Scenarios

7.6.1. Determination of Optimal Scenarios

In this chapter total 72 scenarios were proposed and the study objectives such as impact on production cost, or emission level were investigated. Now, the question may arise that based on the results and study objective which scenarios are the most promising scenarios. To answer this question accurately, it is essential to investigate many factors which influence the results presented in this section. For instance, it has been assumed that certain levels of windfarms will be installed for each scenario. The impact on power quality, power system stability etc. have not yet considered and will certainly act as a constraint to achieve such high level of intermittent generation. But in a strategic assessment model, taking into account some important factors are usually essential to have a model to satisfy the purpose.

In this study, several objectives may be used as important factors, and based on the behaviour of each scenario to these factors, the most optimum scenarios to be chosen. Some of these factors include:

1. Production Cost;
2. Emission Level (and cost of emission);
3. Cost of Imbalance;
4. Network Losses; and
5. Spinning Reserve Level.

Each of these factors if taken into account as the most important factor, will result in different solution for the optimal energy mix. i.e. if network losses is used as a dominant factor, the first three scenarios which show the lowest network losses are all in scenario 4-1. But if production cost of each unit of electricity is considered, then this solution will be different and scenario 2 will represent the first three lowest production cost. Using network losses as a factor will certainly be important if cost of reinforcing the network to reduce the network losses and increasing the efficiency is taken into account and is an important factor for decision makers. Using spinning reserve level and cost of imbalance for example, is certainly a reasonable factor for network operator as it reflects the balancing cost of system due to intermittent generation.

Since the objective of this research is to quantify the value of wind power, and the only parameters which have been considered in evaluating the value of wind power were energy trading potential, and emission reduction capability of windfarms, therefore using these two factors as dominant factors to determine the most optimal scenarios is reasonable.

Each factor has different weight in determination of the optimal scenarios. If production cost, or emission level is studied individually, they result in two different solutions for the most optimal scenarios. To take into account these two factors, the main problem which has to be tackled is that these two factors have two different units; production cost has £/MWh unit, and emission level is presented by $kgCO_2/MWh$. Emission level is presented as cost of emission therefore these two factors can be combined together and be used as a main factors to determine the most optimal scenarios.

As shown in fig. 7.36 these two factors are independent from each other, each has different weight when combined together. This is very important for cost of emission, as the costs calculated for the emission varies significantly by different costs of carbon.

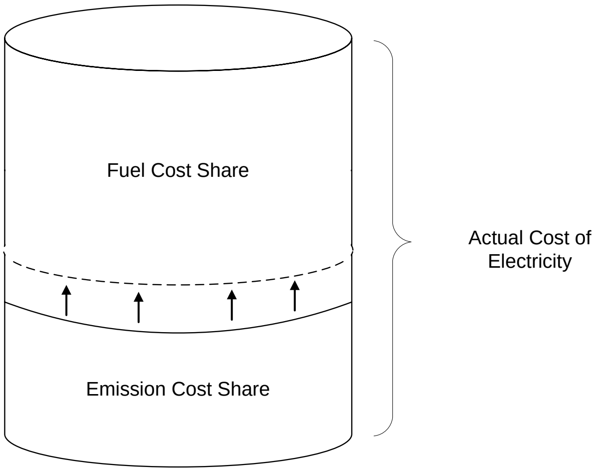

Fig. 7.36 Model for actual Cost of Electricity

Figure 7.37 shows the impact of combining the production cost and emission cost on total cost of electricity whilst carbon price is assumed £11/tonne of carbon. Since we calculate the total CO_2 output but must include cost of carbon, it is essential to convert the CO_2 to carbon[2].

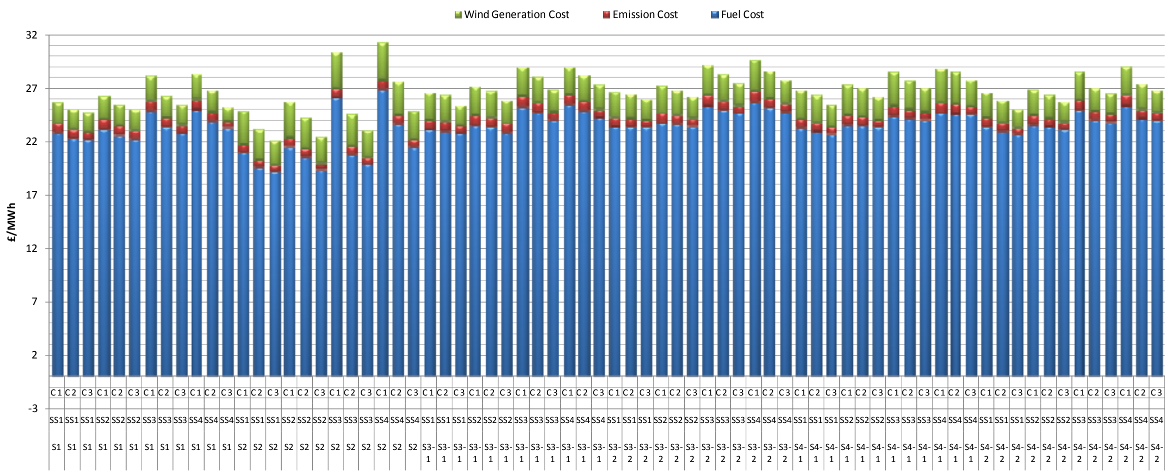

Fig. 7.37 Make up of Actual Cost of Electricity
[S: Scenario, SS: Sub Scenario, C: Case]

[2] One kg of CO_2 is equal to 0.243 kg of carbon.

As shown in this figure, electricity price will include the cost of carbon as well as generation cost, this will increase the total electricity price since additional cost is imposed to the system.

Table 7.12 shows the first 12 optimal scenarios based on their actual cost of electricity whilst the cost of carbon is assumed £11 per tonne. It is obvious from this table that wind power is mainly the dominant factor in determination of which scenarios are optimal scenarios. This is because according to this table, when wind power has high capacity (as shown in scenario 2) and whenever windfarms are installed at south, the actual electricity cost is the lowest.

Table 7.11. The first top12 Scenarios based on their Actual Cost of Electricity (Carbon Price £11/tonne)

Rank	Scenario	Sub Scenario[3]	Case	Actual Cost Electricity (£/MWh)
1	Scenario 2	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	22.08
2	Scenario 2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	22.40
3	Scenario 2	Sub_Scenario 3	Case 3 (100% Nuclear Power Replacement)	23.02
4	Scenario 2	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	23.14
5	Scenario 2	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	24.26
6	Scenario 2	Sub_Scenario 3	Case 2 (50% Nuclear Power Replacement)	24.51
7	Scenario 1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	24.67
8	Scenario 2	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	24.86
9	Scenario 2	Sub_Scenario 1	Case 1 (No Nuclear Power Replacement)	24.89
10	Scenario 4-2	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	24.98
11	Scenario 1	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	24.99
12	Scenario 1	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	24.99

As mentioned, the table 7.11 is based on the carbon price of £11 per tonne. It is important to consider the impact of changes in carbon price as the share of emission cost will increase in actual cost of electricity and it may change the ranking of these scenarios and one scenario which has not been included in the first 12 cheapest scenarios, may be included since at high carbon prices, the emission cost may become the dominant factor.

[3] Sub Scenarios are defined as follows:

	North		South	
	On-Shore	Off-shore	On-Shore	Off-shore
Sub Scenario 1	16%	24%	24%	36%
Sub Scenario 2	24%	16%	36%	24%
Sub Scenario 3	24%	36%	16%	24%
Sub Scenario 4	24%	36%	24%	16%

As shown in table 7.12, if price of carbon is increased up to about £25/tonne, the ranking of the most optimal scenarios will change. Although the first 8 scenarios will still be similar to the situation where carbon price was £11/tonne, but scenario 4-2 and 1 will show the lower electricity price and will be ranked 9 and 11 respectively. The scenarios which show "lower" electricity cost compared with others when cost of carbon is increased are highlighted by green colour. These scenarios will be ranked higher and those scenarios which show "higher" cost are highlighted by yellow colour and will be ranked lower.

Table 7.12. The first Top 12 Scenarios based on their Actual Cost of Electricity (Carbon price £25/tonne)

Rank	Scenario	Sub Scenario	Case	Actual Cost Electricity (£/MWh)
1	Scenario 2	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	22.83
2	Scenario 2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	23.17
3	Scenario 2	Sub_Scenario 3	Case 3 (100% Nuclear Power Replacement)	23.84
4	Scenario 2	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	24.07
5	Scenario 2	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	25.22
6	Scenario 2	Sub_Scenario 3	Case 2 (50% Nuclear Power Replacement)	25.47
7	Scenario 1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.64
8	Scenario 2	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	25.73
9	Scenario 4-2	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.78
10	Scenario 2	Sub_Scenario 1	Case 1 (No Nuclear Power Replacement)	25.91
11	Scenario 1	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	25.98
12	Scenario 1	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	26.02

7.6.2 Recommendation of Optimal Scenarios

The scenarios proposed in this chapter aim to reflect the impact of various economy situations and policies on generation mix. In this section a set of generation mix which show the lowest electricity cost in each scenario are recommended.

Based on the results in this section, table 7.13 shows the cheapest case with emphasis on the optimal penetration of nuclear power for each scenario. In other word, the cheapest scenario happens when windfarms are installed at south and with a higher load factor and wind power may become the dominant factor. However, whilst the cheapest case is shown, but the fact that this case may not be achievable, due to various regulatory and technical constraints such as high cost of network reinforcement is also taken into account. Thus, the second and third recommendations are also shown based on different locations for the windfarms.

As shown in table 7.13, for each scenario three recommendations of generation mixes are presented, based on the actual cost of electricity observed. In scenario 1, it is shown that wind power is the dominant factor as even if less nuclear power is replaced but windfarms can be places at south, the actual cost of electricity will be cheaper compared with a situation in which 100% of nuclear power plant replacement is occurred but the windfarms have a lower load factor. In scenario 2, it can be said the impact of nuclear power replacement and wind power on the actual cost of electricity have both same weight. If all nuclear power plants are replaced, the 2nd and 3rd ranks in this scenario can occur even if wind power has a lower factor than a sub-scenario in which wind power has high load factor and installed at south.

Table 7.13 Recommendation of the Best cases for each Scenario for Carbon Price £11/tonne

Scenario	Rank	Sub Scenario	Case	Actual Cost of Electricity (£/MWh)	Emission Cost Share
Scenario 1	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	24.67	3.07%
	2	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	24.9920	3.22%
	3	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	24.9934	3.29%
Scenario 2	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	22.08	2.67%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	22.40	2.71%
	3	Sub_Scenario 3	Case 3 (100% Nuclear Power Replacement)	23.02	2.78%
Scenario 3-1	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.36	2.74%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	25.85	3.67%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	26.30	3.36%
Scenario 3-2	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.96	2.72%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	26.14	3.50%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	26.41	3.11%
Scenario 4-1	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.41	2.59%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	26.19	3.34%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	26.30	3.07%
Scenario 4-2	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	24.98	2.51%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	25.66	3.43%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	25.80	3.01%

The recommendations shown in table 7.13 are based on the carbon price of £11/tonne. It is also interesting to investigate the impact of changes in carbon price on the optimal cases for each scenario. Thus, table 7.14 repeats the same recommendations but based on the new carbon price of £25/tonne. As shown in table 7.14, it is clear that the cheapest case is when all nuclear power plants are replaced by new capacities, and windfarms are located at south. This is certainly what was expected. But the cases shown in scenario 1 and 2 are slightly different that other scenarios. In scenario 1, the second ranked case occur when windfarms are installed at north (mainly on-shore) and nuclear power replacement is at 100% replacement. The production cost calculated for this scenario is very close to sub scenario 2 of this case, CCGT plants which are mainly installed at south and have higher efficiency levels. In scenario 2, unlike other scenarios, 2nd and 3rd ranked cases occur based on the suitability of the windfarms' location. In this scenario, it becomes clear that due to very high penetration of wind power in the system, wind is the dominant factor in determination of the optimal scenarios.

Table 7.14 Recommendation of the Best cases for each Scenario for Carbon Price £25/tonne

Scenario	Rank	Sub Scenario	Case	Actual Cost of Electricity (£/MWh)	Emission Cost Share
Scenario 1	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.64	6.71%
	2	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	25.97	7.79%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	26.01	7.03%
Scenario 2	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	22.83	5.86%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	23.17	7.23%
	3	Sub_Scenario 3	Case 3 (100% Nuclear Power Replacement)	23.84	6.75%
Scenario 3-1	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	26.24	6.02%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	26.87	7.97%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	27.43	7.32%
Scenario 3-2	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	26.86	5.98%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	27.06	7.62%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	27.46	6.79%
Scenario 4-1	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	26.25	5.70%
	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	27.06	7.27%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	27.33	6.71%
Scenario 4-2	1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.78	5.53%

	2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	26.54	7.47%
	3	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	26.79	6.60%

7.7 Chapter Summary

This chapter established the assessment framework that can be used to evaluate the merit against each potential future scenario. The relative merit of each scenario is assessed through comparing the production cost, emissions, system reserve requirement, total network losses, and contribution of such generation technology on the security of supply.

The main findings of this chapter include:

- The results in this chapter show that increasing the wind power penetration in the GB power system will increase the need for spinning reserve. The level of increase depends on type of generators, generation mix pattern as well as demand level. The level is not solely related to installed capacity of wind power. For the same installed capacity of wind power in different generation mix patterns, spinning reserve requirement is different.

- In the GB power system, since load centres are located at South (England) and on-shore wind resources are mainly at North (Scotland) the bottleneck in the interconnector between England and Scotland will significantly impact on the value of wind power. This is because of the need for extra power in the south at times when the bottleneck happens. Providing such power will reduce the efficiency of power generation both for generators located in Scotland since they may be forced to operate at lower output levels, and for generators in England since they may be required to start-up and operate with less efficient patterns.

- Off-shore windfarms can become a major source of electricity generation in the GB power system more than ever if they are connected to grid in England. This will reduce the interconnector's bottleneck, and give wind power the opportunity to displace higher capacities of conventional plants. It was shown in this chapter that how the location of windfarms has impact on out study objectives such as production cost and emission level. It was also shown that whilst the location of windfarms is a major factor in changing the network losses, it will result in changing the energy share of other power generation technologies.

- In the absence of nuclear power, coal fired and CCGT power plants will become the main base-load plants. The emission level of such plants is high compared with nuclear power, such displacement may result in not meeting the emission reduction target set by the government unless more aggressive targets are set for the industries as a whole.

- Nuclear power combined with wind power can provide a high level of resilience for the electricity generation industry. The impact of such combination on production cost, and emission level is also very promising. The magnitude of benefits from differing contribution from nuclear power will be established for varying wind penetration and location as future work.

- With regard to the optimal scenarios, it can be concluded that in presence of uncertainty about the future of generation mix, different scenarios may be the optimal scenarios depending on the weight of influencing factors. It was shown in this chapter that if production cost and emission cost are considered as the main influencing factors, the share of each factor differs depending on the cost of carbon. Changes in the cost of carbon will be responded differently by different scenarios, depending on how sensitive they are to changes in the cost of carbon. In order word, if lower the emission level is observed in a scenario, although it may result in a high electricity cost due to high fuel costs, but by increasing the carbon price, this scenario may show a relatively lower electricity price. Therefore, determination of which scenarios are the optimal scenarios is something which has to be done whilst changing the carbon prices are also taken into account.

7.8 References

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Chapter 8. Feasibility of Demand Response in the GB Power System

This chapter presents the role of demand response in a large power system with significant wind power penetration. In order to do so, the value of wind power in the GB power system is estimated under different scenarios which were discussed in the previous chapter. Once the value of wind power is known, the role of demand response in changing this value by compensating for wind power deficits can be quantified. Different demand response levels are investigated, whilst taking into account different prices which have to be paid for demand response. It is also shown that how different emission prices have Impact on feasibility of demand response.

8.1 Value of Wind Power in the GB Power System

In Chapter 7, different hypotheses were considered in which wind power has different capacities. The value of wind power in a large system can be estimated in terms of operational savings (in fuel costs and emission costs) in two ways:

1. By calculating the value of individual windfarms.
2. By calculating the value of wind power as aggregated values of all windfarms connected to various locations in the grid.

In order to calculate the value of individual windfarms, it is essential to consider the energy trading opportunity of each windfarm by taking into account the wind profile of each windfarm. If the lifetime value of a windfarm is to be calculated then the cost of building individual windfarms is required. This method on a small system was investigated in chapter 3.

In a large system, the dispatch process is done centrally (considering a monopoly power system); therefore, the value of wind from the dispatcher’s point of view is the total cost savings in the dispatch process as a result of the existence of all windfarms in the system and the value of wind can be calculated as aggregated values of all windfarms.

In order to do so, two sets of variables; emission level and production costs are required for each scenario. For the base case in each scenario it is required to calculate to total production costs and emission when no wind power exists. Then by comparing the wind case, and calculating the different in these costs, the value of wind power can be calculated.

As there are many variables for all different scenario, sub-scenario and cases, and since the objective of this chapter is to show the impact of demand response, only the results for the base case (case no. 1) and sub-scenario 3 for all scenarios are presented. Table 8.1 shows the value of wind for the base case (case no. 1) and sub-scenario 3 for different scenarios where no demand response is present.

Table 8.1.Value of Wind Power for all Scenarios (£/MW/Year)

Scenario	Sub-Scenario	Case no.	Wind Capacity (MW)	Value of Wind (£/MW/Year)
Scenario 1	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	22000	96821
Scenario 2	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	34000	84708
Scenario 3-1	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	22000	96153
Scenario 3-2	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	20000	95568
Scenario 4-1	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	23000	79757
Scenario 4-2	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	25000	83458

Since production cost and total emission level for each scenario is different, therefore the value of wind power calculated for each scenario is different. The highest value of wind is observable in scenario 3-1. This is because of the high level of emission level which is produced by thermal plant; and in particular coal plant. In this scenario in the base case (with no wind power) over a year of generation scheduling around 478kg CO_2 / MWh is being produced by conventional plants. By adding wind power in the system, this level will be minimized down to 382 Kg CO_2 / MWh, resulting in higher value for wind power. The impact on production cost (mainly fuel cost) of electricity by conventional plants is also significant. In this scenario the production cost for no wind case is around £10.7bn. Although by introducing the wind power, cost of imbalance will be added to the system which is around £48.6m, but the fuel saving resulted by wind power will reduce the production cost down to £10bn resulting in around £700m saving.

This will be followed by scenario 3-2 in which again, conventional plant has high penetration, however due to lower demand level contribution of wind power to reduce the operation of the conventional plants is limited. In scenario 1 since CCGT plant has a very high penetration level, they will be the dominant thermal power generator in the system. Having less emission level compare with coal plant, will give them priority dispatch. Therefore by having the wind power in the system, although the clean wind energy will displace some conventional plant and reduces the emission level, but since this value is not as high as previous scenarios, the value of wind will be lower by nearly

£585/MW/Year. Although this value may seem to be very small, but in lifetime assessment of value of wind power, small changes in the value of wind power may expedite the payback period by few years as shown in chapter 3.

The lowest value of wind power is observable in scenario 4-1 in which it was assumed that due to economy down-turn, demand will have negative growth rate and peak demand will be as low as 54GW. In this scenario, since the low demand can be met by conventional plant with relatively low emission level, wind power may not displace high capacities of conventional plant. By adding the wind power into the system, the issue of intermittency still requires operation of some conventional plant for back-up purposes and maintaining spinning reserve which results in higher marginal emission output and fuel cost levels. Therefore, the value of wind will be lower due to limited savings which can be made on emission and fuel cost by adding wind power.

8.2 Demand Response to Increase the Value of Wind Power

In a large system where windfarms are located at different locations, designing a demand response to wind power system has to take into account the constraints which may be imposed by network. In other word, dispatching the demand response depends on the available demand response capacity at each location, as well as the network and generation constraints. These calculations will become extremely difficult when response to not only one windfarm, but also to the aggregated effect of the all windfarms in the system is to be studied. Therefore in order to reduce the complexity, the following assumption is made that the total demand response's availability in the system which is calculated can respond to the aggregated output the windfarms in the system. Such system monitors the outputs of all windfarms. So the network operator can also reduce the "total" demand on the system.

The diagram in figure 8.1 shows the algorithm designed for utilization of demand response in a large system in this thesis. The required information from demand side includes total demand level from all different demand sectors, and the demand response potential. In supply side, total fuel costs of generators, as well as their emission output need to be quantified. The information required from windfarms include their total output, and forecasting error to compensate for the additional spinning reserve requirement, and level of compensation level required from demand response. It is also essential to derive the emission price since the savings made from increasing the output of windfarms has the carbon emission element.

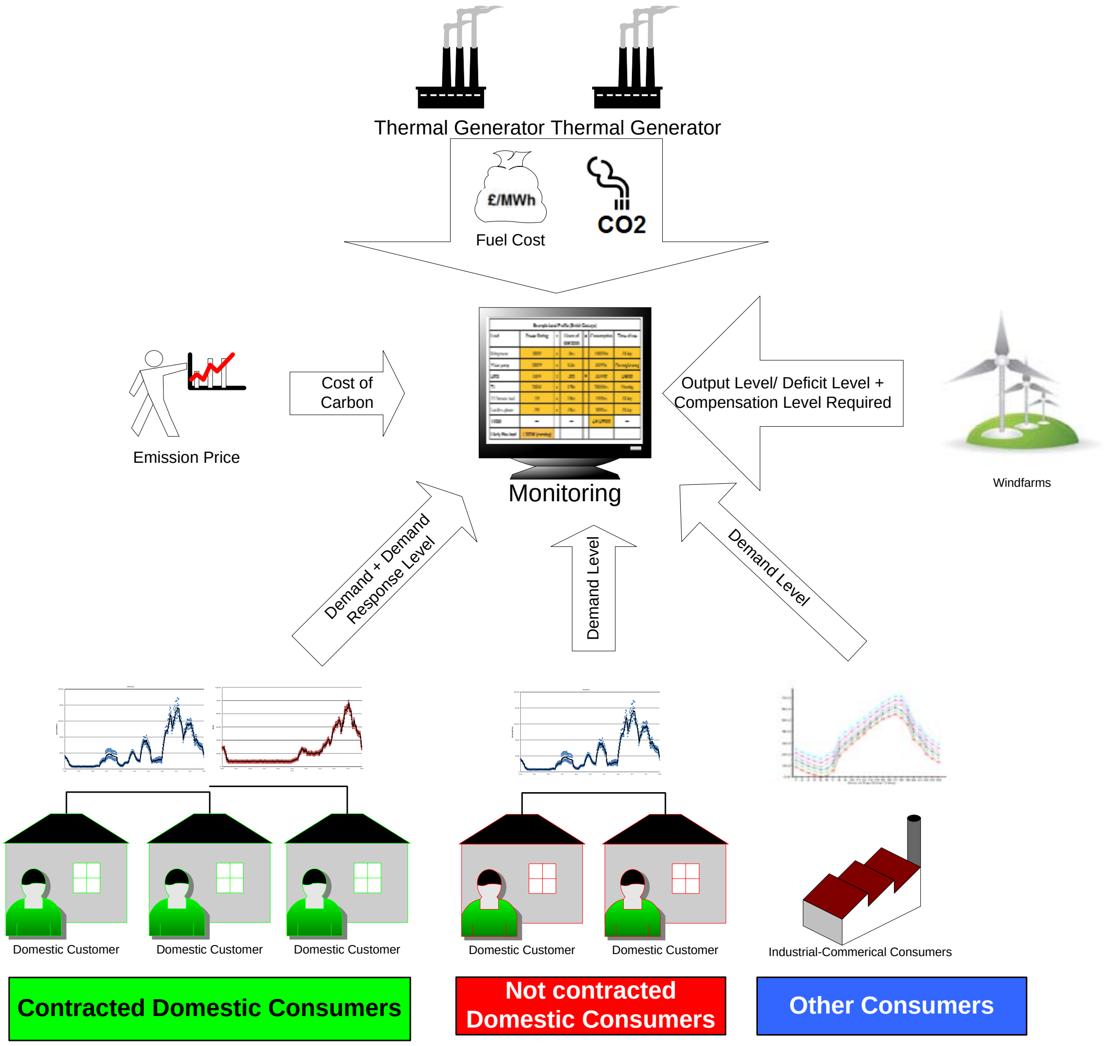

Fig. 8.1 Architecture of demand response to wind power in a large system

8.2.1. Impact on Value of Wind Power

The savings produced by demand response to wind power can be included into the value of wind power, and be accommodated within the initial calculated value of wind power in section 8.1.

The demand response for different scenarios has a different impact on the value of wind power. As mentioned before, scenario 1 and scenario 4-1 will benefit more than any other scenario from demand response to wind power. In scenario 1, due to high capacity of coal fired and CCGT plants, and the high penalty costs incurred due to high emission output of these types of plant, when demand response is integrated with wind power, a considerable amount of emission will be saved. This will result in very high changes in the value of wind power as shown in fig. 8.2.

In Scenario 4-1, since wind power has a very high penetration level, and reducing the intermittency of such high capacity of wind power with demand response increases the value of wind power.

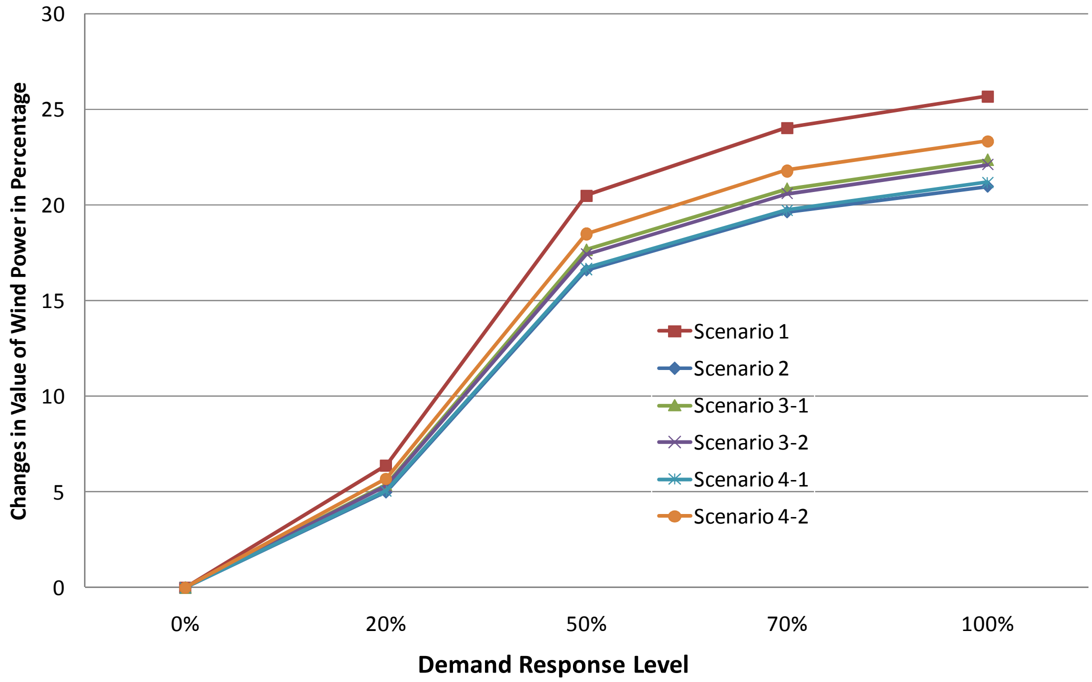

Fig. 8.2 Changes in value of wind power with different demand response levels

Figure 8.3 and table 8.2 shows the value of wind power for all the different scenarios when the carbon price was assumed to be £25 per tonne of carbon. The value of wind power increases by increasing the demand response level in the system since wind power is less intermittent and less fluctuating. This increase at low demand response levels is relatively high compared with the high level cases. This is because of the degree of limited savings which could be achieved making the wind power less fluctuating.

Table 8.2.Value of Wind Power (£/MW/Year)
with different Demand Response Levels

Demand Response Level	Scenario 1	Scenario 2	Scenario 3-1	Scenario 3-2	Scenario 4-1	Scenario 4-2
0%	96821.33	84708.5	96153.37	95568.41	79757.78	83458.34
20%	103126	89147.63	101614	100914.4	83988.87	88472
50%	120646.4	101558.2	116767	115745.6	95729.44	102405.4
70%	126090.3	105393.8	121481.3	120360.8	99382.25	106734.6
100%	128778	107181.4	123839.8	122675.1	101210.5	108870.8

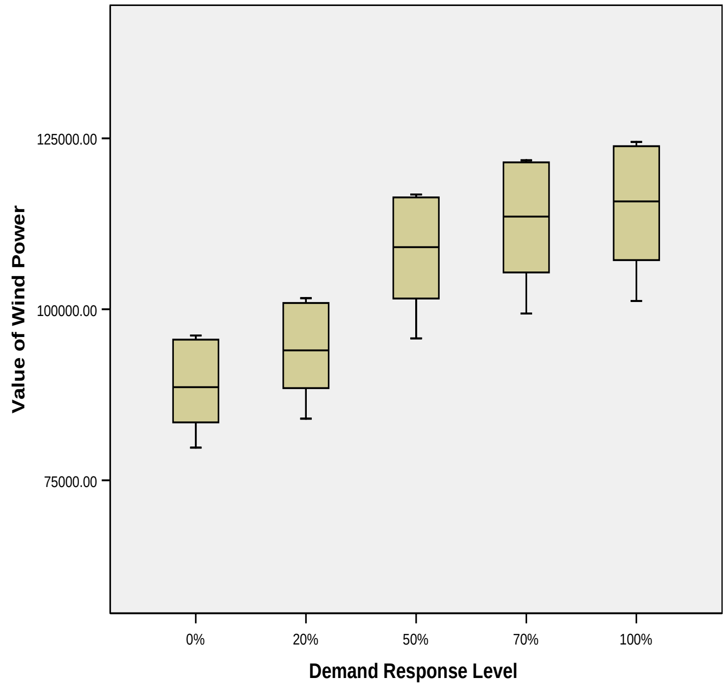

Fig. 8.3 Value of wind power with different demand response levels

The most important aspect of incorporating the demand response in a real large system, is to quantify the available level of demand response. This was done in the previous chapter, and it was shown that what proportion of demand can become responsive. This may limit the contribution level of demand response, i.e. it may be impossible to compensate for 100% wind power output deficiency in a large system. At the same time, in practice, 100% contribution from demand response will never be required, since not all the windfarms' power output will be 0% of their rated power output.

In Chapter 6 it was shown that maximum available demand response from England and Wales at the time of system peak is about 22GW, and at the time of when the lowest demand level is observed is around 10GW. The problem with demand response to wind power is that it does not coincide with time of system peak; demand response will be required whenever wind power output has deficit. Therefore if demand response which is to be contracted for wind power comes from ***domestic sector***, the levels higher than 10GW ***can never be guaranteed***, and levels over 22GW ***can not be provided***.

In table 8.3 it is shown that the maximum capacity of demand response required to provide certain levels of responsiveness. It is obvious that 20% demand response level can be guaranteed for all different scenarios, and in scenario 2, 70% and 100% responsiveness may never be provided since the total capacity of demand response required is higher that the total capacity of demand response which could be provided.

Table 8.3. Maximum Demand Response Level Required for Each Scenario in MW

Demand Response Level	Scenario 1	Scenario 2	Scenario 3-1	Scenario 3-2	Scenario 4-1	Scenario 4-2
0%	0.00	0.00	0.00	0.00	0.00	0.00
20%	4391.35	6786.78	4390.88	3991.75	4591.75	4991.00
50%	10978.37	16966.94	10977.21	9979.37	11479.37	12477.50
70%	15369.71	23753.72	15368.09	13971.12	16071.12	17468.51
100%	19761.06	30540.49	19758.97	17962.87	20662.87	22459.51

8.2.2. Discussion on Savings on Production Cost and Emissions due to Demand Response

In chapter 5, it was shown how demand response can increase the value of wind power. By combining the wind power with demand response, the savings which are produced due to the existence of intermittent generation will be maximized through reducing the negative impact of intermittency of wind power which incurs additional operational cost. Demand response's impact in a large system is to reduce total production cost, and emission level while it responds to wind power fluctuations. Table 8.4 shows the savings in production cost and emission level in different scenario at different demand response levels in £ per MWh of demand response.

Table 8.4 Cost saving with different demand response levels

	Demand Response Level	0%	20%	50%	70%	100%
Scenario 1	Saving on Production Cost	0	10819	18153	16593	13058
	Saving on Emission Cost	0	1128	1269	1248	1492
Scenario 2	Saving on Production Cost	0	9581	16374	15128	12076
	Saving on Emission Cost	0	849	973	967	1172
Scenario 3-1	Saving on Production Cost	0	7680	12675	11472	8907
	Saving on Emission Cost	0	830	919	894	1054
Scenario 3-2	Saving on Production Cost	0	5518	9121	8261	6422
	Saving on Emission Cost	0	600	665	648	765
Scenario 4-1	Saving on Production Cost	0	6769	11699	10878	8756
	Saving on Emission Cost	0	732	849	849	1038
Scenario 4-2	Saving on Production Cost	0	8279	14293	13282	10683
	Saving on Emission Cost	0	862	998	997	1219

It is observable from table 8.4 that at different responsiveness levels, the savings which are produced due to demand response is different. An interesting characteristic of these graphs is the difference in the peak value occurrence. In other word the maximum contribution of demand response in each scenario will occur at different responsiveness level. At low responsiveness levels, the wind profile used in this study is still highly variable and fluctuating; and therefore issues such as poor efficiency of generators still exists. It is also shown that the degree of benefits will be reduced at very high levels close to 100% demand response level. This is because the benefit of demand response in increasing the efficiency of power generation is limited to make the wind power output less intermittent. At very high demand response levels, although wind power is fluctuating less, other characteristics and constraints of the power system still exist. In this study, demand response is only responding to wind power fluctuations. The disconnected demand response level for each block will have to be recovered (re-connected) in the next block. This is due to limitation on total number of hours that each group of load could be disconnected. Therefore, demand variations which may require start-up of a conventional plant, network thermal limits which may result in change in dispatch pattern will not be diminished while demand response only responds to wind power variations.

This has been investigated in fig. 8.4 to 8.7 where it is shown the impact of different demand response levels on marginal price of different generation technologies associated with the number of hours they generate the electricity within certain price ranges. These graphs, known as radar graphs are suitable to show the variations of a single variable. What shown on this graph is an in fact total hour of operation of a power plant whilst its marginal price of electricity is between two different prices; i.e. between £0-£1/MWh, or £2-£3/MWh. For any given power plant, it is desirable to reduce the total high price hours, and increase the total low price hours. By injecting the wind power into the system, it is also important that overall hours of operation also drop.

It is shown in fig. 8.4 that when no demand response exists in the system, marginal price of electricity generated by coal plants is as high as £17-£18/MWh for a very short period. Generally coal power stations are being operated at their higher output levels, since at that point the efficiency of power generation is maximized. Plants with such characteristics are not always being operated at their maximum output due to several constraints mentioned above. By increasing the demand response level in the system, coal fired plants will be generating electricity with less cost for higher number of hours compared with the base case where no demand response existed. At high levels of demand response, coal fired stations will operate much more efficiently, as no such high price spike is observable and plants will generate electricity at lower price for a higher number of hours.

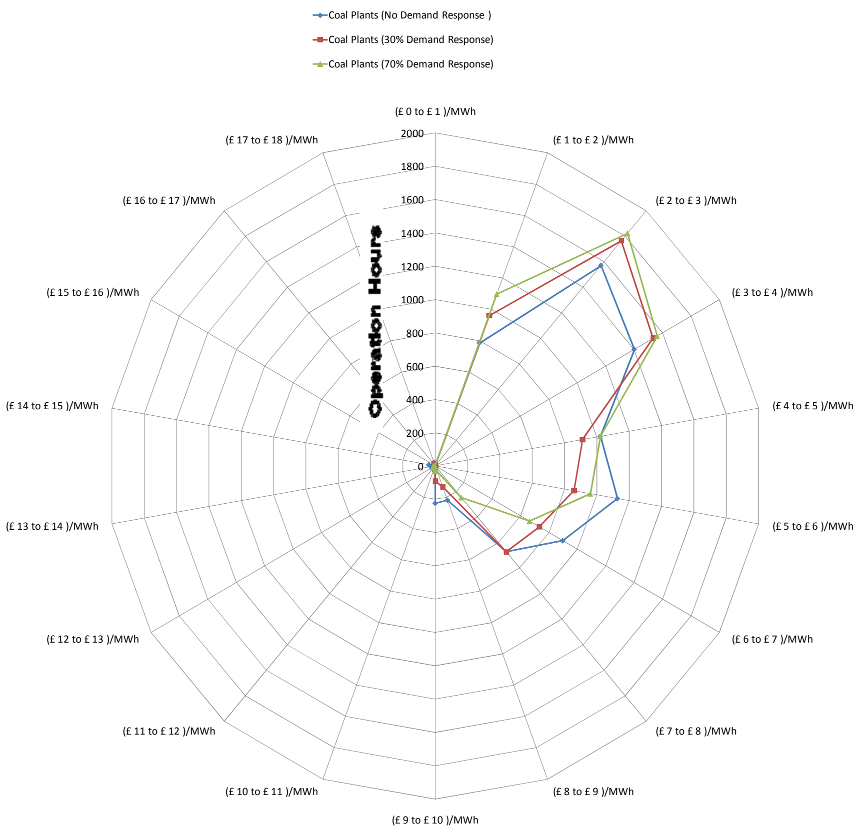

Fig. 8.4 Marginal price of electricity generated by coal plants.

The impact of different demand response levels on CCGT plants is investigated in fig. 8.5. Similar to coal fired plants, the impact of different demand response levels on CCGT plants is reducing the number of hours that marginal price of electricity generation is high, and increasing the number of hours that electricity can be generated with lower marginal price.

When no demand response exists in the system, the highest price observed by CCGT plants is between £31-£32/MWh. The highest price observed for the case when 30% demand response exists in the system is £28-£29/MWh. This clearly shows the contribution of demand response on increasing the efficiency of power generation by conventional plants when wind power exists in the system.

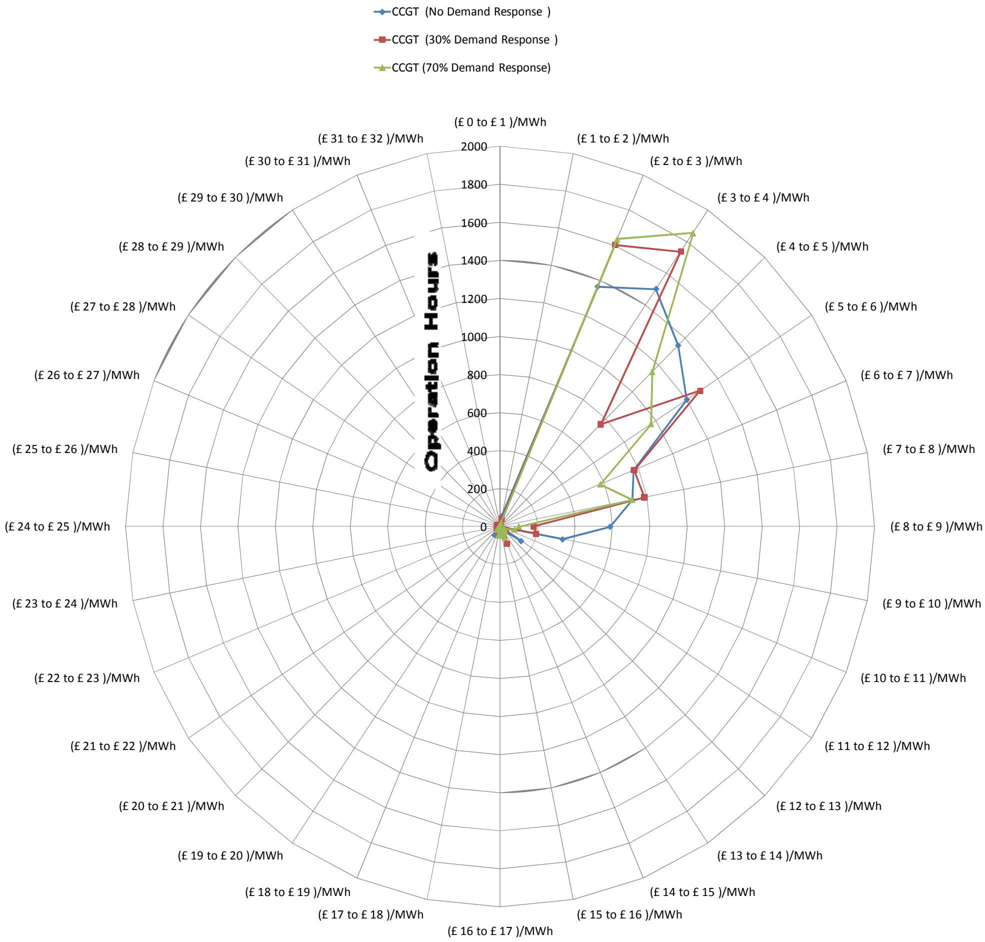

Fig. 8.5 Marginal price of electricity generated by CCGT plants.

The impact of different demand response levels on OCGT plants is investigated in fig. 8.6. Apart from reducing the price spikes by demand response, demand response will result in a considerably reduced number of operation hours of OCGT plants in general. OCGT plants had a high ramp-up and ramp-down rate, and short start-up time, and are utilized as peaker plants .With increasing the intermittent generation, and to cater for the power fluctuations of intermittent plants, these plants may have to be operated more often. This will result in higher cost since OCGT plants have much higher marginal electricity generation price compared with other thermal plants.

The highest price of electricity generated by OCGT plants when no demand response exists in the system is £56-£57/MWh. When 30% demand response level exists in the system the highest observed price will be reduced down to £41-£42/MWh which shows the contribution of demand response in increasing the efficiency of power generation by OCGT plants.

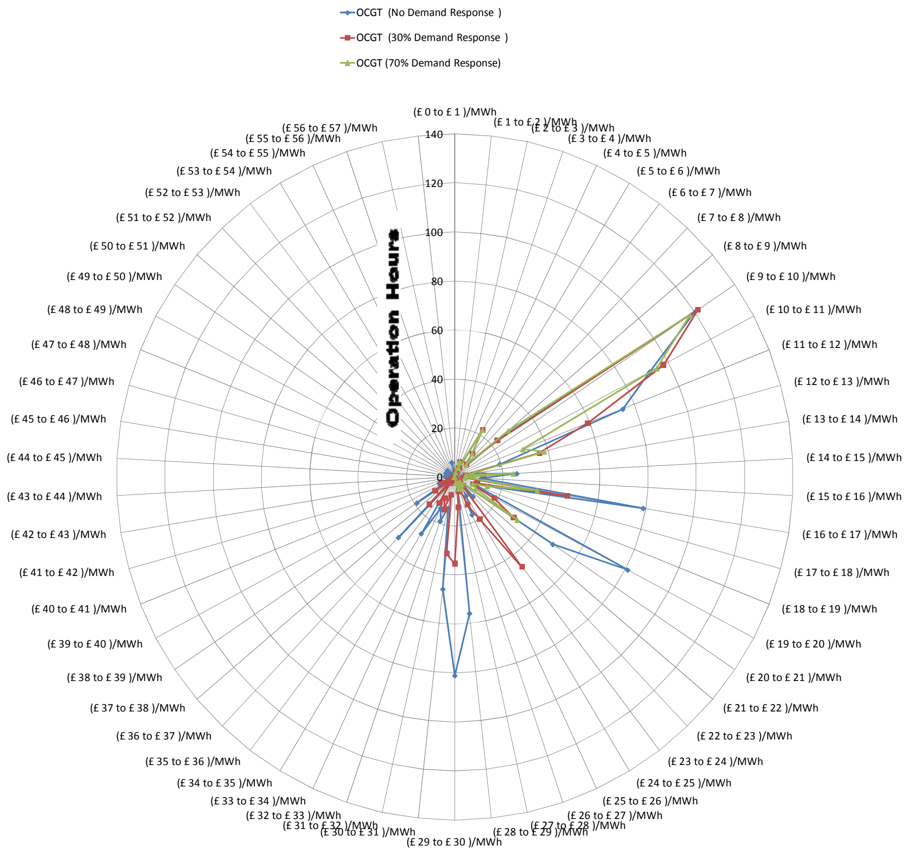

Fig. 8.6 Marginal price of electricity generated by OCGT plants.

Demand response particularly reduces the operation hours of OCGT plants, as well as reducing the price spikes due to higher efficiency of power generation. This will be investigated in the next part. OCGT power plants have relatively low capital costs and relatively flexible operations, but these plants are exposed to uncertainty in gas prices which form the largest part of risk with regard to revenue. As shown in fig. 8.6, demand response can minimize the price volatility as well as reducing the marginal cost of OCGT plants. This will reduces the risks associated with such plants for investors.

The impact of demand response on nuclear power is not much on marginal price of electricity generated by them as shown in fig. 8.7. This is because nuclear power stations generally have a very low ramp-rate and very high start-up and shut-down times, and are mainly being operated as base-load plant with quite a constant power output level. However, our results show that since the base load generation will increase with demand response to wind power, such a system will provide the opportunity for nuclear power plants to operate higher number of hours due to the low carbon electrical energy they can generate.

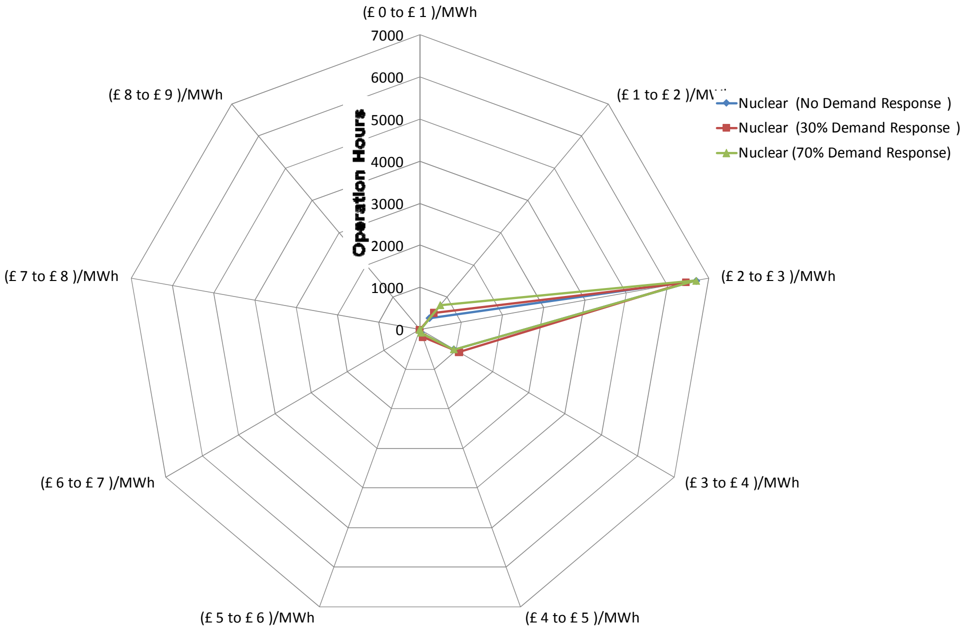

Fig. 8.7 Marginal price of electricity generated by nuclear plants.

It is also interesting to investigate the impact of the demand response on total operation hours of different power plants. As shown in fig. 8.8, demand response changes the total hours of operation of different power plants. The impact on peaker plants such as OCGT is significant reduced up hours. This is because the variation of wind power output is minimized; therefore the need to utilize OCGT plants will be reduced.

Base load plants which also have a low emission output such as nuclear power plants will see an increased operation hours. Therefore it can be said that demand response combined with wind power increases the base-load power generation. This is because less intermittent power in the system in fact reduces the variability of the total demand is seen by a base-load plant and allows supply of load with these types of power plants.

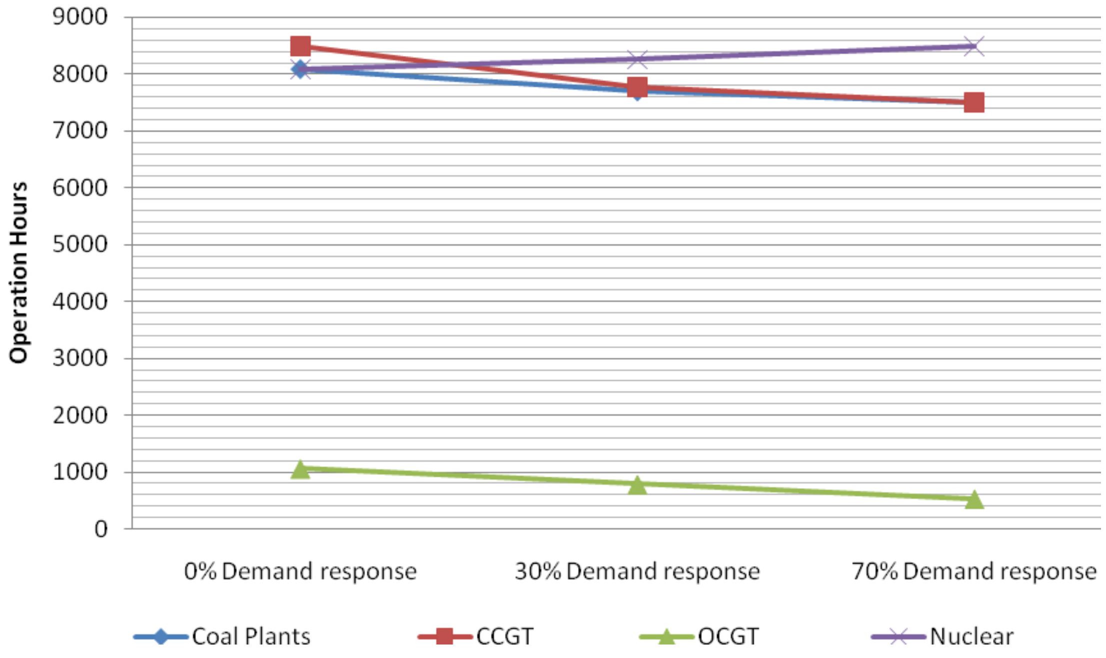

Fig. 8.8 Total hours of operation of different plants (average)

Overall, demand response increases the efficiency of power generation by thermal plants. This in turn will result in reducing the marginal electricity price generated by thermal plants. Figure 8.9 shows the average price of electricity generated by different thermal plants in a year of generation scheduling.

The average price of electricity generated by different plants depends on both total operation hours, and their marginal price of generation at each generation scheduling block. As shown in fig. 8.9 the demand response reduces the average price of electricity generated by some plants. The impact of the demand response is higher on OCGT plants as shown. The reason for that is that because very high penetration of wind power is proposed in the studied scenarios which result in badly operation of OCGT plants. Whilst demand response minimizes the need for responding the OCGT plants to wind power variations, it results in cheaper production cost of electricity generation by OCGT plants since the efficiency of power generation is increased.

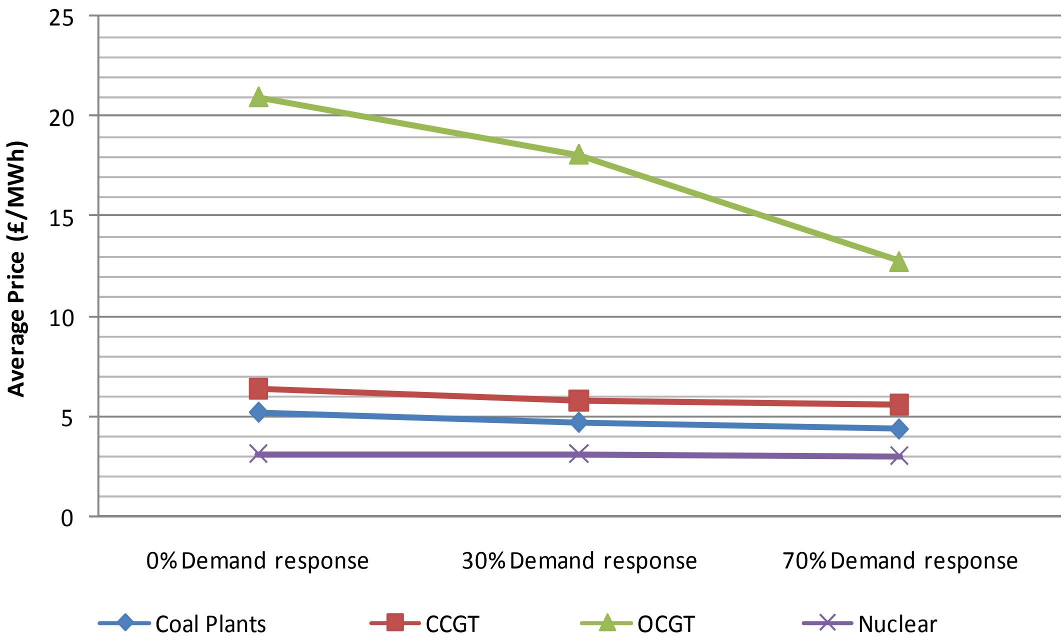

Fig. 8.9 Average price of electricity generated by different plants.

The added value to each plant can be quantified in terms of reduced or increased operational hours, and magnitude of change in its marginal production cost. It was shown that why the operational hours of an OCGT plant will be reduced, as well as its marginal cost. The OCGT plants are mainly act as peaker plants for sudden changes in demand level, or in an intermittent system with wind power for wind power deficit compensation. If it is argued, that demand response is beneficial to the system by mainly reducing the cost of OCGT plants, it might be an obvious argument.

Therefore, it is important to investigate the overall impact of demand response on something which may seem no connection with demand response; such as a base load plant like nuclear power. Many argue that demand response; and mare importantly dynamic demand response which is investigated in this work, does only shift the load. Therefore, smoother load seen by generators, reduces the need for operating the peaker plants. This work extended this topic by investigating the demand response's impact on base-load plants.

Figure 8.10 shows the operational cost of nuclear for each case by different demand response levels. As illustrated in this figure, ***total energy supplied by nuclear power stations will increase by 2%*** when demand response can compensate for wind power deficits only at 30% level. ***The energy share of nuclear power is increased by 5%,*** when demand response level is around 70%. Although these values may seem very small, but this can certainly increase the revenue of a nuclear power station considerably providing no other constraint limits this level of power transfer.

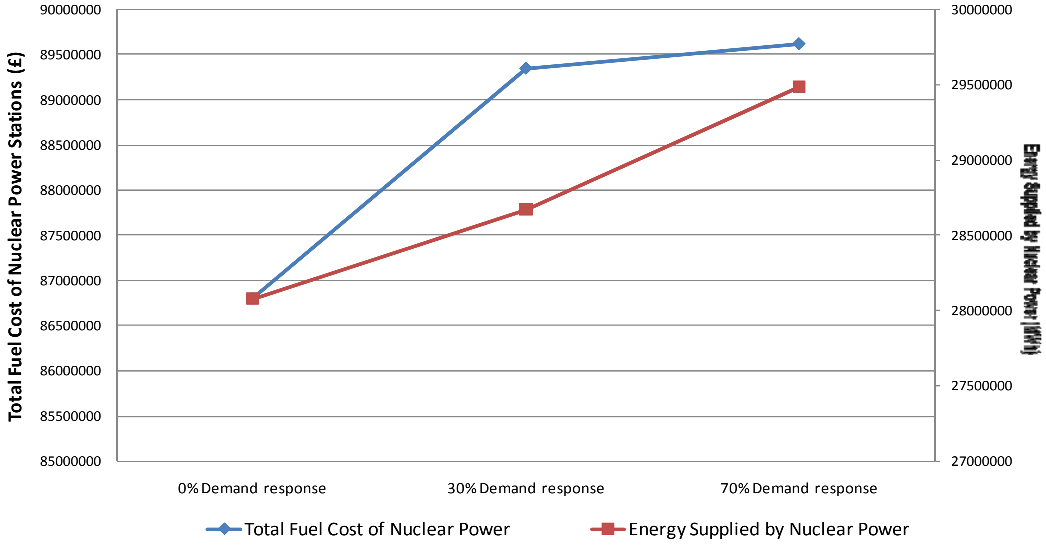

Fig. 8.10 Fuel cost of nuclear power stations versus energy supplied by nuclear power.

Another important role of demand response apart from compensate for wind power deficits, is to contribute to overall system reliability. This was discussed in chapter 5 that how demand response can provide the additional spinning reserve requirement due to increasing the intermittent generation. This will remove the “additional” burden from generator to supply the increasing level of spinning reserve. As mentioned before, reducing the spinning reserve level, will result in better operation of thermal plants. If the cost associated with such improved to be investigated individually, it is essential to calculate the total operation cost, with and without demand response to show the degree of benefits with demand response as shown in fig. 8.11.

As illustrated in this figure, by supplying the additional spinning reserve requirement through demand response, the cost of spinning reserve will be reduced by nearly 4.5%. This reduced cost reflects the improved efficiency of thermal plants which previously were supposed to provide additional spinning reserve to cover the risk brought to the system by intermittent generation, as well as the risk of power plants’ outage. It must be noted that no demand response is actually utilized to come up with this cost reduction. The only assumption which is made is that the additional spinning reserve requirement due to wind power can be maintained by demand response.

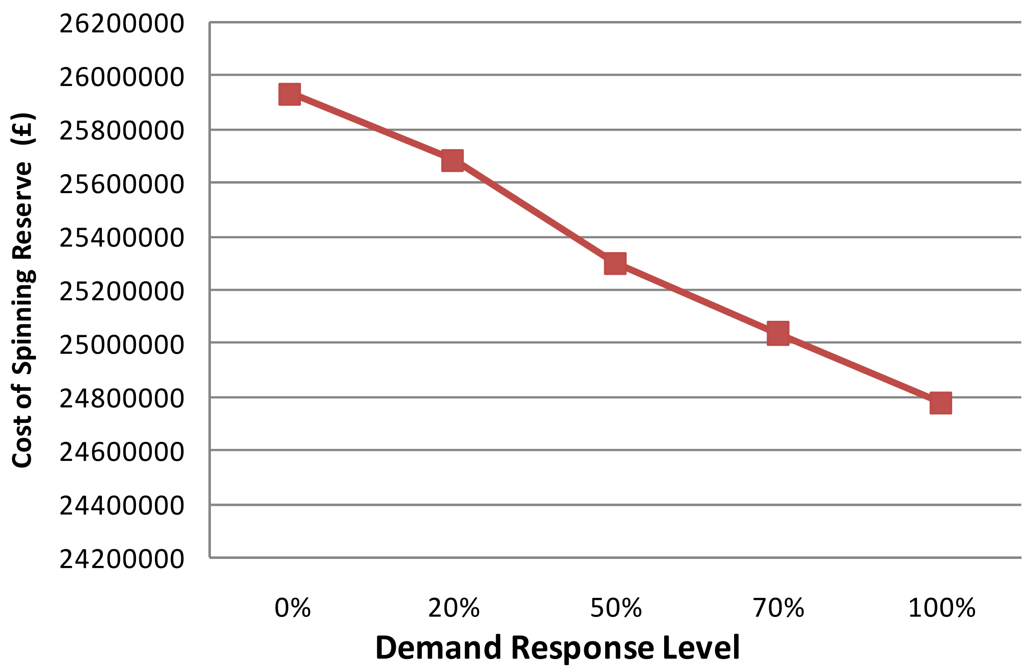

Fig. 8.11 Cost of spinning reserve for different demand response levels.

Different types of risks are associated with different power plants. The risks with regard to fuel price volatility for gas power plants were mentioned before. But other large plants such as coal fired and nuclear power plants are very capital intensive, but the fuel costs are relatively low. Coal and uranium have low price volatility. These power stations are therefore more exposed to the financial risks of whether they can repay the capital based on the volume/price of electricity off-take from these plants. Table 8.5 shows the risks facing the investment in energy sector [1]. The contribution of demand response in minimizing these risks is also mentioned with regard to the impact on power generation based on our study.

Table 8.5 Risks associated with Investment in Power Generation Industry

		Nature of Risk	Contribution of Demand Response
Economic Risk	Market risks	• Inadequate price and/or demand to cover investment and production costs • Increase in input cost	Power plants such as nuclear will see higher load factor. Marginal price of electricity will be reduced as efficiency of power generation increases.
	Construction risk	• Cost overruns • Project completion delays	The need for building additional capacity will be minimized if demand response is seen not only as an energy resource, but also as a capacity resource.
	Operation risk	• Insufficient reserves • Unsatisfactory plant performance • Lack of capacity of operating entities • Cost of environmental degradation	Demand response can provide spinning reserve. Efficiency of power generation increases, and as a results: Marginal emission output and total emission output of plants will also be reduced.
Political Risk	Regulatory risk	• Changes in price controls and environmental obligations	Risk will be minimized by increasing the efficiency of power generation, and as a result marginal emission output and fuel cost will also be minimized.

8.3 Sensitivity to Different Emission Prices

The value of wind power calculated in this work is based on the savings made on fuel cost of conventional generators and reduced emission levels. Emissions levels are translated into cost by taking into account the cost of carbon. Therefore changes in any of the elements of demand response such as fuel price, or emission cost will change the value of wind power.

Emission prices change from time to time to react to the need for cleaner energy generation. The value of a low carbon power generation technology such as nuclear or wind power, will change significantly by changing the emission prices. Therefore a sensitivity analysis is performed to quantify the degree of changes in the value of wind power with different emission prices.

Figure 8.12 shows the value of wind power with different prices of carbon. As expected, the higher the cost of carbon, the higher the value of wind power. The most interesting thing which is observable in fig. 8.10 is the impact of different carbon prices on different scenarios and changes in the ranking order of different scenarios in terms of the value of wind power.

In fig. 8.12 in the base case when carbon price is £25, wind power in scenarios 3-1 and 3-2 has higher value than scenario 1. But by increasing the carbon prices, wind power in scenario 1 will have the highest value. This is because it is assumed that fuel prices will remain the same, and the emission element in the value of wind power calculation will change. Since the amount of emission produced by each scenario is different, therefore by changing the emission prices, it will become the dominant factor of change in the value of wind power.

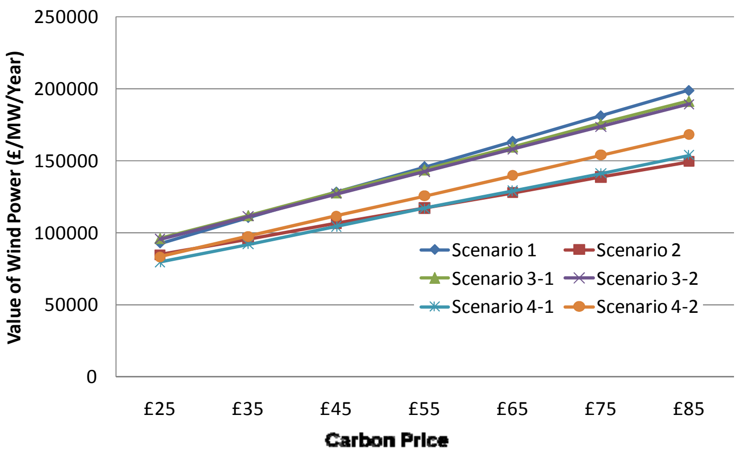

Fig. 8.12 Value of wind power with different carbon prices.

When wind power is combined with demand response, by increasing the price of carbon, since the emission reduction done by demand response will have a higher value, the value of wind power increases. As shown in fig. 8.13 for a typical scenario (scenario 1), two main elements must be taken into account; demand response level and price of carbon. These two elements both have impact on the degree of benefits from demand response.

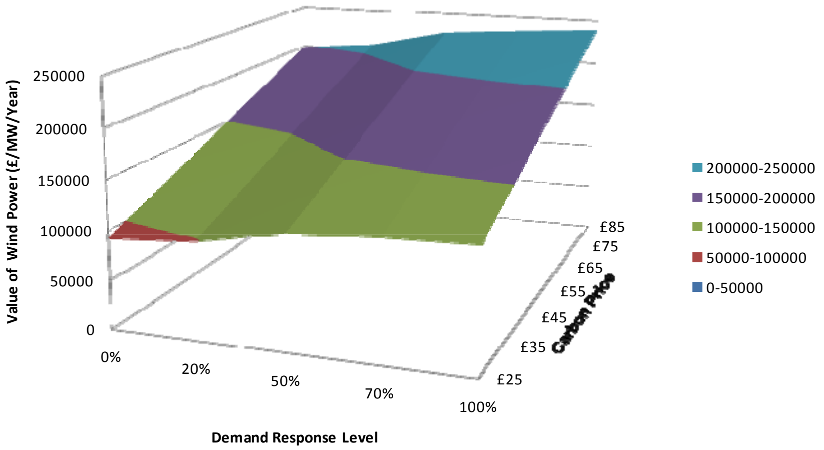

Fig. 8.13 Value of wind power combined with demand response with different carbon prices in scenario 1.

If all scenarios are to be studied together, to investigate the impact of increasing the carbon prices, whilst the demand response level varies, two main observations can be made. Firstly, increasing the value of wind power by increasing the cost of carbon as discussed before. But another important observation which is shown in fig. 8.14 and table 8.6 is increasing the range of values of wind power for all scenarios. This means that wind power can have significantly different value if price of carbon is high. This in fact means that if the revenue which could be earned from a system containing demand response and wind power is influenced by high carbon prices, making the decision on what level of demand response is suitable required detailed analysis as done in this work.

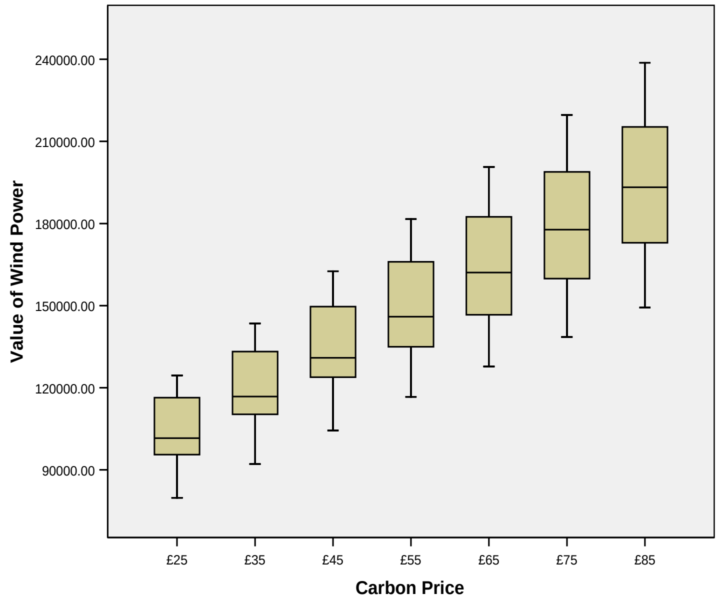

Fig. 8.14 Value of wind power with different carbon prices for different demand response levels.

Table 8.6. Value of Wind Power Combined with Different levels of Demand Response for Different Carbon Prices.

	Demand Response Level	**Scenario 1**	**Scenario 2**	**Scenario 3-1**	**Scenario 3-2**	**Scenario 4-1**	**Scenario 4-2**
Carbon Price £25	0%	96821	84709	96153	95568	79758	83458
	20%	103418	89148	101614	100914	83989	88472
	50%	121753	101558	116767	115746	95729	102405
	70%	127450	105394	121481	120361	99382	106735
	100%	130262	107181	123840	122675	101211	108871
Carbon Price £35	Demand Response Level						
	0%	110256	95470	112018	111188	92063	97544
	20%	116799	100053	117692	116743	96460	102747
	50%	134704	112697	133189	131913	108467	116986
	70%	140344	116652	138078	136701	112256	121471
	100%	143524	118738	140877	139448	114425	123997
Carbon Price £45	Demand Response Level						
	0%	127991	106231	127882	126807	104369	111630
	20%	134772	110959	133769	132572	108930	117022
	50%	153061	123836	149610	148081	121205	131566
	70%	158897	127910	154675	153041	125129	136207
	100%	162568	130294	157913	156221	127640	139124
Carbon Price £55	Demand Response Level						
	0%	145725	116992	143747	142426	116674	125715
	20%	152744	121865	149846	148401	121401	131296

	50%	171418	134976	166032	164248	133942	146146
	70%	177450	139168	171272	169382	138003	150943
	100%	181613	141851	174950	172995	140855	154250
Carbon Price £65	Demand Response Level						
	0%	163459	127753	159611	158045	128979	139801
	20%	170716	132771	165924	164230	133872	145571
	50%	189775	146115	182453	180416	146680	160727
	70%	196003	150426	187869	185722	150877	165679
	100%	200657	153407	191987	189768	154069	169377
Carbon Price £75	Demand Response Level						
	0%	181193	138515	175476	173664	141285	153886
	20%	188689	143676	182001	180059	146342	159846
	50%	208132	157254	198875	196584	159417	175307
	70%	214556	161684	204466	202062	163750	180415
	100%	219702	164963	209023	206541	167284	184503
Carbon Price £85	Demand Response Level						
	0%	198927	149276	191340	189283	153590	167972
	20%	206661	154582	198079	195887	158813	174121
	50%	226489	168393	215297	212751	172155	189887
	70%	233109	172942	221063	218402	176624	195150
	100%	238747	176520	226060	223314	180499	199629

As shown in table 8.6 apart from increasing the value of wind power with demand response by increasing the carbon price, the main change which is observable is in ranking order of scenarios. This is due to different emission share in each scenario which has impact on value of wind power. For instance, in the base case; when the cost of carbon is £25/tonne, scenario 2 shows the higher value of wind power compared with scenario 4-1. This is because in scenario 2, the value of wind power is mainly composed of savings made on fuel cost due to very high penetration of wind power. However, if cost of carbon increases, scenario 4-2 will show higher value of wind power since the savings is mainly emission saving in this scenario. This is further investigated in the following section.

Another observation in the results reveals which scenario is benefiting more from demand response with regard to changes in carbon price. As shown in table 8.6, when price of carbon changes by 40% from £25/tonne to £35/tonne, the changes in the value of wind is between 12%-17%, and 10%-16% for different scenarios in the base case when demand response level is 0% and 20% respectively. By increasing the demand response level, the changes in value of wind will be reduced down to 10%-14% compared with previous case when carbon price is cheaper. This shows that by increasing the demand response, scenarios based on how much savings can be achieved from emission saving and fuel cost saving (different shares) will show different values of wind power. It is also interesting to observe that at 0%-20% demand response levels, scenario 1 compared with scenario 2 will show significant changes in the value of wind power by increasing the carbon price. If demand response level is increased and at for example 100% demand response level, scenario 2 will show higher changes in the value of wind power compared with scenario 1.

8.4 Impact on Optimal Scenarios

In chapter 7, 12 scenarios were chosen as optimal scenarios based on their overall cost of electricity which includes both fuel cost of thermal plants, and cost of emission output. It is interesting to also investigate the impact of demand response on those optimal scenarios. As shown in this chapter, demand response can reduce the fuel cost by improving the efficiency of power generation, and reduce the number of hours of operation of thermal plants. This will also result in reduction in total emission output of thermal plants. Therefore, if in a system demand response is also present, it will certainly be a factor which could determine which scenarios are optimal, as it is an influencing factor. Considering the fact that demand response is a commodity which can be traded, therefore it has a price which has to be paid for. Assessment of such price depends on many factors. For example, the price of demand response may depend on peak demand, time, and different levels among different consumers. Each commodity form, and the associated pricing scheme, elicits a different response from participants revealing different aspects of their private information. That information is used to reach an allocation. In general the greater the information, the more efficient (optimal) can be the allocation. However, obtaining more information needs a more complex commodity/ pricing scheme [2-4]. To perform the analysis and study the impact of demand response whilst considering the cost of demand response, it is assumed that demand response can be provided by consumers, and the price which is paid to demand response will be equal for all different types of consumers. Although, this assumption is likely to be changed in a real market with real participants, but it can reflect the "average" cost of demand response. Equation 8.1 shows how average cost of electricity with demand response is calculated.

$$C_{unit} = \frac{(FC_W + FC_{WDR} + C_{DR} + C_w) + (CE_w + CE_{DR})}{Total\ Energy} \tag{8.1}$$

where C_{unit} is the average cost of each unit of electricity;

FC_w is the fuel cost with wind power;

FC_{WDR} is the fuel cost with demand response (response to wind power);

C_{DR} is the cost of demand response;

C_w is the cost of wind power;

CE_w is the cost of emission saved with wind power; and

CE_{DR} is the cost of emission saved with demand response.

It is clear from eq. 8.1 that $(FC_{DR} + C_{DR})$ and $(CE_w + CE_{DR})$ show the savings made through demand response on fuel cost and emission cost respectively. Savings depend on the cost and different levels of demand response. In order to create such assessment framework different prices for demand response has been considered.

Figure 8.15 shows the savings made on fuel costs of conventional plants with different demand response levels and different prices of demand response for scenario 1, sub-scenario 3, case 1. For any given scenario, the fuel costs savings will be similar to what is shown in this figure. But the difference is in fact in the points shown on this graph. Three points a, b, and c are shown on this graph to indicate the differentiations among different scenarios. Point “a” in fact indicates the total savings on fuel cost with demand response on the base case. The savings depend on the factors mentioned before and vary between different scenarios depending on the generation mix characteristics. Point “b” will move in different scenarios and indicates the degree of benefits of demand response with different prices for demand response. This means that each scenario depending on each characteristic may benefit differently from different levels of demand response. Therefore if demand response in to be implemented for each scenario, different levels of demand response may play a different role in different scenarios.

Points shown by “c”, are in fact the points that due to high price which has to be paid to certain levels of demand response in each scenario, no savings can be made on fuel costs of conventional. However, in evaluation of value of wind power or price of electricity, as shown in equation 8.1, although savings made on fuel cost may be negative, but there may be still opportunity for demand response to increase the value of wind power if cost of emission saved is still higher compared with the case with no demand response. Any value below the base case graph (the dark blue representing 0% demand response level) is in fact indicating lower saving on production cost compared with a case where no demand response exists in the system. Although these values are still positive, but they indicate that since the cost of demand response is higher than the savings compared with the no demand response case, the value of wind power at higher levels may be reduced.

In evaluation of value of wind power, when demand response is added to this problem as shown in eq. 8.1, two variables are being affected; production cost and emission cost. Increasing the demand response level, reduced the intermittency of wind power, and therefore the emission level will reduce as shown before. Thus, according to fig. 8.15, although savings on production cost may be lower at higher levels of demand response with increasing the cost of demand response, but it may save substantial amount of emissions. It is also important the different graphs showing different demand response levels, and in particular the dark-blue graph which represents 0% demand response level. This graph in fact shows the savings only due to wind power, thus, not sensitive to changes in demand response prices.

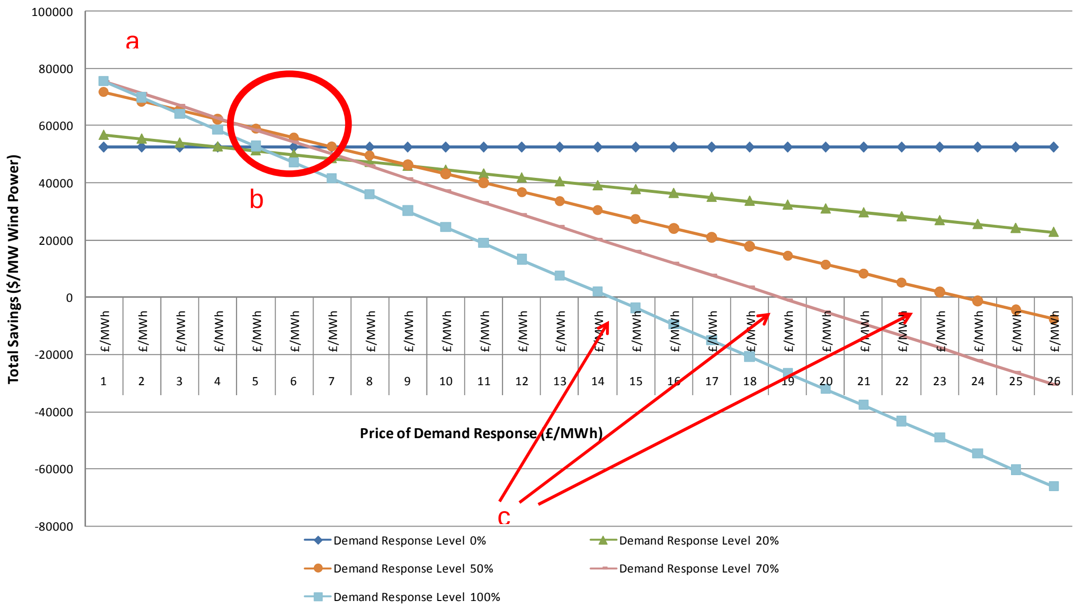

Fig. 8.15 Fuel Cost Savings by Demand Response for typical scenario (Scenario 1).

Table 8.7 shows the ranking of the first three top cases for for demand response price of £0/MWh. It can be seen from this table that similar ranking will be resulted by demand response if the price of demand response is assumed to be £0/MWh, although the actual cost of electricity is reduced due to savings made on fuel cost and emission cost.

By comparing table 8.7 and table 7.12 in previous chapter, it can be seen that all different scenarios will see a reduction in their actual cost of electricity due to demand response. In terms of ranking the scenarios, some scenarios will be ranked higher compared with others, and scenario 4-2 will go down. This is because some scenarios will benefit more from the demand response compared with others. By comparing these two tables, a slight change in the actual cost of electricity is observable. For example the actual cost of

electricity for the first rank will be reduced by 0.96%, whilst this reduction for the second rank is only 1% which is in fact the lowest cost reduction observed for 20% demand response level. Such low level of demand response in fact is not a real remedy for the variability of wind power. At this level, power fluctuations still exist, therefore the problems such as high number of start-ups of thermal plants still exists, although slightly improved.
It must be noted that in the top 12 scenarios, less changes is observable, but if all 72 scenarios are studied, several changes in term of ranking the scenarios will be seen.

Table 8.7. The first Top 12 Scenarios based on their Actual Cost of Electricity with Demand Response 20% and £0/MWh

Rank	Scenario	Sub Scenario	Case	Actual Cost Electricity (£/MWh)
1	Scenario 2	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	22.61
2	Scenario 2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	22.94
3	Scenario 2	Sub_Scenario 3	Case 3 (100% Nuclear Power Replacement)	23.61
4	Scenario 2	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	23.84
5	Scenario 2	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	24.98
6	Scenario 2	Sub_Scenario 3	Case 2 (50% Nuclear Power Replacement)	25.23
7	Scenario 1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.39
8	Scenario 2	Sub_Scenario 1	Case 1 (No Nuclear Power Replacement)	25.42
9	Scenario 2	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	25.48
10	Scenario 4-2	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	25.51
11	Scenario 1	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	25.71
12	Scenario 1	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	25.76

The higher the demand response, the higher the benefits associated with it, only if the cost of demand response is assumed to be £0/MWh. This is because wind power in each scenario will be less intermittent with demand response. The degree of benefits as shown in table 8.8 increases and the actual cost of electricity for all scenarios will be lower. However, it can be seen that there is some changes in the ranking of different scenarios, although the demand response level is same for all scenarios. Scenario 4-2 will be ranked higher compared with the previous table.

As shown in this table, the cost reduction for 70% demand response level is significant. The first rank wills how about 3.6% reduced actual cost of electricity, whilst this actual cost of electricity reduction trend continues and the highest level of reduced cost is seen for the rank 11 in which the actual cost of electricity is reduced by nearly 4.5%. Such high level of reduction in the actual cost of electricity in a real system can reflect significant improved efficiency of power generation.

Table 8.8. The first Top 12 Scenarios based on their Actual Cost of Electricity with Demand Response 70% and £0/MWh

Rank	Scenario	Sub Scenario	Case	Actual Cost Electricity (£/MWh)
1	Scenario 2	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	21.77
2	Scenario 2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	22.09
3	Scenario 2	Sub_Scenario 3	Case 3 (100% Nuclear Power Replacement)	22.74
4	Scenario 2	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	22.98
5	Scenario 2	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	24.08
6	Scenario 2	Sub_Scenario 3	Case 2 (50% Nuclear Power Replacement)	24.32
7	Scenario 1	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	24.42
8	Scenario 2	Sub_Scenario 1	Case 1 (No Nuclear Power Replacement)	24.50
9	Scenario 4-2	Sub_Scenario 1	Case 3 (100% Nuclear Power Replacement)	24.52
10	Scenario 2	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	24.54
11	Scenario 1	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	24.70
12	Scenario 1	Sub_Scenario 1	Case 2 (50% Nuclear Power Replacement)	24.78

If each scenario is studied individually with demand response, it can be see that if no price is taken into account for demand response, the rankings for the best case in each scenario will not change by different demand response levels as shown in table 8.9. However, by comparing this table and table 7.14 in chapter 7 where no demand response existed, the changes in the rankings of the cases for each scenario will be seen. This highlights the role of demand response in an optimal generation mix problem, which also highlights the importance of studying the potential and benefits of demand response in any given generation expansion problem.

In this table sub-scenario 4 for scenario 1 will be ranked second. This is slightly different compared with other scenarios. In scenario 1, the second ranked case occurs when windfarms are installed at north (mainly on-shore) and nuclear power replacement is at 100% replacement. The production cost calculated for this scenario although is very close to sub scenario 2 of this case, but since demand response will significantly increase the energy share of nuclear power, this sub-scenario will show lower actual cost of electricity, compared with the case where windfarms have better location but nuclear power replacement is lower. This shows that in this hypothesis, nuclear power is the dominant factor in determination of the actual cost of electricity. The benefit of demand response is to reduce the actual cost of electricity by nearly %5.

Table 8.9 Recommendation of the Best cases for each Scenario with Demand Response (£0/MWh)

Scenario	Rank	Sub Scenario	Case	Actual Cost of Electricity (£/MWh)	Sub Scenario	Case	Actual Cost of Electricity (£/MWh)
		20% Demand Response			70% Demand Response		
Scenario 1	1	SS 1	C 3	25.39	SS 1	C 3	24.42
	2	SS 4	C 3	25.71	SS 4	C 3	24.70
	3	SS 1	C 2	25.76	SS 1	C 2	24.78
Scenario 2	1	SS 1	C 3	22.61	SS 1	C 3	21.77
	2	SS 2	C 3	22.94	SS 2	C 3	22.09
	3	SS 3	C 3	23.61	SS 3	C 3	22.74
Scenario 3-1	1	SS 1	C 3	25.98	SS 1	C 3	24.99
	2	SS 2	C 3	26.61	SS 2	C 3	25.61
	3	SS 1	C 2	27.16	SS 1	C 2	26.15
Scenario 3-2	1	SS 1	C 3	26.59	SS 1	C 3	25.57
	2	SS 2	C 3	26.79	SS 2	C 3	25.76
	3	SS 1	C 2	27.19	SS 1	C 2	26.17
Scenario 4-1	1	SS 1	C 3	25.99	SS 1	C 3	24.99
	2	SS 2	C 3	26.79	SS 2	C 3	25.77
	3	SS 1	C 2	27.07	SS 1	C 2	26.07
Scenario 4-2	1	SS 1	C 3	25.51	SS 1	C 3	24.52
	2	SS 2	C 3	26.27	SS 2	C 3	25.26
	3	SS 1	C 2	26.53	SS 1	C 2	25.53

Now if the price of demand response is also included in the assessment framework, the benefits associated with demand response will vary depending the price has to be paid for certain levels of demand response. Figure 8.16 shows the actual cost of electricity for a scenario 1, sub-scenario 1, case 1. This is a typical curve for any given scenario with different prices of demand response and different demand response levels. As illustrated in this picture, the actual price of electricity will reduce by increasing the demand response level whilst the price of demand response is below £7/MWh. By increasing the price of demand response, and increasing the demand response levels, the actual price of electricity is increasing. The reason behind was discussed in chapter 5.

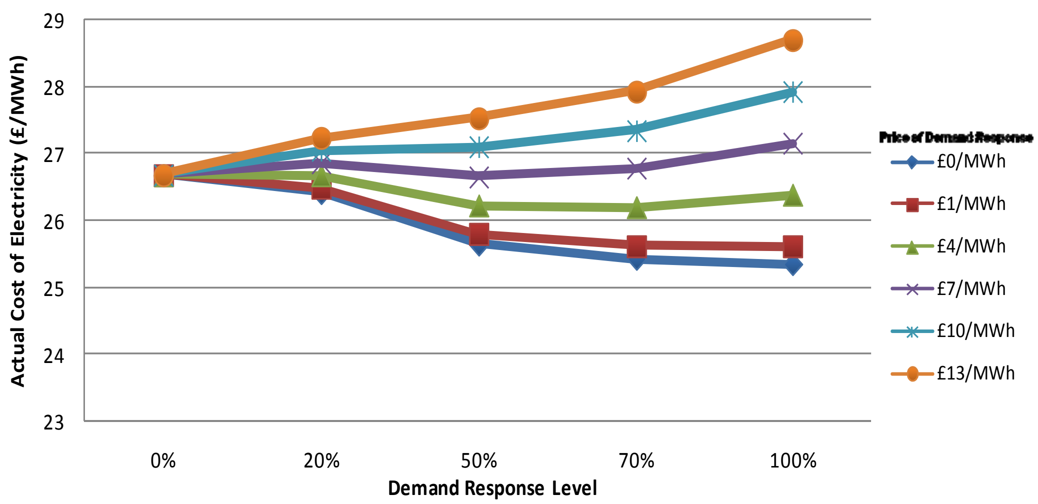

Fig. 8.16 Actual Cost of Electricity by Demand Response for Scenario 1.

This reduction in the actual price of electricity can also be included in the savings resulted by wind power, in order to quantify the value of wind power with different demand response levels. As shown in fig. 8.17 different range of values for wind power will be observed. At low demand response prices, value of wind power will increase. The impact of different demand response levels will also be observed in a way that low demand response levels will show lower range. This is because even if the price of demand response is too high, the losing (instead of saving) is limited to the low level of demand response.

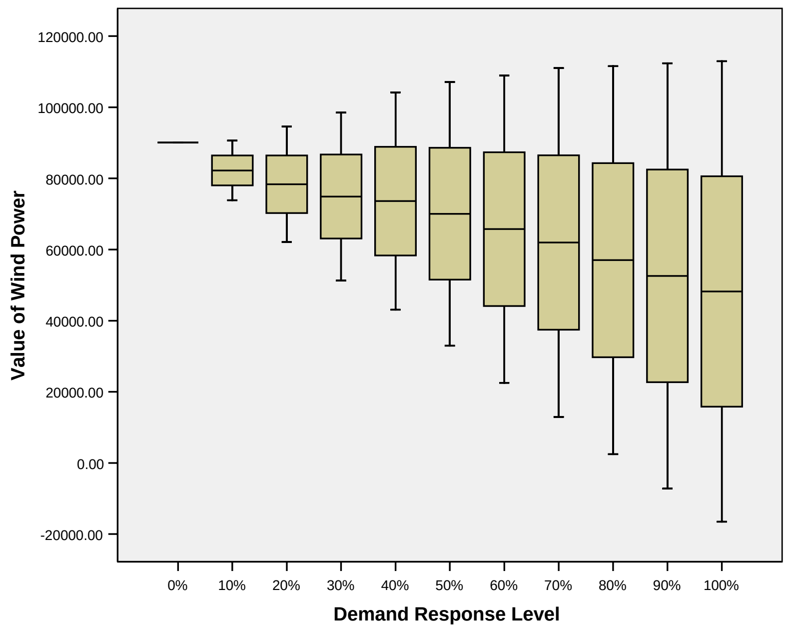

Fig. 8.17 Value of Wind Power for Scenario 1 with Different Levels of Demand Response Whilst the Price of Demand Response Varies between £0/MWh to £26/MWh.

By increasing the demand response level, the range of values observed for value of wind power will increase. Since different prices for demand response are included in this graph

(£0-£26/MWh) the increase in the range of values observed for the value of wind power is due to changes in the “lowest” value for the wind power; not the highest in certain demand response prices. In other word, when the price of demand response is too high, the highest observed value of wind power will be constant; and in fact is the 0% demand response level. In fact after paying £7/MWh for demand response the highest value of wind power is constant, whilst the lowest value tends to decrease.

8.5 Chapter Summary

This chapter provided the results for assessing the value of wind power combined with demand response in a large system. The quantification available demand response as a resource was performed in chapter 6. The main results of this chapter include:

- Based on the available demand response as a resource, it was shown in this chapter that how the value of wind power changes with different degrees of demand response. When demand response is combined with wind power, two main elements have impact on the value of wind power; degree of responsiveness and price which has to be paid for such responsiveness level.

- Different degree of responsiveness will increase the value of wind power as wind power will become smoother. However when the price of demand response which increases by increasing the responsiveness level is taken into account, the degree of benefits; or added value of wind power changes. The reason for the change in the value of wind power is due to changes in operation pattern of the thermal generators which change the objective parameters, such as, changes in the marginal price of electricity generation due to more efficient operation of thermal generators. It was also shown that how at different emission prices, different values for wind power are expected.

- Demand response combined with wind power will also reduce the total emission produced by conventional plants. Therefore increasing the price of emission may increase the added value of wind power by demand response. This may even make the demand response feasible at higher prices which have to be paid to maintain certain levels of responsiveness, although the fuel cost saving may be negative.

8.6. References

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Chapter 9. Conclusions

9.1 Summary of the Work in this Thesis

This thesis aimed to create a link between current DSM methods which are particularly applied to domestic sector, and power system operation in which wind power is expected to have high level of penetration. Since wind power is intermittent, a dynamic demand side management method is required to respond to these changes. Among all different DSM methods which were investigated, demand response has the capability to respond to any signal in real time. Such technology can enable a power system operator to remove the burden of both providing the spinning reserve, and back-up power from thermal generators, and instead maintain such capacity from demand response. It was shown how demand response can increase the value of wind power by providing the extra reserve required for wind power, and cater for wind power deficits.

The main findings of this work include:

A. Assessment framework for studying the value of wind power;

- Traditionally, only network energy losses have been considered as a measure to find the optimum location; lower losses indicate a better location provided appropriate availability of wind energy exists. Generally, energy losses can be reduced in the network by installing windfarms next to the load centres. They will reduce supply requirements from more distant resources, thereby by reducing transmission losses which are effectively wasted supply.
  But it was shown that although the overall network losses are different for different grid-location of windfarms, it should not be solely used as an indicator for suitability of the grid-location. When the aim is to find the best location, the impact of the location depends on where the windfarm is installed relation to the electricity generation side must also be taken into account. These effects include:
    - The impact on total number of shut-down and start-up of conventional plants due to change in the dispatch pattern.
    - The impact on marginal cost of electricity generated by conventional plants whilst the location of windfarms may change the power dispatch, hence changing the total production cost.
- The grid location of windfarms has an impact on the payback period of the capital costs invested to build the windfarms. Capital costs can be recovered over

different time scales; therefore the amount of profit that can be made after the break-even point depends on the location of the windfarm. Hence, the benefit of windfarms must be studied in different time horizons:

- In the short-term by placing the windfarms at appropriate locations in the grid, the day-to-day running of power system will be with less deviation of security parameters and these parameters have an impact on reliability of the system.
- Long-term benefits included the ability of the current network to supply increasing demand without network re-enforcement. The degree of these benefits significantly varies from location to location where a windfarm is connected to.

B. Maintaining reliability and increasing the need for spinning reserve:

- A methodology to calculate the spinning reserve for a given system with intermittent generation is developed. This calculations based on this method reflects the actual risk on the system imposed by:
  - Demand forecasting error;
  - Wind forecasting error; and
  - Conventional generators outage rate.

  and the benefits of this method include:
- Different levels of spinning reserve requirement have impact on the life-time value of wind power. This is mainly due to changes in the operation pattern of thermal generators by changing their efficiency level (the higher the spinning reserve requirement, the lower the efficiency of thermal plants). Changes in the marginal fuel cost, and emission output of thermal plants are two important elements which change the overall cost in the system.

C. Impact of DSM programmes on value of wind power:

- DSM programmes van benefit the system by reducing the fuel costs and emission levels. In a system with intermittent generator, DSM programmes (non-dynamic) may increase the value of wind power by reducing the thermal generators' cost and increasing the cost-savings through windfarms. The results show that 21% increase in the value of wind power may be achieved just by shifting about 16% of loads from peak to off-peak periods.
- Dynamic DSM programmes (demand response) will further increase the value of wind power through:

  - o Reducing the need for additional spinning reserve for wind power;
  - o Reducing the variability of wind power which:
    - Increase energy share of wind power;
    - Reduces the number of start-up and shut-down of thermal plants;
    - Increases the efficiency of power generation which will reduce the cost and emissions.
  - o The results suggest that cost savings about £150,000/MW demand response may be achieved. This excludes the costs associated with demand response (such as cost of implantation, etc.).
- The impact of demand response on value of wind power was studied, and the result suggest that demand response may expedite the payback period for a windfarm from 10-12 years down to 2-3 years if 100% demand response can be maintained. The expedition in breakeven point will be limited when cost of demand response is taken into account, and in fact high compensation levels may not be feasible.
- The results indicate that if the cost of demand response is taken into account, the degree of feasibility of this technology with regard to value of wind power will be limited to demand response prices up to £6/MWh.

D. Potential for Domestic Demand Response:

The technique used in this thesis to generate the load profile of domestic household' appliances was based on the probability of operating different appliances by different groups of consumer. Since the availability of data for any statistical analysis is an essential factor, and because the data required in this technique is widely available for different locations in England and Wales, this technique can be used to assess the potential of demand in a location to become responsive. It was shown that the domestic demand response's potential is different throughout the day since the consumption pattern of different appliances is different. It was shown that fridge-freezers which compose the base load in the domestic sector have the potential of becoming responsive since interruptions of up to nearly two hours may not jeopardize the service provided by fridge-freezers.

E. Changes in generation Mix and impact on power system operation:

- The results in this chapter show that increasing the wind power penetration in the GB power system will increase the need for spinning reserve. The level of increase depends on type of generators, generation mix pattern as well as demand level.

The level is not solely related to installed capacity of wind power. For the same installed capacity of wind power in different generation mix patterns, spinning reserve requirement is different.

- In the GB power system, since load centres are located at South (England) and on-shore wind resources are mainly at North (Scotland) the bottleneck in the interconnector between England and Scotland will significantly impact on the value of wind power. This is because of the need for extra power in the south at times when the bottleneck happens. Providing such power will reduce the efficiency of power generation both for generators located in Scotland since they may be forced to operate at lower output levels, and for generators in England since they may be required to start-up and operate with less efficient patterns.

- Off-shore windfarms can become a major source of electricity generation in the GB power system more than ever if they are connected to grid in England. This will reduce the interconnector's bottleneck, and give wind power the opportunity to displace higher capacities of conventional plants. It was shown in this chapter that how the location of windfarms has impact on out study objectives such as production cost and emission level. It was also shown that whilst the location of windfarms is a major factor in changing the network losses, it will result in changing the energy share of other power generation technologies.

- In the absence of nuclear power, coal fired and CCGT power plants will become the main base-load plants. The emission level of such plants is high compared with nuclear power, such displacement may result in not meeting the emission reduction target set by the government unless more aggressive targets are set for the industries as a whole.

- Nuclear power combined with wind power can provide a high level of resilience for the electricity generation industry. The impact of such combination on production cost, and emission level is also very promising. The magnitude of benefits from differing contribution from nuclear power will be established for varying wind penetration and location as future work.

- With regard to the optimal scenarios, it can be concluded that in presence of uncertainty about the future of generation mix, different scenarios may be the optimal scenarios depending on the weight of influencing factors. It was shown in this chapter that if production cost and emission cost are considered as the main influencing factors, the share of each factor differs depending on the cost of carbon. Changes in the cost of carbon will be responded differently by different scenarios, depending on how sensitive they are to changes in the cost of carbon. In order word, if lower the emission level is observed in a scenario, although it may result in a high electricity cost due to high fuel costs, but by increasing the carbon price, this scenario may show a relatively lower electricity price. Therefore, determination of which scenarios are the optimal scenarios is something which has to be done whilst changing the carbon prices are also taken into account.

F. Effect of demand response on value of wind power in a large system:

- Based on the available demand response as a resource, it was shown in this chapter that how the value of wind power changes with different degrees of demand response. When demand response is combined with wind power, two main elements have impact on the value of wind power; degree of responsiveness and price which has to be paid for such responsiveness level.

- Different degree of responsiveness will increase the value of wind power as wind power will become smoother. However when the price of demand response which increases by increasing the responsiveness level is taken into account, the degree of benefits; or added value of wind power changes. The reason for the change in the value of wind power is due to changes in operation pattern of the thermal generators which change the objective parameters, such as, changes in the marginal price of electricity generation due to more efficient operation of thermal generators. It was also shown that how at different emission prices, different values for wind power are expected.

- Demand response combined with wind power will also reduce the total emission produced by conventional plants. Therefore increasing the price of emission may increase the added value of wind power by demand response. This may even make the demand response feasible at higher prices which have to be paid to maintain certain levels of responsiveness, although the fuel cost saving may be negative.

Chapter 10. Limitations and Suggestions for Further Work

10.1. Limitations

The rationale for this work stemmed from a need to quantify the benefits of demand response combined with wind power to maximize the value of wind power. However, in doing so, the technical aspects bringing about benefits have been considered, i.e. reducing the number of start-ups and shut-downs, and operation hours of thermal generators and reduction in their production cost and emissions, more efficiently operation of generators and reducing their marginal fuel costs and emission output, changes in the network losses as a result of changes in the power-flow pattern in the network with windfarms.

Other costs brought about by demand response has not been taken into account, such as the capital cost of demand response, network reinforcements for added security and ability to transport the energy from windfarms which are combined with demand response to consumers. Besides, the most important factor which has not yet been taken into account for implementing such system is studying the impact of such level of demand responsiveness on stability of power system. Considering such high level of load which has to be disconnected and reconnected within a short period of time, it is essential to draw a framework to study the impacts on stability of power system.

10.2 Future Work:

In this thesis the potential for demand response to cater for energy output deficits of windfarms was investigated and the benefits were highlighted. Demand response should in theory mimic generation resources providing the same services in terms of response to the output of a windfarm. The generators in power system are not only studied as electrical energy generation sources just to supply the demand. Regardless of whether or not a generator is online, the total capacity of a generator is an important factor to maintain the reliability of the power system. The generation expansion problem always takes into account the demand growth and retirement of old generation technologies. Demand response can be valued as a capacity resource, to delay building new generation technologies. This has to be studied in the context of the sustainable generation mix problem where the capacity, constraints, costs and characteristics of different generation technologies are included.

Studying the benefits of demand response to electrical supply networks was limited to investigating the impact of demand response to reduce the total losses in the transmission lines. Such technology can reduce the loading of the transmission and distribution network as any required time, as a result of sudden increase in total demand or a fault. This will result in transmission and distribution reinforcement deferral as a result of demand response which will increase the value of such technology. This has not been taken into account in this thesis and has to be studied and such value be combined with energy trading value of demand response to draw a realistic picture of the costs and benefits associated with demand response.

Another interesting space for further development of this work is to develop the dispatch pattern of generators while restrictions such as extremely high carbon prices may require generators to cap their total emission output. Whilst the dispatch pattern used in this study aims to minimize the total emission, but it does not take into account any regulatory constraint on total allowed emission output of generators. If this is to be taken into account, it will have impact on availability of generators, production cost, emissions and in fact all parameters which were used to calculate the value of wind power will change.

Appendix A

Reduced GB Network

A.1 Network Data:

A.1.1 Bus Data:

Bus Name	Bus Voltage (KV)	Bus ID	Bus Type
DRAK4	400	Drakelow 400	0
PENN2	275	Penn 275	2
BUSH1	132	Bushbury 132	2
BUSH2	275	Bushbury 275	0
DRAK1	132	Drakelow 132	2
DRAK2J	275	Drakelow 275J	2
DRAK2K	275	Drakelow 275K	0
WIEN1	132	Willenhall 132	2
WILL1	132	Willington 132	2
WILL2J	275	Willington 275J	0
WILL4	400	Willington 400	2
BISW2	275	Bishops Wood 275	2
KITW2	275	Kitwell 275	2
OCKH2	275	Ocker Hill 275	2
OLDB2	275	Oldbury 275	2
BESW2	275	Berkswell 275	2
BUST2	275	Bustleholm 275	2
COVE2	275	Coventry 275	2
FECK2	275	Feckenham 275	2
HAMH2	275	Hams Hall 275	2
NECH2	275	Nechells 275	2
FECK4	400	Feckenham 400	2
HAMH4	400	Hams Hall 400	0
CELL4	400	Cellarhead 400	2
IRON4	400	Ironbridge 400	2
RUGE4T	400	Rugeley 400T	2
LEGA4	400	Legacy 400	2
DAIN4	400	Daines 400	2
MELK4	400	Melksham 400	0
COWL4	400	Cowley 400	2
RATS4	400	Ratcliffe-on-Soar 400	2
COTT4	400	Cottam 400	3
CREB4	400	Creyke Beck 400	0
NORT4	400	Norton 400	0
NORT2	275	Norton 275	0
STEW2	275	Stella West 275	2
STEW4	400	Stella West 400	0
COCK4	400	Cockenzie 400	2

PEWO4	400	Penwortham 400	0
HARK4	400	Harker 400	0
HARK2	275	Harker 275	0
STHA4	400	Strathaven 400	2
STHA2	275	Strathaven 275	0
INKI4	400	Inverkip 400	0
LOAN2	275	Longannet 275	0
COCK2	275	Cockenzie 275	0
TEAL2	275	Tealing 275	0
TEAL1	132	Tealing 132	0
ERRO1	132	Errochty 132	0
KINT2	275	Kintore 275	0
BEAU2	275	Beauly 275	0
BEAU1	132	Beauly 132	0
DOUN2	275	Dounreay 275	0

A.1.2 Line Data:

Bus from Name	Bus To Name	*R*	*X*	*B*
BESW2	COVE2	0.000084	0.00075	0.005186
BESW2	FECK2	0.00014	0.001427	0.010328
BESW2	HAMH2	9.48E-05	0.000952	0.010848
BISW2	FECK2	9.18E-05	0.000912	0.00652
BISW2	KITW2	0.000123	0.00111	0.007576
BISW2	KITW2	0.000109	0.000989	0.006746
BISW2	PENN2	0.000121	0.001209	0.009926
BUSH2	OCKH2	4.99E-05	0.000496	0.049564
BUSH2	PENN2	9.84E-05	0.000892	0.007439
BUST2	NECH2	2.09E-05	0.000285	0.083889
CELL4	DAIN4	9.34E-05	0.001022	0.033629
CELL4	DAIN4	9.34E-05	0.001022	0.033629
CELL4	DRAK4	7.76E-05	0.000849	0.027933
CELL4	DRAK4	7.77E-05	8.5E-05	0.027977
COVE2	HAMH2	4.64E-05	0.000708	0.00646
COVE2	WILL2J	0.000212	0.002448	0.019143
DRAK4	HAMH4	5.03E-05	0.00055	0.018101
DRAK4	RUGE4T	3.54E-05	0.000387	0.012748
DRAK4	WILL4	2.89E-05	0.000317	0.010419
FECK4	HAMH4	7.37E-05	0.000806	0.026532
FECK4	IRON4	0.000113	0.001234	0.040629
FECK4	MELK4	0.000185	0.00201	0.0649
FECK4	COWL4	0.000226	0.002806	0.13518
HAMH2	NECH2	0.000024	0.000367	0.003347
HAMH2	OCKH2	0.000144	0.00136	0.012196
IRON4	LEGA4	0.000106	0.001157	0.038102

IRON4	LEGA4	0.000106	0.001157	0.038102
IRON4	RUGE4T	0.000127	0.001159	0.035491
KITW2	OCKH2	6.08E-05	0.000552	0.006139
KITW2	OLDB2	3.57E-05	0.000331	0.008632
RATS4	WILL4	3.51E-05	0.000398	0.013205
DRAK4	RATS4	0.000056	0.000613	0.027269
BUSH2	DRAK2K	0.000168	0.001606	0.011267
BUSH1	WIEN1	0.000277	0.000568	0
BUST2	DRAK2J	7.96E-05	0.001215	0.011091
BUST2	DRAK2J	7.96E-05	0.001214	0.011077
COTT4	RATS4	5.48E-05	0.001526	0.051707
COTT4	RATS4	5.48E-05	0.001526	0.051707
CREB4	COTT4	9.39E-05	0.001457	0.049988
CREB4	COTT4	9.39E-05	0.001457	0.049988
CREB4	NORT4	0.000154	0.00228	0.084572
CREB4	NORT4	0.000154	0.00228	0.084572
STEW2	NORT2	0.000232	0.00241	0.01764
STEW2	NORT2	0.000232	0.00241	0.01764
COCK4	STEW4	0.000178	0.001483	0.004516
COCK4	STEW4	0.000178	0.001483	0.004516
PEWO4	DAIN4	0.000139	0.001658	0.058722
HARK4	PEWO4	0.000286	0.002809	0.088963
HARK4	PEWO4	0.000286	0.002809	0.088963
HARK4	STHA4	0.00022	0.002396	0.053253
STEW2	HARK2	0.000492	0.00343	0.025013
HARK2	STHA2	0.000177	0.001688	0.003648
STHA4	INKI4	0.000151	0.001613	0.052296
STHA2	LOAN2	0.000163	0.002136	0.005842
STHA2	COCK2	0.000421	0.003456	0.011121
LOAN2	COCK2	0.000475	0.007695	0.026028
LOAN2	TEAL2	0.000467	0.004826	0.003968
TEAL1	ERRO1	0.007179	0.017089	0.008174
TEAL2	KINT2	0.00122	0.01072	0.011071
KINT2	BEAU2	0.00182	0.00731	0.009228
ERRO1	BEAU1	0.01242	0.03143	0.001048
BEAU2	DOUN2	0.00122	0.00836	0.06892

A.1.3 Transformer Data:

Bus From Name	Bus From Voltage (Kv)	Bus To Name	Bus To Voltage (KV)	*R*	*X*	*B*
FECK4	400	FECK2	275	1.76E-05	0.001609	0
HAMH4	400	NECH2	275	0.000017	0.0016	0
DRAK4	400	OLDB2	275	0.000017	0.0016	0
DRAK4	400	PENN2	275	0.000017	0.0016	0

IRON4	400	PENN2	275	0.000017	0.0016	0
OCKH2	275	WIEN1	132	0.000151	0.008333	0
WILL2J	275	WILL1	132	0.000294	0.012283	0
WILL2J	275	WILL1	132	0.000294	0.012283	0
WILL4	400	WILL1	132	0.000153	0.00792	0
WILL4	400	WILL2J	275	3.29E-05	0.002415	0
WILL4	400	WILL1	132	3.29E-05	0.002415	0
BUSH2	275	BUSH1	132	0.000156	0.007575	0
BUSH2	275	BUSH1	132	0.000153	0.00775	0
BUSH2	275	BUSH1	132	0.00016	0.007604	0
DRAK2J	275	DRAK1	132	0.000378	0.011933	0
DRAK2J	275	DRAK1	132	0.00035	0.012	0
DRAK2K	275	DRAK1	132	0.000301	0.013333	0
DRAK4	400	DRAK2J	275	2.13E-05	0.001604	0
DRAK4	400	DRAK2J	275	2.13E-05	0.001604	0
DRAK4	400	DRAK2K	275	2.17E-05	0.001608	0
NORT4	400	NORT2	275	1.72E-05	0.001508	0
NORT4	400	NORT2	275	1.17E-05	0.001592	0
STEW4	400	STEW2	275	0.000023	0.001646	0
STEW4	400	STEW2	275	1.18E-05	0.00156	0
HARK4	400	HARK2	275	0.000018	0.001706	0
STHA4	400	STHA2	275	0.000018	0.001706	0
TEAL2	275	TEAL1	132	0.00041	0.01189	0
BEAU2	275	BEAU1	132	0.0003	0.01218	0
BEAU2	275	BEAU1	132	0.0005	0.01221	0
BEAU2	275	BEAU1	132	0.0005	0.01225	0

A.1.4 Generators' Data:

Bus Name	Status 1=Available. 0=Outage	Voltage (KV)	Power MW	Reactive-Power MVar	Reactive-Power MVar(absorption)
PENN2	1	275	12747	13000	0
BUSH1	1	132	0	1200	0
DRAK2J	1	275	0	1500	-750
WILL1	1	132	228	400	0
WILL4	1	400	207.7	1500	-750
BISW2	1	275	0	1800	0
BESW2	1	275	0	1800	0
BUST2	1	275	0	200	0
COVE2	1	275	0	1800	0
FECK2	1	275	0	1500	-750

FECK4	1	400	0	1500	-750
CELL4	1	400	0	3000	-150
IRON4	1	400	964	1000	0
RUGE4T	1	400	1018	1100	0
LEGA4	1	400	0	9300	-2850
DAIN4	1	400	2180	2500	-1000
MELK4	1	400	8525.9	8300	-3000
COWL4	1	400	17241	17000	-3000
RATS4	1	400	5167.4	5100	0
CREB4	1	400	4669	5000	0
STEW2	1	275	420	420	0
STHA4	1	400	0	0	0
COCK4	1	400	0	0	0
NORT2	1	275	3132	0	0
HARK4	1	400	16210	16210	0

A.1.5 Reactive Shunt Devices:

Bus Name	Voltage (KV)	Reactive Power(MVar)	Status 1=Available. 0=Outage
PENN2	275	61.35	1
BUSH1	132	72.48	1
DRAK1	132	726	1
WIEN1	132	217.8	1
WILL1	132	34.53	1
WILL4	400	80	1
BISW2	275	45.53	1
KITW2	275	12.82	1
OCKH2	275	166.26	1
OLDB2	275	103.22	1
BESW2	275	234.81	1
BUST2	275	11.46	1
COVE2	275	132	1
FECK2	275	54.31	1
HAMH2	275	212.49	1
NECH2	275	15.78	1
CELL4	400	24.36	1
IRON4	400	582.74	1
RUGE4T	400	91.71	1
RATS4	400	204.51	1

A.1.6 Load Data:

Bus Name	Bus Voltage	Active Load (MW)	Reactive Load (MVar)
PENN2	275	2061.527	906.6898
BUSH1	132	1573.756	660.5869
DRAK1	132	1075.078	403.4751

WIEN1	132	786.5452	331.6679
WILL1	132	2982.336	1332.075
BISW2	275	2999.24	1348.898
KITW2	275	2550.384	828.1818
OCKH2	275	863.8031	435.9577
OLDB2	275	758.291	345.1368
BESW2	275	2592.767	1179.334
BUST2	275	2591.611	840.9517
COVE2	275	3373.532	1315.931
FECK2	275	1389.58	583.9608
HAMH2	275	1458.833	613.5668
NECH2	275	2920.859	1395.313
HAMH4	400	1508.831	489.7794
CELL4	400	4831.754	2076.829
IRON4	400	2267.477	851.0601
RUGE4T	400	1247.908	525.4343
LEGA4	400	604.9505	0
DAIN4	400	847.6525	0
MELK4	400	6001.853	-658.658
COWL4	400	13062.03	117.6175
RATS4	400	886.5402	330.2968

A.2. Base Case Conventional Generation Data

A.2.1 Generation Type and Location

Generation Type / Node Number	OCGT	CCGT	CHP	Nuclear	coal	Oil
Elvanfoot				Nuclear (1), (2), (3), (4) 4*602.5MW	Coal (1), (2) 2*576MW	
Eccles	Gas (1)	Gas (4) and Gas (5) 2* 762MW	CHP(1)		Coal (3), (4), (5), (6) 4*576MW	
Harker		Gas (6) , Gas (7),Gas (8) , Gas (9),Gas (10), Gas (11), Gas (12) 7*597MW	CHP(2)	Nuclear (5), (6) 2*601.5MW	Coal (7-26) 20*490.7MW	
StellaWest					Coal (27)	
Norton		Gas (13) , Gas (14),Gas (15) , Gas (16),Gas (17) 5*385MW		Nuclear (7), (8) 2*603MW		
Penwortham		Gas (18)	CHP(3)	Nuclear (9), (10) 4*601.5MW	Coal (28-33) 6*613.3MW	
Creyka Beck		Gas (19) , Gas (20),Gas (21) , Gas (22),Gas (23) 5*790MW				
Daines				Nuclear (11), (12) 2*490MW		
Melksham	Gas (2)	Gas (24) , Gas (25),Gas (26) 3*1227MW	CHP(4)	Nuclear (13), (14) 2*630.5MW	Coal (34-39) 5*411MW	Oil (1)
Cowley	Gas (3)	Gas (27) , Gas (28),Gas (29),Gas (30) , Gas (31),Gas (32) 6*1048.5MW		Nuclear (15), (16) 2*540.5MW	Coal (40-49) 10*517.7MW	Oil (2-5) 4*615MW
Ironbridge					Coal (50), (51) 2*482MW	

Rugeley					Coal (52), (53) 2*509MW	
Willington			CHP(5)			
Ractiliffe		Gas (33), Gas (34) 2* 743MW		Nuclear (17), (18) 2*830,2MW	Coal (54-57) 4*505.25MW	

A.2.2 Generation Fuel Cost and Emission Coefficients

	Fuel Cost Coefficients			CO2 Emission Coefficients				
	a	b	c	α	β	γ	δ	ε
Gas(1) OCGT	0.07832	130	400.6849	-0.05094	0.04586	0.000008	8	0.778
Gas(2) OCGT	0.07832	130	400.6849	-0.05094	0.04586	0.000008	8	0.778
Gas(3) OCGT	0.07832	130	400.6849	-0.05094	0.04586	0.000008	8	0.778
Gas(4) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(5) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(6) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(7) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(8) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(9) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(10) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(11) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(12) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(13) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(14) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(15) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(16) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(17) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(18) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(19) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(20) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(21) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(22) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(23) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(24) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(25) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(26) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(27) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(28) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(29) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(30) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(31) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(32) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(33) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
Gas(34) CCGT	0.052672	43.6615	231.521	-0.07134	0.02133	0.000003	6	0.551
CHP(1)	0.004895	11.8495	665.1094	-0.05555	0.05151	0.00005	6.667	0.551
CHP(2)	0.004895	11.8495	665.1094	-0.05555	0.05151	0.00005	6.667	0.551

CHP(3)	0.004895	11.8495	665.1094	-0.05555	0.05151	0.00005	6.667	0.551
CHP(4)	0.004895	11.8495	665.1094	-0.05555	0.05151	0.00005	6.667	0.551
CHP(5)	0.004895	11.8495	665.1094	-0.05555	0.05151	0.00005	6.667	0.551
Nuclear(1)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Nuclear(2)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Nuclear(3)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Nuclear(4)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(5)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(6)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(7)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(8)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(9)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Nuclear(10)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Nuclear(11)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Nuclear(12)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Nuclear(13)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(14)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(15)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(16)	0.000213	4.4231	395.3749	N/A	N/A	N/A	N/A	N/A
Nuclear(17)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Nuclear(18)	0.000276	5.645147	217.887	N/A	N/A	N/A	N/A	N/A
Coal(1)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(2)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(3)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(4)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(5)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(6)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(7)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(8)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(9)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(10)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(11)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(12)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(13)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(14)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(15)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(16)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(17)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(18)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(19)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(20)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(21)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(22)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(23)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836

Coal(24)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(25)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(26)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(27)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(28)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(29)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(30)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(31)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(32)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(33)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(34)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(35)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(36)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(37)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(38)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(39)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(40)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(41)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(42)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(43)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(44)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(45)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(46)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(47)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(48)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(49)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(50)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(51)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(52)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(53)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(54)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(55)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(56)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Coal(57)	0.014142	16.0811	212.3076	-0.02094	0.07389	0.00001	9	0.836
Oil(1)	0.328412	56.564	86.3852	-0.05554	0.0649	0.0002	2.857	0.974
Oil(2)	0.328412	56.564	86.3852	-0.05554	0.0649	0.0002	2.857	0.974
Oil(3)	0.328412	56.564	86.3852	-0.05554	0.0649	0.0002	2.857	0.974
Oil(4)	0.328412	56.564	86.3852	-0.05554	0.0649	0.0002	2.857	0.974
Oil(5)	0.328412	56.564	86.3852	-0.05554	0.0649	0.0002	2.857	0.974

Appendix B

B. Value of Wind Power Results (for Chapter 3)

Year	Bus No. 30 (£)	Bus No. 5 (£)	Bus No. 19 (£)	Bus No. 26 (£)	Capital Cost (£)
1	2319108.31	1281867	1467371	2052911.34	8000000
2	3381165.6	1868909	2139367	2993063.6	8000000
3	4383106.44	2422723	2773326	3879999.7	8000000
4	5328333.65	2945189	3371400	4716731.86	8000000
5	6220057.44	3438082	3935621	5506101.83	8000000
6	7061306.29	3903074	4467905	6250790.48	8000000
7	7854937.28	4341747	4970060	6953326.94	8000000
8	8603645.76	4755589	5443791	7616097.18	8000000
9	9309974.52	5146006	5890707	8241352.13	8000000
10	9976322.41	5514324	6312326	8831215.29	8000000
11	10604952.5	5861793	6710079	9387689.97	8000000
12	11197999.7	6189595	7085318	9912666.08	8000000
13	11757478.3	6498842	7439318	10407926.6	8000000
14	12285288.2	6790584	7773279	10875153.4	8000000
15	12783222.1	7065813	8088337	11315933.5	8000000
16	13252971.1	7325462	8385562	11731763.8	8000000
17	13696130.5	7570415	8665962	12124056.4	8000000
18	14114205.4	7801502	8930491	12494143.9	8000000
19	14508615.7	8019508	9180047	12843283	8000000
20	14880700.8	8225175	9415476	13172659.5	8000000

C. Generation Scheduling Results for the Reduced GB System

Scenario	Sub Scenario	Case No.	Production Cost (£/MWh)	Emissions (Kg CO2/MWh)	Annual Losses (MWh)	Spinning Reserve (at the time of System Peak in MW)
Scenario 1	Sub_Scenario1	Case 1 (No Nuclear Power Replacement)	22.9	314.38	3084655	3154.93
Scenario 1	Sub_Scenario1	Case 2 (50% Nuclear Power Replacement)	22.38	301.06	3011243	2911.09
Scenario 1	Sub_Scenario1	Case 3 (100% Nuclear Power Replacement)	22.22	283.44	2994568	2793.71
Scenario 1	Sub_Scenario 2	Case 1 (No Nuclear Power Replacement)	23.21	352.16	3131675	3154.93
Scenario 1	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	22.66	320.37	3077245	2911.09
Scenario 1	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	22.32	307.79	3035648	2793.71
Scenario 1	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	24.95	364.45	3303455	3154.93
Scenario 1	Sub_Scenario3	Case 2 (50% Nuclear Power Replacement)	23.4	331.99	3104566	2911.09
Scenario 1	Sub_Scenario3	Case 3 (100% Nuclear Power Replacement)	22.84	298.76	3101435	2793.71
Scenario 1	Sub_Scenario 4	Case 1 (No Nuclear Power Replacement)	25.05	375.45	3393678	3154.93
Scenario 1	Sub_Scenario 4	Case 2 (50% Nuclear Power Replacement)	23.95	329.96	3250466	2911.09
Scenario 1	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	23.34	218.31	3171979	2793.71
Scenario 2	Sub_Scenario1	Case 1 (No Nuclear Power Replacement)	21.03	298.18	3560000	3511.12
Scenario 2	Sub_Scenario1	Case 2 (50% Nuclear Power Replacement)	19.62	272.19	3492000	3450.06
Scenario 2	Sub_Scenario1	Case 3 (100% Nuclear Power Replacement)	19.23	220.28	3434000	3271.57
Scenario 2	Sub_Scenario 2	Case 1 (No Nuclear Power Replacement)	21.55	318.64	3695000	3511.12
Scenario 2	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	20.64	280.12	3597000	3450.06
Scenario 2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	19.46	227.08	3480000	3271.57
Scenario 2	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	26.17	324.78	3911453	3511.12
Scenario 2	Sub_Scenario3	Case 2 (50% Nuclear Power Replacement)	20.86	282.12	3760000	3450.06
Scenario 2	Sub_Scenario3	Case 3 (100% Nuclear Power Replacement)	19.92	239.87	3694000	3271.57
Scenario 2	Sub_Scenario 4	Case 1 (No Nuclear Power Replacement)	26.95	334.78	3934000	3511.12

Scenario 2	Sub_Scenario 4	Case 2 (50% Nuclear Power Replacement)	23.68	302.12	3871000	3450.06
Scenario 2	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	21.54	256.5	3776000	3271.57
Scenario 3-1	Sub_Scenario1	Case 1 (No Nuclear Power Replacement)	23.19	352.53	2832000	2307.62
Scenario 3-1	Sub_Scenario1	Case 2 (50% Nuclear Power Replacement)	23.09	330.75	2775000	2273.88
Scenario 3-1	Sub_Scenario1	Case 3 (100% Nuclear Power Replacement)	22.83	260.03	2765000	2227.4
Scenario 3-1	Sub_Scenario 2	Case 1 (No Nuclear Power Replacement)	23.51	372.53	2913000	2307.62
Scenario 3-1	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	23.4	340.75	2860000	2273.88
Scenario 3-1	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	22.94	300.03	2847000	2227.4
Scenario 3-1	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	25.27	382.53	3039990	2307.62
Scenario 3-1	Sub_Scenario3	Case 2 (50% Nuclear Power Replacement)	24.8	335.75	2982000	2273.88
Scenario 3-1	Sub_Scenario3	Case 3 (100% Nuclear Power Replacement)	24.08	285.33	2963000	2227.4
Scenario 3-1	Sub_Scenario 4	Case 1 (No Nuclear Power Replacement)	25.5	356.47	3132000	2307.62
Scenario 3-1	Sub_Scenario 4	Case 2 (50% Nuclear Power Replacement)	24.92	335.58	3100000	2273.88
Scenario 3-1	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	24.28	305.96	3085000	2227.4
Scenario 3-2	Sub_Scenario1	Case 1 (No Nuclear Power Replacement)	23.44	326.78	2619000	1995.03
Scenario 3-2	Sub_Scenario1	Case 2 (50% Nuclear Power Replacement)	23.4	307.16	2612000	1892.99
Scenario 3-2	Sub_Scenario1	Case 3 (100% Nuclear Power Replacement)	23.37	264.55	2612000	1849.66
Scenario 3-2	Sub_Scenario 2	Case 1 (No Nuclear Power Replacement)	23.74	356.78	2712000	1995.03
Scenario 3-2	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	23.66	317.16	2707000	1892.99
Scenario 3-2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	23.5	269.65	2705000	1849.66
Scenario 3-2	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	25.39	386.78	2837324	1995.03
Scenario 3-2	Sub_Scenario3	Case 2 (50% Nuclear Power Replacement)	25.03	327.15	2820000	1892.99
Scenario 3-2	Sub_Scenario3	Case 3 (100% Nuclear Power Replacement)	24.72	274.65	2810000	1849.66
Scenario 3-2	Sub_Scenario 4	Case 1 (No Nuclear Power Replacement)	25.74	396.96	2851000	1995.03
Scenario 3-2	Sub_Scenario 4	Case 2 (50% Nuclear Power	25.21	347.74	2837324	1892.99

		Replacement)				
Scenario 3-2	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	24.87	294.54	2832000	1849.66
Scenario 4-1	Sub_Scenario1	Case 1 (No Nuclear Power Replacement)	23.31	320.66	2486000	1903.91
Scenario 4-1	Sub_Scenario1	Case 2 (50% Nuclear Power Replacement)	23.02	302.05	2477000	1832.97
Scenario 4-1	Sub_Scenario1	Case 3 (100% Nuclear Power Replacement)	22.73	246.47	2480000	1749.07
Scenario 4-1	Sub_Scenario 2	Case 1 (No Nuclear Power Replacement)	23.58	340.66	2574000	1903.91
Scenario 4-1	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	23.51	322.05	2553000	1832.97
Scenario 4-1	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	23.4	256.47	2539000	1749.07
Scenario 4-1	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	24.45	370.66	2654924	1903.91
Scenario 4-1	Sub_Scenario3	Case 2 (50% Nuclear Power Replacement)	24.23	322.6	2629000	1832.97
Scenario 4-1	Sub_Scenario3	Case 3 (100% Nuclear Power Replacement)	24.12	266.37	2613000	1749.07
Scenario 4-1	Sub_Scenario 4	Case 1 (No Nuclear Power Replacement)	24.71	380.66	2689000	1903.91
Scenario 4-1	Sub_Scenario 4	Case 2 (50% Nuclear Power Replacement)	24.62	352.6	2665000	1832.97
Scenario 4-1	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	24.57	296.37	2660000	1749.07
Scenario 4-2	Sub_Scenario1	Case 1 (No Nuclear Power Replacement)	23.41	334.69	2750000	2239.6
Scenario 4-2	Sub_Scenario1	Case 2 (50% Nuclear Power Replacement)	23.02	290.98	2735000	2149.56
Scenario 4-2	Sub_Scenario1	Case 3 (100% Nuclear Power Replacement)	22.73	234.84	2713000	2058.61
Scenario 4-2	Sub_Scenario 2	Case 1 (No Nuclear Power Replacement)	23.58	345.23	2936000	2239.6
Scenario 4-2	Sub_Scenario 2	Case 2 (50% Nuclear Power Replacement)	23.44	303.33	2905000	2149.56
Scenario 4-2	Sub_Scenario 2	Case 3 (100% Nuclear Power Replacement)	23.18	258.87	2900000	2058.61
Scenario 4-2	Sub_Scenario3	Case 1 (No Nuclear Power Replacement)	25	364.69	3161589	2239.6
Scenario 4-2	Sub_Scenario3	Case 2 (50% Nuclear Power Replacement)	24.08	308.7	3076000	2149.56
Scenario 4-2	Sub_Scenario3	Case 3 (100% Nuclear Power Replacement)	23.91	264.23	3040000	2058.61
Scenario 4-2	Sub_Scenario 4	Case 1 (No Nuclear Power Replacement)	25.4	378.76	3234000	2239.6
Scenario 4-2	Sub_Scenario 4	Case 2 (50% Nuclear Power Replacement)	24.24	324.73	3208000	2149.56

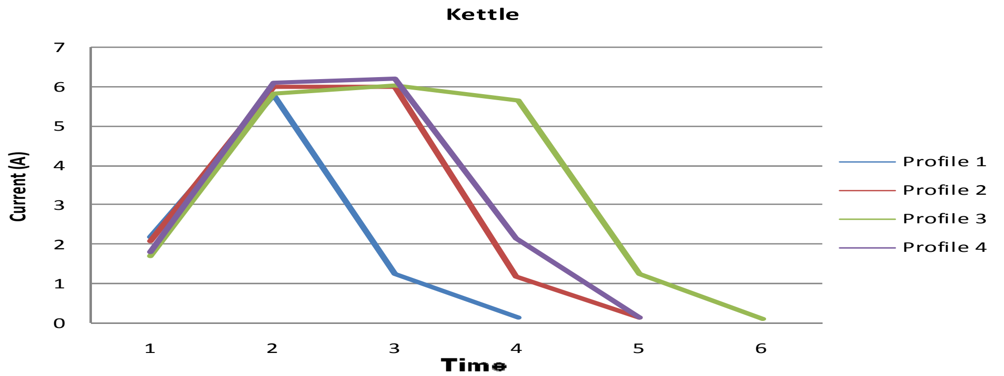
Scenario 4-2	Sub_Scenario 4	Case 3 (100% Nuclear Power Replacement)	24.02	289.45	3189000	2058.61

Appendix D

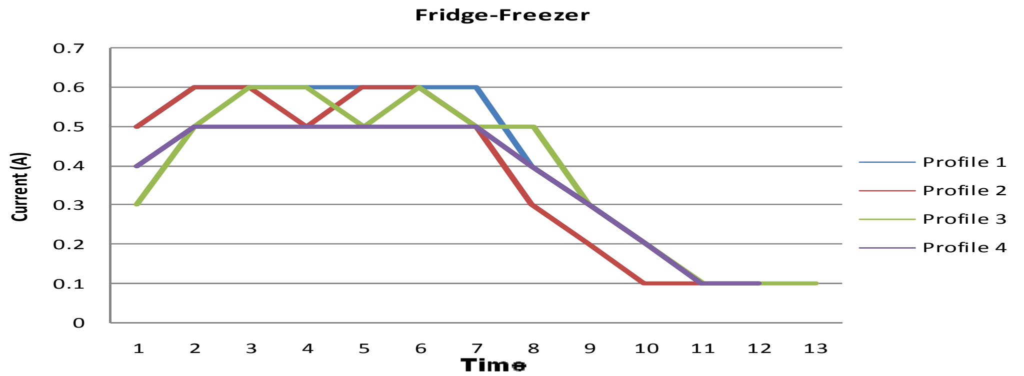
D. 1 Different Load Profiles of Domestic Appliances

(Time is in Minutes)

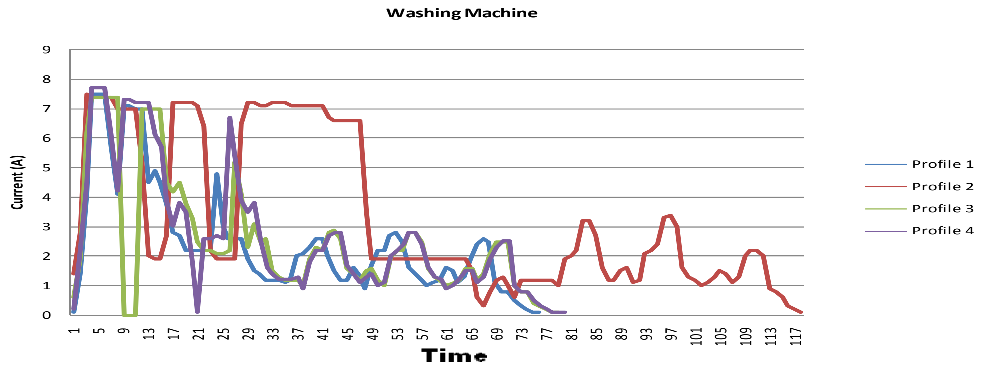
D.1.1. Kettle



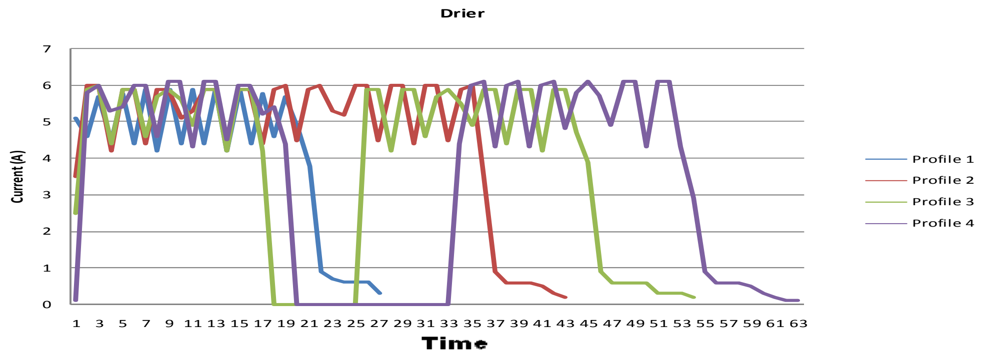
D.1.2. Fridge-Freezer



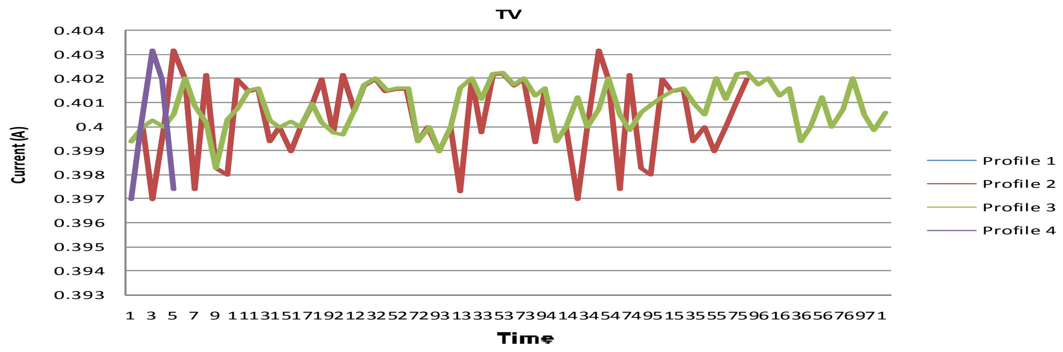
D.1.3 Washing Machine



D.1.4. Drier

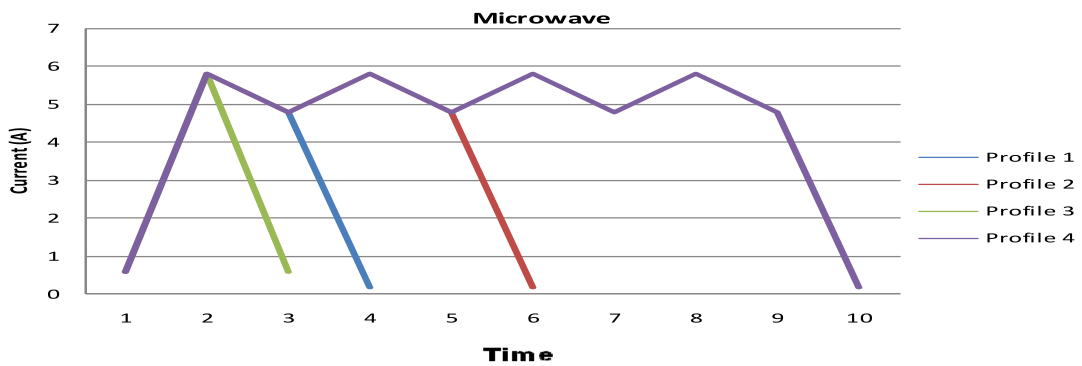


D.1.5. TV

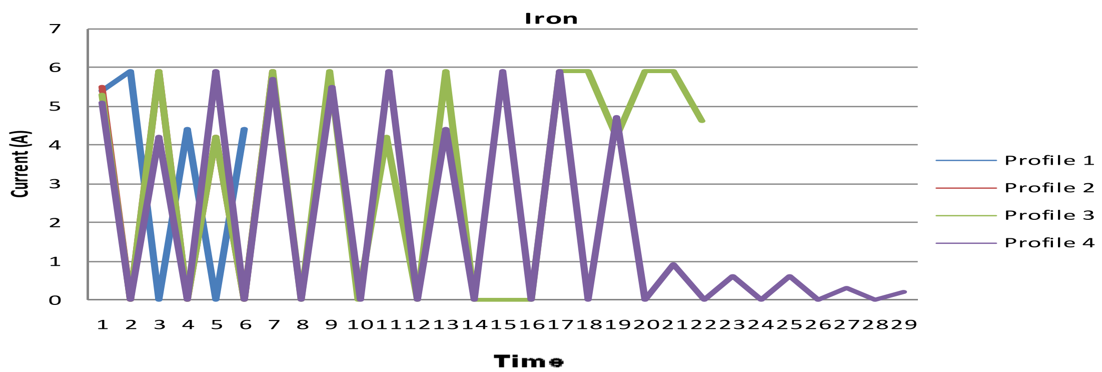


D.1.6. Cooker

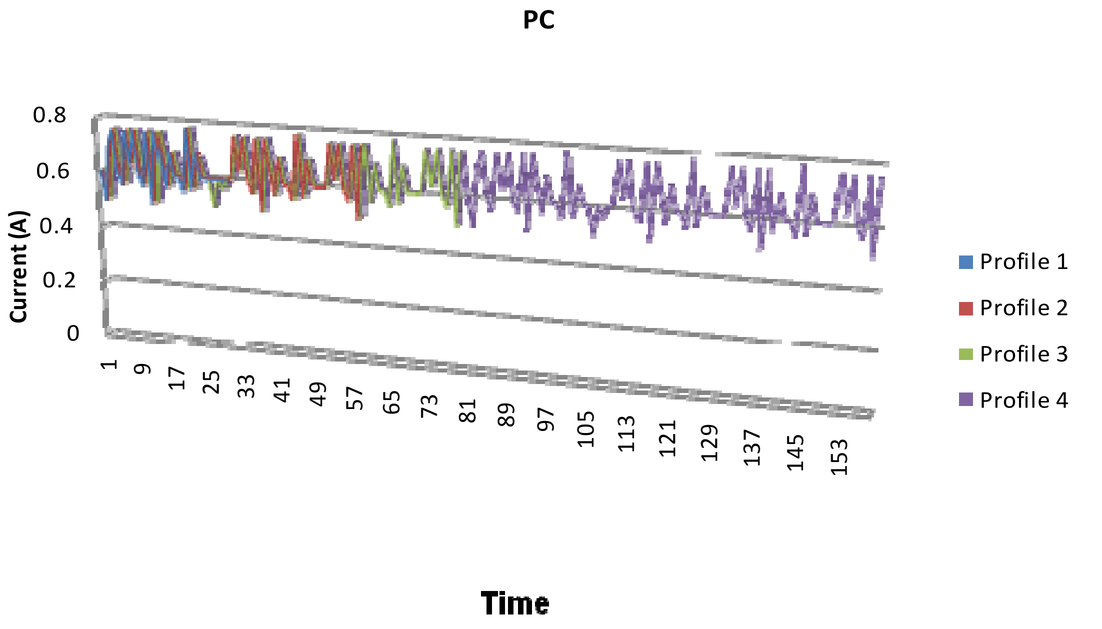
D.1.7. Microwave



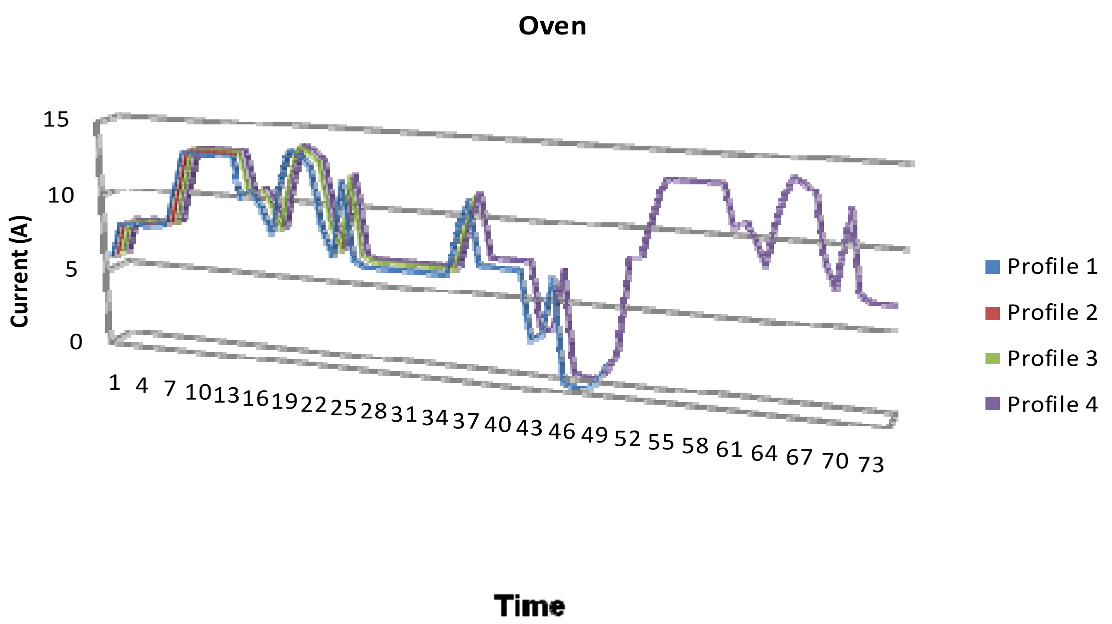
D.1.8. Iron



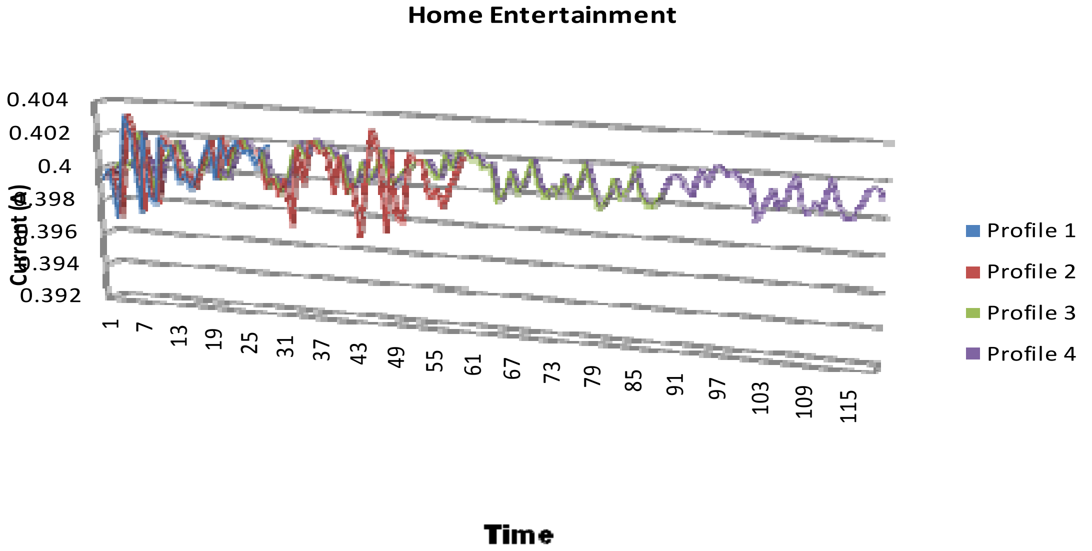
D.1.9. PC



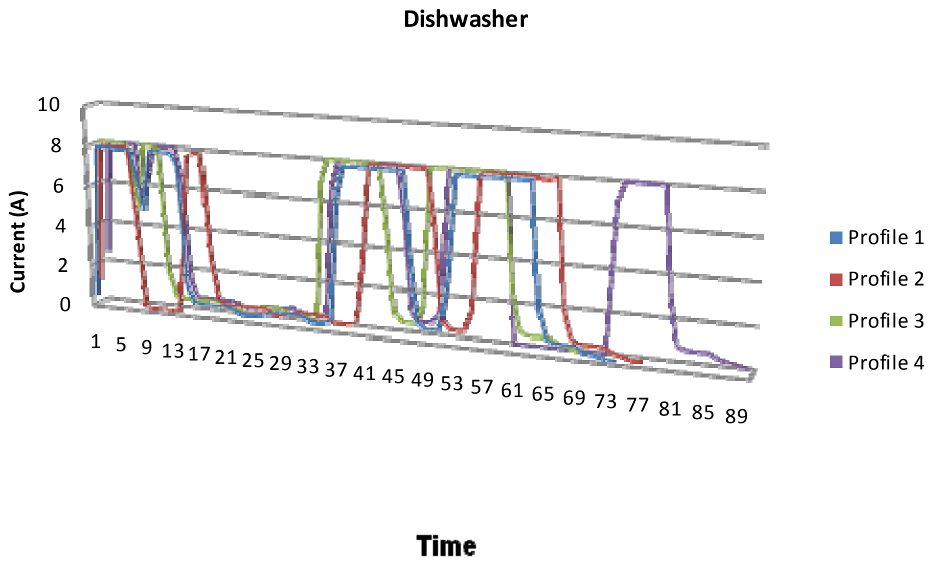
D.1.10. Oven



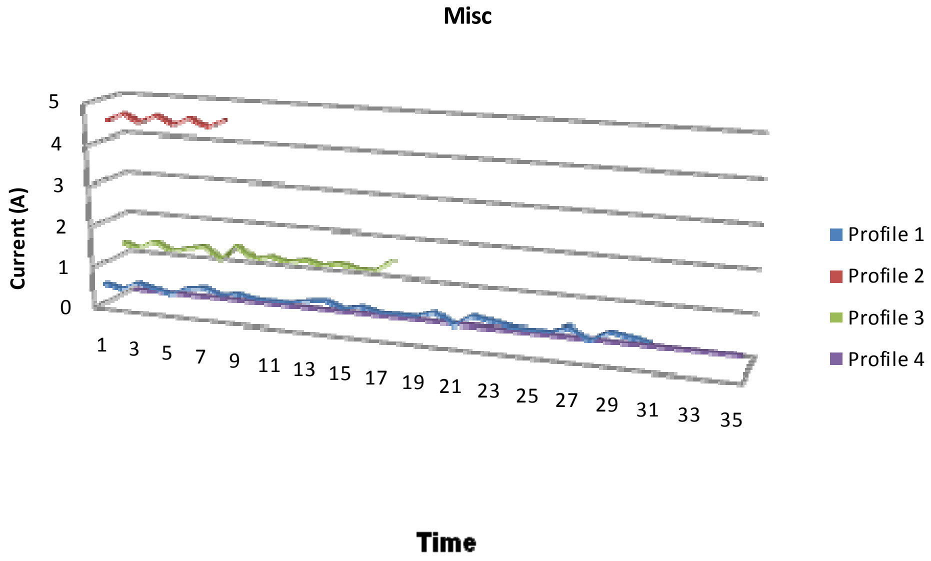
D.1.11. Home Entertainment (DVD Player, X-Box etc,)



D.1.12. Dishwasher

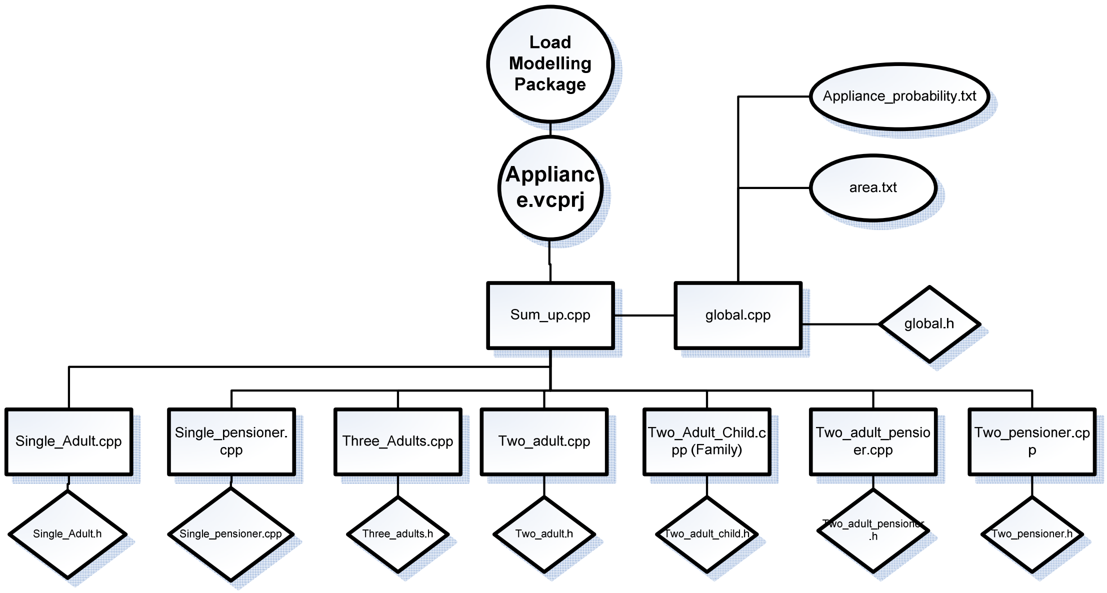


D.1.13. Miscellenous Appliances



Appendix E

E. 1 Flowchart of the Package



Appendix F

F.1. Technical Reports:

1. V. Hamidi, F. Li Optimal Energy Mix for the GB Power System in 2020. Submitted to Areva T&D June 2009

F.2. Journal Publications

1. V. Hamidi, F.Li, “Responsive Demand to Increase the Value of Wind”, accepted by The International Journal of Innovations in Energy Systems and Power (IJESP) , August 2008.
2. V. Hamidi, F.Li “Lifetime Value of Wind at Different Locations in the Grid”, IEEE Transactions on Power Delivery, December 2009 (Submitted)
3. V. Hamidi, F.Li, F. Robinson “Domestic Demand Modelling for Demand Side Management Purposed” Journal of Electric Power System Research, August 2009
4. V. Hamidi, F.Li, “Impact of Different Spinning Reserve Levels of Value of Wind Power”, IEEE Transactions on Power Systems, March 2009 (Submitted)
5. V. Hamidi, F.Li, “Impact of Demand Response to Increase the Value of Wind Power” Institute of Engineering and Technology (IET) Journal of Renewable Power Generation , June 2009.

F.3 Conference Publications

1. V. Hamidi, F. Li, “Effect of Windfarm Location on Value of Wind by Considering Security”, IEEE Power Engineering Society General Meeting, Pittsburgh, July, 2008.
2. V. Hamidi, F. Li, “Effect of Responsive Demand in Domestic Sector on Power system Operation in the Networks with High Penetrations of Renewables”, IEEE Power Engineering Society General Meeting, Pittsburgh, July, 2008.
3. V. Hamidi, F. Li, “Modelling the Responsive Demand in Domestic Sector to Increase the Value of Wind”, Power System Computation Conference, Glasgow, UK, July, 2008.
4. V. Hamidi, F. Li, “Value of windfarm location and penetration on operation of power system and benefits of responsive demand”, Third conference on Electric Utility Deregulation and Restructuring and Power Technologies, Nanjing, China, April 2008.
5. V. Hamidi, F. Li and F. Robinson, “Responsive Demand in Networks with high penetration of Wind Power”, IEEE Transmission and Distribution, Chicago, USA, April, 2008.

6. V.Hamidi, F. Li, “New Control Methods in Demand Side Management to Improve the Security of Supply in the UK's Electricity Network", University Power Engineering Conference, Brighton, UK, 2007.

New Control Methods in Demand Side Management to Improve the Security of Supply in the UK's Electricity Network

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ABSTRACT

Distribution networks across the UK are expected to connect substantial embedded generation in near future as .One of the key means to combat climate change. The majority of embedded generation are expected to be renewables that have intermittent nature with poor persistence. This would pose serious problem to the security and quality of supply that distribution network operators (DNOs) have license obligation to comply, (distribution network operators do not generally hold reserve, but take load shedding as the consequential action of not sufficient reserve). Existing solutions include: 1) Backing up intermittent generation by partially loaded plant or storage devices, they tend to be expensive and well research; 2) better managing demand so that they can follow changing patterns of generation. Demand side management is an old topic, traditionally they are used to smooth demand curve to maximise the efficiency of conventional generation where they can be controllable and predictable. As the characteristic of future generation changes, new demand side mechanism needs to be sought, allowing the demand to follow the intermittent generation and is the subject of this research. The paper firstly looks into the potential demand manipulation that can be achieved from existing control mechanism and its associated value to the security of supply The paper then investigates the potential contribution to network security from greater demand side management and the requirement for additional control mechanism to achieve the full potential d benefit. Finally, the benefits to the system security will be quantified to a system with varying degree of intermittent generation

Keywords: Responsive Load, Spinning Reserve, Demand Side Management, Operational Reserve

1. Introduction:

The UK's strategy is to generate 10% of electrical energy from renewables and 10GWe of CHP by 2010. Besides, UK is committed to reduce the CO_2 emissions down to 20% by 2010. Distribution Generations (DG) have an important role to achieve these goals in the UK, although the present structure of networks circumscribes implementing DGs; Having an adequate amount of power reserve is a must in all electricity networks to keep the system always stable and running to supply the loads with less interruption.

Besides, by *Demand Side Management* Programmes network operators can improve the quality of supply, reliability and eliminate the issues regarding to peak load and unnecessary load shedding especially in domestic sector which is responsible for 29% of total electricity consumption of the UK.

On the other hand maintaining the security of supply depends on several parameters. *Spinning reserve* has an important role is providing security for the system as it is an online source of generation which can be used with less delay (less then 10 seconds) and in case of contingency like dropping the frequency as a result of sudden and unexpected increase in load level or lose of a generation unit. Spinning reserve can be used up to 10 minutes until supplement reserve becomes available.

Classically, spinning reserve comes from an online source of generation which is not loaded fully. This leads to three consequences: 1) a plant may not operate at their most efficient settings; 2) a considerable revenue will be lost which otherwise could be sold in the energy market; 3) Requirements in reserve in a system with significant intermittent generation will grow, which will require more expensive and controllable generation to back up.

Recently some researchers believe that by shedding some types of load for a short while, not only they do not make any inconvenience for consumers but also they can provide adequate amount of extra required power to keep the entire the electricity network stable. These loads could be those which their operation cycle does not have a visible effect such as air conditioning systems or fridges, in fact *Passive Loads*.

Demand Side Management as a means of providing system reserve is a less attractive options. Contracts for demand reduction at peak times are normally set up between network operators and large industrial customers. For domestic consumers, economic 7 and 10 are the main options to shift energy consumption from the peak hours to off-peak hours through economic incentives. This of course is driven by consumer demand patterns, whereby, peak demands tend to be on the day time and trough demands tend to be at night. To incentive consumers to consume more at night and less on the day, DNOs set cheap tariff for night and expensive tariff for days. Therefore this research paper focuses on

2. Demand Side Management Programmes:

There are various DSM programmes have been widely introduced and used in most of the countries. In the UK there are several types of DSM programmes have been implemented since 1970's oil crises which caused a big concern in terms of Energy Security in the world, particularly in Europe. DSM consists of several programmes which aim to control the loads in a way to benefit both consumers and utilities without any inconvenience for consumers. Domestic sector in the UK is responsible for about 29% of total Electricity consumption. This energy is being consumed in several ways. Figure 1 compares the domestic sector end-use consumption modes.

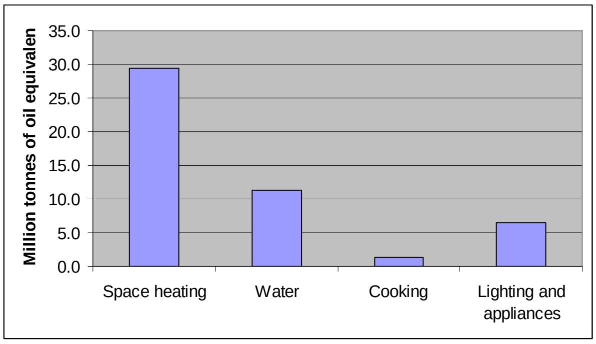


Figure1. Domestic Sector End-use Consumption in the UK[2]

Space heating in the UK because of the typical climate of the country is the most consumer of total energy in domestic sector. For sake of this, most of the DSM programmes have focused on space heating throughout several schemes which load management if the most famous one.

Load Management (LM) is one of the DSM programmes that have been widely exercised in most of the countries as it directly controls the load. The principle of LM is that the user profit increases during off-peak period, therefore controllable loads are vital in LM. They are included programmes such as multi tariff energy (known as Economy 7 and Economy 10 in the UK) which by shifting the loads from peak hours to off peak hours aim to clip the peak load in daily demand curve. DTI's 2006 figures show that a standard credit Economy 7 customer with a non-home supplier, on average, paid £23 less than a customer who had not changed supplier. Equivalent savings for direct debit customers were £39.

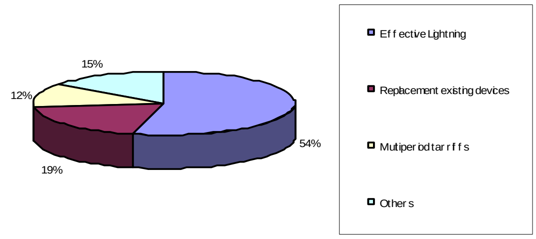


Figure2.Most Popular LM Programmes in Domestic Sector

There are other LM programmes also which effect differently but ultimately they improve the load characters such as flexibility and load factor which are in benefit of both consumers and network utilities. By improving load factor network is less in need of temporary sources of power either comes from sources of reserve or from temporary generation units which are much more expensive than normal power as the difference between the peak load and base load is less therefore generation units which are committed to supply the demand can work in a continues cycle with less sudden increase in amount of delivered power. Figure2 shows the most popular load management programmes in domestic areas.

In this paper southwest of the UK domestic areas have been considered for the research. In this area with 25,492 domestic consumers; total electricity consumption is 116,811GWh which in comparison with industry and commercial sector with 118,832GWh is slightly less.

Like most other parts of the UK peak load usually happens in winter time because of high demand of heating loads. On this research passive loads are considered as controllable loads because by putting control on them they will not cause any inconvenience for consumers.

Electric Space Heating accounts just over 30% of total energy consumption in domestic sector. Demand side management programmes which have considered water heating or space heating systems are not very new. Ripple control systems have been introduced in 1960's-1980's and still have widely been used to control water heating systems. Because of energy storage capacity of water turning off it does not make any inconvenience for consumer to participate in demand side management. These types of loads are considered as passive loads in terms of Demand Side Management.

Another aspect of using the passive loads is to extend their use not only to manage the power consumption in a way that both utilities and consumers can benefit from it, but also to use the load as a backup in the network instead of some extra generations (spinning reserve) which are supposed to be for security of the network in case of contingency. In the following chapters we will see how load can be used as spinning reserve in the system; the main focus will be on renewable based generation

3. Power Reserve in the System:

There are several types of Power Reserve available in the network. Each of them has specific application, such as compensating demand prediction errors and serving the loads in case of losing a unit etc. They are included:
(1) Regulatory reserve (frequency response partners) [7]
(2) Spinning reserve
(3) Contingency reserve (Operating Reserve)
Spinning reserve has several definitions but in general spinning reserve Service may be provided by generating units that are on-line and loaded at less than maximum output, ready to serve additional demand and which can be fully applied in ten minutes. Classically spinning reserve is calculated during unit commitment (UC). Spinning reserve is often required to be a certain percentage of the load or be capable of making up the loss of the largest generator while sometimes these reserve requirements have been calculated as a function of the probability of not having sufficient generation to meet the load. Table.1 presents some different equations which are used in different places to estimate amount of spinning reserve.
The rate of Spinning Reserve / Average Demand is an indicator of reliability of the network as it shows how much energy is available

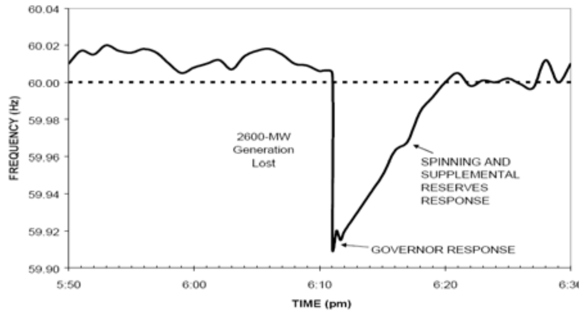


Figure3: An example for Frequency drop and the frequency recovery in the network [4]

Country	Calculation of the amount of spinning reserve
UCTE	No specific recommendation. The recommended maximum is $\sqrt{10L_{max\ zone}+150^2}-150$
Belgium	UCTE rules. Currently at least 460 MW by generators.
France	UCTE rules. Currently at least 500 MW.
The Netherlands	UCTE rules. Currently at least 300 MW.
Spain	Between $3\sqrt{L_{max}}$ and $6\sqrt{L_{max}}$
California	$50\% \times \max(5\% \times P_{hydro} + 7\% \times P_{other\ generation}; P_{largest\ contingency}) + P_{non-firm\ import}$
PJM	1.1% of the peak + probabilistic calculation on typical days and hours

Table1. Calculation of Spinning Reserve [5]

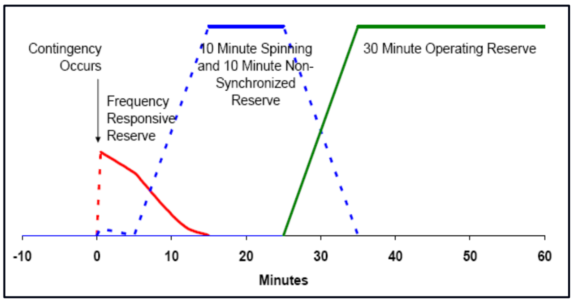


Figure 3.Operation of different reserves in the Network [4]

4. Spinning reserve in the UK:

National Grid Company (NGC) is responsible to provide adequate amount of reserve for the system from different sources. The Spinning Reserve is among necessary services which NGC is obliged to provide along with black start [5]. The participants in providing reserve are free to provide the reserve either from generation units or through shedding the demand.
Roughly about 1.5GW spinning reserve is usually planned for the system depending on time/day which usually is higher during winter. The power providers are being paid £/MWh they supply power, however the rate of Spinning Reserve varies during the day. Figure

The NGC's minimum standard for units participating in providing spinning reserve (known as Fast Reserve) is [3]:

1. Flexibility of the units providing reserve by a short notice either by generating power or reducing demand within 2 minutes short notice
2. Minimum intractable block 50MW or combination of more than one block equal to 70MW
3. Delivery rate of 25MW/min and commitment of minimum 15 minutes.

Besides, the location of units participating in providing fats reserve is also considerable although it has not been noted as a requirement.
Meeting such requirements is a must and failure to meet these requirements means the bidder will not be considered as a candidate to participate in fast reserve market.

5. Responsive Loads as a source of Reserve:

I.e. an average ownership rate of refrigerator units in the UK domestic areas is 1.7%. It means in each house on average there are more than one unit of refrigerator. If an average power consumption of a fridge is assumed 150W in operation mode (about 140W on defrosting mode; depending on type of device) therefore by having about 205W passive load in each household which comes from refrigeration units in total in an area like Bath and North East Somerset about 15.68MW passive load exists. Not only refrigerator units can be classified as passive load, devices such as electric heater, air conditioning, washing machine, dryer etc. they are all have the capability of being controlled either automatically or be called by network operator in event of need of shedding the load. By extending this assumption into the UK electricity network in which more than 116,811GWh power is being consumed just in domestic sector, where in that day about 640MWh fast response (Spinning Reserve) has been scheduled by National Grid, then by having responsive loads roughly 6% of total of demand (just from refrigeration units, assumed all are in duty cycle) is always available to be shed and work instead of having spinning reserve in the system. [2]

Figure 4 shows daily requirement of fast reserve in our exampled day (16th December 2005). Fast reserve requirement is currently being scheduled for all the days in the month on the same daily basis. This requirement covers weekdays, Saturdays, Sundays and Bank Holidays in December.

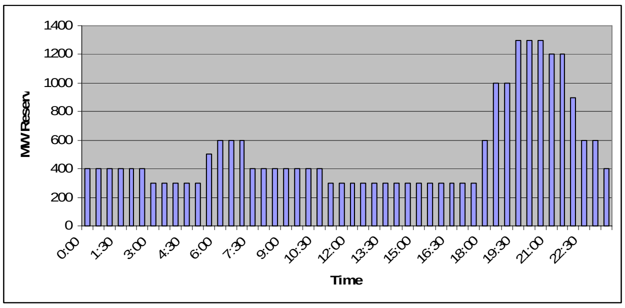


Figure4. Fast Reserve requirement in December 2005

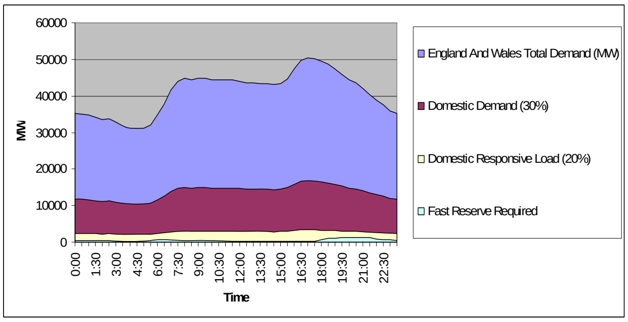


Figure5. Total Demand, Domestic Demand, Domestic Responsive Load and Fast Reserve required on our example day.

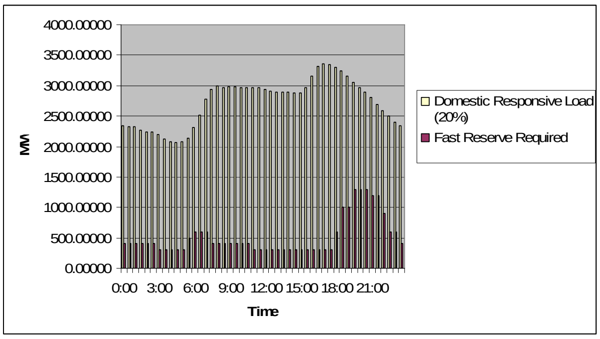


Figure6. Domestic Responsive Load and Fast Reserve required on our example day.

Figure6 clearly shows that spinning reserve requirements can be covered by either shifting responsive loads or shedding them in case of need to utilize spinning reserve. This estimation may be just a bit far from reality as the power consumption in domestic area does not necessary follow the total demand curve therefore the amount of available responsive load does is not always a certain percentage of total demand. But this estimation is necessary for the first instance as the total domestic power consumption pattern is unknown at the moment.

By extending this topic responsive loads can have a capacity credit like generation units, depending on regions and the amount which each unit can contribute as an ancillary source of reserve in the system:

$C = Total\ Number\ of\ Consumers$

$D = Total\ Demand$

$R = Total\ Flexible\ Load$

$aD = average\ Demand\ per\ Household$

$aR = average\ Flexible\ Load\ per\ Household$

$D = aD \times C\ \ regional\ Demand$

$R = aR \times C\ \ regional\ Flexible\ Demand$

$aDt = S \times D$

$S = responsive\ Load\ Capacity$

$aDt = Total\ responsive\ demand$

Responsive Load Capacity could be a unique number for each household, district, town etc.

By knowing this number network operators can determine the possible amount of demand which could be shed in case of needing extra power. Therefore aDt is a function of R and ND which demonstrates the total amount of responsive load at any time. aDt could be vary time to time according to the demand profile of the network. It can also be vary if loads can set to be in a way to respond in just specific times, i.e. just in peak hours then the consumers can make sure they will not be called to shed their loads in off peak hours. S can actually have 2 different values; (1) one is the general amount of its contribution in 24hours which indicates the contribution to Spinning Reserve and (2) another rate can be its *Sectional Value* which presents the capability of demand to be reduced during peak hours to avoid using ancillary sources of generation for just a few hours. The Sectional Value becomes more important in networks with significant amount of renewable generation where utilities make more effort to be relied on present sources are generation rather than importing power from non-renewable sources. In next section we will assess the ability of responsive loads to provide enough reserve for the system.

$$\sum_{n=1}^{n=\infty}(Ti.Pi) = Dt + Losses + R \geq 0 \quad \textit{For the syetem without responsive Load}$$

$$\sum_{n=1}^{n=\infty}(Ti.Pi) = Dt + Losses + R - Df \geq 0 \; \textit{For the system with responsive Load}$$

$$Df = \textit{Total responsive Demand}$$

$$Df = S \times Dt$$

6. Responsive Loads in Renewable Generation System:

As the UK's strategy is to generate 10% of total electricity from renewable sources by 2010 and because of intermittency nature of these sources, the operation reserve and spinning reserve margin of the system may change depending on rate of penetration of these sources although the believe is on no change in spinning reserve by 10% penetration of renewable source and just 36MW additional regulation to maintain the frequency at no-wind level [1]; i.e. in the future we should expect to see more small wind farms participating in supplying the loads. However at the moment because of existing conventional system we are always relied on other sources as a backup to supply the loads in case of any failure or sudden increase in load etc. but in the future we expect to be relied more on renewable sources rather than non-renewables.

Thereby responsive loads can make their most of their efficiency in renewable systems which fast responding to failure or lose of any units can be maintained by reducing the demand very fast and as serving the loads can be optimized according to level of available generation. The nature of the responsive load's contribution in maintaining reserve is slightly different than before and it will be achieved by a mixture of responsive loads and energy storage units; during low output of generation units such as when wind's speed is slow in wind turbine units responsive loads can make a big contribution on supplying loads for longer period of time from renewable sources without starting to use energy storage devices.

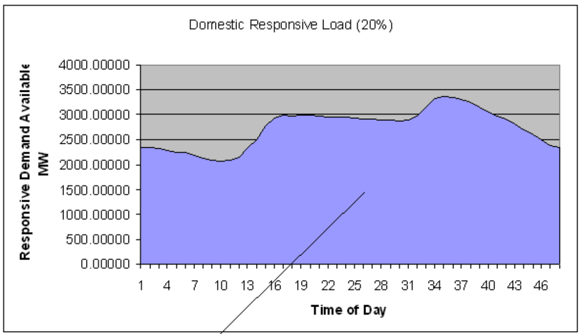
Responsive loads in renewable systems by clipping the extra demand at the times when generation rate is not enough to supply the total load will improve the reliability of the system; in fact they make the system less needful to ancillary sources of power in intermittent based generation networks.

Responsive loads as a means of reserve have some advantages over generation units providing reserve; i.e. a big constraint in providing spinning reserve from generation units is ramping rate. Participant units such as pump hydro units have all different ramping rates; it means they have different level of providing spinning reserve in MW per minute, times 10 minutes. Although NGC have the minimum ramping rate level of 25MW/Min but not all the existing generation units can participate in providing fast reserve.

Responsive loads are faster to response in comparison with ordinary fast reserve. There will not be any limit in terms of speed of shedding the passive loads as long as committed loads act appropriately. The problems such as synchronising and network transmission limits will be eliminated as well.

7. Requirements of Implementing Responsive Loads:

To implement the responsive load an accurate analysis of load profile is essential at the first instance to find the resources which are capable as responsive load at each period of time i.e. in summer we can not rely on heating systems which are usually turned off naturally. This can work like unit commitment and there should be a same programme which can determine availability of responsive loads. Because most of the passive loads have the nature of smooth power consumption therefore we can expect that the determined amount of their contribution.



$$\int_{t=00:00}^{t=23:59} Dr.dt \text{ MWh } \textit{Responsive Demand available for Utilization}$$

Responsive loads are in fact non-spinning sources of reserve for the system that must comply same

Because responsive loads are in fact specific types of loads which can response to power variations therefore analysing the load curve roughly will give us a prediction of how much responsive load is available in entire system. Besides, online monitoring of the system seems to be an essential task to have accurate information of real time condition of reserve loads. Therefore communication between load and system should be designed.

Also there should be some financial incentives for consumers who take part in Demand Response programme. It can be done through guaranteed money back to them or subtracting from their electricity bill for the hours that they are supposed to shed their loads. Another way to bring the consumer's interest to this programme is to establish a market such as the present reserve market operated by NGC in which load owners can offer the time and volume of the load that are happy to shed. [3]

Fast reserve in the system must have some characteristics that responsive loads need to have to be able to be recognised as a source of reserve; flexibility of spinning reserve is a must and it means that at any time that system needs extra power it must be provided by responsive loads. This obligates all the loads to respond to system's call for shed in a reasonable time. It will happen only if a reliable communication system between network operator and load exists. This scenario is become more important in networks with high capacity of intermittent generation as the output of the network is changeable depending on intermittent sources such as wind, therefore network operator-demand communication may happen several times a day.

8. Constraints:

Shedding the loads for a long period is not a possible option as it brings trouble for consumers; imagine air-conditioning loads can not be turned off for a long time as it might be very hot. Besides, by a small financial incentive consumers are not happy to shed their loads as the profit and convenience that they loose might be more than they get by participating in this programme.

Another big constraint is controlling so many loads which need to be tripped at the same time and it may work as a huge transient in the system and make the system unstable.

On the other hand the cost of lost load is another issue as by shedding the load we will loose the revenue which used to come from supplying the loads, however the cost evaluation is complex as not only the lost load must be considered, but also the cost of the communication and devices which need to be installed is also must be considered.

Conclusion:

By controlling some types of loads in the system the amount of reserve which usually is provided by generation units can be provided by shedding the loads which will not cause any inconvenience for consumers. By extending this into the whole system a kind of market can be provided for responsive demand which can work like the reserve market in which the participants can declare the amount that they are willing to provide as a responsive load.

Future Work:

The evaluation of responsive load and the amount which can change the load factor is the topic which will be focused on in the future as well as assessing the reduction in the cost by reducing the committed units in supplying the load and providing reserve.

Demand Response in the UK’s Domestic Sector

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Abstract— The purpose of this paper is to assess the current level of demand responsiveness among domestic loads. The paper first studies different load profiles of domestic consumers which are composed of power consumption of end-use appliances. Afterwards, it differentiates those loads which could become responsive and evaluates the aggregated effect of these loads and the margin which could be derived from them. The area which has been considered is a residential area; consists of results have been demonstrated on a real residential network in southwest of the UK; small residential area in city of Bath.

Index Terms-- **Responsive Demand, Dynamic Demand, Load Profile, Demand Side Management.**

1. INTRODUCTION

Along with restructuring the electricity market in the UK and government’s aim to draw 20% of total electricity from renewables together with reducing the carbon dioxide emissions down to 26-32% by 2020, demand side has been given a superior likelihood to contribute in attaining this target. Maintaining the security of supply is also becoming increasingly strategic issue considering both volatility of wholesale energy prices, and limited facilities for electricity generation, transmission and distribution which has resulted that suppliers becoming unable to fulfill their contractual obligations.

Domestic sector in the UK is responsible for nearly one third of electricity consumption and the related emissions into the atmosphere resulted by electric power stations. In the UK, the domestic sector is the largest contributor to winter peak demand, and growing domestic electricity demand is straining the available power generation and transmission infrastructure, and meeting the peak demands in winter is increasingly expensive and high price spikes is seen as shown in figure 1 [1].

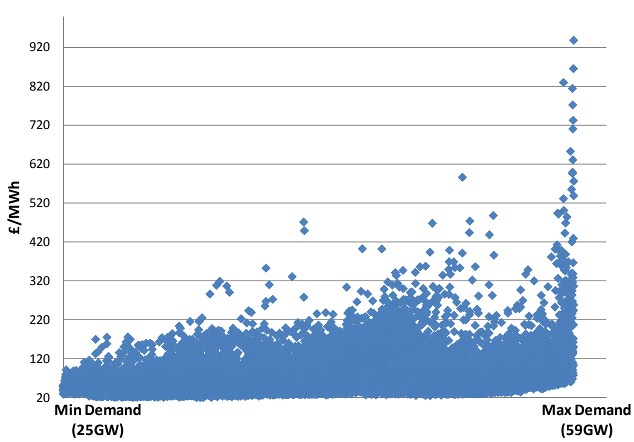

Figure 1. Wholesale Price of Electricity at different Demand Levels

Demand has been participating in improving economy, security and reliability of electricity industry as well as eliminating the environmental concerns since the beginning of introducing Demand Side Management (DSM) programs in the early 1970’s. Dynamic Demand (Responsive Demand) is one of the DSM methods which is intended to be utilized while supplying the load is either restricted because of a network constraints or demand has exceeded over the available power. Section 18 of the Climate Change and Sustainable Energy Act [2], requires the government to report on responsive demand technologies and determines whether it is appropriate to take further action to use responsive demand technologies or not. Services which are currently provided through responsive demand require communication between load and network in order to dispatch negative load upon to network request to provide services such as spinning reserve [3], frequency control [4], Short-Term Operating Reserve (STOR) [5].

The negative aspect of current schemes for employing responsive demand is that they all consider large consumers which upon to instruction of network operator are able to reduce huge bulk of load (i.e. minimum 3MW for STOR) and in fact small domestic demand are not able to participate in these programmes, nonetheless domestic sector accounts for 29% of total electricity consumed in the UK and loads in this sector have the capability to become responsive and if the collective-effect of responsive demand derived from residential consumers be considered it may have more advantages than current methods in particular in the UK as residential consumers are mostly located in high density areas and many issues as a result of concentration of domestic demand such as need for distribution network reinforcement, may be rectified by considering aggregated effect of responsive demand in domestic sector.

The biggest barrier in utilizing the domestic demand response is lack of information regarding the consumers’ behaviour and consumption pattern. Small domestic appliances have a random operation pattern depending on the type of consumer. Studying the individual consumers’ load profile is also not feasible due to the small demand level among domestic consumers. Therefore, it is required to have a generalized tool which is applicable to a group of consumers. Since the aim is not to forecast the demand, but to assess the potential for demand responsiveness, such generalized tool if takes the factors which have impact on consumption pattern results in satisfactory outcome.

In this paper a generalized tool to assess the responsiveness level among domestic consumers is presented. Electricity tariffs which have impact on consumption pattern of domestic consumers are taken into account and different load profiles for different groups of consumers are studied. Then by distinguishing those loads which have the potential to become responsive through numerical example on domestic sector, total responsiveness level is assessed.

This structure of this paper is as follows: section two studies different load profiles in the UK and shows the impact of different electricity tariffs on the load profile of domestic consumers. In section three, the load profiles of domestic consumers are studied by breaking them down into the load profile of end-use appliances. In section four the responsiveness is explained and aggregated amount of all the loads which could become responsive is modelled. Finally by presenting a numerical example in a small residential area with different type of load profiles, total amount of load which could become responsive is quantified.

2. Load Profile in the UK

Load profile shows the consumption pattern of power and is one of the unique characteristics of each consumer because of the dissimilarity need for power in terms of time, level depending on several factors; such as number of people living in each house; their job, age and education level, type of house, climate conditions etc. In the UK, 8 different standard load profiles have been introduced by Elexon. They are included:

1. Profile Class 1 Domestic Unrestricted Customers;
2. Profile Class 2 Domestic Economy 7 Customers;
3. Profile Class 3 Non-Domestic Unrestricted Customers;
4. Profile Class 4 Non-Domestic Economy 7 Customers;
5. Profile Class 5 Non-Domestic Maximum Demand (MD) Customers with a Peak Load Factor (LF) of less than 20%;
6. Profile Class 6 Non-Domestic Maximum Demand Customers with a Peak Load Factor between 20% and 30%;
7. Profile Class 7 Non-Domestic Maximum Demand Customers with a Peak Load Factor between 30% and 40%;
8. Profile Class 8 Non-Domestic Maximum Demand Customers with a Peak Load Factor over 40%.

Power consumption in particular among domestic consumers is either non-restricted or committed to some sort of demand management. DSM programmes aim to modify the load profiles of consumers in order to increase the efficiency and reliability of power systems. Some programmes directly change the load profile by installing the devices which control the power consumption of appliances such as using artificial intelligence based load control for domestic lighting. Other programmes may commit consumers to control their power consumption in return of financial incentives; Time-of-Use (ToU) tariffs which offers cheaper rate for power consumption during a period. ToU tariffs for households were first introduced in 1965 and led to a very important development of electric storage water heaters and the corresponding growth of off-peak consumption [6]. In the UK; Economy 7 is the well-known scheme for domestic consumers and it gives 7 hours continuous low tariff power (mostly overnight) to consumers. Another scheme is called Economy 10 in which 10 hours low tariff is split between day and time; usually 2 hours in the morning, 3 hours in the afternoon and 5 hours overnight.

In 2006 16% of total domestic consumers were committed to Economy 7 tariff; this is equal to 27% of total electrical energy consumed in domestic sector [7]. The commitment level varies across the country but in general consumers save money through reducing their consumption during the day and shift their demand in off-peak hours. Figure 2 and 3 show different types of domestic load profile for the autumn season in the UK.

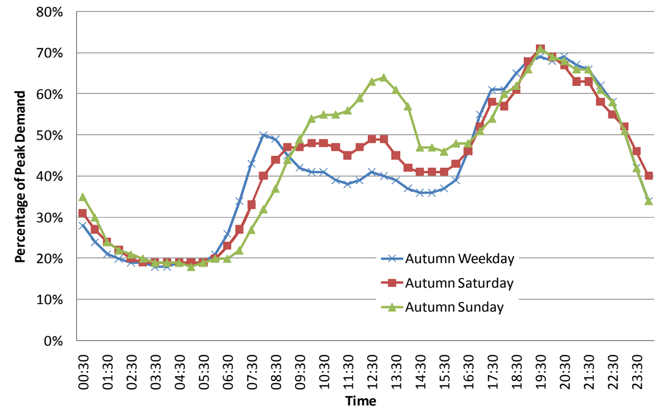

Figure 2. Domestic Unrestricted Load Profile

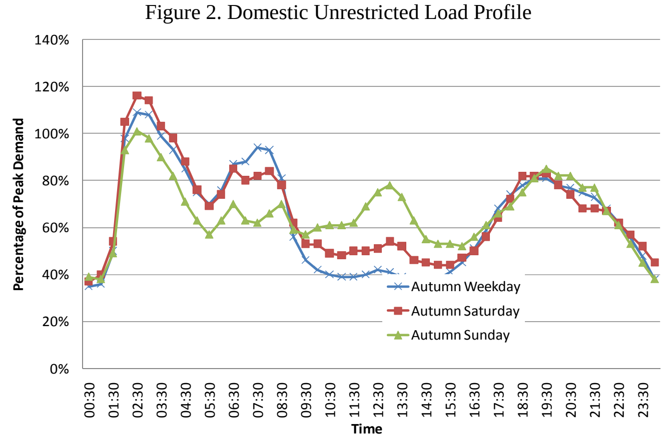

Figure 3. Domestic Economy 7 Load Profile

3. Domestic End-use Electricity Consumption

Total electrical energy consumed is aggregated individual appliances power consumption. Domestic appliances are divided into different groups; cold and wet appliances, brown appliances, cooking and lighting and miscellaneous appliances [8]. Table I shows the domestic electrical appliances and figure 4 corresponds to total electricity consumed by domestic appliances in million tones of oil [9].

Table I. Domestic Load Groups

Type	*Members*
Cold Appliances	Refrigerators: one door refrigerators with or without frozen compartment, fridge-freezers: two door combination refrigerators ,Upright freezers, chest freezers
Wet Appliances	Washing machines: any automatic washing machine including the washing cycle of

	washer-dryers, Tumble dryers: all types of dryers including the drying cycle of washer-dryers, dishwashers
Cooking Appliances	Electric ovens: including grills Electric hobs Microwaves: includes combination microwave/grill/convection ovens Electric kettles: includes all types of electric kettle Mixer (Hand mixer or Stand-up mixer) Hot drinks makers: coffee and tea makers, Sandwich toasters Pop-up toasters Deep fat fryers, Electric frying pans Slow cookers Cooker hoods Food preparation appliances: mixers, blenders, processors, whisks etc.
Lighting Appliances	Incandescent: 100W, 60W and 40W, Tungsten halogen: an average wattage of 30W Fluorescent strip: an average wattage of 63WCFL (compact fluorescent light bulb): an average wattage of 15.3W
Brown Appliances	Televisions, VCRs (video cassette recorders), Non-portable audio equipment: hi-fi systems, record players etc Satellite control boxes for TVs, Cable control boxes for TVs, Portable audio equipment: Cassette recorders, radios, clock radios, X-boxes (games etc.)
Miscellaneous Appliances	Irons: steam irons and dry irons Vacuum cleaners DIY equipment: drills, torches, battery chargers, Garden equipment: lawn mowers, trimmers, hedge trimmers, Other home care equipment: sewing machines, floor polishers, lights on extension cords, Hair styling equipment: hair dryers, curling tongs Small personal care appliances: electric toothbrushes, electric razors, Electric towel rails, Electric blankets Electric instantaneous showers, Central heating pumps, Personal computers, Computer printers, slide projectors, electric typewriters etc.

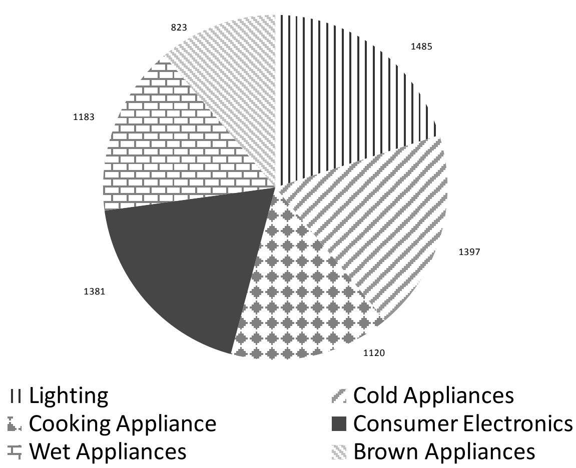

Figure 4. Domestic End-use Electricity Consumption in 2005 (Million tonnes of oil equivalent)

Each household depending on factors influencing on overall power consumption has different load profile. These factors known as behavioural factors included: geographical location of houses, socio-economic factor includes employment, age, education, size and type of the houses, number of occupants etc. Mansouri *et all* in [8] has demonstrated these behavioral factors which change the load profile in the UK. Ownership rate is the total number of appliances divided by the number of households owning at least one of each device. Ownership level of different domestic appliances in the UK in typical is shown in figure 5 [9]. This graph indicates that on average most of the domestic consumers in the UK own at least one “Iron”, however this may change for a household with 9 members living together.

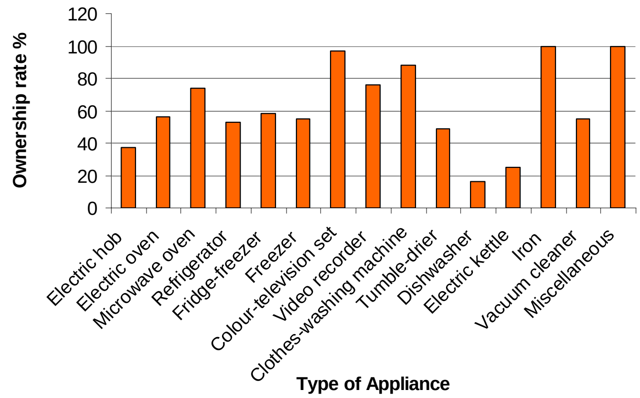

Figure 5: Ownership rate of domestic appliances

The general equation to calculate the total daily power demand that is applicable to all end-use appliances is:

$$Di_t = N_i \times C_i \times Fi_t \tag{1}$$

$$Ei = \alpha . \sum_{t=0:00}^{t=23:59} Di_t \tag{2}$$

where:

Di_t is total power required by component *i* at time *t*;

N_i is the number of appliances of type *i* ;

C_i is load type *i* energy consumption (watt);

Fi_t is the fraction of the connected load of type *i* in at time *t* ;

Ei is the daily energy consumption of load type *i*.

As Fi_t in particular for domestic sector depend on type of day (weekday, Saturday, Sunday) another coefficient” α ” needs to be multiplied to the equation (2) in order to differentiate the energy consumption of each appliance in different days. Besides, N_i which represents the number of appliances of type *i* depends of socio-economic situation of each household. Therefore a comprehensive aggregated demand requires considering these modules as well.

Time-of-use tariff programs change the mode of operation of domestic electrical appliances; they mainly influence on space heating and water heating as shifting the time of operation of these two end-use appliances does not cause inconvenience and overall satisfaction of consumers is not affected. Figure 6& 7 shows the end-use power consumption in domestic unrestricted and domestic-economy 7.

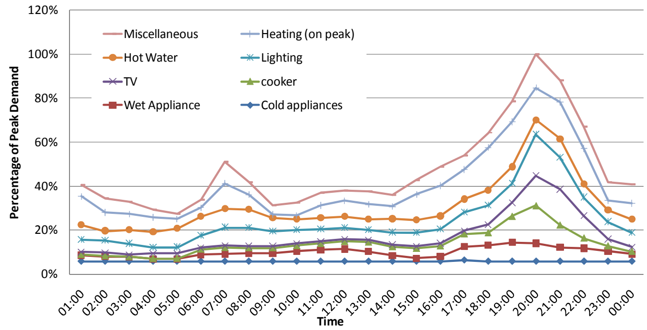

Figure 6: Domestic non-restricted End-use Power Consumption

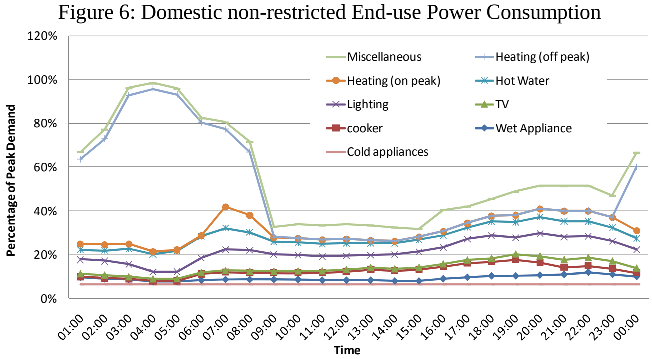

Figure 7: Domestic Economy 7 End-use Power Consumption

4. Responsive Demand

Responsive Demand (Dynamic Demand) refers to the reduction of customer energy usage at times of peak usage or contingency in order to help address system reliability, reflect market conditions and pricing, and support optimization or deferral. Demand response programs may also include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling. Responsive demand as one of the DSM programmes has been used in power system since 1960's where ripple controllers had been installed with the intention of reducing the energy consumption of water heating units as one of the direct load management methods [10]. Recently new type of responsive demand has been introduced to provide ancillary services such as spinning reserve.

There are two major categories of responsive demand [11]:

1. Price-based demand; such as response real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods.

2. Incentive-based demand response programs pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices.

To evaluate the amount of load which could become responsive it is important to know the load profile of the proposed consumer. If load are to become responsive like load shifting programs the overall satisfaction of consumers should not be affected, therefore only those loads may become responsive which have more elasticity and may be shed in response to network operator or even autonomously by detecting the network variations. These loads named "Passive Loads" may include Heating, Wet and Cold appliances.

Depending on the tariff method which customers are being billed the amount of responsiveness varies. Figure 8 shows the amount of available load which could become responsiveness in percentage of total demand at each hour.

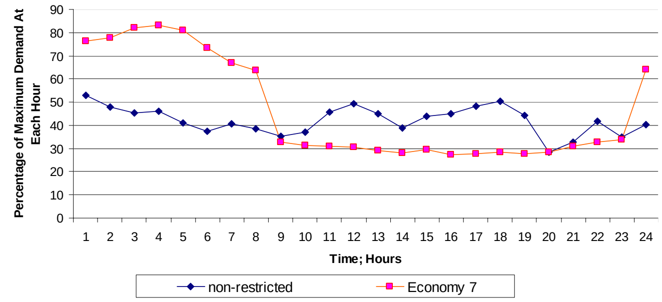

Figure 8: Available Load with Responsiveness Capability

5. Numerical Example in Domestic Sector

This paper aims to show how in a network with different load tariffs, the level of responsiveness may change. The proposed network is a small area in the city of Bath; in the Southwest of the UK. The area which has been studied is mainly residential including a major educational centre which includes halls of residence. In table II the area's data has been demonstrated [12]. Our study to calculate the level of responsiveness has only considered the domestic sector of this area despite the fact that industrial and commercial consumers may have also opportunity to make some of their loads responsive.

Table II. Bath and North East Somerset Area Middle Super Output Are (SOA)12 Data

Total Population	9,435
Number of Households	3,459
Number of non-restricted domestic meters	3267
Number of domestic Economy 7 meters	625
Number of industrial/commercial meters	434

To calculate the total demand it is important to distinguish two different load tariffs as total level of responsiveness is different in each case, sum of responsiveness level is quantifies by multiplying number of meters which represent Economy 7 tariff consumers by the responsiveness level of this profile, plus multiplying number of meters which represent non-restricted consumers by the responsiveness level of this profile and divide it by total number of domestic consumers:

$$RD_t = \frac{(Nn_t \times rn_t) + (Ne_t \times re_t)}{NT} \tag{3}$$

where

RD_t is total level of responsiveness at time t;

Nn_t is the number of non-restricted consumers;

Ne_t is the number of Economy 7 consumers;

rn_t is the level of responsiveness for non-restricted consumer at time t;

re_t is the level of responsiveness for Economy 7 consumer at time t;

NT is total number of domestic consumer.

Figure 9 shows the total level of responsiveness in this area among domestic loads.

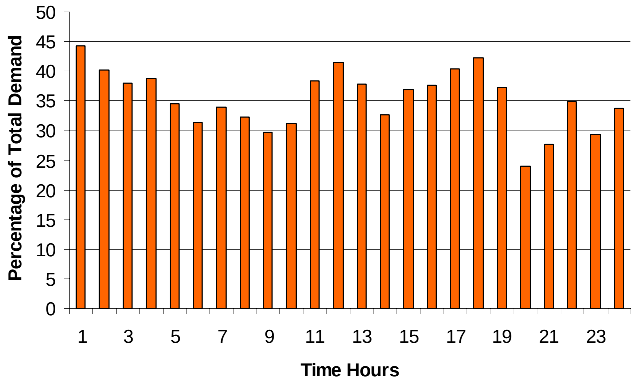

Figure 9: Total Level of Responsiveness

It is observable from figure 9 that responsiveness level does not necessarily correspond to the overall demand level at different times. In fact, it is dependent on different types of appliances which are used. Total responsiveness level over night is higher compare with other times, since major electrical appliances at these times are night storage heaters, and fridges which both can become responsive.

Such information can be used by different utilities. An electricity supplier can contract domestic demand response to lessen the need for purchasing the electricity at high prices from the market, and in return offer incentives to the domestic participants. A distribution network operator may also contract domestic demand response to minimize the stress on distribution networks by reducing the sudden increase in demand, and in the long-term it may alleviate the need for network reinforcement as a result of demand growth. If domestic demand response is offered to large number of consumers, this could benefit the network operator in balancing the demand and supply process. In contingencies such as losing a generator, or fault on a transmission line, dispatch pattern and power transit from different zones will have to be changed to maintain the stability of the system. In many occasions load shedding occurs as network or generators are unable to supply the current demand level. Since domestic demand response can be used instantly and is available at different zones, maintaining demand-supply balance will be possible through reducing the demand from a group of domestic consumers while the interruption in the overall service will be minimized.

6. Conclusions

Responsive demand is currently providing variety of services for power systems. Demand response as a product is either utilized as a reliability based product, or for economical purposes. In both cases, information regarding the concentration, location and capacity of available demand response is required. This technology has been employed in many power systems across the world, and industrial loads are the major participants. Domestic consumers have not benefited from this technology, neither the network, as quantifying the level of responsiveness for domestic consumers requires performing load profile assessment for individual customers and aggregate the total load profile of a group of consumers. As domestic demand level for individual consumers is very small compare with large industrial loads, such assessment requires having generic load profiles of different appliances so the calculations are simpler. This paper proposed a generic approach to quantifying the level of responsiveness among domestic consumers. Load profile of different appliances owned by a group of consumers are derived and depending on their electricity tariff which influences the operation pattern of different appliances, total load profile is modelled. It was shown that demand response can be provided by certain types of domestic appliances. Hence, it is required to study those appliances to see what proportion of demand can become responsive.

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RESPONSIVE DEMAND TO INCREASE THE VALUE OF WIND POWER

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Abstract –In this paper, the impacts of domestic responsive demand on increasing the security, reducing the emissions and production cost in an intermittent system is presented. Additional benefits such as value of wind and reducing the need for investment in expanding the network is also demonstrated. The quantification was evaluated on the IEEE 30 busbar system through Security Constraint Unit Commitment (SCUC).

Keywords: Responsive Demand, Renewable Energy, Security Constrained Unit Commitment, Demand Side Management

1 NOMENCLATURE

$C(c,e,s)$	Objective function (cost, emission and security)
I	Number of generation unit
p_i	Scheduled power for unit i
p_l	Power losses in the network
p_D	Power Demand
p_r	Power Reserve
Si	Security violation
αs	Scaling security factor
αc	Scaling cost factor
αe	Scaling emission factor
τs	Boolean variable for security
τc	Boolean variable for production cost
τe	Boolean variable for emission
FCi	Fuel cost
MCi	Maintenance cost
STi	Start up cost
SDi	Shut down cost
BMi	Base maintenance cost
IMi	Incremental cost
$\alpha i, \beta i, c$	Cost coefficients
TSi	Turbine start up cost
BSi	Boiler start up cost
MSi	Start up maintenance cost
Di	Number of hours down
ASi	Boiler cool down coefficient
K	Incremental shutdown cost
$\alpha, \beta, \gamma, \delta, \varepsilon$	Emission coefficients
Sv	Voltage security violation
Sg	Generator reactive power security violation
τv	Voltage Boolean variable
τb	Branch flow Boolean variable
τg	Generator re-power Boolean variable
$CSPPi$	Capacity Limit of Unit i to provide Spinning Reserve
SPi	Maximum contribution of unit i to spinning reserve
Sb	Branch power flow security violation

2 INTRODUCTION

With increasing fuel prices and environmental concerns, the government in the UK has obliged energy suppliers to obtain a specific and annually increasing percentage of the electricity they supply from renewable sources. This is known as Renewable Obligation (RO) target and the target is 10% for 2010, and subsequently rising to 15.4% for 2015–2016 [1]. Since the cost of wind turbine generators and therefore wind generation cost have been reduced to a great extent and the UK is one of the windiest countries in Europe, integration of windfarms is economically and environmentally attractive in windy regions and there is widespread public support for them. Therefore the prospectus for wind industry will be that they may become among major power production means in near future [2].

However, the intermittency and diffuse nature of wind energy creates difficulty in easily integration of them into the network. On the other hand, network limits will further push this issue by problems such as network congestions in transmission lines or voltage rise in busbars in case they may not be fully dimensioned to accommodate additional large scale windfarms. These problems necessitate subsequent changes in conventional methods of operating the power system and additional means such as providing extra reserve or backing up wind resources with conventional plants or using [1]FACTS devices to mitigate transmission congestion.

Demand Side Management (DSM) programmes have been practicing widely almost in all the countries since 1960-70's. The ultimate goal of DSM programmes is to increase the efficiency of energy consumption in demand side which will benefit both consumers and utilities. DSM consists of several programmes which all influence over consumer's energy consumption pattern; i.e. in the UK multi-tariff electricity known as Economy 7 and is very well known. Consumers can benefit from cheaper electricity during off-peak and for electricity utilities meeting the demand will be easier as total peak in the network will be reduced. Lower peak will result in more reliable power

[1] Flexible Alternating Current Transmission System device is used to enhance controllability and increase power the transfer capability of the network.

system, cheaper electricity and it defers early network reinforcement.

Generally DSM programmes are designed to make the load more elastic by mechanism such as shifting or disconnecting the load in order to [3]:

1. reduce the peak demand;
2. fill the demand curve valleys; and
3. bring strategic load growth.

The problem of current practiced DSM programmes is that they are unable to mitigate intermittency issues dynamically. Reducing peak load may help to lessen the need for utilization of peaker units to serve the demand but in case of loosing the total power coming from a windfarm, they are not the solution. On the other hand as renewables may be integrated mostly in remote distances at distribution level where network may also be limited then need to reinforce the network may also add up on top of these to transport the extra power from renewables.

Responsive demand as one of the DSM programmes has been in power system since 1960's where remote switching ripple controllers where installed in order to reduce the energy consumption of water heating units as one of the direct load management methods [4]. Recently new type of responsive demand has been introduced to provide ancillary services such as spinning reserve. Responsive demand is a technology which enables the demand to respond via communication or autonomously and be disconnected from the circuit until the system recovers itself either form a contingency or power shortage [5]. Price Responsive Demand is also another type of responsiveness in which demand can respond to generation price variations [7]. Responsive demand for large bulk loads is currently being practiced by system operators for reserve and frequency regulation purposes [17].

Previous researches have studied the impact if responsive demand on power system operation and control including reducing emission, cost saving, providing spinning reserve and frequency regulation [6-10]. However their studies are based on industrial loads which are large bulk loads.

The contribution of this paper is first to demonstrate the potential of demand responsiveness in domestic sector among small loads. This evaluation has considered power consumption pattern of different appliances in domestic sector. Then it is shown that how different DSM methods can benefit the power system operational parameters; fuel cost, emission and security violation index, when renewables are penetrated into the system. Finally responsive demand dispatching algorithm is proposed and the benefits of responsive demand is also presented.

3 RESPONSIVE DEMAND IN DOMESTIC SECTOR

Power consumption in domestic sector in different networks has different patterns depending on socio-economic factors of the society. Other factors such as energy management programs also change the demand curve shape. But in general domestic sectors tends to have two peak demand during the day, one in the morning when people are getting ready to go to work and demand for power is high because of cookery, hot water and lighting loads are all being utilized. Another peak which is higher usually happens in the evening, when people tend to eat dinner, watch TV and more lighting loads are consuming energy. The aim of load management programmes; such as Economy 7 which offers cheaper tariff for electricity to consumers, is to shift a proportion of these peak demands to off peak hours. Figure 1 shows typical domestic demand with different electricity tariffs. It can be observed that Economy 7 tariff increases the power consumption during the off peak periods. This will lead to an increased domestic night time load giving a more balanced use of the electricity network across the day.

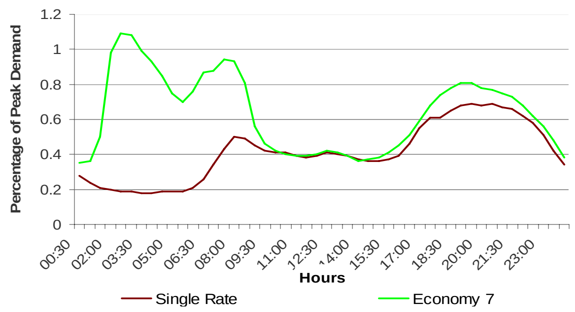

Figure 1: Different Domestic Power Consumption Patterns

Shifting the demand will benefit the power system in many aspects; reducing the variable cost of meeting the demand and reducing the total system peak which will result in meeting the future increasing demand with delayed network reinforcement.

To lessen the impact of sudden power loss resulted by intermittent plants, the existing DSM methods which have been practicing in domestic sector, may not mitigate this problem. The technology which will enable the loads to respond to the system incidents such as power output fluctuations of renewables, overloading the lines, etc. is responsive demand.

In domestic sector, different types of load have the capability of becoming responsive; those with passive mode of operation and those which are not time dependant such as fridge or air conditioner. Demand for electricity is indirect, consumers actually demand the services provided by the electricity rather than the electricity itself. Therefore passive demands are those which minor interruptions in their mode of operation do not have any effect on consumers overall satisfaction of delivery of the electricity service.

The first step to implement such demand responsiveness is to identify those loads which are capable to become responsive. Figure 2 and 3 show different duty cycle of different types of load in domestic sector in twodifferent charging tariffs. Figure 2 represents Economy 7 when peak usually happens in the early hours of the morning and figure 3 shows a single tariff system with normal peak time in the evening. Table 1 also shows the different groups of load in domestic sector.

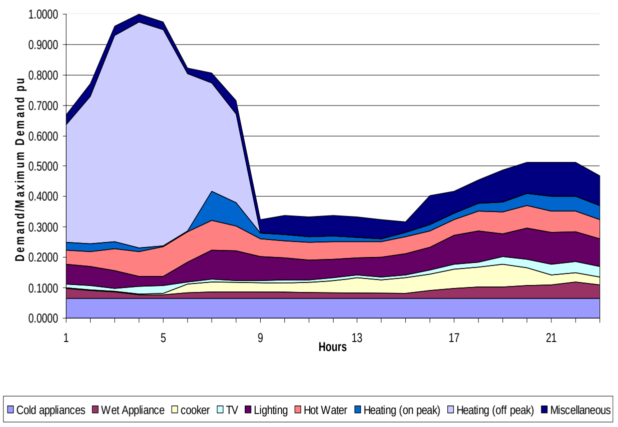

Figure 2: Multi Tariff Domestic Demand (Economy 7)

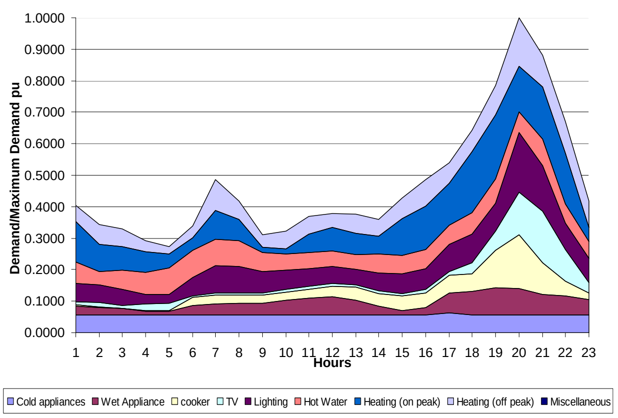

Figure 3: Single Tariff Domestic Demand

Type	Members
Cold Appliances	Refrigerators and fridge-freezers
Wet Appliances	Washing machines, washer-dryers, Tumble dryers and dishwashers
Cooking Appliances	Electric ovens: including grills Electric hobs, Microwaves, Electric kettles, Mixer, Hot drinks makers, Sandwich toasters and Pop-up toasters, Deep fat fryers. Slow cookers Cooker hoods and Food preparation appliances
Lighting Appliances	Incandescent, Tungsten halogen, Fluorescent strip including compact fluorescent light bulb
Brown Appliances	Televisions, VCRs, audio equipment including hi-fi systems, Satellite control boxes for TVs, Cable control boxes for TVs, Portable audio equipment: Cassette recorders, radios, clock radios and X-boxes.
Miscellaneous Appliances	Irons: steam irons and dry irons Vacuum cleaners DIY equipment: drills, torches, battery chargers, Garden equipment: lawn mowers, trimmers, hedge trimmers, Other home care equipment: sewing machines, floor polishers, lights on extension cords, Hair styling equipment: hair dryers, curling tongs Small personal care appliances: electric toothbrushes, electric razors, Electric towel rails, Electric blankets Electric instantaneous showers, Central heating pumps, Personal computers, Computer printers (LaserJet or Facsimile machines Answering machines Other office equipment: slide projectors, electric typewriters etc.

Table 1: Different Groups of Load in Domestic Sector

Water heating and space heating are usually considered seperetaley as most of the houses use non-electric heating systems. In our study, we assumed that Cold and wet appliances as well as water heating and space heating are those which could be considered to become responsive.

4 ASSESSMENT TOOL

In this part, we show the operational parameters of a power system when renewables have been penetrated into the system. Firstly by performing a short-term unit commitment we derive the fuel cost, emissions and security violation index. Then by performing we introduce Economy 7 tariff and compare our results with a case in which no DSM method was used. Finally the dispatching algorithm and effect of responsive demand is shown.

The aim of the Security-Constrained Unit Commitment (SCUC) problem is to find the hourly generation, reserves and price sensitive load schedule that minimizes the sum of energy costs, reserve costs and the negative of revenue from price-sensitive load over a twenty-four hour period subject to meeting all the network security constraints such as apparent power flow constraints, generator reactive power output constraints and voltage in busbars. SCUC is being considered more and more recently because Security of supply is one of the major concerns of network operators and they have license obligation to run the system at certain security level at all the time.

Security Constrained Unit Commitment aims to minimize $C(c,e,s)$ and increase the security (through minimizing the security violation indexes) in a scheduling period with regarding to Production cost *"c"* ,Emissions *"e"* and Security violation index *"s"*:

$$MinC(c,e,s) = (\sum_{i=1}^{N}[\tau c.\alpha c.c(Pi) + \tau e.\alpha e.e(Pi)] + \tau s.\alpha s.s) \quad (1)$$

4.1 Generation Cost:

Generation cost is a function of fuel cost, total start-up cost, shut-down cost and maintenances:

$$c(Pi) = FCi(Pi) + MCi(Pi) + STi(Pi) + SDi(Pi) \quad (2)$$

Fuel cost is

$$FCi\ (Pi) = \alpha i.Pi^{2} + \beta i.Pi + ci \quad (3)$$

where $\alpha i, \beta i$, ci are Cost coefficients.

Maintenance cost is a function of Base maintenance cost (*BMi*), and an incremental cost depending on output power:

$$MCi\ (Pi) = BMi + IMi\ .Pi \quad (4)$$

Total start-up cost (*STi)* is a function of turbine start-up cost *TSi* and the boiler Start-up cost *(*BS_i*)* and number of hours that unit *i* has been down (D_i*)*, and (AS_i*)* is the boiler cool down coefficient.

$$STi = TSi + [1 - e^{(Di\ /\ ASi)}].BSi + MSi \quad (5)$$

Shut-down cost for each unit is a number depending on the output power of that unit. *K* is shut-down incremental cost:

$$SDit = KPi \quad (6)$$

4.2 Emission:

Some of the pollutants produced by fossil fired plants in large quantities are sulphur dioxide SO_2, carbon dioxide CO_2, nitrogen oxides NO_x, hydrocarbons and coal fired plants also produce fly ash and metal traces. In this paper we have only considered NO_x emissions:

$$e(Pi) = \alpha.Pi^{2} + \beta Pi + \gamma + \delta.e^{\varepsilon.Pi} \quad (7)$$

where $\alpha, \beta, \gamma, \delta, \varepsilon$ are the emission coefficients.

4.3 Security:

The Security function consist of 3 main objectives; voltage at busbars, apparent power flow in branches and reactive power generated by generation units:

$$s = \tau v.sv + \tau b.sb + \tau g.sg \quad (8)$$

sv, sb and *sg* are voltage, apparent power flow and generator reactive power security violation indices and τv, τb and τg are the Boolean variable to either include these violation indices or not.

Voltage at busbars must always be set between a minimum and maximum limit at all the scheduled generation period. This could be done through generator voltage set point, transformer tap settings or reactive power control. The voltage rise due to installed wind-farms at each busbar depends on the injected power:

$$\Delta V = \frac{P_{inj} \times R + Q_{inj} \times X}{V_s} \quad (9)$$

where ΔV represents the voltage deviation due to generation unit installed at that bus bur, and P_{inj} & Q_{inj} are active and reactive power injected from generation unit and *R & X* are line resistance and reactance and V_s is the nominal voltage .In SCUS calculations there is always a limit for ΔV ; i.e. between 1.06 -0.94 per unit of the nominal rate is the current practiced allowed voltage deviation at distribution level in the UK.

Apparent flow (Complex power; $S = P + jQ$) in transmission lines is one of the constraints which sometimes cause decomitting a unit or keeping its output up to certain level as transmission lines are running up to their maximum capacity; some thing which is known as transmission congestion.

In power systems voltage collapse usually happens when the reactive power is not enough to meet inductive loads such as induction motors etc. Generation units generate certain amount of reactive power and exceeding this limit will reduce the security of supply.

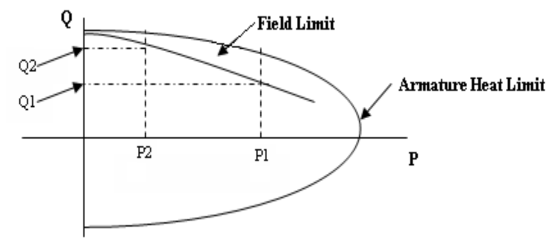

Figure 4: Generator Power Output Capability Graph.

Other constraints:

Apart from those mentioned objective constraints during unit commitment, there are several other constraints which must be considered:

4.4 Crew constraints:

With thermal power plants, particularly starting up and shutting down generation units needs a certain number of crews to operate and sometimes because of lack of crews, it is impossible to start up or shut down more than one unit at a time.

4.5 Minimum up and down time:

In some plants i.e. nuclear, hydrothermal etc, because of economic efficiency and technical constraints it is impossible to shut down a unit before a certain duration of being in duty is reached; again once a unit is turned off it may be impossible to start it up and bring it back to network before certain number of hours of being off-duty is reached. These units have different characteristic than "Peaker" units; for instance gas turbine units which usually are not subject to a minimum up and down time and can start up and supply peak demand and shut down straight after peak period.

4.6 Generator output limits

Generation units must be scheduled to operate within their maximum and minimum rated output in terms of active (*PGi)* and reactive power (*QGi)*:

$$PGi\min \le PGi \le PGi\max \qquad QGi\min \le QGi \le QGi\max \quad (10)$$

4.7 Spinning Reserve

Total Generated power in the system must meet demand, network losses and required Spinning Reserve. Spinning reserve is the amount of power always available to be dispatched in the system to meet sudden demand increase or being used in minor contingencies.

$$\sum_{i=1}^{N} Pi \ge Demand + Network\ looses + Spinning\ reserve \quad (11)$$

$$\sum_{i=1}^{N} (CSPPi - Pi, SPi) \ge Spinning\ reserve \quad (12)$$

CSSPi is Capacity Limit of Unit i to provide Spinning Reserve and *SPi* is the Maximum contribution of unit i to spinning reserve.

4.8 Negative Reserve Requirement

Negative reserve is to make sure at each scheduling period there are sufficient generation units in the system which are running at certain amount higher than their minimum generation limits. This is to allow their output be reduced in case of loosing the demand in case of an event predicting it higher than actual value [11].

4.9 Generator Ramping Up and Ramping Down Rate

The ability to increase (or decrease) the output power of a generator in a certain amount of time is called Ramping Rate. Generation units have different ramping rates and this must be considered in unit commitment. Ramping rate is particularly important for those units which are due to be committed to supply power reserve (especially spinning reserve) as certain amount of reserve is supposed to be generated by these units. Network operators i.e. NGC in the UK, have their own criteria for selecting units providing spinning reserve which in the UK is 25MW/minute within 2 minutes of instruction and to be sustained up to the minimum of 15 minutes [12].

4.10 Reliability Must Run Units (RMR)

In the power system generation units that the ISO determines are required to be on-line [at certain times] to meet applicable reliability criteria requirements [13]; such as voltage support or during system maintenances.

4.11 Regulatory Must Run Units (RGMR)

The main purpose of regulatory must-run units is to maintain "fair" competition in a deregulated market. A good example of regulatory must-run units is hydro power plants. Most of these power plants are multipurpose units which were designed both for power generation and irrigation purposes. Allowing a hydropower plant to participate in the competitive market may defeat the agricultural purpose [13]. Another example of RGMR units exists in places where heat demand is added on top of power demand. In order to supply enough heat, we must make sure that enough thermal units such as Combined Heat and Power (CHP), which are designed to provide heat in all heat demand areas, are committed at each scheduling period. Renewable energies; in particular large windfarms are usually given priority dispatch in unit commitment problem, because they have zero fuel cost and green energy certificate carrier.

4.12 Regulatory Must Take Units (RMTU)

In deregulated energy markets there are power purchase agreements (PPA) which occurred prior to the deregulation and carried over to the deregulated market. Examples of regulatory must-take units are nuclear power plants, cogenerations, and PPAs with other entities such as neighboring countries. It means in UC calculations these PPAs also need to be considered [13].

4.13 Qualified Unit Providing Ancillary Services in Deregulated Energy Market

Ancillary services usually are provided by specific units. In deregulated energy market where price bidding exists both for power and ancillary services, not all the generation units can participate in providing ancillary services. At each period some power utilities which normally participate in providing ancillary services may or may not be available.

4.14 Balance between Demand and Power in Deregulated Energy Market

In a deregulated Energy market (DEG), network operators particularly those who provide ancillary services such as spinning reserve or operating reserve, are allowed to either supply an extra power into grid or by reducing the demand to reduce the need of an extra reserve. This is a new term in DEG which has been using in some parts of the world [14]. Therefore by committing those companies which are allowed to shed the load to unrequire the network to extra power, in fact the demand which needs to be supplied is being reduced and network parameters must be studied well before committing generation units as it may cause voltage rise in the system because of extra power which is not being consumed. There are also other ways such as pump storages, interchange etc. All the power which is due to be achieved from these sources must be subtracted from total required reserve [15].

5 TEST SYSTEM

The IEEE Standard 30 Bus Test System [16] has been chosen for our project. Figure 5 shows the proposed network, the main objective of our research is to integrate responsive demand into the system, after running the simulation without the presence of responsive demand, those appliances in domestic sector which were capable to become responsive have been selected to act as responsive demand and they respond to output of wind generators. In the network there are different types of generators; coal fired, gas fired and wind generators. Table 2 shows the generators cost and emissions characteristics and Table 3 shows Minimum Up Time (MUT), Minimum Down Time (MDT), Ramp rate, Minimum and Maximum power output and locations of conventional plants. All generators data apart from generator No. 9, 10 and 11 are derived from IEEE Reliability Test System RTS-96[16].

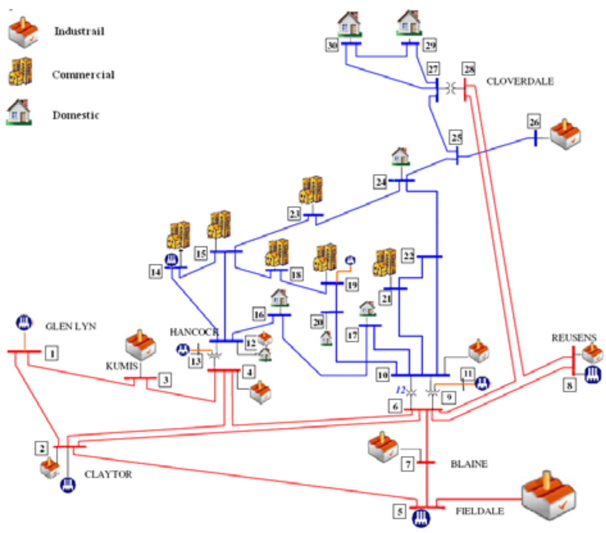

Figure 5: The IEEE 30 Bus Test System with different types of demand

Total conventional plants capacity is 300MW while 2 windfarms have 15MW (windfarm No.1 capacity factor = 26%) and 20MW (Windfarm No.2 capacity factor = 29%) installed capacity. Figure 6 shows weekly output of two windfarms. As shown in figure 5 in different locations different types of demand exist. These 2 windfarms were placed on bus number 24 as it is absolutely consists of domestic loads. It is assumed that responsive demand is only available in domestic sector and their mode of responding to the network depends on output of windfarms.

Unit No	*a*	*b*	*c*
1	0.02	1.2	40
2	0.01	0.8	38
3	0.06	4.5	45
4	0.01	0.4	30
5	0.06	5.2	23
6	0.05	2.2	42
7	0.05	3.0	45
8	0.04	1.8	53
Wind 1	0.00	0.0	0
Wind 2	0.00	0.0	0

Table 2: Generator Fuel Cost Characteristics

Unit	MUT	MDT	Ramp Rrate	*Pmin*	*Pmax*	Busbar No.
1	3	2	5	10	35	11
2	2	2	4	10	45	5
3	3	2	7	8	40	2
4	3	2	6	10	60	1
5	1	1	6	5	25	19
6	2	1	5	2	30	14
7	2	2	7	5	35	8
8	2	1	4	5	30	13
Wind 1	0	0	4	0	10	24
Wind 2	0	0	4	0	15	24

Table 3: Other Generators Charactristics

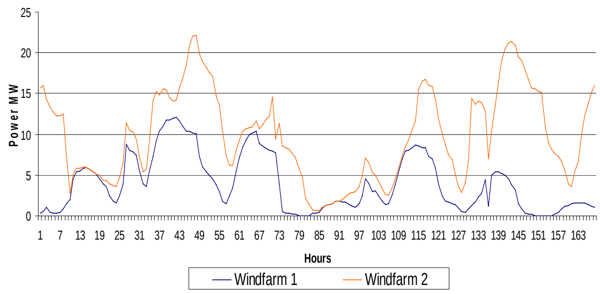

Figure 6: Weekly output variations of Wind farms

6 RESULTS

6.1 Production Cost

Total generation cost; which is total running cost of conventional plants, is significantly differs in presence of responsive demand. Without responsive demand whenever wind output drops conventional plants needs to supply the demand. As result of intermittency these fluctuations may happen at any time and the magnitude and speed of these fluctuations usually obliges network operators to utilize those units which could be utilized free of constraints such as a long uptime or down time. These units are usually OCGTs which are very expensive to run and the difference in cost at each case is because of reducing the need for running these units. Table 3 shows the result of our simulation for each case. We have considered several cases; first when there is no demand side management program is implemented and the results show generation cost is $85228.3, By having 16% multi-tariff demand the generation cost will reduce by 1.3% down to $84057.69 . 1.3% drop in generation cost in a network with total 300MW demand may not be noticeable but in a real network this reduction is significant. After introducing responsive demand in the network this reduction is more significant and total generation cost for single rate with responsive demand and economy 7 with responsive demand will be respectively $84032.73 and $82414.13.

6.2 Security Index

As mentioned in section 3.3 security violation index consists of three main objectives; voltage in busbars, reactive power of generators and active power flow over transmission lines. Any of these factors if violates over its limits make the unit commitment and economic dispatch decisions unacceptable. Even under the limits these objectives may violate from their nominal points. We have allowed voltage on busbars to be considered if they are between 1.09pu and 0.95pu of nominal value. At the end by considering the loading level of transmission lines, voltage on busbars and generators maximum reactive power the security violation indices have been calculated and the total security violation index is sum of these indices. It is clear according to eq.8 in section 3.3 that smaller security index represents more secure network. For security constrained unit commitment usually pre contingency and post contingency analysis also add up on top of security index. The results for security index show it is 29.699, by having 16% multi-tariff demand[2] it will be down to 28.451. After introducing responsive demand in the network security index for single rate with responsive demand and economy 7 with responsive demand will be respectively 27.940 and 23.850 representing more secure network.

6.3 Emissions

Emissions which all come from conventional units are calculated in this simulation. As we expected in the worst scenario where there is no demand management in the network we see the highest level of emission. Demand side managements significantly reduce the emissions as it is noticeable in table 4, 1.3 tones of NO_x emissions could be reduced just by multi tariff demand. This amount can be further reduced down to 2.15 tones if responsive demand is mixed with economy 7 tariff.

Case	Production Cost *$*	Security *Index*	Emission *Tones*
Single rate	$85228.30	29.699	27.99547
16% Domestic Economy 7	$84457.69	28.451	26. 63810
Single rate with Res. Demand	$84032.73	27.940	26.05713
16% Domestic Economy 7 with Res. Demand	$82414.13	23.850	25.84281

Table 4: Power System Operational Parameters Results

6.4 Value of wind:

Renewable plants can also help to diversify the energy supplies and displace conventional plants, considering intermittency and the current level of installed wind capacity (around 6%), the displacement level is limited up to 35% of total installed capacity of windfarms. This level is lower in higher penetration of wind generation as other issues such as balancing between demand and power may limit it down to 20% if wind has 20% penetration level [18]. Displacing the conventional plants by wind power, will result in fuel cost saving and emission reduction and is known as "Value of Wind". Value of the wind can be assessed in very different ways with varying degree of sophistication. It could be simply defined as just the amount of the energy which could be produced from a wind generator, nonetheless this is not an ideal model as it neglects additional cost imposed by wind variability [19]. Reference [20] presents two definitions for the value of wind with regard to intermittency; first it is the avoided cost of thermal power generators when using wind power. These are the operating costs (mainly fuel costs) of thermal power stations as well as the fuel saved in electric boilers. Second definition is much wider, it includes all socio-economic effects of integrating wind compared with non-wind case. For this we must calculate the socio-economic surplus (sum of consumer and producer surplus). When looking at the differences in the socio-economic surplus between reference and wind cases, we get the value of wind to the whole market. Higher value of wind will result in more economic electric power system and less polluted environment.

In this research we have only assumed the avoided fuel cost of thermal plants. In order to evaluate this value for each MW installed capacity of wind, we use the equitation below:

$$Value\ of\ Wind\ = \frac{C(No\ wind\ ) - C(\ with\ wind\ )}{P(Wind\ )}\ \$/_{MW} \qquad (12)$$

Where C is total production cost and P represents the installed wind capacity in MW.

By increasing the wind penetration as the power injected to the network through wind will reduce the need for running conventional plants, therefore total production cost is cheaper in general with increasing the wind penetration. However this is not always the case as network constraints such as busbar voltage rise where windfarms are installed, and the unit commitment decisions may change and total production may increase. On the other hand with increasing the wind penetrations the need for back-up power may also increase. This increase may happen at certain penetration levels where local demand still needs to be fed by other plants or at certain locations where transmission system connected to the network is not able to transport the power comes from renewables. This is one of our findings in bus No.24.

There are several mitigations to rectify these problems as mentioned before in section 2. Our proposed method is based on involving demand to respond to some objectives:

- wind generator output variations;
- busbar Voltage rise or drop; and

[2] Currently (2007) in the UK 16% of domestic consumers who are supplied by major suppliers are participating in Economy 7 scheme which led to an increased domestic night time load giving a more balanced use of the electricity network across the day. More recently there has been a preference for gas central heating rather than electric heating, which has meant that many customers who are on Economy 7 tariffs no longer have a large night time load [1].

- power flow congestion known as Transmission Congestion.

These are the areas which demand can respond in a way to maximize the utilization of renewables. In this project so far we have just considered the wind generator variations and demand can respond to these variations, by any mean which demand can be responsive; such as communication between loads and network or detecting these variations in demand side autonomously. However we have only considered shedding the load in case wind power output drops below certain level. This level is 10MW when 15% of total domestic loads will respond to it and in fact negative load will increase the value of wind and the amount of available responsive demand differs for single and economy 7 tariffs.

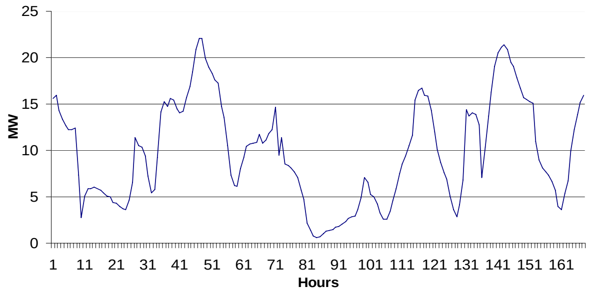

Figure 7: Aggregated Two Windfarms Power Output

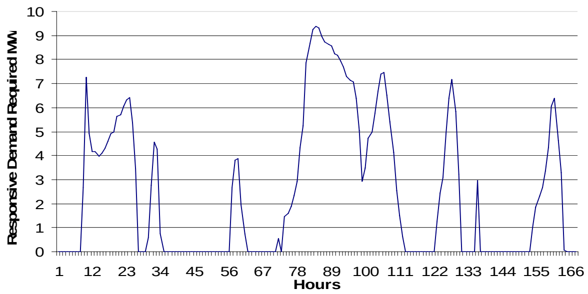

Figure 8: The Difference of Windfarms output to 10MW

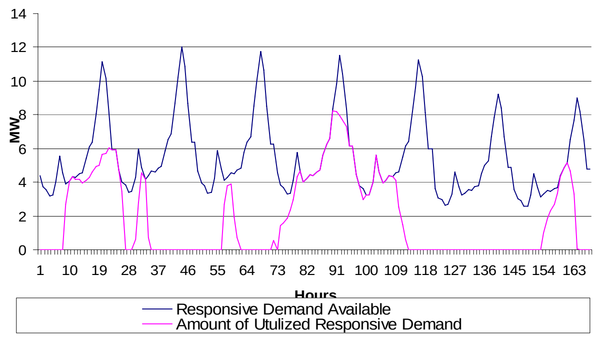

Figure 9: Amount of Available and Utilized Responsive Demand for Single tariff Demand

The calculation of requited responsive demand is done according to following equation:

$$RD_t = Pm - Pw_t$$

where RD_t is required responsive demand at time *t*, Pm is the final goal power which in this paper is set to 10MW and Pw_t is output of intermittent generators at the time *t*.

Figure 10 shows the algorithm for dispatching the responsive demand.

The total generation cost without wind in our system was calculated $96444.22. As 35MW of total wind capacity is installed in the network value wind for each case is calculated according to equation 12. Table 5 shows the calculated value of wind for each scenario.

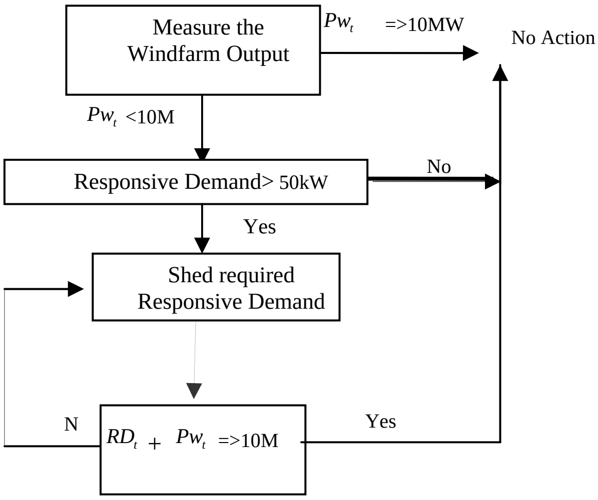

Figure 10: Responsive Demand Dispatching Algorithm

Case	Value of Wind $/MW
Single Rate with 10% Wind Penetration	320.4
Economy 7 with 10% Wind	342.4
Single Rate with Responsive Demand and 10% Wind Penetration	354.6
Economy 7 with Responsive Demand and 10% Wind Penetration	400.8

Table 5: Value of Wind in Different DSM Programme

The results show the increase of value of wind in presence of demand side management programs. When value of wind is greater, it means the network needs to use the conventional plants less to serve the demand and in fact it is more *"Sustainable"* electricity generation network.

7 CONCLUSIONS

Considerable worldwide interest in the potential of demand-side management techniques has the potential of reducing balancing costs for system operators and so, as a side effect, reducing the additional costs of intermittent renewables as well as reducing the emissions.

Currently there is considerable interest in exploring the possibilities of high penetrations of wind energy into electricity networks and mitigating the barriers to increase the wind penetration. This paper demonstrates the effect of dynamically participation of demand in reducing the cost, emission and increasing the security of the power system in a system in which renewables have substantial installed generation capacity in the system. The study shows that different appliances in domestic sector have the capability to become responsive. However as loads in domestic sector are small loads, in order to provide such demand responsiveness in domestic sector, loads are aggregated and the effects of aggregated responsive demand dispatched from domestic loads on power system operational parameters have been demonstrated.

The benefit of dispatching responsive demand from domestic sector is not only limited to reducing the total cost and emission of the network because reducing the need to generate more power. One important benefits of providing such demand which could respond dynamically is increasing the security. Security in this paper is defined as improving the voltage profile by lessening the voltage deviations on busbars, reducing the power flow across the network on branches and generators capability to generate reactive power. This will postponed the need for reinforcement of the network and more loads could be supplied without investment to expand the network to accommodate them.

The value of wind shows the economical impacts of investing money to build a windfarm and determines whether the revenue which comes by operating a windfarms will pay back the capital cost of it or not. We also showed that value of wind which is the net benefit of wind power to the grid could be increased by having responsive demand in order to respond to power output of windfarms.

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Responsive Demand in Networks with High Penetration of Wind Power

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Abstract—The value of renewables is significantly affected by their penetration, concentration and location. Value is further affected by the responsiveness of demand which will reduce the need for back up power through non-renewable sources. By increasing the penetration of renewables in power systems, demand side participation become more important. Demand Side Management (DSM) programs have been studied for a long time and among all DSM programs Responsive Demand seems to be the most applicable type of DSM for a system with significant intermittent generation. It mitigates issues such as required reserve, network congestions and higher/lower voltage profiles and thus results in less operation cost although little attention has been made to quantify the benefits of responsive demand. In this paper, the value of wind generation without responsive demand is quantified first, by introducing responsiveness in the demand side, the reduction in operation cost is calculated and the additional benefits are quantified. The quantification was evaluated on the IEEE 30 busbar system through Security Constraint Unit Commitment (SCUC) and the results indicate the benefits of responsive demand on operational and environmental characteristics in power system.

***Index Terms*--Dynamic Demand, Value of Wind, Demand Side Management, Generation Scheduling, Responsive Demand**

I. NOMENCLATURE

$C(c,e,s)$	Objective function (cost, emission and security)
I	Number of generation unit
P	Scheduled power for unit i
Si	Security violation
αs	Scaling security factor
αc	Scaling cost factor
αe	Scaling emission factor
τs	Boolean variable for security
τc	Boolean variable for production cost
τe	Boolean variable for emission
FCi	Fuel cost
MCi	Maintenance cost
STi	Start up cost
SDi	Shut down cost
BMi	Base maintenance cost
IMi	Incremental cost
αi , βi ,c	Cost coefficients
TSi	Turbine start up cost
BSi	Boiler start up cost
MSi	Start up maintenance cost
Di	Number of hours down
ASi	Boiler cool down coefficient
K	Incremental shutdown cost
α , β , γ , δ , ε	Emission coefficients
Sv	Voltage security violation
Sg	Generator reactive power security violation
τv	Voltage Boolean variable
τb	Branch flow Boolean variable
τg	Generator re-power Boolean variable
$CSPPi$	Capacity Limit of Unit i to provide Spinning Reserve
SPi	Maximum contribution of unit i to spinning reserve
Sb	Branch power flow security violation

II. INTRODUCTION

Issues associated with the integration of wind power into power system have been characterized as either engineering issues, operational issues or planning issues [1, 2, 3 and 4].

Engineering issues include harmonics, reactive power supply and voltage regulation, frequency control, fault level, island operation.

Operational issues include the effect of intermittent power output into non-intermittent (conventional) networks, operating reserve requirements, unit commitment and economic dispatch.

Planning issues concern the appropriate modeling and evaluation of intermittent wind resources compared to conventional resources.

An accurate quantification of the economical benefits of renewable generation is of supreme importance considering the strategies set out in order to mitigate above issues. Value of Renewable Penetration is a term which deals with this concept; Holttinen *et all* in [19] define two definitions for value of wind; first it is the avoided cost of thermal power when using wind power. These are the operating costs (mainly fuel costs) of thermal power as well as the fuel saved in electric boilers. Second definition is much wider, it includes all socio-economic effects of integrating wind compared with non-wind case. For this we must calculate the socio-economic surplus (sum of consumer and producer surplus). When looking at the differences in the socio-economic surplus between reference and wind cases, we get the value of wind to the whole market. Higher value of wind will result more economic system and less polluted environment. The value of wind is reduced by the fact that its power is not firm; it is

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intermittent so that the wind generator output will often deviate from the committed level.

An accurate wind forecasting can reduce, but not eliminate these deviations and will result in higher value of wind [22].

To increase the value of wind Brooks *et all* in [20] suggests integration of hydroelectric generation mixed with wind generation because both have stochastic pattern. Black *et all* [21] have demonstrated the role of storage devices to mitigate the intermittency and ease the integration of wind energy and increase the value of non-fossil fuel plants.

As renewable energies must be installed in locations where the main source of the energy is available, most of the past research projects have been focusing on identifying the best geographical location of renewable units and less research has been done in dealing with location of renewable plants in the grid. It is important because high penetration of renewables in the network will further push the transmission tie-lines to their power transfer limits and cause problems such as network congestion, voltage security or even voltage stability where the network is already under stressed due to the uncertainty of generation and demand and power market transactions [6] i.e. voltage rise happens in rural areas with high penetration of renewables and low demand; again this is mainly because of the traditional structure of the network which may not accommodate additional power [7, 8].

If any renewable unit is to be integrated into any power system it needs to be considered in unit commitment problem in that system to evaluate the effect of injecting power through renewable units on the whole network and to calculate the total energy production cost with respect to several objectives; cost, emission and security [5].

In the process of solving the unit commitment problem, intermittent generation units have some constraints; such as ramp-rate constraint for generation scheduling and for reserve activation like conventional plants as well as their most significant character; intermittency. In addition integrating high level of renewables has implications for the planning and operation of transmission system and sometimes fails to extract the full output of renewables because of transmission congestion.

Although, one effect of increasing the proportion of embedded generation will be to reduce the flow across the interface between the transmission and distribution networks and this will tend to delay the need for reinforcement of parts of the transmission network, but it is unlikely to remove the need for the substations that exist at the interface between the transmission and distribution systems (i.e. the Grid Supply Points). These will continue to be required to balance the fluctuations between generation and demand in that specific part of the distribution network from minute to minute.

The traditional solution to mitigate intermittency is to back up renewable units with other sources of power either through running units or by energy storage devices. However the only solution to mitigate the issues with regarding to the network is to invest in network reinforcement.

Demand Side Management (DSM) Programs have been used for a long time for different purposes such as increasing the efficiency of the power system and saving the energy. Economy 7 and Economy 10 are the most widespread type of DSM programs in the UK which by shifting the demand will reduce the peak demand and the need for running the peak time running units which are usually expensive units will be eliminated. The current DSM methods which shift the demand could benefit system with renewables but not in terms of mitigating the intermittency issues because power fluctuation may happen at any time therefore demand shifting methods can not solely be a solution for intermittency.

One of the stand of the art types of DSM; Dynamic Demand (Responsive Demand) is being used in US to provide ancillary services in particular spinning reserve [9]. Dynamic demand is a type of load which is flexible and is ready to be shed if a network needs extra power. This type of demand usually includes passive loads such as air conditioning, water heating and refrigerators which if turned off upon to request by the network operator, do not cause difficulty for consumers.

The problem with existing methods is that they only consider the benefits which could be achieved in short term in terms of improving the efficiency of the power system and none of them deeply considers the effects of implementing these methods in much wider aspect which usually requires more investment and may benefit whole the system in long term. Demand is actually the first object of power system and all reliability and investment analyses of the network is being done by considering the demand as end point of the system which must be supplied. Through this method demand could be managed to benefit the whole the system such as other objectives at the distribution level; i.e. transmission congestion which stops network to accommodate more power and requires more investment to expand it.

In an intermittent environment the value of wind is one of the most important objectives which needs to be studied well before any investment in building and installing windfarms, as in terms of cost it basically represents the amount saved per MW through adding the new windfarm.

In this research project we have demonstrated a system with both conventional plant and intermittent unit. We run our simulation; first without any DSM program and get technology specific characteristics of the system such as production cost, security and emission and calculate the value of wind. Then by introducing Responsive Demand in the domestic Sector we aim to shift their consumption to off peak and especially when output of windfarms is not adequate and compare the outcomes of this case with the previous case.

III. Assessment Frame Work

Unit commitment is used in this research project as an assessment tool to determine the value of wind with and without responsive demand.

The aim of the Security-Constrained Unit Commitment (SCUC) problem is to find the hourly generation, reserves and price sensitive load schedule that minimizes the sum of energy costs, reserve costs and the negative of revenue from price-sensitive load over a twenty-four hour period subject to meeting all the network security constraints such as apparent power flow constraints, generator reactive power output constraints and voltage in busbars. SCUC is being considered more and more recently because Security of supply is one of the major concerns of network operators.

Security Constrained Unit Commitment aims to minimize $C(c,e,s)$ and increase the security (through minimizing the security violation indexes) in a scheduling period with regarding to Production cost *"c"* ,Emissions *"e"* and Security violation index *"s":*

A. Objective function

$$Min\, C(c,e) = (\sum_{i=1}^{N}[\tau c.\alpha c.c(Pi) + \tau e.\alpha e.e(Pi)] + \tau s.\alpha s.s) \qquad (1)$$

B. Generation cost

$$c(Pi) = FCi\,(Pi) + MCi\,(Pi) + STi\,(Pi) + SDi\,(Pi) \qquad (2)$$

C. Fuel cost

$$FCi\,(Pi) = \alpha i.Pi^{2} + \beta i.Pi + ci \qquad (3)$$

D. Maintenance cost

$$MCi\,(Pi) = BMi + IMi\,.Pi \qquad (4)$$

E. Start up cost

$$STi = TSi + [1 - e^{(Di\,/\,ASi)}].\,BSi + MSi \qquad (5)$$

F. Shut down cost

$$SDit = KPi \qquad (6)$$

G. Emission Function

$$e(Pi) = \alpha\,.Pi^{2} + \beta\,Pi + \gamma + \delta\,.e^{\varepsilon\,.Pi} \qquad (7)$$

H. Security Function

The Security function consist of 3 main objectives; voltage as busbars, apparent power flow in branches and reactive power generated by generation units:

$$s = \tau v\,.sv + \tau b\,.sb + \tau g\,.sg \qquad (8)$$

I. Voltage Security Violation

This is a term which deals with the voltage at bus bars which must always remain between a minimum and maximum limit at all the scheduled generation period:

J. Apparent Power Flow

Apparent flow (Complex power; $S = P + jQ$) in transmission lines is one of the constraints which sometimes cause decomitting a unit or keeping its output up to certain level as transmission lines are running up to their maximum capacity; some thing which is known as transmission congestion.

K. Reactive Power generated by units

In power systems voltage collapse usually happens when the reactive power is not enough to meet inductive loads such as induction motors etc. Generation units generate certain amount of reactive power and exceeding this limit will reduce the security of supply.

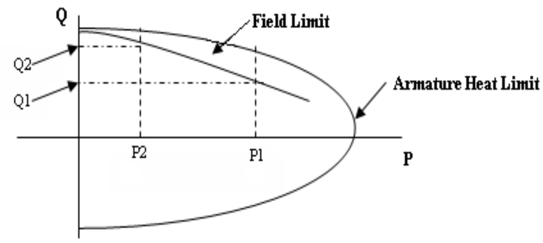

Fig 1. Generator Power Output Capability Graph.

Other constraints:

Apart from those mentioned objective constraints during unit commitment, there are several other constraints which must be considered:

L. Crew constraints:

With thermal power plants, particularly starting up and shutting down generation units needs a certain number of crews to operate and sometimes because of lack of crews it is impossible to start up or shut down more than one unit at a time.

M. Minimum up and down time:

In some plants i.e. nuclear, hydrothermal etc, because of economic efficiency and technical constraints it is impossible to shut down a unit before a certain duration of being in duty is reached; again once a unit is turned off it may be impossible to start it up and bring it back to network before certain number of hours of being off-duty is reached. These units have different characteristic than "Peaker" units; for instance gas turbine units which usually are not subject to a minimum up and down time and can start up and supply peak demand and shut down straight after peak period.

N. Generator output limits

Generation units must be scheduled to operate within their maximum and minimum rated output in terms of active and reactive power:

$$PGi\min \le PGi \le PGi\max \qquad QGi\min \le QGi \le QGi\max \qquad (9)$$

O. Spinning Reserve

Total Generated power in the system must meet demand, network losses and required Spinning Reserve. Spinning reserve is the amount of power always available to be dispatched in the system to meet sudden demand increase or being used in minor contingencies.

$$\sum_{i=1}^{N} Pi \ge Demand + Network\ looses + Spinning\ reserve \qquad (10)$$

$$\sum_{i=1}^{N} (CSPPi - Pi\,, SPi\,) \ge Spinning\ reserve \qquad (11)$$

P. Negative Reserve Requirement

Negative reserve is to make sure at each scheduling period there are sufficient generation units in the system which are running at certain amount higher than their minimum generation limits. This is to allow their output be reduced in case of loosing the demand in case of an event predicting it higher than actual value [10].

Q. Generator Ramping Up and Ramping Down Rate

The ability to increase (or decrease) the output power of a generator in a certain amount of time is called *Ramping Rate.* Generation units have different ramping rates and this must be considered in unit commitment. *Ramping rate* is particularly important for those units which are due to be committed to supply power reserve (especially spinning reserve) as certain amount of reserve is supposed to be generated by these units. Network operators i.e. NGC in the UK, have their own criteria for selecting units providing spinning reserve which in the UK is 25MW/minute within 2 minutes of instruction and to be sustained up to the minimum of 15 minutes [11].

R. Reliability Must Run Units (RMR)

In the power system generation units that the ISO determines are required to be on-line [at certain times] to meet applicable reliability criteria requirements [12]; such as voltage support or during system maintenances.

S. Regulatory Must Run Units (RGMR)

The main objective of regulatory must-run units is to maintain "fair" competition in a deregulated market. A good example of regulatory must-run units is hydro power plants. Most of these power plants are multipurpose units which were designed both for power generation and irrigation purposes. Allowing a hydropower plant to participate in the competitive market may defeat the agricultural purpose [12]. Another example of RGMR units exists in places where heat demand is added on top of electrical demand. In order to supply enough heat, we must make sure that enough thermal units (Combined Heat and Power CHP) which are supposed to provide heat in all heat demand areas are committed at each scheduling period.

T. Regulatory Must Take Units (RMTU)

In deregulated energy markets there are power purchase agreements (PPA) which occurred prior to the deregulation and carried over to the deregulated market. Examples of regulatory must-take units are nuclear power plants, cogenerations, and PPAs with other entities such as neighboring countries. It means in OPF, ED and UC calculations these PPAs also need to be considered [12].

U. Qualified Unit Providing Ancillary Services in Deregulated Energy Market

As mentioned in (9.5) ancillary services usually come from specific units. In deregulated energy market where price bidding exists both for power and ancillary services, not all the generation units can participate in providing ancillary services. At each period some power utilities which normally participate in providing ancillary services may or may not be available.

V. Balance between Demand and Power in Deregulated Energy Market

In a deregulated Energy market (DEG), network operators particularly those who provide ancillary services such as spinning reserve or operating reserve, are allowed to either supply an extra power into grid or by reducing the demand to reduce the need of an extra reserve. This is a new term in DEG which has been using in some parts of the world [13]. Therefore by committing those companies which are allowed to shed the load to unrequire the network to extra power, in fact the demand which needs to be supplied is being reduced and network parameters must be studied well before committing generation units as it may cause voltage rise in the system because of extra power which is not being consumed. There are also other ways such as pump storages, interchange etc. All the power which is due to be achieved from these sources must be subtracted from total required reserve [14].

IV. Implementation

A. Test System

The IEEE Standard 30 Bus Test System [15] has been chosen for our project. Figure 2 shows the proposed network, the main objective of our research is to integrate renewables into the system, after running the simulation without the presence of any wind farm, 2 wind farms step by step have been added to this system in different locations. Table 1 shows the generators cost and emissions characteristics and Table 2 shows Minimum Up Time (MUT), Minimum Down Time (MDT), Ramp rate, Minimum and Maximum power output and locations of conventional plants. All generators data apart from generator No. 9, 10 and 11 are derived from IEEE Reliability Test System RTS-96[15]. Total conventional plants capacity is 300MW while 2 windfarms have 15MW (windfarm No.1 capacity factor = 26%) and 20MW (Windfarm No.2 capacity factor = 29%) installed capacity. Figure 3 shows weekly output of two windfarms.

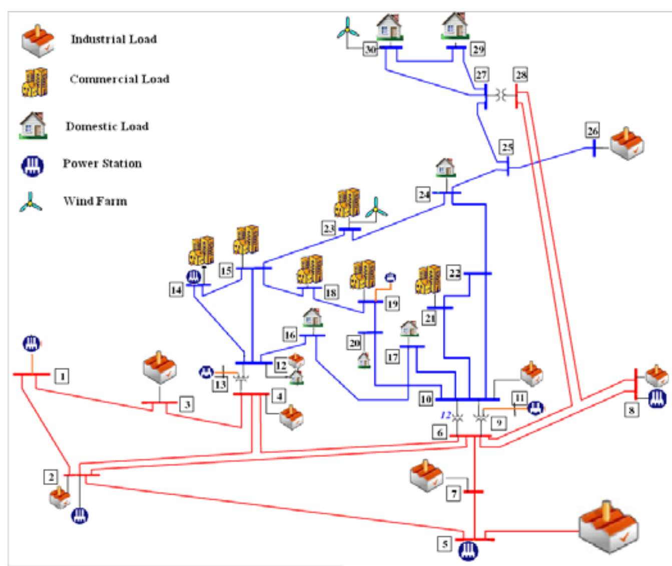

Fig 2. The IEEE 30 Bus Test System.

TABLE I
GENERATOR COST AND NOx EMISSION CHARACTERISTICS

Unit	a	b	c	α	β	γ	δ	ε
1	0.02	1.2	40	9.9E-2	-5.6E-2	4.1E-2	1.5E-4	3.86
2	0.01	0.8	38	5.6E-2	-6.1E-2	4.8E-2	1.0E-4	3.3
3	0.06	4.5	45	7.6E-2	-5.1E-2	2.6E-2	1.0E-8	8.0
4	0.01	0.4	30	3.4E-2	-3.6E-2	5.3E-2	1.0E-6	2.0
5	0.06	5.2	23	3.5E-1	-5.1E-2	2.3E-2	1.0E-8	8.0
6	0.05	2.2	42	4.4E-2	-5.1E-2	3.4E-2	1.0E-8	8.0
7	0.05	3.0	45	1.8E-1	-5.1E-2	2.9E-2	1.0E-8	8.0
8	0.04	1.8	53	5.2E-2	-9.5E-4	3.1E-2	2.3E-4	6.67
9	0.00	0.0	0	0E+0	0E+0	0E+0	0E+0	0.0
10	0.00	0.0	0	0E+0	0E+0	0E+0	0E+0	0.0

TABLE II
OTHER GENERATOR CHARACTERISTICS

Unit	MUT	MDT	Ramp Rate	*Pmin*	*Pmax*	Busbar No.
1	3	2	5	10	35	11
2	2	2	4	10	45	5
3	3	2	7	8	40	2
4	3	2	6	10	60	1
5	1	1	6	5	25	19
6	2	1	5	2	30	14
7	2	2	7	5	35	8
8	2	1	4	5	30	13
9	0	0	4	0	10	23
10	0	0	4	0	15	30

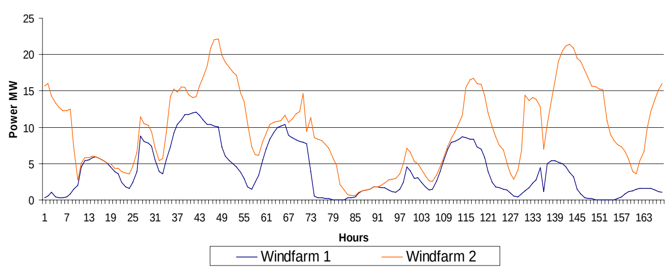

Fig 3. Weekly output variations of Wind farms.

B. Demand Data

For each period of unit commitment, load forecasting is a must and several research projects have been practicing the methods which give less error in predicting the demand which needs to be supplied [16, 17]. Failure to meet predicted demand can lead to shedding the load which can lead to severe economical and security issues. Total demand characteristic regardless of the specific type of demand varies in electric networks. There are several factors available in network policies which affect demand such as multi tariff charging method; single rate, double rate or Economy 7 (E7) and Load Factor (LF). As each sector in the system represents different electricity load patterns, then it is necessary to know which demand sectors exist in this network and which model of demand they are representing.

In this project 80% of total demand has been assumed to be domestic and it has been assumed and proportion of domestic weekly demand has a pattern which is shown in Figure 4.

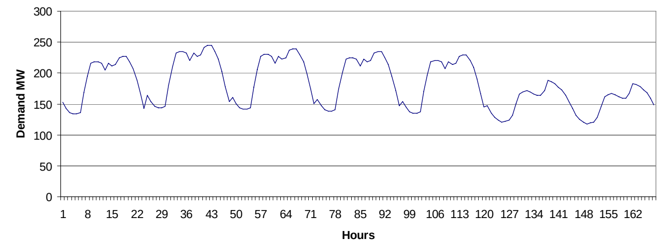

Fig 4. Demand variations during a week.

C. Responsive Demand

In our test system we have divided the loads into 3 categories; industrial, commercial and domestic. We assume that all responsive loads are available in domestic sector and will respond whenever output of windfarms drops. The response setting has defined as:
If Wind Output < 10MW then reduce the demand by 5%
If Wind Output < 5MW then reduce the demand by 10%

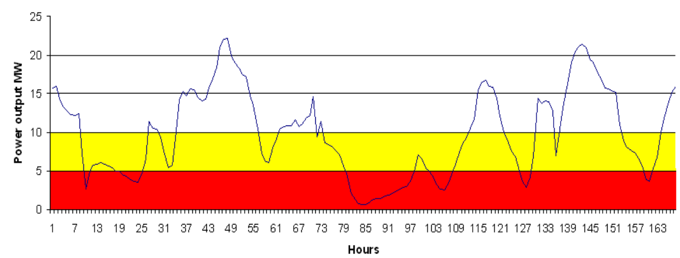

Fig 5. Aggregate output of Windfarms and effects level of responsive demand.

D. Variables

After scheduling the units to supply demand with zero percent penetration of wind power the results have been compared with 5%, 6% and 10% installed wind penetration connected to the network and by moving this amount of capacity across the network the benefit of locating then in each bus compared with other cases has been demonstrated. by dynamic optimization method, unit commitment (UC) has been performed [2]. The following variables have been considered and compared together in each case:

- total system emissions;
- system production costs;
- security violation index;
- value of wind.

V. RESULTS

Generation Scheduling in presence of windfarm was performed and results shown below indicates the network variables which differ in each case.

A. Production Cost

Production cost which is assumed total running cost of conventional plants is shown in figure 6. Each unit has its own running cost and total cost is aggregation of them.
When we assume that loads in the network respond to wind variations, by shedding the demand according to our mentioned setting in III we see a big difference in production

cost. This is not just because of supplying less demand; as each unit has different production cost and gas units which are usually being used to supply load for a short time are very expensive to run. When demand drops according to wind output reduction, the need for running gas units is minimized and as a result total production cost is lower.

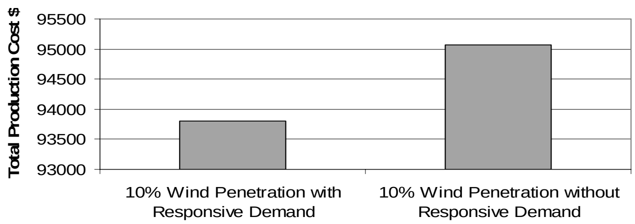

Fig 6. Total Production cost.

B. Total Emission:

Total emission in the network comes from conventional plants which spread NOx and CO2 into atmosphere. We have just considered NOx emissions in our study. Again by reducing the demand, need for running conventional plants at some points are eliminated and total emission is lower.

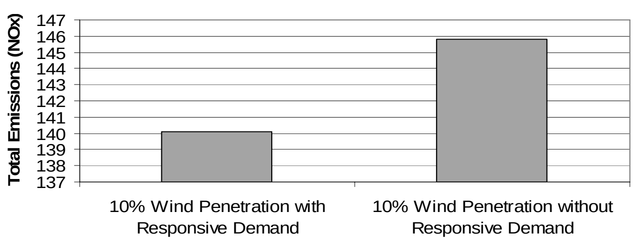

Fig 7. Total Emission.

C. Impact on Security:

Our main interest is impact of responsive demand on security index violation of network. Security objectives have been defined in II.8. One of the key issues in locating windfarms is network limitation in transferring power across the network on branches. This is one of our objectives which considers thermal limits of transmission lines. Another object is required amount of reactive power from generation units. Wind units can supply substantial amount of reactive power and by reducing the demand when windfarms have less energy share in the system, the need for getting more reactive power from other plants is eliminated and will result in more secure network. In terms of voltage limits in busbars, again by reducing the demand, those busbars which are accommodating conventional plants will not see much difference in output of conventional plants and voltage rise/fall does not happen.

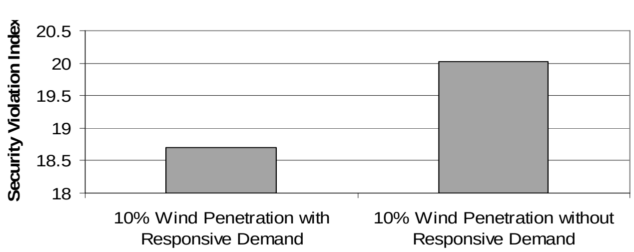

Fig 8. Security Violation Index

It must be noted that when security index is lower, it represents a more secure network as security objectives have less violation from their desired points; i.e. voltage in busbars can vary between 0.950-1.09 per unit. Below and beyond these points, unit commitment is invalid.

D. Impact on Value of Wind:

Value of wind is defined in equation below:

$$Value\ of\ Wind = \frac{C(No\ wind) - C(with\ wind)}{P(Wind)}\ \$/MW \qquad (12)$$

Where C is total production cost and P represents the installed wind capacity in MW.

Value of wind shows how much money could be saved through in supplying the demand per MW installed wind capacity. It is clear that by reducing the total generation cost (while we assume that we utilize total output of windfarms) value of wind increases by 17% in presence of responsive demand. This value could be vary by changing the methodology of implementing responsive demand and consider

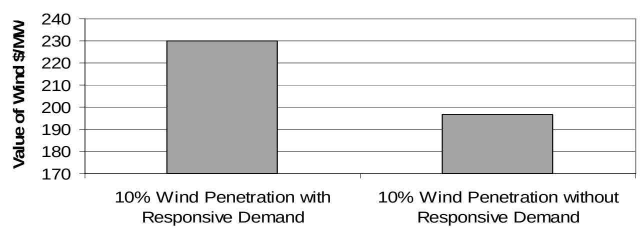

Fig 9. Value of Wind

VI. CONCLUSIONS

Responsive demand in networks with high penetration of intermittent generation can have a positive effect on operational, planning and environmental characteristics. It provides the opportunity for load growth and enhanced robustness with minimal addition growth of the transmission system, make greater use of renewable such as wind systems, increases energy efficiency and reduce pollution and emissions and increases the level of local reliability to ensure the necessary power quality standards has met.

In this project we assumed that in domestic sector we can have such responsive demand which responds to intermittent units output variations. Reducing the demand either automatically or by communication between network and load can benefit the network both in short term by improving the transmission capacity and will reduce the need for network reinforcement in long term. However if it requires communication between network and demand; then a substantial investment may be needed to provide such facilities.

In previous DSM methods shifting the demand has always been considered rather than shedding it. But it may not benefit systems with high penetration of renewables as much as networks with lower penetration as aim of shifting the demand is just to reduce the peak demand and reduce the need for running peaker power units. But this is not the only issue in networks with high penetration of renewables and a solution is needed to mitigate the output power fluctuations and this is the aim of responsive demand which considers shedding the demand.

Whenever shedding the demand is considered as a solution to improve the efficiency and reliability it must always be noted that evaluating the value of lost load (VOLL) is very important and not all types of loads are able to participate in responsive demand program.

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VIII. BIBLIOGRAPHY

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