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Sustainable generation mix as a reference in effective design of electricity market structures and rules

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Sustainable Generation Mix as a Reference in Effective Design of Electricity Market Structures and Rules

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PhD Thesis Abstract

Energy efficiency and sustainability in the electricity supply industry will continue to retain high priority in the foreseeable future despite the changing commercial and regulatory environments. This calls for substantial but progressive changes in electricity market design if renewable, cleaner and more efficient generation technologies are to significantly contribute to the generation mix. This research is concerned with the development of a methodology to determine the sustainable generation mix for use as a reference in the design of electricity market structures and rules.

Sustainability issues surrounding electricity generation are discussed together with the role played by generation technologies in environmental damage. The work identifies and discusses key factors affecting the generation mix. The generation mix was determined based on total generation costs including external costs due to emissions. Technology specific characteristics were considered in determining capacity contributions of the technologies. The energy and emission contributions were determined by conducting a series of generation schedules based on an annual load profile leading to the evaluation of the economic and environmental performance of the generation mix.

The developed methodology was tested on a system with a peak demand of 4.2GW and 11 candidate generation technologies. Simulation results show that by shifting the generation mix, it is possible to significantly reduce greenhouse gas emissions with a marginal increase in generation costs.

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Chapter 1

Introduction

THE introduction briefly describes the background, the motivation, objectives and the contribution of this thesis. It also gives an overview of the thesis layout.

1.1 Climate Change and Electricity Generation

Scientific evidence for climate change due to the build-up of greenhouse gases in the atmosphere continues to strengthen. Although there is no consensus on how much time there is before the climate change becomes irreversible, it is widely accepted that climate change is already underway and urgent action is needed now. Energy supplies form the lifeblood of our economy yet energy use is the prime source of greenhouse gas emissions. The international community is responding to this challenge by implementing measures to combat climate change. Major international programmes include the United Nations Framework Convention for Climate Change, the Intergovernmental Panel on Climate Change and the Asia Pacific Partnership on Clean Development and Climate.

Electricity generation is the largest producer of greenhouse gases. Specifically, electricity generation from fossil fuels is the chief cause of the emissions problem in the electricity supply industry. The industry therefore has to be a significant part of the solution to the climate change challenge.

1.2 Generation Planning

Generation planning can be classified into two categories namely operational planning and investment planning. The two are interrelated but have different timescales.

1.2.1 Operational Planning

Operational planning is a short term problem that deals with generation and maintenance scheduling. In the decentralised electricity markets, generation compete to serve demand. The operations are guided by the market structures and rules.

An opportunity therefore exists to influence the operation of generation to reduce greenhouse gas emissions.

1.2.2 Investment Planning

Investment planning is a long term problem concerned with investment in generation capacity. As with operational planning, the market structures and rules influence the viability of the various generation technologies. Investors tend to favour technologies that yield the best rate of return in order to maximise their profits.

The market therefore has a profound role to play in the mitigation of climate change since it can influence both generation investment and operation.

1.3 Motivation

Future generation of electricity will need to be more efficient, economical and more environmentally friendly in order to make a significant contribution to emissions reduction. In the United Kingdom, about 40% of the average domestic consumer's bill is made up of generation costs, therefore efficiency improvements will not only help to keep electricity affordable but also to cut on greenhouse gas emissions. However, there will need to be a significant shift in the generation mix in order to meet the current aspirations of reducing greenhouse gas emissions.

The application of an ideal generation mix as a reference in electricity market design would assist in the formulation of market structures and rules that can effectively provide economic signals to incentivise investment into cleaner, renewable and more efficient generation technologies.

1.4 The Objective of this Work

The objective of this work was to determine sustainable generation mixes based on a given number of candidate generation technologies and scenarios. The purpose of these sustainable generation mixes is to provide reference generation mixes for use in determining market structures and rules as well as providing sustainability performance indicators for market design.

1.5 The Challenge

1.5.1 Uniqueness of Electricity Markets

While commodity markets are well established, electricity markets are still in their infancy. The challenge with electricity markets is that, unlike commodities, electricity has to be produced to meet demand on a second by second basis. Effective market design requires in-depth understanding of the principles governing power system operation. Investment in the power system is capital intensive and the increasing uncertainty in the deregulated environment mean that it is critical that the investors get clear signals form the market concerning the appropriateness of investments in specific generation technologies and electrical networks.

1.5.2 Need to Address Uncertainties

In most market and economic studies, high level scenarios are setup. Often, the selection of generation technologies and capacities for such scenarios is based on assumptions. Sometimes these assumptions are derived from historic data which may not be relevant to prospective technologies. However, based on estimate costs and operating characteristics of the candidate technologies it is possible to determine generation mixes that are more suitable in quantitatively representing the high level scenarios.

1.5.3 Drawbacks with Current Approaches to Generation Mix

Current generation mix approaches tend to consider only an evolutionary trajectory based on existing generation. A reference generation mix should be free from such limitations as they can always be considered as constraints during the investment planning stage. Therefore, the market structures and rules should, if necessary, be capable of discouraging prospective or even existing generation technologies if they do not meet the desired sustainability criteria.

1.6 Contribution

The main contributions of this work are as follows:

- To bring a deeper understanding of the potential of the electricity supply industry for climate change mitigation;
- To develop a new methodology for determining sustainable generation mixes that can be used as references in electricity market design;
- To demonstrate the potential of the electricity supply industry for climate change mitigation using the new methodology.
- To introduce a multi-agent simulation model on which a market simulation model can be built upon.

1.7 Thesis Layout

This thesis is arranged as follows: Chapter 2 deals with sustainability issues in general and within the electricity supply industry and the international response to the sustainability challenge. It also gives a review of deployed, demonstrated and prospective electricity generation technologies. It then discusses related work and the intended application of the developed methodology. Chapter 3 deals with the factors that affect the generation mix broadly classified into technology specific characteristics, the electricity supply industry and network planning issues.

The methodology developed is explained in Chapter 4. The key variables are outlined followed by the detailed methodology. Chapter 5 presents the test data used for demonstrating the methodology and the results as well as the discussion of the results. A general discussion is given in Chapter 6. Complementary approaches for mitigation of climate change within the electricity supply industry are discussed together with synergies with other research activities. Chapter 7 presents the conclusions of the thesis and Chapter 8 outlines further work.

Chapter 2

Sustainable Power Generation

THIS chapter discusses sustainability issues in general and within the electricity supply industry. It also looks into international response programmes to the sustainability challenge. A review of deployed, demonstrated and prospective electricity generation technologies is given. Finally, the chapter discusses related work and the intended application of the developed methodology.

2.1 What is Sustainability?

Sustainability in its broad sense can be defined as the ability of the current generation to provide for its needs without damaging the ability of future generations to provide for themselves. Ideally, sustainable processes can be carried out over and over without causing environmental degradation or resulting in prohibitively high costs. While technological advancements have greatly improved people's lives through highly effective means of harnessing naturally occurring energy sources, the sustainability of today's processes are increasingly being scrutinised (Boyle *et al.*, 2003c). Energy needs are largely responsible for environmental degradation due to extraction, handling and processing of primary energy resources (mostly fossil), their use and disposal within the various sectors of the economy.

The rate of depletion of existing fossil fuel bodies today threatens extinction of such sources within a relatively short space of time. At current production rates, proven coal reserves are estimated to last 164 years while proven oil and gas reserves are equivalent to around 41 and 67 years respectively (WCI, 2006). Hazards associated with extraction and handling of fossil fuels include environmental pollution from spillage of oil resulting in loss or damage of marine life, vegetation and some animal life on land, explosions in coal, oil and natural gas mining and handling complexes. The processing and use of the fuels in the various sectors of economy (for example electricity generation, transportation, industrial, etc.) produces greenhouse gases[1] (GHGs), particulate matter, heavy metals and solid wastes, all of which have undesirable effects on the environment and human and animal health.

[1]The six main greenhouse gases are carbon dioxide (CO_2), nitrous oxide (N_2O), sulphur oxide (SO_2), methane (CH_4), hydrofluorocarbons (HFCs), sulfur hexafluoride (SF_6) and perflourocarbons (PFCs).

There have been reports of acid rain and respiratory problems in humans and other animals, linked with SO_2 and NO_X (Boyle *et al.*, 2004; Meier and Munasinghe, 2005a). GHGs are strongly believed to be the major force behind global warming in most recent decades. Adverse weather effects in recent years have been attributed to global warming. Some of the gases like SF_6 and HFCs also cause depletion of the ozone layer which exposes the earth and its inhabitants to harmful radiation from the sun. In the case of nuclear power which is not fossil, there are serious public perception issues centered around health concerns from radioactive emissions from reactors and the disposal of waste materials. The disposal of nuclear waste has been a subject of much heated debate up until this day.

Major global response programmes to climate change include the United Nations Framework Convention on Climate Change, UNFCCC, established in 1992, the Intergovernmental Panel on Climate Change, IPCC established in 1998, the Kyoto protocol signed in 1997 and the Asia Pacific Partnership on Clean Development and Climate (AP6) announced by President George Bush in 2005. The objective of the UNFCCC was to stabilise GHG levels of concentration in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate system (UNEP/IUC, 1997).

The Kyoto protocol was entered into as a follow up to the UNFCCC. Under this protocol, parties included in Annex I[2] shall pursue limitation or reduction of emissions of GHGs to at least 5 percent below 1990 levels in the commitment period 2008 to 2012 (UN, 1997). There are three mechanisms through which the Kyoto protocol is

[2]'Party included in Annex I' means a Party included in Annex I to the Convention (UNFCCC), as may be amended, or a Party which has made a notification under Article 4, paragraph 2 (g), of the Convention. *http://unfccc.int/parties_and_observers/parties/annex_i/items/2774.php*

implemented namely, the Joint Implementation (JI) Projects[3] (these generate Emission Reduction Units, ERUs), the Clean Development Mechanism (CDM) Projects[4] (these generate Certified Emission Reductions or Removals, CERs) and the International Emissions Trading (IET). GHG allowances, ERUs and CERs can be traded through the IET to meet emission targets. The details of the implementation of emission reduction strategies are up to the individual countries.

Table 2.1. Carbon emission forecasts for the UK. *Source: Energy Review 2006*

	Carbon dioxide Emissions [million tons]				
	1990	2000	2005	$_{forecast}$2010	$_{forecast}$2020
Power stations	55.7	43.1	47.1	42.5	45.0
Refineries	5.0	4.9	5.6	5.7	5.7
Residential	21.1	23.2	22.3	20.3	20.6
Services	8.3	8.2	6.8	5.9	6.9
Industry	35.3	33.4	31.4	32.6	30.6
Transport	35.1	35.9	37.1	32.6	32.5
Total	**160.5**	**148.7**	**150.3**	**139.6**	**141.3**

Table 2.1 shows the UK carbon emission levels from 1990 to 2005 and forecasts for 2010 and 2020. The UK government has committed to produce 10% of its total electricity generation from renewables by 2010 and 20% by 2020. As a long-term objective, the government intends to cut CO_2 emissions by 60% by around 2050. Although nuclear power plants have low emissions[5], they are perceived as extremely hazardous by the general public and therefore undesirable. The future of nuclear generation is uncertain in the UK although the government has thrown its weight

[3]Joint Implementation is a programme under the Kyoto Protocol that allows industrialised countries to meet part of their required cuts in greenhouse gas emissions by paying for projects that reduce emissions in other industrialised countries.

[4]Clean Development Mechanism is a mechanism that allows developed nations to achieve part of their reduction obligations under the Kyoto Protocol by funding projects in developing countries that reduce emissions.

[5]Although nuclear generation does not directly produce carbon emissions, it does indirectly produce them from mining, fuel processing and nuclear plant construction.

in support of nuclear generation in its energy review (DTI, 2006a). This leaves current and upcoming generation technologies to cover for plant closures and demand increase, thereby creating vast opportunities for renewable and embedded generation. However, the original power systems were not designed with distributed generation in mind, neither were the electricity markets specifically designed for power systems with high penetrations of distributed generation. The design of electricity markets has to be adapted to these new requirements to ensure that they can deliver secure and reliable power supplies economically in an environmentally friendly manner.

2.2 Mitigating Environmental Damage within the Electricity Sector

Table 2.1 shows that electricity generation is the largest contributor to carbon emissions. This is mainly due to two reasons: firstly convenience and versatility of electricity hence its widespread use and secondly, the vast majority of the primary energy resources are fossil fuels. Within the electricity sector as a whole a number of measures can be employed to mitigate environmental damage by holistically looking at the spectrum of available complementary options as follows:-

- Adopting an optimal generation mix that effectively exploits cleaner and renewable generation technologies,
- Improving generation (energy conversion) efficiencies,
- Improving transmission and distribution efficiency and
- Efficient energy utilisation.

This thesis is concerned with the choice of the combination of generation technologies that leads to the most sustainable generation mix. Improvement of generation technologies and ways of improving efficiency of energy utilisation are beyond the scope of this thesis.

Different countries have varying proportions of the primary energy resources, both renewable and non-renewable. Where fuels are imported, there are risk factors associated with the source and route of the fuels, diplomatic relations, international market price fluctuations, etc. On the other hand, fuel diversity is recognised to enhance security of supplies (Lewis, 2006). The electricity transportation system also has security constraints that may impose some restrictions on the utilisation of some generating units either because of their location or due to their operating characteristics. The challenge in today's decentralised power systems is to maintain acceptable security levels while utilising cleaner, more efficient and renewable generation, most of which is intermittent, at affordable costs to the consumers.

Realistically, sustainability is a relative concept. What is really sought here is the generation mix that has significantly reduced environmental impacts while at the same time being reasonably affordable in terms of the actual cost of electricity generation. This is an optimisation problem which recognises the fact that there are external costs in the generation of electricity due to emissions. Hypothetically, if appropriately considered at the investment planning stage, emission costs can effectively influence the generation mix in a way that reduces environmental damage. There are two ways of dealing with the emissions problem:-

1. If costs of emissions are known, then the optimisation variables are the electricity generation costs including emission costs.

2. On the other hand, if there is no established mechanism for valuing emissions, then the optimisation will in addition to minimising costs, also minimise the total emission from the generators.

There are several emissions trading schemes in place today, for example, the UK Emissions Trading Scheme (ETS), the European EU-ETS and the Chicago Climate Exchange (CCX). They are basically cap and trade systems[6]. The basic unit of trade is one metric tonne of CO_2 or equivalent (tCO_2e). Prices of emissions tend to vary considerably on the market; Figure 2.1 shows the variation of the EU ETS CO_2 allowance price ranging from €7/tCO_2 to €31/tCO_2 between January 2005 and June 2006 (DTI, 2006a). The price volatility is caused by uncertainties about which countries will meet their targets and if countries have the political willpower to implement the necessary changes in their energy consumption (Camyab *et al.*, 2006).

Studies that attempt to evaluate the cost of emissions from electricity generation tend to concentrate on leveling the playing field based on generation costs including externalities for the different generation technologies in a way that credits cleaner generation (Kuri and Li, 2005). Another option is to cost the damages caused by the pollutants from electricity generation (Chernick and Caverhill, 1991; Braun, 2004; Meier and Munasinghe, 2005b). A summary of studies to assess the environmental and health impacts of energy use are summarised by Boyle *et al.* (2004). It notes that there are wide variations in the estimated values for external costs. This approach is very subjective as there are no standard ways of evaluating the cost of damages,

[6]Cap and trade is an administrative approach used to control pollution by providing incentives for achieving reduction in pollutant emissions. A central authority sets a limit or 'cap' on the amount of pollutants that can be emitted. Groups that intend to exceed their limits may buy emissions credits from entities which are able to stay below their designated limits. This transfer is normally referred to as a 'trade'. Source - web: http://en.wikipedia.org/wiki/Cap_and_trade Last accessed 13 July 2006.

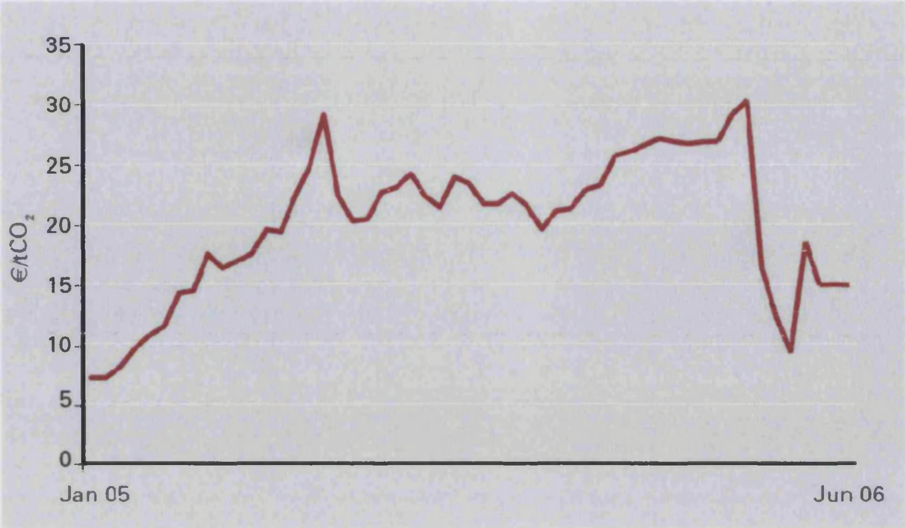


Figure 2.1. The EU Emission Trading Scheme allowance price, Jan 2005 – Jun 2006. *Source: DTI, 2006*

for example, the health damages caused to humans and animals by emissions from electricity generation, or by acid rain, or land degradation due to particulate emissions, etc. In this thesis, the approach taken considers the cost of emissions from electricity generation payable in respect of the amount of emissions at the market price of the emissions. Sensitivity analysis was deemed adequate in addressing the uncertainties introduced by market price fluctuations.

2.3 Generation Technologies

Electricity generation technologies can be classified into three main categories, namely fossil fuel, renewable energy and nuclear technologies. Within each of these categories, there are different variants depending on the type of fuel or primary energy resource and the technology used in the construction of the generators. Below is a discussion of some of the common technologies that are either currently in the market, demonstrated or prospective.

2.3.1 Fossil Fuel Technologies

There was a marked increase in global energy use in the nineteenth and twentieth centuries. The energy was mainly derived from burning cheap and abundant fossil fuels. Coal was the first to be exploited at massive scales, followed by oil and then natural gas. These fossil fuels now supply around 80% of the world's energy consumption (Boyle *et al.*, 2003a).

Gaseous emissions considered to be an environmental burden from fossil fired generation plant are carbon dioxide, nitrogen oxides, nitrous oxide and sulphur dioxide. Carbon dioxide is given most of the attention because it is by far the worst greenhouse gas compared to other emissions from electricity generation from fossil fuels. Only carbon dioxide is considered in phase 1 of the Kyoto Protocol under the EU ETS. EU carbon dioxide emission account for 24% of global emissions (Limbrick, 2006). An appraisal of the UK energy research development and demonstration and dissemination (ESTU, 1994) covers the extraction and conversion of fossil fuels in detail as well as the fossil fuel generation technologies themselves. Some of these fossil fuel technologies are briefly discussed below.

Conventional Steam Cycle (CSC)

This technology is with coal, heavy fuel oil (HFO) or orimulsion[7]. The fossil fuel is combusted to raise steam for driving the turbine generator train to produce electricity. The technology variants in this category are based on fuel and waste handling systems. In order to improve combustion efficiency in coal fired plants, the coal is pulverised. similarly, HFO fuel is atomised and for orimulsion, steam assistance is

[7] Orimulsion is a bitumen-in-water emulsion. It is found in the eastern part of Venezuela. It can be used in HFO fired plant with modification of the burners

required to achieve good atomisation. Fuel specification variation affects both environmental and technical specification, for example, a lower sulphur content reduces the electrostatic precipitator efficiency and could lead to an increase in particulate emissions although the sulphur emissions would be reduced. Steam technologies being deployed nowadays employ Advanced Super Critical (ASC) boilers[8] (Spalding, 2005). Typical CSC plant data is given in Tables A.1 and A.2.

Open Cycle Gas Turbine (OCGT)

This technology uses gas turbines to generate electricity without heat recovery from the exhaust gas. Efficiency of the technology is low (around 31% for new plant) and is worsened by its intermittent operation as it is used to meet peak demand. It comes in small capacities, typically less than 70MW in the UK (they are basically aero-engine derivatives). The units are very flexible in their operation as they can be started up quickly and ramped to full power in a relatively short time. They run on distillate oil (gas-oil). Typical data for OCGT plant is given in Table A.4.

Combined Cycle Gas Turbine (CCGT)

This technology uses a combination of gas and steam turbine technologies to generate electricity. Compressed air is passed into the combustor where it is mixed with fuel and burnt, raising both its temperature and pressure. The gases are expanded through a gas turbine driving a generator. The exhaust of the gas turbine is used to produce steam which is expanded through a steam turbine coupled to another electricity generator. Typically, the gas turbines are designed to run off gaseous or liquid fuels. One major advantage of this technology is that it is highly modular,

[8]Advanced supercritical boiler design improves efficiency by increasing the working fluid pressure and allowing superheating of the steam to higher temperatures.

typically, one unit consisting of two gas turbines feeding one steam turbine with the combined output not exceeding 700MWe. Typical plant data is given in Table A.3. When fueled by natural gas, the CCGT offers a significant reduction in environmental emissions in comparison to coal and oil fueled technologies. This technology has been deployed.

Integrated Gasification Combined Cycle (IGCC)

This technology employs an intermediate gaseous product stage in the generation of electricity from coal, HFO or orimulsion. A gasifier produces fuel gas from coal or its alternatives. The gas is cleaned and then burnt with compressed air in the combustor to produce hot air at high pressure. This air is used to drive an air compressor and a gas turbine driving a generator to produce electricity. The hot turbine exhaust gas is used to raise steam in a boiler. The steam is used to drive a steam turbine driving a generator to produce additional electrical power.

Gasification involves partial oxidation of coal or its alternatives with air, oxygen and optionally steam. Gaseous emissions are more easily controlled under gasification conditions than in the combustion process. Environmental burdens for the IGCC are minimised by the ability of the gas cleaner to efficiently remove undesirable compounds before the combustion process. Notable variants of the gasifiers are the moving bed gasifier, fluidised bed gasifier and the entrained bed gasifier. These are categorised by the physical arrangements of the reacting materials and hence the reaction kinetics. Typical plant data is given in Table A.4. IGCC is a deployed technology.

Fluidised Bed Combustion (FBC)

In the UK, the pulverised fuel system is the established method for coal combustion. Concerns over emissions have led to the requirement to modify coal fired plants using this method. The fluidised bed combustion technology for coal powered generation provides an alternative means to control emissions and improve efficiency. The fluidised bed is formed by air flow rising through a bed of fine solid particles, lifting them so that they do not rest on each other in the process. The solid particles retain their physical and chemical properties while taking the shape of the container, hence resembling a fluid. For coal fuel, inert particles should form more than 99% of the bed. These inert particles are heated to incandescence. Pulverised coal introduced to the bed is heated to ignition almost instantly. The heat generated in the process sustains the bed temperature. Typical FBC plant data is shown in Table A.5.

Two notable variants of this technology are the circulating fluidised bed combustion (CFBC) and pressurised fluidised bed combustion (PFBC) technologies. In CFBC, the velocity of the air is increased thereby increasing the rate of oxygen supply. This results in improved heat output over the FBC system. Because of the high speed of the air, the burning cloud fills the combustion chamber and a cyclone is used to extract the ash. Additionally, circulation of fuel provides a longer residence time in the combustion chamber resulting a high carbon burn-out rate, typically greater than 98%. The PFBC uses air above atmospheric pressure. This reduces the volume of the plant. A notable drawback with this technology is the need to introduce fuel against high pressure into the combustion chamber. The same applies for the removal of ash. CFBC is a deployed technology while PFBC is a demonstrated technology.

Hybrid Cycle

The hybrid cycle improves the efficiency of electricity generation from coal by combining integrated gasification combined cycle and fluidised bed combustion technologies. This way, the difficulties associated with the individual technologies can be mitigated. Basically, the char from the coal gasification process is fired in a fluidised bed combustor. The gas from the gasification process is used to power the gas turbine and the exhaust from this process, together with the heat generated in the fluidised bed combustor, is used to raise steam for the steam turbine. As with the IGCC, emission control is better achieved pre-combustion as compared to post combustion of the produced gas. The technology is not deployed in the UK at the moment, requiring further research and development work.

Fuel Cells

The use of fuel cells in power generation has not yet reached commercial levels but there is considerable research and development in the area. There has been a lot of interest in the automotive industry, with a number of demonstration vehicles having been constructed and currently being tested. Nine cities in Europe are taking part in the fuel cell bus trial, including London which runs seven hydrogen powered buses since January 2004 (The Fuel Cell Bus Club, 2006). It may yet be a considerable time before this technology emerges on the electricity networks on a large scale. Initially it might be used in combined heat and power (CHP) generation. Basically, in a fuel cell, a primary fuels is reacted with oxygen to produce heat and electricity. A fuel cell consists of two electrodes permeable to gases and the electrolyte which carries the electric charge between the electrodes. Common fuels are hydrogen, natural gas and methanol. The outputs are high or low grade heat and electrical power.

Fuel is reformed, a process in which the fuel undergoes a chemical process to give a hydrogen rich gas and CO_2, and the hydrogen rich gas is fed to the fuel cell where *dc* electrical power is produced. Hot exhaust gases from the cell are used to power a gas turbine which is coupled to a generator. The exhaust from the gas turbine is then used to power a steam turbine as in the CCGT technology. Effectively this gives triple cycle process, that is electricity is generated at three stages; fuel cell, gas turbine alternator and steam turbine alternator. Single cycle fuel cells also exist. Major advantages of this technology are higher electrical generation efficiencies (up to 60%) and reduced environmental impact. However, initial capital costs are high.

Magnetohydrodynamics (MHD)

Power generation is achieved by passing an electricity conducting medium (in this case, hot combusted gases seeded with a chemical compound to enhance conductivity) through a magnetic field at right angles to its flow direction, producing an electric field perpendicular to both the flow direction and the magnetic field. The electric charge is collected by electrodes arranged perpendicular to the magnetic field. Enhancing the conductivity of the gas, the strength of the magnetic field and increasing the speed of the gas increases the output power. A range of fuels can be used with this technology; coal, natural gas, oil and coal gas. Natural gas provides the simplest system but CCGT is preferred to MHD as it is a proven technology, has lower capital costs and also has comparable efficiencies to the MHD technology (around 50%). Although this is not a new technology, it has not been deployed yet.

Typical plant data for the prospective technologies i.e. Hybrid Cycle, Fuel cells and MHD are shown in Table A.6.

Carbon Capture and Storage (CCS)

The need for fuel diversity, rising gas prices, political instability in regions of significant gas resources and stable coal prices are making coal an attractive option once again. CCS together with advancements in boiler technologies and other coal technologies provide a competitive platform for 'clean' coal technologies.

Carbon capture refers to the separation of the greenhouse gas CO_2 (rather than the actual carbon by itself) from fossil fuels either pre or post combustion. In order to prevent the CO_2 from entering the atmosphere, it has to be stored in air tight environments or used in chemical processes. Pre-combustion carbon capture involves the removal of carbon or carbon dioxide during primary fuel processing or conversion into a secondary fuel. When coal or HFO is gasified in the IGCC technology, the CO_2 can be captured before the combustion process. Post-combustion carbon capture from power station flue gases can be achieved by cryogenic distillation, chemical absorption, physical absorption, membrane separation and physical adsorption (ESTU, 1994). Since these methods are applied to the flue gases, they are suitable for retrofitting to power stations that do not comply with environmental emission standards. Figure 2.2 shows the fossil fuel-fired generation technologies and their relationships with each other.

The abatement of CO_2 is completed by permanent use or disposal of the separated gas. Five possible ways of disposal are the commercial market, ocean disposal, salt cavities, enhanced oil recovery and depleted oil or gas reservoirs. Of late, there has been considerable interest in the last two disposal options, which are already deployed technologies. Deep ocean disposal is believed to give enormous storage potential but the possible disturbances to the ecosystem are not well understood.

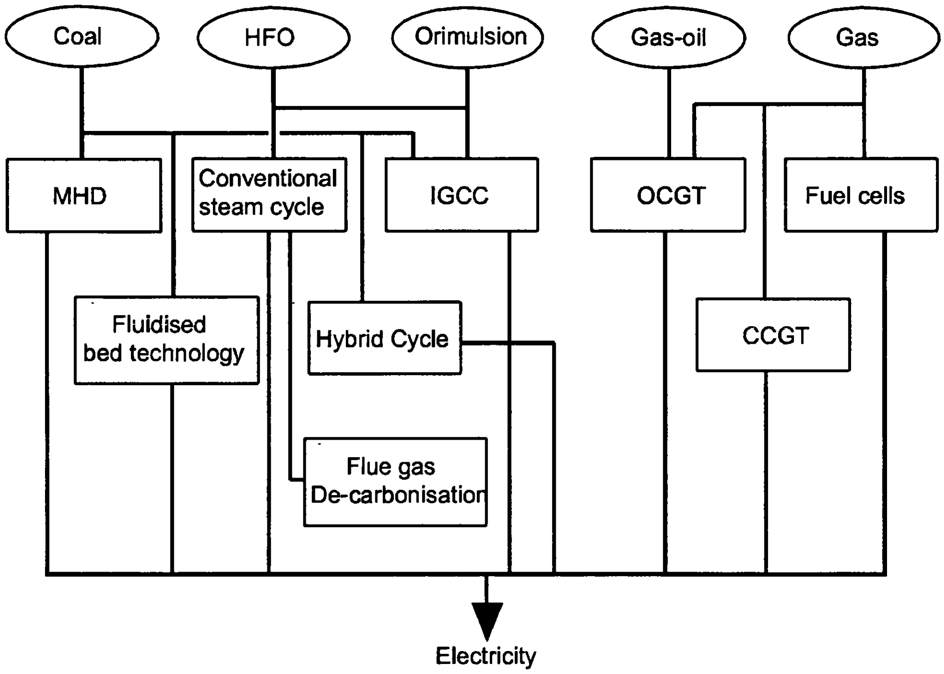


Figure 2.2. Fossil fuel-fired generation technologies. *Source: ETSU 1994*

Table 2.2 gives an indication of the effectiveness of the cryogenic separation technology. Basic construction costs are in the region of £527,000 per t/h CO_2 capacity. Operating and maintenance costs are in the region of £14,500 per t/h CO_2 capacity (ESTU, 1994). Availability could be as high as 98% such that the availability of the generation plant becomes the limiting factor since it is much lower than this, typically less than 90%. Recovery efficiencies of up to 98.6% can be achieved. Electricity consumption for the unit is in the range of 300kWh/t CO_2.

Table 2.2. Change in main gaseous emissions from a large Coal CSC fitted with cryogenic separation technology. *Source: ETSU 1994*

Gaseous emissions	Without CO_2 removal	With CO_2 removal
Carbon dioxide (kg/Gj)	249	3.5
Sulphur dioxide (g/Gj)	3326	0
Nitrogen oxides (g/Gj)	960	0

Under the Large Combustion Plant Directive (LCPD, 2001/80/EC) in Europe, combustion plants with a thermal output of greater than 50MW must meet the Emission Limit Values (ELVs) for SO_2, NO_x, and particles, specified in the LCPD (EU, 2001). For an operator of an existing plant to be exempted from the ELVs, they must submit a written declaration to the competent authority not to operate the plant for more than 20,000 operational hours starting January 2008 and ending no later than December 2015. Unless old coal plants in Europe are retrofitted with technologies to limit these emissions, they will be set to close by 2015 or the expiry of their 20,000 hours, whichever comes first. Typical plant data for FGD and low NO_x burners are given in Table A.7.

2.3.2 Nuclear Technologies

The most common nuclear technologies employed in electricity generation today are the gas cooled reactor systems, pressurised light water reactor systems and advanced reactor designs. The nuclear technology has been surrounded by controversy due to the high capital and back-end costs, risks associated with the radiation emitted from the operation of the plants and significantly, waste disposal from these plants. Because of the nature of reactions in the reactor, nuclear plants are inflexible and therefore used for base load, leaving the other technologies to regulate their outputs to match electricity demand and supply. The future of nuclear power generation is not certain especially in the UK where there is a significant interest in other generation technologies including renewables.

Nuclear power generation accounts for around 20% of electricity generation in the UK with a current capacity of 12GW (DTI, 2006a). Due to scheduled closures of nuclear plant reaching the end of their life time, if no new nuclear plants are built by 2025, there will only remain one nuclear plant, Sizewell B pressurised water reactor with a net capacity of 1.2GW. The EU large combustion plant directive will result in large coal plant closures giving rise to a large generation/demand gap, commonly known as the 'energy gap'. Nuclear technologies may still have a place in the future energy mix since they have low gaseous emissions. However, their lack of flexibility and perceived hazards may downplay their deployment.

2.3.3 Renewable Technologies

Renewable technologies not only reduce greenhouse gases but also present a sustainable way of generating electricity as the underlying energy conversion processes can be repeated many times without significant environmental degradation. A number of renewable technologies exist today, most notably, wind, hydro, biomass, wave, tidal, stream and solar. The first three are commercially viable technologies and they have been deployed.

Hydro

Until as recent as 1993, hydro-electric generation had been widely perceived as emission free and therefore 'clean' (WCD, 2000). Hydro-electric generation, although a renewable technology, produces greenhouse gases in the form of CO_2 and methane from rotting organic matter in the reservoirs. Emissions are mainly produced by vegetation and soils flooded by the reservoirs as well as the decomposition of aquatic plants and algae, and from organic matter washed into the reservoir from upstream. Evaluation of emissions from hydro generation should be on net basis, i.e. difference in emissions from the catchment before and after a dam is built. For this reason, Hydro generation plants above a certain size (usually 10MW) do not qualify for climate change levy[9] (CCL) exemption or for certification as 'green' energy sources. Because of their short startup times and high ramp rates, hence high operational flexibility, they are often used as fast response reserve for frequency control. This is a very vital service in today's decentralised power system. Most of the large sites suitable for hydro generation have already been used in industrialised countries. There is still scope however for micro hydro generation.

Wind

Wind generation is the fastest growing renewable technology at the moment with some 130 windfarms with a total capacity of 1832.55MW (BWEA, 2006) in the UK and some 40,504MW installed in Europe (EWEA, 2006). Turbine sizes are increasing as well as hub heights. 5 MW prototypes are available with turbine blades more than 100m in diameter (EWEA, 2003). Technological advancements in wind turbine technologies are resulting in decreasing capital costs for the plants. This, coupled with tightening environmental legislation is enabling the deployment of the technology into power systems today.

The integration of wind energy into the grid is a subject of active research. The German Energy Agency Dena study (BWE, 2005) demonstrates that large scale integration of wind energy in the electricity system is technically and economically feasible. On the other hand, while wind power is 'clean', it is highly intermittent and difficult to predict compared to conventional plant. This potentially poses significant threats to wider system security for systems with significant amounts of wind penetration. A notable constraint for wind development in the UK is the seemingly high resistance from the public especially for onshore wind farms.

[9]The Climate Change Levy aims to encourage the non-domestic sectors (industry, commerce, and the public sector) to improve energy efficiency and reduce emissions of greenhouse gases. It came into effect on 1st April 2001 in the UK.

Biomass

Sources of biomass energy include trees, timber waste, wood chips, sugar cane, grass, leaves, manure, sewage, and municipal solid waste. Biomass technologies free the energy bound up in chemical compounds in organic matter, mainly in form carbon and hydrogen. The organic matter can be gasified or burnt directly. Directly fired biomass power plants are relatively inefficient unless they are implemented as combined heat and power plants. In accordance with international guidelines from the IPCC and the UNFCCC, CO_2 emissions from biomass combustion are not included in the national total but methane and nitrous oxide are included. This is due to the fact that carbon is balanced by photosynthetic uptake while the nitrous oxide and methane are not. A major advantage with biomass is that it can be stored and used on demand, hence it is not intermittent like wind which can not be stored.

Other Renewables

Other renewable technologies are generally still commercially not viable, requiring significant research and development. Solar power conversion into electricity is characterised by low efficiencies (typically 15% for commercially available cells) and high capital costs. There is scope for deploying solar technology at a highly embedded level in distribution systems as they can be integrated into buildings. There is significant research in solar tidal and stream generation technologies (Boyle *et al.*, 2003b).

2.4 The Sustainable Generation Mix Problem

2.4.1 Background

Generation mix refers to the mixture of the technologies used in generating electricity. It is normally quoted in the context of the contributions of the different generation technologies to the total production rather than the respective capacities. The current UK generation mix is shown in Figure 2.3.

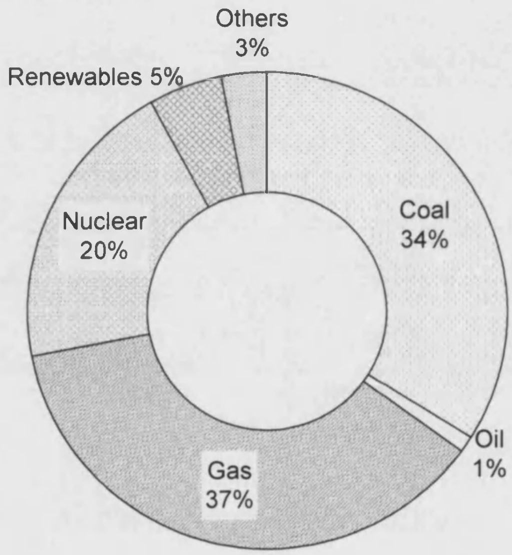


Figure 2.3. 2005 UK electricity generation mix *Source: DTI 2006*

In the decentralised environment, investment in generation is driven by demand growth and/or existing generation plant closures. Investment in a specific technology depends on the expected total costs and revenues as well as the level of risk associated with that technology. In the short term, the actual contributions of the different generation technologies depends on relative fuel costs and other variable operational and maintenance costs. Optimising short term operational costs does not guarantee that the total costs including capital and fixed costs are optimal, instead, it influences the operating regime of the technology, for example, cheap operational costs will result in the technology being operated to meet base load. This in turn influences the prospects of long term utilisation of the technology.

International efforts to mitigate environmental damage due to GHGs greatly influence the energy policies adopted by many countries and hence investment in renewable, cleaner and more efficient generation technologies. On the other hand, market signals have a strong influence on choice of technologies for investment, for example, the share of Gas-fired generation has steadily increased over the past decade owing to the lower capital costs, operational flexibility of the generators and abundant affordable natural gas. There have been concerns about over-reliance on gas if the current market trends prevail. This would lead to reduced diversity in the electricity generation arena thereby threatening the security of supplies, especially given that most of the gas is imported from politically unstable regions. As a direct result of this, clean coal technologies are becoming attractive given the rising gas prices and stable and relatively low coal prices.

2.4.2 Related Work

The investigation of a sustainable generation mix to be used as an ideal generation mix in market design is closely related to generation expansion planning. In generation planning, the objective is to determine the types, sizes and locations of future generation capacities as well as their timing so as to continue to meet demand reliably and economically subject to environmental constraints. On the other hand, the sustainable generation mix sought in this work is not necessarily based on just additional capacity but may mean that in order to achieve a given sustainability level (economic and environmental), some of the existing generation technologies may need to be either discontinued and replaced by cleaner, renewable and more efficient generation or may have to be modified to comply with certain environmental requirements, e.g. the LCPD which comes into effect in 2008.

Most of the issues applied to generation expansion planning are relevant to this investigation. El-Habachi (2002) investigates the generation mix planning problem using genetic algorithms to determine the least cost capacity addition schedule in terms of type, location, capacity and number of each candidate plant over the planning horizon. Flexibility of the generation mix is of paramount importance for economic sustainability. Tanabe *et al.* (1993) applied the dynamic programming method to the problem of flexible generation mix planning under uncertainty, to determine type and capacity of additional generation. Zhao *et al.* (1996) investigated the fuzziness of decision making and planning parameters. A robust generation mix ensures stability in economic and environmental performance of the power system. The methodology presented in this thesis uses sensitivity analysis to determine a robust generation mix solution for a given range of possible future scenarios.

The methodology presented builds upon the basic concept by Murray (1998). The concept uses the total generation costs plotted against utilisation time so that the cheapest technology can be determined at different utilisation levels. The points at which the technologies change from one to another are interpreted based on the load duration curve to give the capacities of the generation technologies. However, the capacities obtained this way are only approximate as they assume that that generation is always available when it is needed. Also, Murray (1998) does not attempt to determine the energy and emission shares of the different technologies, implying that one would have to make overly assumptions to determine these quantities. The detailed explanation of the improved methodology is given in Chapter 4.

Most of the existing classical generation planning methodologies do not address the issue of intermittent generation, usually because it is mostly driven by environmental requirements rather than the usual demand increase, plant closures, etc. Several studies do however address the challenge of integrating intermittent generation, mostly wind generation, into the bulk power supply system (Johnson and Tleis, 2005; Dale, 2005; BWE, 2005). In this study, wind generation is considered alongside other emission reduction technologies based on total generation costs including environmental costs as determined on the emissions market.

Typically, in generation expansion planning, the aim is not to achieve specific emission levels but only a reduction since there is no scope for forced retirement of existing plant. To add on to this, network effects (according to the existing network and likely future network expansion plans) are included in the generation expansion solutions. While suitable for planning, these approaches are not suitable for strategic policy formulation to aggressively cut down emissions as they tend to be limited by what already exists. It is sensible that as much as possible, the existing generation capacity is kept running with or without modifications while additional capacity is added but when the rate at which the required reduction of emissions exceeds that which can be achieved through reactive/responsive generation planning, then it is important that efforts in the development of the desirable generation capacity is guided by a clear and transparent ideal generation mix.

This thesis presents a framework for determining such generation mixes so that market structures and rules, regulatory and incentive schemes can be formulated based on informed and realistic possible generation mixes under different likely future scenarios.

2.5 Sustainable Generation Mix as a Reference in Market Design

The sustainable generation mix problem directly translates into an optimisation problem that is concerned with minimising the total generation cost while meeting the demand and environmental requirements as well as being affordable. The economics of the generation technologies and the availability of fuels or, generally, primary energy resources greatly influence the generation mix. In the decentralised and competitive environment, electricity market operations are guided by market structures and rules. Depending on the thrust of the energy policy, the rules are designed in a way that significantly affects the way generating companies invest in the different technologies and operate them. In the design of electricity markets, it is important to have a clear idea of what sort of generation mixes can deliver the required sustainability levels while keeping up with both short term and long term system security and delivering affordable electricity.

A clear and stable energy policy is key to guiding the investment in generation technologies. For it to be effective, electricity market design must be consistent with the energy policy. The underlying premises in electricity market design (WEC, 2001) are:

- Enhancing consumer choice and enabling effective competition in electricity generation and supply,
- Mitigating market power abuse,

- Apportioning costs to those parties causing them,
- Providing economic signals to enable timely and economic investment in transmission infrastructure and appropriate generation technologies in order to maintain security of supplies in an environmentally friendly manner.

Regulation and government intervention are not uncommon in electricity markets owing to the need to protect consumers from excessively high electricity prices, the need to promote renewable energy technologies, and maintaining fuel diversity. Unregulated, electricity markets will not necessarily deliver economic and sustainable solutions because each market participant aims to maximise their profit and not the social welfare of the global system. If not mitigated, market power abuse could render a market ineffective in delivering economic and secure electricity supplies. It is therefore important to ensure that market design addresses those issues that could lead to unsustainable market outcomes in terms of the market design objectives highlighted above.

Market simulation to determine the performance of market structures and rules will suggest a certain mix of generation depending on the costs of the different technologies, the regulatory environment, and environmental policies being implemented. In the competitive market, the resulting generation mix will not necessarily be optimal due to issues associated with market organisation, for example, the degree to which market power can be relied upon by the market participants, transmission congestion and the methods used to reward generation flexibility and capacity.

The ideal 'sustainable' generation mix determined according to the method proposed in this thesis will help in identifying such generation mixes for a range of plausible possible future scenarios. In designing the market, it would then be possible to assess the suitability of the proposed structures, rules and other market mechanisms in achieving the desired generation mix for a given range of scenarios. This sustainable generation mix would also provide a benchmark against which market performance can be measured. Key performance indicators for market performance would be the adequacy of generation, the amount of emissions produced and the levelised cost of electricity generation.

Chapter 3

Factors Influencing Generation Mix

THE factors influencing generation mix are discussed in this chapter. These are dealt with according to three broad categories namely technology specific characteristics, the electricity supply industry and network planning issues.

A generation mix is determined based on a number of factors that are interrelated. An exploration of these factors is presented here, first looking into technology specific characteristics then the structure of the electricity industry and finally network planning issues. It is important to understand the issues raised here if a sustainable generation mix is to be achieved through implementation of appropriate market structures and rules.

3.1 Technology Specific Characteristics

Different generation technologies have their merits and pitfalls. Basic analysis of these may be considered in three categories namely; economic, environmental and operational characteristics. Often these three are non-commensurate, that is, a cheap technology may have an undesirable environmental burden although it may have reasonable operation characteristics. A good example of this is the coal powered conventional steam cycle which is highly polluting and cheap when emission costs are not taken into account. On the other hand, for security reasons, out of merit generation (i.e. more expensive compared to the system marginal price) may end up being utilised. Consequently, a diverse and distributed generation mix is considered more resilient to security threats relating to failure of the main interconnected power system, part thereof or due to insufficient supplies of a particular type of fuel that is overly relied upon.

3.1.1 Generation costs

Generation costs specific to a given technology are mainly determined by the fuel type and the generation plant itself (construction, installation, operation, maintenance and decommissioning). The split of costs between capital and operation costs often distinguish the manner in which the technology is operated. Technologies with high capital costs and low operation costs are often used as base loading units, for example, nuclear and conventional coal plants. Low capital costs and high operation costs result in plants being used to meet peak demand, for example gas fired plants. There are of course other factors that may affect the way specific plants may be operated depending on their location, emissions and operational characteristics.

3.1.2 Environmental Pollution

In the UK and many other countries, electricity generation accounts for most of the human generated greenhouse gas emissions – see Table 2.1. The electricity supply industry is therefore expected to play a major role in reducing GHG emissions. Emissions trading schemes now influence how specific technologies are operated, acting in a way to encourage less polluting technologies while discouraging more polluting ones. For example, the European Large Combustion Plant Directive will reduce the share of the large conventional coal technologies to extinction by 2015 (EU, 2001) if they are not retrofitted with emission reducing technologies. This opens the door to other less polluting technologies thereby increasing their market share.

3.1.3 Operational Characteristics

The delicate exercise of balancing generation and demand requires flexibility on the part of generation to follow demand in real time. In the traditional power system, it was sufficient to have intermediate and peaking generation technologies with some degree of flexibility while base load plant like nuclear was highly inflexible. The share of renewable generation technologies like wind generation is increasing at a phenomenal rate owing to incentives for investment in renewable generation technologies and related supporting mechanisms. Invariably, these technologies are variable, less predictable and less firm compared to conventional generation. Due to the high value placed on these technologies, it means that other technologies have to be more flexible if the renewable energy is to be effectively harnessed. Increased demand flexibility could play a significant role alongside generation flexibility in creating sustainable electrical power systems.

3.2 Electricity Supply Industry Structure

The structure of the electricity supply industry affects the way the power system is organised. Traditionally, the industry was centrally organised in a vertically integrated structure. In order to facilitate open electricity markets, these centralised structures were decentralised by unbundling and subsequent privatisation of the emergent business units. One of the key areas where competition was much sought was the generation sector. Generation and transmission planning methodologies and investment strategies have changed significantly as a result of the decentralisation.

3.2.1 Centralised Structure

Under the centralised structure, generation planning was carried in close consultation with transmission planning as both tasks were responsibilities of the same entity. This meant that the degree of certainty as to the availability of transmission capacity was high. Also, because of the size of the utilities, it was easier to buy fuel in bulk, well in advance hence locking fuel prices and hedging against risks associated with price fluctuations. The electricity prices were also guaranteed since there was no competition. Ideally, the choice of generation mix was based on maximising the social benefit in terms of costs, security of supplies and other factors such as emissions although the emphasis on environmental protection then was not as strong as it is now.

Generation tended to be mostly in the form of large central power stations and industrial combined heat and power (CHP) plants. There was no real incentive for independent power producers to invest in electricity generation. With demand largely inflexible and generation having an obligation to meet demand, central generation was planned and constructed to meet expected future demand. This fact, coupled with the lack of appropriate commercial arrangements and legal frameworks for inclusion of independent generators meant that the independent power producers were effectively shut out. Under this structure, there was no competition in generation and it can be argued that if all key variables were appropriately included in the planning stage, the resulting generation mix was optimal from a global view point.

3.2.2 Decentralised Structure

The paradigm shift in the industry structure has created competition in electricity generation. Generation and transmission are no longer the responsibility of the same body. For the transmission system planner, the uncertainties of generation locations increased and the same is true for generation in respect of future transmission system capacity. The fundamental difference in terms of generation ownership and operation is that the generation companies are commercial entities that have to operate profitably in order to provide real returns for the shareholders. These entities are subjected to much greater risks compared to the central generation owner since they compete against each other and they are exposed to price fluctuations on domestic and international markets. It is increasingly becoming difficult to secure capital for new projects due to increased risks and also the mere small size of the entities which mean that they may be operating at high gearing ratios.

With the introduction of emissions trading, the generation entities have to invest more in either more efficient and cleaner generation or in re-powering their existing generation assets to improve generation efficiencies and reduce emissions. A notable shift from the centralised structure is that under the decentralised structure, the obligation for a generating entity to meet demand does not apply (Padhy, 2004). In other words, the generation entities are not obliged to make their plant available unless they have a contractual obligation to do so. The theory here is that if there is insufficient capacity then the market price of electricity will increase and incentivise the generation entities to participate in the market. The immediate challenge becomes that of market power abuse by strategically withholding capacity by large generation entities. The market design should be able to deal with these issues.

As the operating environment changes, the generation entities adjust their generation portfolios in order to be competitive, comply with environment legislation and maximise their market share so as to maximise profits. The fact that there now exist more generation entities with smaller portfolios compared to the centralised regime theoretically means that the shift in generation mix becomes more dynamic in response to the needs in the industry. Thus the market structure and its associated rules have a very important role to play in the delivery of a sustainable generation mix.

Due to high commercial pressures on generation companies, they will endeavour to do everything that maximises their profit as long as they meet their legal obligation or license conditions. Achieving a sustainable generation mix in a competitive market environment therefore hinges on market structures and rules designed based on informed decisions about the true inputs into generating electricity and wheeling it to the consumers as well as the side effects of the generation technologies employed. These need to be appropriately weighed and balanced, hence the attempt in this work to determine a reference generation mix for informing market design.

The World Energy Council commissioned a report (WEC, 2001) in 2001 on electricity market design and creation in Asia Pacific. Countries Studied are Australia, New Zealand, Indonesia, The Philippines, Thailand, China, Taiwan, Hong Kong and The Republic of Korea. A number of similarities can be drawn from almost all the competitive electricity markets implemented in the world. Competition in generation is normally the first target in every electricity market reform.

3.2.3 Motivation for Decentralisation

Over the past ten to fifteen years, restructuring of the electricity supply industry has resulted in the formation of electricity markets in many countries around the world. Among some of the most important drivers for this change process are: introducing competition in generation and retail of electricity, attracting private investment, lowering electricity prices, consolidating public finances and promoting integration of the power grid (WEC, 2001). Other drivers for electricity market reforms are environmental concerns that prompted improved efficiencies, conservation, conversion into cleaner fuels, emission free renewables and distributed generation (Khatib, 2003).

The transformation to decentralised systems has been facilitated by rapid technological developments in generation technologies and computation systems used for metering together with unprecedented developments in information and communication technologies. The new structures are geared towards competition at the generation and retail levels of the electricity supply chain. It is widely accepted that through effective competition, it is possible to achieve improved quality of electricity supplies at even lower costs. Many governments have pursued this route through unbundling and privatization of the electricity supply industry in a bid to stimulate economic growth through efficient planning and use of resources driven by clear price signals in competitive markets.

3.2.4 Preconditions for Introducing Competition

The world energy council report (WEC, 2001) highlights the preconditions that must be met in order to implement an effective competitive electricity market as follows:

- Excess generation capacity with many competing generators,
- Attractive investment environment,
- High electricity prices prior to the introduction of competition,
- The political will to lower electricity prices and
- Easy access to a well connected power grid.

The first condition is essential if true competition is to be achieved since for the generation entities, there should be a real possibility of failing to run if they are not competitive. In the absence of market power abuse, this should lead to an economically efficient market. Inevitably, the generating entities are exposed to risks related to failure to generate enough sales to break even, use contracted fuel supplies, etc. Generation technologies likely to be marginalised are those that tend increase the exposure of the market entities to more risks. The combination of market rules (trading rules) and incentive schemes is critical in shaping the generation mix in a given power system.

Easy access to a well connected power grid is also another critical factor in achieving effective competition. In an environment where generation investment is not centrally planned together with the electricity networks, it is possible to have insufficient network capacity to connect additional generation in specific locations. For example in the UK, there is a vast amount of wind generation potential in Scotland (some possible 6.2 GW) (NGET, 2005) while the bulk of the demand is in the South East of the country. The Anglo-Scottish interconnecter has a north-to-south power transfer capability of only 2300MW (NGET, 2005). The development of the transmission system around this area has a big impact to the deployment of wind generation up in Scotland. Thus accessibility and availability of network capacity can also influence the deployment of some generation that is location specific like wind, tidal or wave power generation.

3.2.5 Emergent Market Structures

Although electricity market structures can be classified into a number of categories, no two countries have quite the same implementation due to differences in energy resource compositions, energy policies, economic status, geographical layout, demographic distribution as well as climatic conditions (WEC, 2001).

If the playing field were level and there were no transmission constraints, effective competition would naturally force expensive generation out of business. However, due to system security requirements and transmission constraints, ancillary markets do exist alongside the primary energy market. This is due to the fact that electricity is produced and utilised according to real time demand. Any unexpected changes in the system configuration, generation or load results in a power imbalance and remedial action has to be applied without delay or else part or all of the system will experience a blackout. This creates the ancillary market to provide system reserve, frequency support, voltage and reactive power support as well as black start capability. Due to the monopolistic nature of transmission and distribution infrastructure, competition in the operation of the grid has not been taken up. Instead, the networks or the so called 'wires' business has been left as a regulated monopoly. On the retail end of the chain, it is now widely accepted that electricity supply services are distinct from the wires business and can be competitively offered to customers, thereby bringing customer choice.

Based on these facts, electricity markets have been developed around the globe. Market structures can be broadly categorised into five groups (WEC, 2001). Some hybrid versions of these are also known to exist.

Simple Central Market

This is a basic market structure, using existing pre-unbundling generation and total consumption metering for large customers and operated by an independent system operator. It represents a slight shift from the traditional structure. Input costs and contract terms could be verified by a regulator. The dispatch priority would be on safety and security reasons, minimisation of payments and merit order for non contracted generation. Generators would be paid on contract terms while suppliers would pay contracted terms or averaged costs including any ancillary services. This approach is simplistic and may not deliver efficiency due to lack of transparency (lack of a spot market).

Pool with System Marginal Price

Generators and some or all of wholesale suppliers (purchasers) bid into a pool. The system marginal price becomes the selling price for all generators. This may or may not be increased with an uplift payment to cater for contribution to ancillary services and transmission constraints. Some customers can bid to reduce demand. This system was used in the UK (pre-NETA[10]) and Argentina, with some capacity payments. In Australia and New Zealand, it was used without addition of capacity payments. Dispatch is by merit order of generator bids. This market type was later abandoned in the UK for lack of transparency, failure to recognise generator flexibility, lack of demand side participation and vulnerability to market power abuse. One major advantage of this structure is that it encourages market entry by small generators due to reduced risk of not being selected in the merit order.

Pool with Pay-As-Bid Price

Generators are paid the price they bid, thereby encouraging them to follow their price curves. The demand side can also bid on the same basis. The problem of market power can also manifest due to generators guessing the market clearance price. This setup does not encourage small generators especially those operating marginalised plant. There is an incentive for aggregation in generation as large generators buy out stranded small generators. This has a tendency to reduce the number of market participants, which is detrimental to the pursuit of effective competition.

[10]NETA – New Electricity Trading Arrangements. NETA was introduced in England and Wales on March 27, 2001.

Contracts with Dispatch Priority and System Balancing

Based on the Nordic Pool, this market structure became popular in the USA in the late 1990s. It was also adopted in Spain and the UK (under NETA) in the early 2000's. Generators enter into direct contracts with load serving entities (suppliers). Plant is despatched with priority for contracted output rather than merit order. Variations have been reported in other countries like Chile where the pool also exists only to allow generators to optimise their costs of meeting the contracts. Balancing is the other important feature of these markets. This allows the system operator to balance the system in real time. Power imbalances resulting from load forecasting errors, unexpected plant failures and system constraints are resolved through the balancing market. The balancing market can be viewed as an optional pool where market participants can provide their service at relatively short notice. This approach has proved to be fairly robust but it is also lacking where there is high diversity in plant types and it tends to be very complex. It is very common for less competitive generation plant to become marginalised because of aggressive competition. For example, under NETA, plant with less predictable output like wind can be exposed to disproportionately volatile and unfavourable prices (CAG, 2003).

Minimalist Model

This was found only in Germany, where the nine privately owned utilities were not in favour of the EU directive on third party access allowing certain customers to be eligibly supplied other than by their local utility. The government went on to introduce legislation to allow competition for all customers. No central system was developed for charging for use of the transmission system and other services normally provided by the system operator. This saw a reduction of electricity prices by

25% - 30% but only about 2% of customers switched supplier. Some have suggested that there were not much gains in switching supplier while others suggested that it was the difficulty in switching that caused the low number of customers to switch. The most important lesson from this is that it is not always necessary to have a centralised administration of the development of all trading arrangements.

3.2.6 Market Operation

Despite the changing structure of the electricity supply industry, priority remains on secure and economic operation of the power system. The operation of the physical power system depends on the behaviour of the market participants, who in turn respond to market signals. The strength of these market signals is a direct measure of the effectiveness of a market structure and its associated rules. The ability of the market agents to exercise market power also depend on the market structure and the rules. This has an indirect impact on the power generation patterns and the utilisation of power plants. The market participants formulate their strategies based on maximising their profit, prescribed trading arrangements and their competitors behaviours.

Trading Arrangements

The market arrangements specify the framework in which the market participants interact and what products can be traded. The main issues are how the bulk of the energy is traded, how demand and generation are balanced and the provision of ancillary services. One critical issue that has been a subject of much debate is the treatment of generation capacity (Barrera and Crespo, 2003). This is an issue of how the market deals with generation investment especially for those technologies that have low load factors , typical of peaking units. If these technologies are marginalised then they may disappear from the market, leading to reduced diversity in the generation mix and possible insufficient generation capacity to meet the demand securely.

One of the key aspects of market reforms is the accounting of all system operation costs and making the market participants responsible to meet them (Kirschen, 2001). This is particularly so in contracts based markets where the bulk of the energy is traded in bilateral contracts. Market participants who fail to honour their contractual obligations cause imbalances in generation and demand. This raises the costs of system operation as the system operator has to engage additional resources to balance the system. During settlement, the participants that were long pay the system sell price (SSP) while those that were short pay the system buy price (SBP) as shown in Figure 3.1.

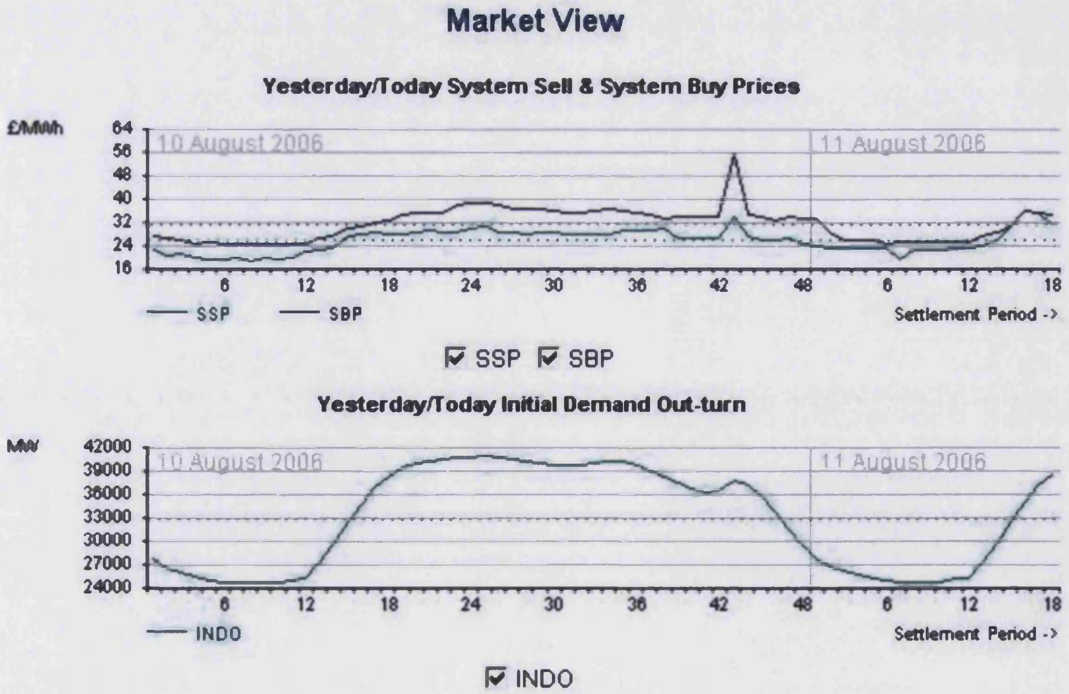


Figure 3.1. *Balancing Mechanism (BM) report showing SSP and SBP for the 10^{th} and 11^{th} of August 2006. Source: http://www.bmreports.com/bwx_reporting.htm*

Less predictable generation exposes the generation company to imbalance prices. In the absence of renewable generation incentive schemes, this would downplay the deployment of renewable technologies as most of them are less predictable and intermittent compared to conventional generation. In the UK concerns have been raised by generating companies over the inclusion of wind and other intermittent generation in their generation portfolios (CAG, 2003), however there were other factors that have enabled the uptake of wind generation in particular. These include the Renewable Obligation Certificates (ROCS) and Climate Change Levy.

Provision of Ancillary Services

The transmission system operator is charged with keeping the system balanced. System balancing refers to the exercise of matching generation and demand while maintaining system security. The system operator must have sufficient resources to draw upon in the event of credible contingencies arising so as to keep the 'lights on'. In pool based markets, for example, the pre-NETA UK POOL system, the system operator could run out-of-merit generators according to security requirements. In bilateral based markets, the balancing mechanism is a market in which market participants, both generation and demand submit bids and offers from which the system operator draws upon in order to maintain the system in 'balance'. This means that generation companies can strategically invest in generation technologies that have the specific characteristics that enable them to trade specific services, for example, spinning reserve, fast response, voltage support and black start.

Incentives

In order to encourage the uptake of upcoming renewable and cleaner technologies, incentives have been implemented. These are normally in form of capital grants and preferential treatment of some generation technologies, for example, with the ROCs, the price is set such that if a plant generates an amount of energy qualifying for the scheme, they will be guaranteed at least that price. This has the effect of reducing the risk associated with competition on the generation company's part. In the UK, there have been concerns about the certainty of continuation of these incentive schemes in future, raising fears that the generation assets may become stranded if the incentives were removed.

In pool systems, aggressive competition can drive prices down until some generation technologies can not recover their full costs, maybe because of their low utilisation factors. In order to attract investment in generation, some systems (Cramton, 2002) have adopted the concept of a capacity payment payable to all generators that bid into the pool whether selected to run or not. In systems where this in not the case, some generating companies may be reluctant to invest in certain types of generation that could fail to recover capital costs. This could affect the generation mix in such a way that could increase overall system operation costs or the environmental burden or even compromise system security.

3.3 Network Planning

Power system investment planning is carried out in order to meet future electricity demand economically while maintaining the quality and security of electricity supplies. As the load grows, there is need to ensure that generation plant is timely commissioned to meet the increased load. The network also needs to have the capability of reliably transporting the generated power. There is also need to maintain plant in order to keep it in good working order and maximise its life. All this can be achieved through effective planning.

Challenges being faced in power system planning range from lack of accurate information for system parameters, for plant that belongs to third parties, increasing risks and uncertainties, the changing environmental legislation and regulation of the network businesses. Typical power system investment planning is meant to address the following issues:

- Reliability requirements – frequency and duration of supply interruptions,
- Voltage levels – to be within stipulated limits,
- Frequency specifications – to be within stipulated limits,
- Waveform distortion – not to exceed maximum allowed,
- A reasonable rate of return on capital investment and
- Safety standards.

Network planning has a significant a role to play in the global goal of increasing the sustainability of future power systems by way of facilitating efficient, cleaner and renewable generation technologies. Therefore network planning has a profound influence on the generation mix.

3.3.1 Transmission Network Planning

Specific requirements depend on the functional zone of the system, for example, in generation, the requirement is to determine how much capacity is to be installed where and when, so as to satisfy expected demand at some point in the future and to provide sufficient reserve margin to perform corrective and preventive maintenance. In transmission systems, it is desirable to provide sufficient capacity to efficiently wheel power from the large generating stations to grid supply points. System stability is given special attention so that system security can be ascertained. This ensures that the system can continue to operate in the face of credible contingencies like sudden loss of a large generator, transmission line, load or other system plant.

The major challenges in network planning today are due to the need to accommodate cleaner and renewable generation technologies which are invariably different from conventional generation. With conventional generation only in the system, deterministic rules were sufficient in network design. With the introduction of intermittent generation these deterministic rules may not be able to adequately account for the diversity of the intermittent generation (Johnson and Tleis, 2005; Bell *et al.*, 2006). However, deterministic rules have the advantage of being simple to apply and hence transparent – a quality desirable under open network access in a competitive environment. If network design is driven by probabilistic cost-benefit analysis, then a sufficiently accurate representation of the intermittency would be necessary.

In Great Britain, the transmission licensees are required to develop their networks in accordance with the GB Security and Quality of Supply Standards (SQSS). The GB SQSS contains deterministic rules that specify minimum security requirements for the main interconnected transmission system (MITS) as well as cost-benefit criteria to ensure efficient investment levels. Development operation and maintenance of the MITS is also guided by the grid code. The grid code (NGET, 2006) also specifies conditions for the connection of generation such as reactive power and voltage support capabilities as well as fault ride through capabilities of the generators directly connected to the MITS.

Although there is expected to be a a significant amount of highly distributed generation, large generation is still expected to play a critical role in the foreseeable future due to the need to have sufficient frequency response, voltage support and to maintain system stability. In this thesis, generation mixes were analysed based on generation connected to the transmission system with the recognition that distributed generation could be included by developing appropriate models for actual demand and embedded generation to be included in the study model in order that all generation can be included in the study.

3.3.2 Distribution Network Planning

Distribution systems were traditionally passive, primarily designed to convey power from the grid supply points to customers. These are comparatively weak networks which are generally operated radially. This, coupled with the environmental conditions, contributes to the high number of outages to customers (approximately 80 %). As such, the challenge in distribution system planning is to deliver energy to end customers within certain quality constraints (frequency, voltage, flicker, harmonics, frequency and durations of interruptions and so forth) at a reasonable cost (Jenkins *et al.*, 2000).

The introduction of embedded generation in distribution systems has meant that the distribution system now has two functions; to supply power to end customers and to wheel locally generated power within the distribution system. Problems that were once associated with the composite generation and transmission system become apparent in a distribution system with high penetration of embedded generation (e.g. stability, adequacy, and operational problems related to connection of load and generation).

The current strong campaign for high efficiency, cleaner and renewable generation as well as distributed generation has seen the role of distribution systems changing from passive unidirectional power flows to more active networks. The uptake of embedded generation schemes depends on commercial signals and it would be difficult to determine the amount of embedded generation that will be connected to a given distribution network at some point in the future. Even if this were to be known in advance, it would be difficult to determine how much energy would be made available from these generators, thus further complicating the issue of demand forecasting for the transmission system planner.

The challenges of integration of embedded generation include disruption of voltage control schemes based on line drop compensation techniques, increase in fault levels, disruption of protection schemes, operation issues to do with safety and switching as well as clear legislation and standards laying out tariff structures and responsibilities for the embedded generation owner and the distribution network owner. The increasing amount of embedded generation in distribution systems makes them have characteristics somewhat similar to transmission systems as listed below:

- When embedded generation is installed to provide capacity instead of construction of additional lines and substations (approved option in engineering recommendation ER P2/5 in the UK), there is a complication that if it is tripped on network isolation from the grid, then on restoring grid supplies, the load would demand power before the embedded generator can be connected. This is the case where embedded generation is not allowed to operate in island mode.

- The system becomes active, thus there will be need to actively control voltage and the flow of reactive power to support the real power flows. System stability becomes an issue in the distribution system and will have to be managed unlike previously when it used to be sufficient to only consider system adequacy.
- The relatively cheap IDMT relays used in distribution systems protection would no longer suffice.
- Fault levels could significantly increase to prohibitive levels especially in urban areas where they are already high due to relatively low network impedances and high load densities.

Embedded generation can improve the quality of supply although careful network design and operation need to be adopted in order to avoid the problems mentioned (Kuri *et al.*, 2004). A significant amount of work is ongoing to resolve the challenges of integrating distributed energy resources in distribution systems. The Embedded Generation Working Group (EGWG) was set up by the DTI[11] and OFGEM[12] to review the implications of increased penetration of distributed generation on the UK distribution systems as a result of the government's commitment to renewable generation. This was in recognition that the deterministic assessment used in ER P2/5 does not adequately account for the security contribution from distributed generation (ERTSG, 2004). The EGWG developed the P2/6 methodology to address the security issues due to increased penetration of distributed resources.

[11]Department of Trade and Industry
[12]Office of Gas and Electricity Markets Authority

Other initiatives also include the UK Generic Distribution System (UKGDS) to assist in harmonising studies on distribution systems among various research communities (DTI, 2006b). The IEEE Standards Committee has also established the IEEE P1547 interconnection standards for Interconnecting Distributed resources with the electric power system.

Chapter 4

Generation Mix Solution Method

THE developed methodology is described in this chapter. The key variables are outlined followed by the detailed methodology. Also described in this chapter is the multi-agent production simulation model. Although not fully utilised in this thesis, the multi-agent model forms a solid basis for further development of a market simulation model which is a vital component in market design.

Sustainability problems related to environmental pollution from electricity generation can be partly resolved by dispatching existing generation to minimise emissions subject to security constraints (Talaq *et al.*, 1994; Tsuji, 1981; Kermanshahi *et al.*, 1990). The pitfall with this approach is that there is a limit beyond which more generation capacity would need to be installed in order to achieve additional environmental pollution mitigation. In the long term, the installed generation mix would need to shift in such a way as to reduce environmental pollution. This can therefore be addressed through generation planning. In a decentralised and competitive environment, generation planning is no longer done centrally, neither is it tightly linked to transmission system planning. It is of paramount importance to plan for generation and transmission investment in a manner consistent with future sustainable power generation.

Optimal generation mix is concerned with the establishment of a mixture of generation types with minimum capital and running costs when following the demand profile while meeting the emission requirements. In today's markets, the emissions are presented as costs associated with either the actual emissions or technologies to reduce these emissions such as FGD and CCS. In the centralised power system, as far as generation costs are concerned, the objective is simply to minimise total generation costs subject to local and system constraints (Richter Jr and Sheble, 2000) whereas in the competitive market environment, the market players aim to maximise their profit, which does not necessarily translate into a global optimum generation mix. The approach presented in this thesis therefore considers the global optimal generation mix as the ideal mix that the market should strive to achieve.

4.1 Key Variables

The variables considered to be of significant importance to the outcome of a generation mix were grouped into three categories namely technology type, generation characteristics and generation location. The variables are briefly described below.

4.1.1 Generation Technology

Statuses for different generation technologies range from deployed technologies, demonstrated technologies to prospective technologies. The risks for choosing technologies in the late stages of their life cycle include unacceptable environmental burdens, obsolescence and possible high operation and maintenance costs. On the other hand, technologies that are in their early stages are often associated with grid integration challenges and usually high costs as in the case with wind generation. Some technology specific variables are listed below:

- Fuel type (fossil, non-fossil and renewable).
- Energy conversion process (combustion technology and the actual conversion to electrical energy.
- Emissions reduction technologies.

Generation technologies are usually specified by these three variables, for example, Coal IGCC with CCS, doubly-fed induction wind generator, coal ASC, coal ASC with FGD etc.

4.1.2 Generation Characteristics

Generation characteristics vary widely and can be classified under economic, operational and environmental categories. The contribution of a given technology in the generation mix depends on its characteristics as well as those for the other incumbent technologies. For example, wind generation has very low environmental burdens but has high capital costs and requires the other generation technologies in the mix to be flexible in order to accommodate its intermittency. Therefore the weights placed on these characteristics have an influence on the generation mix.

Economic Characteristics

- Capital costs: Investment in generation plant is capital intensive therefore capital costs form a significant part of the total generation costs.

- Heat input characteristics: These are applicable to fossil fired technologies and other technologies where heat input is required. The efficiency of the heat production and exchange process significantly affects the economics of the generation technologies. Conventional steam cycle technologies based on coal have low efficiencies (around 33%) while higher efficiency technologies have efficiencies in the range 45% to 50% which is low compared to the efficiency of the alternators.

- Operation and maintenance costs: These are generally split into fixed and variable operation and maintenance costs where the fixed costs are independent of the production level while the variable costs depend on the production level.

Operational Characteristics

- Thermal cycling: For technologies based on heat input, the heat components place constraints on the minimum up and down times due to thermal stress limits. The startup and shutdown times are also restricted for the same reason.

- Load factor[13]: Higher load factors mean that unit production costs could be lower as fixed costs are spread over the entire production quantity.

- Capacity credit[14]: A low capacity credit may mean that investment in conventional generation plant has to be maintained while also investing in the technologies with low capacity credit. However, the energy share of the conventional generation may drop due to the energy contribution from low capacity credit technologies.

- Availability: The availability of generation technologies making up the generation mix determine the amount of plant margin[15] needed to securely meet peak demand.

- Economic lifetime: This has a big impact on the viability of an investment project. The payback period of a project should be within its economic life period for it to be economically viable.

[13]Load factor is defined as the ratio of the average power output to the installed generation capacity over a period of time, usually one year.

[14]Capacity credit is a term used to describe the amount of conventional generation plant capacity that can be displaced by variable generation without compromising the risk of failure to meed demand due to insufficient generation capacity. It is usually expressed as a ratio of the displaced capacity to the displacing capacity.

[15]Plant margin is the amount by which installed generation capacity exceeds peak annual demand expressed as a percentage of the annual peak demand.

Environmental Characteristics

- Emission characteristics: Emissions trading effectively convert the emissions into costs, hence emission characteristics are a significant factor in influencing the generation mix outcome.

4.1.3 Generation Location

As the distance between generation and load increases, the cost of utilising that generation increases due to transportation and potential congestion. However, some generation technologies like wind have to be located in specific geographical location where the primary energy naturally occurs. Therefore its not just the costs directly associated with the energy conversion processes that influence the selection of technologies but other external issues such as transmission requirements also come into play.

This points out that transmission system planning has a significant role to play in facilitating the development of sustainable generation in electrical power systems. Deterministic transmission planning methodologies based on conventional generation may not be adequate for dealing with variable generation such as wind. Transmission planning methodologies therefore need to be revised in light of wind and other intermittent generation being expected to contribute significantly to renewable energy generation.

4.1.4 Global Variables

Global variables are those variables that are partly dependent on other industries apart from the electricity supply industry and as such they are jointly decided by a number of economic sectors. The variables of interest here are the fuel costs and emission costs. Participants in the fuel markets include those in the transport sector, industrial sector including electricity generation, agriculture, etc. and the same can be said about emissions although the actual participants may differ. The point is these players have different background and driving forces in terms of their demands for fuels and their emissions.

4.2 Problem Formulation

4.2.1 The Objective Function

The objective of the optimal generation mix is to minimise the total generation costs comprising of capital, fixed and variable operating costs while meeting demand: *Min* $\mathfrak{F}$.

$$\mathfrak{F} = \sum_{k=1}^{K} \left(CC_k + FC_k + VC_k \sum_{t=1}^{T} U_{kt} \right) \qquad £/kW/year \tag{4.1}$$

subject to

$$\sum_{k=1}^{K} P_{kt} = D_t \tag{4.2}$$

and

$$P_{kt} <= CAP_k \tag{4.3}$$

where K is the number of generation technologies considered, CC_k is the annuitised capital cost for technology k expressed in £/kW/year, FC_k is the annuitised fixed operation and maintenance cost for technology k expressed in £/kW/year, consisting of non-capital costs that are independent of production levels e.g. fixed maintenance costs, insurance costs, etc. VC_k is the variable cost for technology k expressed in £/kWh. It consists of fuel costs, non-fuel variable operation and maintenance costs. T is the number of time periods t in a year in hours. U_{kt} is a binary variable which takes the value '1' when technology k is utilised during time period t and a value of '0' if not utilised. CAP_k represents the installed capacity for technology k in kW and P_{kt} is the power output in kW for technology k at time period t while D_t is the system demand in kW at time t. $D_t, t = \{1, 2, ..., T\}$ defines the annual load profile.

Example:
Consider a technology k with an annuitised capital cost of £34.5/kW/year, an annuitised fixed cost of £10/kW/year and a variable cost of 0.2p/kWh. If the technology is utilised for a total of 3000 hours per year, the total generation cost GC_k for the technology can be determined as follows:

$CC_k = £34.50/kW/year$
$FC_k = £10/kW/year$
$VC_k = 0.2p/kWh$
let $h = \sum_{t=1}^{T} U_{kt} = 3000 \ \ hours/year$

$$\therefore \quad GC_k = CC_k + FC_k + VC_k \times h$$
$$= 50.5 \quad £/kW/year$$

The generation costs were expressed in £/kW/year rather than the standard £/kWh because the later requires generation system production simulation which in turn requires that the capacities be defined beforehand. At this stage, no, capacities have been defined yet. The first step in solving this problem would be to determine the technology capacities followed by running the production simulation to determine the energy and emission contributions of the various technologies.

4.3 Optimisation Approaches

The generation mix problem investigated in this thesis is closely related to the generation expansion problem. There is however one major exception, that is, in generation expansion, the problem is to determine the amount, type, location and the timing of generation capacity to be added in order to meet future load demand while in the problem investigated here, an ideal generation mix, independent of what is currently installed, is sought for a given set of candidate technologies and future scenarios. The ideal generation mix is one which gives minimum total generation costs and environmental emissions. In the generation mix problem under investigation, it suffices to consider the capital costs for the candidate technologies whereas in generation expansion, there is the additional need to consider salvage costs for generation that is retired during the planning horizon. The similarities in the two problems include the fact that they are both related to long term generation investment, therefore there is need to determine the generation technologies and their capacities in both cases.

There are many generation expansion planning software tools available today including the Electric Generation Expansion Analysis System (EGEAS) by EPRI[16] and the Wien Automatic System Planning Package (WASP) from IAEA[17]. EGEAS has been applied to integrated resource planning including generation expansion planning by many utilities in the US and by many other countries around the world. WASP is also used in many countries, mostly developing countries. WASP determines the least-cost generation system expansion plan that adequately meets demand while respecting user-specified system reliability constraints.

WASP uses dynamic programming to determine the optimal expansion plan for the power system under consideration (IAEA, 2001). Dynamic programming is one of the most widely used algorithms in generation expansion planning (Park *et al.*, 2000). The advantage of dynamic programming is that it is inherently optimal and can handle capacity additions during any of the time periods within the planning

[16]EPRI - Electric Power Research Institute
[17]IAEA - International Atomic Energy Agency

horizon. A notable drawback is the 'curse of dimensionality' inherently associated with dynamic programming. To mitigate this drawback, WASP and EGEAS use a heuristic tunneling technique in the dynamic programming optimization routine where users pre-specify states and successively modify tunnels to arrive at a local optimum (Park *et al.*, 2000). Chen *et al.* (2004) applied the Lagrangian Relaxation method to the investment decision problem in their Jiaotong Automatic System Planning Package (JASP), to overcome the 'curse of dimensionality'. However the problem with Lagrangian Relaxation is that it is inherently sub-optimal. It also assumes hat a solution always exists for the dual problem. Park *et al.* (2000) used a genetic algorithm to solve the generation expansion problem. The advantages of genetic algorithms are that they can not only treat the discrete variables but also overcome the dimensionality problem. Additionally, they have the capability to search for the global optimum although there may be problems with premature convergence and duplications among population strings as the evolution progresses (Goldberg, 1989).

These tools use the current state of the system as the initial condition for the simulation and capacity additions and retirements are taken into account as they occur during the course of the expansion of the generation system within the planning horizon. It is perceivable that the generation mix resulting from the optimal generation expansion does not necessarily represent the optimal combination of generation technologies in the absolute sense. Yet the problem at hand seeks to determine that optimal combination of generation resources that is not based on a chronological evolution of the generation system. Essentially, it is not a planning problem.

The operational problem is solved by running a generation production simulation to determine the production costs, to model network constraints as well as to determine generation adequacy for a proposed generation expansion plan. WASP uses probabilistic simulation to calculate production costs, employing linear programming for determining the optimal dispatch policy. In the production simulation of WASP, a year is split into 12 sub-periods. For each of the sub-periods, probability simulation is applied. The production simulation is based on the load duration curve. In JASP, the production simulation also solves the operational problem using a probabilistic production simulation. In solving the problem at hand, a finer time resolution would be desirable in order to capture output characteristics of intermittent generation.

Use of the load duration curve in production simulation ignores the chronological variations in output of intermittent generation like wind that depend on weather. An approach that uses a time series load profile, at one hour resolution, throughout the year is better placed to deal with variable or intermittent generation as it effectively modifies the generation dispatch solutions within each operational time period.

Although the problem being tackled in this thesis bears some resemblance to the standard generation expansion planning problem, the methodology proposed to solve it was not developed as a retrofit of the typical generation expansion planning packages as they serve different purposes. The investment stage is based on an extension of the idea originally developed by Murray (1998) in which the total technology generation costs are directly compared. The original concept did not provide a way of dealing with generation technology unavailabilities or intermittency, neither did it mention the operational aspect of the problem. The approach proposed in this work to solve the operational problem is not based on the load duration curve. Instead, it considers annual load profiles at hourly resolution. It also simulates generation unit unavailabilities. The major advantage of the proposed methodology is that it provides a framework that can handle variable generation technologies.

An important issue to note is that these tools are used to provide guidance as the final solutions would still have to be subjected to other conditions that may not be adequately simulated with these models. An example would be complications with planning applications which may mean that it may not be possible to deploy the desired capacity of a given technology. However, as far as the optimal generation mix is concerned, it is still important to be able to determine the ideal generation mix to deliver a given sustainability level so that the significance of the different barriers to the establishment of the generation mix can be assessed.

4.4 The Proposed Methodology

Recognising that the solution sought after here is not for a generation expansion plan but for an independent generation mix to form an ideal reference for use in market design, the approach adopted was based on an extension of the concept introduced by Murray (1998). rather than modification of typical generation expansion planning tools.

4.4.1 Methodology Overview

Figure 4.1 shows the overview of the proposed methodology. Only key processes are indicated in the block diagram with a brief description of the general process flow given. Further on, a more detailed account of the model implementation is

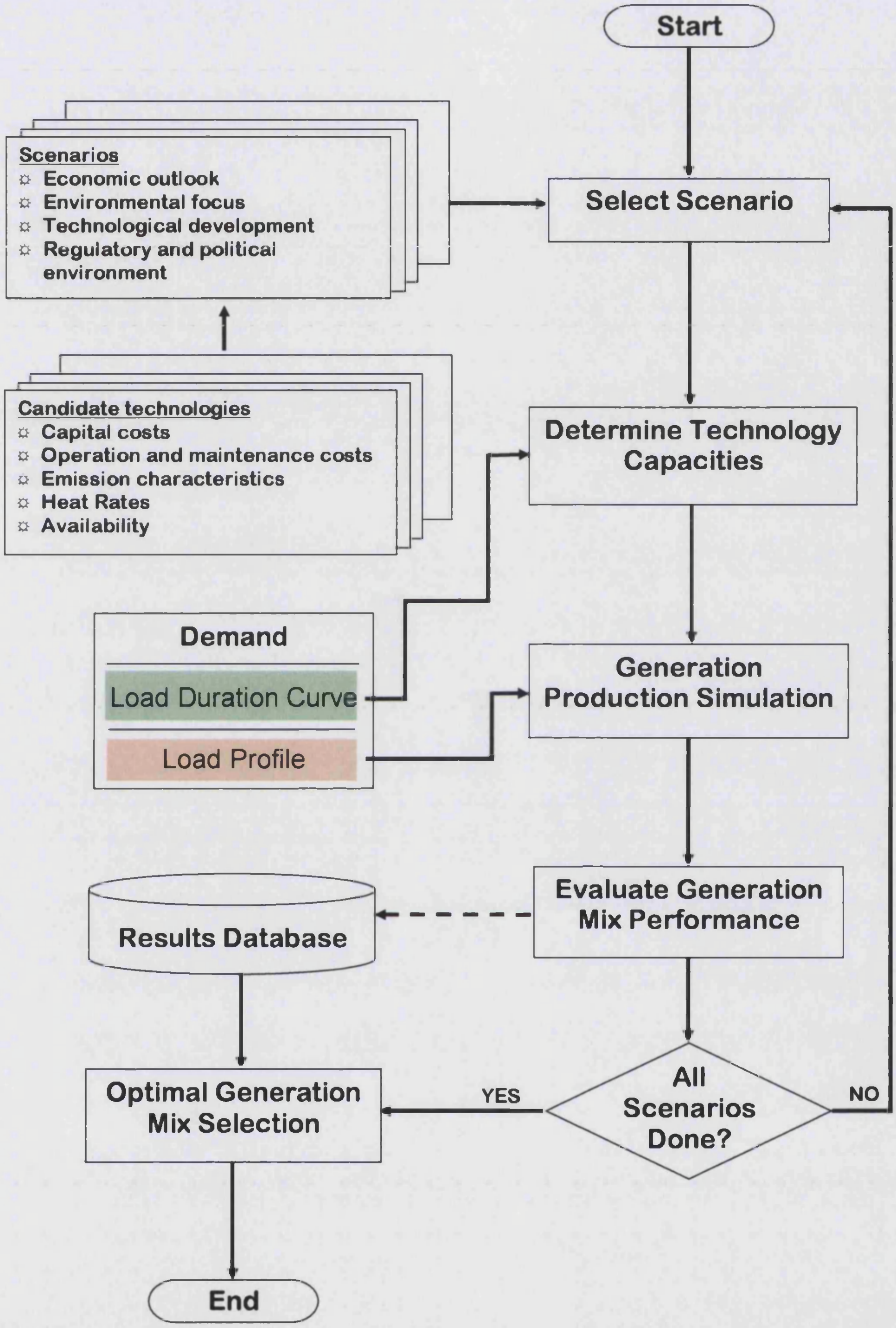


Figure 4.1. Block diagram showing the overview of the proposed methodology.

given. The methodology works with scenarios that focus on technological developments (to identify candidate generation technologies), environmental attitudes (to determine emission price regimes), economic outlook (to represent the ability to invest in new technologies, set high emission prices, etc.) and regulatory and political environment (to capture public views and regulatory impact on the selection of technologies and investment). The methodology also employs a sensitivity analysis to capture a wide range of variation in input data as a way of dealing with uncertainty in future scenarios.

1. **Input Data Selection:** The choice of input data is based on the scenario selected. Such input data include candidate technologies and their cost and emission characteristics, fuel, capital and emission costs, interest rate, demand profiles, etc.

2. **Determining Technologies and their 'Utilisations':** 'Utilisation' here refers to the number of time periods per year that the technology is operated irrespective of the loading levels. From the candidate generation technologies, the technologies that form part of the optimal generation mix are determined based on a comparison of the overall technology generation costs at different 'utilisation' levels. The approximate 'utilisations' are determined at this stage.

3. **Determining Technology Capacities:** The respective capacities for the different technologies are determined based on the expected 'utilisations' and the load duration curve. The shape of the load duration curve thus has an impact on the respective capacity shares of the various technologies in the resulting generation mix solution.

4. **Dealing with Technology Availabilities/Capacity Credit:** The capacities determined above assume that generation is available whenever it is required to meet demand. In practice however, this is not the case. Generating units may not be available due to breakdowns or planned outages. For intermittent generation, there is an additional dimension of variability of output which results

in relatively low capacity credit for such generation. The solution is therefore modified according to the technology specific operational characteristics relating to effective capacity for conventional and intermittent generation.

5. **Discretising Generation Capacities:** This part deals with the fact that generator capacities exist in discrete quantities, therefore the capacities determined have to be rounded up or down to discrete quantities. A generic unit size of 100MW was used in this methodology. It is appreciated that generation technologies would have different typical unit sizes. However, given that some of the technologies that may be modelled may not exist yet, it was decided that for generic studies, this assumption is adequate to make objective comparison between the different candidate technologies.

6. **Generation Production Simulation:** Running generation system production simulation provides a way to determine how the different generation technologies contribute to the total energy and emissions production as well as the the production cost. This simulation is based on the load profile and the generation capacities determined above. It is essentially a multi-period generation dispatch optimisation.

7. **Determining Generation Mix Performance:** The performance of the generation mix solution is calculated based on total system generation costs and emissions obtained from the production simulation. These are calculated as levelised electricity costs and emissions for the entire system and are used as sustainability measures in terms of affordability of electricity and environmental pollution respectively.

8. **Sensitivity Analysis:** In order to capture uncertainties in the input data, a sensitivity analysis is carried out in which the data are varied and the above

steps are repeated for the modified inputs. The results for each simulated case are stored for analysis after all the cases have been completed.

9. **Analysis of Results:** The results stored for the individual simulated cases are analysed to compare the performance of the various generation mix outcomes and identify a robust solution. It is appreciated that this forms an indicative solution of the generation mix as there are other considerations that may affect the final decision such as political influence and public opinion which may not be adequately modelled in this way.

4.4.2 Determining Technologies and their Utilisations

In a system with a number of technologies, economic dispatch minimises the variable component of the total generation costs and not the capital and fixed costs. In order to minimise the total generation costs, it is necessary to consider longer timescales. Over a year[18], the total generation costs C_k for technology k can be calculated according to the following expression:

$$C_k = CC_k + FC_k + VC_k \times h \qquad \pounds/kW/year \tag{4.4}$$

where CC_k is the annuitised capital cost in £/kW/year, FC_k is the annuitised fixed operation and maintenance cost in £/kW/year, VC_k is the variable cost in £/kWh and h is the number of running hours per year.

The first step involves the modelling of the total technology generation costs according to equation 4.4. This is followed by plotting the total generation costs for the different technologies against the number of running hours so that the least cost

[18]One year is a convenient time for studies as the load cycles annually. Longer time scales can be treated as multiple year periods with adjustments for load growth and variations in other parameters such as input costs.

technology at any given number of running hours can be determined. Finally, the number of running hours in a year for each technology can be deduced from the plot. The three steps are explored in further detail below.

Modelling Total Generation Costs

The approach adopted splits the total annual generation costs into variable and fixed costs. Fixed costs are independent of the production level. They include the annuitised capital costs, annuitised fixed operation and maintenance costs. The variable costs depend on the production and consist of fuel costs, emission costs and variable operation and maintenance costs excluding fuel and emission costs. These cost components are presented below:

Capital Costs: Capital costs for generation technologies are normally provided in £/kWh. For a given interest rate r and a technology k with an economic life of n years and a capital cost of cc_k £/kW, the annuitised capital cost can be determined as below:

$$annuity\ factor = \left(\frac{1}{r} - \frac{1}{r(1+r)^n}\right) \tag{4.5}$$

$$CC_k = \frac{cc_k}{annuity\ factor} \quad £/kW/year \tag{4.6}$$

Fixed Operation and Maintenance Cost: As with capital costs, fixed operation and maintenance costs are normally specified in £/kW. Similarly, the annuitised fixed operation and maintenance cost for a technology k with a given fixed operation and maintenance cost of fc_k £/kW can be determined using the following expression:

$$FC_k = \frac{fc_k}{annuity\ factor} \quad £/kW/year \tag{4.7}$$

Variable Costs: The variable costs consist of fuel costs, emissions costs and non-fuel, non-emissions variable operation and maintenance costs. These are usually given in £/kWh. It is necessary to split the variable costs in this analysis as variable operation and maintenance costs are largely technology dependent whereas fuel and emissions costs, in addition to being technology dependent, also depend on fuel and emissions prices which can vary considerably.

- *Fuel Costs:* For thermal technologies, fuel costs are only incurred when the a generation unit is running. The characteristic heat input curve for thermal technologies $H_{ku}(P_{ku})$ was modelled as a quadratic function such that the fuel cost function $f_{ku}(P_{kt})$ for unit u of technology k for period t was determined as follows:

$$H_{ku}(P_{kut}) = a_{ku} \cdot P_{kut}^2 + b_{ku} \cdot P_{kut} + c_{ku} \quad BTU \tag{4.8}$$

$$f_{ku}(P_{kut}) = F_k \times H_{ku}(P_{kut}) \quad £ \tag{4.9}$$

where F_k is the price of fuel for technology k in $£/BTU$, a_{ku}, b_{ku}, c_{ku} are heat rate coefficients for unit u of technology k and P_{kut} is the unit output power in MW. In reality, generator heat input functions are much more complex, sometimes non monotonous and discontinuous as in the case with multi-cycle turbine. The simplification here enables generic type studies to be carried out without onerous tasks in handling otherwise complex fuel cost functions. The amount of assumptions that go into these kinds of studies do not warrant exact cost inputs as they vary even between units of the same technology due to differing fuel supply arrangements, and operation strategies adopted by different owners, hence levelised values are normally used in such analyses.

At this stage of the problem, the technology capacities have not been decided yet, therefore it is not possible to run a production simulation to get the loading levels P_{kut}. However, average fuel costs can be evaluated based on rated power output of the generating unit. A typical unit size is chosen for a given technology k, say $PMAX_k$ kW. Substituting P_{kut} in equation 4.9 with $PMAX_k$ gives the fuel cost at full load over time period t.

If t is one hour, then the fuel cost $f_{ku}(P_{kut})$ in equation 4.9 has units of £ per hour. Therefore the full load average fuel cost ffc_k for the technology k can be determined as follows:

$$\begin{aligned} ffc_k &= F_k \cdot \frac{H_k(PMAX_k)}{PMAX_k} \\ &= F_k \cdot (a_{ku} \cdot PMAX_k + b_{ku} + \frac{c_{ku}}{PMAX_k}) \quad £/kWh \end{aligned} \tag{4.10}$$

- *Emission Costs:* The only external generation costs considered here were due to CO_2 emissions from fossil powered generation since CO_2 is the worst GHG gas of all the gaseous emissions from electricity generation. Where carbon capture and storage were considered, the sequestration costs were used as well as emission costs payable for the unrecovered CO_2 emissions. Although there are other GHG emissions from other generation technologies e.g. methane from biomass and dams (WCD, 2000), these were not included as they are very difficult to measure. The CO_2 emissions did not include indirect or embodied emissions due to plant construction or other processes related to the operation of the plant, for example CO_2 emissions from fuel extraction and transportation. The following expression was used to determine the amount of CO_2 emissions, $E_{ku}(P_{kut})$ in terms of the real power generated by unit u of technology k

in time period t:

$$E_{ku}(P_{kut}) = (1 - \alpha_{ku})(\beta_{ku}P_{kut} + \gamma_{ku}) \quad tonnes \tag{4.11}$$

where α_{ku} is the fraction of the total CO_2 emissions recovered from the process and β_{ku} and γ_{ku} are CO_2 emission coefficients. Given a nominal cost ec per tonne of CO_2 emissions, the external cost $EC_{ku}(P_{kut})$ incurred by unit u during time t is as follows:

$$EC_{ku}(P_{kut}) = sq \cdot \alpha_{ku} \cdot (\beta_{ku} \cdot P_{kut} + \gamma_{ku}) + ec \cdot (1 - \alpha_{ku})(\beta_{ku} \cdot P_{kut} + \gamma_{ku}) \quad £ \tag{4.12}$$

simplifying gives:

$$EC_{ku}(P_{kut}) = (sq \cdot \alpha_{ku} + ec \cdot (1 - \alpha_{ku}))\,(\beta_{ku} \cdot\ P_{kut} + \gamma_{ku}) \quad £ \tag{4.13}$$

where sq is the sequestration cost in £/tonne of CO_2 recovered. Of course the cost of emissions is determined on the emissions market. Unfortunately, this market involves other sectors of the economy that also produce emissions. This makes it difficult to model the price of emissions for use in estimation of external generation costs. This problem can be overcome by performing a sensitivity analysis based on different values of emissions costs.

If the the time period t is one hour, then the emissions cost $EC_{ku}(P_{kut})$ in equation 4.13 has units of £ per hour. The full load average emissions cost fec_k for the technology k can thus be determined as follows:

$$fec_k \;=\; \frac{(sq \cdot \alpha_k + ec \cdot (1 - \alpha_k))(\beta_k \cdot\ PMAX_k + \gamma_k)}{PMAX_k} \quad £/kWh \tag{4.14}$$

– Variable Operation and Maintenance Costs: The expression for operation and maintenance costs $OMC_{ku}(P_{kut})$ incurred during time period t can be modelled as follows:

$$OMC_{ku}(P_{kut}) = B_{ku} + I_{ku} \cdot P_{kut} \quad £ \tag{4.15}$$

where B_{ku} and I_{ku} are the base maintenance cost and the incremental cost coefficients for the unit u of technology k respectively.

The base component of the maintenance cost is fixed and therefore has been taken into account under fixed operation and maintenance costs above. The variable operation and maintenance cost $vOMC$ incurred during time period t can therefore expressed as shown below:

$$vOMC_{ku}(P_{kut}) = I_{ku} \cdot P_{kut} \quad £ \tag{4.16}$$

If the the time period t is one hour, then the variable operation and maintenance cost $vOMC_{ku}(P_{kut})$ in equation 4.16 has units of £ per hour. The full load average emissions cost vom_k for the technology k is given by the following expression:

$$\begin{aligned} vom_k &= \frac{I_k \cdot PMAX_k}{PMAX_k} \\ &= \quad I_k \qquad £/kWh \end{aligned} \tag{4.17}$$

The variable cost component of the total generation cost for technology k is given by the summation of the full load average fuel cost ffc_k (equation 4.10), the full load average emissions cost fec_k (equation 4.14) and the full load average variable operation and maintenance cost vom_k (equation 4.17) in the expression below:

$$\begin{aligned} VC_k &= ffc_k + fec_k + vom_k \\ &= F_k \cdot (a_{ku} \cdot PMAX_k + b_{ku} + \frac{c_{ku}}{PMAX_k}) \\ &\quad + \frac{(sq \cdot \alpha_k + ec \cdot (1-\alpha_k))(\beta_k \cdot PMAX_k + \gamma_k)}{PMAX_k} \\ &\quad + I_k \qquad\qquad\qquad\qquad £/kWh \end{aligned} \tag{4.18}$$

Determining the Technologies

The total generation costs for each technology over a year (given in equation 4.4) can be plotted against the number of running hours to give Figure 4.2 (Murray, 1998). This illustration is based on five candidate technologies, technology 1 to technology 5. Technology 1 has low fixed costs (*indicated by a low y-axis intercept*) but

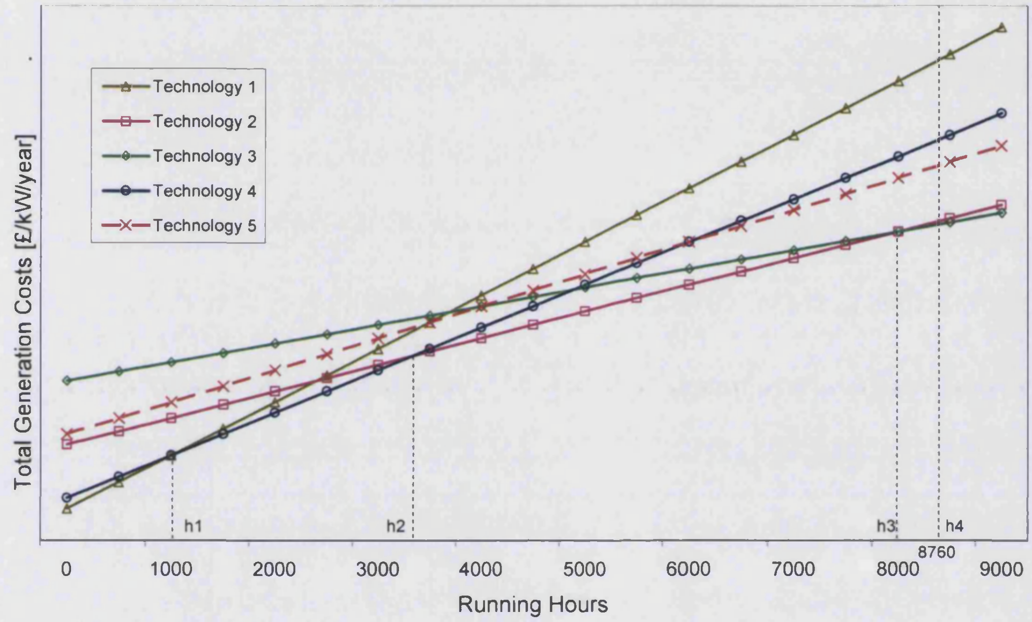


Figure 4.2. Variation of total generation cost with running time by generation technology

has a high component of variable costs (*indicated by a steep positive gradient*). This implies that in the economic dispatch, this technology would be utilised during times of high demand when generation capacity with low variable costs can not meet demand by itself. An example of this is the CCGT technology. On the other extreme, technology 3 has high fixed costs and low variable costs hence is likely to be used as base load, e.g. nuclear generation.

For any number of running hours within the year, the preferred generation technology is the one with the cheapest combination of variable costs and distributed fixed costs. Thus between $h3$ and $h4$ hours it is attractive to use technology 3 in incremental mode. The value of $h4$ coincides with the number of hours in a year (i.e. 8760). Clearly, technology 3 is the base load generation. Similarly, between $h2$ and $h3$ hours, technology 2 becomes more attractive. On the other end of the graph, technology 1 is the most attractive technology between 0 and $h1$ hours and this represents peaking capacity. If a generation technology does not have the least total generation costs at any number of running hours, then theocratically that technology does not make it into the optimal mix solution (e.g. technology 5 in Figure 4.2). In practice however, there are other factors that may make the technology desirable e.g. the need to maintain a diverse range of energy sources.

The fixed costs (costs at 0 running hours) show that generation technologies with low utilisation have relatively low capital costs and high variable costs while those with a higher utilisation have higher capital costs and lower variable costs. In practice, fixed costs are distributed over the period that the technology is utilised.

Determining Technology 'Utilisations'

As mentioned earlier, the term 'utilisation' here refers to the number of hours the technology is expected to be utilised in a year expressed as the total number of hours per year. It does not refer to the actual loading levels as at this level no generation capacities have been determined yet to enable the production simulation to be run. The ranges of running hours $[0 \quad h1]$, $[h1 \quad h2]$, etc. in Figure 4.2 actually represent the ranges in which the the specific technologies operate in incremental mode. The number of hours the technology is expected to be run in a year is the upper value of the range (say $h4$ in range $[h3 \quad h4]$), with part loading in the range and full loading up to the lower value of the range, i.e. $h3$.

This naturally leads to the estimation of expected 'utilisations' of the different technologies. The estimate 'utilisation' $\mathfrak{U}$ for technology k can be determined as follows:

$$\mathfrak{U}_k = \frac{max(\mathfrak{R}_k)}{8760} \qquad \mathfrak{R}_k = [h_k^{min} \ \ h_k^{max}] \tag{4.19}$$

where 8760 is the number of hours in a year.

4.4.3 Determining Technology Capacities

Having decided the technologies that have the minimum generation costs in Section 4.4.2 the next step is concerned with determining the respective capacities for the selected technologies. Firstly, the load duration curve is constructed from the annual load profile for the whole system. Figure 4.3 shows how the technology capacities are determined based on the total generation costs and the load duration curve. The load duration curve in Figure 4.3 shows the demand levels for the sys-

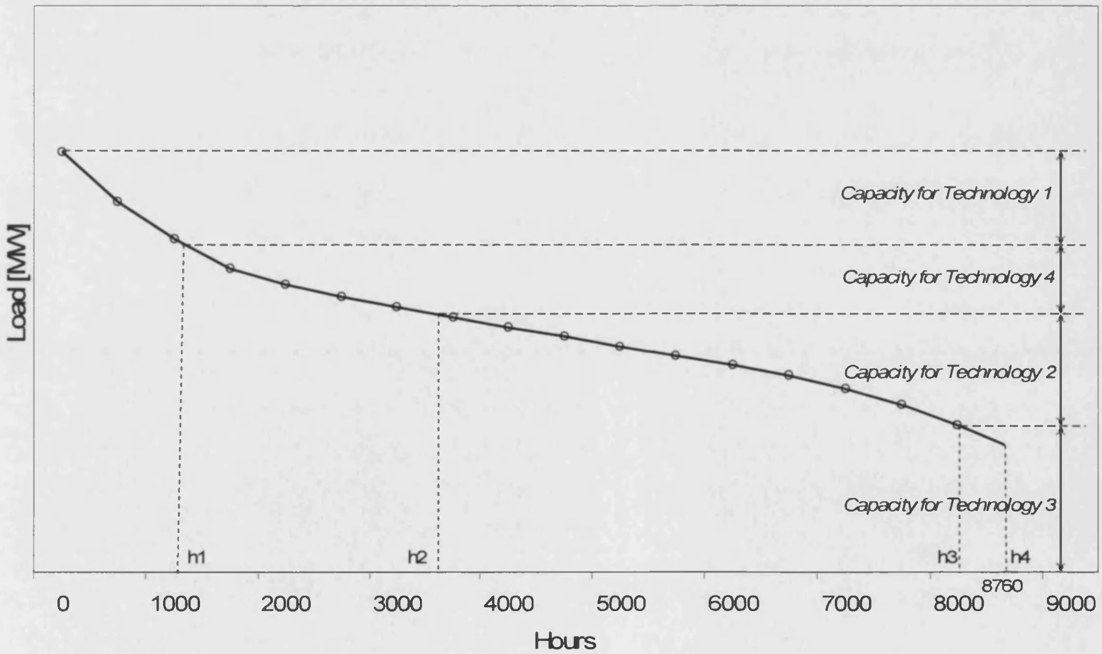


Figure 4.3. Derivation of technology capacities (*to be read in conjunction with Figure 4.2*).

tem and the duration for which it occurs over a year. The load levels at the points where the cost graphs intersect with each other in Figure 4.2, denoted by $h1$, $h2$, $h3$ and $h4$ indicate the cumulative capacities for the generation technologies selected. From Figure 4.3, it can be seen that the capacity for technology 3 is given by the load level at $h3$ which covers most of the base load. The expression for the capacity is given below.

$$CAP_k = Load(h3) \times 1000 \qquad kW \tag{4.20}$$

For the remaining technologies, the capacities can be determined according to the following expression:

$$CAP_k = (Load(min(\mathfrak{R}_k)) - Load(max(\mathfrak{R}_k))) \times 1000 \quad kW, \qquad \mathfrak{R}_k = [h_k^{min} \;\; h_k^{max}] \tag{4.21}$$

At this point the respective capacities for the selected technologies have been decided. The capacities have been chosen to exactly meet the load. However, it is recognised that the actual capacities should allow for unscheduled unit outages otherwise the risk of failing to meet demand due to insufficient available generation capacity would be very high. The next section addresses this aspect of the problem.

4.4.4 Dealing with Technology Unavailabilities

Generation technologies have different availability characteristics. Taking these into account would affect the required generation capacities to meet demand at all times, which is the ultimate goal in generation planning. Inevitably, this would also affect the energy contributions of the generation technologies. Unit thermal constraints also place constraints on the cyclic loading of thermal generation plant, also possibly affecting the energy contributions of the different technologies constituting the generation mix. These factors also affect the total amount of emissions produced by the generation plant.

Another very important issue in future power systems is that of intermittent generation. The capacities derived here would not be appropriate for intermittent generation as its capacity credit is significantly less than the rated capacity even after adjusting the rated capacity to account of plant unavailabilities. A remedy for this challenge is presented and discussed later in this section.

The technology capacities determined in Section 4.4.3 are the effective capacities or 'the firm capacities' that must be provided. In order to determine the actual capacities to be installed, the availability of conventional generation needs to be known while the capacity credit for intermittent generation need to be known. The following expressions give the relationships between the effective capacities and the installed capacities.

Conventional Generation:

$$InstalledCapacity_k = \frac{effectiveCapacity_k}{MeanAvailability_k} \quad MW \tag{4.22}$$

Intermittent Generation:

$$InstalledCapacity_k = \frac{effectiveCapacity_k}{CapacityCredit_k} \quad MW \tag{4.23}$$

where capacity credit was defined as the ratio of conventional capacity that can be displaced by the intermittent capacity to the intermittent capacity without compromising generation adequacy. Due to the low capacity credit of intermittent generation, the estimates for its capacity will be rendered very inaccurate. The capacity credit is determined in a separate study based on unit availabilities during times of peak demand, and sizes of the generation units within the generation mix. A report on quantifying system costs for additional renewables (ILEX, 2002), commonly known as the 'SCAR' report, shows that the capacity credit of intermittent generation decreases with increasing penetration of such generation. Figure 4.4, adopted

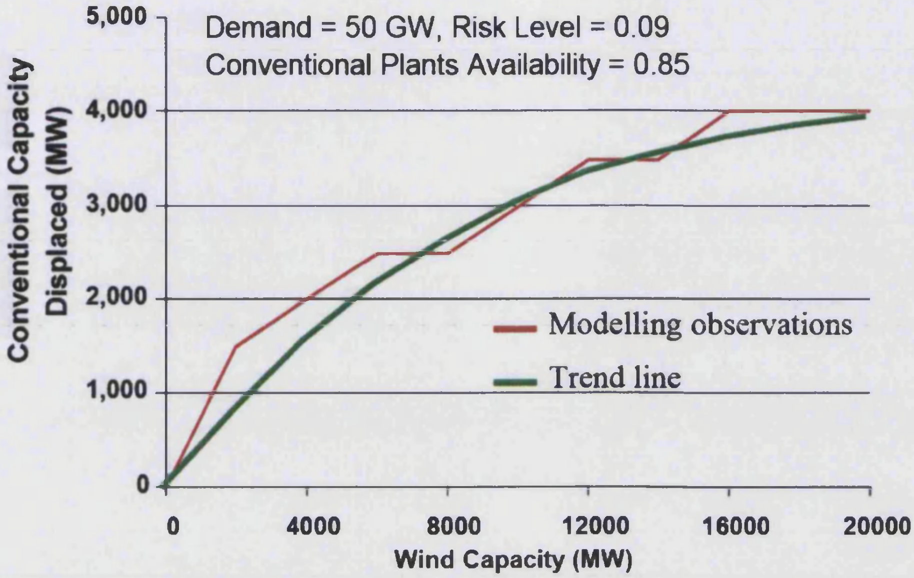


Figure 4.4. Conventional plant capacity that can be displaced by wind generation. *Source: ILEX ENERGY consulting 2002.*

from the SCAR report illustrates the concept of capacity credit The ability of intermittent generation to displace conventional generation decreases with its increasing penetration. For low penetration levels of intermittent generation, its capacity value is significant – 4GW of wind generation displace 1.5GW of conventional generation in Figure 4.4, representing a capacity credit of 38%). At higher penetration levels, the capacity credit drops remarkably, e.g. 20GW of wind capacity displace 4GW of conventional capacity representing a capacity credit of 20%.

For generation with zero variable costs like wind, its plot in Figure 4.2 would be flat, meaning that the introduction of wind generation would tend to displace base load generation. Since investment costs for wind capacity are high, it follows that if considered during the setting up of a new generation system, it would first displace generation with the most investment costs, which falls squarely on base load generation. Due to its poor capacity credit, it will likely be unable to provide the capacity suggested by the model due to limited available wind resource. This is likely to be the case especially if the wind technology costs continue dropping with technological advancements.

When part of base load generation is reduced, the remaining capacity will run with less part loading since it is generally not as flexible as peaking generation in dealing with the intermittency of the wind generation. Intermediate and peaking generation should therefore be able to cope with the variation in the output of the wind capacity.

Installing the intermittent capacity suggested in equation 4.23 would most likely not be cost effective both from generation investment and from transmission requirements view points. Due to limitations of the wind resource or generally suitable wind farm sites, it may not be possible to realise the capacities determined in equation 4.23. The approach below was proposed to deal with the intermittent capacity.

Dealing with Intermittent Generation

The actual installed intermittent capacity was taken as that determined in Section 4.4.3. If this capacity is above the actual available resource then it would have to capped to that which can realistically be developed. Using the expected capacity credit of the intermittent generation, its effective capacity was determined as follows:

$$effectiveCapacity_k = InstalledCapacity_k \times CapacityCredit_k \quad MW \tag{4.24}$$

Finally, the next cheapest generation was considered to take up the discrepancy between the installed and effective capacities for the intermittent generation. Figure 4.5 illustrates this concept. If technology 2 is intermittent generation, then the effective capacity mapping for that technology on the load duration curve gives

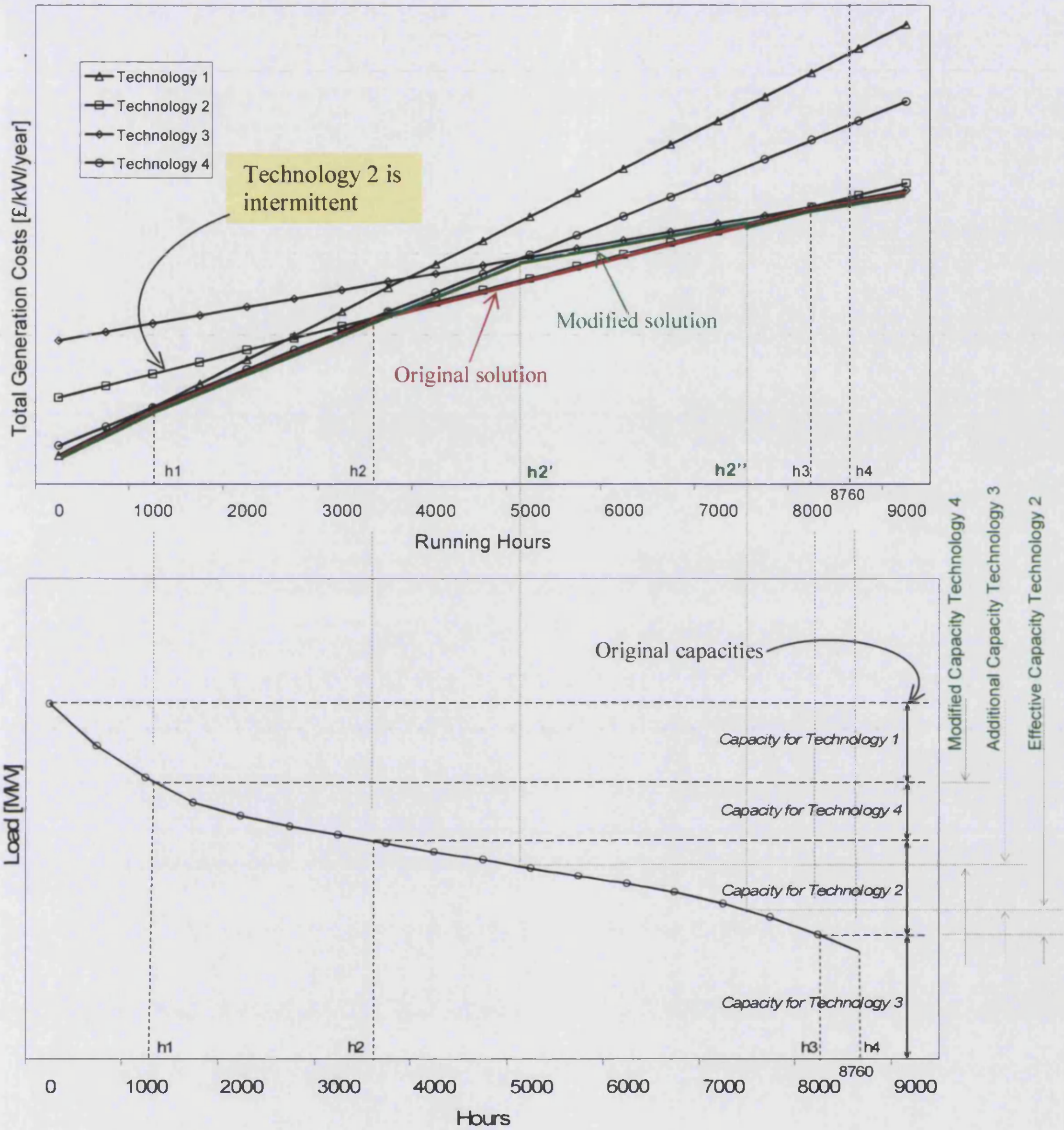


Figure 4.5. The impact of intermittency on generation capacities and utilisations.

$h2''$ running hours. At this stage, technology 3 becomes more cost effective until point $h2'$ when technology 4 becomes more cost effective. The point $h2$ is effectively shifted to point $h2'$. It is important to note that it is possible to end up with another technology that may have initially failed to make it in the preliminary generation mix (i.e. the first approximation of the generation mix presented in Section 4.4.3).

The capacity 'utilisations' can be re-evaluated from the modified solution as described in Section 4.4.2. Special care needs to be taken when dealing with technologies for which the capacities are not presented as contiguous blocks in the revised solution (e.g. technology 3) since the 'utilisations' for the different blocks would be different. The mean 'utilisation' for the technology was defined according to the weighted individual 'utilisations' as follows:

$$\mathfrak{U}_k = \frac{\sum_{i=1}^{I} u_{ki} \times CAP_{ki}}{\sum_{i=1}^{I} CAP_{ki}} \tag{4.25}$$

where u_{ki} is the utilisation of a contiguous block of capacity i, CAP_{ki} of technology k

4.4.5 Discretising Generation Capacities

Generator units come in discrete sizes therefore the capacities that have been determined above need to be converted into an integer number of units. This methodology uses a unit size of 100MW such that a capacity of 1660MW is rounded off to 1700MW which is equivalent to 17 units of 100MW each. Rounding was done to the nearest 100MW. It is appreciated that the unit size affects the overall performance in terms of mean availability but for a generic study of this nature, the errors introduced were assumed to be sufficiently small to be addressed by sensitivity analysis.

4.4.6 Generation Production Simulation

Having determined the capacities of the generation technologies, the next stage is to simulate the generation operation using a production simulation model. This provides a way of evaluating the contribution of each technology to the energy and emissions, enabling the sustainability of the generation mix to be evaluated.

Ultimately, the production cost and emission levels form the basis of comparison of the different generation mixes.

The approach taken in the production simulation model employs a series of generation scheduling solutions stepping through all the four seasons of the year at hourly resolution to determine the production cost, energy and emission contribution levels for the chosen technologies. A one hour time is was adopted to enable the demand profiles to be captured more accurately and also to effectively capture the characteristics of intermittent generation since they affect the scheduling solutions. The process considers unit availabilities, minimum up and down times for thermal plant, fuel and emission costs, operation and maintenance costs and simplified startup and shutdown costs. This enables the performance of the candidate generation mix solutions to be evaluated in terms of levelised generation costs (pence per kWh) and emission levels (kgCO_2 per kWh).

As discussed in Section 3.2, the operating regime of the power system has an impact on the performance of the power system. Two major paradigms for power system operation are the centralised and the decentralised operation. In determining an optimal generation mix suitable for use as a reference in market design, it is necessary to determine which of the two operation regimes best optimises the operation planning problem. This can be achieved by modelling generation production based on the two operating regimes and comparing the solutions in terms of the overall production costs and emissions.

In the centralised environment, a global optimum is sought, while in the decentralised environment the individual market entities seek to optimise their production in order to maximise their profits. The optimisation based on the centralised regime is expected to give a more optimal global solution relative to the decentralised regime. Therefore, the optimum solution based on the centralised setup was adopted after comparing the performance of the solutions from the centralised and decentralised based generation production simulation models described in Section 4.4.8.

Multi-period generation scheduling is a two stage process consisting of unit commitment followed by optimal generation dispatch for each period. Since this is an operational problem, it is focused on the short term optimisation of system operation therefore it deals with variable costs rather than total generation costs. Fixed costs can not be optimised in these short timescales as they were already decided at the investment stage. Before the description of the production simulation model used, a brief discussion on unit commitment and generation dispatch is presented.

Unit Commitment

In practice, unit commitment is carried out in advance based on expected demand to be served by the generation portfolio, unit production costs and unit outage plans. Minimum unit up and down time and spinning reserve constraints are handled at this stage as well as other constraints such as must-run and must-out units. Closely related to the unit commitment algorithm is the dispatch algorithm. This decides the loading levels of the units 'committed' to run during a given period. Solving the dispatch problem allows the unit ramp rate constraints, unit active power output limit constraints and system power balance constraints to be checked.

The unit commitment problem is well documented in literature (Padhy, 2004). Approaches to the unit commitment problem range from rule-of-thumb methods to theoretically complicated methods. The scope varies from one company to another depending on available generation technologies, particular operating constraints and preferred approach. The reason why the problem is strongly oriented towards reducing fuel costs is that they form a significant component of the variable operating cost. For large utilities, reducing fuel costs by a paltry 0.5% can result in savings of millions of dollars per annum (Baldick, 1995; Li *et al.*, 1997). In the UK, about 40% of the average consumer's bill is made up of generation costs (CAG, 2003) (this includes other generation costs apart from variable operating costs). With increasing environmental awareness emission costs are increasingly being considered in the unit commitment problem.

An exact long term unit commitment is impossible due to exorbitant computing time (Huang *et al.*, 1998; Vemuri and Lemonidis, 1991) while on the other hand the extrapolation of the short term unit commitment solution is inadequate as it ignores many constraints such as maintenance and price increases (Padhy, 2004). With the introduction of intermittent generation in the system, long term unit commitment solutions will have to be very flexible. Even if the unit commitment were to be performed well in advance, it would have to be revised close to real time due to unscheduled plant unavailabilities and variable available capacity from intermittent generation, the extent of revision depending on amount of intermittent generation and other factors like unit sizes and transmission constraints.

Classical unit commitment algorithms such as dynamic programming, Lagrangian relaxation, branch and bound, bender's decomposition have been applied to the unit commitment problem. Although dynamic programming is a powerful and inherently optimal search algorithm, it tends to be demanding in terms of hardware requirements due to the need to store intermediate results (Wood and Woolenberg, 1996; Padhy, 2004; Nieva *et al.*, 1986). The Lagrangian relaxation on the other hand is inherently sub-optimal (Ruzic and Rajakovic, 1991; Virmani *et al.*, 1989). It has been used to solve the unit commitment problem in conjunction with the bender's decomposition (Romero and Monticelli, 1994; Ma and Shahidehpour, 1997). Evolutionary algorithms such as genetic algorithms (G. B. Sheble *et al.*, 1996; Dasgupta and McGregor, 1994), and simulated annealing (Wong and Wong, 1994; Annakkage *et al.*, 1995) have also been used to solve the unit commitment problem but they have the drawback that they tend to be very slow although they are capable of finding the global optimum.

For a large system with many generating units, these methods can become quite onerous on hardware requirements also requiring long times to solve. Also these methods are well suited to centralised electricity markets. For these reasons, an agent[19] based generation production simulation model (Nagata *et al.*, 2002; Conzelmann *et al.*, 2005) was adopted in this work. The advantages of agent based modelling are that it provides a way of representing the different market entities with different characteristics and in so doing provides flexibility by distributing tasks among several sub-processes thereby presenting an opportunity to efficiently manage hardware resources. Another very important attribute is that it is scalable, making it suitable for modelling larger systems efficiently. Any of the generation scheduling algorithms mentioned above can be employed by the individual generation entities according its operational strategies. The individual optimisation problems for the generation entities have a smaller dimension compared to the global optimisation, however with an increasing number of generation entities, the global solution resulting from the individual entity optimal solutions may be sub-optimal depending on the the market structure and rules.

[19]An agent is a software representation of a decision making unit. Agents form the basic building blocks in the modelling of complex adaptive systems.

As the problem dealt with one year at one hour resolution, it meant that the number of unit commitment problems to be solved was $N \times hours\_per\_year$ where N is the number of generating entities. However, pursuant to the centralised approach adopted, all generation was assumed to belong to one generating company. Simplified heat rate and emission functions were used to reduce the computational burden. Continuous and differentiable functions were assumed in order to enable the generating units to be dispatched in equal incremental cost mode subject to unit power output constraints. The approach taken has the advantage that it is fast. Given the amount of assumptions about generator characteristics, costs, etc, it was felt that a more accurate solution at the expense of speed was not justifiable. To increase the credibility of the solution, generator availabilities were modelled based on Bernoulli trials, assuming that when a unit was available, then full capacity was available and nothing when not available. Unit minimum up and down time constraints were also taken into account.

Environmental and Economic Dispatch

It is worth noting that in the decentralised environment, the economic dispatch is concerned with maximising profit and not necessarily minimising costs as discussed. Since markets value all tradables in monetary terms, environmental constraints can be conveniently handled by assigning a monetary value to the emissions and treating the emissions as any other costs. The utilisation of specific technologies would therefore be sensitive to the value assigned to the emissions. This forms the basis on which the market plays a vital role in influencing the generation mix and hence the sustainability of power generation. However, it is also recognised that transmission constraints play an important role in the utilisation levels of generating units. Modelling the transmission system with the dispatch solution enables transmission constraints as well as generator reactive power limits to be checked. To some degree, these are solved by re-dispatching generation.

4.4.7 The Production Simulation Model

The agent-based production simulation model developed is capable of handling an arbitrary number of generating entities and load serving entities simultaneously, subject to availability of computer memory. Since this thesis is not concerned with modelling of market economics, basic agents were used to represent demand and generation with the objective of meeting demand at minimum cost.

Agent Based Modelling (ABM) - An Overview

Recent research in complex adaptive systems (CAS) is beginning to produce understanding of complexity in natural systems due to interaction of multiple, simple but adaptive components. The advantages of these models for general modelling are that they have the ability to produce complex emergent behaviour out of a relatively small set of rules and they can be used to estimate solutions to non-linear complex problems. They are also consistent with the theory that organisations are adaptive systems.

Each adaptive component is called an agent. An agent is a software representation of a decision making unit. The decision making unit represented could be a physical component, decision maker or an organisation. Intelligent agents are those that are capable of learning from experience and also perform experiments in search of self improvement, thereby adapting to the changing environment. Intelligent agents are normally called agents and they have the following characteristics:

- Autonomy: ability to independently create and implement strategies.

- Reactive: being able to sense the environment and modify its behaviour accordingly.
- Inference: inferring task related issues from the environment.
- Adaptive: having learning and self improvement capability.
- Collaboration: working with other agents to achieve a common goal.
- Negotiation: The ability to negotiate with each other.
- Temporal continuity: having persistent identity and state over long periods.

More advanced agents can even have personalities similar to humans such as co-operation for the 'public good', caution and greed.

An agent simulation consists of the agents and a framework for their interaction. The agents can be configured to compete against each other while cooperating in achieving a global goal. Business enterprises, economic and market models, biology and ecology systems can be viewed as complex adaptive systems. Due to the complexity of such systems, it is extremely difficult to assess the behaviour of the different components based entirely on mathematical formulations.

In computer programming, agents can be viewed as an extension to the object oriented programming (OOP) model. A basic agent can be modelled as an active object capable of directing its own behaviour based on its desired goals, the changing environment under the influence of external factors and the evolution of other agents within the system. Tesfatsion[20] described an agent as "referring broadly to a bundle of data and behavioral methods representing an entity constituting part of a computationally constructed world".

[20] http://www.econ.iastate.edu/tesfatsi/

Discrete event simulations with multiple quasi-autonomous agents have been used to assist in decision making in areas such as batch manufacturing, transport and logistics for over 25 years (Farukui and Eakin, 2002). The revolutionary new idea in computer CAS research is to let the agents evolve, adapting to the environment which is itself being changed by external factors, sometimes the agents themselves acting in such a way as to change the environment. Tesfatsion (2001) applied agent based modelling to computational economics problems, electricity restructuring and market design (Nicolaisen *et al.*, 2001), and other economic areas.

Several agent based electricity market models have been implemented. Honeywell Technology Centre developed the Simulator for Electrical Power Industry Agents (SEPIA) in conjunction with the University of Minnesota. The Centre for Complex Adaptive Systems Simulation (CCASS) of the Argonne National Laboratory, Illinois, modelled electric power markets (Electricity Markets Complex Adaptive Systems (EMCAS)), gas markets and their interdependency using CAS (Conzelmann *et al.*, 2005). Towards the introduction of NETA in England and Wales, the proposed market was modelled using a large scale application of multi-agent evolutionary model (Bunn and Olivera, 2001). The agent-based model was able to provide pricing and strategic insights ahead of NETA's implementation.

A notable drawback with agent based modelling is that it is difficult to validate the models as it is difficult to accurately determine how an entity would behave under given circumstances. Empirical validation methods were proposed by Tesfatsion (2006) in which descriptive and predictive validation techniques are applied. The challenge is how to implement and present these methods in a scientifically appropriate format.

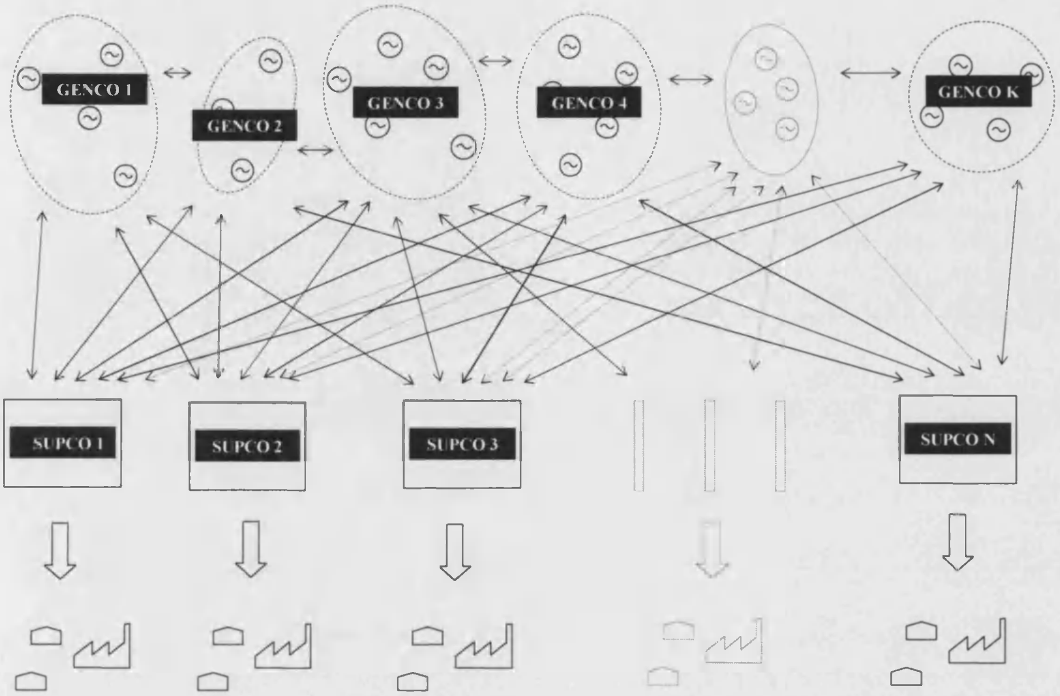


Figure 4.6. Block diagram showing interaction between GENCO and SUPCO agents.

Application of ABM to the Multi-Period Generation Scheduling Problem

The model developed for generation scheduling can handle an arbitrary number of generation and load serving entities. Each entity is modelled as an agent. Within their operating environment is also an administrator/facilitator agent responsible for the roles of the system operator and the settlement agent in today's deregulated markets. The facilitator agent is referred to as the SETCO. The load serving entities, referred to hereafter as SUPCOs, purchase generation from the generating companies, referred to hereafter as GENCOs, to meet their forecasted demand. The prices offered by the GENCOs depend on their aggregate cost functions and the generation already committed for that trading period on an incremental price basis.

The block diagram of Figure 4.6 shows the main agents and their communication relationships. Each GENCO has a generation portfolio while each SUPCO has a group of consumers that it serves. The GENCOs can interact with each other as well as the SUPCOs while the SUPCOs only interact with GENCOs. Demand flexibility was not modelled, hence SUPCOs are passive agents that only purchase generation to meet their forecasted consumer demands.

The model offers the flexibility to model different market structures and is scalable. With GENCOs and SUPCOs, a bilateral contract based market can be modelled. Reducing the number of SUPCOs to one changes the market structure to a POOL. Having one GENCO and one SUPCO effectively gives the centralised arrangement.

There is also provision to model the network if the generator locations, types and capacities are specified. This was implemented in the form of an *ac* load flow to allow for the evaluation of generator reactive power constraints, network losses, voltage limit violations as well as branch thermal loading violations. Network modelling would be carried out on the generation dispatch solutions for each trading period. It is hoped that this would give indications of areas likely to require network reinforcement for different ideal generation backgrounds.

The GENCO Agent

The GENCO agent is the most active agent in the simulation, being responsible for the price determination at each output level for the entire generation portfolio for a generating entity. It also deals with unit outages and the actual dispatch of the generating units. Figure 4.7 shows the main attributes of the GENCO agent. A typical generating company in today's markets runs a generation portfolio based on a mix of technologies strategically chosen to achieve economic and operational efficiency. With the changing environmental, economic and regulatory environments, the portfolio mix is bound to change depending on the economic signals provided by the market. At the beginning of the simulation, the GENCO agent analyses the

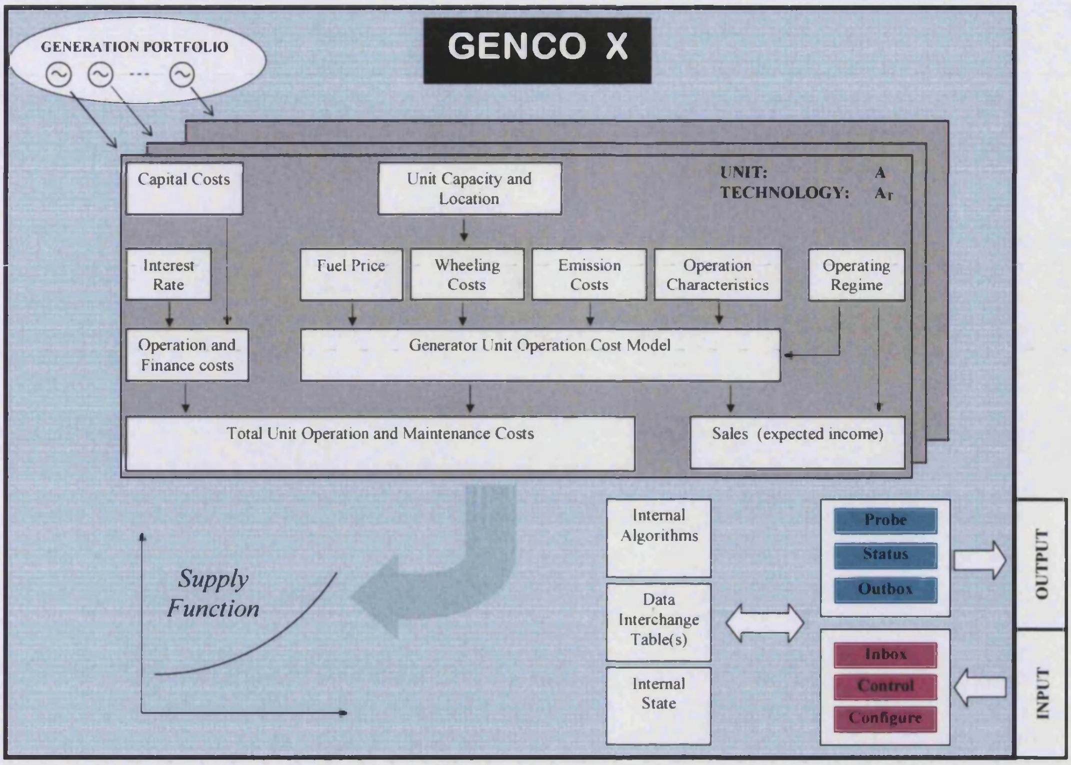


Figure 4.7. Block diagram showing organisation of the GENCO agent.

cost characteristics of its units based on heat rates (for thermal plants), costs associated with emissions and their abatement and capital costs. An aggregated supply curve is then determined based on an economic/environmental dispatch at each loading level within the total power output capabilities of the generation portfolio.

The aggregate cost function for a GENCO is determined by considering all the costs described under the subsection '*Modelling Total Generation Costs*' above. Ideally, this would represent the true cost of generating electricity and injecting it into the power grid if the wheeling costs are included as well. Figure 4.8 shows an aggregated cost function of a typical GENCO, indicating the variable and fixed components of the total generation costs. Variable cost recovery is straight forward since it is easy to immediately pass them on to the consumers in each time period. The variable costs

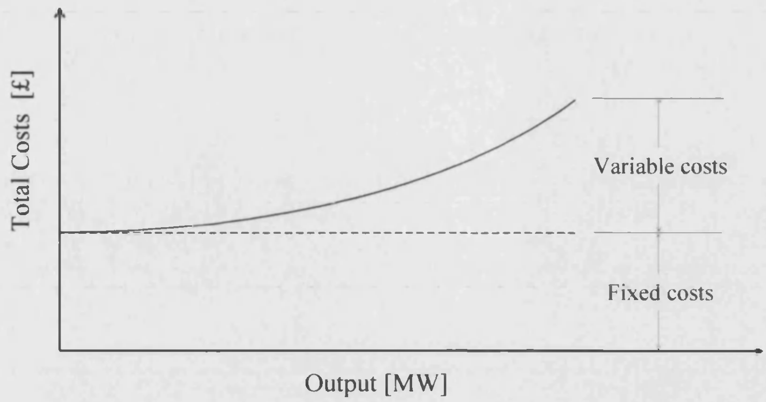


Figure 4.8. Typical aggregate cost function of a GENCO.

C_V can be determined as follows:

$$C_V(P_{out}) = \frac{v(P_{out})}{P_{out}} \qquad £/MWh \tag{4.26}$$

where $v(P_{out})$ is the the variable cost at GENCO loading level P_{out} MW in a one hour time period expressed in pounds hour. This is very different from the fixed costs. For a generating unit that is highly utilised, fixed costs can be spread over the entire time frame. However for those generating units that will be used less frequently the fixed costs have to be recovered during those short times the units are run. The utilisation level for each of the generating units was estimated based on technology (Discussed in subsection *'Determining Technology Utilisations'* above). Based on these utilisations, the fixed costs charged for each MWh produced (C_F) are determined as follows:

$$C_F = \frac{Total\ Annual\ Fixed\ Cost}{Rating \times Annual\ Hours \times Utilisation} \qquad £/MWh \tag{4.27}$$

The higher the expected utilisation, the lower the fixed costs per MWh. Figure 4.9 shows the variation of fixed costs with utilisation.

Generally, plants with low operation costs and high capital costs are used to supply base load meaning that they have a high utilisation while intermediate and peaking

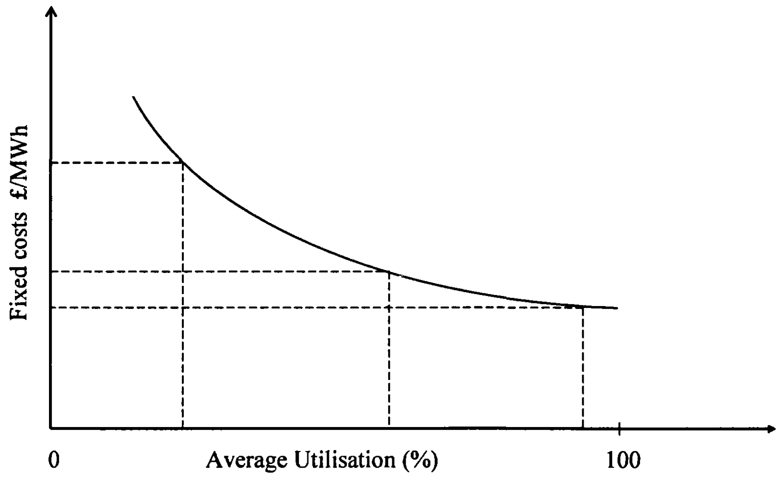


Figure 4.9. Variation of fixed costs with average utilisation.

units have relatively lower capital costs and high operating costs, usually due to expensive fuel costs.

A GENCO responds to a request from a SUPCO by providing costs for the requested quantities of generation (*quotations*) for a given trading period and reserves the quoted units pending feedback of acceptance or rejection from the SUPCO. In reality, these quotations are valid for a short time after which they expire and they are made available to other purchasers. This aspect was not modelled as it is concerned with the dynamics of the interaction of market agents rather than the generation scheduling solution. If the feedback is positive, then the reserved units are confirmed. If the feedback is negative, the reserved units are made available again. In this model, the quotations are based on true costs (i.e. the GENCOs faithfully follows their aggregate supply cost functions) and the SUPCOs purchase the cheapest generation. Full costs are considered here as the GENCO has to recover its total costs from its sales.

Figure 4.10 shows the process by which a GENCO commits its generation portfolio capacity for a trading period in advance. The sequence of events are as in Table 4.1.

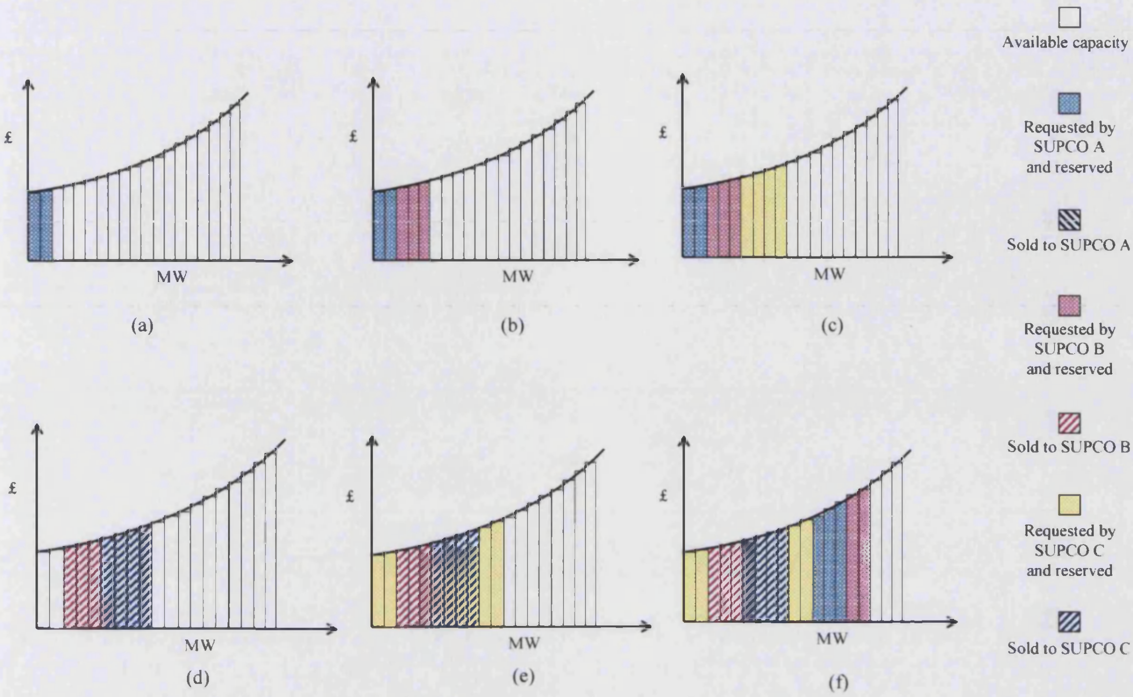


Figure 4.10. Commitment of a GENCO's generation portfolio capacity for a trading period in advance.

This sequence of events is asynchronous and can not be predicted in the model execution. This is a characteristic of agent based systems and it does not compromise the final solution; it can be viewed as an alternative to the sequential flow control in single thread programming.

The SUPCO Agent

The SUPCO agent forecasts demand based on the consumers that it serves. In this model, it basically follows a given load profile. It purchases generation to meet demand for each of the trading periods in advance. It probes all GENCOs for prices for a given quantity, requesting a small quantity at a time and only accept the cheapest. All GENCOs and SUPCOs run simultaneously, therefore the order in which they conduct their transactions can not be known in advance. Each SUPCO agent

Table 4.1. Interaction between a GENCO and SUPCOs (*To be read in conjunction with Figure 4.10*).

Figure	SUPCO A activity	SUPCO B activity	SUPCO C activity
4.10 (a)	Request quotation for 2 units. Units reserved pending confirmation	*Obtaining quotations from other GENCOs*	*Obtaining quotations from other GENCOs*
4.10 (b)	*Obtaining quotations from other GENCOs*	Request quotation for 3 units. Units reserved pending confirmation	*Obtaining quotations from other GENCOs*
4.10 (c)	*Obtaining quotations from other GENCOs*	*Obtaining quotations from other GENCOs*	Request quotation for 4 units. Units reserved pending confirmation
4.10 (d)	Rejects the 2 reserved units. Units become available again	Accepts the 3 reserved units. Units become confirmed	Accepts the 4 reserved units. Units become confirmed
4.10 (e)	*Obtaining quotations from other GENCOs*	*Obtaining quotations from other GENCOs*	Request quotation for 4 units. Units reserved pending confirmation
4.10 (f)	Request quotation for 3 units. Units reserved pending confirmation	Request quotation for 2 units. Units reserved pending confirmation	*Obtaining quotations from other GENCOs*

has a well defined goal to accomplish, that is to meet its demand at minimum cost, and the global scope of these sub goals is to supply the total demand at minimum cost. Since emissions and carbon sequestration costs are included, the solution inherently takes care of emission controls. The problem of where the money paid for these emissions is spent is out of scope for this study.

Each SUPCO agent traverses all GENCOs requesting quotations for a predefined standard quantity. A GENCO with uncommitted capacity responds with the quantity that it can offer (which can be smaller than the quantity requested) and the price per MWh. After receiving responses from all GENCOs, the SUPCO sorts them to find the cheapest one. It then proceeds to send an acceptance feedback (purchase) to the GENCO with the accepted quotation and negative feedbacks (rejections) to all other GENCOs. This process goes on until the SUPCO demand is met or there is no more generation capacity in the system. Although demand flexibility was not modelled, it is appreciated that demand responsiveness could offer important services in systems with significant intermittent generation.

The SETCO Agent

The SETCO agent is not directly involved in the transactions between the GENCOs and the SUPCOs, instead it coordinates/facilitates the activities in the model. There is only one SETCO agent in a system of GENCOs and SUPCOs. Since the execution of the GENCOs is asynchronous, it is necessary to synchronise them at the dispatch juncture. After dispatch, they go their ways again until the next dispatch which occurs at the next trading period. If the network is modelled, the SETCO also initiates the power flow algorithm embedded in the model to evaluate the system security index for the dispatch solution. It then aggregates and saves the results in a file that it keeps appending at the end of each trading period. The generation scheduling results collected include such variables as the security violation index (if the network is modelled) and its components (described below), total demand, the selected technologies and their respective capacities, emissions, energy contributions, operating costs (fuel, fixed and variable maintenance and operation costs, startup and shutdown costs) and the number of time periods where demand exceeded available generation as well as the generation shortfall. This forms a pool of data that is used in the analysis of the different generation technologies constituting the generation mix.

Network Impact on the Dispatch Solutions

If the network is modelled in the production simulation, its impact on the energy and emission contributions of the technologies can be evaluated based on the constraints it presents to the power flow in the system. The network constraints affect the generating units around congested areas. This in turn affects the operation costs and possibly the emissions. In order to evaluate the network impact on generation scheduling, the locations, types and sizes of the generators need to be specified. This was not investigated in this thesis due to unavailability of criteria for deciding the locations of the generation technologies determined in the generation mix investigation. Furthermore, the generation mix determined in this thesis is not an extension to an existing generation capacity base already installed in a network.

There are many factors that influence the location of generation, for example, the availability of the wind resource for a wind farm, a suitable site for a hydro power plant, re-powering of an existing plant or sometimes public acceptability issues. A notable challenge from the network point of view is that the network was not designed with some of the energy resources that are now being considered seriously, for example wind power which unlike conventional generation, is variable. As discussed in Chapter 3.3, the ideal generation mix could be compromised due to limited investment capability in network infrastructure.

Due to the complications in estimating the cost of transmission reinforcement and expansion costs, a static security measure was formulated to give a measure of security violations, assuming that the locations, types and sizes of generators were specified. Worsening security index indicates the need to either invest in the transmission infrastructure or to have to reschedule generation giving a generation mix further away from the desired one. The static security violation index S was defined follows:

$$S = \tau_v + \tau_b + \tau_q \tag{4.28}$$

where τ_v, τ_b and τ_q are the busbar voltage, branch power flow and generator reactive power limit violations calculated respectively as follows:

$$\tau_v = \sum_{m=1}^{M} \delta v_m, \quad \delta v_m = \begin{cases} 0 & if \;\; v_m^{min} \leqslant v_m \leqslant v_m^{max} \\ (v_m - v_m^{max})/(v_m^{max} - v_m^{min}) & if \;\; v_m > v_m^{max} \\ (v_m^{min} - v_m)/(v_m^{max} - v_m^{min}) & if \;\; v_m < v_m^{min} \end{cases} \tag{4.29}$$

$$\tau_b = \sum_{y=1}^{Y} \delta b_y, \quad \delta b_y = \begin{cases} 0 & if \;\; b_y \leqslant b_y^{max} \\ (b_y - b_y^{max})/(b_y^{max}) & if \;\; b_y > b_y^{max} \end{cases} \tag{4.30}$$

$$\tau_q = \sum_{z=1}^{Z} \delta q_z, \quad \delta q_z = \begin{cases} 0 & if \;\; q_z^{min} \leqslant q_z \leqslant q_z^{max} \\ (q_z - q_z^{max})/(q_z^{max} - q_z^{min}) & if \;\; q_z > q_z^{max} \\ (q_z^{min} - q_z)/(q_z^{max} - q_z^{min}) & if \;\; q_z < q_z^{min} \end{cases} \tag{4.31}$$

where M is the number of busbars in the system, Y is the number of branches and Z is the number of generating units connected to the system.

The role of the transmission system planner in the decentralised environment is to provide adequate transmission capacity economically in a coordinated manner so as to facilitate competition in generation. In the face of unprecedented uncertainty in future generation types and locations, the transmission planning methodologies will need to undergo significant but gradual changes. Ideally, the transmission system should not compromise the optimal generation mix.

Provision of transmission infrastructure is not dealt with in the market place (i.e. it is a monopoly and therefore a regulated business). Its planning needs to flexible and robust enough to adequately deal with the uncertainties in future generation mixes.

4.4.8 Determining Generation Mix Performance

The performance of the generation mix can be measured by the levelised electricity generation cost C_L and the levelised emissions E_L which are determined as follows:

$$C_L = \frac{Total\ Generation\ Costs}{Total\ Energy\ Supplied} \qquad p/kWh \qquad (4.32)$$

$$E_L = \frac{Total\ Emissions}{Total\ Energy\ Supplied} \qquad kgCO_2/kWh \qquad (4.33)$$

where total generation costs include capital and operation costs. The two variables, C_L and E_L were used as performance indicators for the generation mix solutions as they relate to the affordability and environmental sustainability of the generation mix. They are determined by simulating the generation production. Two production simulation setups can be considered, namely the centralised and decentralised simulation. In order to enable the comparison of the results from the simulations, they have to be based on the same generation mix in terms of the actual installed capacities. Theoretically, a globally optimised solution should have superior performance compared to a combination of locally optimised solutions.

The dispatch in both the centralised and decentralised model setups was based on equal incremental cost for the generating units within their output power capabilities, minimum up and down times and availability constraints. The difference in the setups is due to the following:

- *Number of entities:* The centralised setup has a single SUPCO and a single GENCO. The objective of the GENCO is to minimise the production costs subject to unit and system constraints while the decentralised setup has more than one GENCO and SUPCO. The GENCOs aim to maximise their profits.

- *Generation dispatch:* In the centralised case, the optimisation of the generation dispatch considered all the system generation for every time period. In the decentralised case, each of the GENCOs optimises the dispatch of generation units that belong to itself only. This means that for the decentralised case, the overall system dispatch consists of individual GENCOs' optimised dispatches.

- *Generation costs:* The generation costs for the centralised simulation were evaluated directly from the dispatch solutions explicitly including fuel costs, emission costs, operation and maintenance costs, startup and shutdown costs for each scheduling period of the analysis year together with the capital costs. On the other hand, for the decentralised simulation, each GENCO determines the selling price according to an aggregate cost function that is determined beforehand based on its generation portfolio economic characteristics. The cost function consists of a variable component dependent on the production level and a fixed component depending on the annual fixed costs and expected utilisation of the generation plant (discussed under subtitle *'The GENCO Agent'* above). The actual production cost incurred by the GENCO can be calculated in the model as in the centralised setup by adding up the production costs as they are incurred although in practice, the actual production costs are not known outside the GENCO.

- *Total emissions:* Total system emissions are calculated according to the loading levels of the individual generating units. The emissions from the two simulations would be expected to be different since the unit loading levels in the single optimisation case of the centralised simulation are not necessarily the same as those of the of the multiple optimisation case of the decentralised simulation.

The results from the two production simulations can be compared to determine which of the two gives optimal results. The setup that results in optimal performance can be adopted for the evaluation of the performance of all the scenarios. In order to find the effect of number of GENCOs on the generation mix performance, their number can be varied while keeping the number of SUPCOs the same.

4.4.9 Sensitivity Analysis

Due to uncertainties in future movements of technology costs, production input costs, demand, commercial and regulatory pressures, it is important to determine the sensitivity of the generation mix to a fairly diverse range of possible future conditions. This is very useful in identifying those generation mixes that not only meet the desired sustainability criteria but are also robust.

Those generation mixes that are very sensitive to key inputs can be avoided in favour of those that are generally less sensitive. This is of paramount importance especially for a generation mix to be used as a reference in market design as it should be stable in the long term, resulting in policies, markets structures and rules that are stable. This inspires confidence in the market participants and can aid in creating a conducive investment environment.

Chapter 5

Sustainable Generation Mix Solution

THIS chapter presents the test data used for demonstrating the methodology and the results obtained. A discussion of the results is also included.

5.1 Introduction

The results presented in this chapter were determined based on the methodology outlined in Chapter 4. The candidate generation technologies and their characteristics are presented as well as the load data. The presentation of results is based on two scenarios, the base case scenario and the green scenario and a sensitivity study to determine the sensitivity of the generation mix to the variation of emission and gas fuel costs. A discussion of the results is also included.

To demonstrate the influence of market structures and rules on the operation of a given generation mix, a case study is also presented based on the base case generation mix. Firstly, the performance of the generation mix operated in a centralised structure is compared to the that of the generation mix operated in the decentralised structure. This comparison forms the basis for the choice of the production simulation setup for evaluating the performance of the generation mix outcomes. Secondly, the performance of the generation mix is investigated under various levels of maximum permissible generation share for each GENCO in the decentralised structure.

5.2 Input Data

The data used in the study was obtained from various recent studies including the most recent UK Energy Review Report (DTI, 2006a). Although most of the detailed data was obtained from a variety of reports from the energy research community, the energy review document gave more up-to-date data that has guided the selection of data and assumptions used in the final simulations. Key input data is presented below.

5.2.1 Generation Technologies

The selection of generation technologies used was based on currently deployed and demonstrated generation and emission reduction technologies. Below is a list of the actual technologies considered.

- Coal Fired Technologies:
  - Advanced super critical (ASC). This is a deployed technology using pulverised coal fuel and is superior to the conventional steam cycle (CSC).
  - ASC with flue gas desulphurisation (ASC/FGD). This technology is currently being deployed around the world.
  - ASC with FGD and CCS (ASC/FGD-CCS). CCS is a demonstrated technology.
  - ASC retrofitted with FGD and CCS (ASC/R-FGD-CCS). Retrofitting existing coal fired ASC technologies with FGD and CCS technologies provides an option for the coal fired power stations to continue operation beyond 2015 when the LCPD would otherwise force such stations to close.
  - Integrated gasification combined cycle (IGCC). This is a deployed technology.
  - IGCC with CCS (IGCC/CCS)
- Gas Fired Technologies:
  - Combined cycle gas turbine (CCGT). This is a deployed technology.
  - CCGT with CCS (CCGT/CCS).
- Wind Technologies:

- Onshore wind. Wind technology is deployed with a rapidly growing installed capacity.

- Offshore wind

– Nuclear Technologies:

- Pressurised water reactor (PWR). This is a deployed technology. The future of nuclear generation is surrounded by controversies over safety issues from the radioactive radiation from the stations and from the spent fuel.

Conventional Generation Technology Parameters

Table 5.1. Conventional generation technology characteristics

Technology	Heat Input coef.			Capacity	η	Avail.	Life
	a	b	c	[MW]		[%]	[years]
CCGT	12	3000	150000	100	58.0	85	35
CCGT/CCS	16	3100	155000	100	50.0	85	35
ASC	25	2900	450000	100	33.5	85	40
ASC/R-FGD-CCS	18	3200	450000	100	3.5	85	30
ASC/FGD	15	4800	460000	100	45.6	85	50
ASC/FGD-CCS	11	3700	600000	100	36.6	85	50
IGCC	10	2800	550000	100	44.5	85	35
IGCC/CCS	3	3500	550000	100	39.0	85	35
NUCLEAR	3	2800	480000	100	36.0	85	35

The heat input coefficients in Table 5.1 are those specified in equation 4.8 and the unit of energy is BTU when output is expressed in electrical kWh. Energy units conversions are given in Appendix D. *Avail.* is the availability of the technology, *Capacity* is the unit capacity used in the study and η is the HHV[21] efficiency expressed as a percentage. The heat input coefficients were selected to give roughly the given efficiencies at full load and reduced efficiency with part load operation. The heat input curves are shown in Figure B.5 and the heat rate curves are shown in Figure B.4 in Appendix B.

Table 5.2. Conventional generation technology further characteristics

Technology	CO2 coef.		MUT	MDT	Capital	O & M Cost	
	β	γ	[hour]	[hour]	$£/kW$	F [£/kW]	V [p/kWh]
CCGT	0.38	0.03	0	0	500	13	0.20
CCGT/CCS	0.38	0.03	0	0	590	9	0.17
ASC	0.84	0.04	3	2	1000	40	0.18
ASC/R-FGD-CCS	0.78	0.04	4	2	1400	24	0.25
ASC/FGD	0.82	0.04	4	1	960	17	0.17
ASC/FGD-CCS	0.84	0.04	3	1	1000	26	0.27
IGCC	0.62	0.02	2	1	1300	19	0.12
IGCC/CCS	0.62	0.02	3	2	1400	26	0.26
NUCLEAR	0.00	0.00	10	10	1800	56	0.00

CO_2 emission coefficients in Table 5.2 are as used in equation 4.11 and the unit is kg when power is expressed in MW. Figure B.6 in Appendix B show the relationship between the CO_2 emissions and output power for the fossil fired thermal technologies.

Intermittent Generation Technologies Parameters

The intermittent generation considered was wind and therefore there are no heat input parameters specified. The capital costs for onshore and offshore windfarms

[21]The Higher Heating Value (HHV) is the maximum potential energy released during complete oxidation of a unit of fuel. It includes the thermal energy recaptured by condensing and cooling all products of combustion.

were assumed to be 820£/kW and 1550£/kW respectively, fixed costs were assumed at 44£/kW and 46£/kW respectively and variable costs were assumed to be zero in both cases.

100 MW wind farm sizes were considered for both onshore and offshore. Ten wind speed time series were generated at hourly resolution for the entire year based on the Weibull distribution with the following parameters: scale parameter of 7m/s and the shape parameter of $1.4 + i/10$ where i is the series identity. The series are uncorrelated. The individual wind farms, the number of which was determined in the generation mix, were randomly assigned to any of the ten series.

To introduce seasonal variations in the wind speeds, the means of the wind speeds were modified for the four seasons according to the following expressions:

$$SummerMean_i = OriginalMean_i \times 0.6 \tag{5.1}$$

$$AutomnMean_i = OriginalMean_i \times 0.5 \tag{5.2}$$

$$WinterMean_i = OriginalMean_i \times 1.5 \tag{5.3}$$

$$SpringMean_i = OriginalMean_i \times 0.9 \tag{5.4}$$

To convert the wind speed to electrical power output, the online Danish Wind Industry Association Wind Turbine Power Calculator[22] was used to derive the per unit power curve in Figure 5.1. The actual data used to plot this figure is given in Table B.1.

Figure 5.2 shows the load duration curve for wind power production for a total installed wind capacity of capacity of 2000 MW.

[22]http://www.windpower.org/en/tour/wres/pow/index.htm

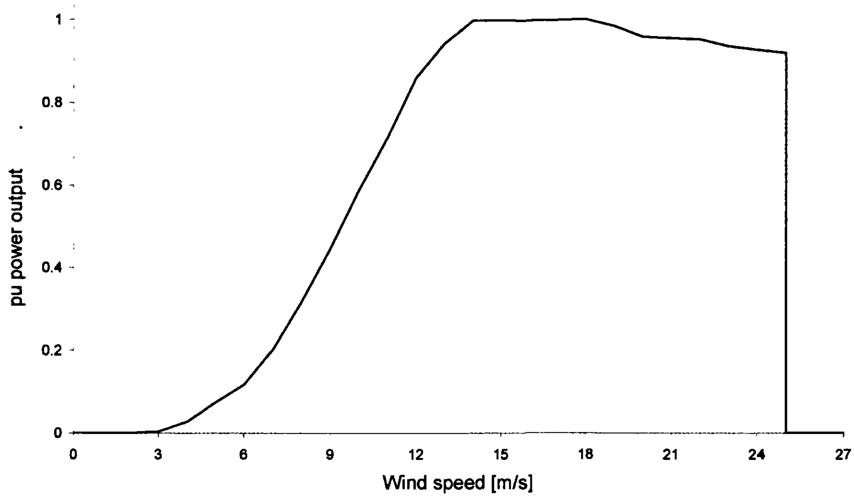


Figure 5.1. Wind turbine per unit power output curve. *Derived from: http://www.windpower.org/en/tour/wres/pow/index.htm.*

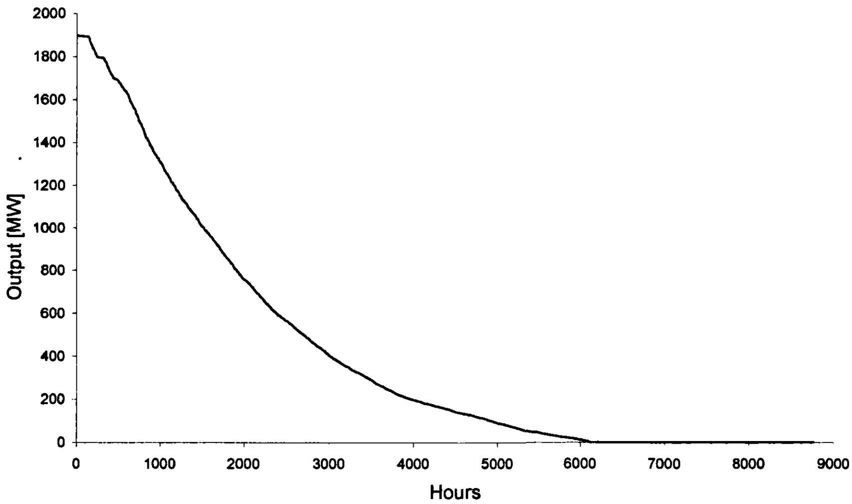


Figure 5.2. Load duration curve for wind power production

5.2.2 Load Data

Load data was obtained from RTS96 (1999) and modified to give a peak demand of 4,242 MW. Figure 5.3 shows typical daily load profiles for business and non business days for the four seasons of the year and Figure 5.4 shows the annual load duration curve for the load profile used in this study. The detailed load profile data is given in Tables B.1, B.2 and B.3.

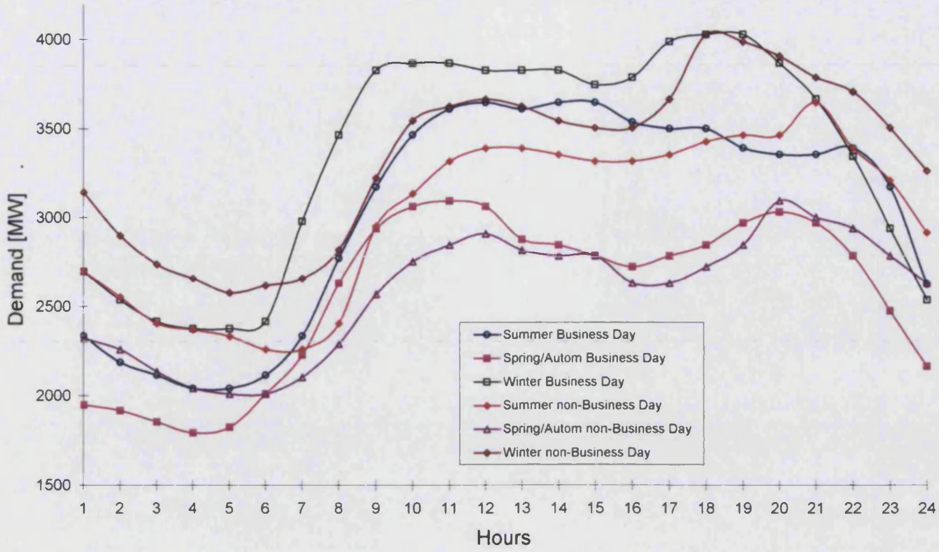


Figure 5.3. Seasonal system demand by sample day. *Source: IEEE Reliability Test System 1996.*

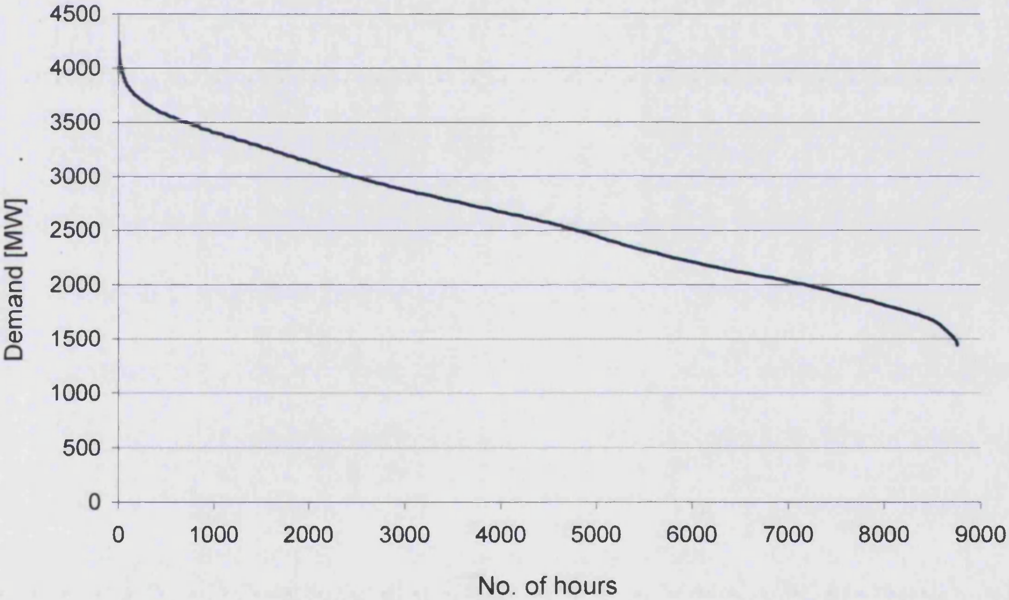


Figure 5.4. Load duration curve. *Source: IEEE Reliability Test System 1996.*

5.2.3 Costs

Fuel Price

Fuel price assumptions were based on current trends on the market. Depending on world events, these may increase or decrease. The simulation base case assumed gas a gas price of 40 pence per therm. Coal price was assumed at US$2.4 per GJ while nuclear fuel was assumed at US$1.8 per GJ. The actual fuel costs were determined according to the specific generation technology heat rates given in Table 5.1.

CO_2 Emission Costs

CO_2 costs vary according to the position of the emissions market. When the market is long, the price is low and vice versa. The study considered a base case of cost £0/ton of CO_2 (tCO_2) emitted into the atmosphere. The actual CO_2 emissions were determined according to the CO_2 emission functions and parameters specified in Table 5.2.

CO_2 Sequestration Costs

CO_2 sequestration technologies have been demonstrated but are yet to be deployed. Indicative costs are in the range of £8/t CO_2. It was assumed that the CO_2 recovery rate was 90%.

Capital Costs

Capital costs used for the different technologies are given in Table 5.2. In the simulations, these were considered as annuities calculated based on the economic lifetime of the technology (given in Table 5.1) and the interest rate.

Operating Costs

The operating costs consist of fuel fuel costs and operation and maintenance costs. Fuel costs have been addressed above. Fixed and variable operation and maintenance costs are given in Table 5.2. The variable costs were determined according to the production level for the year while the fixed costs were annuitised as with the capital costs.

Interest Rate

Interest rate on capital was assumed to be a flat rate of 6% per annum for the entire lifetime of the project.

5.3 Scenarios

There is a large number of factors that influence generation mix as discussed in Chapter 3. The influence of key factors and assumptions on the generation mix can be modelled through sensitivity analysis. Three cases were considered here as follows:

- **Base Case Scenario:** Gas cost was assumed at 40p/therm chosen against a background of average winter (Nov-Mar) gas prices for 2004/5 and 2005/6 of 32.67p/therm and 67.24p/therm respectively (National Grid, 2006). CO_2 costs were assumed at 0£/tCO_2. This represented a system where investment in generation and dispatch are not constrained by carbon dioxide emissions. The base case scenario was considered in two instances, one with the nuclear option and the other without. This was in recognition of the uncertainties surrounding the future of nuclear generation in future.

- **Green Scenario:** The cost of gas was maintained at 40p/therm as in the base case but the cost of CO_2 was assumed to be 20£/tCO_2. The CO_2 cost is higher than the current prices on the emissions market but it is expected that these prices will increase in future as it is likely that the emission allowances in the second phase of the Kyoto Protocol (2008 - 2012), will not be allocated free of charge as in the first phase.

– **Gas and CO_2 Price Sensitivities:** Due to the high volatility of the gas and CO_2 prices, sensitivity analysis was performed to determine the sensitivities of the generation mix solutions to these two. CO_2 prices were assumed to vary from 0£/tCO_2 to 40£/tCO_2 while gas costs were assumed to vary from 30p/therm to 100p/therm. The upper limit for the CO_2 prices was based on the expectation that environmental legislation will further tighten in the foreseeable future while the range for gas costs was based on the volatility observed on the gas markets as shown in Figure 5.5.

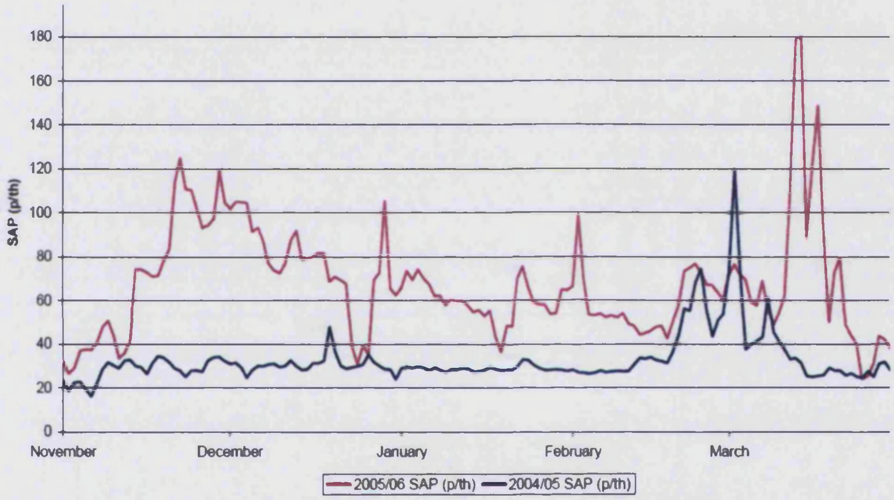


Figure 5.5. 2004/05 and 2005/06 System Average Prices (SAP) for gas. *Source: National Grid 2006*

5.4 Results

This section presents the results based on the scenarios described above. In the base case and the green scenarios, the optimal generation mixes were determined first with the nuclear option and then without. This was in recognition that the future of nuclear generation still hangs in the balance. In the subsequent sensitivity analysis, the nuclear option was not considered as it tended to overshadow other technologies due to its low operating costs and relative insensitivity to gas and emission price variations.

The energy supplied in all the scenarios is the same at 22.86 TWh and the total capacity varies due to differing availability rates for the selected technologies. The results are further discussed in Section 5.5.

5.4.1 Base Case Scenario

Gas cost: 40p/therm, CO_2 cost: 0£/tCO_2

Base Case Scenario with Nuclear

In order to arrive at the generation capacities for the optimal generation mix, the total generation costs for the candidate technologies were compared with each other at different running hours as described in Section 4.4.3. Figure 5.6 graphically shows how the generation mix capacities were determined. The load duration curve used is that shown in Figure 5.4.

In the first instance, the ideal capacities were determined according to equations 4.20 and 4.21 as follows:

$$\begin{aligned} CAP_{NUCLEAR} &= Demand(h3) \\ &= 1641MW \end{aligned} \tag{5.5}$$

$$\begin{aligned} CAP_{ASC} &= Demand(h2) - Demand(h3) \\ &= 2291 - 1641 \\ &= 650MW \end{aligned} \tag{5.6}$$

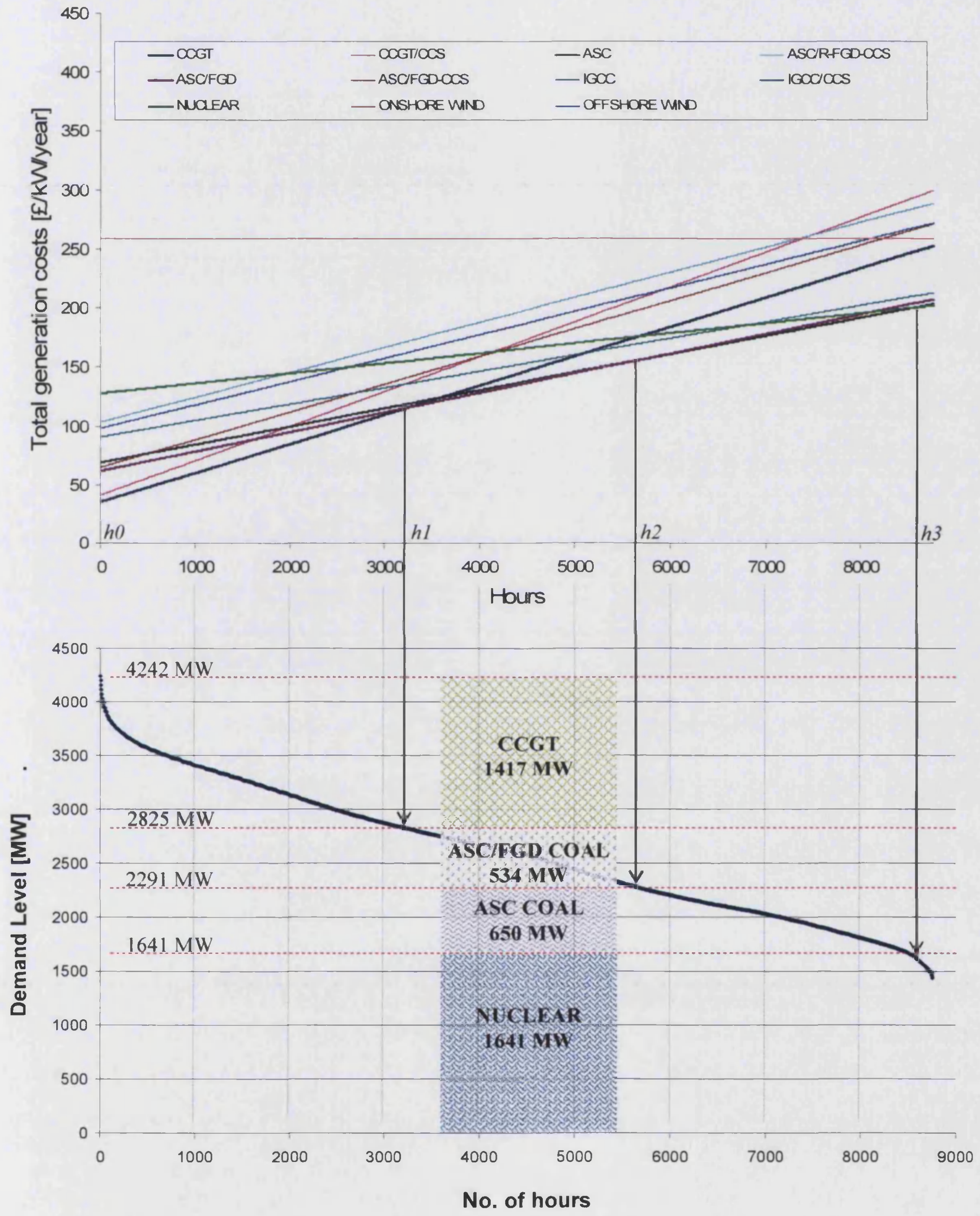


Figure 5.6. Graphical illustration of generation capacity derivation

$$\begin{aligned} CAP_{ASC/FGD} &= Demand(h1) - Demand(h2) \\ &= 2825 - 2291MW \\ &= 534MW \end{aligned} \tag{5.7}$$

$$\begin{aligned} CAP_{CCGT} &= Demand(h0) - Demand(h1) \\ &= 4242 - 2825MW \\ &= 1417MW \end{aligned} \tag{5.8}$$

where $h0$ to $h1$ are the running hours at which the total generations cost graphs for the different technologies forming the lower bound intersect in the cost comparison plot in Figure 5.6. Accounting to technology unavailabilities (see Section 4.4.4), equation 4.22 was applied to give the following modified capacities based on mean availability of 0.85 for each of the technologies.

$$\begin{aligned} CAP'_{NUCLEAR} &= \frac{CAP_{NUCLEAR}}{MeanAvailability_{NUCLEAR}} \\ &= 1641 \div 0.85 \\ &= 1931MW \end{aligned} \tag{5.9}$$

where $CAP'_{NUCLEAR}$ is the modified nuclear capacity. Repeating the same process for the other three technologies gives the following modified capacities:

$$\begin{aligned} CAP'_{ASC} &= 765MW \\ CAP'_{ASC/FGD} &= 628MW \\ CAP'_{CCGT} &= 1667MW \end{aligned}$$

The modified capacities were then discretised by rounding off to the nearest 100MW, being the generic unit capacity selected for purposes of this analysis. Table 5.3 shows the final capacities constituting the optimal generation mix as well as their proportions.

Table 5.3. Generation mix capacities for the base case with the nuclear option.

Technology	Nuclear	ASC	ASC/FGD	CCGT
Capacity [MW]	1900	800	600	1700
Proportion [%]	38	16	12	36

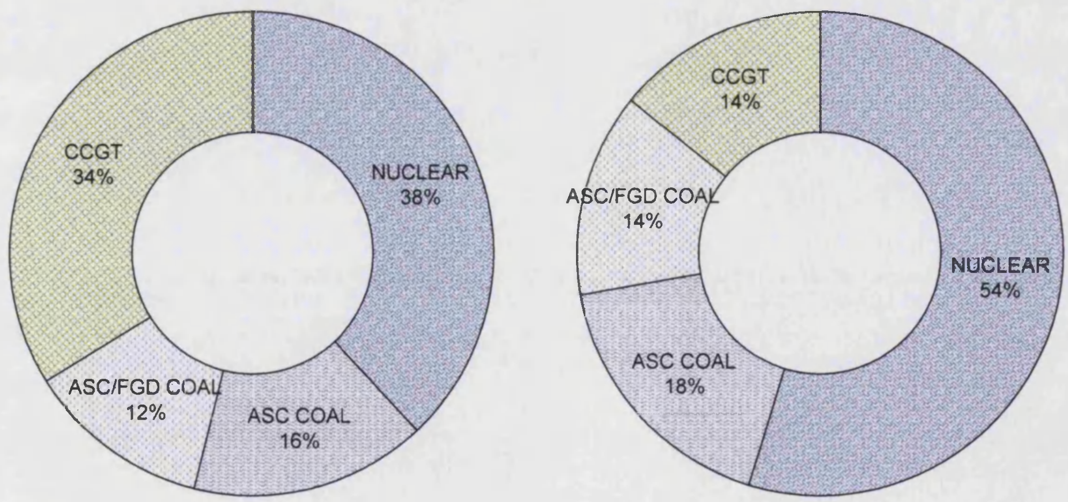
The energy and emission contributions from the technologies were determined by running production simulation based on the determined capacities and the annual load profile. The actual operation costs were also determined from this simulation. For each scheduling period, the energy contribution, emission contribution as well as the individual technology operating costs including fuel costs were determined and then added together to determine the annual quantities. Table 5.4 shows this aggregation process for the technology energy contributions.

Figure 5.7(a) shows the capacity contributions of the generation technologies to the generation mix from Table 5.3 while Figure 5.7(b) shows the respective energy contributions or the 'fuel mix' from Table 5.4. The total installed generation capacity is 5,000 MW. Nuclear has the largest energy share of 54%, followed by coal based technologies (ASC and ASC/FGD) with an energy share of 32% and finally CCGT with 14% energy share.

Out of the eleven candidate technologies considered, the four shown in Figure 5.7 form the optimal mix under the conditions simulated. According to Figure 5.7(b), nuclear supplies the bulk of the base load while on the other extreme CCGT provides peaking capacity. This is consistent with power system operation theory and practice since nuclear is largely inflexible and CCGT is flexible, with short start up and shut down times and high output power ramp rates. Additionally variable costs for nuclear generation are low compared to CCGT as shown in Figure 5.6.

Table 5.4. An illustration of how the annual energy contribution is aggregated for each technology in the generation mix.

Period	Production [MWh]			
	Nuclear	ASC	ASC/FGD	CCGT
1	1900	145	60	170
2	1832	80	60	170
3	1760	80	60	140
4	1500	296	114	150
5	1400	322	236	170
6	1200	454	381	150
7	1400	576	499	160
.	.	.	.	.
.	.	.	.	.
.	.	.	.	.
T - 1	1200	656	476	150
T	1500	368	124	150
Annual	12.5GWh	4.02GWh	3.10GWh	3.27GWh
Contribution	54%	18%	14%	14%



(a) Capacity Contribution (b) Energy Contribution

Figure 5.7. Generation mix for base case with the nuclear option

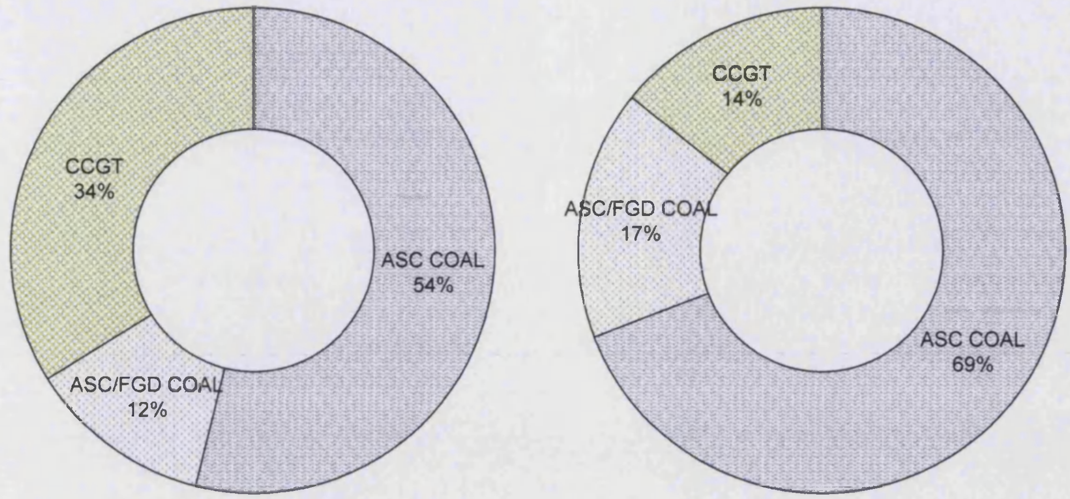
A gentle gradient for the generation cost line implies low variable costs since the *y-axis* intercept represents lumped annual fixed costs for each technology.

Production Simulation Model Selection

A generation production simulation case study was conducted to determine the market structure that gives optimum performance of the generation mix based on levelised generation costs and emissions. The results of the case study are presented in Section 5.4.4. The centralised structure performed better than the decentralised structure in all the variants of the decentralised structures modelled, both in terms of generation costs and emissions. The centralised production simulation model was therefore adopted in the evaluation of the base case generation mix performance and for all the generation mixes in the subsequent scenarios and sensitivity analyses. The effect of varying the number of GENCOs was also investigated.

Base Case Scenario without Nuclear

Figure 5.8 shows the capacity and energy contributions to the generation mix for the base case scenario without the nuclear option. The detailed process of arriving at the generation mix is omitted in this case and all the subsequent cases for clarity. It is basically the same as that presented for the base case. Total installed generation capacity is 5,000 MW. Excluding the nuclear option is achieved by ignoring the 'nuclear plot' in Figure 5.6. This leaves ASC to meet all the base load, with the other two technologies, i.e. ASC/FGD and CCGT, largely unaffected. This shows that in the absence of nuclear power, if there are no emission costs, the least cost generation mix would be dominated by ASC COAL technology. This is mainly due to its relatively cheap fuel costs.



(a) Capacity Contribution (b) Energy Contribution

Figure 5.8. Generation mix for base case without the nuclear option

5.4.2 The Green Scenario

Gas cost: 40p/therm, CO_2 cost: 20£/tCO_2

Green Scenario with Nuclear

The total installed generation capacity is 4,900 MW. When the CO_2 cost is increased to 20£/tCO_2 and the nuclear option is included, the ASC based coal technologies are rendered unattractive due to high their high emissions that expose them to the emissions cost. This is shown in Figure 5.9.

As shown in Figure 5.10(a) and Figure 5.10(b), nuclear dominates the generation mix. In practice, the need to have a diverse energy mix may mean that even if nuclear is attractive, its capacity may have to be limited in order to give way to other sources of energy. Besides, proven nuclear ore deposits are finite, therefore over-dependence on nuclear is not desirable.

It is interesting to note that CCS technology becomes attractive with CCGT when the cost of emissions increases to 20£/tCO_2. This together with the disappearance of

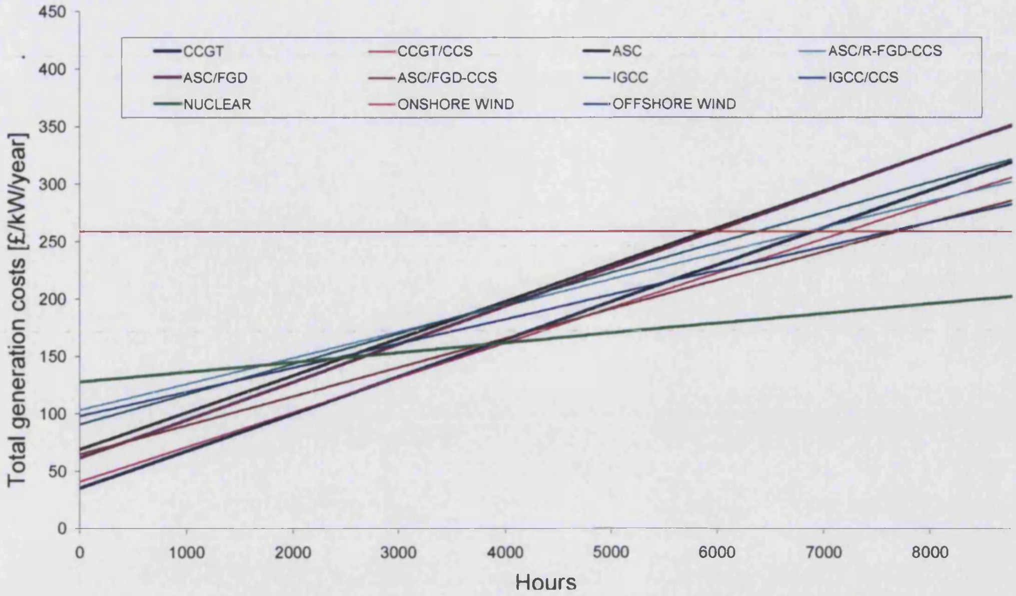
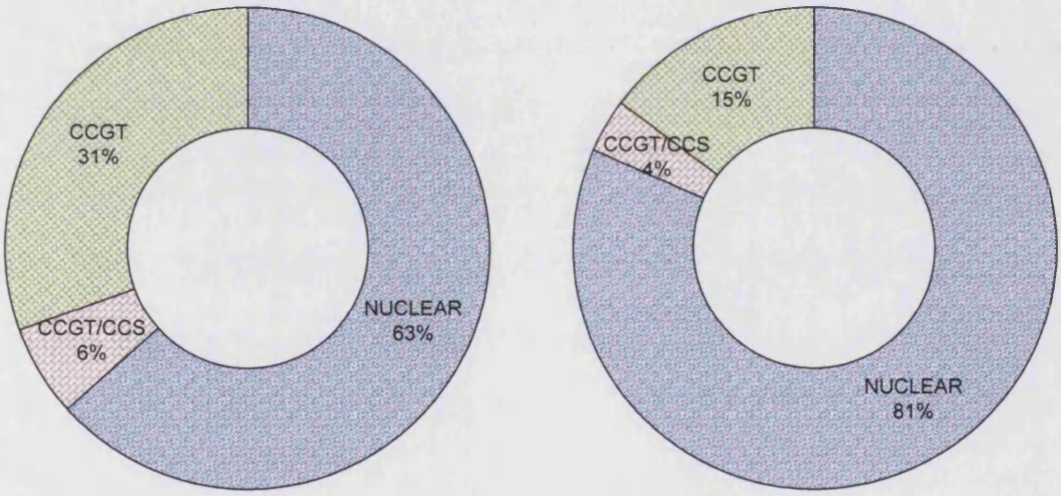


Figure 5.9. Domination of generation mix by nuclear



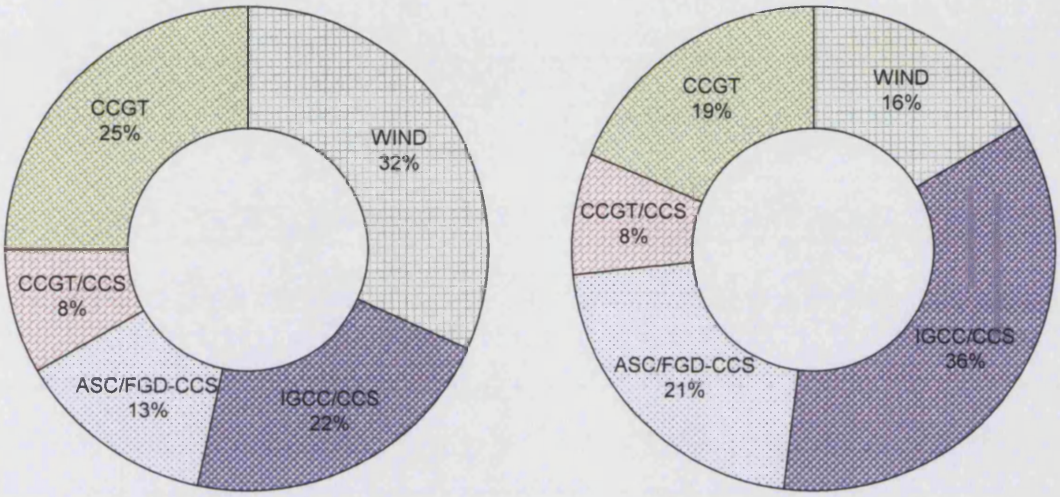
(a) Capacity Contribution (b) Energy Contribution

Figure 5.10. Generation mix for the 'green' scenario with the nuclear option

ASC COAL and ASC/FGD which are more polluting mean that the resulting generation mix produces less emissions while meeting the same energy requirements. Table 5.5 shows how the costs and emissions change between the two scenarios considered so far.

Green Scenario without Nuclear

Excluding the nuclear option brings WIND, ASC/FGD-CCS and IGCC/CCS into the generation mix in addition to CCGT and CCGT/CCS in Figure 5.10. The resulting generation mix with a total installed generation capacity of 6,000 MW. is shown in Figure 5.11. Clean coal technologies take up a sizable energy share; IGCC/CCS



(a) Capacity Contribution (b) Energy Contribution

Figure 5.11. Generation mix for the 'green' scenario without the nuclear option

– 36% and ASC/FGD-CCS – 21%, giving a total energy contribution of 57%. CCGT appears in all cases considered so far due to its low emissions hence it is less sensitive to changes to emission costs. Wind generation becomes attractive as a result of the increased CO_2 cost. The load factor of the wind generation is 50%, which is on the high side. The load factor depends on the underlying wind characteristics. An assumption was made that wind would generate power as long as the sufficient wind was blowing. It was also assumed that there would be sufficient transmission capacity to wheel the energy generated by wind.

Table 5.5 shows the cost and emission performance of the generation mixes under the two scenarios considered so far. Generally, it can be concluded that the generation mix solution is sensitive to the price of emissions and that the emissions and the unit generation costs are affected by the resulting shift in generation mix. While the generation mix solutions incorporating the nuclear option result

Table 5.5. Cost and emission performance of generation mixes under base case and 'green' scenarios

	Base Case Scenario		Green Scenario	
	with nuclear	no nuclear	with nuclear	no nuclear
Unit Cost [p/kWh]	3.48	3.26	3.71	3.62
Emissions [kgCO_2/kWh]	0.31	0.77	0.06	0.11

in slightly higher unit costs, the resultant CO_2 emissions in absolute terms are very low compared to generation mix solutions without the nuclear option. However, the tabulated results will change if the nuclear capacities are capped to maintain a diverse generation mix.

The variation of emissions from the base case to the green scenario is -80% for the case with nuclear and -86% for the case without the nuclear option. Corresponding changes in generation costs are +7% and +11% respectively. This shows that with the nuclear option the reduction in emissions is higher than that for the case without nuclear. However, the increase in generation costs for nuclear is higher. The drop in emissions per given increase in unit generation costs for the case with nuclear is 11% while that for the case without nuclear is 8%. This shows that including the nuclear option in the technology mix has a higher benefit in terms of emissions reduction per given increase in costs.

5.4.3 Sensitivity Analysis

The sensitivity analysis on the generation mix was based on gas costs varying from 30p/therm to 100p/therm in steps of 10p/therm and emission costs varying from 0£/tCO_2 to 40£/tCO_2 in steps of 5£/tCO_2. These sensitivity studies do not include the nuclear option as it would effectively mask other technologies (see Figure 5.10) since its variable or fixed costs are independent of gas and emissions costs and the variable costs are low compared to the other technologies.

In the previous cases, the actual capacities were given, with pie charts showing the relative proportions of the capacities and their energy contributions. However, in order to enable comparisons between different cases in the sensitivity analysis, the capacity and energy contributions were presented as bar graphs, with the actual detailed capacity and energy contribution values given in Appendix C.

Figure 5.12 shows the shift in the generation mix for emission costs up to 20£/tCO_2. The gas price was varied for each level of emission costs to show the impact of gas costs for a given level of emission costs. Coal based ASC is attractive for low values of emissions costs, i.e. below 10£/tCO_2. The insensitivity of the ASC COAL capacity to gas price variation is due to the fact that it forms cheaper part of the base load. CCGT exists throughout these cases and is the most sensitive to gas prices as it is dependent on the gas fuel. CCGT/CCS is attractive when the price of emissions is higher than 10£/tCO_2 and the gas price is low. Wind generation becomes attractive for emission costs higher than 5£/tCO_2.

Figure 5.13 shows the energy contributions of the various technologies. As with capacities, CCGT and CCGT/CCS are the most responsive to gas cost variations since they are the only technologies using gas. The trend in this figure closely resembles that of the capacities in Figure 5.12. Up to emissions costs of 10£/tCO_2, ASC/FGD

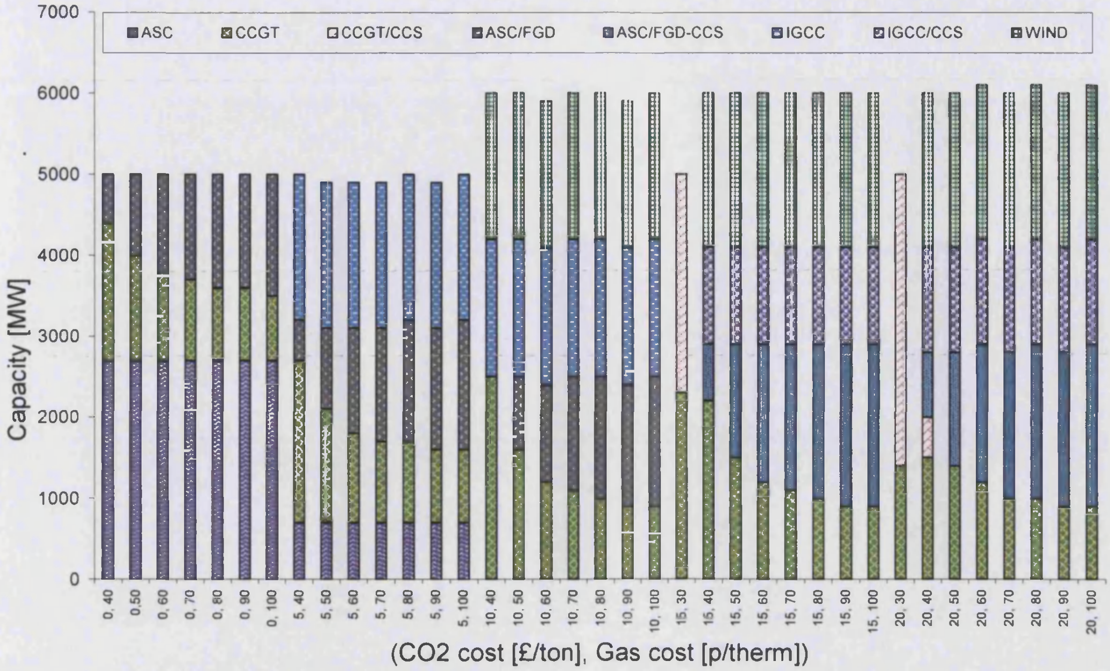


Figure 5.12. Generation mix capacities for emission costs up to 20£/tCO_2.

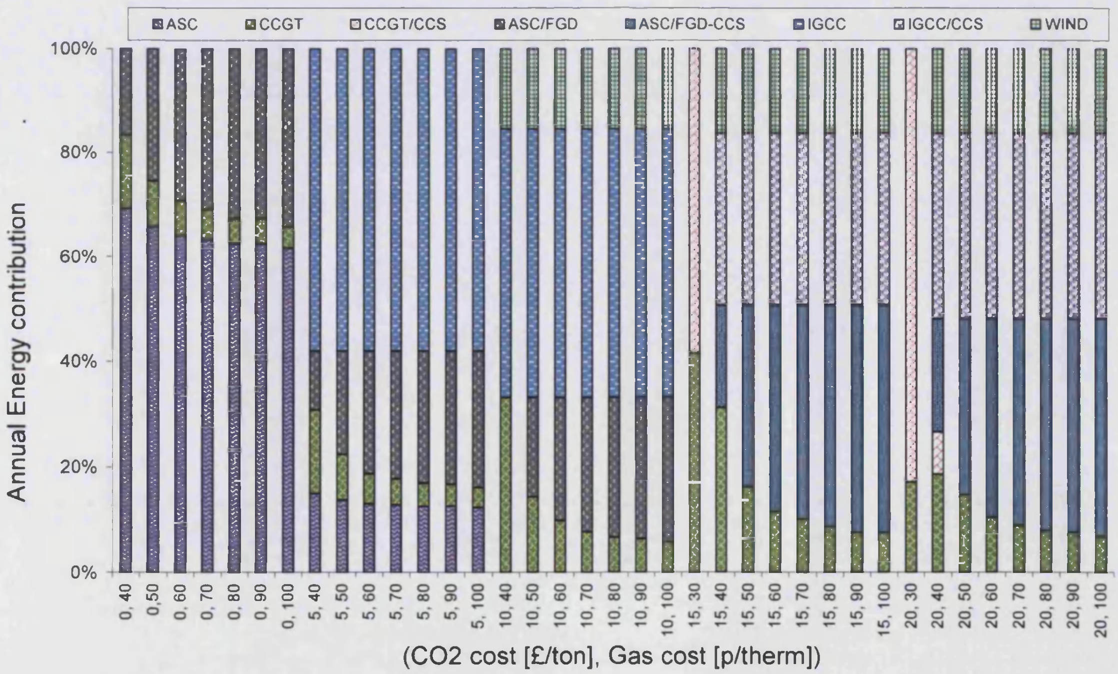


Figure 5.13. Generation mix energy contributions for emission costs up to 20£/tCO_2.

displaces CCGT according to energy contributions, the displaced amount increasing with increasing gas costs. Above emission costs of 15£/tCO_2, ASC/FGD-CCS takes over from ASC/FGD. This is in direct response to increasing emission costs.

It is also interesting to note that IGCC/CCS also takes over from IGCC above emission costs of 10£/tCO_2. Generally, from Figures 5.12 and 5.13, it can be seen that technologies with CCS become more attractive alongside wind generation as the emission costs increase.

Figure 5.14 shows the generation mix capacity contributions for emission costs ranging from 25£/tCO_2 to 40£/tCO_2. Figure 5.15 shows the energy contributions corresponding to the capacities in Figure 5.14. Both the capacity and energy trends continue smoothly from the previous set of figures (Figures 5.12 and 5.13). It can

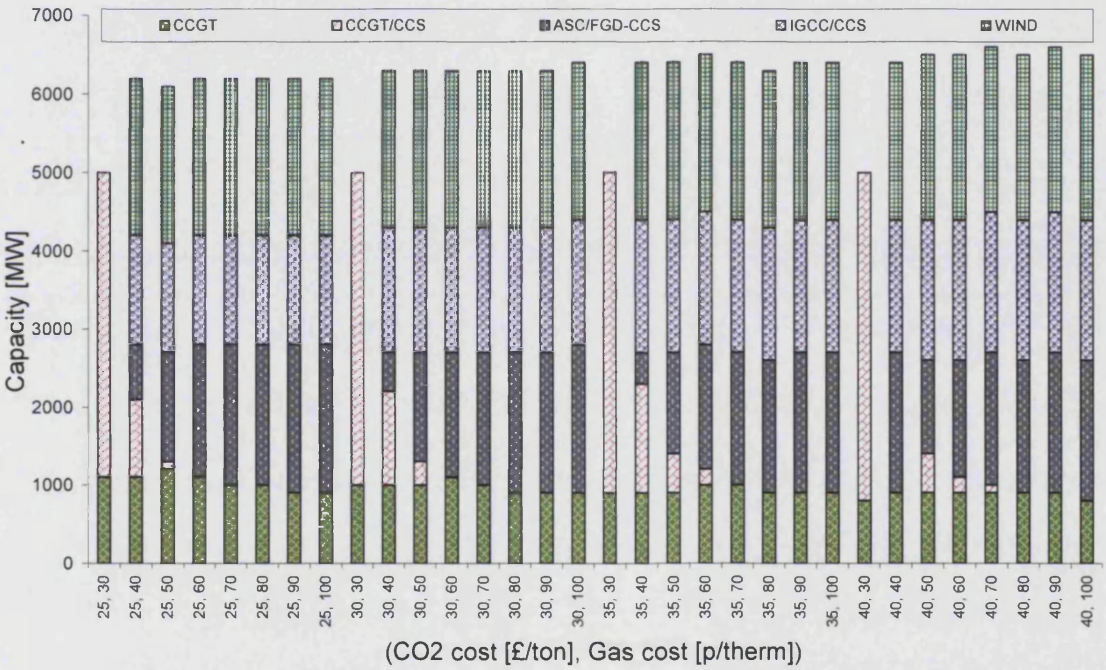


Figure 5.14. Generation mix capacities for emission costs in the range 20£/tCO_2 to 40£/tCO_2.

be noted that the energy share of CCGT gradually decreases with increasing emission costs, giving way to technologies with CCS, i.e. ASC/FGD-CCS. 'Clean' coal technologies, IGCC/CCS and ASC/FGD-CCS, supply a large share of the energy (around 75%) and wind provides about 18% of the total energy in most of the cases. The few cases with CCGT and CCGT/CCS constituting the entire generation mix

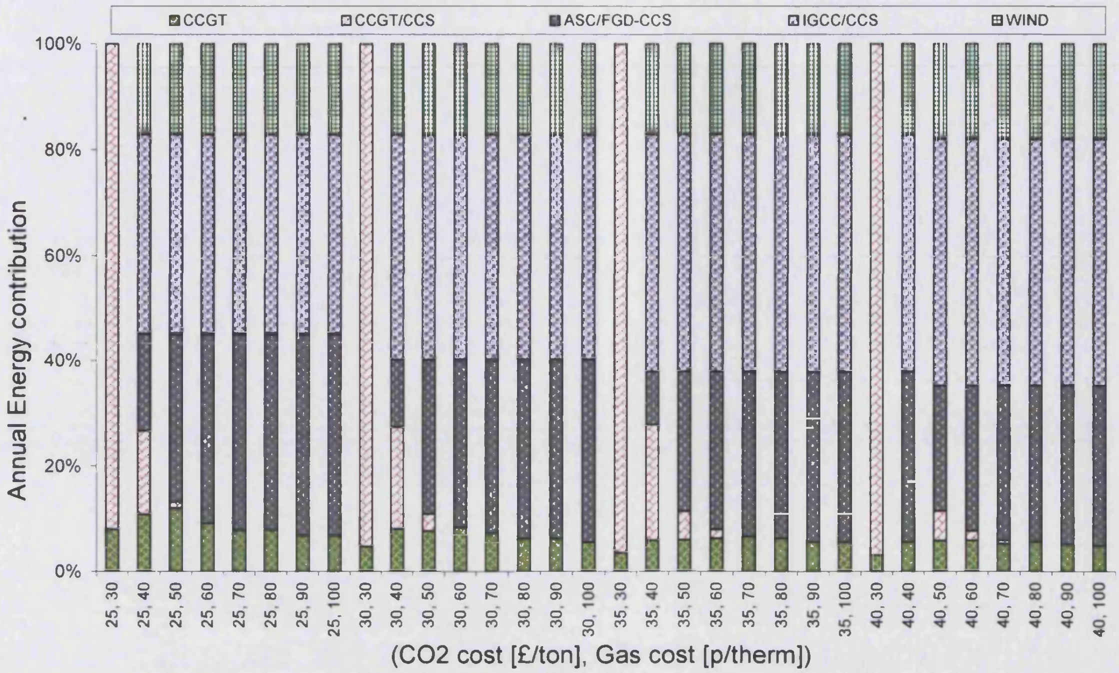


Figure 5.15. Generation mix energy contributions for emission costs in the range 20£/tCO_2 to 40£/tCO_2.

can be disregarded on the basis of lack of diversity which could have serious security implications especially given the dependance on gas imports in many countries and the volatile gas prices.

So far, the impact of emission and gas cost fluctuations on the generation mix has been presented. It is important to know how the unit generation price varies in the sensitivity study. Figure 5.16 is a surface plot of the unit cost against emission and gas costs. Generation unit costs are minimum for minimum gas and CO_2 emissions costs at 2.84p/kWh. This increases monotonically to 4.23p/kWh at maximum gas and CO_2 emission prices. The surface is generally evenly gentle except for a rather sharp change in gradient at a gas cost of 40p/therm and a relatively gentle change in gradient at a carbon cost of 15£/tCO_2.

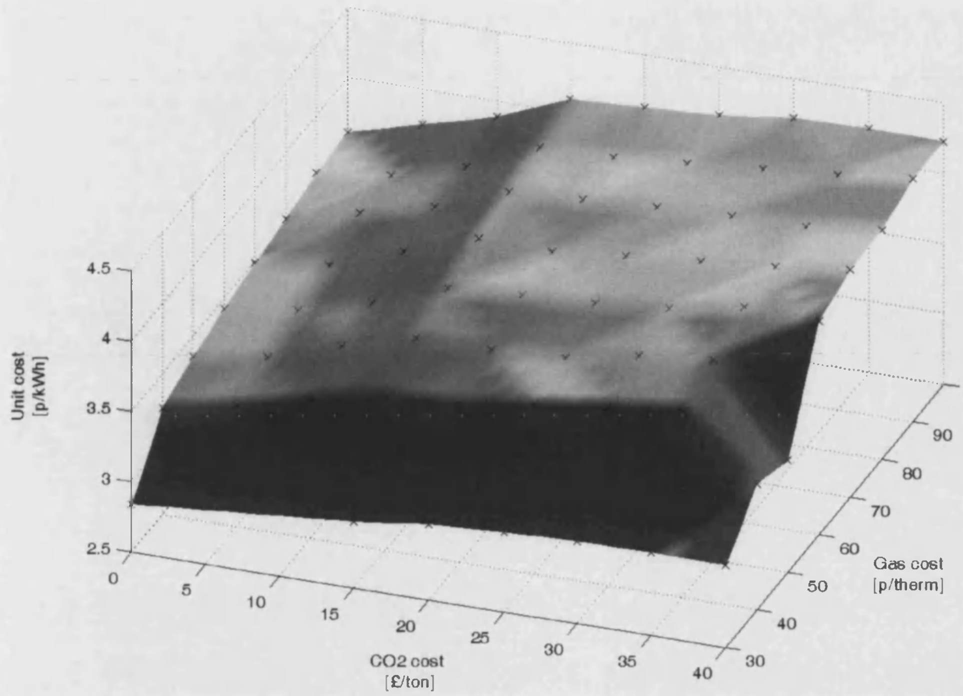


Figure 5.16. Sensitivity of generation unit costs to variations in gas and emissions prices.

The gradient change at 40p/therm gas price is due to the unrealistic generation mix consisting only CCGT and CCGT/CCS which result in relatively cheap unit generation costs of below a gas price 40p/therm. At carbon costs of 15£/tCO_2, the gradient change is due to the introduction of technologies with CCS as replacements of non CCS technologies (IGCC and ASC/FGD). The surface gradient becomes more gentle after these two cost levels (40p/therm gas cost and 15£/tCO_2 emission cost) due to the use of the use of CCS technologies whose benefits in terms of avoided emission costs outweigh their costs.

Figure 5.17 shows the sensitivity of CO_2 emissions to variations in emission and gas costs. At low emission costs (0£/tCO_2 – 10£/tCO_2), an increase in gas costs results in increased CO_2 emissions due to displacement of 'cleaner' CCGT by ACS/FGD which is 'dirtier'. As the emission costs increase beyond 10£/tCO_2, the level of CO_2 emissions rapidly drops from around 0.8kgCO_2/kWh to less than 0.1kgCO_2/kWh.

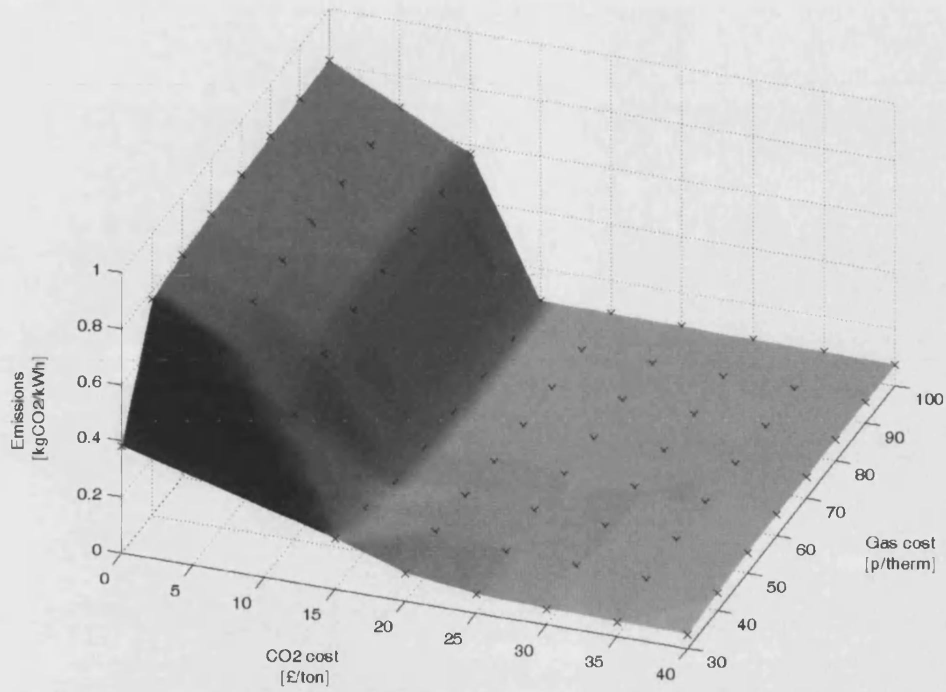


Figure 5.17. Sensitivity of CO_2 emissions to variations in gas and emissions prices.

This was attributed to wind generation and CCS technologies that dominate the lower part of the emissions surface.

The surface plot of Figure 5.18 shows the emissions captured by CCS technologies. The plot confirms that the large drop in emissions shown in Figure 5.17 is mainly due to the CCS technologies.

Coal technologies could still play a significant role in a low carbon generation system if they are used with CCS. However, for these technologies to be viable, emission costs have to be sufficiently high (in excess of 10£/tCO_2). Additionally, wind generation has an important role to play as well since it consistently appears in all cases where the emission cost is 10£/tCO_2 and above.

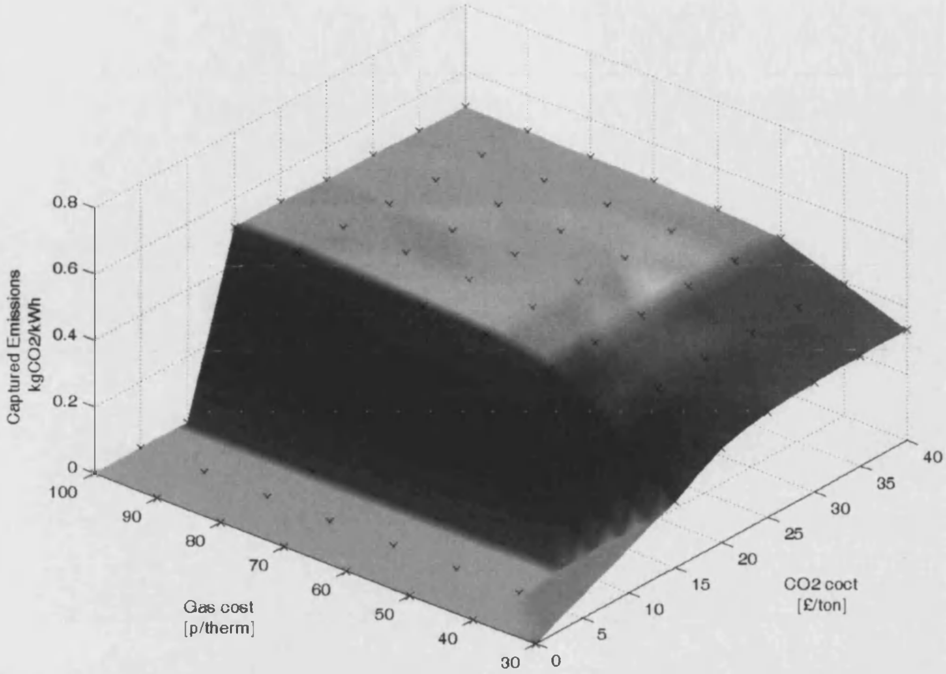


Figure 5.18. Sensitivity of CO_2 emissions captured by CCS technologies to variations in gas and emissions prices.

5.4.4 Comparison of Production Models

In the first instance, a comparison was made between the centralised generation production model and decentralised models in general. This enabled the selection of the centralised model for use in the production simulation in the generation mix problem. In the second instance, a comparison between decentralised models with different number of GENCOs was made. This serves to demonstrate that market rules that govern the maximum permissible generation capacity for a GENCO can have a bearing on the performance on the operation of the system generation in the short term and consequently in generation investment in the longer term.

Centralised versus Decentralised Generation Production Models

The implementation of production model based on centralised and decentralised market structures was introduced in Section 4.4.8. Figure 5.19 shows the levelised generation costs for the centralised simulation and that for the decentralised simulation based on the base case generation mix. Additionally, for the decentralised simulation, the 'income' from the energy sales are shown based on the summation of the individual GENCO accepted bids. The value of accepted bids can be considered as the component of the GENCO income in respect of the generating units' investment and production simulation i.e. GENCO overhead costs were not modelled. Each GENCO bids according to its cost function that is determined according to its generation portfolio, as described in Section 4.4.7 under the GENCO model description. This analysis is concerned with the overall generation system performance rather than that of the individual generation portfolios of the GENCOs.

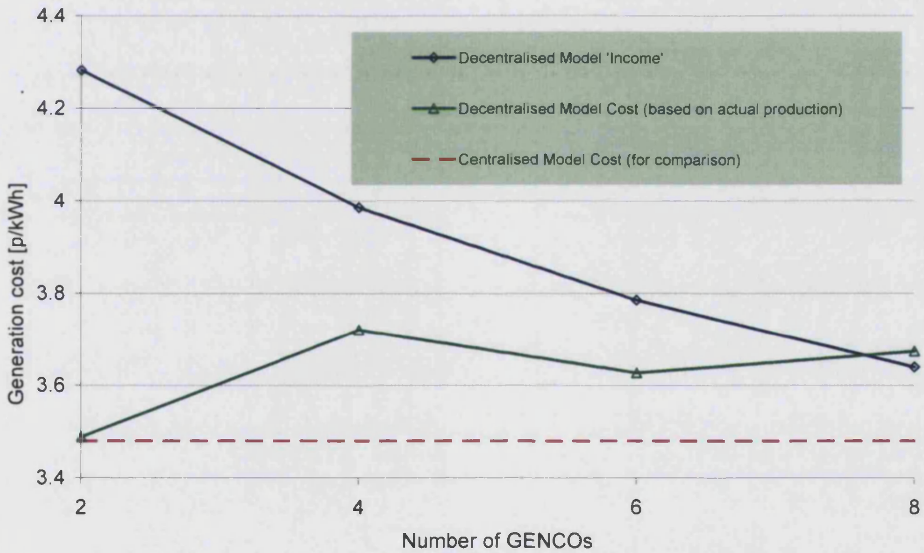


Figure 5.19. Generation cost performance comparison of centralised and decentralised Production Simulation Models.

Table 5.6 gives the cost and emission performances of the different decentralised production simulations. These are also compared against the cost and emission performance of the centralised generation production simulation of 3.48 p/kWh and 0.31 $kgCO_2$/kWh respectively.

Table 5.6. Summarised results for centralised and decentralised production simulations.

No. of GENCOs	Costs [p/kWh]		Emissions
	Actual	Bids	[$kgCO_2$/kWh]
2	3.49	4.28	0.38
4	3.72	3.99	0.50
6	3.63	3.79	0.48
8	3.67	3.64	0.47

The system emission performance for the centralised and decentralised models is shown in Figure 5.20. The figure is based on data from Table 5.6

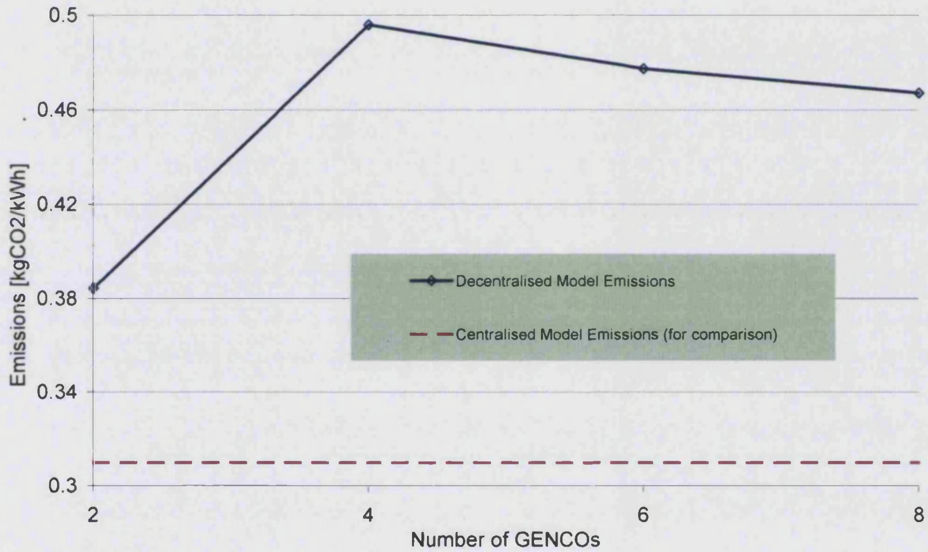


Figure 5.20. Emission performance comparison of centralised and decentralised Production Simulation Models.

For purposes of comparison between centralised and decentralised optimisation models, the total generation costs based on the actual production are compared. It can be seen from Figure 5.19 that the centralised model outperforms all the modelled decentralised cases. This is expected since the global optimum is not necessarily a combination of several local optima of the individual generation portfolios from the different GENCOs. In the later, the solution is likely to be sub-optimal.

It is not sufficient to just consider costs here since the other very important performance indicator is the total system emissions. The emission comparison is shown in Figure 5.20. Again, as in Figure 5.19, the centralised case outperforms all the decentralised cases modelled. For this reason, the production simulation for all the scenarios studied were based on the centralised case as it gave the optimal solution. Apart from the determined generation mix being used as a reference in market design, its production performance can also be used as a benchmark to measure the effectiveness of market operation of the power system for the given generation mix. Thus it is important for the market to drive the generation capacity mix in the 'right' direction as well as the operation of that generation mix.

Varying the Number of GENCOs

Four cases of decentralised production model simulations were investigated. The number of GENCOs was varied from 2 through 8 in steps of 2. All of them were based on the base case generation mix. The generation capacity shares for the individual GENCOs are summaries in Table 5.7. The actual generation capacity distributions by technology for the different cases are given in Tables B.2 to B.5 in Appendix B.

Table 5.7. GENCO generation capacity shares for the 4 decentralised cases modelled.

No. of GENCOs	Capacity shares [%]	Average capacity share [%]
2	$44, 56$	50
4	$20, 24, 26, 30$	25
6	$16 \times 4, 18 \times 2$	16.7
8	$12 \times 6, 14 \times 2$	12.5

When the number of GENCOs is increased, their capacity shares are reduced as the total generation capacity is maintained constant. In Figure 5.19, the 'income' plot is the total value of supply contracts secured by the all the GENCOs in the system. As mentioned earlier, the GENCO bids are based on the aggregate cost function for the generation portfolio, constructed according to the installed capacities fixed and variable costs, expected number of running hours per year as well as the mean availability (equations 4.27 and 4.26. This forms the basis of the initial bidding function of each GENCO. With adaptive GENCO agents, the GENCOs would then modify these functions so as to maximise their profit. Strategic bidding for GENCOs was not modelled as it is out of scope of this study. Since the aggregate cost functions for all GENCOs were based on the same formulation, the 'incomes' for the decentralised simulations with different numbers of GENCOs can be directly compared to give an indication of the opportunity that exists to maximise profit.

In the decentralised environment, the generation costs seen by the consumers are those represented by the 'income' plot and not the actual costs incurred in respect of capital and operation of the generation plant. The difference between the 'income' and the actual costs represents the 'profit'. It is important to note that the terms income, actual cost and profits here only related to the technical operation of the generation portfolios and not other costs related to the business e.g. license fees, use of network charges, insurance fees and other management overheads. In practice, all these costs are incorporated into the bidding formulations.

Figure 5.19 shows that for 2 GENCOs, the actual generation costs are only slightly higher than those for the centralised case i.e. 3.49p/kWh versus 3.48p/kWh. However, the overall GENCO income is very high compared to the actual cost, that is, 4.28p/kWh versus 3.48p/kWh. Since the energy contracts are secured in advance of the actual production, the actual production costs can not be known with certainty at the time of establishing the contracts. The tendency by the GENCOs would then be to charge more than what they estimate to incur in the production of their expected sales in order to make a profit. This tendency to maximise profit is mitigated by competition in the generation industry. However if for very few GENCOs, say two of them, with significantly large generation capacity shares it is relatively easy for them to collude in order to keep their incomes high, rendering competition ineffective. This is conceivable since each of the GENCOs can manipulate its generation output to create an artificial shortage, thereby pushing the prices high.

With 4 GENCOs, the actual generation cost increases from 3.49p/kWh with 2 GENCOs to 3.72p/kWh due to individually optimised generation portfolios resulting in a suboptimal solution. The 'income' drops from 4.28p/kWh with 2 GENCOs to 3.99p/kWh. This shows that the estimation of the actual production costs gets more accurate compared to the case with 2 GENCOs. The difference between the income and the actual cost drops from 0.79p/kWh ($= 4.28 - 3.49$) to 0.27p/kWh ($= 3.99 - 3.72$) with 2 and 4 GENCOs respectively. With reduced market share for the individual GENCOs (see Table 5.7), the ability to abuse market power is reduced and thus it is more difficult for the GENCOs to raise their prices to match profit levels with fewer GENCOs.

The difference between 'income' and actual costs drops further with 6 GENCOs i.e. from 0.27p/kWh with 4 GENCOs to 0.16p/kWh. Thus using the same aggregate cost function formulation, the opportunity to make profit reduces with increasing number of GENCOs. Although still able to make a profit, the pressure on the GENCOs to minimise their costs is increased, thus increasing the overall market efficiency. It is interesting to note that using the same formulation of the aggregate cost function for a higher number of GENCOs, the ability to recover costs disappears. This shows that there is a certain capacity share below which it is not economical to operate a generation portfolio. Of course in practice, the GENCOs would attempt to inflate their prices to operate at a profit but competition would be stiff. Those entities that fail to break even would be stranded and bought up by others that are doing well, thereby reducing the number of GENCOs and increasing the average GENCO capacity share. Clearly, the number of GENCOs or the maximum permissible individual GENCO generation capacity can have an impact on the operational performance of the market.

The operation of the system generation provides the vital economic signals that investors need when making decisions to invest in generation capacity. The prospect of making profit in the generation business is one of the most important factors considered. If this condition is met, the investor would then have to determine those generation technologies that have the minimum overall generation costs or precisely, those that present the best opportunity to maximise profit. Therefore in market design, it is critical to ensure that the structures and rules are designed for a specific range of target generation mixes to ensure their optimum operation as well as to attract investment in the desired generation technologies. Market design is out of scope of this thesis.

5.5 Discussion of Results

In real power systems, the incumbent generation mixes are not necessarily optimal in terms of economic and environmental sustainability. In the deregulated market environment, generation planning is not centralised. It is left to the investors to invest in technologies that make sound business cases. Market design therefore plays a pivotal role in providing appropriate signals to guide investment into a sustainable generation mix. The methodology developed allows the market designer to determine the combination of generation technologies that will deliver appropriate economic and environmental performance. This then forms part of the basis against which to formulate price signals, incentive schemes and policy on market design in order to come up with effective markets.

The presented methodology is heavily reliant on input data and assumptions. Critical data includes the characteristics of generation technologies, fuel and emission price forecasts, interest rates as well as the demand profiles. Sensitivity analysis allows the selection of a robust solution by choosing a solution on a stable part of the solution surfaces for example in Figures 5.16 and 5.17. The generation mix solutions on the relatively flat part of the surface (Gas cost greater than 40p/them and CO_2 cost greater than 15£/tCO_2) result in low emissions of CO_2 at a marginally lower cost (due to the gentle gradient compared to the areas outside this region).

The solutions around the central region of the desired solution are robust to price variations therefore should be able to deliver sustainability in electricity generation in the face of a relatively wide range of input variations. Table 5.8 shows the generation mix solutions in the central area of the solution surface in Figures 5.16 and 5.17. The six solutions are consistent with regards to the technologies and their respective capacities. Any of the generation mix could be chosen or some aggregation can be performed according to the mean or median capacity by technology.

In a full study, the sensitivity analysis would include more variables than the ones varied here. For example, the following can be varied: capital costs, operating costs, fuel costs other than gas, interest rates, technology availabilities, etc. The selection of the final solution would depend on the variables selected to be the key performance indicators for the generation mix. In this study, the performance indicators are the unit generation cost and CO_2 emissions.

Table 5.8. Generation mix solution forming the central region of the solution surface (Figures 5.16 and 5.17)

Costs		Capacity [MW]				
£/tCO_2	p/therm gas	CCGT	ASC/FGD-CCS	IGCC/CCS	WIND	Total
25	60	1100	1700	1400	2000	6200
25	70	1000	1800	1400	2000	6200
25	80	1000	1800	1400	2000	6200
30	60	1100	1600	1600	2000	6300
30	70	1000	1700	1600	2000	6300
30	80	900	1800	1600	2000	6300

This study did not consider pre-existing generation. For a generation planner, it is critical that existing generation should be accounted for. However, this study has an extra degree of freedom in that it seeks to determine the ideal generation mix that can deliver the level of sustainability required. Therefore this ideal generation mix can be used as a target for the market to strive to achieve. Although parts of the study are applicable to generation planning, the intended application is not generation planning. If the existing generation needs to be included, then the capital costs have to be adjusted for the existing generation to reflect the true capital expenditure whether due to the capitalisation of plant or retrofits.

If nuclear is introduced, it would tend to mask all the technologies that have high pollution and those fitted with CCS due to their high operating costs. If the capacity is controlled however, it will displace some of the base capacity in the generation mix. As mentioned earlier, controlling the capacity of any one technology that tends to dominate the generation mix may be necessary to avoid over-reliance on too few generation sources which could threaten security of electricity supply.

Chapter 6

Discussion

A general discussion is given in chapter. Complementary approaches for mitigating climate change within the electricity supply industry are discussed together with synergies with other research activities.

Existing power systems were designed based on cost and reliability criteria (Jenkins *et al.*, 2000). With the growing evidence of global warming and climate change, there is increasing pressure on power systems to become more environmentally sustainable. Although this thesis focuses on the generation mix, there are other initiatives that can be considered in combating climate change within the electricity supply industry, for example, improving the efficiency of energy conversion into electricity for both renewable and non-renewable generation, improving efficiency of transmission and distribution systems and energy utilisation.

6.1 Complementary Approaches

6.1.1 Energy Efficiency Improvement

The overall thermal efficiency of electricity generation is only 38.5% (Philips, 2000). Transmission and distribution losses accounted for 7.4% of losses in the UK in 1988 (Philips, 2000) and 7.2% in the US in 1995 (CCT, 2003). This means that about 69% of the energy is lost during conversion and transmission. For a fuel like natural gas, that can directly substitute electricity in heating applications in the home, clearly it would be more efficient to use gas rather than electricity for heating applications. Philips (2000) argues that central gas-powered electricity generation should be discouraged in favour of combined heat and power schemes that recover the waste heat from electricity generation with efficiencies as high as 90% depending on the type of boiler used. This could have a huge impact in cutting greenhouse gas emissions simply from the efficiency improvement point of view.

6.1.2 Demand Management

Efficiency improvement of energy utilisation is as critical as it is in generation, transmission and distribution. Apart from improvement of the actual technical efficiency of electrical appliances (e.g. efficient lighting, refrigeration, air conditioning, fans, cookers and water heaters), there is scope to manage energy consumption through effective demand management.

Demand management, also known as demand side management (DSM) and synonymous to 'demand response' (DR) in the competitive markets, refers to actions that influence the quantity of energy consumed by users (NERA, 2003). DSM includes actions targeting to reduce peak demand during periods when the energy supply systems are constrained. Although peak demand management does not necessarily reduce the energy consumption, it reduces the need to invest in network and generation capacity.

Even if there was no threat from global warming, there would still be need to increase the contribution of renewable energy as fossil fuel and nuclear deposits are finite. Therefore the need to conserve energy will always be there. In this respect, consumer education to raise awareness in the area of energy conservation and utilisation efficiency forms a significant part of the solution the problem of sustainability in the electricity supply industry.

6.2 Synergies with Other Research Activities

Within the FutureNet consortium, this research is related to research activities on scenarios and market design. The scenarios work focuses on future electricity network development and technologies that might be applied in the electricity supply industry under different future circumstances for 2020 and 2050 (Elders *et al.*, 2005). Scenarios in Table 6.1 were developed for 2050 based on four principal factors namely; economic growth, technological growth, environmental focus and regulatory structure. These are high level scenarios that capture a range of possible future paths for development of conditions in which energy networks exist.

Table 6.1. Names and key parameters of UK electricity industry scenarios. *Source:Institute for Energy and Environment, University of Strathclyde, Glasgow*

Scenario Name	Economic Growth	Technological Growth	Environmental Attitudes	Political and Regulatory Environment
Strong Optimism	More than recently	Revolutionary	Stronger	Liberalised
Business as Usual	Same as recently	Evolutionary	As at present	Liberalised
Economic Downturn	Less recently	Evolutionary	Weaker	Liberalised
Green Plus	Same as recently	Revolutionary	Much stronger	Liberalised
Technological Restriction	More than recently	Evolutionary	Stronger	Liberalised
Central Direction	Same as recently	Evolutionary	Stronger	Interventionist

The scenarios work specifies the likely generation technologies and their relative capacities for the six scenarios. Below is are the generation technologies suggested for the 'Strong Optimism' scenario.

- *Wind*: Total wind generation capacity of about 50 – 60GW supplying about 25% of electricity demand. Most of this would be located offshore,
- *Biomass*: Total capacity of 10 – 15GW and generating about 15% of electricity demand,
- *Wave*: Approximately 15GW and contributing about 10% electrical energy,
- *Nuclear*: 8 – 10GW capacity of new technology generation accounting for 10 – 15% of electricity generation,
- *CO_2 capture*: Approximately 10GW of new CCGT,
- *Micro-generation*: Strong fuel cell development. Total capacity of 30–35GW producing 35% of electricity and
- *Photovoltaic*: Deeply embedded in distribution systems. Total capacity 5GW, contributing 1 – 2% of electricity generation.

Using the methodology developed in this thesis, it would be necessary to specify the technologies and their characteristics. The resulting generation mix would depend on the required reductions in emissions levels as well as the generation costs considered to be commensurate with the circumstances considered in the specific scenario. It is possible that some of the technologies may not make it into the generation mix. That would be extremely valuable as it gives an early opportunity to detect technologies that are likely to face viability problems.

In electricity market design, if the target sustainability levels can be met without certain technologies, there would be no need to have incentives to encourage these technologies unless there are other needs that can be addressed by bringing back those technologies e.g. to enhance diversity. Using the methodology developed, a more transparent rationale for deciding the capacities of specific technologies can be put forward.

The results show that the generation mix solution is sensitive to the price of emissions. If the emission allowances are allocated generously in the National Allocation Plans[23] (NAPs), then the market will be long and as a consequence, the emissions prices fall (Neuhoff *et al.*, 2006). Therefore, the allocation of NAPs should always be set below the minimum emissions that can be achieved by existing capacity at any time until the required environmental sustainability levels have been achieved.

6.3 General Comments

The issue of whether to consider existing generation or not in the ideal sustainable generation mix problem can be considered in the following way: the purpose of the sustainable generation is to provide a reference that will enable the effective design of electricity markets that can deliver the right economic signals to guide investment into the sustainable technologies. The actual generation mix may not be the same as the reference at the end of the day due to network constraints or other barriers but is is important to have a clear target that can deliver the required sustainability. For this purpose, it is therefore not necessary to include existing

[23]Under the EU ETS, each participating country proposes a National Allocation Plan (NAP) including caps on greenhouse gas emissions for power plants and other large point sources. The NAP must subsequently be approved by the European Commission.

generation as some of it might actually need to be phased out to make way for more sustainable generation.

In the developed methodology, a given technology's capacity may have to be restricted for various reasons including low capacity credit and the need to increase diversity of supply, thereby reducing the risk of supply failure. Other reasons may be inadequate primary energy resource, for example wind capacity or limited biomass supply.

Chapter 7

Conclusions

THIS Chapter draws conclusions to the thesis based on the application of the presented methodology to the test data.

Electricity generation is the largest single contributor to the emission of greenhouse gases into the atmosphere which are believed to be the major driving force behind global warming. Global warming is threatening the globe and its inhabitants with extinction due to extreme weather effects and rising sea levels. International response to this challenge places a strong obligation on the electricity supply industry and other polluting industries to reduce their emission levels in order to mitigate climate change.

Opportunities exist throughout the electricity supply chain (i.e. generation, transportation and utilisation of electricity) to engage measures to combat climate change. This could be in the form of choice of sustainable electricity generation mixes, increased use of renewable, cleaner and more efficient generation technologies, efficient transmission and distribution of electricity and conservation and efficiency in energy utilisation. An integrated energy policy is key to the successful introduction and implementation of these measures.

This thesis investigated sustainable generation mix in terms of the total generation costs and emissions of carbon dioxide for a given set of candidate generation technologies and possible future scenarios. The other measures mentioned above were not investigated but it is appreciated that they form an important complementary part of the solution package to the challenge of climate change within the electricity supply industry. The methodology presented in this thesis provides a way of determining the sustainable generation mix given a range of likely future scenarios in terms of candidate technologies and their costs and operational characteristics, demand, fuel costs and other financial parameters such as discount and interest rates.

Deployed, developing and prospective methodologies were considered in the thesis based on their likely capital, fuel and operating costs. The operational characteristics that were considered are: the unit minimum up and down times, intermittency and plant availability rates. The study was based on an annual system demand profile with a peak of 4.2GW. The generation mixes were determined so as to meet the load profile at an hourly resolution for the entire year. This ensured that the seasonal and daily variations in demand characteristics were captured.

The scenarios considered backgrounds of varying gas prices and carbon dioxide emissions costs to represent scenarios with high and low environmental focus and a wide range of gas prices. Also, there is provision to change the portfolio of candidate generation technologies in recognition that some technologies such as nuclear may be discredited on public acceptability grounds even though they would significantly contribute to meeting the emission reduction targets at affordable costs. The key performance indicators chosen were the levelised costs of generation and carbon dioxide emissions.

The generation mix solution is sensitive to the cost of emissions. Simulation results show that if the environmental focus is low, signified by low emission costs, then more polluting generation technologies continue to have significant contributions in the generation mix and cleaner generation technologies may find it difficult to break in. Low emissions costs on the emissions trading markets are most likely to be caused by large national allocation plan emission allowances. It would thus be difficult to create the 'right' economic signals to attract investment into renewable and cleaner generation technologies based on pure market economics. In such cases, in order to pursue the ideal sustainable generation mix, incentives may have to be designed to attract investment into specific generation technologies.

If the environmental focus is high (high emission costs), heavily polluting technologies like Advanced super critical coal become less attractive due to high emissions costs, thereby making a case for introducing retrofit emission reduction technologies and new less polluting generation technologies as well as renewable generation. Results show that at high emission costs, it becomes cheaper to use cleaner generation technologies for example, technologies using carbon capture and storage and renewable generation. Clean coal technologies become attractive at high emissions costs.

The most important observation is that electricity could still be affordable with a very different generation technology mix from the base case, with emissions as low as 0.06kgCO_2/kWh from a base case of 0.31kgCO_2/kWh (with the nuclear option) or 0.11kgCO_2/kWh from 0.77kgCO_2/kWh without the nuclear option. These figures represent more than 5 fold reduction in emissions. However, the corresponding increase in generation costs (3.48p/kWh to 3.71p/kWh with nuclear and 3.26p/kWh to 3.62p/kWh without nuclear) is a mere 11% for the case without nuclear, even lower at 7% for the case with nuclear. The results also show that including the nuclear option in the technology mix has a higher benefit in terms of emissions reduction per given increase in generation costs.

If the back-end complications (decommissioning and waste disposal) associated with nuclear technologies are appropriately considered in legislation, nuclear generation could have a significant role to play in the future generation mix due to its relatively low operating costs.

Results show that it is possible to determine the mix of generation technologies that can meet a given level of sustainability based on affordability and environmental performance in terms of emissions for a given range of likely scenarios. As the objective of the research was to determine the sustainable generation mix for use in market design, the problem was decoupled from generation planning since the later is not carried out as part of market design. The advantage of decoupling 'ideal' sustainable generation mix from generation planning is that when the 'ideal' generation mix is determined, it then enables the market designer to formulate appropriate market reform or market mechanisms, incentives and regulation in order that investors are encouraged to invest in the desired technologies and discouraged to invest in those technologies that do not meet the sustainability requirements.

Also developed in this thesis is a multi-agent production simulation framework that is adaptable to different market structures and scalable. From comparisons of the different multi-agent production simulation models, it was observed that, ideally, a single optimisation of the whole system results in a more optimal solution compared to multiple optimisation of the disaggregated problem space. However, in practice, decentralisation is the favoured approach and the vehicle to enable efficiency is effective competition. It was also observed that restricting the size of the individual generation entities (generation capacity) can have an impact on the performance of the generation mix. Most notably, there exists the opportunity to have prices that are well above costs, ideally hoping that this would create viable competition. However, the fewer the market entities, the higher the tendency to engage in collusive behavior and hence to maintain artificially high prices if market power is not mitigated. Although the ideal generation mix determined here is based on the centralised case, it is fully appreciated that in practice, this ideal mix would be attempted through a decentralised approach, hence the need to determine the reference generation mix to be used in market design.

Although the basic implementation of the framework was demonstrated, its full potential would become evident with further expansion of the scope of this thesis to include the actual market modelling, employing adaptive agents to investigate the impact of different market structures and rules on the generation mixes. Significant modelling work is required to transform the agents into intelligent and adaptive components to enable detailed market modelling.

Chapter 8

Further Work

FURTHER work to improve the methodology and scale it up are presented in this final chapter.

Including Embedded Generation

In recognition of the fact that embedded generation penetration is expected to increase significantly in future power systems, it would be necessary to further develop the model to be able to handle such generation sources. This involves building models of embedded generation to represent the output characteristics as well as their emissions and most importantly, the correlation between their outputs and demand variation. This would to have a more complete picture about the generation sector in terms of policy formulation on which technologies to pursue and how to ensure that the appropriate external costs are accounted for in the liberalised market environment.

Including Reserve Constraints

Another important area is that of generation reserve. Sufficient reserve must be maintained during the generation scheduling simulation. This would have an impact on system operating costs and emissions, most likely both of them would increase. Of particular interest would be the situations with high penetration of embedded generation and those with high penetration of intermittent generation connected to the transmission system.

Other Greenhouse Gases

While only carbon dioxide is the only greenhouse gas considered, it is likely that in future, more greenhouse gases will also be traded in the emissions markets. The generator emission models would therefore need to modified to include other greenhouse gases.

Scaling up the Study

The final test of the methodology would be application to a real study. This would mean that extensive data would need to be gathered to enable all the input data to be specified. Specific intermittent generation can also be specified together with capacity limits for any technology if they are applicable. Given the high number of inputs, the sensitivity study should be expanded in scope to cover more variables.

Further development of the Multi-Agent Simulation Model

The developed multi-agent model employs basic agents, that at this stage only serve to break down the task of production simulation to model decentralisation of the generation production. Extension of this work would directly lead to the need to extensively model the performance of the determined generation mixes in different market structures with different rules. This would provide the necessary feedback to check not only the affordability and environmental performance but also the long term performance of the market in terms of maintaining a conducive environment for investment in the desired generation technologies so as to transform the generation mix towards the ideal solution.

Further development in the multi-agent system is required in the form of integrating intelligent and adaptive capabilities in the agents (market entities). This involves developing algorithms for bidding strategies, learning from history and inference as well as developing proactive behaviour. There would also be need to develop interfaces and structures to handle market structure and rule specifications at system level.

These modifications require the extension of the scope of this thesis to include the actual market design, in which case market modelling becomes an integral part.

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Valuing Emissions from Electricity Generation: Towards a Low Carbon Economy

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Abstract--**Renewable and high efficiency generation technologies are increasingly being integrated into the power system to mitigate environmental damage. The introduction of these new technologies has commercial and technical challenges. Compared with conventional generation, these technologies are considered to be expensive and require subsidies. Current electricity markets do not put a significantly strong value on environmental emissions to attract sufficient investment in renewable and high efficiency generation technologies. This paper proposes a methodology for determining the value of emissions from electricity generation so as to provide a level playing field for conventional and new generation technologies alike. Studies were carried out with three generation technologies - pulverized coal, natural gas combined cycle and wind power plants with a total of ten generators. Network constraints were simulated using the IEEE 30 bus test system. The results indicate that it is possible to attract investment in cleaner generation technologies based on emission cost values.**

Index Terms—**Renewable generation technologies, Internal costs, External costs, Emissions, Competitive markets.**

I. Introduction

The signing of international agreements like the Kyoto Protocol and the commitment by many governments to provide secure and environmentally sustainable energy systems is changing the way in which the electricity supply industry operates. Electricity markets were primarily designed based on the economic operation of the power system. For the generators, operating costs have mostly considered internal costs, that is, operation and maintenance costs (including fuel costs), as well as capital costs which are armotised over the economic life time of the generating plant. However, the tightening environmental legislation has made additional costs applicable to certain generators based on the amount of environmental pollution they cause. Emissions trading schemes have been put in place in a number of countries as a way of mitigating environmental damage from electricity generation. In the UK, renewable obligation certificates have been introduced to attract investment in renewable generation technologies.

As a plausible contribution to bulk energy supplies, renewable energy technologies are still in their infancy. Given that nuclear generation is faced with extinction and demand continues to grow, clearly, renewable technologies will not be able to bridge the gap alone. Renewable energy technologies tend to be weather dependent and although their outputs are predictable to some extent, they are not controllable. If both demand and environmental targets are to be met, then other technologies will need to be considered. Fossil fired plant is relatively well understood and large fuel deposits are still available therefore it makes sense to invest in technologies that improve generation efficiencies as well as reduce emissions from fossil fueled plants.

Electricity market regulators are beginning to consider the inclusion of external costs in evaluating the actual costs of electricity. It is thus important that the price of electricity bears a proportional component that reflects the amount of pollution from the generation technologies utilised. Pollution costs can be considered as external costs to the operation of generating plant and their evaluation is a non-trivial task. They are real costs in the sense that they have a direct impact on the welfare of the ecosystem, for example, impact on health, materials and crops. They can also affect property prices due to noise or air quality degradation. Several researchers have attempted to monetarise pollution [1], [2] but here, looking from the regulator's point of view, the aim is to determine the price of environmental emissions that will result in an even playing field for all generation technologies.

The rest of the paper is structured as follows: section II briefly looks at the challenges that are faced by renewable and cleaner technologies in general, section III discusses some methods of dealing with the emission problems, section IV describes the problem formulation, Section V discusses the implementation procedure, section VI presents the results while section VII discusses the results and finally, conclusions are drawn in section VIII.

II. The Challenges

A. Commercial Challenges

Given the increasing difficulties in securing planning permission for large electricity generation projects, risks and uncertainties associated with such large projects and the huge capital outlays required, investors tend to favour small projects that are modular and hence flexible, quicker and

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easier to construct and do not require excessively huge financial commitments. This has resulted in a boom in dispersed generation which varies from small plants like solar cells, small wind generators, micro-turbines, to large installations like large industrial combined heat and power (CHP) plants and wind farms. Most of this generation is embedded in distribution and sub-transmission systems.

In most of the cases, they are non-dispatchable and some of them are intermittent like wind. The penetration of these technologies is still low in most countries and they tend to face a number of barriers such as commercial viability and technical challenges in integrating them into the bulk power supply system. In order to meet the environmental targets, there is need to create fair competition within the generation sector and as the penetration increases, the market operation has to accommodate these technologies.

Generators fired from fossil fuels tend to have lower internal costs compared to the less polluting ones. Therefore, external costs need to be accounted for in order to fairly compare different generation technologies. Whichever way, it appears that accounting for external costs of electricity generation will raise the cost of electricity. However, this is a viable way of dealing with discrimination against dispersed generation making increased penetration into the power system. The true commitment of any government to achieving the emission targets is tested when proposals suggest an increase in the price of electricity in order to meet the set targets.

B. Technical Challenges

Most renewable energy sources tend to be available at specific geographical sites, for example hydro power, wind, and solar. Another type of dispersed generation which is site specific is CHP. If a given industrial process has heat and electricity requirements such that a CHP plant is viable, then the generation gas to be at that site. From the network planner's point of view, the only variable in these cases is the amount of power injection that the network can accommodate at that site and hence the rating of the generating plant to be installed. As for the network operator, the challenge is to ensure that whether or not the dispersed generator is online, electricity supply statutory requirements are met. Undoubtedly, this will increase the operating cost of the power system.

Of all renewable generation technologies, wind power plants have increasingly become more and more commercially viable, hence the rapid increase in their integration into the power system. One of the major concerns is the volatility of wind power plant outputs which threatens system security and tends to increase operation costs. Plant capacity ratings may be violated if generation scheduling of conventional plant is not properly coordinated with wind power plant outputs. Typically, most of the renewable generation technologies that do not utilise directly connected synchronous machines tend to be poor at voltage support. This calls for a change in planning and operation methodologies for power systems with significant non-dispatchable dispersed generation.

C. Environmental Challenges

Renewable and non-renewable generation of electricity has environmental impacts. However some of the impacts threaten global sustainability, for example, fossil fired plants pose a significant public health risk and contribute to global warming due to the greenhouse effect. Some of the pollutants produced 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. It must however be noted that electricity is more efficient and versatile than other forms of energy therefore substituting other forms of energy with electricity helps in reducing pollution. Electricity does not produce environmental emissions at the point of use; environmental pollution from electricity generation is concentrated at specific points where the power plants are located hence containing and dealing with the problem becomes much easier [3].

Environmental aspects of electricity generation include such issues as mining of fuels, their transportation, storage and the disposal of their combustion byproducts. Coal, oil and gas are by far the most fuels used in electricity generation and of these, coal is the 'dirtiest'. It produces higher carbon, NOx, SO_2 emissions and solid waste. Unfortunately, coal generation technologies are generally considered cheap. This of course does not take into consideration the environmental costs.

Within the electricity industry today, it is well accepted that efficiency improvement in generation, transmission and utilisation of electricity contributes to mitigation of the pollution problems caused by electricity generation. Not all conservation and efficiency-in-use measures require large investments but they do require policies and promotion through public education and most importantly pricing mechanisms.

III. Dealing with Emissions

Coal plants still provide the bulk of electricity in many countries [4] – US (50 % in 2002), UK (37 % in 2003), Poland (94 %), Greece (50 %) and Germany and Denmark (47 %) in 2000. Local availability of large coal deposits in areas of demand like the US and China and the amount of investment already made in coal technology mean that it will continue to be exploited into the foreseeable future. Gas price rises also tend to increase the demand on coal.

In the short term, emissions can be reduced by improving plant generation efficiency [3], [4]. This can be achieved by retrofitting a supercritical boiler and modifying the steam turbines, yielding reductions in carbon dioxide emissions by up to 20 %. Competing technologies can also be deployed such as integrated gasification combined cycle (IGCC) or circulating fluidized bed (CFB) especially when using high sulphur or high ash coal. Additional reductions can be achieved by co-firing biomass.

Carbon dioxide sequestration is another way of reducing CO2 emissions into the atmosphere. It consists of three stages; carbon dioxide capture before it enters into the atmosphere, transportation, and injection into storage reservoirs [5] (geological formations or marine waters). Carbon dioxide can be captured before or after combustion [6].

Additional investment in carbon dioxide reduction technologies will increase the cost of electricity. Electricity markets need to recognize this fact. The regulator will need to allow these costs to be passed to the consumers only to the extent that enables the environmental targets to be met efficiently and economically. This can be viewed as leveling the competitive playing field for the various generation technologies.

IV. Problem Formulation

A. Internal Cost Formulation

For the purpose of conducting this study, an ideal market is assumed, that is one in which there is no abuse of market power. Here, the production cost of electricity (COE), C_{OE} is assumed to be that of the true operating costs C_o of the generating units including fuel costs, overheads, maintenance costs and capital costs C_c.

$$C_{OE} = C_o + C_c \quad c/kWh \tag{1}$$

Ideally, generation dispatch will reflect the underlying economics in the generation plant. External costs to electricity generation such as wheeling costs and emission costs will also be reflected in electricity market prices. Market forces will then work out so as to discourage generation that results in high wheeling and emission costs as well as other costs in an optimum fashion. Based on these assumptions, it is desired to minimise the emissions and power system constraint violations in addition to minimising the more commonly considered internal costs of electricity generation. Under a competitive market environment, the emissions may have to be traded according to technology types since different technologies have different emission characteristics and impacts on the operation of the power system.

In this case, only emission costs will be considered as external costs. In order to include network constraints, a power flow solution with minimum constraints violation is sought from the candidate generation schedule patterns. This has the effect of reducing wheeling costs while at the same time ensuring system security. This effectively results in a security-constrained economic dispatch based generation scheduling problem. It can be mathematically formulated as follows [7]:

Minimise Operational cost (*OC*)

$$OC = \sum_{i=1}^{N} \sum_{t=1}^{\Gamma} FC_{it}(P_{it}) + ST_{it} + SD_{it} + MC_{it} \quad \$/kWh \tag{2}$$

where $FC_{it}(P_{it})$ is the fuel cost of unit i in period t, P_{it} is the scheduled power for unit i during period t, Γ is the number of time periods, N is the number of units, ST_{it} is the start up cost of unit i in period t and SD_{it} is the shutdown cost of unit i in period t. The characteristic cost function can be expressed as a quadratic formulation as follows:

$$FC_{it} = a_i \cdot P_{it}^2 + b_i \cdot P_{it} + c_i \quad \$/h \tag{3}$$

where a_i, b_i and c_i are the cost coefficients. The start up cost can be expressed as follows:

$$ST_{it} = TS_{it} + [1 - \exp(D_{it} / AS_{it})] \times BS_{it} \quad \$/h \tag{4}$$

where TS_{it} is the turbine start up cost, BS_{it} is the boiler startup cost, D_{it} is the number of hours down and AS_{it} is the boiler cool down coefficient. Similarly, the shutdown cost is given by the following expression:

$$SD_{it} = KP_{it} \quad \$/h \tag{5}$$

where K is the incremental shutdown cost. The maintenance cost function can be expressed as follows:

$$MC_{it}(P_{it}) = BM_{it} + IM_{it} \cdot P_{it} \quad \$/h \tag{6}$$

where BM_{it} is the base maintenance cost and IM_{it} is the incremental maintenance cost for unit i in period t.

The minimization problem (1) is subjected to unit and system constraints. Commonly considered unit constraints are: minimum up-time, minimum down-time, generator active and reactive power capabilities and ramp rate limits. System constraints that are normally taken into consideration are system power balance, spinning reserve, must run units, must out units, crew constraints network and environmental constraints.

B. External Cost Formulation

Since we need to determine the minimum value of the external costs that will bring conventional generation technologies and higher efficiency and renewable generation at par, it suffices at to dispatch generation based on system economy so that the cost associated with the emissions can later be evaluated. From the generation schedules, the energy share, S_T^E of each generation technology in the market can be estimated as follows:

$$S_{T^E} = \frac{1}{n_T} \sum_{k=1}^{n_T} S_k \qquad (7)$$

$$S_k = \frac{E_k}{\sum_{i=1}^{N} E_i} \qquad k \in \{i, \ldots, N\} \qquad (8)$$

where n_T is the number of units of a given technology T that are in the system under study, S_k is the share of unit k, N is the total number of generating units in the system and E_k is the energy contribution of unit k.

Now, given the capital costs for the different generation technologies, their operational costs derived from (2), various financial assumptions like inflation rate, discount rate, project economic life, e.t.c, the COE (1) can be evaluated. The actual COE for individual units is affected by network constraints which dictate the pattern of use in addition to the ordinary cost based characterization. Up to this point, this methodology could be used to evaluate the optimum rating of generating plant for a given power system at various locations.

The COE can be aggregated by technology type by averaging the COEs of the same technology generating plant. It has to be noted that the COE is sensitive to the financial performance of other generation technologies in the same power system as the technologies have to compete for supplying the demand. The primary assumption is that there is sufficient excess generation in order to have effective competition – one of the preconditions for effective competition in the generation sector. The technology aggregated COE can be calculated as follows:

$$COE_T = \frac{1}{n_T} \sum_{k=1}^{n_T} COE_k \qquad (9)$$

where COE_T is the cost of electricity for technology T, n_T is the number of generating units of a given technology T, COE_k is the cost of electricity of the k^{th} unit of a given technology T.

Following the same method for the aggregation of the COE, the emissions can also be aggregated like wise. Carbon dioxide has the most significant greenhouse effect because it is produced in very large quantities since carbon is the most abundant element in organic fossil fuels (coal, natural gas and oil). The amount of carbon dioxide emissions tends to be proportional to the power generated. On the other hand, other emissions like NO_x do not have straight forward relationships with power produced.

At this stage, the technology aggregated emissions and COEs are known. The question becomes that of determining the right value to assign to these emissions so as to attract investment into means of increasing plant efficiency, reducing emissions and exploitation of renewable energy resources. Depending on practical CO_2 reduction gains from plant modifications, the costs of renewable technologies and the costs of efficiency improvements, emission prices that strike an optimum between affordability and environmental targets can be determined.

The financial analysis for the various cleaner production projects suggested above need to be considered in detail so as to determine values for emission costs. This is extremely challenging in the current economic environment characterized by volatile fuel prices, economic recession, many risks and uncertainties, changing regulatory and commercial environments. Depending on the outcome, different technologies may have to pay differently for their emissions for the sake of maintaining competitiveness in the open electricity Market.

One way of dealing with the problem is to determine the target penetration level of renewable energy or a target reduction level for emissions, then determining the price of emissions that makes all technologies have the same COE. For this model to work the units must be optimally rated and positioned in the power system so that they have high utilisation factors, there also needs to be a guard against unrealistically expensive technologies. The later issue is to do with limitations in investment capabilities.

Assuming that the cleanest technology (i.e. zero emission technology) has the highest internal cost, say COE_T^{max} , the cost of emissions C_E can be determined as follows:

$$C_E = \frac{1}{N_T} \sum_{j=1}^{N_T} \left(\frac{COE_{T^{max}} - COE_{T^j}}{EMIS_{T^j}} \right) \quad \$/ton \qquad (10)$$

where N_T is the number of technologies represented in the power system, and $EMIS_T^j$ is the emissions produced by technology j in the system. Alternatively, the emission costs may be aggregated by technology to give C_{ET}, the aggregated emission cost.

$$C_{ET} = \frac{1}{n_T} \sum_{j=1}^{n_T} C_{E^j} \quad \$/ton \qquad (11)$$

$$C_{E^j} = \frac{COE_{T^{max}} - COE_j}{EMIS_j} \quad \$/ton \qquad (12)$$

where n_T has the same definition as in (9), C_E^j is the emission cost of unit j, $EMIS_j$ is the emission cost of unit j and COE_j is the cost of electricity of unit j. In order to ensure compatibility with COE, the emissions, $EMIS_j$ and $EMIS_T^j$ are also discounted and adjusted for load growth.

While it appears that this is a price scaling up exercise for the more conventional generation, it should be noted that only technologies that meet specific efficiency and emissions reduction criteria can be considered owing to practical commercial viability issues such as clean energy payback time.

V. Implementation

Three technologies were represented in this study. These are pulverized coal (PC), natural gas combined cycle (NGCC) and wind power plants. A total of ten generators were used, representing the technologies as follows PC (four units totaling 50.8 % of installed capacity), NGCC (four units constituting 38.8 % of total installed capacity) and wind (two power plants constituting the remaining 10.4 % of installed capacity). Table I shows a summary of the generators that were installed at the various sites on the IEEE 30 bus test system and their technology types.

TABLE I
SUMMARY OF GENERATORS USED

Gen #	Type	Rating (MW)	Node	Capital Cost ($/kWh)	O&M Costs ($/kWh)	Fuel Costs ($/kWh)
1	PC	35	11	1100	0.01	0.0027
2		45	5	800	0.01	0.0020
4		60	1	1100	0.01	0.0013
8		30	13	1100	0.01	0.0032
3	NGCC	40	2	500	0.006	0.0059
5		10	19	500	0.002	0.0062
6		30	14	500	0.006	0.0050
7		35	8	500	0.006	0.0055
9	Wind	15	27	1200	0.001	0
10		20	24	1200	0.001	0

The generators were scheduled for one week following the hourly demands of the system loads modified according to demand scaling factors given for week one [8]. An assumption was made that the load factor remains fairly the same throughout the year so the energy share of each generation technology remained the same. Wind power was not curtailed. Rather, conventional generation was dispatched around the wind plant output. Any violations that resulted, for example, bus bar voltages limit violations were avoided by discarding generation schedules that fell out of the limits.

The underlying algorithm in the dispatch program is a dynamic program which uses a power flow routine to validate the schedules. The results from this program are raw individual unit power outputs for each dispatch period, as well as individual unit emissions for each dispatch period. NO_x and CO_2 emissions were considered in this study. Excel spreadsheets were used to consolidate the data into the energy and emission shares by plant and by technology as well as determining the costs of emissions.

In order to carry out a financial analysis for each unit to determine its COE, some assumptions were made about the financial parameters. Project economic lives of 25 years were assumed for all plants. To take into account inflation and the time value of money, a discount factor of 12 % per annum was used. The load was assumed to grow at an annual rate of 2 %. It was also assumed that the percentage energy and emission shares of the plants were fixed for the entire project life. Indicative unit cost data was taken from various sources [9], [10].

VI. Results

The generation shares are shown in Table II for a run of the system that assumes an economic dispatch of generation.

TABLE II
GENERATION TECHNOLOGY ENERGY SHARES

Technology	Energy Share %
PC	78.4
NGCC	16.3
Wind	5.3

Based on the figures in Table I, the financial analysis of the various projects were performed to determine COE and emission values shown in Table III below.

TABLE III
COST OF ELECTRICITY AND COST OF EMISSION VALUES

Technology	Unit #	COE (c/kWh)		Tons Emissions/yr	
PC	1	2.83	2.66	645	6347
	2	2.23		762	
	4	2.5		4455	
	8	3.08		485	
NGCC	3	3.51	4.35	144	538
	5	7.79		51	
	6	3.06		156	

	7	3.02		187	
Wind	9	5.29	5.00	0	0
	10	4.71		0	

Applying (11) and (12) yields the results shown in Table IV below.

TABLE IV
AGGREGATION OF COST OF EMISSIONS BY TECHNOLOGY

Technology	C_{ET} (c/ton)	C_E (c/ton)
PC	22	17
NGCC	236	
Wind	--	--

C_E – Overall cost of emissions
C_{ET} – Technology aggregated cost of emissions

VII. Discussion of Results

A number of observations were made during the scheduling process. Some of them are:

- No universal value of emissions can be determined for all power systems because the economics of each power system heavily depend on the available energy mix and the relative costs of these energy sources.
- The choice of discount rate should realistically reflect the risks in the industry since the effectives of the emissions pricing mechanisms depend on it.
- The network can have constraining effects on certain generators due to inadequate plant capacity, especially during peak demand periods.
- Plant economics currently determine at what load demand level the generator normally starts generating.
- Generally, economic dispatch of generation results in high emission levels. This results from the fact that the market is profit based and the regulator tends to cap electricity prices.

From Table IV, it can be seen that the overall cost of emissions of 17 c/ton is lower than both the aggregated technology emission costs of 22 c/ton and 236 c/ton. Using the overall cost of emissions, the supported investment is much lower compared to using the technology aggregated costs, i.e. $1,170.45 compared to $2,666.02. These figures would be realized if the emissions could be reduced to zero, however this is not the case so the investments that can be supported in both cases are much less.

A comparison of technology aggregated emission costs against the corresponding emissions shows that more efficient generation produces less emissions and it is interesting to note that the emission costs are high. In this case the price paid for emissions by the more efficient generation is 538 x 236 = $1269.67 compared to 6347 x 22 = $1396.34. Thus, although the less polluting generator pays more per ton of emissions, it pays about 9 % less overall. This is purely to maintain competitiveness across the generation sector since all these generation technologies are needed for various reasons such as economy, system security, emission reduction, e.t.c.

Fig. 1 shows the rationale behind this concept. Since the markets work by converting everything into monetary terms, this approach would blend well into market mechanisms. It also gives a direct incentive to invest in emission reduction technologies so as to avoid these costs.

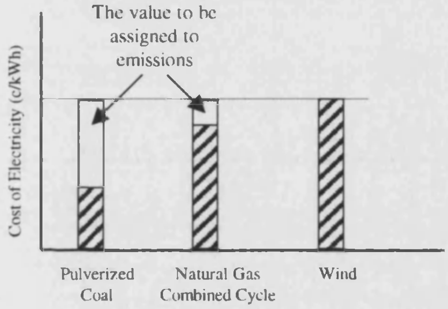

Fig. 1. Illustration of the emissions valuing concept

VIII. Conclusions

The methodology presented in this paper demonstrates that it is possible to assign emission values based on realistic power system economics. Investments derived from emission costs give incentives to existing generators to improve on emission reductions, improve efficiency and also gives incentives to investment in cleaner generation technologies. This model can also be adopted for the market. It can be adapted to the movement in market trends to keep updating emission values to ensure effective competition in the generation sector, meet environmental emission targets and attract investment in renewable and efficiency improvement technologies within the generation arena.

Further work will be required in the form of providing a feedback loop to evaluate the impact of emission values assigned on the performance of the system, competition in generation and environmental performance. This could for instance be used to determine the most appropriate way of interpreting the different emission values obtained by different levels of aggregation.

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X. BIOGRAPHIES

Bless Kuri (Student M' 2004) received his BSc and MSc degrees from the Universities of Zimbabwe and Bath in 1996 and 2003 respectively. He held the position of Project Engineer for two years with Autocontrol Systems, planning and implementing Industrial Automation and Control projects. In 2000, he joined the Zimbabwe Electricity Supply Authority as a Planning Engineer. He is currently pursuing a PhD degree. Areas of interest are electricity market design and Power Systems Planning, Operation and Control.

Dr. Furong Li was born in Shannxi, China. She received her B.Eng. in Electrical Engineering from Hohai University, China in 1990, and her Ph.D. in 1997 with a thesis on Applications of Genetic Algorithms in Optimal Operation of Electrical Power Systems. She took up a lectureship in the Power and Energy Systems Group at the University of Bath in 1997. Her major research interest is in the area of economic operation and planning of power systems.

Generation Scheduling in a system with Wind Power

Furong Li *Member, IEEE* and Bless Kuri *Student, IEEE*

***Abstract*—In recent years, environmental concerns have significantly increased the pressure for cleaner and more efficient generation of electricity. In the UK and some European countries, there are requirements to produce a certain amount of electricity from renewable generation. Wind power is expected to contribute significantly to the renewable energy targets owing to advancements in wind technologies, falling capital costs, abundance of the free resource and commercial viability. However, wind is intermittent and unpredictable, posing serious threats to power system security. Despite the changes in generation mix and the market operation of power systems, priority remains on maintaining system security and minimising operation costs. This poses a fundamental challenge to the traditional generation scheduling methodologies that have worked well in hydrothermal dominated and vertically integrated environments. This paper evaluates the impact of wind generation on the generation schedule, particularly the overall fuel cost, amount of emissions and system security. The analysis is based on the IEEE30 bus test system, with conventional and wind generation plant over a period of one week. Results show that spinning reserve and production costs increase with increasing amounts of intermittent generation and emissions are reduced accordingly. System security initially improves but deteriorates with significant wind power penetration.**

***Index Terms*—Power generation scheduling, Power system security, Wind power generation**

I. Introduction

The need to combat environment damage due to electricity generation is the largest single driver making the case for renewable energy generation, of which wind is currently the dominating renewable technology. Wind power generation is expected to continue increasing due to falling wind plant capital costs, commercial viability and market scalability and abundance of the free resource. Large capacity wind farms are connected to transmission or sub-transmission systems. The nature of wind power is such that it is difficult to predict and it is also intermittent, thereby threatening system security.

Current generation scheduling methodologies are mainly based on minimising power system operation costs subject to system security. Due to the changing commercial and environmental environment, this approach is no longer adequate in systems where renewable intermittent generation like wind is making significant inroads. Methods exist in literature for incorporating security aspects due to congestion [1], [2], [3] unit ramping and thermal stress [4], [5] and voltage/reactive constraints [6]. In cases where emissions have been included in the generation scheduling problem, conventional type thermal plant such as gas and oil plants have mainly been assumed [2], [7]. These plants are more efficient and less polluting but, generally more expensive to run compared to the traditional coal plants. Wind power provides 'clean' electricity. However, being intermittent and unpredictable, poses a real threat to system security compared to the less polluting conventional plant that has mostly been considered in literature.

This paper investigates these unprecedented challenges caused by wind generation to the generation scheduling problem. Production costs, environmental costs and emissions are considered in the implementation of optimal generation mix for a system with wind generation. These three are non-commensurate, that is the improvement in one of them results in the deterioration of at least one of the others [8]. The generation schedule, over one week at one hour resolution, was optimised with dynamic programming. Several optimisation algorithms exist for the generation scheduling problem: stochastic algorithms [9], genetic algorithms [10], ant colony search algorithms [11], lagrangian optimisation [1], [4], [5], neural networks [12] and dynamic programing [13], [14] among others. A dynamic programing algorithm was adopted for solving the scheduling problem due to its inherently optimal nature. The methodology is computationally intensive but it was manageable for the test system used.

The rest of the paper is organised as follows: Section II outlines the problem formulation. Section III details the implementation of the methodology while results are presented and discussed in section IV. Finally, section V concludes the paper.

II. Problem Formulation

A. The Basic Problem

In each unit commitment period generation is dispatched as follows:

$$Min\,\mathfrak{F}(c,e) = \sum_{i=1}^{N}\left[\tau_c\cdot\alpha_c\cdot c(P_i)+\tau_e\cdot\alpha_e\cdot e(P_i)\right]+\tau_s\cdot\alpha_s\cdot s \quad (1)$$

where $\mathfrak{F}(c,e)$ is the objective function to be minimised in each period with respect to the production cost c and emissions e and P_i is the scheduled power output for unit i. s is the security violation index for the given generation schedule, α_s is a scaling factor and τ_s is a boolean variable to include or exclude the security constraint. N is the total number of units. τ_c and τ_e are boolean variables for the selection or deselection of cost and/or emissions as criteria for generation dispatch and

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α_c and α_e are scaling factors to make the cost and emissions comparable when both are considered simultaneously. The production cost is given determined as follows [15]:

$$c(P_i) = FC_i(P_i) + MC_i(P_i) + ST_i(P_i) + SD_i(P_i) \quad (2)$$

where FC_i, MC_i, ST_i and SD_i are the fuel, maintenance, start up and shut down costs of unit i respectively. The characteristic curve for the fuel cost is normally modelled as a quadratic function.

$$FC_i(P_i) = a_i \cdot P_i^2 + b_i \cdot P_i + c_i \quad (3)$$

where a_i, b_i, c_i are cost coefficients. The maintenance cost is defined by

$$MC_i(P_i) = BM_i + IM_i \cdot P_i \quad (4)$$

where BM_i is the base maintenance cost and IM_i is the incremental cost. The startup cost is described by

$$ST_i = TS_i + \left[1 - e^{(D_i/AS_i)}\right] \cdot BS_i + MS_i \quad (5)$$

where TS_i it the turbine startup cost, BS_i is the boiler startup cost, MS_i is the startup maintenance cost, D_i is the number of hours down and AS_i is the boiler cool down coefficient. Similarly, the shutdown cost is described by

$$SD_{it} = KP_i \quad (6)$$

where K is the incremental shutdown cost.

Emission characteristics are generally widely spread. Only NO_X emissions have been considered here. NO_X emissions are generically related to the power output by the following expression [8]:

$$e(P_i) = \alpha \cdot P_i^2 + \beta \cdot P_i + \gamma + \delta \cdot e^{\varepsilon \cdot P_i} \quad tons \quad (7)$$

where α, β, γ, δ and ε are emission coefficients

The security violation index is applied as a constraint in the application of the dispatch. For each candidate dispatch solution in a given period, the security violation index is determined as follows:

$$s = \tau_v \cdot s_v + \tau_b \cdot s_b + \tau_g \cdot s_g \quad (8)$$

where s_v, s_b and s_g are the security violation indices corresponding to busbar voltages, branch power flows and generator reactive powers respectively. τ_v, τ_b and τ_g are boolean variable to include or exclude the respective indices. The three indices are described as follows:

$$s_v = \sum_{j=1}^{J}(|V_j^{ideal} - V_j| - V_j^{\delta})^2 \quad if \ |V_j^{ideal} - V_j| > V_j^{\delta} \quad (9)$$

$$s_b = \sum_{k=1}^{K}(|S_k^{max} - S_k| - S_k^{\delta})^2 \quad if \ (S_k - S_k^{max}) > S_k^{\delta} \quad (10)$$

$$s_g = \sum_{m=1}^{M}(|Q_m^{maxl} - Q_m| - Q_m^{\delta})^2 \quad if \ (Q_m - Q_m^{max}) > Q_m^{\delta} \quad (11)$$

where J, K and M are the numbers of bus bars, branches and generating units respectively. V_j, S_k and Qm are voltage at bus j, apparent power flow in branch k and reactive power generated by unit m. The *ideal* superscript denotes the desired value of the respective variable and the max superscript denotes denotes the rated value while the δ superscript denotes the tolerance allowed for the variable, that is the maximum deviation allowed from the desired or rated value.

There are other constraints that constrain the generation dispatch problem. The following are normally considered in literature.

- *Minimum Up Time:* Once turned ON, a generating unit should not be turned OFF immediately,
- *Minimum Down Time:* Once turned OFF, unit must be kept OFF for for a certain number of hours before it can be brought back online,
- *Generator output limits:* The units must be operated within their rated maximum and minimum real and reactive power output limits:

$$P_i^{min} \leqslant P_i \leqslant P_i^{max}, \quad Q_i^{min} \leqslant Q_i \leqslant Q_i^{max} \quad (12)$$

- *Ramp rate limits:* These limits are imposed by the maximum allowable rates of change in boiler temperature and pressure and torsional stress on the generator rotor.

$$\triangle P_{it} \leqslant \triangle P_{it}^{max} \quad (13)$$

where $\triangle P_{it}$ is the difference in scheduled output of unit i between period t and period $t-1$.

- *Power Balance:* The total generation in period t should equal the total load plus losses.

$$\sum_{i=1}^{N}(\tau_i \cdot P_i) = D^f + losses \quad (14)$$

where τ_i is the up/down status of unit i, D^f is the forecast demand.

- *Spinning Reserve:* This is normally specified in terms of excess online generation capacity.

$$\sum_{i=1}^{N}(\tau_i \cdot P_i) - D^f - losses - R \geqslant 0 \quad (15)$$

where R is the spinning reserve requirement.

- *Must-Run Units:* The must-run status is assigned to some units at certain times due to voltage support requirements on the transmission system and other operational requirements like system maintenance.
- *Must-Out Units:* Some units may be unavailable during certain times due to forced outages and planned maintenance.
- *Crew Constraints:* A limited crew can not operate a number of units simultaneously, hence starting up or shutting down two or more units at the same plant may not be possible.

B. Problem Expansion into Multi-period

Using classical dynamic programming techniques, the problem can be extended into the multiple period scope by considering period by period generation dispatch incorporating the 'dynamic' constraints. At the end of the scheduling horizon there would be a set of solutions from which the choice of the final solution can be based on cumulative costs, emissions, security violation index or any combination of them.

III. Implementation

A. Assumptions

In this implementation, the basic assumption that [16]

> *"a policy is optimal if, at a stated stage, whatever the preceding decisions may have been, the decisions still to be taken constitute an optimal policy when the result of the previous decisions is included"*

is made on the basis of the theorem of optimality which states that optimal policy must contain only optimal sub-policies.

The production costs used in this analysis are mainly fuel costs as they form a significant proportion of the generation costs and they are fairly representative of other related costs because they generally depend on the operating level as well as the amount of time the unit was running. Due to the shear size of the energy sector in any economy and the share of the electricity supply industry (which can be more than 50% in advanced economies [17]) electricity production costs are quite significant. For large utilities, reducing fuel costs by a paltry 0.5% can result in savings of millions of dollars per annum [18], [19]. In the UK, 40% of the average consumer's bill is made up of generation costs [20].

It is also assumed that wind forecasting gives reasonably accurate wind outputs within the time frame considered – which is far from what is currently achievable. Fuel cost functions for generators are assumed to be quadratic and the emission functions are assumed to be continuous functions. In reality, these functions are much more complex especially for multi-stage units where they can be discontinuous and non monotonic.

B. Variables

The variables of interest considered in this analysis were:

- wind power penetration,
- spinning reserve level,
- total system emissions,
- system production costs and
- security violation index.

C. Test System

The IEEE 30 bus test system shown in Fig. 1 was used with a total of 10 generators. Two of the generators were wind farms that were assumed to be in geographically different zones. The total capacity of generators 1 to 8 was 300 MW while the peak load during the week considered was 244 MW excluding losses, which were not been considered in the analysis. Generator 9 represented a wind farm of 15 MW installed capacity while generator 10 represented a wind farm of 20 MW installed capacity. The capacity factors for the two wind generators were 0.26 and 0.29 for generators 9 and 10 respectively for the period considered. Their respective energy shares were 2.16 % and 3.22 %, resulting in a total wind penetration of 5.37 % into the test system. The diversity factor for the two wind farms was 1.37. The system load profile followed that of week one in the load profile data provided in the IEEE Reliability Test System – RTS 96 [21], based on an annual peak demand of 283 MW.

TABLE I

Generator Cost and NO_x 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	RRate	P_{min}	P_{max}	Busbar
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	15	27
10	0	0	4	0	20	24

Tables I and II show the generator characteristics. In table II, MUT and MDT stand for minimum up and down time in hours respectively. $RRate$ is the ramp rate in MW per minute and P_{min} and P_{max} are the unit minimum and maximum power ratings respectively in MW.

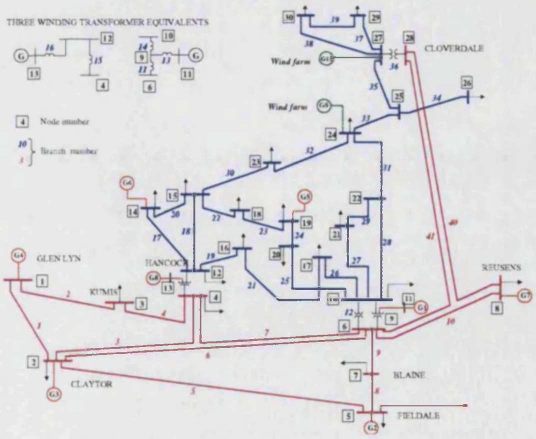

Fig. 1. The IEEE 30 Bus Test System

D. Dynamic Program Application

The problem was solved using a dynamic programming technique with backtracking. Candidate unit commitment states were pre-qualified buy applying unit constraints such as the minimum up and down times, minimum power output, must-run, e.t.c. For each commitment state selected, unit dispatch was attempted based on (i) fuel, startup and shutdown costs and (ii) emissions depending on the dispatch mode selected. The resultant generation schedule was checked for static security by running an ac power flow. Only those candidate solutions that satisfied the constraints within certain tolerances were saved as potential candidates. The number of candidate solutions saved in each block (scheduling period) was adjustable to allow for tuning for optimising the speed and accuracy of the application. Each saved solution also included with it the three merit scores: costs, emissions and a security violation index.

For the wind generators, their output was not curtailed as long as the connection circuits were not overloaded beyond certain tolerances. This meant that scheduling of conventional generation was done around the wind power.

At the end of the scheduling horizon, the backtracking algorithm was implemented to trace back the solution that met the selected optimisation criteria. Three basic criteria were implemented, namely cost, emission and security together with their combinations.

To enable comparisons, the same wind generation pattern was maintained throughout the runs while the penetration and spinning reserve levels were varied.

IV. Results and Discussion

A. Impact of Wind Penetration Level

Figures 3, 4 and 5 show the impact of increasing the penetration of intermittent generation on emissions, production costs and system security respectively in the power system while spinning reserve was held constant at 15 % of hourly demand. Cost and emission graphs indicate that the two values decrease with increasing penetration up to the maximum penetration investigated. At 5.37 % wind penetration, the cost was reduced by 7 %, which is a substantial amount. Emissions were reduced by 5 % to 6 %, in line with the amount of emission free energy generated. As expected, the emissions progressively decrease with wind penetration but the costs, while decreasing, do so at a progressively declining rate. System security also seems to follow the same trend as depicted by the security violation index. The introduction of wind generation is clearly beneficial in this case.

Increasing wind penetration tends to reduce the use of the more expensive peaking units if generation is based on cost while emission based dispatch tends to retain the use of those peaking units with lower emissions.

Another interesting observation in Fig. 3 is that when dispatch and schedule optimisation are based on costs, the emissions increase significantly and the converse is true for emission based dispatch and schedule optimisation. Similarly, in Fig. 4 emission based dispatch and schedule optimisation increases system production costs. In the study case, system security was significantly damaged when generation was dispatched based on emissions and the schedule was optimised based on emissions.

Case	Dispatch		Optimisation Based on			Security Constrained
	Economic	Emission	Economic	Emission	Security	
A	YES	NO	YES	NO	NO	NO
B	NO	YES	NO	YES	NO	NO
C	YES	YES	YES	YES	NO	NO
D	YES	YES	YES	YES	YES	NO
E	YES	NO	YES	NO	NO	YES
F	NO	YES	NO	YES	NO	YES
G	YES	YES	YES	YES	NO	YES
H	YES	YES	YES	YES	YES	YES

Fig. 2. Key to Figures 3, 4 and 5

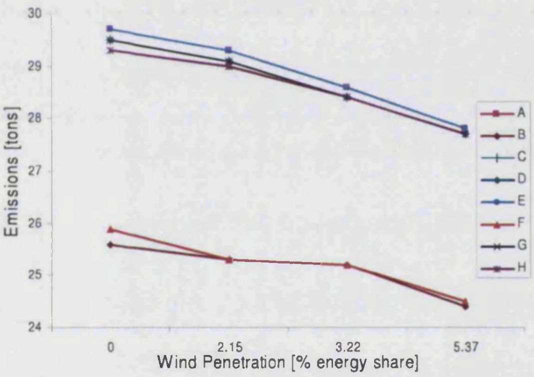

Fig. 3. Impact of wind penetration on emissions

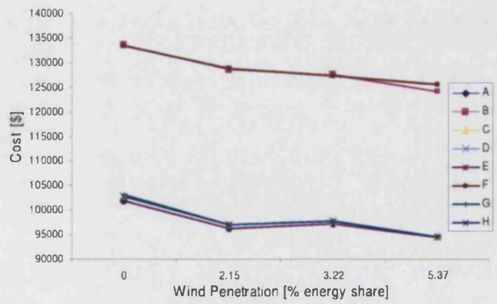

Fig. 4. Impact of wind penetration on costs

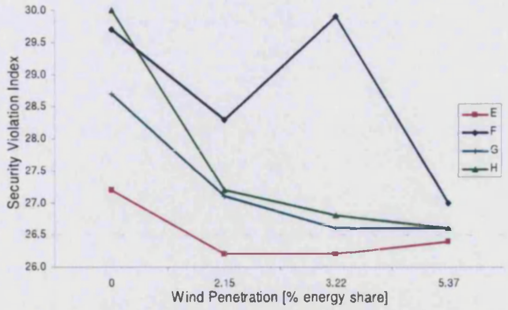

Fig. 5. Impact of wind penetration on security

B. *Impact of Spinning Reserve*

The impact of varying the spinning reserve for the different penetration levels is shown in Figures 7, 8 and 9. The cost/reserve graph indicates that the costs increase with the level of spinning reserve. This is so because some units have to be run on part load just to make sure that there is enough spinning reserve and this causes the overall system production costs to go up. Up to 5.37 % penetration, the costs drop by up to 8 %. It is however interesting to note that when the two wind farms were each connected in turn, the reduction in costs remained unchanged despite their different capacities and capacity factors. Further reduction in costs as a result of the connection of both wind farms can be partly attributed to the diversity in the wind resource characteristics of the two farms. The impact of increasing spinning reserve on emissions is consistent with the level of penetration.

System static security, as measured by the security violation index here, deteriorates with increasing spinning reserve. This, rather startling characteristic, is due to the dispatch and optimisation regimes employed that tend to push some generating units and some busbar voltages towards their reactive power and voltage limits respectively. Security performance tends to improve as the wind penetration increases to some extent then it starts to deteriorate more rapidly as shown by the steeper lines corresponding to the 3.22 % and 5.37 % wind penetration.

Case	Code: Data	Code: Trend	Description
1	▲	—	Generators 1 to 8 only available – Wind farms OFF
2	▲	—	Generators 1 to 8 available + Generator 9 (15 MW wind farm)
3	◆	—	Generators 1 to 8 available + Generator 10 (20 MW wind farm)
4	■	—	Generators 1 to 8 available + Generator 9 (15 MW wind farm) + Generator 10 (20 MW wind farm)

Fig. 6. Key to Figures 7, 8 and 9

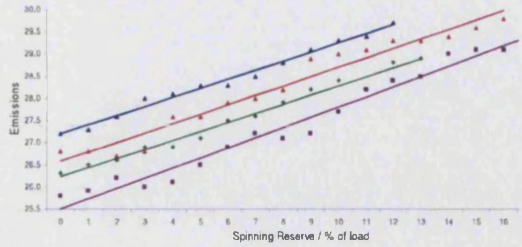

Fig. 7. Impact of system spinning reserve on emissions

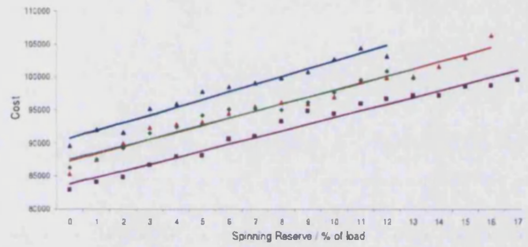

Fig. 8. Impact of system spinning reserve on costs

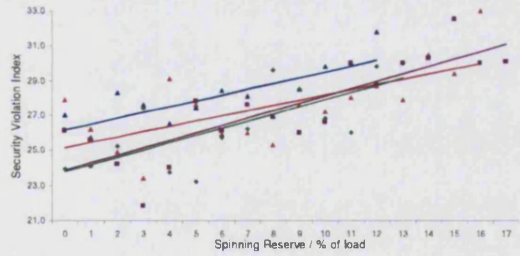

Fig. 9. Impact of system spinning reserve on security

V. Conclusions

It has been shown that a low penetration level of wind generation can improve the economic, environmental and security performance of a system without system reinforcement if generation is carefully scheduled. Generation scheduling based on either economic dispatch, environmental dispatch or security constraints individually gives unsatisfactory results. The balance between these three depend on specific network, generation characteristics as well as the load characteristics.

Using the approach investigated in this paper, generation schedules can be determined to meet specific performance criteria as described in the work. By analysing network loading and voltage profiles, the rating and location of new generation can be determined. 'Weak' network spots can also be identified for reinforcement in order to achieve the desired performance.

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Distributed Generation Planning in the Deregulated Electricity Supply Industry

B. Kuri, *Member, IEE*, and F. Li, *Member, IEEE*

***Abstract*—Distributed generation (DG) is increasingly becoming more important in the power system because of its high efficiency, small size, low investment cost, modularity and most significantly, its ability to exploit renewable energy resources. However commercial and regulatory requirements create challenges for the deployment of DG in distribution systems. Due care must be taken during the planning stage to ensure that system security and quality of supplies are not degraded by the introduction of the new DG. It is also important, particularly in the deregulated environment, that the DG scheme must be economically viable. The task of distributed generation planning is further complicated by many uncertainties and risks in today's power markets that render the traditional deterministic planning tools inadequate. This work proposes a framework for embedded generation planning in line with these challenges and with special emphasis on the risks and uncertainties.**

***Index Terms*—Distributed generation, Planning, Risk and uncertainties.**

I. Introduction

It has been widely accepted that DG is a viable option in solving utility distribution systems capacity problems [1]-[3]. Given the many uncertainties and risks in the deregulated environment, DG is favourable because of its modularity, low investment costs and hence reduced capital risk [1], [2], [4]. Their small sizes (plant area) make it easier to find sites and also shorten construction times. It is also acknowledged that DG can improve security of the power supplies and present opportunities for diversifying the fuel mix in electricity generation, thereby providing an additional variable in overall power system efficiency control.

On the other hand, the installation of DG in the network has technical, environmental and commercial challenges that need to be managed properly if the benefits detailed above are to be achieved [5]-[7]. Technical challenges include the disruption of existing voltage control mechanisms and protection equipment, plant thermal constraints, short circuit levels, stability and network operation and control issues. Additional technical challenge is uncertainties associated with generation technologies which may become outdated resulting in reduced project life span. This could be due to unsustainably high maintenance or operational costs as a result of obsolescence. Environmental challenges depend on the generation technology chosen, for example, wind turbines may not be sited in certain areas even if the wind resource is favourable. Commercial challenges are the changing market conditions and regulations: energy and fuel prices, operating costs, maximum operating profit, incentive schemes and variation of load demand from the projected figures.

According to the Kyoto Protocol [8], the EU has to substantially reduce emissions of green house gasses (GHGs). In the UK, it is expected that by 2010, carbon emissions from power generation will be 45% of the total emissions [4]. The government has responded by setting targets for renewable energies and carbon emissions at 10% of electricity generation from renewable resources by 2010, 20% by 2020 and reduction of carbon emissions by 60% by around 2050[9]. This demands renewable based DG like wind, solar, biomass and many others making greater contribution for future energy provision.

The government has recognised the need to incentivise investment into these clean generation technologies. This is signified by the introduction of Renewables Obligation Certificates in April 2002 (ROCs) and substantial research funding on efficient and sustainable energy and distributed generation.

This paper proposes a planning paradigm for effective planning of DG in distribution systems with due consideration of today's deregulated electricity market and that of the foreseeable future. The model exploits the desirable features of embedded generation while ensuring effective feedback paths so that constraints are effectively taken into consideration. It also recognises the need to deal with uncertainties and appropriate techniques in evaluating risks at the planning stage of the project. The framework will ensure that only those environmentally and economically viable projects are implemented.

Section II of the paper discusses general DG planning issues and in section III, risks and uncertainties in the electricity supply industry are analysed together with potential techniques in dealing with them. Section IV describes the proposed DG planning framework and its organization and finally section V concludes the paper.

II. Distributed Generation Planning

DG best identifies with the distribution system, hence planning approaches for the two are closely related. Power distribution planning models are predominantly mathematical optimisation problems. This planning problem has been attempted by linear programming, dynamic programming and non-linear programming with a certain degree of success [10]. Because of the dimension of real-life problems, solving these

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models is onerous unless the problems are simplified. Dramatic transitions of the electricity markets and the ever-increasing uncertainties and risks have increased the complication and rendered models based on these formulations inadequate. Heuristic based approaches and more recently artificial intelligence (AI) techniques have been employed to circumvent the limitations of the more traditional approaches [3], [10], [11].

Khator and Leung (1997) [10] identified two major approaches in distribution systems planning, namely single period and multi-period approaches. The first approach assumes a static load during the planning horizon and there is no relationship between network reinforcement from one year to the next. For DG, this model is not suitable as it does not exploit the modularity of the plant and it does not acknowledge the fact that DG output is unlikely to remain constant given the increasing penetration of DG and the increasing competitive nature of power markets.

The multi-period approach on the other hand can be considered as a series of single period models, time subscripted to take care of time dynamic variables [12]. This could be enhanced by considering the formulation and modeling of correlated time-dynamic decisions such as only one installation at a location and mutually exclusive installations.

The multi period approach was pursued for this model because of its ability to respect time dependant variables. This approach also accommodates DG planning as means of reinforcing the network on an incremental basis, thereby taking advantage of the modularity of DG plant. It also helps in reducing the risk and uncertainty in DG projects.

III. Risk and Uncertainty in DG Planning

Risk is the hazard to which we are exposed because of uncertainty. It is also associated with decisions. Uncertainties can be classified under internal and external factors, the former can be controlled to a certain extent, while the latter are out of control for a DG planner. Internal factors, such as system losses, reliability and project cost overruns can be dealt with by better management of project design, execution and operation. External factors, such as regulations and legislations, fuel prices and technological innovations will have to be included in the planning process in order to reduce their uncertainty [4].

Before the privatisation of the electricity supply industry (ESI), risks and uncertainties were fewer because tariffs were almost fixed [4]. Under the deregulated environment, electricity markets are volatile, characterised by uncertainties in future fuel prices, tariffs, cost of capital, competition, regulation, demand growth and other possible sources of income (e.g. ancillary services). There are also technical uncertainties such as breakdowns, forced outages, technological changes and future environmental legislation. With increasing pressure on generators to run financially sound businesses, risk analysis becomes increasingly important even on relatively small generation projects like DG. Traditionally, for small projects, sensitivity analysis was sufficient as a tool for assessing the risks of a project. This rather deterministic approach is no longer adequate in view of the facts mentioned above.

A number of methods have been used in assessing risks and uncertainties. These include sensitivity analysis, decision analysis, break-even analysis and Monte Carlo simulation [4], [13]. Sensitivity analysis is simple and has been used for small projects (typically of the same size as DG). It measures the response of internal rate of return (IRR) or the net present value (NPV) to predictable changes in inputs. More thorough analysis based on probabilistic approaches is normally used in assessing the overall effect of varying inputs for bigger projects. Such approaches take into account the interdependency between the inputs; for example, an increase in fuel price affects the price of electricity. The price of electricity will impact on demand; hence the cash flows for the project are affected by the interdependence of these two inputs. Even though DG projects are relatively small, they remain capital intensive and as such the probabilistic approach is recommended here.

In risk analysis, credible inputs and outputs of the project are represented by probability distribution curves where each event is assigned a probability of occurring [4]. Experience in and knowledge of the power system and the associated market is required in drawing these distribution curves. Using the Monte Carlo approach, values for the variables are selected randomly with their probabilities of occurring. For each set of variables, a value of IRR is calculated. Repeating the process gives an IRR curve from which the most likely IRR and its probability of occurring can be determined. Similarly, the most likely NPV and its probability can also be determined. The strength of the Monte Carlo simulation is its ability to handle imprecise variables and to recognise their covariance. The output is in the form of a distribution curve from which mean outcomes, variances and other statistical parameters can be determined.

This approach should enable planners to make appropriate decisions in the deregulated environment characterised by many risks and uncertainties.

IV. The Proposed DG Planning Framework

The flow chart for the proposed planning framework is shown in Figure 1. The model design is based on a modular approach to allow for easy updating of the model to keep abreast with changes in the future power markets. It is envisaged that the carbon economy will gain momentum and the distribution system will become more active. Ancillary services are also predicated to penetrate the distribution network area of the power system. Further more, the framework can be used as a specification in the organisation of a computer package to solve the problem. This approach also provides requirements for the planning engineer to choose the most appropriate tool for each sub-task. Techniques to deal with risks and uncertainties are embedded in the modules. These modules are analysed below:

A. Scenario Identification

The future electrical power system is expected to have many distributed generators in the distribution network. The design, operation and control of the networks will differ from what it is today. The power markets and regulatory environment will also undergo changes to create the effective commercial

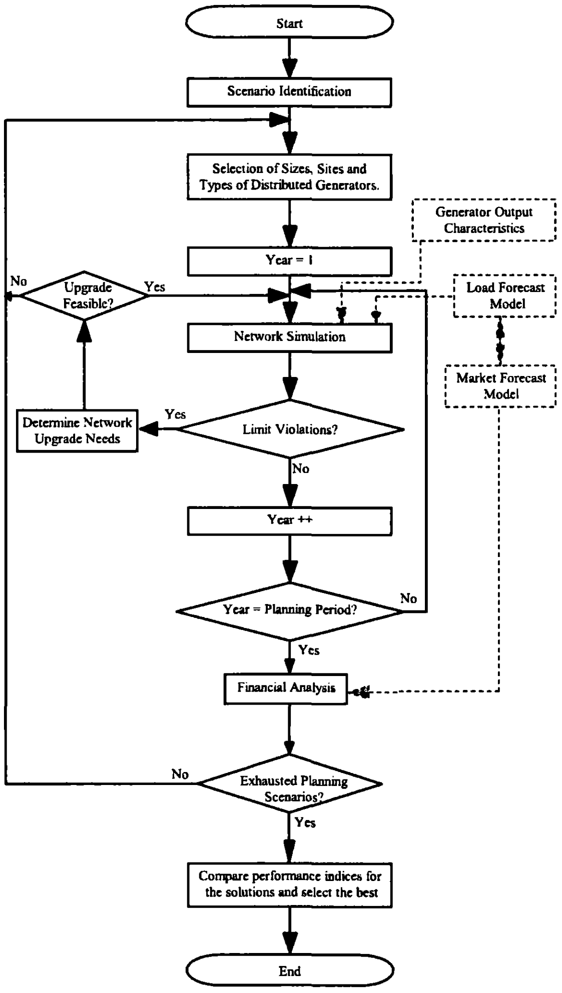

Figure 1 - DG planning model flow chart

drivers to encourage efficient and sustainable energy generation and utilisation.

Environmental requirements are expected to tighten and depending on the overall performance of the carbon economy, incentives for low-carbon energy options may be increased or reduced. Choice of DG technology today depends on what the likely technical and environmental requirements of the future. Another important element is the timing of projects. For instance, the second phase of a project, implemented after a number of years, may need to be modified to cater for the new requirements that could not be foreseen at the planning stage.

While the change in the network structure is not going to be abrupt, it is envisaged that it will be significant. It is therefore prudent for the planner to set the scenario within which DG is planned.

B. DG Output Characteristics

In order to appropriately simulate a network in which a renewable generator is installed, a model of the respective resource has to be used with appropriate input parameters.

The output characteristics of generators depend on the characteristics of their energy resources, those of the prime movers where appropriate and the actual generators [14]. There is a great deal of research activity in determining the characteristics of stochastic renewable resources. . Some of these are site and weather dependent such as wind and solar power, making the modeling an extremely challenging task.

Admittedly, these models can be highly complex, however, advantage could be taken of advances in computer applications that conceal the complexity as in the case of weather forecasting applications. A lot of work is required in creating the models in a suitable form that allows ease of use by the planner. AI techniques have been used in weather forecasting with certain degree of success. It is hoped that these will be useful in modeling renewable DG output characteristics.

It should be appreciated at this point that the models would need to be capable of simulating generators associated with storage devices as this has a far-reaching impact in the technical and economic performance of the DG scheme. Electricity storage devices are currently an area of active research. They are expected to play an important role in the future power system [15].

C. Load Forecasting

Load forecasting is very important in the evaluation of DG projects. There are two aspects of load forecasts in this context. One is the system load forecast and the other is the load demand on the DG scheme. While it may be relatively easy to predict the overall load forecast for the system, predicting the demand on a DG scheme is a daunting task. This is particularly so in the long term, which happens to be most important in system planning. This is due to the perceived increased penetration of DG in future distribution systems. System planning is very much dependant upon future views regarding load levels and locations. Also, financial planning remains tied to revenue and expense forecasts, which are mainly based on future energy sales and peak demands.

Long term load forecasting is normally carried out based on trend analysis and other factors like the rate of substitution of other fuels by electricity or vice-versa. Long term load forecasting for the system is fairly well understood and working models do exist from which data can be readily tapped. Load demand forecasting for DG schemes is complicated by the increasing penetration of distributed generators into the distribution system. It is possible that the output from a DG scheme could be reduced as more DG emerges. This is likely since network load will not expand as rapidly as DG is expected to emerge. Primarily, the concept of DG is not transmission of power to other networks, but rather the energy is utilised in the local vicinity. This cuts back on system losses and improves efficiency. For the purposes of DG planning, an appropriate load-forecasting model has to be adopted and its output is used in network simulation, financial and economic analysis as well as market forecasts.

D. Market Forecasting

The performance of the deregulated ESI in terms of efficiency, security, reliability and quality of supply is dependent upon the market structure. In DG planning, market forecasting is of importance in determining the financial performance of the scheme. Future load and prices for fuel, electricity and services form the basis of project financial analysis. Inflation projections will have the effect of eroding real earnings from a project.

The market can be used as a commercial driver to encourage development of sustainable and efficient energy generation. It is expected that the UK market will undergo some major changes in the in light of the need to meet emission targets that have been set for the near and long terms [9]. Like any other feedback system, the market will have a system to evaluate the effectiveness of the various market strategies so that appropriate modifications can be implemented if necessary.

Rather than assuming that estimated values for the various market variables are correct, it would be better to have a model that will give expected values for different scenarios to enable the planner to assess the risks due to the various uncertainties. The model should also be able to account for the correlation between the various variables and their interrelationships with time.

E. Network Simulation

Network simulation is carried out in order to determine those technically feasible options. It is desirable to have the DG installed in a network in such a manner that it causes minimum disruption and contributes to the reduction of losses, improvement of power quality, security and reliability. A distributed generator installation is assessed against these criteria at this stage. Siting and sizing of embedded generators has been tackled by a number or researchers [1], [2], [3]. The emphasis was mainly on satisfying technical constraints and reducing network losses. None of these clearly addressed the problem of evolving the simulations into the future to ensure that these projects remain technically and financially sound throughout planning horizon. This is not a trivial task as the future market parameters are not deterministic. Probabilistic market and load forecast models would give the planner a better approach to deal with this problem. However, the network simulation will have to be based on a time dynamic approach in order to be compatible with the load and market forecast models.

Inputs to network simulation are the network model, site, capacity and characteristics of the DG, load forecast for the system, load demand on each DG, market model and the planning period. Results from the simulation reveal any technical shortcomings of the network in terms of the following:-

- Voltage levels,
- Fault levels,
- Generators, transformers and lines capacity,
- Stability,
- Harmonic distortions and
- Reliability indices.

If there are such limitations, the planner has the option of modifying the site, size or type of generator and/or the network in order to satisfy the technical requirements. If the DG installation does not warrant the necessary reinforcement cost, then the reinforcement is abandoned, otherwise a note is made of the reinforcement needed and its timing so that it can be appropriately included in the financial analysis later in the project evaluation process.

There are a number of ways to reinforce a network including line conductor upgrade, construction of a new line and/or substation and installing an embedded generator. If it is decided to reinforce the network, then the reinforcement option chosen should be cost effective and compatible with the overall planning strategy in terms of uncertainties and risks. It is also important to ensure that these reinforcements are well timed to avoid unnecessary load curtailment or constraining the DG.

Network simulation can be tedious for multi-period planning models that are desirable for DG planning. The time dimension brings with it the need to run the simulation for each sub period. This considers changes that may occur to the system due to installation of other distributed generators, new loads and future system load according to load forecasts. Due to the amount of work involved, this area has until now been cluttered with assumptions that simplify the problem. Some of the simplifications are uniform rate of load growth, linear relationship between losses and load and assuming no major changes in the network configuration throughout the life of the project.

Splitting the planning period into sub-periods allows us to determine network reinforcement strategies on an incremental basis and provides the flexibility of changing the scope if project conditions change. This approach reduces the uncertainties associated with projection of parameters into the far future. It also allows for phased capital expenditure in smaller amounts, thereby reducing capital risk.

Some researchers have worked on the multi period planning models [3], [12] but their work does not particularly address the issue of risk and uncertainties. Advantage can be taken of the high computer processing power available today to simulate the network in greater detail.

F. Financial Analysis

Financial analysis is concerned with the evaluation of net discounted benefits, hence the profitability of the project. It is mandatory in the privatised electricity industry that projects are profitable. As such, projects are undertaken because they are needed, they are the least cost solution and they are profitable [4]. To provide a measure of financial performance, the following are some of the indices that are determined for each option: IRR, benefit/cost ratio, payback period and the NPV. Of equal importance is the choice of the least cost solution. Typically, these indices are calculated based on the most likely forecast values. Using a probabilistic approach (together with dynamic load and market forecast models), sets of these indices can be determined based on a number of cases, each with an assigned likelihood. Depending on the probability distribution of these values, a more informed and robust decision can be reached.

For a given project there are normally a number of technically viable options. The least cost option is normally chosen so that the project is cost effective. However, depending on the relative risks of the options, the least cost option may be traded off for one with less risk. It is prudent that these conflicting factors are carefully balanced before commitment is made on any option.

Due attention needs to be paid to the choice of the discount rate for the project in order to provide a reasonable return on the investment while at the same time providing a hedge against the risk and uncertainties in the market. Traditionally, most of the uncertainties were accounted for in the choice of the discount rate and adding a contingency to the overall cost [4]. This is no longer sufficient as the risks are substantially higher and uncertainties are on the increase.

V. CONCLUSIONS

The planning framework proposed in this paper emphasizes on dealing with risks and uncertainties in distributed generation planning. The paper set out the technical, environmental and commercial challenges brought about by the highly dynamic electricity markets and its regulation that are characterised by increased risks and uncertainties. The paper aims to depict a full picture of the challenging planning problem and paves a way forward for an effective planning tool capable ofreducing uncertainties, ultimately, assisting the planner in prescribing a technically and commercially viable distributed generation project in the deregulated electricity supply industry.

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VII. BIOGRAPHIES

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Optimisation of Rating and Positioning of Dispersed Generation with Minimum Network Disruption

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***Abstract*–The paper presents a new technique for assisting network planers determine the optimum rating and position of dispersed generators in an established distribution network, considering practical objectives and constraints over a number of planning years. The tool exploits conventional techniques in assessing the constraints imposed by the network, subsequently using Genetic Algorithms to provide an optimization of the decision making process. The operation of the technique was demonstrated on the IEEE 14 bus system, suggesting that the developed tool is flexible and effective in addressing concerns faced by practical planning engineers.**

***Index Terms*—Dispersed generators, Established network, Fault level, Genetic algorithms.**

I. Introduction

Small and medium sized dispersed generation using renewable sources of energy offers a valuable alternative to conventional generation for utilities to reduce emissions. The additional benefit from these systems is the potential reduction of losses in the power delivery process as they can generate power close to the end users.

Because of the nature of dispersed generation, their construction times are relatively short and as their penetration into the system becomes greater, this could become shorter. Dispersed generation is inherently modular; this allows a quick response to both market forces and increases in peak demand. [1], [2].

Under the Kyoto protocol, both the EU and UK have agreed to substantially reduce CO_2 emissions to help combat climate change [3]. The UK government has committed itself to generate 10% of its total electricity generation from renewable sources of energy by 2010 and 20% by 2020. As a long-term objective, the government has an ambitious target of reducing CO_2 emissions by 60% by 2050 [4], as part of an essential action to stabilise global warming.

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Unfortunately, most distribution networks have been designed to transport power from either power grids or occasionally large generators to consumers. These systems were rarely envisaged to support directly connected small and medium sized dispersed generation. These changes to the use of the network together with the potentially high penetration of dispersed generation have led to the need for an effective and easily used technique to optimise both the rating and positioning of these generators within an established network.

The issues that need to be considered in the choice of rating and positioning of dispersed generators include both technical and commercial factors. The technical issues include the adequacy of the network's and associated plant's thermal rating, fault levels and sufficient voltage support to ensure both the security and quality of electricity supply. The commercial issues include the cost of the dispersed generation, installation charges, operating costs, revenue expectations and value of reduced losses in the network. The problem is therefore multi-faceted with a number of objectives, some of which will inevitably conflict with one another. Also, the problem is such that the system is not static, instead it is continuously changing, a single optimal solution is therefore difficult if not impossible to find. At the end of the process, a compromise has to be reached which satisfies most of the parties concerned and accepts that the real situation will rarely be the same as that analysed. The variability of the problem and the imprecise nature of the data available to the planner have led to the choice of a robust decision making process which can handle these characteristics, namely Genetic Algorithms.

This paper presents a software system that has been formulated to provide essential support for decision making concerning the choice of the ratings and the positioning of dispersed generation in an established distribution network. It uses conventional techniques to assess some of the constraints imposed by the network and genetic algorithms to provide an optimisation for the decision making process. The operation of the technique is demonstrated using the IEEE 14 bus system [5]. The results suggest that the developed system is flexible and effective in addressing concerns faced by practical planning engineers.

II. PROBLEM FORMULATION

This technique was developed to handle multi-objective and complicated problem formulations considering practical constraints in the choice of the rating and positioning of dispersed generation. The objectives considered were:

- The minimisation of system losses,
- The minimisation of disruption to the existing network
- The minimisation of costs.

and,

- The maximisation of the rating of the dispersed generator

This has resulted in the following objective function formulation:-

$$C=\sum_{i=0}^{Y}\frac{C_i}{(1+r)^i} \quad £ \qquad (1)$$

$$E=\sum_{i=0}^{Y}\frac{E_i}{(1+r)^i} \quad kWh \qquad (2)$$

$$Min \quad F(X)=\frac{C}{E} \quad £/kWh \qquad (3)$$

where:- C and E are the net discounted costs (£) and energy (kWh) over the entire planning period respectively, X is the solution vector, C_i is the overall cost (£) incurred in year i, r is the discount rate, E_i is the expected energy sold (kWh) in year i and Y is the planning period in years.

The network load was assumed to grow at a constant rate and uniformly throughout the network. The overall cost takes into consideration the change in network technical losses for each candidate solution in each year during the planning period according to the following formula:-

$$C_i = C_{Ci} + C_{Oi} - E_{Li} * C_{Ei} \qquad (4)$$

where:- C_{Ci} and C_{Oi} are capital and operational costs in year i respectively, E_{Li} is the reduction in losses in year i (kWh) and C_{Ei} is the unit cost of energy from the distribution network owner.

These objectives were subject to the following constraints:-

- The network voltage levels should be held within specified limits,
- The short circuit limitations of network plant needed to be respected,
- The thermal capacity limitations of network plant needed to be respected

and,

- Generator real and reactive power capabilities needed to be respected.

These are represented by the following equations:-

$$v_{\min} \le v_i^n \le v_{\max} \quad n=1,2,\ldots,N \qquad (5)$$

$$P_{g\min}^k \le P_{gi}^k \le P_{g\min}^k \quad k=1,2,\ldots,K \qquad (6)$$

$$Q_{g\min}^k \le Q_{gi}^k \le Q_{g\min}^k \quad k=1,2,\ldots,K \qquad (7)$$

$$S_{\min}^b \le S_i^b \le S_{\min}^b \quad b=1,2,\ldots,B \qquad (8)$$

$$f^n < f_{\max} \quad n=1,2,\ldots,N \qquad (9)$$

where:- N is the number of nodes in the network, K is the number of generators and B is the number of branches (transformers and lines), v_i is the node voltage in year i, P^k_{gi} and Q^k_{gi} are real and reactive power generated by generator k in year i respectively and S^b_i is the apparent power flowing in branch b in year i and finally f^n is the fault level at node n in the base year of the project.

The principal advantage of this technique was its ability to aid the planner to make an informed decision in a short time. This was because the system inherently performs load flow and short circuit calculations for each candidate solution and directly handled voltage and capacity constraints over the entire planning period. Additionally, the system performs the least cost analysis as the basis for comparing the various candidate solutions. This considers the reduction in system losses, and inherently, the capacity utilisation of the dispersed generator.

The solution is in the form of connection parameters, which provided high quality solutions for the rating and positioning question. The system also recognised that as with any decision making tool, the final decision for implementation rests with the planner.

III. Implementation of Genetic Algorithms

A. Genetic Algorithms

Genetic algorithms are a family of computational optimisation models that are inspired by the evolutionary process. Goldberg (1989) [6] and Hopgood (2001) [7] cover the theory of genetic algorithms. They are gaining increasing popularity in power systems planning [2], [8]-[10] because they are robust and have inherent ability to efficiently optimise discrete multi-model, multi-objective and constrained problems. They are immune to the limitations imposed by the traditional means as they work with a coding of the parameter set instead of the actual parameters, explore the search space in a parallel manner and do not use derivatives or other auxiliary knowledge but use objective function payoff values and probabilistic rules [6].

B. Genetic Algorithm Implementation.

The key steps in the implementation of GAs involve formulation of the fitness function for the problem, choice of representation and coding techniques for the solution, evaluation the fitness of each candidate solution and application of the genetic operators, namely reproduction, crossover and mutation iteratively to evolve the solutions until a desirable solution is obtained.

C. Selection and Coding of Control Variables

Four control variables were identified to for each solution vector. These were the position, size, power and the voltage variables. A node chosen for installation of a generator was treated as a PV bus, thus the node active power and voltage values had to be specified within their specified limits. Not all sites and sizes were used each time, so candidate sites and sizes of generators were also specified. Thus the solution vector X was formulated as follows:-

$$X = [x, s, p_s, v]$$
$$x \in \{selected \quad sites\},\ s \in \{selected \quad sizes\},$$
$$p_s^{\min} \leq p_s \leq p_s^{\max} \text{ and } v_{\min} \leq v \leq v_{\max} \quad (10)$$

where:- p_s^{min} and p_s^{max} are the minimum and maximum power output values for generator size s in pu and v_{min} and v_{max} are the lower and upper voltage limits in pu.

Binary coding was used for all the four variables so that each coded solution vector consisted of a binary string, whose length varied dynamically depending on the number of candidate sites and generators.

D. Fitness Evaluation

The fitness function was derived from the objective function by transforming it so that the minimisation problem became a maximisation problem. The following transformation was used:-

$$Max \quad Z(X) = K - F(X) \qquad (11)$$

where:- $Z(X)$ is the fitness function and K is a constant such that $K - F(X) \geq 0$.

The fitness of each candidate was evaluated according to the fitness function. After calculating all the fitness values for each population generation, the values were scaled and stored with their respective candidates. Scaling helped prevent premature convergence and better discrimination of solutions later in the genetic algorithm run.

E. Applying The Genetic Operators

Reproduction, crossover and mutation are the three basic operators that guide the decision making process.

Reproduction is based on selection of more fit individuals to replace those weaker ones. Single point and uniform crossover were implemented, during which candidate solutions were randomly paired and made to partially swap their bits (genes). Single point crossover was found to yield better results compared to uniform crossover. Both the reproduction and crossover rates were controlled to give best performance of the genetic algorithm. Mutation was implemented with a small probability (around 1% to 2%) to introduce variety to the population and to guard against premature loss of important notion. This evolutionary process is shown in Figure 1.

F. Constraint Handling

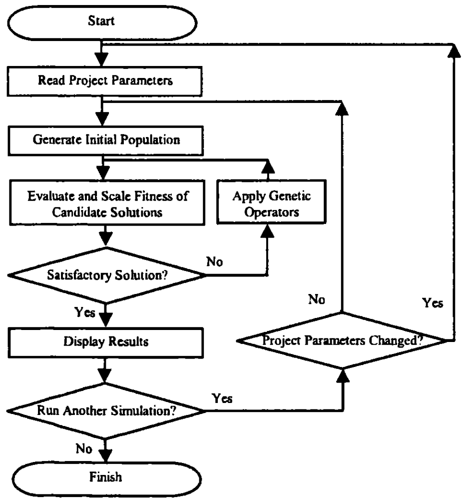

Fig. 1. Implementation of the optimisation algorithm

During the generation and subsequent refinement of the individual solutions, voltage levels, fault level and capacity constraints represented by equations (5-9) were applied to each solution in order to validate it. Those that did not satisfy any of the constraints were discarded. Another solution was generated and tested until one was found which satisfied the constraints. Figure 2 shows the procedure for constraint handling.

Short circuit calculations were executed using the Z bus and the node voltages obtained from the load flow solution of the network. For each generator installation, a Z bus for the system was built. The fault level calculation was based on applying a three-phase short circuit at each node in the system. It was assumed that only one such fault occurs at a time, thus representing the N-1 contingency. The three-phase short circuit case was chosen because it gives the most severe fault level and accordingly, it is used in specifying switchgear rupturing capacity. It is also the easiest fault to calculate. The simulation was carried out at peak loading conditions.

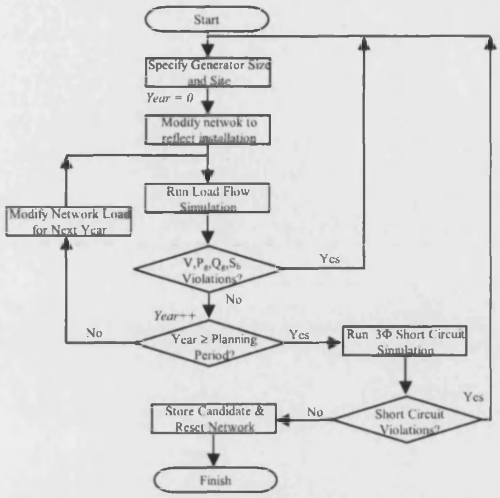

Fig. 2. Constraint handling

IV. Test System and Test Results

A. Test system

The decision making tool was demonstrated using the IEEE 14 bus system [5], the block diagram of which is shown in Figure 3.

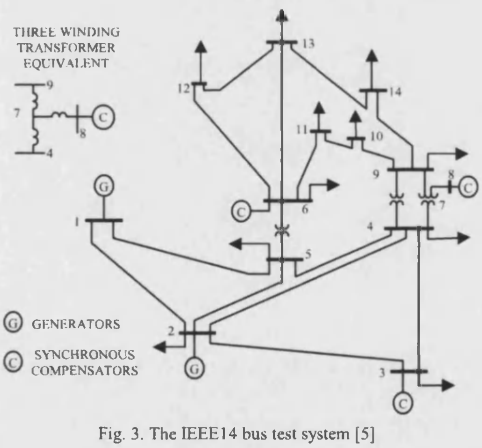

Fig. 3. The IEEE14 bus test system [5]

The details of the embedded generators used are given in Table 1. All the embedded generators used were synchronous machines. The reactance value used for each candidate generator was taken as the total reactance determined by summing the transient reactance of the generator and the leakage reactance of the transformer, where a transformer was used to connect the embedded generator to the network. The planning period used in the simulation was 20 years. A discount rate of 10% was used.

Table 1: Details of dispersed generators

Rating (MVA)	X' (pu)	P Min/Max (MW)	Qg Min /Max (MVAr)	Unit Cost £ 000	Average Production Cost £/kWh	Installation & Comm. Costs £000
25	0.4	5/22	-5/11	15 700	0.029	5 500
50	0.3	10/45	-20/22	30 000	0.030	11 400
100	0.3	25/90	-50/44	68 000	0.027	27 200
250	0.4	50/225	-100/109	130 000	0.024	59 200
300	0.4	60/270	-120/131	200 000	0.022	100 000

B. Test results

Before executing the genetic algorithm, the following parameters were set in the analysis: the location of candidate sites, details of candidate generators, including their technical and financial parameters, discount rate and length of the planning period in years. The following were also set; maximum short circuit capacity allowed for the existing switchgear, minimum and maximum voltage allowed, and the study base in MVA. At this stage, it was also decided whether reverse power flow would be allowed at the slack bus bar or not. Finally, for the genetic algorithm, the reproduction and crossover rates were varied between 30 and 70% and the mutation rate was varied between 1% and 2%.

The tests are conducted considering three common scenarios when planning dispersed generators in an established network. They are: the position of given dispersed generators; the rating of the dispersed generators on given sites; the position and rating of dispersed generators in the absence of preferred position and rating. In the case of the IEEE 14 bus system, the available generator ratings were chosen to be 25MVA, 50MVA, 100MVA, 250MVA and 300MVA. Separate studies were carried out for the HV and LV side of the network.

1. Case 1. Optimum Location for a 25MVA Generator.

This optimisation was first broken down into two studies; the first considered the HV network and the second the LV network.

The possible locations in the HV network were at sites 1, 2, 3, 4 and 5. The analysis quickly identified site 3 as the optimum location for connecting the 25MVA generator. All power generated is consumed locally resulting in reduced technical losses. Installation of the generator at this location results in minimum increase in fault levels hence switchgear upgrades could be avoided resulting in cost saving.

In the LV network, the possible sites were 6, 9, 10, 11, 12, 13 and 14. Of these, two locations were identified as offering good solutions. Based on fault level increase following the addition of the generator, location 12 was the optimum. However, when operating costs were considered to be more important, locating the generator at location 14 resulted in the lowest losses. Here the planner has to take into consideration the advantages and disadvantages of each option and make a judgment as which is a better solution.

2. Case 2. Optimum Location for a 100MVA Generator.

As with case 1, this analysis was also broken down into two studies, one for the HV network and one for the LV network. In both studies, the analysis highlighted the resulting fault levels as being the dominant limitation and revealed that there was a need to increase the ratings of the switchgear.

Following switchgear upgrading, location 3 was identified as offering the optimum location in the HV network and location 14 offered the optimum location in the LV network.

3. Case 3. Optimum Rating for a New Generator to be added to the Network.

In this analysis, it was assumed that the switchgear ratings would be increased as required and therefore this constraint was removed and the objective of the optimization was to identify the largest size of generator which the network could accept and where this could be connected.

Considering the HV network, the analysis revealed that the optimum size of generator was 250MVA and that this could be connected at location 3.

The analysis of the LV network revealed that the largest generator it could accept was 100MVA and that this would be connected at location 14. Larger generators were restricted largely by line thermal capacity limitations.

V. Conclusions

It has been demonstrated that the proposed software tool provides essential support for decision making in siting and sizing embedded generators in an existing distribution system. Given a wide choice of generators and possible sites, the developed software tool has effectively narrowed down the number of options that the planner can concentrate on. The final decision, as to the actual position and rating, as always rests with the planner.

This technique has only considered synchronous generators. Induction generators would perform in a similar way except that their capability to feed into faults is much lower than that of synchronous generators. Generators with power electronic interfaces to the grid are not capable of supplying fault currents hence they would not raise the fault levels. Their drawback is that they are so expensive that they may not be the least cost option. They are also a potential source of harmonics if not properly controlled.

Looking into the future, the developed tool could be enhanced by improving the short circuit routine to include other types of faults apart from the currently implemented three-phase symmetrical fault.

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VII. Biographies

Bless Kuri received his BSc and MSc degrees from the Universities of Zimbabwe and Bath in 1996 and 2003 respectively. He held the position of Project Engineer for two years with Autocontrol Systems, planning and implementing Industrial Automation and Control projects. In 2000, he joined the Zimbabwe Electricity Supply Authority as a Planning Engineer in distribution systems. He is currently pursuing a PhD degree. Areas of interest are electricity market design and Power Systems Operation and Control.

Miles Redfern (M' 1979) received his BSc degree from Nottingham University and PhD degree from Cambridge University in 1970 and 1976 respectively. In 1970, he joined British Railway Research, and in 1975, moved to GEC Measurements where he held various posts including Head of Research and Long Term Development and Overseas Sales Manager. In 1986, he joined Bath University with interests in Power Systems Protection and Management.

Dr. Furong Li was born in Shannxi, China. She received her B.Eng. in Electrical Engineering from Hohai University, China in 1990, and her Ph.D. in 1997 with a thesis on Applications of Genetic Algorithms in Optimal Operation of Electrical Power Systems. She took up a lectureship in the Power and Energy Systems Group at the University of Bath in 1997. Her major research interest is in the area of economic and secure operation of power systems.

IMPACT OF MARKET STRUCTURES AND RULES ON THE OPERATION OF POWER SYSTEMS IN A COMPETITIVE MARKET ENVIRONMENT

B. Kuri

University of Bath

ABSTRACT

Despite the changing structure of the electricity supply industry, priority remains on secure and economic operation of the power system. The operation of the physical power system depends on the behaviour of the market participants, who in turn respond to market signals. The strength of these market signals is a direct measure of the effectiveness of a market structure and its associated rules. The ability of the market agents to exercise market power is dependent upon the market structure and the rules that they operate under. This has an indirect impact on the power generation patterns and the utilisation of power plants. The market derived generation pattern will deliver certain system security, economic and environmental performance. This work investigates the effect of the different market structures and their respective rules on the operation of the power system. The impact of these structures and rules on the long-term investment in power system infrastructure is also looked at.

Keywords: Competitive markets, Market structure, Power System Operation

INTRODUCTION

The principles of power system operation remain the same despite the changing operating environment. Priority remains on secure and economic operation of the power system regardless of the market model in place. Delivering secure and economic operation depends on the effectiveness of the day-to-day operation strategies (short-term) and the available generation and transmission capacity (determined in long-term). Traditionally, with the vertically integrated systems, a single entity was in charge of both power system operation planning and system planning. Capacity reinforcements and additions were relatively easily co-ordinated with operational requirements in terms of secure and economic operation of the system. In the deregulated environment, it is the responsibility of the market to ensure that secure and economic operation of the system continues as well as economic and timely investment in power system infrastructure.

The competitive environment is characterised by competition between generation entities, power marketers, brokers and load serving entities, with only the networks being operated as regulated businesses. The extent of competition depends on level of development of the market. The system operator is charged with securely and economically operating the power system in a coordinated manner, yet the system operator does not have direct control over generation and demand in an open market environment. The decentralised nature of today's liberalised markets is the basis of the fundamental challenges facing these markets: delivering secure and economic operation of the power system and timely and economic investment in power system infrastructure. Many different market structures have emerged around the world and they vary in their effectiveness in tackling the challenges outlines above.

Although there are many different market structures for wholesale electricity markets, they can be broadly classified into three main categories namely (i) mandatory pool with system marginal price, (ii) mandatory pool with pay-as-bid price and (iii) contracts with dispatch priority and system balancing [1], [2]. In this paper, the short-term and long-term impact, on power system operation, of these market structures is looked at.

OPERATIONAL ASPECTS

In this analysis, the following aspects of power system operation were looked at:

- short-term
  - Generation scheduling and dispatch,
  - Economic performance
  - System security and
  - Environmental performance.
- long-term
  - Investment in system infrastructure.

The three short-term aspects give an indication of the performance of the market structure while the long-term aspect is concerned with investment in the power system in order to have a sustainable market operation into the future. A market structure that fails to adequately address the later will subsequently suffer from the first three aspects in the future and therefore would be unsustainable. Environmental performance of the power system in terms of greenhouse gas emissions is becoming of great importance, evidenced by governmental emission targets for the industry. For example, in the UK the electrical energy from renewable resources is targeted at 10% by 2010 and 20% by 2020 towards an overall 60% reduction in CO2 emissions by 2050 [3].

As a base case, the traditional vertically integrated structure was used since it is the origin for almost all power systems in the world. The reasons for abandoning the vertical structure vary between different countries but there are a number of common reasons that were identified [2], for example, introducing customer choice, lowering electricity prices while maintaining secure supplies, providing transparent markets, attracting private investment, dealing with stranded costs and reducing debt.

The performances of the structures of interest are looked at here according to the operational aspects outlined above.

Mandatory pool with system marginal price

The are two basic variants of this model: (i) the system operator accepts sufficient bids from generators to meet load demand which is generally non-responsive and (ii) the system operator accepts bids from both generators and demand and balances the two. In either case, the system marginal price (which is also the market clearing price) is determined as illustrated in Fig. 1. The generation bids are arranged in merit order based on cost in an unconstrained dispatch. Every generator whose bid was accepted gets paid the same price (shaded area in Fig. 1), that is the system marginal price.

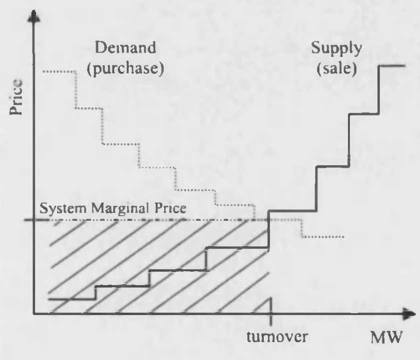

Fig 1. Determination of the System Marginal Price

It therefore does not matter how much the generator bids as long as the bid is accepted, except for the unit that sets the marginal price. Since the bids are selected without considering system constraints, the system operator may have to accept additional out-of-merit generation bids in order to meet system security requirements. These generators are paid what they bid, which is higher than the system marginal price. Thus the effect of including security constraints increases the pool purchase price. However, the system operator has direct access to the generators as long as they have submitted bids into the pool. Hence system security is not threatened in this setup.

Assuming that generator bids are closely related to their true production costs, the pool system with system marginal price can deliver secure supplies economically in the short term. It would also be possible to determine the proportion of the total costs attributable to achieving system security by considering the cost of ancillary services – generally in the form of out-of-merit generation whose bids are accepted for system security reasons.

Collusive behaviour and market power abuse by especially large generators can result in high generation prices which are not related to the costs, most notably in a system without demand flexibility. While the resultant system operation may be secure, it would not be economic. This is one of the reasons that caused the England and Wales pool system to be abandoned in 2001 in favour of the New Electricity Trading Arrangements (NETA) [4].

In most pool structures, it is recognised that there is need to reward capacity that is available whether it has been selected to generate or not and as such there is usually a capacity payment to all registered generators that are available in the system. In the short term, this payment may not really make a difference in generation turnout but in the long-term, those less frequently used generators tend to disappear from the market if they feel that it is not viable to have no compensation for being available. This can also cause investment in new generation plant to diminish as investors fear that they may not be able to recover their investment costs. The consequences of this are generation deficit at times of peak demand and the subsequent damage to system security. In the open market, electricity prices will tend to spike during peak demand times leading to the imposition of price caps by the electricity market regulators.

Although generation is unbundled in this case, its dispatch is still centralised to some extent, therefore the system operator still has some level of control on the generation schedule since the merit order can be overridden to accommodate security requirements. It is therefore necessary that there is enough spare capacity to allow the system operator to maintain system security.

If emissions are considered, the generators may also need to provide their unit emission characteristics to the system operator to consider in addition to the costs. However, this would make the process less transparent and complicated. An emissions management scheme may have to be implemented separately from the pool system for example through some king of an emissions market. If the generation mix is dominated by heavily polluting plant then the effect of emission trading will be to increase prices of electricity from base load plant, making previously marginalised plant and most renewable generation technologies more viable. The introduction of intermittent renewable generation like wind power can have a negative impact on system security [5], depending on the generation mix – which inevitably translates into increased costs [6].

Depending on how the capacity payments are treated in a pool structure with system marginal price, it could be possible to achieve economic and secure environmentally friendly power system operation both in the short-term and long-term.

Mandatory pool with pay-as-bid price

The two basic variants under the mandatory pool with system marginal price also apply here and the system marginal price is determined in the same way. The only difference in this case is that the generators get paid what they actually bid rather than the system marginal price as shown by the shaded area in Fig. 2 below.

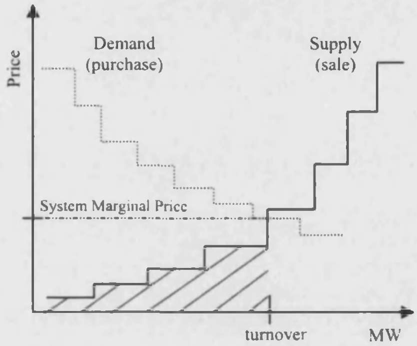

Fig 2. Payments received by generators

Ideally, this would force the generators to submit bids that truly reflect the production costs because generators do not only have to strive to get selected but also to be able to maximise their profit – the two of which are conflicting. Even this market structure is prone to market power abuse especially when there are a number of large generators that can afford to speculate on the system marginal price and strategically position themselves as close as possible to the marginal system price.

Marginal generation plant may find the environment too harsh and concerns have been raised that this structure encourages aggregation of generation as the smaller generators, who are most exposed to risk, are likely to get stranded and eventually be bought by the large ones. Depending on the market implementation, there may be rules that limit the maximum capacity of each generating entity to avoid oligopolistic behaviour.

The generation available to the system operator remains the same as in the pool with system marginal price and therefore, the short-term performance is most likely similar if it is assumed that market power abuse can be mitigated.

Competition is more aggressive in this model because of the increased risks of not being selected therefore it is more difficult to maintain marginal plant running or to attract investment in new generation as the risk of failing to recover costs beyond short-run or production costs is very high.

The problem of ensuring that economic and secure system operation can be maintained into the future arises when capacity is not rewarded appropriately. The real problem is that expensive generation is normally used during peak times and therefore for lower durations. During the short times that they run, they would have to recover both capital and operational costs. This results in price spikes and the regulator usually responds by capping the prices to avoid price volatility and exposing the customers to excessive electricity prices. To restore viability in the generation sector, a capacity payment has commonly been introduced. However consumers tend to feel that it is unfair to pay for generation when it is doing nothing but the truth is that this is a form of 'security' insurance that they do not always see when it is drawn upon [7].

Contracts with dispatch priority and system balancing

This represents a major stride towards true open markets. In this market model, the bulk of demand is met through bilateral contracts between generators and consumers/load serving entities. Generally, contracts are non-standard, that is the two parties are free to agree on the exact terms of the contracts. In some markets, the lead time in the forwards and futures contracts can be up to three years. To augment the bilateral contracts, the spot market normally runs about 24 hours ahead of real time to enable the market participants to fine tune their physical positions to reflect their revised forecasts of demand and generation availability. It also enables the system operator to decide on the most relevant balancing services close to real time. Standardised products (energy) are traded on the spot market and in this respect, it can be viewed as some kind an 'open pool' which is however not mandatory. At gate closure, the market participants may submit non-mandatory bids and offers from which the system operator balances the system. Because of the operational challenges in real time balancing of the system, the bid/offer selection is normally a closed process.

This market structure is highly liberalised and enables the generators to enter into suitable contracts with load serving entities, knowing that these contracts are firm. They can strategically structure their contracts so as to break even and make a profit. Moreover, there are several means by which the market participants can hedge against risks in the market place, for example, forward contracting, financial instruments like options and swaps and they can also trade in the spot market and finally they can submit bids into the balancing market [8].

Although the system operator is still charged with the economic and secure operation of the power system, most of the energy traded (for example, 98 %+ in the UK market) is through transactions generated and executed in the open market place. Generation is no longer centrally dispatched. There are various rules that aim to make generators more responsible and accountable for their actions that may jeopardise system security, for example a market participant that fails to fulfil their contract position and cause an imbalance in the system is penalised according to the extent of the imbalance due to them. The system operator then makes sure that whatever imbalance that exists in the system is balanced through acceptance of balancing mechanism bids and offers and other instruments at their disposal. But power balance does not necessarily imply a secure system therefore the system operator also has to consider other aspects of security like static security, voltage stability and dynamic stability. Thus the system operator can only manage system security within prescribed market mechanisms. Therefore, the security performance of a system is largely a function of the market structure together with its associated rules that govern the operations of the market participants as well as the performance of the system operator.

This market structure allows the market participants to reflect the economics of the underlying production processes and the value of plant as both influence the final price of electricity produced by the generators. It also makes it difficult for market entities to abuse their market power and most importantly, deals with the problem of capacity payment explained in the first two market structures. However, there are other factors that affect the attractiveness of the investment environment like stability of government and regulatory policy and other political factors.

If market forces are allowed to dominate, certain plant will tend to disappear due to some rules in the market that may discriminate against such plant. This may not be desirable due to the need to achieve some goal that is not well integrated in the market and therefore there would be no appropriate market mechanisms to address the goal. An example is renewable generation which is crucial in meeting environmental targets. Without the introduction of renewable obligation certificates in the UK, renewable generation would not have made as much contribution to the total electricity generation. It is important however to ensure that these goals are addressed with appropriate market mechanisms to ensure that normal market forces drive performance and most importantly, future sustainability of the market operations.

Short-term and long-term secure and economic power system operation in this case is heavily dependent on the how the market rules are designed to achieve the various goals.

DISSCUSION

In the traditional power systems, all the objectives in power system operation, both short-term and long-term, were handled by a single entity. Technically, this is a sound setup since overheads are reduced and there is likely to be better coordination of system operation and planning. However, in practice, it has been proved that such massive structures tend to be inefficient especially when they are operated as single entities [2].

Moving away from the traditional systems has meant that the various emergent entities have to be reorganised to be able to give a comparable performance of the power system as before or better. From the power system operation point of view, the challenges increase with increasing decentralisation of the power system. There is more and more reliance on the market structure and the associated rules to deliver system performance both in the short-term and in the long-term.

Pool based structures tend to have complications with dealing with the problem of rewarding generation capacity availability, especially for less frequently used plant. Short-term operation is relatively less challenging as the dispatch is largely centralised.

With contract based structures the system operator does not have real control over generation and demand as they interact in the market and the system operator has to ensure that whatever position the market is, it is secure. If not, they have to 'balance' the system. The challenge can be worsened by the time that the system operator is given to make all the necessary decisions, that is from gate closure to real time operation. In the UK, this time is only one hour. Capacity payment is not represented explicitly here but if the electricity prices are very low, the generators may fail to recover their capital costs, resulting in the same problem with pool systems if capacity payments are low.

CONCLUSIONS

It was found that the physical operation of the power system has remained the same despite the changes in the operating environment. However, the methods by which the actual generation schedules are arrived at, how security, costs and emissions are managed have radically changed since the times of the vertically integrated systems.

The major challenges in system operation emanate from the decentralisation of the system and the reliance on the market to provide adequate generation capacity, security and environmental friendly power systems. Most countries have successfully continued to maintain secure power system operation in the new market structures, thereby demonstrating that it is possible to run the power system in a decentralised fashion with market forces dictating the activities in system operation.

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EFFECTIVE DESIGN FOR COMPETITIVE ELECTRICITY MARKETS

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ABSTRACT

The deregulation of the electricity supply industry has resulted in the formation and growth of numerous electricity markets including retail, wholesale and ancillary markets. Effective design of electricity markets seeks to integrate principles of market economics with the physical characteristics of power system operation. An efficient electricity market should produce cost reflective prices, reliable and secure electricity supplies and adequate infrastructure. It should be transparent, providing a level playing field for all market participants and have a mechanism to detect and deter market power abuse. Most importantly, the market should be robust enough so as not to result in the collapse of the power system in the presence of market flaws. This paper looks into various types of markets among the deregulated electricity supply industries and analyses market design principles for efficient and competitive markets. The paper puts special emphasis on wholesale energy markets as they form the major trading hub in the electricity market.

Keywords: Market design, Market reform, Competition

INTRODUCTION

Under the vertically integrated structure, planning for the entire power system was centralized. In most countries, rising costs of electricity which were attributed to inefficiencies in the electricity supply industry had by far the most influence on market reform. Often this rise in prices would be caused by over investment in the electric infrastructure which mainly results from over ambitious load forecasts, coupled with over manning and poor performance of plant. For example state governments in Australia over-invested in generation capacity anticipating a mineral boom which did not materialize [1], consequently increasing electricity prices paid by consumers.

Other drivers for market reform include the pressure to attract more investment, manage operational problems associated with dispatching large pools and deliver supply reliability required by customers. Against a background of rising debt, many governments have turned to deregulation of state owned utilities in a bid to stimulate economic growth through efficient use of resources driven by clear price signals in competitive markets. Economic theory holds that having a large number of players in direct competition increases economic efficiency expressed in higher quality services and lower product prices. Unlike most commodities, electricity can not be efficiently stored in large quantities yet, hence it has to be produced just when it is needed.

Under the traditional vertically structured electricity industry there was no customer choice and competition in the provision of generation and retail services. This paradigm has significantly shifted to competitive electricity markets. Despite this shift, priority has remained on delivering quality, secure and economical electricity supplies. The challenge is to develop and maintain suitable legal and commercial frameworks to enable these markets to operate in a way that promotes effective competition without compromising the aforementioned priority. This forms the basis of the market design problem.

A market design can be network specific as reform objectives vary from country to country. This paper considers a market bounded by national boundaries. Where a block of countries are involved, it is prudent to develop a standard market design approach that will harmonize co-ordination and control of the power system and enable seamless market operations. The later is beyond the scope of this paper.

REFORM OBJECTIVES

Market reform objectives are generally specified in the energy policy. According to a World Energy Council report on electricity market design and creation in Asia Pacific [1] commissioned in 2001, some of the top objectives of electricity market reform are introducing competition in generation and retail services, providing transparent markets, introducing customer choice, lowering prices while maintaining quality and security of supplies, attracting private investment and dealing with stranded costs and reducing debt.

The objectives have to be decomposed into measurable criteria for use in the design and evaluation of the relevant markets. Market design should be consistent with the government's energy policy in order to ascertain regulatory stability which gives confidence to customers, the electric power industry and investors alike. This can create an environment where sufficient investment could be secured to maintain adequate and timely electric infrastructure and technological innovation, thereby enabling efficient utilization of resources [2].

It is expected that the energy policy is stable and well formed to enable planning into the far future. However, modifications are inevitable due to challenges that crop up with time for example new technologies environmental and commercial pressures.

THE DESIGN PROCESS

The design process typically starts by transforming objectives into specifications. These are then used to determine the appropriate market structure and rules that will best satisfy the objectives. There are a number of possible market structures [1], therefore it is necessary to have a way of screening the contending options. Market simulation is proposed as a suitable tool for screening and refinement. This helps to thoroughly assess the likely performance of a market design before it is launched. Fig 1 below shows a simplified block diagram for the design process of a market.

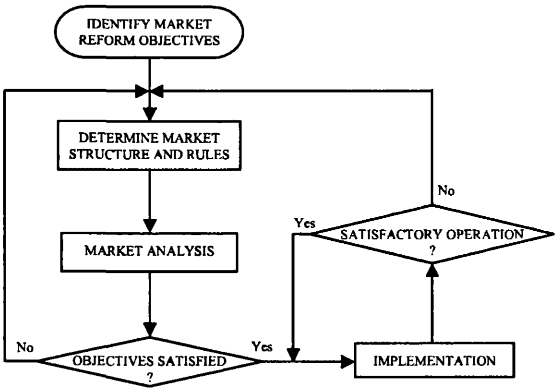

Fig 1. Market Design Process

Changing commercial, regulatory and environmental regimes may require the market to change in order to maintain efficient operation. Thus it is necessary to have procedures for reviewing market operations from time to time and for making modifications.

There are a number of critical issues that need to be resolved. These include prerequisite conditions that are needed for the creation of competitive markets and issues to do with the choice and implementation of market rules. These are briefly looked at below.

Preconditions for Introduction of Competition

The World Energy Council report [1] identifies seven preconditions for successful introduction of competition in generation. These are: (i) an attractive investment environment, (ii) excess generating capacity (typically between 20 and 25%), (iii) many competing generators (the number depends of diversity of generating plant), (iv) high current prices in generation and supply, (v) the will to lower electricity prices, (vi) easy access to the grid and (vii) a well connected grid (one with minor constraints). If there is not sufficient generation then it may be necessary to introduce competition in construction of generation plant. On the supply side there also needs to be many participants and most importantly, the supply business should be separated from "wires" business to allow customer choice of suppliers.

Market Design Issues

"Good market design begins with a thorough understanding of the market participants, their incentives, and the economic problem that the market is trying to solve" [3]. The design committee should be independent of interested parties lest the final designs are compromised resulting in failure to satisfy market objectives. While a simple design is desirable, oversimplification often leads to a poorly designed market.

Issues that need special attention are: ensuring that market rules encourage generators to express their true costs, ensure market liquidity, demand side response to real time prices of electricity, market power mitigation and ensuring that market changes are subject to constraints and clear arbitration. The rules have to make provisions for market participants to deal with risks associated with the nature of electricity markets. For example, risk can be reduced through the use of financial hedging contracts, futures and forwards contracts. The rules should be clear and must not contradict energy reform objectives as this can result in loss of confidence among market participants and investors.

Market Structure and Rules

The ability of a market to deliver is highly dependant on its structure and the market governance in place. The structure refers to the market entities and the legal and commercial structures that bind them. Market rules bind all participants; govern their activities and define their relationships. They cover transaction issues, from contract establishment, obligatory and commercial services, bids and offer submission, environmental requirements to settlement and payment as well as conflict resolution.

Market power mitigation and economic efficiency issues are dealt with through market rules. For example, in order to ensure fair competition, a limit may be imposed on the total generating capacity that can be owned by one entity.

Market Entities
Market participants have to be qualified as any of the predefined market entities depending on what operations they intend to engage in. The following are the most common market entities found in most competitive markets: generators, suppliers, customers, transmission system operators, brokers and marketeers. Fig 2 shows the relationships between these entities in a bilateral wholesale market. Relationships between these parties are critical in achieving effective competition and fair trading practices. The transmission system operator is charged with the responsibility of operating the power system securely and economically as well as ensuring adequate investment in infrastructure through charging for the use of the transmission system. In the interest of all traders, the system operator should not have any interests in generation or supply. Generators should compete to sell their services. The same applies for suppliers. Customers should be allowed to choose their supplier irrespective of the owner of the transmission or distribution system to which they are connected (thus network ownership and energy wheeling should be separate entities). Brokers do not generate, purchase or sell energy; instead, they act like middlemen by facilitating transactions between buyers and sellers. Marketers buy and sell energy but they do not own any generation facilities. The last two parties help improve market liquidity.

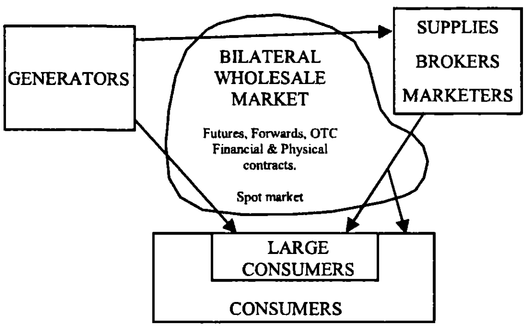

Fig 2. Relationships Between Market Entities

There are other entities that are not directly involved in the trading but are crucial in the running of these markets. These are the network owners, market administrators and the regulator. Networks are regulated businesses because they are naturally monopolistic. The network owners have to develop and maintain the networks to improve efficiency in an economical and coordinated manner. The administrator is responsible for the governance of the market as well as implementing a settlement process and arbitrating disputes between market participants should they arise. It is also essential that the administrator does not have interests in generation or supply businesses. Finally, the regulator is responsible for ensuring that the market operates efficiently and that there is no abuse of market power.

Power Markets
Principally, there are energy markets, ancillary markets and capacity markets in some cases. In some countries there are also transmission markets [4].

Wholesale energy trade can be via a pool (centralized market) or bilateral contracts (over-the-counter and futures and forwards contracts) and spot markets. Contract and spot transactions can be conducted on the power exchanges. Bilateral contracts can also be directly entered into by market participants. The power exchanges also report market prices. Market prices should be reported close to real time as far as is practicable to enable demand to respond to real time price variations on the spot market.

The nature of ancillary services allows the procurement of services say once every half year or on a seasonal basis. The services that should be available on this market are system reserve, frequency and voltage support and black start capability. Demand side management should also be considered together with other reserve services. Competition is achieved by floating tenders for the provision of these services.

In countries where there is a market for transmission, transmission rights are used to allocate the right to a market participant to schedule and dispatch their generation. The transmission rights can either be financial or physical. They are commonplace in the USA where they are also used as a congestion management technique in addition to being a form of payment for use of the transmission system. The rights are allocated via an auction. Market power determines the price of these rights and it is expected that where capacity is scarce, this will be reflected in high prices and effectively provide locational signals for infrastructure investment.

Capacity markets are implemented to recognize and encourage investment in generation plant. However, they do not promote system reliability in the short term as capacity payments are made to registered generators irrespective of their actual availability. Although they tend to encourage investment in generation, they do not give locational signals as to where generation is needed most and they are not performance based, hence they are not economical.

MARKET MODELS

Wholesale energy markets can be categorized into four models namely the mandatory pool with system marginal price, mandatory pool with pay as bid price, contracts with dispatch priority and system balancing and the minimalist model [1]. These are briefly discussed below.

Mandatory Pool with System Marginal Price
Under this arrangement, generators submit their bids into the pool that is run by the system operator. The bids are arranged in merit order according to bid prices. The bid price for the last generator chosen to satisfy forecasted demand (market clearing price) becomes the system marginal price and all generators whose bids have been accepted are paid this price. The major disadvantage of this system is that after considering the unit commitment and economic dispatch of the system close to real time, it may be necessary to engage out-of-merit generators for system security reasons. The issue here is that these out of merit generators are paid their bid prices which are higher than the market clearing price. Also, because there is no incentive for generators to bid prices close to their costs, their bids are likely to be inflated, resulting in profiteering.

In this setup, large generators can abuse their market power because demand is inelastic (not responsive), since consumers do not take part in the pool, and the system operator is obliged to secure sufficient generation to meet demand. This model however provides a conducive environment for new market entrants, as they will be cushioned by large generators through clearing prices and reduced risk of not being selected in the merit order.

Mandatory Pool with Pay-as-bid Price
At face value, this model sounds like a solution to the problems of the pool with system marginal price but it has its own problems. There is no guarantee that there will be no market power abuse as sufficiently large generators could spend time forecasting demand and guessing the market clearing price [3]. By bidding most of their generation close to the clearing price they could still successfully inflate their incomes. Added to this, it becomes difficult for economically marginalized generators, small generators and new entrants to survive in that environment. It may therefore encourage aggregation of generation entities, thus undoing the objectives of market reform. This model is not used its pure form.

Modifications of this model could seek to incentivise generators to bid prices close to their costs and to expose a reasonable portion of demand to market price variations in the hope that there will be enough demand response to dampen price spikes, especially during peak demand periods. One way of achieving this could be to allow the demand side to submit bids to reduce demand and be paid accordingly. This would obviously be limited to large consumers. Studies have shown that a demand response of 2-5% is sufficient to substantially stabilize market prices [5].

Both in this model and the first one, market power may be mitigated by making generators submit multi-part bids that separate startup, shutdown, no-load and energy costs [3]. This enables the generators to directly express the underlying costs and helps the system operator to perform better-informed unit commitment and economic dispatch.

Contracts with Dispatch Priority & System Balancing
Various forms of this model became popular in the late 1990s in USA (California, Pennsylvania, New Jersey, Maryland, New York) and Spain [1]. It forms the basis of the New Electricity Trading Arrangements (NETA) now in place in the UK. The main feature of this model is that generation plant is dispatched with priority for contracted demand. There also exists a balancing market for ensuring that the system is balanced in real time. This can be viewed as a pool of some sort. In some countries like Chile, contracts are mandatory and the pool is used as a means for generators to optimize costs in meeting their contracts. In some countries like New Zealand, this priority exists but contracts are not mandatory and a generator may choose to just take part in the balancing mechanism. In the UK contracts are mandatory but participation in the balancing market is optional. Generators and suppliers normally submit bids and offers to this market as this helps reduce the risk due to possible imbalances as well as present an opportunity to earn extra revenue.

The premises behind this model is to encourage market participants to enter into contracts well ahead of time so that the majority of the energy is traded via bilateral contracts and over-the-counter trades, resulting in minimal energy being traded in the balancing market. In this model, competition is more aggressive compared to pool based models due to the need to secure a contract in order to be dispatched. Contracts provide generators the right to dispatch for long periods; hence they are encouraged to offer cost reflective prices. This results in prices in a contract based market being lower than in a daily pool market [6].

The Minimalist Model
This model was pursued only in Germany. There were nine privately owned large utilities altogether, all opposed to market reform. The passing of the European Union Directive on third party access committed member states to allow certain customers to be supplied other than by their local monopoly distribution businesses. The German utilities failed to agree on a common approach among themselves and also with the government. The

government subsequently introduced primary legislation obliging the utilities to allow competition for all customers [1]. The vertically integrated structures of the utilities meant that transmission charges were bundled, but this had to change now. No central systems were developed and several independent power exchanges have emerged.

The availability of excess capacity enabled competition to effectively take place and this resulted in dramatic price reductions of 25% to 30% being offered to all customer groups. The amount of excess capacity was such that the largest of the nine utilities was smaller than the excess capacity so that it was not possible for any of them to protect their customer base from competition. Additionally, interconnections to neighboring countries allow 50 % of Germany's demand to be met from imports. Generally, there was fear of loosing customers due to long term fuel commitments that they had. This intensified competition for customers.

This showed that market arrangements do not have to be centrally developed. However, a number of conditions need to be rightly set, as seen in the case of Germany, if effective competition is to be realized. It is these conditions that need to be explored in order to develop efficient markets.

SIMULATION

Electricity market simulation is a relatively new area. It is important in evaluating the effect of proposed market structure and rules on a given market before the design is implemented. The effect of market power on competition, economy and system security may be deduced from the simulation. The simulation can also be used to determine suitability of transmission charging methodologies. Of particular importance in the economic operation of the competitive market is how the market encourages the choice of generators that result in optimum system operation in terms of economy and security. Traditionally the system operator was responsible for selecting the units that would generate but under bilateral based competitive markets, we rely on the market signals to achieve this. Finally, simulation can help evaluate market economy and efficiency based on different rules.

WHEN THE MARKET FAILS

Market failure can manifest in insufficient generation and reserves, poor system security and market power abuse. Government intervention has been a major worry, especially for investors [6]. When modifications are made to the market structure and rules, it is of paramount importance that they are based on sound market economics. In other words, appropriate signals have to be used in remedying a problem rather than simplistic approaches like price caps. This coupled with absence of long term contracts culminated in the famous California blackout. Thus if markets are administered properly, there will be no need for such desperate measures and backstop mechanisms to avoid blackouts caused by market flaws.

CONCLUSIONS

The design and operation of electricity markets should always be with reference to the market reform objectives so that any discrepancies should be identified and dealt with in a manner that does not render the market uncompetitive. Appropriate competition and market structures should be adopted to ensure objectives are achieved. This requires clear and transparent markets that are regularly reviewed and updated to keep abreast with the changing environmental and commercial environments. Effective design aims to achieve market objectives with the simplest possible market structures and rules.

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Appendix A

Generation Technology Characteristics

THIS appendix gives typical generation characteristics (capital and operating costs, economic life time, efficiency, availability, emissions and wastes.

Table A.1. Coal fired CSC plant characteristics. *Source: ETSU 1994*

	Small CSC	Medium CSC	Large CSC
Operating characteristics			
Lifetime (y)	40	40	40
Capacity (MW)	<200	200 to 450	>450
Availability	83	80	79
Efficiency (%)	31	32	35
Costs			
Capital (£/MW)	1000	900	800
Variable O & M (p/kWh)	0.03	0.03	0.03
Fixed O & M (£/kW/y)	30	27	24
Emissions/ Wastes			
CO_2 (kg/GJ)	282	273	249
N_2O (g/GJ)	19	19	17
SO_2 (g/GJ)	3775	3638	3326
NO_x (g/GJ)	1368	1325	960
Particulates (g/GJ)	53	51	47
Heavy metals (g/GJ)	27.5	26.5	24.5
Solid waste (kg/GJ)	22.5	21.5	20

Table A.2. HFO fired CSC plant characteristics. *Source: ETSU 1994*

	HFO CSC
Operating characteristics	
Lifetime (y)	30
Capacity (MW)	<200
Availability	80
Efficiency (%)	34
Costs	
Capital (£/MW)	640
Variable O & M (p/kWh)	0
Fixed O & M (£/kW/y)	19.2
Emissions/ Wastes	
CO_2 (kg/GJ)	214
N_2O (g/GJ)	–
SO_2 (g/GJ)	3824
NO_x (g/GJ)	850
Particulates (g/GJ)	113
Heavy metals (g/GJ)	6–23.5
Solid waste (kg/GJ)	26–68

Table A.3. OCGT plant characteristics. *Source: ETSU 1994*

	Old OCGT	New OCGT
Operating characteristics		
Lifetime (y)	30	25
Capacity (MW)	<70	<70
Availability	80	80
Efficiency (%)	18.3	31.5
Costs		
Capital (£/MW)	280	360
Variable O & M (p/kWh)	0	0
Fixed O & M (£/kW/y)	7	7
Emissions/ Wastes		
CO_2 (kg/GJ)	220	161
N_2O (g/GJ)	–	–
SO_2 (g/GJ)	349	0
NO_x (g/GJ)	220	209
Particulates (g/GJ)	–	–
Heavy metals (g/GJ)	–	–
Solid waste (kg/GJ)	–	–

Table A.4. CCGT and IGCC (coal) plant characteristics. *Source: ETSU 1994*

	CCGT	IGCC (coal)
Operating characteristics		
Lifetime (y)	30	30
Capacity (MW)	200–600	200–600
Availability	90	85
Efficiency (%)	50	45
Costs		
Capital (£/MW)	350–250	950–675
Variable O & M (p/kWh)	0	0.1
Fixed O & M (£/kW/y)	12.5–17.5	20.3
Emissions/ Wastes		
CO_2 (kg/GJ)	112	203
N_2O (g/GJ)	3.5	0.7
SO_2 (g/GJ)	0	57
NO_x (g/GJ)	193	160
Particulates (g/GJ)	0	1–9
Heavy metals (g/GJ)	0	20
Solid waste (kg/GJ)	0	17.5

Table A.5. CFBC and PFBC plant characteristics. *Source: ETSU 1994*

	CFBC	PFBC
Operating characteristics		
Lifetime (y)	30	30
Capacity (MW)	200–400	200–400
Availability	85	85
Efficiency (%)	41	41
Costs		
Capital (£/MW)	920–810	950–700
Variable O & M (p/kWh)	0.09	0.07
Fixed O & M (£/kW/y)	24.3	21
Emissions/ Wastes		
CO_2 (kg/GJ)	230	213
N_2O (g/GJ)	60	10
SO_2 (g/GJ)	306	284
NO_x (g/GJ)	290	146
Particulates (g/GJ)	43	8
Heavy metals (g/GJ)	22.5	21
Solid waste (kg/GJ)	28	24

Table A.6. Triple Cycle Fuel Cell (FC), Hybrid Cycle, and MHD plant characteristics. *Source: ETSU 1994*

	FC (Triple Cycle)	Hybrid Cycle	MHD
Operating characteristics			
Lifetime (y)	30	30	30
Capacity (MW)	200	200–400 to 450	200–1000
Availability	85	85	80
Efficiency (%)	60[24]	44	45
Costs			
Capital (£/MW)	925	830–700	1200–800
Variable O & M (p/kWh)	0	0.07	0.05
Fixed O & M (£/kW/y)	12.5	16.8	24
Emissions/ Wastes			
CO_2 (kg/GJ)	94	198	194
N_2O (g/GJ)	–	20	–
SO_2 (g/GJ)	0.43	265	78
NO_x (g/GJ)	0.4	250	510
Particulates (g/GJ)	0	37	37
Heavy metals (g/GJ)	0	19.5	19
Solid waste (kg/GJ)	18	22.5	16.5

Table A.7. Characteristics of retrofit technologies, flue gas de-carbonisation (FGD) and low NO_x burners, to reduce nitrogen based emissions from existing CSC plants. *Source: ETSU 1994*

	Retrofit FGD	Retrofit Low NO_x burners
Operating characteristics		
Availability	85	85
Efficiency (%)	41	41
Electrical demand	40MW for 2GW station	–
Costs		
Capital (£/kW)	160	7.6
Variable O & M (p/kWh)	0.02	–
Fixed O & M (£/kW/y)	4.8	–
Emissions		
NO_x	–	within 650mg/m^3
SO_2	90% removed	–

Appendix B

Input Data

THE input data used to demonstrate the presented methodology is given in this Appendix.

Week	Peak Load	Week	Peak Load
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.2

Figure B.1. Weekly peak load in percent of annual peak. *Source: IEEE Reliability Test System 1996.*

Day	Peak Load
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Figure B.2. Daily peak load in percent of Weekly peek. *Source: IEEE Reliability Test System 1996.*

	winter weeks		summer weeks		spring/fall weeks	
	1 -8 & 44 - 52		18 -30		9-17 & 31 - 43	
Hour	Wkdy	Wknd	Wkdy	Wknd	wkdy	wknd
12-1 am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-noon	95	91	100	93	99	94
noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

Figure B.3. Hourly peak load in percent of daily peak. *Source: IEEE Reliability Test System 1996.*

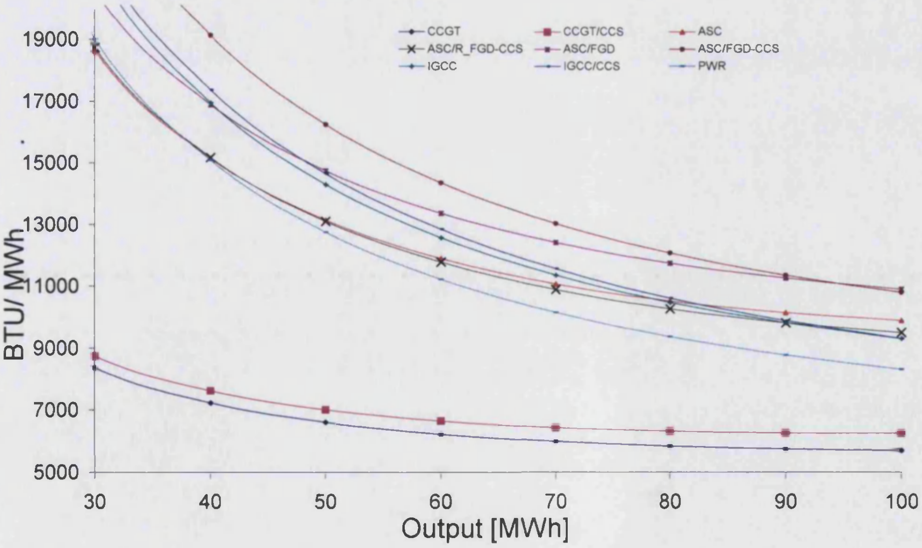

Figure B.4. Heat rate curves for thermal generation technologies.

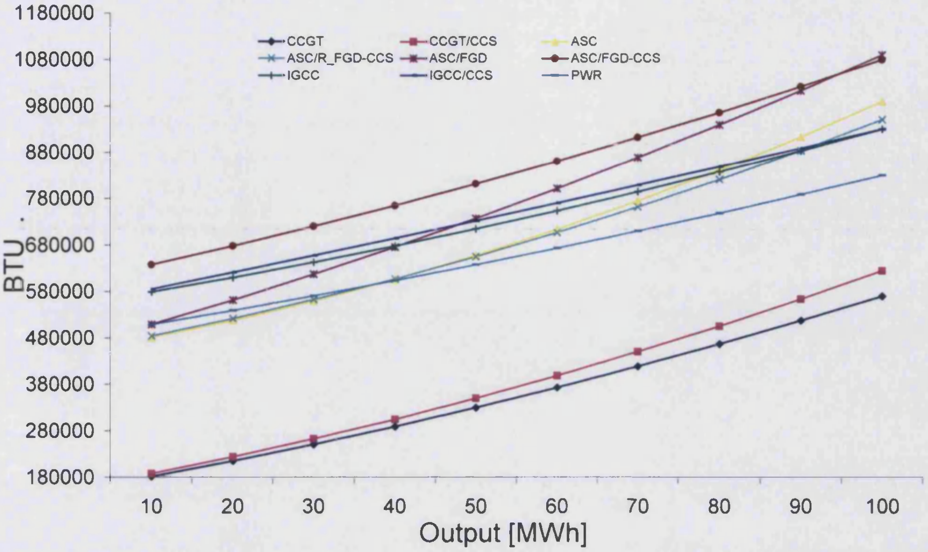

Figure B.5. Heat input curves for thermal generation.

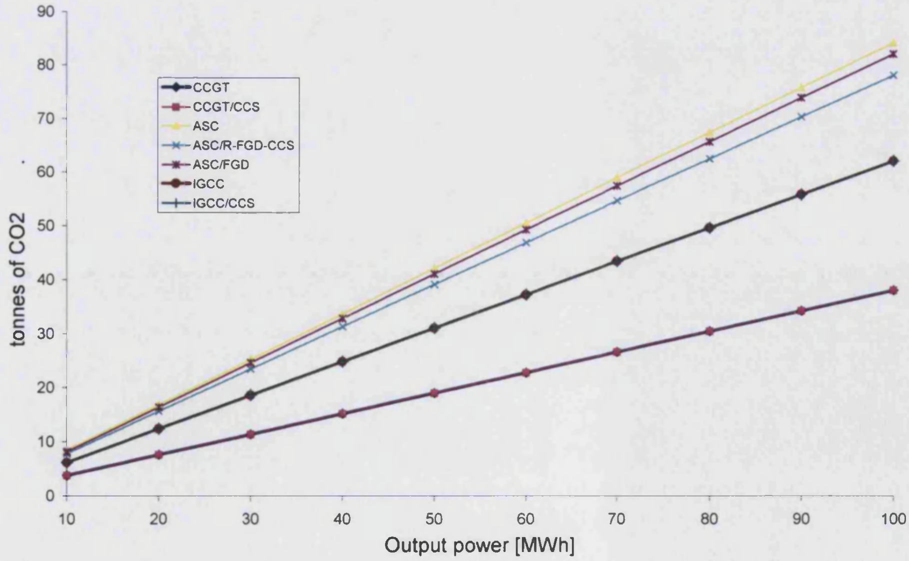

Figure B.6. CO_2 emission characteristics for fossil powered thermal generation technologies.

Table B.1. Wind turbine per unit power output curve. *Derived from: http://www.windpower.org/en/tour/wres/pow/index.htm.*

Wind speed [m/s]	pu power output	Wind speed [m/s]	pu power output
1	0	16	0.9984
2	0	17	0.9968
3	0	18	0.9984
4	0.0032	19	1.0000
5	0.0274	20	0.9839
6	0.0726	21	0.9581
7	0.1161	22	0.9548
8	0.2000	23	0.9516
9	0.3161	24	0.9355
10	0.4468	25	0.9274
11	0.5871	26	0.9194
12	0.7161	27	0.0000
13	0.8597	28	0.0000
14	0.9419	29	0.0000
15	0.9968	30	0.0000

Table B.2. Split of generation capacity between 2 GENCOs.

GENCO	Capacity [MW]				%
	Nuclear	ASC	ASC/FGD	CCGT	
G1	700	500	400	600	44
G2	1200	300	200	1100	56

Table B.3. Split of generation capacity between 4 GENCOs.

GENCO	Capacity [MW]				%
	Nuclear	ASC	ASC/FGD	CCGT	
G1		300	300	600	24
G2	700	200	100		20
G3		300	200	800	26
G4	1200			300	30

Table B.4. Split of generation capacity between 6 GENCOs.

GENCO	Capacity [MW]				%
	Nuclear	ASC	ASC/FGD	CCGT	
G1		300	300	300	18
G2	400	100		300	16
G3	300	300	100	200	18
G4		100	200	500	16
G5	600			200	16
G6	600			200	16

Table B.5. Split of generation capacity between 8 GENCOs.

GENCO	Capacity [MW]				%
	Nuclear	ASC	ASC/FGD	CCGT	
G1		200	100	300	12
G2		100	200	300	12
G3	500	100			12
G4	200	300	100	100	14
G5		100	100	400	12
G6	300		100	300	14
G7	500			100	12
G8	400			200	12

Appendix C

Results

THIS appendix shows the detailed results on which the discussions and graphs in Chapter 5 are based.

Table C.1. Generation mix capacities [MW] for emission costs up to 20£/tCO_2.

CO_2 cost [£/ton]	Gas cost [p/therm]	ASC	CCGT	CCGT/CCS	ASC/R-FGD-CCS	ASC/FGD	ASC/FGD-CCS	IGCC	IGCC/CCS	WIND
0	40	2700	1700			600				
0	50	2700	1300			1000				
0	60	2700	1100			1200				
0	70	2700	1000			1300				
0	80	2700	900			1400				
0	90	2700	900			1400				
0	100	2700	800			1500				
5	40	700	2000			500		1800		
5	50	700	1400			1000		1800		
5	60	700	1100			1300		1800		
5	70	700	1000			1400		1800		
5	80	700	1000			1500		1800		
5	90	700	900			1500		1800		
5	100	700	900			1600		1800		
10	40		2500					1700		1800
10	50		1600			900		1700		1800
10	60		1200			1200		1700		1800
10	70		1100			1400		1700		1800
10	80		1000			1500		1700		1800
10	90		900			1500		1700		1800
10	100		900			1600		1700		1800
15	30		2300	2700						
15	50		1500				1400		1200	1900
15	60		1200				1700		1200	1900
15	70		1100				1800		1200	1900
15	80		1000				1900		1200	1900
15	90		900				2000		1200	1900
15	100		900				2000		1200	1900
20	30		1400	3600						
20	40		1500	500			800		1300	1900
20	50		1400				1400		1300	1900
20	60		1200				1700		1300	1900
20	70		1000				1800		1300	1900
20	80		1000				1900		1300	1900
20	90		900				1900		1300	1900
20	100		900				2000		1300	1900

Table C.2. Generation mix energy [TWh] contributions for emission costs up to 20£/tCO_2.

CO_2 cost [£/ton]	Gas cost [p/therm]	ASC	CCGT	CCGT/CCS	ASC/R-FGD-CCS	ASC/FGD	ASC/FGD-CCS	IGCC	IGCC/CCS	WIND
0	40	15.82	3.26			3.79				
0	50	15.05	2.00			5.82				
0	60	14.66	1.51			6.70				
0	70	14.47	1.30			7.10				
0	80	14.28	1.10			7.48				
0	90	14.28	1.11			7.48				
0	100	14.10	0.93			7.84				
5	40	3.42	3.62			2.55		13.28		
5	50	3.15	1.96			4.47		13.28		
5	60	2.99	1.30			5.30		13.28		
5	70	2.94	1.12			5.54		13.28		
5	80	2.87	1.02			5.71		13.28		
5	90	2.89	0.95			5.75		13.28		
5	100	2.82	0.87			5.90		13.28		
10	40		7.58					11.73		3.54
10	50		3.30			4.29		11.72		3.54
10	60		2.26			5.32		11.74		3.54
10	70		1.76			5.83		11.72		3.54
10	80		1.52			6.07		11.72		3.54
10	90		1.46			6.12		11.74		3.54
10	100		1.30			6.30		11.72		3.54
15	30		9.49	13.38						
15	40		7.13				4.46		7.54	3.72
15	50		3.71				7.88		7.54	3.72
15	60		2.62				8.96		7.54	3.72
15	70		2.30				9.29		7.54	3.72
15	80		2.00				9.59		7.54	3.72
15	90		1.72				9.86		7.54	3.72
15	100		1.72				9.86		7.54	3.72
20	30		3.92	18.95						
20	40		4.27	1.82			4.90		8.13	3.72
20	50		3.36				7.63		8.13	3.72
20	60		2.38				8.62		8.12	3.73
20	70		2.03				8.96		8.13	3.72
20	80		1.80				9.20		8.12	3.73
20	90		1.75				9.24		8.13	3.72
20	100		1.54				9.46		8.12	3.73

Table C.3. Generation mix capacities [MW] for emission costs in the range 20£/tCO_2 to 40£/tCO_2.

CO_2 cost [£/ton]	Gas cost [p/therm]	ASC	CCGT	CCGT/CCS	ASC/R-FGD-CCS	ASC/FGD	ASC/FGD-CCS	IGCC	IGCC/CCS	WIND
25	30		1100	3900						
25	40		1100	1000			700		1400	2000
25	50		1200	100			1400		1400	2000
25	60		1100				1700		1400	2000
25	70		1000				1800		1400	2000
25	80		1000				1800		1400	2000
25	90		900				1900		1400	2000
25	100		900				1900		1400	2000
30	30		1000	4000						
30	40		1000	1200			500		1600	2000
30	50		1000	300			1400		1600	2000
30	60		1100				1600		1600	2000
30	70		1000				1700		1600	2000
30	80		900				1800		1600	2000
30	90		900				1800		1600	2000
30	100		900				1900		1600	2000
35	30		900	4100						
35	40		900	1400			400		1700	2000
35	50		900	500			1300		1700	2000
35	60		1000	200			1600		1700	2000
35	70		1000				1700		1700	2000
35	80		900				1700		1700	2000
35	90		900				1800		1700	2000
35	100		900				1800		1700	2000
40	30		800	4200						
40	40		900				1800		1700	2000
40	50		900	500			1200		1800	2100
40	60		900	200			1500		1800	2100
40	70		900	100			1700		1800	2100
40	80		900				1700		1800	2100
40	90		900				1800		1800	2100
40	100		800				1800		1800	2100

Table C.4. Generation mix energy [TWh] contributions for emission costs in the range 20£/tCO_2 to 40£/tCO_2.

CO_2 cost [£/ton]	Gas cost [p/therm]	ASC	CCGT	CCGT/CCS	ASC/R-FGD-CCS	ASC/FGD	ASC/FGD-CCS	IGCC	IGCC/CCS	WIND
25	30		1.82	21.05						
25	40		2.47	3.63			4.19		8.63	3.92
25	50		2.73	0.28			7.28		8.64	3.91
25	60		2.09				8.21		8.63	3.92
25	70		1.80				8.49		8.63	3.92
25	80		1.80				8.49		8.63	3.92
25	90		1.55				8.75		8.63	3.92
25	100		1.55				8.75		8.63	3.92
30	30		1.06	21.81			0.00			
30	40		1.85	4.41			2.92		9.75	3.92
30	50		1.75	0.75			6.68		9.75	3.92
30	60		1.91				7.27		9.75	3.92
30	70		1.66				7.52		9.75	3.92
30	80		1.42				7.76		9.75	3.92
30	90		1.42				7.76		9.75	3.92
30	100		1.27				7.93		9.73	3.93
35	30		0.82	22.05			0.00			
35	40		1.34	5.02			2.30		10.27	3.93
35	50		1.35	1.24			6.06		10.27	3.93
35	60		1.41	0.39			6.88		10.26	3.93
35	70		1.50				7.15		10.27	3.93
35	80		1.45				7.19		10.29	3.92
35	90		1.29				7.37		10.27	3.93
35	100		1.29				7.37		10.27	3.93
40	30		0.70	22.17						
40	40		1.29				7.37		10.27	3.93
40	50		1.31	1.29			5.44		10.69	4.12
40	60		1.33	0.43			6.29		10.69	4.12
40	70		1.19	0.17			6.70		10.67	4.12
40	80		1.30				6.74		10.69	4.12
40	90		1.16				6.90		10.67	4.12
40	100		1.10				6.94		10.69	4.12

Appendix D

Energy Units and Conversions

THE information presented in this appendix was obtained online from *'http://www.physics.uci.edu/ silverma/units.html'* curtesy of Dennis Silverman at University of California, Irvine, Dept. of Physics and Astronomy.

D.1 Energy Units and Conversions

- A BTU (British Thermal Unit) is the amount of heat necessary to raise one pound of water by 1 degree Farenheit (F).
- 1 Joule (J) is the MKS unit of energy, equal to the force of one Newton acting through one meter.
- 1 British Thermal Unit (BTU) = 1055 J (The Mechanical Equivalent of Heat Relation)
- Power = Current x Voltage (P = I V)
- 1 Watt is the power from a current of 1 Ampere flowing through 1 Volt.
- 1 kilowatt is a thousand Watts.
- 1 kilowatt-hour is the energy of one kilowatt power flowing for one hour. (E = P t).
- 1 kilowatt-hour (kwh) = 3.6 x 106 J = 3.6 million Joules
- 1 calorie of heat is the amount needed to raise 1 gram of water 1 degree Centigrade.
- 1 calorie (cal) = 4.184 J (The Calories in food ratings are actually kilocalories.)
- 1 BTU = 252 cal
- 1 Quad = 1015 BTU (World energy usage is about 300 Quads/year, US is about 100 Quads/year in 1996.)
- 1 therm = 100,000 BTU

D.2 Power Conversion

- 1 horsepower (hp) = 745.7 watts

D.3 Gas Volume to Energy Conversion

- One thousand cubic feet of gas (Mcf) → 1.027 million BTU = 1.083 billion J = 301 kwh
- One therm = 100,000 BTU
- 1 Mcf → 10.27 therms

D.4 Energy Content of Fuels

Fuel	Energy Content
Coal:	25 million BTU/ton
Crude Oil:	5.6 million BTU/barrel
Oil:	5.78 million BTU/barrel = 1700 kWh
Gasoline:	5.6 million BTU/barrel (a barrel is 42 gallons)
Natural gas liquids:	4.2 million BTU/barrel
Natural gas:	1030 BTU/cubic foot
Wood:	20 million BTU/cord

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