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Security assessment of future UK electricity scenarios

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Security of decarbonised electricity systems

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Content:

1.INTRODUCTION

In the context of reducing CO_2 emissions, the UK Government's 2010 targets for Renewables and CHP will make only a small (if symbolically important) contribution. A considerably larger proportion of renewable and other low carbon energy sources (e.g. fuel cells, micro CHP and possibly nuclear) will be required in order to respond to the climate change challenge over the longer time horizon. This new generation will displace the energy produced by large conventional plant, raising serious questions about the ability of such a system to manage the balance between supply and demand, and hence, to maintain the security of the electricity system. Currently, large conventional centrally controlled generators (coal, oil and gas fired, but not nuclear) play a vital role in managing the balance between load and generation in the operation time scale and hence maintaining a secure system. Clearly, meeting variable demand with intermittent, and/or uncontrolled and/or inflexible generation will be a major challenge for secure operation of sustainable electricity systems of the future.

This inter-disciplinary project investigates the security of decarbonised electricity systems with the following objectives:

1. Identification of future UK decarbonised electricity scenarios.
2. Security assessment of decarbonised electricity systems: Capacity and Balancing Aspects.
3. Security assessment of decarbonised electricity systems: Environmental and Economic Aspects.

In the context of our work on the security assessment of decarbonised systems the first objective is to identify the plausible future scenarios for electricity demand as well as generation for the UK. Defining new scenarios being out of the scope of this project, we analysed some of the recently projected UK energy scenarios and deduced the possible medium and long-term UK electricity generation sector development schemes. It should be emphasised that the purpose of our work is not to determine the composition of the future UK generation system. On the contrary, the purpose of this report is to turn the readers' attention to some important technical issues that might emerge due to the projected changes in this composition. Our understanding of the analysed medium term projections shows that the wind power can be expected to be a dominant renewable technology by 2020. Therefore, for the mid-term future UK electricity scenarios we assumed a wide range of wind penetrations up to 40GW. The long-term future UK electricity scenarios are derived from the projections given by the Royal Commission on Environmental Pollution. The derivation of these scenarios is described in Chapter 2.

The focus of this report is basically on the second objective, bearing in mind that this objective deals with many important technical issues regarding security of the future decarbonised UK electricity system. Penetration of intermittent renewable resources can displace the *energy* produced by large conventional plant. However, there are a number of concerns in relation to the ability of this new generation to replace the *capacity* of the conventional plant and in particular its flexibility. This raises a number of questions as to whether the future sustainable system will be able to operate securely and how exactly the *balance* between generation and demand will be managed.

The ability of intermittent sources to replace conventional capacity is investigated for both mid-term and long-term future UK scenarios in Chapter 3. The question here is how the potential low availability of the renewable resource (such as wind, wave and PV) over a period of several days or weeks would be dealt with in a system with a large contribution to overall electricity supply coming from renewable sources. As this is considered to be a plausible situation and massive load curtailments are assumed not to be acceptable, a significant amount of additional generation capacity will need to be available.

Another important question when managing security of decarbonised electricity systems is how to balance their load and generation due to an unpredictable steep increase/decrease in the power provided by intermittent resources or load and sudden loss of generation. Researchers and engineers argue that there will be a need to develop new forms of flexibility in both supply and demand sides in order to satisfactorily manage such situations. In Chapter 4 we investigate how different levels of supply flexibilities can affect the balancing of the demand and generation of the future decarbonised electricity systems.

In a low-carbon electricity energy based system, with intermittent renewable generation producing the vast majority of electricity, considerable capacity of conventional plant may still be required. This would mean the conventional power system might be acting as a backup or standby system, which obviously may reduce the overall value of renewable generation. Due to a relatively small capacity contribution of intermittent sources a considerable number of conventional plants might be running at low output levels over a significant proportion of their operational time to accommodate this intermittent energy. Consequently these plants will have to compromise on their efficiency resulting in increased levels of fuel consumption as well as emissions per unit of electricity produced. At the end of Chapter 4 we investigate this phenomena focusing on the economical and environmental aspects such as: the fuel cost associated with system balancing, CO_2 emissions and possible reduction in energy produced by conventional generating units.

2.FUTURE UK ELECTRICITY SYSTEMS

Historically, conventional generation systems, fossil fuel based thermal and nuclear plants had been the dominant part of the UK's power generation industry. However, due to a number of issues arising since the last quarter of the last century, the power industry, governments and research and development institutions have started to explore alternative options for electricity generation. Among the key drivers for this new focus were the *environmental or climate change impacts* and the *sustainability of the primary energy sources* for the conventional generation technologies. Besides these two basic drivers, the *security of energy supply issue* also emerged as being critically important for the smooth operation and development of both the developing and developed economies. This resulted in an unprecedented interest in renewable technologies that could satisfy the future requirements of electricity production and at the same time be environmentally benign, sustainable in nature and ensure a secure supply of energy.

For the medium-term future the UK government plans 10% and 20% renewables share by the year 2010 and 2020 (revised as 15% by 2015). Due to these renewable targets and other forms of distributed generation by 2010/2020 and beyond, significant amounts of energy presently produced by large conventional plants will be displaced. However, concerns over system costs are focussed on whether these new generation technologies will be able to replace the capacity and flexibility of conventional generating plant. As intermittency and non-controllability are inherent characteristics of renewable energy based electricity generation systems, the ability to maintain the balance between demand and supply has been a major concern. Clearly, meeting a variable load with intermittent, and/or uncontrolled and/or inflexible generation (such as wind, wave and solar) will be a major challenge for secure operation of the sustainable electricity systems of the future.

Among all renewable technologies wind offers the greatest potential for expansion in the United Kingdom in the short to medium term. This is a windy island, and with the exception of Ireland has the most favourable wind profile, both on- and offshore, in Western Europe. Therefore, it is expected that wind power will play a key role to achieve 2010/2020 targets for renewable generation. However, a considerably larger proportion of renewable and other low carbon energy sources (e.g. fuel cells, micro CHP and possibly nuclear) will be required in the long-term in order to respond to the climate change challenge beyond 2020.

In the context of our work on the security assessment of decarbonised systems the first task was to identify the plausible future scenarios for electricity demand as well as generation for the UK. Defining new scenarios being out of the scope of this project, we analysed some of the recently projected UK energy scenarios and deduced the possible mid and long-term UK electricity generation sector development schemes. This task was essential for the subsequent analysis carried out in later chapters and provided the necessary input for the security assessment of the future systems. It involved a detailed literature survey and communication with several relevant institutions to explore the available energy/electricity projections for the UK, with an eventual derivation and selection of credible electricity scenarios.

In the first paragraph of this chapter we discuss energy scenarios. The available scenarios found in literature are described in the second paragraph. The Royal Commission on Environmental Pollution (RCEP) energy projections are described in 2.3, while the derivation of the RCEP electricity scenarios is given in 2.4.

2.1.Energy Scenarios and Their Key Drivers

Energy scenarios that provide a framework for exploring future energy perspectives, including various combinations of technology options and their implications are often used to predict future energy development and their various impacts. These scenarios attempt to cover a wide range of possibilities. Each energy scenario is created using a number of "building blocks" such as population projections, expected economic development, changes in energy efficiency, shifts in fuel usage - fossil and non-fossil, prospects for successful technology innovation and diffusion, level of efforts to tackle environmental problems, extent of mobilisation of funds, as well as the role of relevant institutions and government policies.

Moreover, there can be various objectives met or explored through designing various future energy scenarios. In the UK consideration of mitigation of climate change impact, sustainability and security of energy systems had been the major driving force for the development of most of the medium to long-term energy scenarios. The importance of these considerations for the UK, in projecting the composition of future electricity generating systems having significant share of renewables, is elaborated in the following sub sections.

2.1.1 Environmental impact and climate change

One of the most concerning effects of the production of electricity from fossil fuels is the emission of so-called greenhouse gases (GHG) such as carbon dioxide (CO_2), methane (CH_4), chlorofluorocarbons (CFCs) and other chemicals whose complex molecules are able to absorb infrared radiation more strongly than simpler ones. The emission of greenhouse gases causes global warming at a rate around $0.3^0 C$ per decade [Boy96]. The temperature of the earth is the result of a balance between incoming radiation from the sun and outgoing radiation from the earth. This balance is affected by absorption or reflection, which occur in atmosphere. The molecules of oxygen (O_2) and nitrogen, which are dominant in the atmosphere are made from only two atoms and as such do not absorb the infrared radiation. However, more complex molecules such as these found in greenhouse gases absorb this radiation, trap it near to the surface and therefore keep temperatures higher. There are some predictions by the Intergovernmental Panel on Climate Changes (IPCC) that the concentration of CO_2 can be doubled by 2050, which will cause global warming of between $1.5^0 C - 4.5^0 C$ [Boy96].

Another very serious implication for the UK is the reduction of the Gulf Stream, which could bring less heat to northwest Europe and therefore harsher winters. An increase in global temperatures (and therefore melting sea ice) and precipitation may add more fresh water to the north Atlantic and decrease its salinity. The component of the Gulf Stream driven by the differences in water density is likely to decrease by 25% in the next 100 years.

Another side effect of the burning process is acid rain. These rains are produced when sulphur dioxide and nitrogen oxides (released in the burning process) combine with water in the atmosphere and form sulphuric acid and nitric acid respectively. The result is that any rain that follows is acidic and cause damage to plan life, seriously affecting the growth of forests and erodes buildings and corrodes metal objects [Boy96]. In the UK about 70% of the sulphur dioxide is released from burning processes in power stations.

The United Kingdom is committed under the Kyoto Protocol to reductions in greenhouse gas emissions by 2010 of 12.5 percent, compared with 1990 levels, and the Government have also made a national commitment to achieving a 20 percent reduction in the United Kingdom's CO_2 emissions by 2010, and a 60 percent cut by 2050. The exploitation of renewable energy sources—abundant and inexhaustible—may assist in controlling emissions, and will in turn assist the United Kingdom in meeting its environmental commitments [HOL04].

Nuclear power is the only major source of electricity which could, in theory, be used in all countries on the scale of fossil-fuelled power stations and which does not emit carbon dioxide. However, unfortunately, as the Chernobyl accident demonstrated nuclear power also has the capacity for large scale contamination. While the standards of engineering and the safety requirements of nuclear power plant in the UK are exceedingly high, there is no doubt that the spectre of Chernobyl in the former USSR is the dominant force affecting public

opinion. Secondly, the issue of managing the highly radioactive spent fuel is still open. This discourages the future large scale role of nuclear technology.
The environmental consequences of renewable sources are, virtually without exception, on a much lower scale than for other sources. The most serious effects tend to be aesthetic, such as a reduction in scenic views, and the large number of devices needed to replace the output of a conventional power station resulting in a large area of land being occupied. Due to their relatively very low intensity of environmental damage and consequent lesser impact on climate change, renewables are foreseen as a significant component of the future energy scenarios.

2.1.2 Sustainability and security of energy supply

About thirty years ago sustainability of energy sources was considered as the foremost problem in the energy sector development. Some predictions regarding future resource use were very pessimistic and came into sharp focus in the 1973 (fuel crisis) when the members of OPEC began to coordinate their policies and raised the price of oil dramatically [Boy96]. The shortages expected in those days do not seem imminent at present, taking into account that new explorations using modern technologies proved, with a reasonable certainty, that the fossil fuel reserve could be recovered in the future. However, due to the uneven distribution of natural resources on the earth it is quite probable that countries lacking these resources will find dependence on fossil fuels unsustainable.

As far as security of energy supply is concerned, there can be many causes for breakdowns in the delivery of energy services. Political intervention may create energy security issues, as was the case in 1973 and 1979. Sabotage, technical failures of components with highly bundled energy flows, systemic failures and under-investment are also real problems. Their impact on the energy system today and in the future may be greater than in the past, as there is an increasing stringency in energy supply and demand.

Another factor, arguably of particular concern to the United Kingdom, is the risk inherent in increasing reliance on gas as a primary source of energy. United Kingdom production from the North Sea is now at its peak, and we will become a net importer of gas as early as 2006. As production from the United Kingdom continental shelf tails off over the next 15 years, and with the running down of the coal industry and the closure of coal-fired power stations, we will become increasingly dependent on gas imports to meet our electricity needs. This carries risk, as although imports will come from a number of sources, by 2020 more than half of United Kingdom gas imports are likely to come from Russia [HOL04]. Political risk data provided by the insurance sector suggest that interruptions in such supplies of up to 180 days may occur as often as once every eight years [OX03]. The United Kingdom currently has gas storage facilities equivalent to only 14 days' supply, compared with an EU 15 average of 52 days[OGUK].

Diversity of energy sources will thus be essential if the risk to United Kingdom power supplies is to be mitigated, especially if nuclear power is not available. Renewable energy, in which the United Kingdom is rich, thus has a significant part to play in ensuring the long-term security of power supplies. Renewable energy, despite the difficulties it presents to the day-to-day reliability of electricity supplies, has a significant part to play in ensuring long-term security. It is essential that every effort is made to mitigate the effects of intermittency, so that renewables, in enhancing security of supply, do not undermine reliability.

The immense importance of having securely deliverable energy systems is widely recognized by various governments and major international organizations. The European Commission has already highlighted the significance of this subject [EC00]. It is now widely accepted that diversification of energy supplies and distribution – both by energy type and by source – is an important measure to help improve energy security. Utilising renewable energy sources reduces the need for import of fuels and provides energy security benefits. However, the technological and economic concerns raise questions regarding the reliable and affordable security levels that renewables can provide.

Looking to the future, what the various short-term price and supply disruptions of the last few years have done is to re-emphasize the need for robust, multifaceted energy security policies. One emerging component of these policies is the role which renewables can offer in the strategic development of energy/electricity plans. Therefore all future energy system growth forecasts for the UK are inclined towards renewables.

2.2 Available Scenarios

The first scenario that is described in this section is an official report to the British Government submitted by the Renewable Energy Advisory Group (REAG). The REAG suggest in its report that increasing use of renewable sources will help to reduce environmental damage caused by acid rains, and limit the emissions of CO_2 according to the government commitments [Boy96]. A mid range estimate of the renewable contribution in 2025 is 20% of the 1991 electricity supply. In this report the total potential of the UK renewable energy is estimated to 1060 TWh per year. A significant contribution of about 700 TWh would come from wind offshore and onshore generation. Energy crops could produce about 200 TWh per year and photo-conversion and photovoltaic each about 75 TWh per year. All other renewable technologies, according to this report, could not produce a comparable amount of energy by 2025.

Among the international initiatives to curb the unwanted effects arising from conventional energy production and use, the European Commission (EC) presented the ALTERNER programme. The main purpose of the European Commission’s ALTENER programme was to develop the use of renewable energy in the European Union (EU). Such increased use of renewable energy was promoted in order to limit emissions of greenhouse gases and to reduce the EU dependence on imported energy. The scenario suggested by the ALTENER programme sets European targets for 2005 based on the renewable generation produced in 1991. In order to meet these targets

- wind energy needs to be increased 20 times,
- large hydro needs to be increased by 30%,
- the energy produced by small hydro (under 10 MW) needs to be increased by 100%,
- biomass and waste energy need to be increased 3 times,
- geothermal energy needs to be increased by 3 times.

The total electricity energy obtained by summing up all these sources should be about 280 TWh per year in 2005 [Boy96].

The SCAR report [SCAR02] investigated a number of possible scenarios showing that extending renewable generation to 20% or 30% of demand by 2020 would increase system costs associated with integration of this generation in the UK power systems. The extent of the additional system costs was found to vary considerably, depending on the technology and location of renewable plant. An analysis of the breakdown of the total costs, between the three elements examined – balancing and capacity, transmission, and distribution, demonstrated that balancing and capacity costs, principally the cost of maintaining system security, dominate all other costs. These costs arise because of the intermittency of many renewable technologies, in particular wind, which represents a large proportion of Great Britain’s renewable resource.

The Royal Commission on Environmental Pollution’s Report “Energy — the Changing Climate” was presented to Parliament in June 2000 [RCEP00]. The report promotes a transformation in the use of energy in the UK in order to counter climate change. The Royal Commission recommends that the UK should play a key role in the implementation of the Kyoto Protocol. The RCEP's suggestion is for a reduction in carbon dioxide emissions by some 60% from 1998 levels by about 2050. The RCEP report explores what this will mean for industry and households and highlights how Government policies need to be changed. The future energy system and electricity generation sector composition is discussed in detail in the following section.

The side effects (environmental and climate change) were the main motivation for various governments, international bodies, industries, environmental groups and independent research organisations to consider how the use of fossil fuels can be reduced. In scenarios, which they suggested, the energy obtained from fossil fuels can be replaced to some extent by renewable energy. This work focused on those credible scenarios which were endorsed by the UK government. The proposed structure of the UK's energy system as presented in the RCEP report appears promising for the UK's role in dealing with the CO_2 reduction issue and to address the climate change impact. The Government has also appreciated these scenarios and RCEP recommendations and produced a formal response [GOV03] to the RCEP report. This document summarises the action being taken and proposed, and their relation to the Royal Commission's recommendations. Therefore, we choose RCEP energy scenarios for our research to determine the security of the decarbonised electricity systems.

2.3. RCEP Energy Scenarios

The main purpose of the Royal Commission on Environmental Pollution report was to review energy prospects for the 21st century and their environmental implications. The aim was to identify the actions required in the years ahead in order to develop a sustainable strategy for energy provision and use [RCEP00].

In the light of the international efforts for green house gas control, the RCEP projects the UK's role in GHG emission reduction and suggests various strategies for the energy system evolution in the long-term future. Bearing in mind that the upper limit on the atmospheric concentration of carbon dioxide is 550 parts per million by volume (ppmv)[1] the RCEP suggests that UK carbon dioxide emissions would have to be reduced by almost 60% from their current level by mid-century, and by almost 80% by 2100. Moreover, the RCEP suggests that 'the UK should continue to play a forceful leading role in international negotiations to combat climate change, both in its own right and through the European Union.' [RCEP00].

2.3.1. Background

The projection published by the Department of Trade and Industry (DTI) [DTI02] related to energy consumed by final users, and the consumption of primary energy was the main focus of the RCEP work on the future UK energy scenarios. The DTI suggests that primary energy is used in the UK at an average annual rate of about 300 GW[2] in 1998 and the energy consumed by final users is at an annual average rate of about 210 GW. There is an increase of the primary energy consumption of 24% with respect to 1965 and an increase of about 16% of the energy consumed by final users with respect to the same year.

Almost 90% of the primary energy in the UK is produced by fossil fuels. The Nuclear power share was about 10% in 1998. Coal share was changed from about 150 GW in 1965 to about

[1] Carbon dioxide concentration in the atmosphere at the end of the last glacial period was approximately constant for 10,000 years at about 270-280 parts per million by volume (ppmv). Over the last 250 years, as industrialisation has taken place, the concentration has risen to about 370 ppmv [RCEP00].

[2] *average annual rate* (AAR) is *average* plant output over a *year* expressed in GW or MW [2].

60 GW in 1998. Oil use for transport made its share equal to 33%. Following discovery of large reserves in the North Sea, gas share of UK primary energy rose from zero in 1965 to 37% in 1998. [RCEP00].

Energy losses are caused dominantly by electricity generation. This reflects the lack of any commercial or institutional structure for using the low-grade heat produced while generating electricity [RCEP00].

Due to these facts the RCEP strongly suggest the following two directions for the future energy strategy:

1. The UK must expand considerably the proportion of energy obtained from sources other than fossil fuels (alternative energy sources).
2. Serious reduction in energy use, which would bring the reduction of burning fossil fuels and consequently the threat of all possible consequences of climate changes.

2.3.2. Alternative energy sources

The possible alternatives to fossil fuel sources are [RCEP00]:

- Nuclear power, large-scale inland water power and tidal barrages.
- Non-carbon technologies that have been already applied in some other countries in a significant scale, such as wind power and photovoltaic.
- CHP technologies, which use energy crops and wastes.
- Wave power and tidal streams are very promising technologies in terms of their potential.

At present 28% of electricity in the UK is generated from nuclear power (40% in Scotland), 1.5% from inland water power (about 25% in Scotland). AAR of electricity generation at direct flow stations in 1998 was 0.5 GW and at pumped storage stations was 0.2 GW. The REAG estimated that energy produced from tidal barrages in the UK could be at a level of 5.7 GW AAR. The main obstacles for the further development of nuclear power are waste disposal and public acceptability. The Energy Technology Support Unit (ETSU) argues that any proposal related to new inland water schemes is very likely to be ruled out due to the change of appearance and ecology of the uplands. Both large inland water schemes and tidal barrages have high initial costs in relation to their generating capacity [RCEP00].

Wind power can be generated at wind speeds of 5-25 m/second, while the mean wind speed which makes them financially workable is 7 m/seconds. About a third of the land area of the UK has sufficiently constant winds to make accessible resources equivalent to the whole of the UK's electricity supplies. The main obstacles to the further development of wind power are: effects on the landscape and noise. There is even larger potential (by order of magnitude) in offshore wind farms. The main obstacles in this case would be: the sea bed must be suitable (water depths less than 40 m), construction of the towers and the cables linking them can cause damage to the sea bed, interference with commercial fishing, the dredging of marine aggregates, merchant shipping, military operations, flight paths of birds and visual impact[RCEP00].

Photovoltaic cells efficiency in converting sunlight energy into electricity is about 20% in research devices, but not more 11-15% in practical devices [RCEP00]. The main obstacles to using this technology on a large scale are the high cost of the cells and ancillary equipment, 25-30 years life cycle, and a very low efficiency.

CHP technologies, which use energy crops and wastes, belong to so-called alternative carbon-based technologies. All fuel sources in these technologies contain carbon and CO_2 is emitted when their energy content is released. However, the carbon dioxide which growing plants take up from the atmosphere can compensate for much of the carbon dioxide released into the atmosphere if materials derived from plants are used as a source of energy in place of fossil fuels [RCEP00]. The main obstacles of using energy crops are: farmers and landowners should be willing to devote land to their production in preference to other possible uses, they cannot be easily grown in uplands, they can not be grown on land that could be used for food production, they will change both the appearance and the ecology of the countryside.

According to the RCEP report over 27 millions of tones of municipal solid waste has been produced in the UK each year. The potential of this fuel is about 4 millions tones a year of straw, 1 million air-dry tonnes of poultry litter and 1.7 million dry tonnes of forestry waste, which can produce an AAR of 2 GW of electricity.

Wave power and tidal stream power have considerable potential but require much further work on their technology in other to assess their practicability and demonstrate the technology [RCEP00]. According to the estimates of the wave power density at various locations around the world, the areas which are exposed to regular wind fluxes are those with the largest wave energy resource. The use of this technology can be limited due to: land use sterilisation (shoreline), construction/maintenance sites (shoreline), coastal erosion, fish and marine biota, acoustic noise, navigation hazards [RCEP00].

2.3.3. Potential for reduction in energy use

The RCEP suggest serious reduction in energy use, which would bring about a reduction in burning fossil fuels. Improving efficiency with which energy is used at the stage of final consumption, and large reductions in the losses or in primary energy should be the main targets in the energy reduction schemes suggested by the RCEP.

The RCEP categorises the great variety of energy use into the following four energy sectors:

- the transport sector, which includes road, rail, air and water transport both public and private, and for both goods and passengers (about 34%);
- the domestic sector (about 30%);
- the commercial and public sector, which includes government buildings, commercial offices, education, health, shops, restaurants, commercial warehouses, pubs, clubs, entertainment, religious buildings and miscellaneous other energy sources (about 14%).
- the industrial sector, which includes manufacturing, iron and steel, food and drink, chemicals, building, agriculture (about 22%).

Road transport takes about 77% of the transport sector's final energy use. The potential for reducing energy consumption has been seen in increasing the fuel efficiency of vehicles, reducing road congestion and motorway speed limits, sharing cars for commuting, using public transport, telecommuting and tele-conferencing.

The potential for energy reduction in the domestic sector is in: improved wall insulation, high efficiency boilers, more efficient electrical appliances (25% of domestic final consumption is on electrical appliances), insulation of lofts and hot water cylinders, installation of a higher standard of double glazing, improvements in lightning.

The major problem of commercial and public services is their dependence on electricity. This dependence is higher than for any other sector. The commercial side of the sector accounts for some 60% of the sector's total energy use. The potential for reducing energy in this sector lies in: improvements in heating, cooling and lighting, raising the efficiency of electrical appliances, use of CHP plant with a much lower output than those used in the industry sector.

In the industry sector a significant percentage of energy is used to process heat often at high temperatures (high-grade heat). There is also a large requirement for motive power: machines for moving, shaping, forming, etc. The potential for reducing energy demand here is in greater use of CHP.

2.4. RCEP Electricity Supply and Demand Projections

Four scenarios proposed by the Royal Commission on Environmental Pollution differ in three main aspects: the assumed demands for energy, use of renewable energy sources, and whether baseload capacity is provided by nuclear power or by fossil fuel stations at which the carbon dioxide is recovered and disposed of. All of the proposed scenarios can be categorised with respect to these aspects as follows [RCEP00]:

- ***scenario 1:*** no increase on 1998 demand, combination of renewables and *either* nuclear power stations *or* large fossil fuel power stations at which carbon dioxide is recovered and disposed of
- ***scenario 2:*** demand reductions, renewables (no nuclear power stations or routine use of large fossil fuel power stations)
- ***scenario 3:*** demand reductions, combination of renewables and *either* nuclear power stations *or* large fossil fuel power stations at which carbon dioxide is recovered and disposed of
- ***scenario 4:*** very large demand reductions. renewables (no nuclear power stations or routine use of large fossil fuel power stations).

In the next two sections electricity and supply projections for each of these scenarios are discussed in greater detail**.**

2.4.1. Derivation of electricity supply projections

From the basic scenario outlines given above, the RCEP developed mixes of energy supply technologies for 2050. Using the data provided in the RCEP report (AAR and additional information related to the numbers and types of plants required) and assuming likely load factors for each technology we derived the electricity supply projections for each individual technology. These projections are given in Table 1.

Table 1 – Electricity Supply Predications Implied by Four RCEP Scenarios (TWh)

	Scenario 1			Scenario 2			Scenario 3			Scenario 4		
Source	Capacity (GW)	Load Factor	Energy (TWh)	Capacity (GW)	Load Factor	Energy (TWh)	Capacity (GW)	Load Factor	Energy (TWh)	Capacity (GW)	Load Factor	Energy (TWh)
On-shore wind	15.15	0.42	55.74	7.5	0.44	28.91	0.54	0.37	1.75	7.53	0.437	28.83
Off-shore wind	27	0.422	99.81	26.55	0.428	99.54	27	0.422	99.81	13.2	0.43	49.72
Solar PV	60	0.167	87.78	30	0.167	43.89	3	0.165	4.34	3	0.165	4.34
Wave	7.5	0.5	32.85	7.5	0.5	32.85	7.5	0.5	32.85	7.5	0.5	32.85
Tidal	9.1	0.27	21.52	9.1	0.27	21.52	0	0	0.00	9.1	0.27	21.52
Hydro(small scale)	0.45	0.67	2.64	0.45	0.67	2.64	0.45	0.67	2.64	0.22	0.9	1.73
Hydro(existing)	4.26	0.185	6.90	4.26	0.185	6.90	4.26	0.185	6.90	4.26	0.185	6.90
CHP	13	0.6	68.33	13	0.6	68.33	5	0.65	28.47	2.5	0.54	11.83
Nuclear	55.5	0.935	454.58	0	0	0.00	23	0.825	166.22	0	0	0.00
Fossil fuel (back up)	40	0.29	101.62	30	0.31	81.47	19	0.39	64.91	18.5	0.405	65.63
Fossil fuel	48	0.05	21.02	28.5	0.08	19.97	26	0.06	13.67	20	0.07	12.26
microCHP	0	0	0.00	3.5	0.28	8.58	3.5	0.28	8.58	5	0.26	11.39
Total			952.79			414.61			430.15			247.01

2.4.2. Derivation of electricity demand projections

Having established electricity supply projections it is also important to derive electricity demand projections for 2050. These projections can be calculated using the following information:

1. Conversion factors from energy sectors to end use categories:

Table 2 - Forms of end use for 2050 by sector (%) [RCEP00]

End use category	industry	transport	domestic	services	others
low-grade heat	45	0	80	60	75
Electricity	20	0	20	40	20
high-grade heat	35	0	0	0	5
Transport	0	100	0	0	0
Total	100	100	100	100	100

2. Assumed reductions in demand between 1998 and 2050 by end use categories:

Table 3 - Assumed reductions in demand between 1998 and 2050 by end use (%) [RCEP00]

End use category	scenario 1	scenario 2	scenario 3	scenario 4
Low-grade heat	0	50	50	66
Electricity	0	25	25	33
High-grade heat	0	25	25	33
Transport	0	25	25	33

3. Final energy consumption by sectors in 1998:

Table 4- Final energy consumption by sectors in 1998 [RCEP00]

Sector	AAR(GW)	Proportion(%)
industry	46	22
transport	70	34
domestic	60	29
services	24	12
others	5	2
Totals	205	100

Combining Table 2, Table 3 and Table 4 the final energy consumption in 2050 by each end use can be obtained. Using these three tables the final energy consumption (FEC) by electricity in scenario 1 can be calculated based on the following simple calculation):

$$FEC(electr, scen.1) = 0.20 * 0.22 * 205 + 0.0 * 0.34 * 205 + 0.20 * 0.29 * 205 + 0.40 * 0.12 * 205 + 0.20 * 0.02 * 205$$

$$FEC(electr, scen.1) = 31.57\ GW \approx 32\ GW$$

The final energy consumption can be similarly calculated for each end use and these values are shown in Table 5.

Table 5 - Final Energy consumption projected for 2050, AAR(GW) [RCEP00]

End use category	scenario 1	scenario 2	scenario 3	scenario 4
low-grade heat	87	44	44	30
Electricity	32	24	24	21
high-grade heat	16	12	12	11
Transport	70	53	53	47
total final energy consumption	205	132	132	109

2.4.3.Electricity supply versus electricity demand

The final electricity consumption figures given in Table 5 require some further explanation when they are compared to the figures for electricity generation. In some cases, electricity supply figures given in Table 1 are significantly higher than electricity demand figures (see Table 6).

Table 6 – Electricity generation versus electricity demand, TWh

	1998	scenario 1	scenario 2	scenario 3	scenario 4
Generation	358.25	952.79	414.61	430.15	247.01
Electricity	280.32	280.32	210.24	210.24	183.96
generation-demand difference	77.93	672.47	204.37	219.91	63.05

The disparities between supply and demand projections in Table 6 can be explained by understanding the process of supply-demand matching that was undertaken by the RCEP. This process included the following priorities for the use of fossil fuels in each scenario [Wat03],[WSN04]:

- The first priority is transport;
- The second priority is the generation of electricity to provide backup for intermittent renewables and extra power at peak periods;
- The third priority is the provision of high grade heat;
- The fourth priority for any fossil fuel remaining is the provision of low grade heat.

It is clear from this that a significant part of the electricity generated is not consumed as electricity in some scenarios. Instead it is used to make up for shortfalls in fossil fuel availability for high and low-grade heat. The main technology for this is electrically powered heat pumps. In scenario 1, the RCEP states that most of the demand for low-grade heat and over a third of the demand for high-grade heat will be met in this way.

2.5 Discussion

Finding medium (2020) to long-term (2050 and beyond) electricity system scenarios for the UK is a difficult task. Unfortunately no credible scenarios mentioning the composition of the future electricity generation sector for the medium to long-term horizons were found in the accessible literature. However, there are some useful projections for the entire energy sector, which we found very helpful in this research, in particular those presented by the Royal Commission on Environmental Pollution (RCEP)[3]. The various recommendations made by RCEP have also been endorsed by UK Government and several actions and policies have been lined up in response to their recommendations [GOV03].

[3] Tyndall Integrated Scenarios project (Theme 2 scenarios) were not available when this project was being conducted, however these scenarios are now available from Tyndall.

As we already pointed out, the purpose of our work is not to determine the composition of the future UK generation system. On the contrary, the purpose of this report is to turn the readers' attention to some important technical issues that might emerge due to the projected changes in this composition. Our understanding of the medium term projections analysed, is that wind power is likely to be a dominant renewable technology by 2020. Therefore, for the mid-term future UK electricity scenarios we assumed a wide range of wind penetrations up to 40GW. On the other hand, the long-term future UK electricity scenarios are derived from the projections given by the Royal Commission on Environmental Pollution.

The Royal Commission recommends that the UK should plan to reduce carbon dioxide emissions by some 60% from current levels by about 2050. The Report explores what this will mean for industry and households and highlights how Government policies need to change. Their scenarios were designed for the energy system. It was a challenge for us to derive the future electricity sector projections, as well as to define the future mix of various electricity generating technologies. This chapter focuses on working out the future electricity generation portfolio and the demand estimations pertinent to the RCEP energy scenarios.

Using the data provided in the RCEP report (AAR and additional information related to the numbers and types of plants required) and assuming likely load factors for each technology, we derived the electricity supply projections for each individual technology. Similarly, using other relevant data like conversion factors from energy sectors to end use categories, expected demand reductions and historic final energy consumption data (of 1998), the sectorial final energy consumption for 2050 was computed. The final energy consumption in the electricity sector was translated into the demand for electricity.

In some cases, the computed electricity supply figures were found to be significantly higher than the electricity demand. These disparities between supply and demand projections can be explained by understanding the process of supply-demand matching that was undertaken by the RCEP. A significant part of the electricity generated will not be consumed as electricity in certain scenarios and instead will be used to make up the shortfall in fossil fuel availability for high and low-grade heat. This work has resulted in the preparation of the input for the subsequent analysis carried our in later chapters for the security assessment of the future decarbonised electricity systems.

3.GENERATION ADEQUACY

Electricity system reliability assessment has been traditionally divided into two basic aspects: system adequacy and system security. Adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand or system operational constraints [BiA94]. These include the power plant capacity necessary to generate sufficient electricity, and the associated transmission and distribution facilities to transport electricity to consumer load points. Adequacy is therefore associated with static conditions, which do not include system disturbances. Security relates to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to whatever perturbation it is subjected [BiA94].

From a planning point of view adequacy is a long (mid)-term planning process, the main objective of which is to give early warning signals concerning system reliability, and highlight opportunities or necessities to invest in generation and transmission. On the other hand, the ability of a generation system to respond to the fluctuations of system demand, and the unforeseen outages of both generating units and transmission components, is a short-term planning process whose main objective is to provide balancing of system demand and supply on a second by second basis.

The UK government mid-term generation planning objective is to produce 10% of total electricity from renewable generation by 2010. The aspiration is to produce 20% of the overall demand from renewable generation by 2020. If the targets are to be met by wind power alone, about 13 GW of wind capacity will need to be installed to meet the 10% target and about 26GW to meet 20%, assuming an average load factor for wind generation of 35%. On the other hand, the long-term government objectives seem to be in line with the RCEP scenarios discussed in the previous chapter. In this chapter we analyse adequacy of mid and long-term future UK electricity developments (scenarios).

In the first paragraph of this chapter we briefly discuss the existing European adequacy standard. The results of capacity adequacy of mid-term (2010/2020) scenarios are described in 3.2, while the results of capacity adequacy standards for the long-term RCEP scenarios are presented in 3.3.

3.1.Overview of Generation Adequacy Standards

Adequacy of the power system depends on two factors: the ability of the generation to meet the demand (generation adequacy) and the ability of the transmission system to carry the power from the generation plants to the consumption areas (transmission adequacy). The key drivers of generation capacity adequacy are shown in Fig.1. The damaging consequences of electricity supply shortages (deficits) on the economy and on society are immediate and significant. There is no doubt that the risk of supply deficits can be eliminated through extremely high, but uneconomic levels of investment in generation plant. However, the accepted industry practice, worldwide, is to manage the risk to be at an acceptable level by determining the amount and timing of new plant requirements. The risk is often quantified by taking a probabilistic approach, which accepts that for a defined period of time, demand will not be fully met. The annual generation adequacy standard is used to benchmark the risk. If the level of risk is greater than standard, then additional power generation is required [GAR02].

Generation adequacy studies do not address transmission issues, so the transmission network is completely ignored in these studies and considered of being capable of transferring any system generation to the system supply points. In other words, these studies are based on a single bus network representation where all generating units and supply points are connected to the same bus.

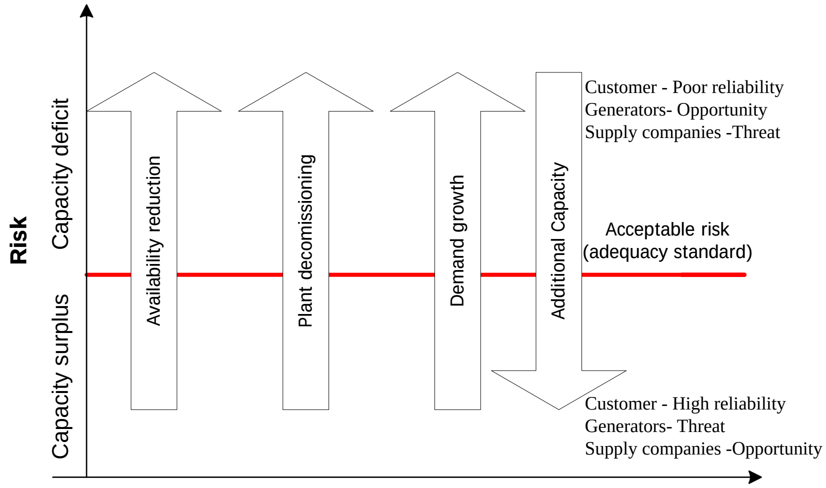

Figure 1. – Capacity adequacy -key drivers [GA02]

The last security standard employed in the UK by the Central Electricity Generating Board (CEGB) proposed that interruptions of supply should not occur more than 9 winters in 100. So the risk of having supply deficits cannot be larger than 9%. Based on probabilities of plant failures from the 1980s the standard would require a capacity margin of about 24%, where the capacity margin is defined as the percentage difference between total system generation capacity and peak system load with respect to the former. The risk of having supply deficits can be measured using the Loss of Load Probability (LOLP) index. Figure 2 shows the change in the risk (LOLP) of having supply deficits when the capacity margin is varied from about 5% to 30%. It can be seen for example that a decrease in capacity margin from 24% to 9% increases the risk from the 9% to 90% (see Fig.2).

The adequacy standard in Ireland proposes that an expectation of failure should not be larger than 8 hours per year. It should be emphasized that this does not mean that all customers will be without supply for 8 hours per year, but rather that there is an expectation that for 8 hours of the year there will be some supply deficits. The adequacy index used in this standard is Loss of Load Expectation (LOLE), which is a mathematical expectation of having supply deficits over the period of one year (hours/year). This adequacy index is a measure of the duration of supply deficits and it cannot be used to measure the magnitude of supply deficits.

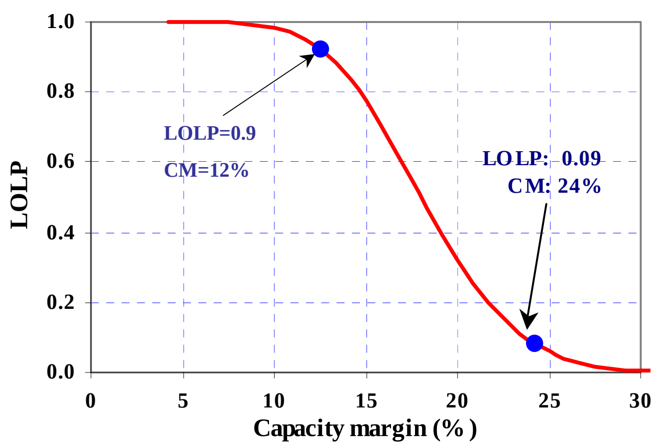

Figure 2. – LOLP versus capacity margin

The transmission system operator in France needs to submit a multi-annual Generation Adequacy Report, no less than once every two years, and subject to the scrutiny of the State [RTE01]. In principle, this report suggests prospective short and long term diagnostics of the balance between electricity supply and demand, and evaluates the new generation capacity required to maintain security of supply in the long-term. The level of supply deficits accepted for the Generation Adequacy Report in France is a mathematical expectation of less than three hours per year (LOLE<3 hours).

The Union for the Co-ordination of Transmission of Electricity (UCTE) co-ordinates the interests of transmission system operators in 20 European countries. Their common objective is to guarantee the security of operation of the interconnected power system. Remaining capacity is used as a measure of generation adequacy for the UCTE. Remaining capacity can be interpreted as the capacity that the system needs to cover the "margin against monthly peak load" (differences between synchronous peak load and sum of non synchronous peak loads) and, at the same time, exceptional and longer-term unplanned outages which the power plant operators are responsible for covering with additional reserves (often estimated at 5% of installed capacity) [UCTE02].

3.2.Capacity Assessment of the Mid-Term UK Electricity Scenarios

The results of the capacity assessment of the mid-term UK electricity scenarios are focused on several issues such as: a quantification of wind backup capacity, capacity and energy displacement by wind at various level of wind penetrations, and the impact of the so-called incidence of calms on capacity adequacy.

In 3.2.1 we firstly describe modelling of generation and demand in our studies and the methodologies used to carry out these capacity assessment studies. A question on everyone's lips these days is: could wind be used for backup or do we need backup for wind. Using a simple illustrative example we have calculated the required backup capacity for two electricity systems: with and without wind whilst maintaining a specified level of security. A simple comparison of the required backup capacity of these two systems is then used to answer the question, related to a quantification of backup capacity requirements in 3.2.2. In 3.2.3 we further discuss possible capacity and energy displacement by wind at various levels of wind penetrations. In the same paragraph we describe the impact of high wind penetrations on the utilisation of conventional generating units. In the last paragraph we present a detail analysis of possible consequences of incidence of calms when no or very low wind conditions coincide with peak and typical winter demand days.

3.2.1.Modelling and methodologies

The conventional units are characterised by their long-term behaviour in terms of their average failure and repair cycles. These cycles can be used to define their average availabilities. Each unit can be fully available with power output equal to its registered capacity or completely unavailable with zero power output. Therefore, the following two state model was applied to simulate the behaviour of conventioal generating units:

- Unit fully available with a probability of 0.85
- Unit completely unavailable with a probability of 0.15

It was further assumed that there is no correlation between the availabilities of conventional units i.e. the failure of one does not increase the risk of failure of others in the system. For each possible combination of available and unavailable units we can calculate total power output injected to the single bus and its probability. For this report a simplified generation system with identical thermal units of generic capacity 500 MW is assumed. If the total capacity of the system is 60 GW (120 Units, each 500 MW) a Gaussian curve shown in Figure 3. can be used to describe the likelihood of having a certain number of generating units in service. It can be seen that the most likely combination is to have 102 units in service

(102=0.85X120). On the other hand, the probability of having less than 85 or more than 115 units in service is very small.

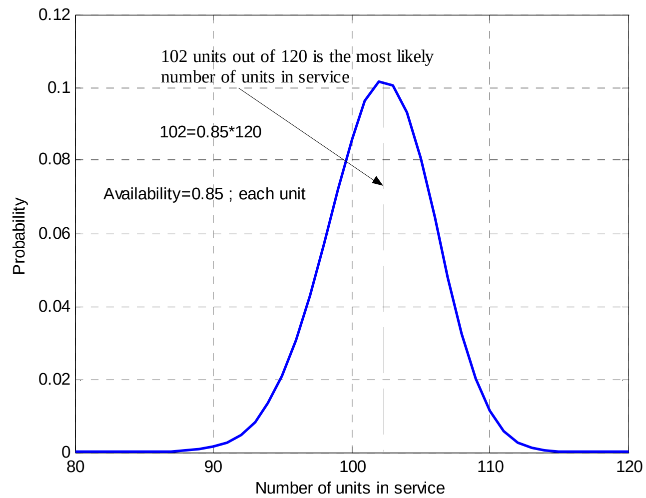

Figure 3. – pdf of total available capacity

Electricity demand in this report is modelled using typical demand business and non-business seasonal days. Six typical days shown in Fig. 4 are summer business/non-business days (S_bd/S_nbd), winter business/non-business day (W_bd/W_nbd), spring/autumn business/non business days (Sp_Aut_bd/Spr_Aut_nbd).

The total wind capacity is represented in the system as a multi-state unit. The multi-state model representation assumes that each level of the total wind power output has availability and transition rates to subsequent wind power output levels. This multi-state unit model is derived from a statistical assessment of annual historical half-hourly profiles of various Great Britain wind farms. The frequency distribution of the wind daily energy obtained from this historical data set is shown in Fig. 5, where total installed wind capacity was 25 GW. For example, the number of days whose wind energy is between 50 GWh and 100 GWh is 70, and almost a half of these are summer days. It can be seen that days with high wind daily energy are very rare and occur mainly during both winter and spring. It should be pointed out that, some very low wind energy days can be expected during the winter. Data from Denmark suggests that the maximum power available rarely exceeds about 80 per cent of the installed capacity. However, the amount of power that System Operators expect, on average, to be available is less than this and is roughly equal, with small amounts of wind, to the average output of the plant—about 30 per cent to 35 per cent of the rated output [DM03].

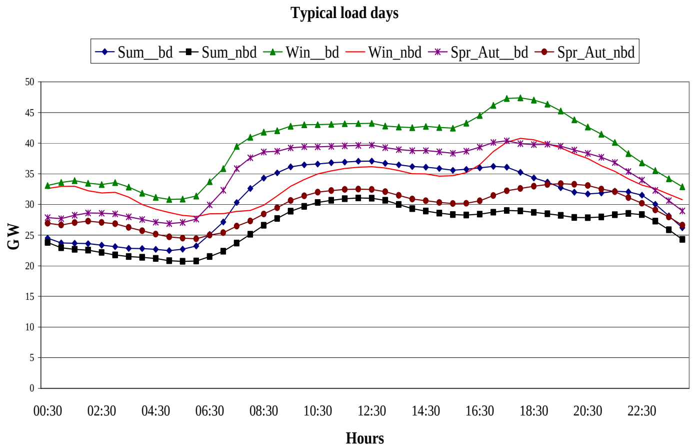

Figure 4. – Typical demand seasonal days

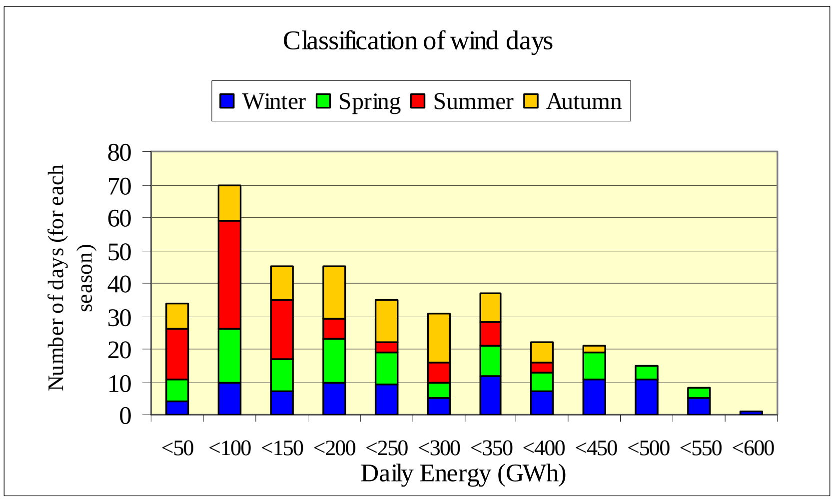

Figure 5. - Frequency distribution of an annual wind output (25 GW installed wind capacity)

The fundamental techniques that can be used to determine adequate levels of generating capacity are categorised into *analytical* and *simulation* techniques. Two analytical techniques, Capacity Outage Probability Table (COPT), and Frequency and Duration (F&D), are used in this work. When assessing the impact of seasonal and time related effects we use a sequential Monte Carlo (MC) simulation.

Using COPT the adequacy of the generation capacity is assessed by implementing the most widely used reliability index, Loss Of Load Probability' (LOLP). The method requires relatively simple input. When modelling the generation system all units are connected in parallel to a single bus system. Each possible combination of units, in either fully up, derated or down state (on forced outage), defines a capacity state of the system. The resulting states are characterised by their available capacities and the associated probabilities. Identical states are merged to yield only unique capacity levels. These states are then combined with corresponding demand states (peak demand) in order to calculate the probability that peak demand will exceed available generation.

COPT neither gives any indication of the frequency of the occurrences of capacity deficits, nor the duration for which they are likely to exist. Furthermore, the severity of shortages, in terms of power and energy is not quantified, (only the probability of a single shortage occurring). In addition to the unit availability levels, the transition rates and frequencies of departures for each state of all units are required. Wind is again modelled as a multi-state unit. The number of transitions among various generation bands of wind power is computed using the Markov chain model given in **[**CSA96**].**

MC simulation uses a random generator to examine and predict patterns of system behaviour in the simulated time horizon and to estimate the expected average value of the various reliability parameters or the frequency distribution of each parameter. It uses a random number generator to create a sequence of unit states in a simulated period. These sequences are than combined to provide a sequence of the total system capacity. If the load pattern is known, information of all supply deficits can be obtained comparing hourly (or half hourly) load values against the values of the total system capacity. This information is used at the end of the simulation period to calculate various adequacy indices.

3.2.2.Quantification of backup capacity requirements

Quantification of the backup capacity requirements for renewables has always been a complex question owing to an absence of any consensus on the definition of this term. In this report, the backup capacity of renewables is assessed through the following two questions:

1. How much conventional generation can be displaced by intermittent sources?
   Or what is the benefit of intermittent sources?
2. How much conventional generation capacity is required to back up intermittent sources?
   Or what is the penalty of intermittent sources?

In order to find the relationship between the above two questions we can consider two-generation systems A & B with and without wind generation respectively. Both systems are subject to serve the same peak demand level of 25GW at a security level of 9% LOLP. To meet the demand with the specified security level, system A requires 32GW of conventional capacity, while system B is comprised of 25GW of wind capacity along with 27.5 GW of conventional generation. Therefore, the answers to the questions raised above can be summarised as follows:

1. 25 GW of wind generation can displace only 4.5 GW of conventional generation (32GW-27.5GW).
2. In terms of additional backup capacity we need an additional 20.5 GW for the system B. The cost of the system A is therefore the sum of the cost of conventional plants and the cost of its backup capacity (backup for conventional, see Fig. 6). On the other hand, the total cost of the system B is composed of the wind capacity cost, cost of backup for conventional and cost of additional backup. Therefore the difference in total costs of the two systems will be:
   Cost of wind capacity (25GW) + Cost of additional backup capacity (20.5GW) **-** Cost of conventional capacity (25GW)

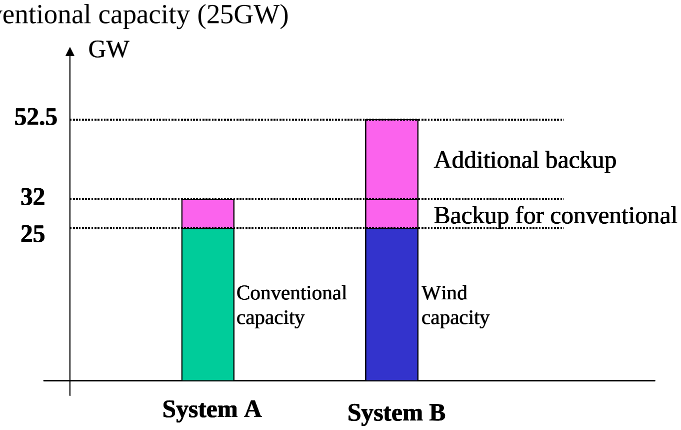

Figure 6. - Illustration of example on backup capacity requirements

3.2.3. Conventional capacity and energy displacement by wind

Using the data described in 3.2.1, capacity adequacy studies were performed for various levels of wind penetration (measured by installed wind capacity) in order to estimate the ability of wind generation to displace conventional capacity. For all these studies we maintained a specified level of risk measured by LOLP. For all wind penetrations capacity adequacy studies were carried out, with and without wind, in order to determine conventional capacity displacement (see 3.2.2). The results shown in Fig. 7. confirm that at small levels of wind penetration the wind capacity contribution is significant. However, when wind penetration level increases these curves begin to saturate. Milborrow in [DM03] argues that the conventional capacity displacement for the UK power system with 12 GW wind penetration is expected to be 3.3 GW. Some other independent studies have yielded results similar to these shown in Fig.7. [SCAR02].

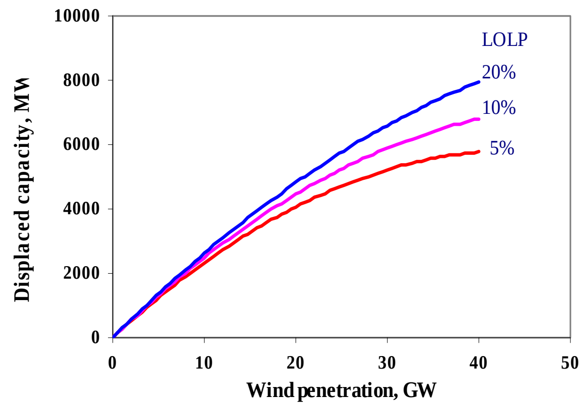

Figure 7. - Conventional capacity displacement by various levels of wind capacity

The load factor of wind output is defined as the ratio of an average wind power output to its installed capacity. In Europe load factors for wind generators normally vary between 20% and 40%. The impact of wind load factor on the capacity credit is shown in Fig. 8. The capacity credit of wind plant in this case is defined as a percentage of the installed wind capacity. At lower levels of wind penetration the capacity credit of wind generation is found to be about the same as the average load factor of wind. However, as the level of wind penetration rises, the capacity credit begins to tail off, as shown in Fig. 8, reaching to almost half of the corresponding load factor at 40GW wind installed. At 25GW wind capacity installed, and maintaining a LOLP of 10%, the capacity credit of wind varies from 16% to 22% of the installed wind against load factors of 30% - 40% respectively. The differences in capacity credit for various load factors also narrows down slightly with the rise in the magnitude of wind penetration in the system.

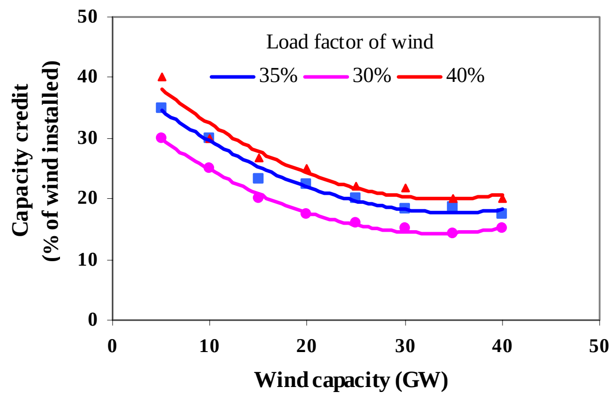

Figure 8. - Capacity credit of wind at various load factors and penetration levels of wind

As the share of wind energy in a generation mix increases, it tends to substitute a greater percentage of conventional energy in comparison to the displaced conventional capacity. A comparison of the displaced conventional capacity and energy is shown in Fig. 9 for various wind penetrations levels. Similarly, to 3.2.3 the specified security level of LOLP<10% is maintained. It was observed that at relatively low levels of wind penetration (below 10 GW wind capacity) the percentage conventional energy displacement is almost twice compared to the percentage of conventional capacity displacement. However, at higher penetration levels this difference in the displaced energy and displaced capacity is further widened. i.e. more than fourfold. at 40 GW wind.

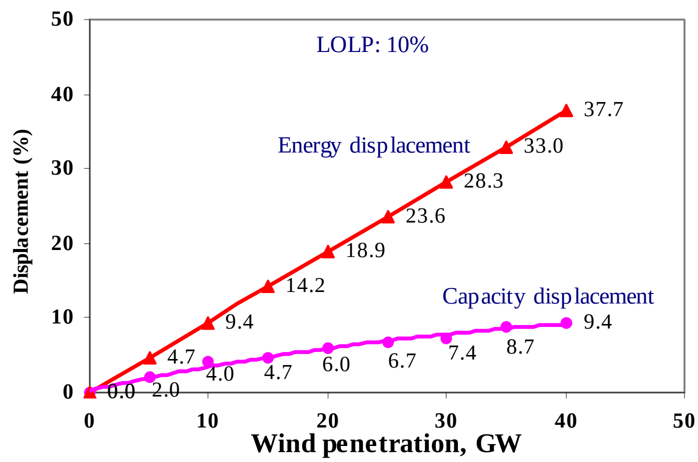

Figure 9. - Conventional capacity and energy displacement at various levels of wind penetration

Due to this disproportion between conventional capacity and energy substitution by the wind source, a considerable number of thermal plants will be running at low output levels over a significant proportion of their operational time in order to accommodate wind energy. Consequently these plants will have to compromise on their efficiency, resulting in increased levels of fuel consumption as well as emissions per unit of electricity produced. This will cause higher electricity production costs. The decrease in plant utilization levels is likely to be uneven across the entire fleet of conventional units. The peaking plants (lower in merit order) may be used more frequently but not for long durations, resulting in higher start-up and shut-down costs, besides increased risks of plant failures due to rapid cycling duty. The mid-merit plants are expected to be the most affected (see Fig. 10), as a significant part of their energy output will be substituted by wind generation. A recent study for the Republic of Ireland[ESB04] also shows that the utilization of base-load and lower merit order units is less affected compared to the units that are placed in the middle of the loading order of conventional units.

The average load factors for conventional plants, with 25GW installed wind capacity at 35% average output, will reduce to about 40% (utilization factor for UK plants in the year 2002 was 54%)[DTI04]. Nevertheless the cost recovery of those plants that might be forced to run at lower load factors will be a major challenge for future electricity systems.

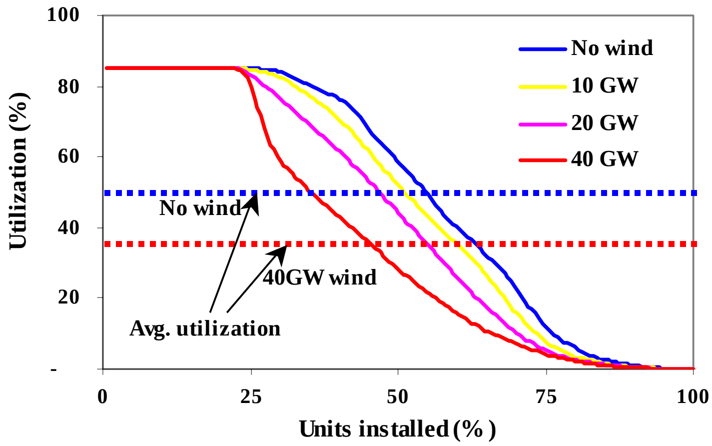

Figure 10. - Conventional plant utilisation at various levels of wind penetration

3.2.4. Incidence of calms

There is no generating unit that is 100% reliable, however a power system with many units operates satisfactorily because the probability of several units failing at the same time is very small. On the other hand, zero or very low power output of all wind generation in an area due to low wind is considered credible. ESB National Grid has recorded instances where all wind farms on the system were producing very little output [GH03].

On the other hand, Milborrow in [DM03] argues that is extremely unlikely that the whole country would be becalmed in winter when winds are stronger. Moreover, as more wind comes onto the system, it is likely to be more widely dispersed, geographically, especially with the growth of offshore wind. It may be noted that the amount of wind power available in western Denmark over the 10 days with the highest peak demands in early 2003 was always equal to, or greater than, the theoretical capacity credit (30-35%).

We believe that serious statistical analysis needs to be performed on a considerable amount of historical data in order to assess the probability of having zero or near zero wind power output from all wind farms. The most serious incidence of calms could be anticyclone "cold snaps" which give high demand but little wind anywhere in the country. Due to lack of data we were not able to estimate the likelihood of such events. On the contrary, we carried out a series of studies assuming different incidence scenarios and calculated how they can affect the value of conventional capacity displacement.

For all of these studies we used the sequential Monte Carlo simulation to assess capacity adequacy of electricity systems where no wind conditions coincide with both winter peak demand and typical winter demand conditions. In all these studies LOLE is used to measure capacity adequacy. Wind installed capacity is 25 GW, winter peak demand is 55 GW and it lasts for 5 consecutive days, while a typical winter business day has its peak equal to 51 GW. Two different case studies are considered (see Fig.11), one whose LOLE=7.3 hours per year (120 conventional units) and the second one whose LOLE=1.5 hours per year. The first one is designated as A1 ("knee" system), while the second one is A2 ("tail" system). It should be noted that the "tail" system is more adequate than the "knee" system.

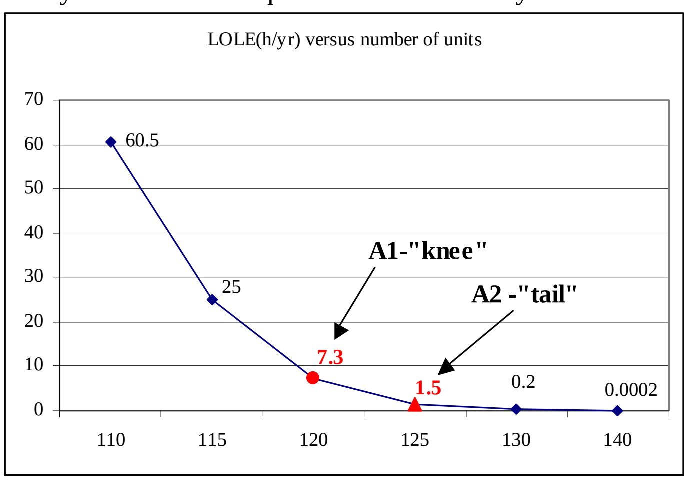

Figure 11. – LOLE (h/yr) versus number of units

3.2.4.1 Coincidence of no wind and peak demand days

Several studies were performed for scenarios in which no wind days coincide with peak winter days. This is the worst-case scenario where we assumed that during winter peak days there is no wind power output at all. The results are shown in Fig.12, for both case studies (A1&A2) and for different numbers of no wind days. The impact of no wind days that coincide with winter peak days is measured by the additional conventional capacity that is required to maintain the initial LOLE values shown in Fig.11. (7.3 and 1.5 h/yr, respectively). It can be seen that if the number of consecutive no wind days that coincide with winter peak days is equal to 5 or 7, the additional capacity needed to maintain the initial adequacy level for both case studies is equal to 4 GW (see Fig. 12). Considering that 25 GW of installed wind in normal circumstances has the capability to displace about 5.5 GW (see 3.2.3) of conventional units, having 5 consecutive no wind days that coincide with winter peak demand will reduce this capability to 1.5 GW.

Additional conventional capacity required by the "tail" system is smaller for 1,2 and 3 no wind days but it becomes the same for 5 and 7 no wind days. This difference is especially large for 1 and 2 no wind days, which means that the "knee" systems, which are at the edge of the adequacy standard, could be a lot more affected by zero wind conditions than a "tail" system.

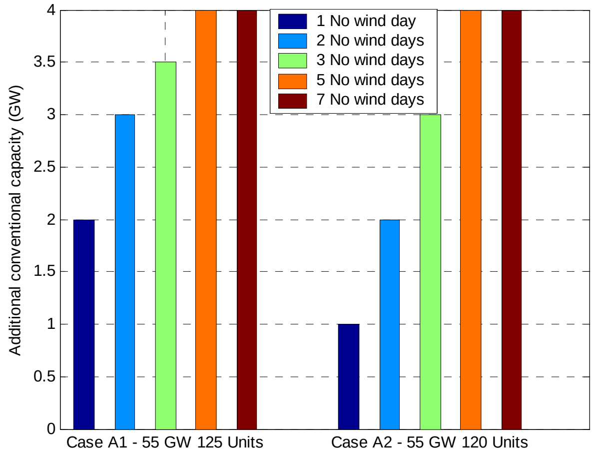

Figure 12. – Impact of no wind days on security level

3.2.4.2. Coincidence of no wind and winter typical demand days

The scenarios analysed in 3.2.4.1 are the extreme ones and certainly not as likely as scenarios where no wind days coincide with typical winter demand business days (non peak winter days whose peak is 51 GW). The results obtained for these scenarios for both "knee" and "tail" systems confirms that coincidences of no wind conditions and typical winter days are not severe (1.5 GW comparing to 4 GW, see both Fig.12. and Fig.13) in the way that the coincidences of no wind conditions and winter peak days described in 3.2.4.1 are. These results are shown in Fig. 13. It should be pointed out that for a smaller number of no wind days (1,2 and 3) that coincide with winter typical days the LOLE is slightly increased but not enough to require additional conventional capacity in order to maintain the specified security level.

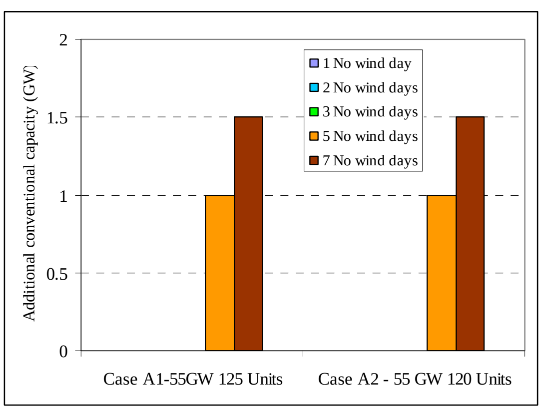

Figure 13. – Impact of no wind days on security level

3.2.4.3.Frequency of no wind days

Researchers and engineers argue that the coincidence of no wind days and peak demand days might happen, but certainly not very frequently. We performed several studies where the frequency of such coincidence is varied from once every year to once in 7 years. The results for the "knee" system are shown in Fig. 14. It can be seen that additional conventional capacity required to maintain LOLE=7.3 hr/yr decreases when the frequency of the coincidence decreases. In terms of capacity adequacy it appears that having 5 no wind days that coincide with winter peak days only once in 5 years is the same as having 5 no wind days that coincide with typical winter days every year (see Fig. 13 and Fig.14).

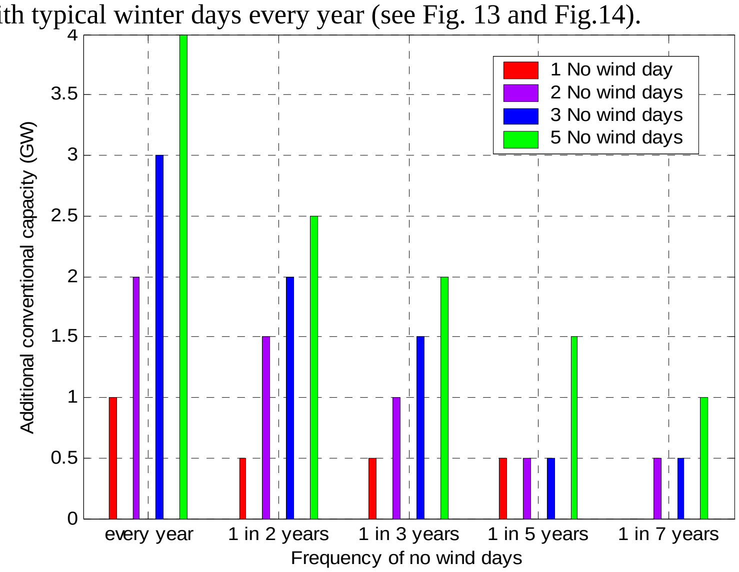

Figure 14. – Impact of frequency of no wind days on security level

3.2.4.4.Available conventional capacity and no wind days

According to the probability distribution function of available capacity shown in Fig.3 it appears not so likely, to have less than 85 or more than 115 generating units in service, out of 120. Considering that conventional units in this study have the same size and availability, the total available capacity (GW) can be calculate as $N_u \times 0.5$, where N_u is the number of available units ($N_u \leq 120$) and 0.5 GW is capacity of each unit. In order to estimate the impact of both available capacity and the coincidence of no wind days and winter peak demand days on supply deficits, we classified all shortages recorded during simulation periods into several bins. Each bin represents a range of available capacity and its size is determined by its lower and upper limits. For example, a shortage that occurs when $N_u = 97$ belongs to the bin whose lower and upper limits are $95 \leq N_u < 100$. Several Monte Carlo simulations are carried out to assess the combined impact of available capacity and the coincidence of no wind days and winter peak demand days. The results for these are shown in Fig.14. for 1, 2, 3 and 5 no wind days.

When there is a regular wind power output on winter peak days shortages can occur only when N_u is between 95 and 110 ("Wind" bars, Fig.15). On the other hand, for no wind conditions shortages can occur even when more than 110 are available ("No Wind"bars, see Fig.15). Having no wind days that coincide with peak demand days we might expect some shortages even when the available capacity is reasonably high ($110 \leq N_u$). Thus we can see that the average number of shortages in the last bin increases from 0.4 (once in 2.5 years, see Fig 15a) to 2.1 (see Fig. 15d) when the number of no wind days that coincide with winter peak days increases from 1 to 5. The average number of shortages increases in the neighbouring two bins ($100 \leq N_u$ and $105 \leq N_u$) due to no wind conditions (“No wind”), while the average number of shortages caused by capacity deficits (“Wind”) remains almost constant. It appears that the coincidence of no wind days and winter peak days tends to generate shortages when available capacity is large, which is very unlikely to happen when there is some wind power contribution.

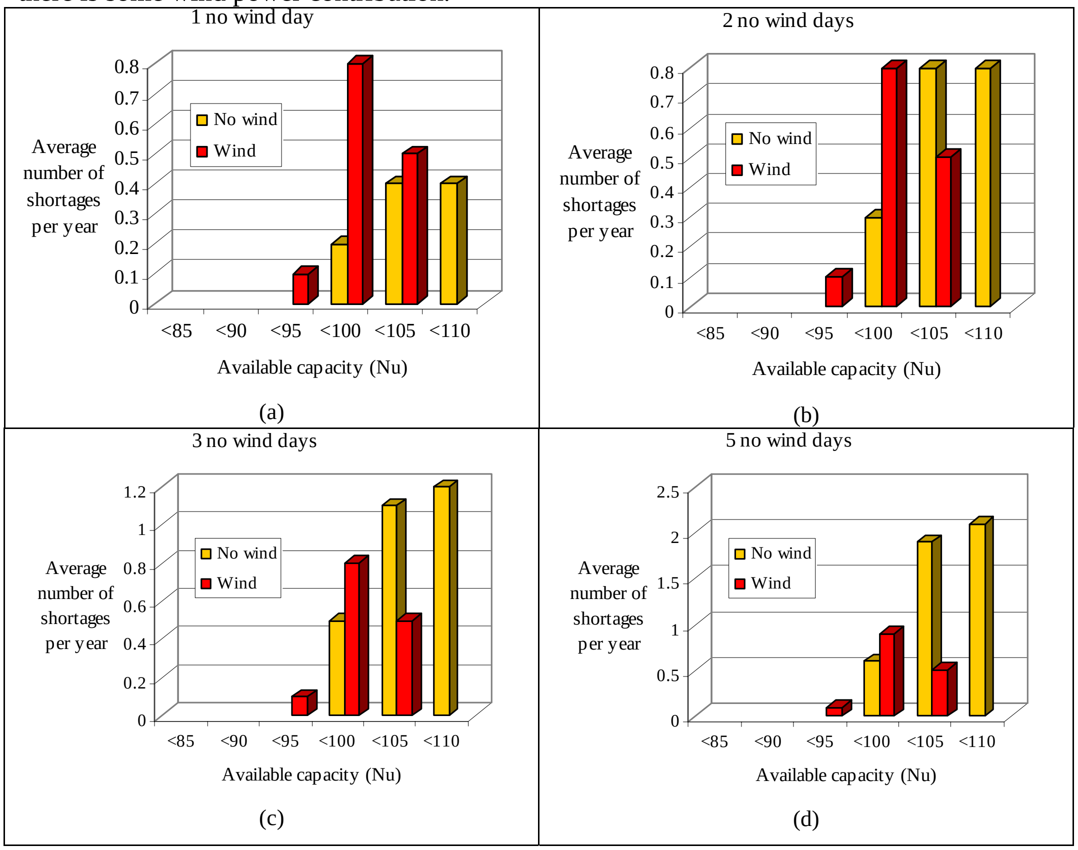

Figure 15. –Available capacity and no wind days

3.3.Capacity Assessment of the Long-Term UK Electricity Scenarios

In this paragraph we discuss the modelling and the results of capacity adequacy studies of the long-term UK electricity scenarios. We assumed that the long-term (2050) UK electricity developments could be in line with the RCEP projections discussed in Chapter 2.

Similarly to 3.2, we first discuss modelling of generation and demand of the RCEP scenarios in 3.3.1. The techniques previously described in 3.2.1 are used again to assess capacity adequacy of the RCEP scenarios. The capacity assessment results of the RCEP scenarios are given in 3.3.2. Considering that RCEP projections strictly specify possible penetrations for all intermittent technologies in each scenario, we have not had the freedom of varying these penetrations that we did in 3.2. Moreover, as we explained in Chapter 2 there is a big disproportion between electricity supply and electricity demand for most of the RCEP scenarios. This forced our capacity assessment for these scenarios in a different direction compared with the capacity assessment described in 3.2. Therefore, we firstly assessed capacity adequacy of these scenarios assuming the total energy matching between supply and demand. Having found that these scenarios are severely inadequate we then reduced their demand until we made them adequate.

3.3.1. Modelling of generation and demand

Modelling of conventional units is already described in 3.2.1. Since the renewable generation within the RCEP scenarios is provided by a very large number of small units, each renewable source can be modelled by using their chronological diagrams. These diagrams for a typical winter day are shown in Fig. 16.

As this report has already explained in 2.4.3, the total electricity demand that has to be supplied by conventional and renewable generation within the RCEP scenarios includes significant amounts of electricity for powering heat pumps. For our analysis of generation adequacy of the RCEP scenarios we assumed that the difference between total electricity supply and demand predictions can be explained by the use of these heat pumps to generate low-grade heat. To model electricity demand that is not used for low-grade heat typical seasonal days given in 2.3.3 are used. On the other hand, the identification of suitable profiles for the electricity used to generate low-grade heat has proven to be more difficult.

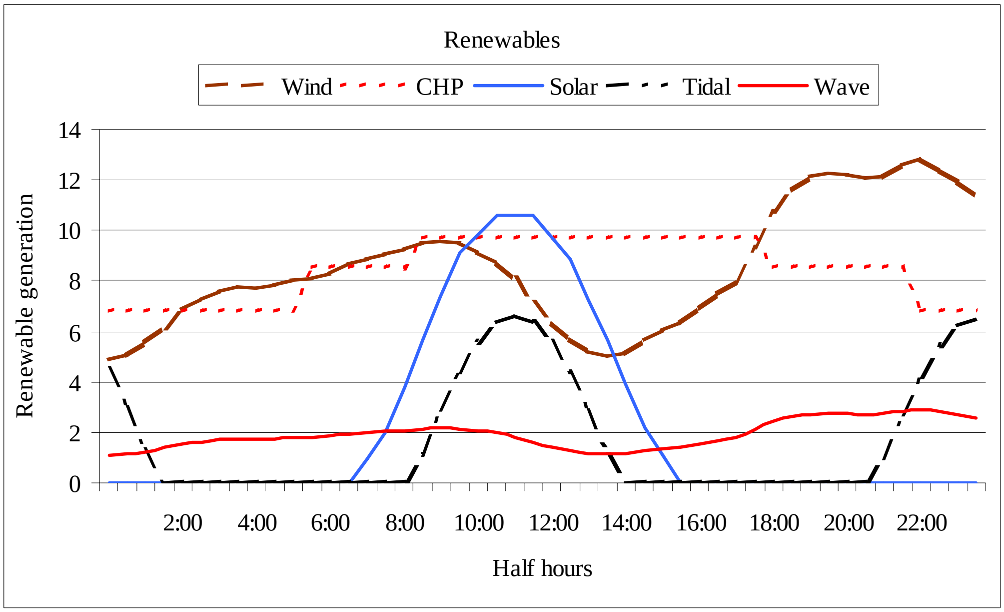

Figure 16. – Typical daily output curves for some renewable sources

In the RCEP report, all use of energy for water and space heating and in industry for drying/separation is categorised as low-grade heat [RCEP00]. Annual and daily profiles for typical UK demand of this low-grade heat are not readily available. As a result, our analysis has estimated these profiles. For annual heat demand variations, estimates have been based on national UK data, which gives overall figures for the various types of low-grade heat [DTI02]. We assumed that demand for space heating is distributed over six months of the year (in late autumn, winter and early spring), while water heating and the use of heat for drying/separation is distributed over 12 months. For daily variations in heat demand, we have used two illustrative profiles:

- A flat heat profile (F), with demand distributed equally throughout the day, and
- A heat profile that is scaled from the electricity demand profiles shown in Fig. 4. (SE). Heat is distributed proportionally to electricity demand throughout the day.

Once the heat and electricity profiles had been created they were combined into an equivalent annual demand profile, which represents the total demand that has to be supplied by conventional and renewable sources of electricity.

3.3.2.Capacity assessment

By combining the two illustrative heat profiles and four RCEP scenarios suggested, we developed 8 sub-scenarios for which capacity assessment studies were performed. For our initial adequacy studies we assumed absolute energy matching between the supply and demand predictions, which means that the entire difference between supply and demand predictions will be used for low-grade heat. The results for these initial scenarios are summarised in Fig. 17. Their capacity adequacy is gauged by using LOLE.

The results obtained for initial sub-scenarios show that all the ones derived from RCEP scenarios 1, 2 and 3 have severe capacity adequacy problems. Within these scenarios, the electricity system is inadequate since the LOLE is significantly higher than the values discussed in 3.1. Capacity inadequacy for these sub-scenarios arises because winter heat demand significantly increases winter peak electricity demand, making shortages of supply more likely. By contrast, the sub-scenarios derived from the RCEP scenario 4 are tolerably inadequate since they breach the discussed adequacy standards (se 3.1) for several hours.

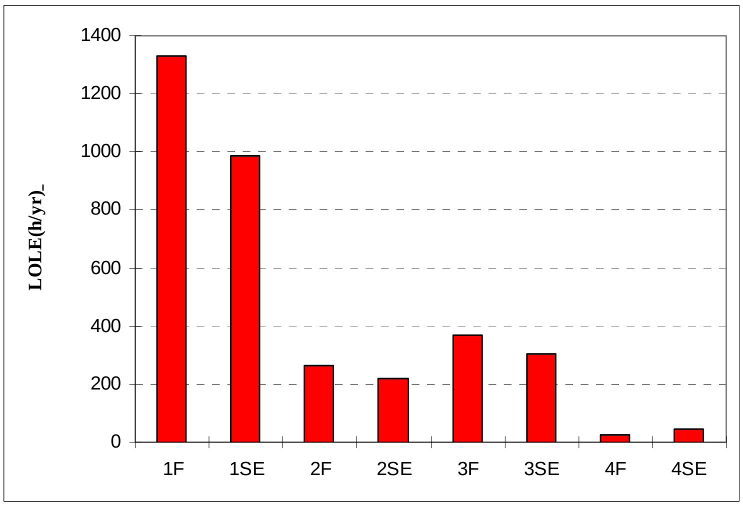

Figure 17. – Capacity assessment of initial sub -scenarios

In order to make these sub-scenarios adequate we performed several studies with reduced heat energy. The results are shown in Fig. 18. The percentage values given in Fig. 18 represent the utilisation of the total supply energy (F Demand as a percentage of generation). It can be seen that only the sub-scenarios derived from RCEP scenario 4 have the utilisation of supply energy similar to the utilisation calculated for 1998. In all other sub-scenarios these percentages are significantly smaller. Another important point is that for all SE sub-scenarios the utilisation is smaller. It means that different heat profiles might seriously impact capacity adequacy. We assumed that the chosen heat profiles are the extreme ones considering:

- F profile is very optimistic considering that there is no coincidence of heat demand peak and electricity demand peak,
- SE profile is very pessimistic considering that heat demand peak and electricity demand peak coincides making the overall peak very large.

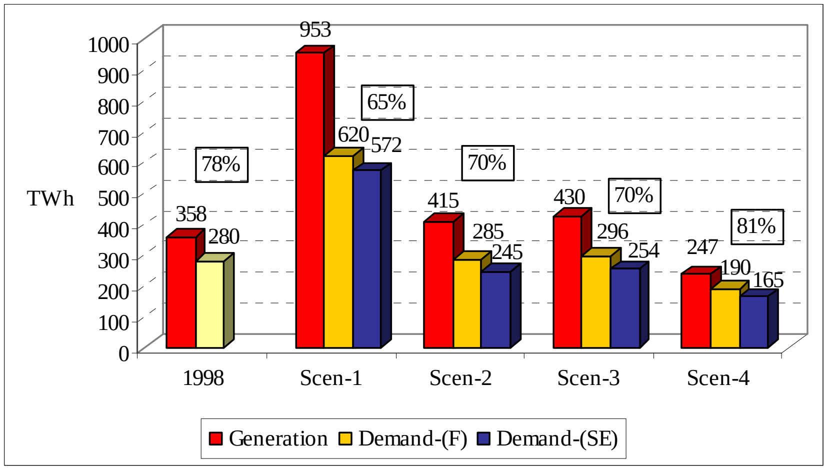

Figure 18. – Adequate sub-scenarios

Further analysis of these eight sub-scenarios reveals a further concern that is particularly important for renewable generators. For most sub-scenarios, there are significant periods of time during the year in which the projected electricity output from renewable sources exceeds projected demand. In such situations, renewable generation would have to be curtailed unless some kind of active demand management was possible to avoid this. This curtailment normally occurs during summer, when renewable generation is high and electricity demand is low.

The energy curtailment for all 8 sub-scenarios for initial sub-scenarios ("Initial – Energy Matching") and capacity adequate sub-scenarios ("Adequate-Heat Demand Reduced") are shown in Fig. 19. It should be noted that the calculated energy curtailment can be extremely high. The maximum amount of energy curtailment is almost 10% (of supply predictions) in scenario 2 for SE heat demand profile. It should be emphasised that for this scenario the total renewable energy is larger than the energy produced by nuclear and fossil fuel units. In general, these values for electricity lost are probably optimistic because the analysis does not include the need for some conventional units to remain on the system to provide reserve. If this reserve were taken into account, it is probable that the percentages of renewable electricity lost would be higher.

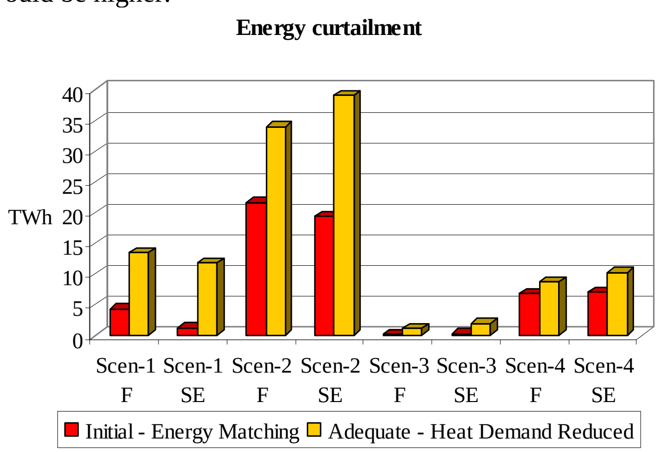

Figure 19. – Energy curtailment in sub-scenarios

3.4. Discussion

The UK Government has set a target for the connection of major volumes of renewable generation sources so that 10% of the overall electricity consumption is supplied from renewable sources by 2010. The aspiration of the Government, as set out in the Energy White Paper, is that this trend continues and 20% of energy should be provided from renewable sources by 2020. Various renewable technologies will contribute to this goal. Given the vast wind resource available and its leading competitive position among renewable technologies, wind generation is expected to be a major contributor to achieve these targets by 2020.

However, in the context of reducing CO_2 emissions, the 2020 targets will only make a small contribution. A considerably larger proportion of renewable and other low carbon energy sources (e.g. fuel cells, micro CHP, and possibly nuclear) will be required in order to respond to the climate change challenge over the longer time horizon. We assumed that the generation and demand projection set out in the RCEP report are currently the most likely UK long-term electricity developments.

In this chapter we presented our results regarding capacity adequacy of both 2020 (mid-term) and 2050 RCEP (long-term) scenarios. There are a number of issues associated with integration of renewables and other low carbon sources in system operation and development. Although penetration of these sources may displace significant amount of *energy* produced by large conventional units, concerns over system operation are focussed on whether these sources will be able to replace the *capacity* and *flexibility* of conventional generating units.

Considering that wind power is likely to play a key role in mid-term future UK scenarios and the fact that wind is intermittent, it will be necessary to retain a significant proportion of conventional plant to ensure adequacy and security of supply. Clearly, the capacity value of wind generation will be limited as it will not be possible to displace conventional generation capacity on a “megawatt for megawatt” basis. Wind generation is considerably more variable than conventional generation and the capacity value of wind generation plant is limited. We carried out a series of analyses for a range of wind penetrations to determine the generating capacity of conventional plant that can be displaced by wind while maintaining the risk of loss of supply at a specified level. We observed that wind generation only displaces a relatively modest amount of conventional plant. In order to maintain the same level of security, a significant capacity of conventional plant will still be required however. At lower levels of wind penetrations the capacity credit of wind generation is found to be about the same as the average load factor of wind. However, as the level of wind penetration rises, the capacity credit begins to tail off.

As we already pointed out, when the share of wind energy in a generation composition increases, it tends to substitute a greater percentage of conventional energy in comparison to the displaced conventional capacity. Due to this disproportion between the conventional capacity and energy substitution by the wind source, a considerable number of conventional plants will be running at low output levels over a significant proportion of their operational time to accommodate wind energy. This will decrease plant utilization levels unevenly across the entire fleet of conventional units. The peaking plants may be used more frequently but not for long durations, resulting in higher start-up and shut-down costs, besides increased risks of plant failures due to rapid cycling duty. The mid-merit plants are expected to be the most affected considering that a significant part of their energy output will be substituted by wind generation.

Researcher and engineers argue that incidences such as anticyclone “cold snaps” which give high demand but little wind anywhere in the country could significantly reduce conventional capacity substitution by wind sources. Due to lack of data we were not able to estimate the likelihood of such events. Instead, we carried out a series of studies assuming different incidence scenarios and calculated how they can affect the value of conventional capacity displacement. We showed that for 25 GW of installed wind capacity such incidence would reduce conventional capacity substitution by 70%. However, if such incidence of calms occurred on typical winter days (not peak winter days) the substitution would be reduced by 30%. The analysis confirms that the less frequent these incidents are, the smaller is this reduction.

On the other hand, the analysed long-term future UK scenarios show big disproportions between electricity supply and generation in three out of four scenarios. When describing these disproportions the RCEP argues that a significant proportion of the projected supply energy could be used in these scenarios for heat purposes. A lack of data regarding use of heat energy forced us to make some assumptions regarding possible heat profiles on a national level. Having established these profiles we then performed capacity adequacy studies for these scenarios, assuming that various proportions of the projected supply energy will be used for heat purposes. Basically, we started from the energy matching between supply and demand assuming that the disproportions mentioned above might be fully used for heat purposes. Considering that such scenarios appeared to be extremely inadequate, we reduced the energy that can be used for heat purposes in order to make these scenarios adequate. The results obtained show that the utilisation of the total supply energy, when these scenarios are adequate, is significantly smaller than the estimated level of utilisation for 1998. Another phenomena for concern is the substantial energy curtailment in scenarios where a significant percentage of energy supply is provided by intermittent sources. For some scenarios this energy curtailment is almost 10%.

4.BALANCING

Capacity adequacy of 2020(mid-term) and 2050(long-term) UK electricity systems is analysed in the previous chapter. Apart from capacity adequacy, which is a long(mid)-term planning process, balancing of these electricity systems on a short-term basis will be a major challenge for their secure operation. This chapter addresses some of the very important issues related to balancing of these future electricity systems.

There are no doubts that response and reserve will play an important role in balancing the future (2020&2050) electricity systems. The role of response and reserve today is briefly discussed in 4.1. The inherent variability of wind generation is a new balancing challenge, which might cause a need for more generating resources to be made available when balancing demand and supply. The magnitudes of this variability for various wind penetration levels and time horizons are discussed in 4.2. If this variability of wind power output was perfectly predictable, the additional cost of operating the system with a large penetration of wind power would not be very significant provided that there is sufficient flexibility in conventional generating units to manage the changes in wind. This additional cost of operating a system are briefly discussed in 4.2, while the impact of generating units inflexibilities is further discussed in 4.3,4.4 and 4.5. We firstly describe these inflexibilities in 4.3 and then use a series of simple "balancing snapshots" to discuss possible impact of these inflexibilities in 4.4. In 4.4 we analyse separately the impact of reserve allocation (shares for synchronised and standing reserve) and the impact of simultaneous system perturbations on balancing. In 4.5 the results obtained through a series of simulations that focus on hourly, year round operation of a power system, are discussed. Similarly to 4.4, these results are used to evaluate the impact of generator inflexibilities and reserve allocation on fuel costs, CO_2 emission and intermittent energy absorption.

4.1Role of Response and Reserve

Generation and demand in an electricity system need to be balanced on a second by second basis. Traditionally, the balance between demand and supply is managed by flexible generation. In real time, the output of large conventional generators would generally be adjusted to match any changes in demand. Fluctuations in frequency for an AC system are normally taken as a measure of the balance between demand and generation. If generation is smaller than demand, frequency falls below 50 Hz, or rises above 50 Hz when generation is greater than demand. Security and quality standards normally define frequency statutory limits (NGC statutory limits are 49.5 Hz and 50.5 Hz). Unacceptable high or low frequency conditions are conditions where the steady state frequency falls outside these limits.

In the time horizon of less than a minute, frequency is controlled automatically through systems that control the output of generators and/or trigger demand reductions. The service required is divided into two categories of control, continuous and occasional frequency response [WoH95]. The frequency response service for continuous control (load following) is primarily provided by central generators equipped with appropriate governing systems that control their outputs to neutralise frequency deviations as a result of relatively slow changes in demand and generation.

The occasional frequency response service is required for the management of system frequency after a sudden loss of generation and can be provided by both generating plants and load reductions (usually industrial customers). This includes frequency response services provided by an instantaneous increase in generation (*synchronised* reserve) or reductions in loads required to minimise the initial frequency drop. In order to bring the frequency back to normal, the operator then calls upon reserves, provided by generators and storage facilities (*standing* reserve).

In the time horizon of about one to a few hours, the balance between demand and generation is managed by forecasting demand and then scheduling appropriate generation. This is a demanding task considering that on a typical winter business day the UK system can experience a demand increase of 12 GW (see Fig.4, between 05:30 and 10:00, demand is changed from 31 GW to 43 GW). In such situations the load/generation balance and frequency are maintained by coordinating the flexible output of large coal and gas plant with help of pump storage facilities.

From the above discussion it is clear that the system operator needs to manage both predictable variations in demand (such as managing morning load demand pickup) but also deal with unpredictable events (perturbations) such as outages of generators and errors in demand forecasts. In order to deal with unpredicted variations in demand and generation, the system operator requires appropriate automatic response, to neutralise rapid variations within a few minutes, and reserves (synchronised and standing) to deal with slow variations over time horizons from several minutes to several hours.

4.2 Intermittancy and Operational Costs

The traditional way of balancing generation and demand described in 4.1 can deal with very large predictable variations in demand. However, operational costs for future electricity systems with high penetrations of intermittent sources can be significantly increased due to unpredictable variations of intermittent sources. If these variations were perfectly predictable, the additional operational costs would not be so significant provided that there is sufficient flexibility in conventional plants to manage these variations of intermittent sources.

Milborrow in [DM03] argues that the maximum measured change in output from 2,400 MW of wind in western Denmark is about 6 MW per minute. Another relevant statistic is the maximum change in average wind power generation over one hour—about 20 % of the rated output of the wind plant [DM03]. EoN has recently reported that observed changes in wind power output were in excess of 3,600MW over six hours (installed capacity of 6,250MW). Statistical analysis of the fluctuations of wind output over the various time horizons was carried out in [SCAR02]. This analysis is summarised in Table 7. If for example the installed wind capacity is 10 GW, the standard deviations of the change in wind generation outputs are 272 MW and 929 MW over time horizons of 1 and 4 hours, respectively. This means that the range of possible changes ($\pm 3\times\sigma$ covers 99%) in wind power output in a 1 hour time horizon would be $\pm\ 3\times 272 = \pm 816$ MW, while this change in a four hours time horizon would be $\pm 3\times 929 = \pm 2{,}787$ MW. In [SCAR02] the information of half-hourly and 4 hourly changes were used to calculate response and reserve requirements, respectively. The authors in [SCAR02] combine standard deviations of wind power output with the standard deviation of changes in demand/generation forecast errors in order to determine the level of overall variations that needs to be managed by response and reserve. In their approach the authors assumed that wind output changes and demand forecast errors are independent (uncorrelated) Gaussian functions, while frequency regulation capacity is specified to be equal to $3\times\sigma$ of the overall system variations (in order to cover 99% of possible mismatches between demand and generation).

Table 7 – Variations in wind power output for different time horizons

Wind (GW)	σ 1 hourly	σ 2 hourly	σ 3 hourly	σ 4 hourly
6	0.164	0.311	0.442	0.558
10	0.272	0.519	0.736	0.929
20	0.544	1.038	1.473	1.858
26	0.708	1.349	1.915	2.415
30	0.817	1.557	2.210	2.787
40	1.089	2.075	2.946	3.716

In order to demonstrate how these unpredictable changes in wind power output can affect operational costs we will use a simple cost calculation. For the sake of simplicity and brevity we assume that our system can provide 500 MW of synchronised (spinning) reserve by Combined Cycle Gas Turbine (CCGT) units and unlimited amount of standing reserve by Open Cycle Gas Turbine (OCGT) units. It is further assumed that the marginal costs for CCGT are 20£/MWh at maximal power output and 25£ at minimum power output (minimum stable generation – MSG). On the other hand, marginal costs for OCGT are 50 £/MWh. Costs of exercised reserve plotted against imbalance are shown in Fig. 20. A few imbalance values have been chosen to describe the calculation of these costs (these values are denoted by triangles in Fig.20):

1. **-**1000 MW – which means that we have generation surplus and there is no need to exercise spinning reserve. However, the costs of holding this reserve can be calculated as $500\,MW \times (25-20)£/MWh = 2500\,£/h$. These costs are associated with efficiency losses due to running these CCGT units part-loaded when not all of the synchronised reserve is exercised. Therefore the costs of reserve are essentially the cost of these losses.
2. 250 MW- means that a half of the spinning reserve is exercised. Costs of holding another half of reserve can be calculated as $250\,MW \times (25-20)£/MWh = 1250\,£/h$.
3. 1000 MW –means that 500 MW of spinning reserve will be fully exercised, but another 500 MW will be provided by OCGT units at $500\,MW \times 50\,£/MWh = 25{,}000\,£/h$. If fully utilised CCGT units were used to cover this imbalance the costs would be $500\,MW \times 20\,£/MWh = 10{,}000\,£/h$. The costs of reserve are the difference between these two costs, or 15,000£/h.

A very similar cost function is drawn for a system, which has 1000 MW of spinning reserve (see Fig. 20). It can be seen that for negative imbalances and some small positive imbalances the system with smaller spinning reserve has smaller costs of reserve. However, for a 1000 MW imbalance costs of reserve for the system with higher spinning reserve are zero and significantly smaller for all imbalances larger than 1000 MW.

These simple cost calculations show that reserve allocation (the chosen “split-point” between spinning and standing reserve) and predictability of possible imbalances will be the key drivers of operational costs. On the other hand this predictability depends on:

- unpredictable wind power variations,
- relatively predictable variations in demand,
- duration of imbalances,
- unpredictable forced outages of generating units.

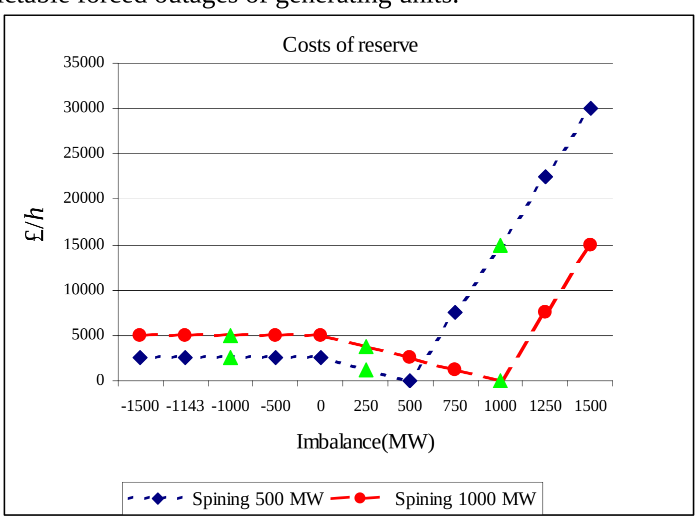

Figure 20. – Costs of exercised reserve

4.3 Generator Inflexibilities

When balancing a power system the operator has to decide which generating units to commit in order to meet the varying demand for electricity. To commit a generating unit means to turn it on or to start it up, bring it up to speed, synchronise it to the system, and connect it so that it can deliver power to the network. The committed generating units are the results of a short-term optimisation problem, whose main objective is to minimise the total fuel cost or to maximise the total profit over a study period of typically a day, subject to a large number of constraints that must be satisfied. These constraints can be classified into two groups:

- *System Constraints:*
  - The total output of all the generating units must be equal to the forecast value of the system demand at each time-point
  - The total spinning-reserve from all the generating units must be greater than or equal to the spinning-reserve requirement of the system at each time-point.
- *Unit Constraints:*
  - Minimum up and down times, which are defined as minimum time that a unit has to be on the system after it has been committed and minimum time that a unit has to be off after it has been de-committed.
  - There can be upper limits on the numbers of start-up events of each generating unit.
  - When a generating unit is committed, its power output must be at or above its Minimum Stable Generation (MSG) value and must not exceed its maximum value.
  - Generating units can be subject to warmth-dependent run-up rates. When such a unit starts-up, it begins operating at a power output below its MSG, and it runs-up to Minimum Stable Generation by following a warmth-dependent non-linear run-up profile, depending on the time that the unit was previously off-load.
  - Generating units are subject to maximum loading up and de-loading rates (ramp up/down rates) when running above MSG.

The way that conventional generating units have been traditionally committed can be significantly changed in the future when high penetrations of intermittent renewable sources are expected. Scheduling solutions and therefore balancing will be highly dependent on the flexibility of generating units. It means that some of the unit constraints described above will play an important role. For the sake of simplicity and brevity we use here very simple examples based on either half-hourly or a few hours snapshots to demonstrate the importance of these constraints (inflexibilities). These snapshots are further discussed in the following paragraph.

4.4.Balancing and Inflexibilities –A Snapshot Analysis

Lets suppose that we have to balance a system whose forecast total demand for the next half an hour is a typical summer or autumn demand, and where installed wind capacity is 26 GW. Lets further assume that baseload generating units will not be used at all for summer demand, in which case the difference between the total demand and forecast wind power output will be fully meet by CCGT units. At the same time, the CCGT units will be used to provide a certain amount of spinning reserve. Three different types of CCGT units are used:

- high flexibility (HF) CCGT units whose MSG=225 MW
- medium flexibility (MF) CCGT units whose MSG=300 MW
- low flexibility (LF) CCGT units whose MSG=375 MW

For all types of units the maximal power output is 550 MW. This means that for example for 1200 MW of spinning reserve, we need 4 ($4 \times 325\,MW \geq 1200\,MW$) HF CCGT units, or 5 $5 \times 250\,MW \geq 1200\,MW$ MF CCGT units or 7 ($7 \times 175\,MW \geq 1200\,MW$) LF CCGT units. It should be noted that in order to provide 1200 MW of spinning reserve these HF CCGT units run part-loaded on MSG and thus deliver $4 \times 225\,MW = 1000$ MW, while medium and low flexibility CCGT units deliver $5 \times 300\,MW = 1500$ MW and $7 \times 375\,MW = 2625$ MW, respectively, while running part-loaded.

4.4.1. Inflexibilities and wind absorption

In order to demonstrate impact of MSG on balancing we used the snapshots shown in Fig. 21. The amount of spinning reserve considered in these snapshots are: σ, $2\times\sigma$, $3\times\sigma$ to $3.5\times\sigma$, where $\sigma = 2.415$ GW is the standard deviations of 4 hours changes of wind power output (see Table 7). The forecast total demand is a low summer demand of 25 GW and the forecast wind power output is 20 GW. Fig. 21 indicates that for larger amounts of spinning reserve less CCGT units will be required to run on an output larger than MSG ("CCGT>MSG"). On the other hand, larger amounts of spinning reserve cause larger curtailment of wind power output especially when LF CCGT units are used. The results confirm that the system with high flexibility CCGT units experiences the smallest wind power curtailment (see Fig. 21, the figures above the bars).

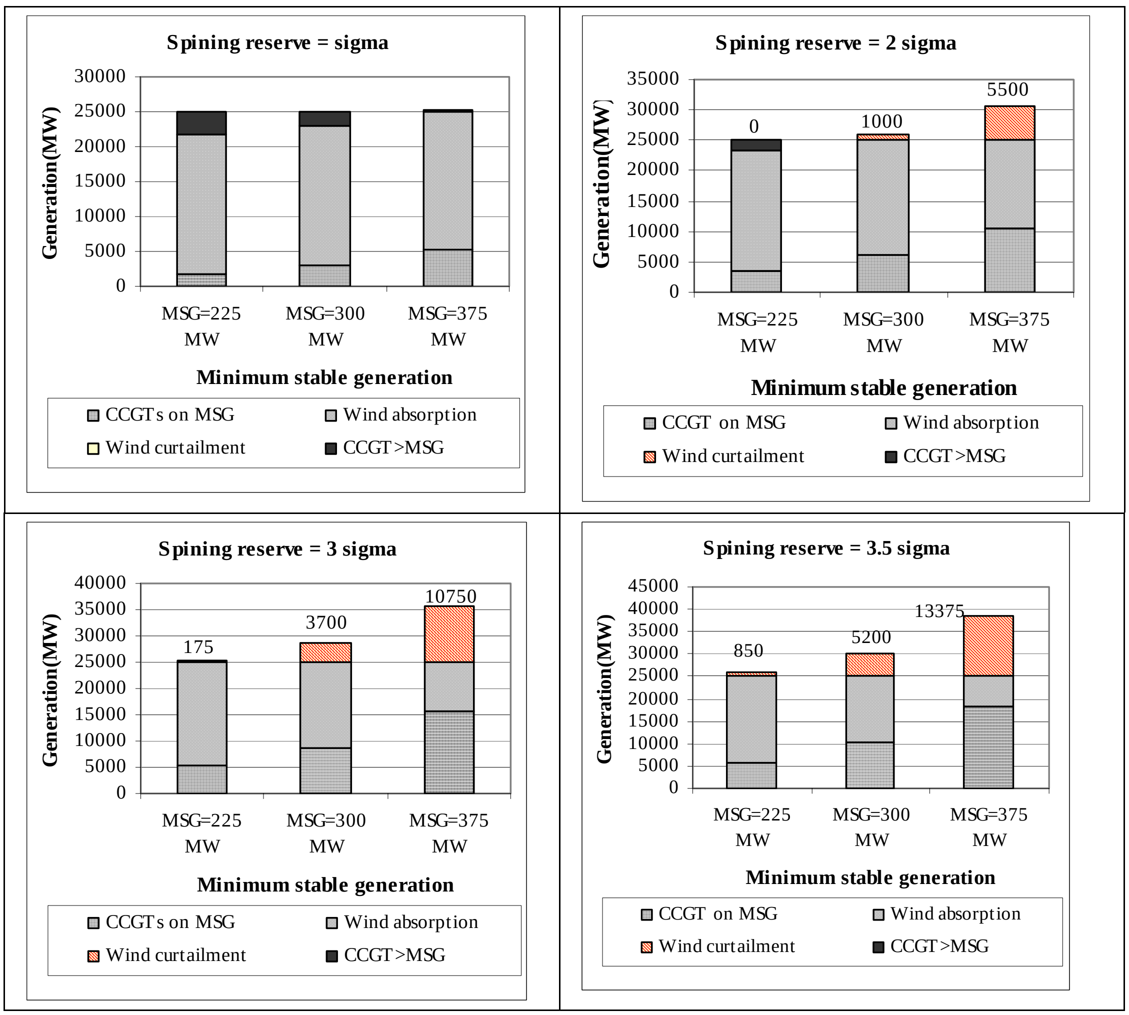

Figure 21 – Units inflexibilities and wind curtailment

4.4.2. Balancing and standing reserve

An alternative to using synchronised reserve for balancing purposes can be the use of either flexible standing reserve, which is supplied by higher fuel cost plant such as OCGTs, or storage facilities. Application of standing reserve could in principle improve the system performance through reduction of the committed synchronised reserve, which again has two positive effects:

1. An increase in efficiency of system operation by reducing the number of part loaded generators
2. An increase in the amount of wind power that can be absorbed as fewer generating units are scheduled to operate, leaving more room for wind. Consequently, this again increases the benefit of wind energy in terms of emissions reductions.

To determine the optimal allocation of reserve is a difficult task. We used a simple snapshot analysis very similar to the one described in 4.4.1, to evaluate the impact of the reserve allocation on wind curtailment and costs of exercised reserve. Standing reserve (OCGT) is changed in a few steps from 500 MW to 5000 MW. The results are depicted in Fig. 22. It can be seen (Fig. 22(a)) that decreasing synchronised reserve (increasing standing reserve) helps with absorbing more wind. However, decreasing synchronised reserve means that less CCGT units are running part-loaded on MSG and consequently more spinning reserve is exercised in order to balance the demand and supply. If the amount of exercised spinning reserve is larger than its specified value, costs of exercised reserve can be rapidly increased (see Fig. 22b, MSG=225, OCGT=5000MW) due to the use of high-cost OCGT units. Assuming a flexible generation system, the allocation of reserve (or the split between synchronised and standing units) will be therefore a trade-off between the cost of holding synchronised reserve and the cost of operating less efficient standing plants with relatively high marginal cost.

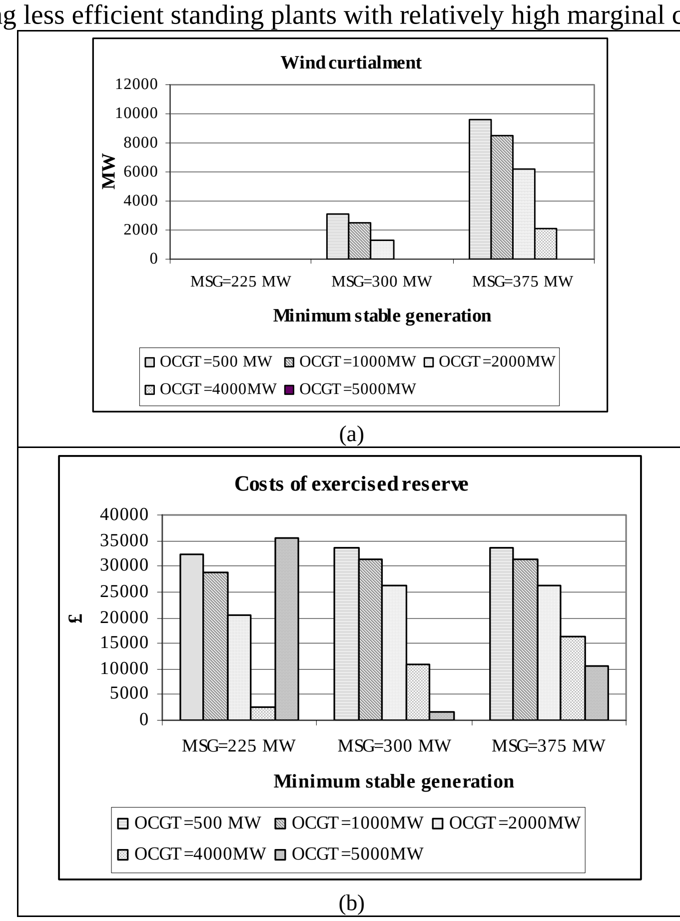

Figure 22 – Balancing and standing reserve – Evaluation through:
(a) wind curtailment (b)costs of exercised reserve

4.4.3. Balancing and baseload generation

For both calculations shown in Fig.21 and Fig. 22 we used systems whose conventional generation is entirely provided by CCGT units. An interesting question would be how much baseload generation each of these systems is able to accommodate with respect to their flexibilities. To answer this question we used another snapshot whose forecast wind power output is 20GW, the total demand is a typical low spring/autumn demand of 35 GW, while the total reserve is 7425 MW and it is split between spinning (3245 MW) and standing reserve (4000 MW). In order to provide this amount of spinning reserve a high flexibility system requires 10 CCGT units running part-loaded on MSG, a medium flexibility system requires 13 CCGT units running part-loaded on MSG, while a low flexibility system requires 19 CCGT units running part-loaded on MSG. The amount of baseload generation that these three different systems can accommodate is shown in Fig. 23. These values are determined in such a way that the costs of exercised reserve and wind curtailment are very similar for each of these systems. These costs are not so different even when the wind power output is different to its forecast value. Figure 23. shows that the high flexibility system is able to accommodate 12.75 GW of baseload generation, while the low flexibility system can accommodate only 7.875 GW.

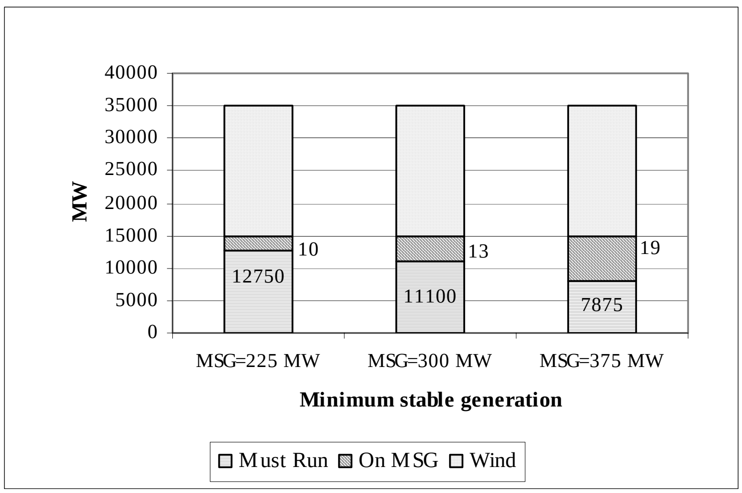

Figure 23 – Baseload generation versus flexibility

4.4.4. Balancing and system perturbations

It has previously been described how a power system is often subjected to various perturbations such as: unexpected forced outages of generating units and unpredictable fluctuations in demand and wind power output. Using a simple 4 hours snapshot we demonstrate how all these perturbation in conjunction with unit constraints, particularly minimum up time might cause serious consequences such as load curtailment.

The snapshot is given in Table 7. The demand forecast is 35 GW in the first hour, 35.5GW in the second hour and 35.6 GW in the third and fourth hour. The total system reserve is 2.5 GW in the first hour and 4.8 GW in the three subsequent hours. It should be noted that a quite substantial amount of reserve is provided during last three hours. This reserve is split between synchronised and standing reserve. Synchronised reserve is 2.5GW for the first three hours (medium flexibility system, 10 CCGT units each provides 250 MW) and 3GW in the last hour (12 CCGT units, each of them provides 250 MW). These CCGT units run part-loaded on MSG (300 MW) and thus provide 3 GW in the first three hours and 3.6 GW in the fourth hour (see Table 7). The forecast wind power output in these four hours is 20GW, 20.5 GW, 21 GW and 20 GW, respectively. There are 12 baseload units, each of them 1GW size, which gives 12 GW of generation for each hour. The system is well balanced for all four hours.

Table 7 – Variations in wind power output for different time horizons

	1 hour	2 hour	3 hour	4 hour
Baseload generation	12000	12000	12000	12000
CCGT(MSG)	3000	3000	3000	3600
Wind(forecast)	20000	20500	21000	20000
Demand(forecast)	35000	35500	36000	36000
Reserve	2500	4830	4830	4830

Lets suppose that one of baseload units is forced out of service in the third hour and due to minimum up time of 2 hours we are not able to commit any available unit in the third and fourth hour. Let us further assume that wind power output is slightly higher than the forecast values in the first and second hour (see Fig. 24) and significantly smaller in the third and fourth hour (see Fig. 24). Demand is as the forecast one for the first hour and 500 MW higher for the three subsequent hours (se Fig. 24). All these unpredicted perturbations cause a positive imbalance of 1000 MW in the first hour, and negative imbalances of 4GW and 5.4 GW in the third and fourth hour, respectively (see Fig. 24). Due to this positive imbalance in the first hour wind curtailment of 1 GW is required in order to balance the system. The negative imbalance in the third hour can be covered by reserve (4.83 GW is reserve for third hour). However, 5.4 GW imbalance in the fourth hour cannot be fully covered by reserve and the difference of 570 MW (5.4 GW –4.83 GW) of demand has to be curtailed.

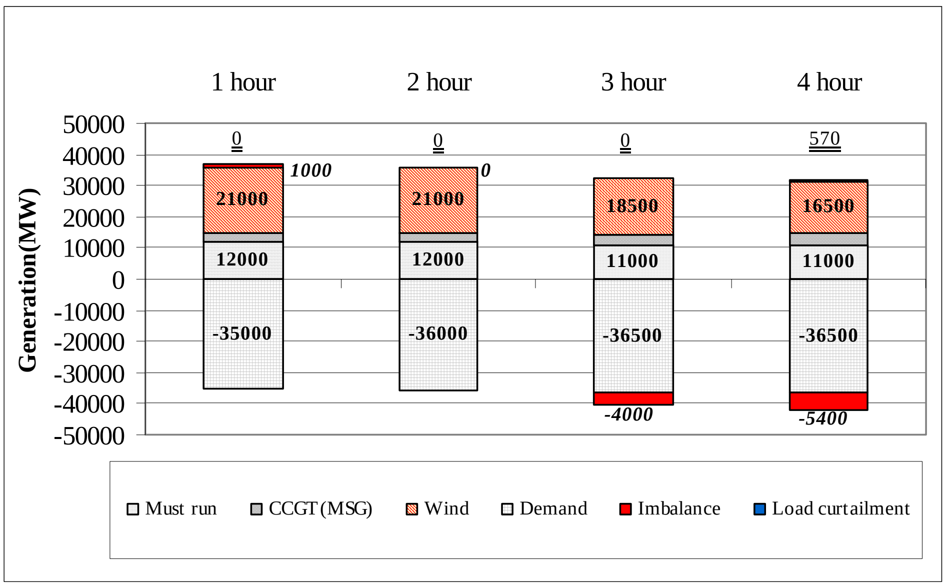

Figure 24. –Impact of system perturbations

The load curtailment in the fourth would be avoided if bulk electrical storage was charged in the first hour instead of wind curtailment, and then discharged in the last hour instead of load curtailment**.** Energy storage systems appear to be an obvious solution to dealing with the intermittency of renewable sources: during the periods when wind generation exceeds the demand, the surplus could be stored and then used to cover periods when the load is greater than the generation. Storage can provide both “positive” and “negative” reserve. In the case where generation is lower than demand, storage is discharged (“positive” reserve), whereas when demand is lower than generation then storage can be charged (“negative” reserve) to balance the system. The ability of storage to provide this “negative” reserve will be of critical importance when low demand conditions coincide with a high level of output of wind generation. The actual magnitude of this inherent benefit will be driven by the amount of wind installed and the flexibility of the generation system.

4.5 Balancing and Inflexibilities – Simulation Analysis

This analysis is based on a detailed simulation of the operation of the system. We simulated, hour by hour, year round operation of the system (including 26 GW of wind capacity) taking into consideration daily and seasonal demand variations and variations in wind output. One of the key advantages of this approach is the ability to optimise more precisely the amount of synchronised reserve required (in each hour) as a function of wind output forecast and the amount of standing reserve available, while taking into account generating unit constraints.

Using these detailed simulations we basically evaluated some economical and environmental benefits of the reserve allocation for systems which have different degrees of flexibility. The benefits were evaluated in terms of (i) reduction in fuel cost associated with system balancing, (ii) corresponding reduction in CO_2 emissions and (iii) reduction in energy produced by conventional generating units. These reductions are calculated with respect to the systems whose entire reserve is provided by synchronised reserve. Simulations are performed varying the amount of standing reserve provided by OCGT units.

Similarly to the snapshot analysis given in 4.4 we studied the behaviour of three generating systems of distinctly different flexibilities. The so-called baseload generation consists of inflexible generating units that run at full output and cannot be turned on and off frequently (such as nuclear). We have also incorporated a segment of the generating units that are moderately flexible and which can be turned on and off but with somewhat limited ability to run part loaded, and a segment of relatively flexible units. Thus, our low-flexibility (LF) system contains 8.4GW of baseload generation, 26 GW of moderately flexible generating units (MSG=77% of their rated maximal power output) and more than 25.6 GW of flexible units (MSG=50% of their rated maximal power output). The medium-flexibility (MF) system used in these simulations is very similar as LF system except that MSG of moderately flexible units is 62% of their rated maximal power output. Finally, high-flexibility (HF) system contains only flexible units whose MSG is 45% of their rated maximal power output.

An alternative to using OCGT units is the use of bulk electrical storage. The inherent advantage of storage over OCGTs lies in its ability to exploit (store) excesses in generation during periods of high wind and low demand, and subsequently make a part of this energy available, and hence reduce the fuel cost and CO_2 emissions. The actual magnitude of this benefit will be primarily driven by the amount of wind installed and the flexibility of the generation system. In systems characterised by low flexibility generation and with large wind capacity installed, the benefits of storage based standing reserve over an OCGT solution will be most significant. A detail comparison of these two options (OCGT and storage) is described in [StM04]

4.5.1.Reduction in fuel cost

The application of OCGT can improve system performance through reduction of the fuel cost associated with system balancing. This is achieved by reducing the amount of synchronised reserved committed, which increases the efficiency of system operation by reducing the number of part loaded generating units and hence increases the amount of wind power that can be absorbed, and consequently reduction in the amount of fuel burnt. This comes from the fact that when operating fewer generating units the amount of wind that has to be rejected when high wind conditions coincide with low demand reduces. However, as it is already described in 4.4.4, remaining surpluses of wind will be wasted in systems with OCGTs providing standing reserve.

The figures shown in Fig. 25 present annual reduction in fuel costs. Note that the range of savings is quite large. As expected, the fuel savings are higher in system with less flexible generation and generally increase with the increase in OCGT capacity used for system balancing[4]

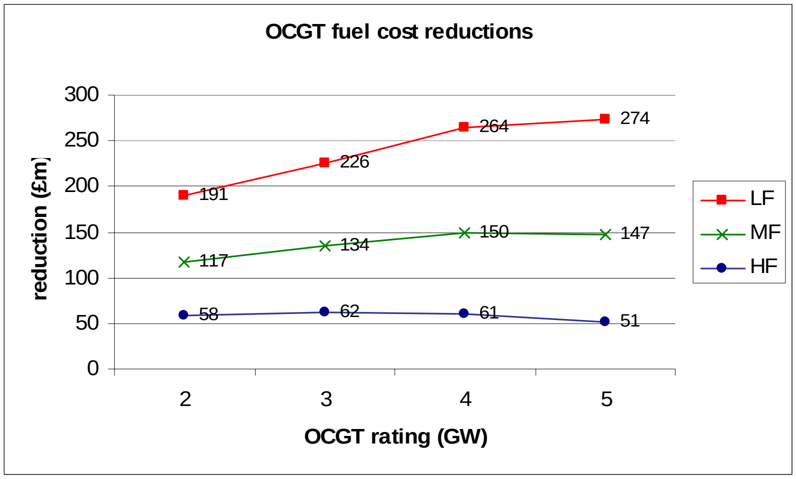

Figure 25. - Reduction of fuel cost associated with balancing

4.5.2.Reduction in CO_2 emissions

Reductions in fuel utilisation in the system with OCGTs will be reflected in the improvement of CO_2 performance of the system. The amount of CO_2 that can be saved by OCGT applications will be system specific, as shown in Fig. 26. As expected, the CO_2 savings are higher in the system with less flexible generation and increase with the increase in OCGT capacity(rating).

Although we observed a slight reduction in benefits of OCGT plant with the increase in capacity in MF and HF (from 4 GW to 5 GW) in terms of fuel cost, the benefits in terms of CO_2 continue to increase. Clearly, the net effect of reducing the amount of part loaded units and increasing utilisation of standing reserve, has environmental benefits, given the assumption that standing plant emits 0.6 tonnes/MWh (in contrast to the emission level of synchronised plant being set at 0.4 tonnes/MWh). On the other hand the net effect on cost would not be beneficial given the assumption that the cost of running an OCGT is set at 50£/MWh (in contrast to marginal cost of synchronised plant being 20£/MWh)

Clearly, the benefits of reducing spinning reserve by employing standing reserve in the form of OCGT could significantly reduce CO_2 emissions. For example, a portfolio of OCGT plant of 3GW installed capacity in a generation system of medium flexibility (MF case), would save 3.07 million tonnes of CO_2 per annum, only marginally below the storage based system.

[4] The slight reduction in benefits of OCGT with increase in capacity used for balancing in MF and HF cases indicates that standing reserve is being utilised more than necessary and that the allocation between spinning and standing reserve could be optimised further.

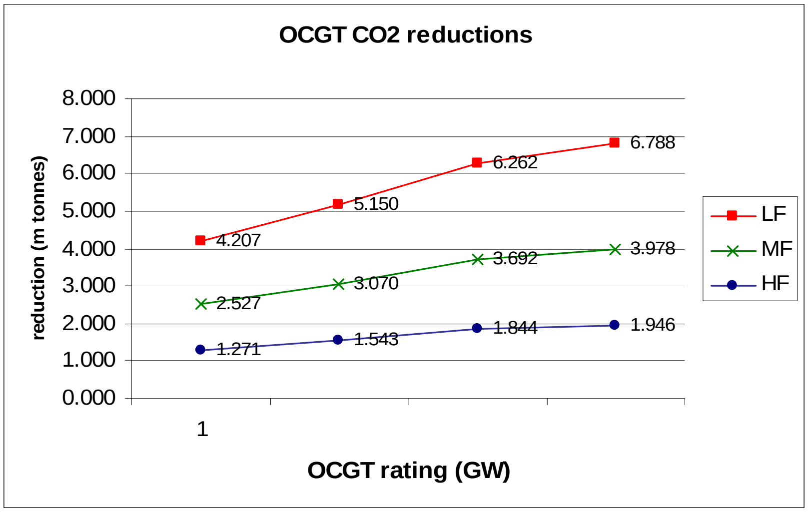

Figure 26. - Reduction in CO_2 emissions

4.5.3 Reduction in energy produced by conventional plant

By using OCGT plant for providing standing reserve, the amount of synchronised reserve committed can be reduced and this will lead to an increase in the amount of wind power that can be absorbed. A consequence of operating fewer conventional generating units is that the amount of wind that has to be rejected when high wind conditions coincide with low demand will be reduced.

One of the outputs of this evaluation is the amount of wind that needs to be curtailed in order to maintain a stable operation of the system. We can hence quantify the savings in wind energy curtailed by using OCGT based standing reserve provision. Figure 27 presents the reduction in the output of conventional plant as a result of using standing reserve in the form of OCGT. This reduction is a direct consequence of the increased ability of the system to accommodate more wind.

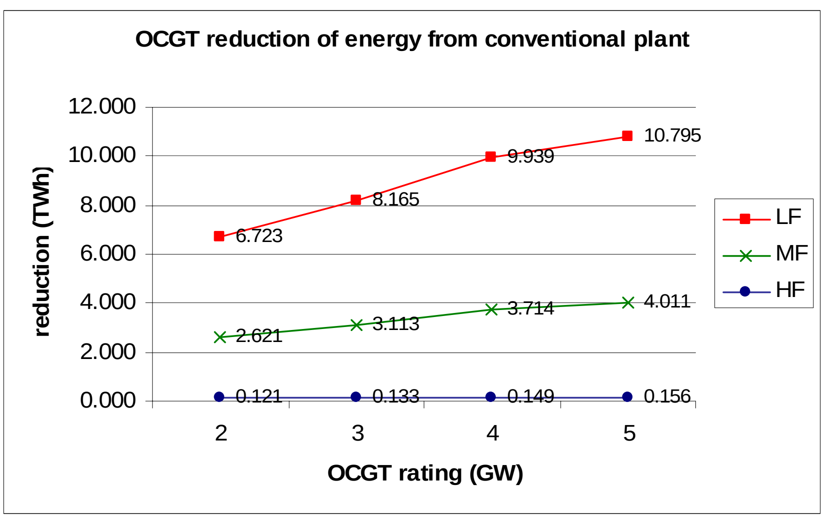

Figure 27. **-** Reduction in energy provided by conventional generation

4.6 Discussion

Generation and demand in an electricity system must be balanced at all times. Traditionally, the balance between demand and supply is managed by flexible generation. In real time, the output of large conventional generators would generally be adjusted to match any changes in demand. When changes in demand are predictable and there are enough flexible conventional units even significant increase in demand can be successfully managed. This has been proven many times in the past when the UK system experiences rapid but expected changes in the overall demand. However, balancing of supply and demand might experience significant changes in the future when the future electricity systems are expecting to accommodate high penetrations of intermittent renewable sources.

The inherent variability of such sources will require more resources to be made available in order to manage short-term balancing between demand and supply. However the amount of additional resource required to manage the unscheduled intermittent power will not be on a "megawatt for megawatt" basis. System operators will need to deal with the variability of the net, aggregated, output of a large group of intermittent sources.

It has been shown in various reports that the magnitude of wind output fluctuations will strongly depend upon the time horizon considered. Clearly, the magnitude of wind fluctuations increases as the time horizon under consideration becomes longer. However, the predictability of wind variations in managing demand and generation balance is very important. If the fluctuations of wind were perfectly predictable, the additional cost of operating the system with a large penetration of wind power would not be very significant, provided that there is sufficient flexibility in conventional plant to manage the changes in wind.

Regarding flexibility of conventional generating units we showed that for large amounts of spinning reserve, inflexible systems might experience significant wind curtailment. Using standing reserve or electrical bulk storage one can decrease this amount of wind curtailment. The allocation of reserve (or the split between synchronised and standing units) is a trade-off between the cost of holding synchronised reserve and the cost of operating less efficient standing plants with relatively high marginal cost.

Using simple snapshots we demonstrated that flexible systems can accommodate more inflexible baseload generating units when balancing supply and demand. At the end of the snapshot analysis we showed that a coincidence of system disturbances (an outage of baseload unit), and bad forecast of demand and wind power output, might cause serious consequences for a power system. Considering a simple four hours snapshot we demonstrated that a system, which is well balanced in terms of energy and has a significant amount of reserve cannot always be satisfactorily balanced on an hourly basis in terms of power. The snapshot analysis showed that due to a coincidence of disturbances and bad forecast of wind power output and demand, the system has surplus of power in the first hour but deficit in the last one. Energy storage systems appear to be an obvious solution to dealing with such situations, during the periods when wind generation exceeds the demand, the surplus could be stored and then discharged in the periods when the load is greater than the generation.

In a low-carbon electricity energy based system, with renewable generation producing the vast majority of electricity, considerable capacity of conventional plant may still be required. This would mean that the conventional power system might be acting as a backup or standby system, which obviously may reduce the overall value of renewable generation. Consequently these plants will have to compromise on their efficiency resulting in increased levels of fuel consumption as well as emissions per unit of electricity produced. At the end of this chapter we evaluated (i) reduction in fuel cost associated with system balancing, (ii) corresponding reduction in CO_2 emissions and (iii) reduction in energy produced by conventional generating units for generation systems with distinctly different generation flexibilities.

5.CONCLUSIONS

The United Kingdom (UK) Government has set new targets for the connection of major volumes of renewable generation sources so that 15% of the overall electricity consumption is supplied from renewable sources by 2015. The aspiration of the Government, as set out in the Energy White Paper, is that this trend continues and 20% of energy is provided from renewable sources by 2020. Even higher contributions from renewable energy sources are expected by 2050.

The main objective of this project was to investigate the security of these future UK decarbonised electricity systems.

There are a number of issues associated with integration of renewable sources in system operation and development. Although penetration of wind generation may displace significant amount of energy produced by large conventional plant, concerns over system security and operation costs are focussed on whether wind generation will be able to replace the ***capacity*** and ***flexibility*** of conventional generating plant.

We observed that wind generation has a relatively small capacity credit. At lower levels of wind penetrations the capacity credit of wind generation is found to be about the same as the average load factor of wind. However, as the level of wind penetration rises, the capacity credit begins to tail off. That is why in order to maintain the same level of system security a significant capacity of conventional plant will still be required.

However, these conventional plants will be required to run either occasionally and/or at part load when shortages of supply are likely to occur due to a low total wind power output. Considering that conventional plants at full load are the most efficient and generate the lowest amount of CO_2 emission (per electricity produced) such occasionally and/or part-loaded plants will be less utilised and/or produce more CO_2 per electricity produced.

Wind capacity credit could be significantly reduced if incidences such as anticyclone “cold snaps” occur. These incidences give high demand but little wind anywhere in the country. Such coincidence of high demand and no wind conditions in the whole country could reduce wind capacity credit by up to three thirds.

Generation and demand in an electricity system must be balanced at all times. Traditionally, the balance between demand and supply is managed by flexible generation. On average, the system operator in the UK commits about 600MW of dynamic frequency control, while about 2,400MW of various types of reserve is required to manage the uncertainty over time horizons of the order of 3-4 hours. These values could be significantly changed for the future UK decarbonised electricity systems, considering that renewable generation is both variable and unpredictable.

Statistical analysis of the fluctuations of wind output over the various time horizons in this report show that magnitude of this variation can be significant. The magnitude of wind output variations will also strongly depend upon the time horizon and wind penetration level. Clearly, the magnitude of wind fluctuations increases as the time horizon under consideration becomes longer. Penetration of wind generation will therefore impose additional requirements on the remaining large conventional plant to deliver both the flexibility and reserve necessary to maintain the continuous balance between load and generation, which will inevitably have cost implications.

The reserve requirements are driven by the assumption that time horizons larger than 4 hours will be managed by starting up additional units, which should be within the dynamic capabilities of gas fired technologies. Over that time horizon, the maximum change in wind output could be about 25% to 30% of the installed wind capacity. Consequently corresponding amounts of reserve will need to be made available to accommodate these changes. This reserve can be provided by running part-loaded synchronised plants or by flexible standing reserve, which is supplied by higher fuel cost plant, such as OCGTs (Open Cycle Gas Turbines) and storage facilities.

Assuming a flexible generation system, the allocation of reserve between synchronised and standing plant will be a trade-off between the cost of efficiency losses of part-loaded synchronised plant providing synchronised reserve (plant with relatively low marginal cost but running at all times) and the cost of operating less efficient standing plant providing standing reserve (plant with relatively high marginal cost but running only occasionally).

Energy storage systems appear to be an obvious solution to dealing with the intermittency of renewable sources: during the periods when wind generation exceeds the demand, the surplus could be stored and then used to cover periods when the load is greater than the generation. Storage can provide both upward ("positive") and downward ("negative") reserve whilst an OCGT plant can provide only upward regulation. In the case where generation is lower than demand, storage is discharged, whereas when demand is lower than generation then storage can be charged to balance the system. The ability of storage to provide this "negative" reserve will be of critical importance when low demand conditions coincide with a high level of output of wind generation. The cost of running storage will be driven by its efficiency and the cost of base load generation, while the cost of running OCGTs will depend on fuel used and the efficiency of the technology employed. The overall effect of the above factors on the relative performance of storage against OCGT plant will be system specific and will depend on the amount of standing reserve utilised.

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