The Costs and Impacts of Intermittency:

An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network

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A report of the Technology and Policy Assessment Function of the UK Energy Research Centre, with financial support from the Carbon Trust

Robert Gross
Philip Heptonstall
Dennis Anderson
Tim Green
Matthew Leach
Jim Skea

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Preface

This report has been produced by the UK Energy Research Centre's Technology and Policy Assessment (TPA) function.

The TPA was set up to inform decision making processes and address key controversies in the energy field. It aims to provide authoritative and accessible reports that set very high standards for rigour and transparency. The subject of the report was chosen after extensive consultation with energy sector stakeholders. It addresses the following question:

What is the evidence on the costs and impacts of intermittent generation on the UK electricity network, and how are these costs assigned?

This UKERC report was part funded by the Carbon Trust and was undertaken by a team of experts from Imperial College London and the Supergen Future Network Technologies Consortium. The work was overseen by a panel of experts, and provides a systematic review of more than 200 reports and studies from around the world.

The report provides a detailed review of the current state of understanding of the engineering and economic impacts of intermittent, or renewable energy sources, such as wind and solar power. It seeks to provide a review of this complex topic that is accessible to the non-specialist.

This report is the first output of the UKERC's TPA function, which was established to produce a wide variety of policy relevant reports on the energy sector to stimulate and inform debate between policymakers, researchers and the wider energy community.

About UKERC

It is the UK Energy Research Centre's (UKERC) mission to be the UK's pre-eminent centre of research, and source of authoritative information and leadership, on sustainable energy systems.

UKERC undertakes world-class research addressing the whole-systems aspects of energy supply and use while developing and maintaining the means to enable cohesive research in energy.

To achieve this we are establishing a comprehensive database of energy research, development and demonstration competences in the UK. We will also act as the portal for the UK energy research community to and from both UK stakeholders and the international energy research community.

Executive Summary

Overview

1. The output of many types of renewable electricity generation, such as wind, wave and solar, is intermittent in nature. Output varies with environmental conditions, such as wind strength, over which the operator has no control. Assimilating these fluctuations has the potential to affect the operation and economics of electricity networks, markets and the output of other forms of generation. It can affect the reliability of electricity supplies and the actions needed to ensure demand meets supply every instant.

2. This report aims to understand and quantify these impacts, and therefore addresses the question 'What is the evidence on the impacts and costs of intermittent generation on the British electricity network, and how are these costs assigned?' It is based on a review of over 200 international studies.

3. The studies have been categorised and assessed. The review process has been overseen by an expert group and the final report has been peer-reviewed by international experts. Stakeholders were consulted through a workshop, and materials produced throughout the assessment process were posted on the UKERC website.

4. This study focuses only on the electricity system implications of the uncontrollable variability of some renewable energy sources, often referred to as *intermittency*[1]. It therefore does not address: the basic costs of renewable generation relative to conventional generation; the environmental impacts of renewable generation; or the direct costs of extending the transmission system to accommodate new generation. The report focuses on incremental developments to the existing electricity system, with a timeframe approximately twenty years into the future. It does not consider the long term potential to reconfigure electricity networks in order to maximise the use of sustainable energy technologies, nor the costs or options for doing so.

The benefits of renewable generation

5. Renewable electricity generation helps to reduce the need to operate power stations burning fossil fuels such as coal and gas. This means that carbon dioxide emissions are reduced.

6. It is sometimes said that wind energy, for example, does not reduce carbon dioxide emissions because the intermittent nature of its output means it needs to be backed up by fossil fuel plant. Wind turbines do not displace fossil generating *capacity* on a one-for-one basis. But it is unambiguously the case that wind energy can displace fossil fuel-based *generation*, reducing both fuel use and carbon dioxide emissions.

7. Wind generation does mean that the output of fossil fuel-plant needs to be adjusted more frequently, to cope with fluctuations in output. Some power stations will be operated below their maximum output to facilitate this, and extra system balancing reserves will be needed. Efficiency may be reduced as a result. At high penetrations (above 20%) energy may need to be 'spilled' because the electricity system cannot always make use of it. But overall these effects are much smaller than the savings in fuel and emissions that renewables can deliver at the levels of penetration examined in this report.

[1]Terminology is controversial, many lean towards the term 'variable' others toward 'intermittent'. Neither term is perfect; the outputs of thermal plant are variable too, and can be intermittent, e.g. during faults. There are no unambiguous terms to capture the difference between renewable and conventional plants, except perhaps exogenously variable (e.g. wind) and controlled-variable (e.g. gas), which would be ungainly. So we have, despite its flaws, stayed with the much used term 'intermittent'.

Impacts on reliability of electricity systems

8. None of the 200+ studies reviewed suggest that introducing significant levels of intermittent renewable energy generation on to the British electricity system must lead to reduced reliability of electricity supply[2]. Many of the studies consider intermittent generation of up to 20% of electricity demand, some considerably more. It is clear that intermittent generation need not compromise electricity system reliability at any level of penetration foreseeable in Britain over the next 20 years, although it may increase costs. In the longer term much larger penetrations may also be feasible given appropriate changes to electricity networks, but this report does not explore the evidence on this topic.

9. The introduction of significant amounts of intermittent generation will affect the way the electricity system operates. There are two main categories of impact and associated cost. The first, so called system balancing impacts, relates to the relatively rapid short term adjustments needed to manage fluctuations over the time period from minutes to hours. The second, which is termed here 'reliability impacts', relates to the extent to which we can be confident that sufficient generation will be available to meet peak demands. No electricity system can be 100% reliable, since there will always be a small chance of major failures in power stations or transmission lines when demands are high. Intermittent generation introduces additional uncertainties, and the effect of these can be quantified.

System balancing impacts

10. The vast bulk of electricity in Britain is supplied through market arrangements comprising bilateral contracts of varying durations between generators and suppliers (wholesalers of electricity). However relatively small, but crucial, adjustments are needed to ensure demand and supply balance each instant. These are made by the system operator, the company with a statutory duty to ensure that electricity supply continuously meets demand. The system operator balances the system by purchasing services from generators or adjustable loads. To ensure these services are available in the timescales required, the system operator enters into contracts for system balancing reserves.

11. System balancing entails costs which are passed on to electricity consumers. Intermittent generation adds to these costs. For penetrations of intermittent renewables up to 20% of electricity supply, additional system balancing reserves due to short term (hourly) fluctuations in wind generation amount to about 5-10% of installed wind capacity. Globally, most studies estimate that the associated costs are less than £5/MWh of intermittent output, in some cases substantially less. The range in UK relevant studies is £2 - £3/MWh.

System reliability impacts and additional system capacity requirements

12. To maintain reliability of supplies in an electricity system, peak demand must not exceed the production capability of the installed generation at that moment. Historically central planners sought to ensure that installed generation capacity could meet forecast peak demand within a planning horizon. In liberalised markets, individual market participants are responsible only for ensuring adequate generation capacity is available to meet their own contracts to supply electricity. In either case, a system margin can be measured which is the amount by which the total installed capacity of all the generating plant on the system exceeds the anticipated peak demand.

13. Unless there is a large amount of responsive or controllable demand, a system margin is needed to cope with unavailability of installed generation and fluctuations in electricity requirements (e.g. due to the weather). Conventional plant – coal, gas, nuclear – cannot be completely relied upon to generate electricity at times of peak demand as there is, very approximately, a one-in-ten chance that unexpected failures (or "forced outages") in power plant or electricity transmission networks will cause any individual conventional generating unit not to be available to generate power. Even with a system margin, there is no absolute guarantee in any electricity system that all demands can be met at all times.

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[2] Reliability is generally assessed by the indicators such as 'loss of load probability'. Potential limitations of such measures are discussed below and in the main report.

14. The risk of demand being unmet can be characterised statistically, and the measure commonly used to quantify this risk is called Loss of Load Probability (LOLP). This measures the likelihood that any load (demand) is not met, and it is usually a requirement of electricity systems that LOLP is kept small[3].

15. Intermittent generation increases the size of the system margin required to maintain a given level of reliability. This is because the variability in output of intermittent generators means they are less likely to be generating at full power at times of peak demand. The system margin needed to achieve a desired level of reliability depends on many complex factors but may be explored by statistical calculations or simplified models. Intermittent generation introduces new factors into the calculations and changes some of the numbers, but it does not change the fundamental principles on which such calculations are based.

16. Intermittent generators can make a contribution to system reliability, provided there is some probability of output during peak periods. They may be generating power when conventional stations experience forced outages and their output may be independent of fluctuations in energy demand. These factors can be taken into account when the relationship between system margin and reliability is calculated using statistical principles.

17. There is some debate over the extent to which existing measures of reliability, particularly LOLP, fully capture the changes that arise when intermittent sources are added to the network. This is because intermittent generation changes the nature of the unreliability that may arise (for example, increasing the number of occasions in which relatively small curtailments of demand may be required). These aspects may be represented by using different statistics to calculate risk, in addition to a simple LOLP.

18. *Capacity credit* is a measure of the contribution that intermittent generation can make to reliability. It is usually expressed as a percentage of the installed capacity of the intermittent generators. There is a range of estimates for capacity credits in the literature and the reasons for there being a range are well understood. The range of findings relevant to British conditions is approximately 20 – 30% of installed capacity when up to 20% of electricity is sourced from intermittent supplies (usually assumed to be wind power). Capacity credit as a percentage of installed intermittent capacity declines as the share of electricity supplied by intermittent sources increases.

19. The capacity credit for intermittent generation, the additional conventional capacity required to maintain a given level of reliability and thus the overall system margin are all related to each other. The smaller the capacity credit, the more capacity needed to maintain reliability, hence the larger the system margin. The amount by which the system margin must rise in order to maintain reliability has been described in some studies as "standby capacity", "back-up capacity" or the "system reserves". But there is no need to provide *dedicated* "back-up" capacity to support individual generators. These terms have meaning only at the system level.

Costs of maintaining reliability

20. The additional capacity to maintain reliability entails costs over and above the direct cost of generating electricity from intermittent sources. There has been some controversy over how to estimate the costs associated with the additional thermal capacity required to maintain reliability. In part this reflects the fact that under current market arrangements there is no single body with responsibility to purchase system margin. This is one reason why costs are less transparent than they are for system balancing services. Some studies have assessed the costs of the capacity required to maintain reliability based on assumptions about the nature of plant providing 'system reserves'. Others have assessed only the change in the total costs of the electricity system as a whole[4]. There is broad agreement between both approaches on the total change to system costs.

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[3]e.g. the LOLP of the pre-privatised electricity system in Great Britain was planned not to exceed 9% - nine winters per century.

[4]The change in total system cost can be characterised as the cost of building and operating intermittent plant, ***minus*** the cost associated with displaced fuel use, ***minus*** the costs of thermal plant that can be displaced (or new investment avoided) because of the capacity credit of the intermittent plant.

21. We have identified the need for an agreed definition for reporting the 'system reliability costs of intermittency'. We suggest that this be based on the difference between the contribution to reliability made by intermittent generation plant and the contribution to reliability made by conventional generation plant. This comparison should be drawn between plants that provide the same amount of energy when operated at maximum utilisation. This provides a measure of the cost of maintaining system reliability and is in addition to the direct costs of intermittent plant. In the main text and Annex 2, we explore this relationship in depth and show that it can be expressed as follows: System reliability cost = fixed cost of energy-equivalent thermal plant (e.g. CCGT) minus avoided fixed cost of thermal plant (e.g. CCGT) displaced by the capacity credit of intermittent plant (e.g. wind). It should be noted that all forms of generation have the potential to impact on system costs, and this is an important topic for ongoing and future research[5].

22. The comparison with conventional generating plant at maximum utilisation (i.e. on 'baseload') is crucial to this calculation. Policymakers and others often seek to compare the average costs of different types of generating plant on a 'like with like' basis. For example, they may wish to compare the cost of wind power with the cost of coal power. This comparison uses levelised costs (£/MWh) that assume that plants are operating at maximum utilisation. If intermittency costs are calculated in any other way there is a danger that comparisons of this nature will not be meaningful[6].

23. Using the definition set out in paragraph 21, the cost to maintain system reliability lies within the range £3 - £5/MWh under British conditions. Again, relative to a comparitor plant operated at maximum utilisation. Impacts can also be expressed in MW terms; additional conventional capacity to maintain system reliability during demand peaks amounts to around 15% to 22% of installed intermittent capacity.

24. This assumes around 20% of electricity is supplied by well dispersed wind power. Current costs are much lower; indeed there is little or no impact on reliability at existing levels of wind power penetration. The cost of maintaining reliability will increase as the market share of intermittent generation rises.

Comparing different electricity systems

25. It is tempting to read across the results of studies on intermittency costs from one country to another, or from one system to another. This can be another source of controversy. The greatest care must be taken in trying to make such comparisons. The impacts and costs of intermittent generation can be assessed only in the context of the particular type of system in which they are embedded. The impacts depend on:

– The quality of the environmental resource on which renewable generation depends, for example the strength of the wind and the degree to which it fluctuates.

– The robustness of the electricity grid and the capacity to transfer power from generators to consumers.

– Regulatory and operating practices, in particular how far ahead the use of system balancing reserve is planned (known as 'gate closure'). The closer to real time reserves are committed, the more reliable will be forecasts of intermittent generation, which can reduce the need for more expensive fast-acting reserve.

– Accuracy of forecasting of intermittent output. Better forecasting can improve the efficiency with which intermittency is managed, both by the system operator after gate closure and by markets over longer timescales. Weather patterns in some regions are more predictable than in others.

– The extent to which intermittent generators are geographically dispersed or are located in a particular area. If wind generators are located close together their output will tend to fluctuate up and down at the same time, increasing variability of the total output and increasing the costs of both system balancing and maintaining reliability.

[5]Variable/operating costs cancel, which is why the expression is concerned only with capital costs.
[6]Studies that do assume 'dedicated' back up is needed, and neglect the comparator plant described in points 21 & 22, give rise to much higher costs.

26. Some conditions in Britain (quality of wind resource, robustness of the grid, relatively late gate closure) will tend to mitigate the impacts of intermittency and keep associated costs relatively low. Others (notably the relative lack of interconnection and relatively small geographical area over which resources are dispersed) will tend to increase the costs of managing the system relative to other regions. Comparisons between Britain and other countries must be treated with the greatest of caution.

Intermittency costs in Britain

27. The aggregate 'costs of intermittency' are made up of additional short-run balancing costs and the additional longer term costs associated with maintaining reliability via an adequate system margin. Intermittency costs in Britain are of the order of £5 to £8/MWh, made up of £2 to £3/MWh from short-run balancing costs and £3 to £5/MWh from the cost of maintaining a higher system margin. For comparison, the direct costs of wind generation would typically be approximately £30 to £55/MWh. If shared between all consumers the impact of intermittency on electricity prices would be of the order 0.1 to 0.15 p/kWh.

28. These estimates assume that intermittent generation is primarily wind, that it is geographically widespread, and that it accounts for no more than about 20% of electricity supply. At current penetration levels costs are much lower, since the costs of intermittency rise as penetrations increase. If intermittent generation were clustered geographically, or if the market share were to rise above 20%, intermittency costs would rise above these estimates, and/or more radical changes would be needed in order to accommodate renewables.

Recommendations for reporting the costs of intermittency

29. When reporting the costs associated with intermittent electricity generation, we recommend that:

a) there be a clear statement of which costs are included and those which are excluded, i.e. short-run balancing costs versus long-run capacity requirements;

b) there be a clear statement of the methodological basis for calculating intermittency impacts;

c) when comparing the costs of intermittent sources versus baseload conventional generation the method described in paragraph 21 be used;

d) that the context of the system into which intermittent generation is being embedded be clearly described.

Recommendations for UK-relevant research and policy

30. We recommend that additional steps are put in place to continuously monitor the effect of intermittent generation on system margin and existing measures of reliability. The effectiveness of market mechanisms in delivering adequate system margin also needs to be kept under review.

31. Intermittent generation can make a valuable contribution to energy supplies, but to ensure reliability of supply, additional investment in thermal capacity is also required. In the short run older plant is likely to provide system margin but, in the long run, investment in new capacity will be needed. Flexible and reliable generation is an ideal complement to intermittent renewables. Policy should encourage and not impede investment in plant that is well suited to complement renewable energy sources and contribute to both reliable operation and efficient system balancing.

32. We recommend that more research be undertaken on the following topics:

- Renewable energy deployment scenarios in which intermittent generation is clustered in particular regions of the UK, including the system impacts of very large offshore wind farms.

- Measures of reliability appropriate to intermittent sources. In particular the merits of, and options for, going beyond 'loss of load probability', (LOLP) in characterising the reliability of an electricity system at high levels of intermittent generation. LOLP measures the likelihood of a capacity shortfall rather than its severity.

- Using these improved measures of reliability, there is a need for on-going monitoring of the British market to assess how actual market response (i.e. decisions to invest in new generation or maintain existing generation in-service) compare to those that would be consistent with the improved reliability measures.

- The definition of an agreed convention for reporting the costs associated with maintaining system reliability.

- Further work on the development of methodologies for assessing the system cost implications of new generating technologies (intermittent or otherwise), in terms of the impacts on the utilisation of incumbent generation.

- The extent to which intervention may be needed to ensure that adequate investment in appropriate thermal plant to maintain reliability is delivered, and the policy options available to do so.

- The implications of different combinations of thermal plant on the costs and impacts of integrating renewable energy in the short to medium term. In particular, the relative impacts of different sizes and types of thermal generation, and of inflexible versus flexible plant, on efficiency of system operation and integration of wind and other renewables.

- Options for managing the additional power fluctuations on the system due to intermittency – including new supply technologies, the role of load management, energy storage etc. Opportunities and challenges for re-optimisation of the electricity system in the long term to cope with intermittent generation, including research on much higher penetrations of renewable sources than the relatively modest levels considered in this report.

Contents

Glossary[7]

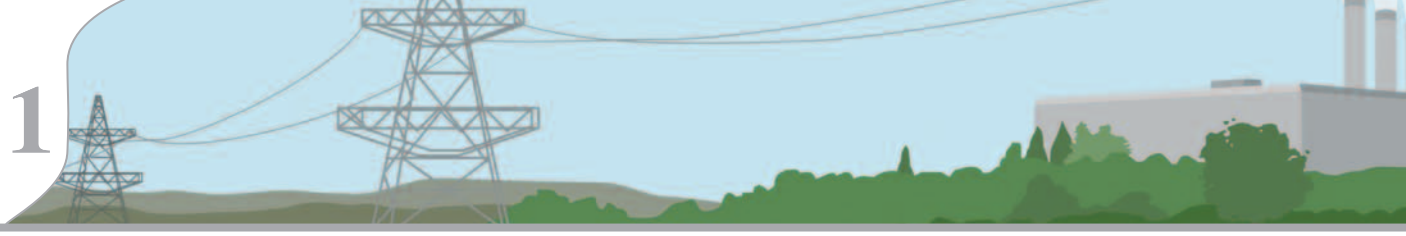
BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Mechanism
BNFL	British Nuclear Fuels Ltd.
BPA	Bonneville Power Administration
BWEA	British Wind Energy Association
CCGT	Combined Cycle Gas Turbine
CEGB	Central Electricity Generating Board
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DENA	Deutsche Energie-Agentur - German Energy Agency
DNUoS	Distribution Network Use of System charges
DTI	Department of Trade and Industry
EC	Commission of the European Union
EPSRC	Engineering and Physical Sciences Research Council
EST	Energy Saving Trust
EU	European Union
GRE	Great River Energy
Grid Code	A document that defines obligatory features of a power generator that is connected to the electricity system
GW	Gigawatt - a measure of power, one thousand MW
GWh	Gigawatt Hour - unit of electrical energy, one thousand MW of power provided for one hour
JESS	Joint Energy Security of Supply Committee (comprised of representatives from National Grid, DTI and Ofgem)
kW	Kilowatt - a measure of power, one thousand watts
kWh	Kilowatt Hour - unit of electrical energy, one thousand watts of power provided for one hour
ICEPT	Imperial (College) Centre for Energy Policy and Technology
IEA	International Energy Agency
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LOEE	Loss of Energy Expectation

[7]Box 2.1 and Annex 6 provide a detailed explanation of terminology

MW	Megawatt - a measure of power, one thousand kW
MWh	Megawatt Hour - unit of electrical energy, one thousand kW of power provided for one hour
NETA	New Electricity Trading Arrangements
NGC	National Grid Company
NGET	National Grid Electricity Transmission (formerly NGC[8])
NISM	Notification of Inadequate System Margin
OCGT	Open Cycle Gas Turbine
Ofgem	Office of Gas and Electricity Markets
OPEC	Organisation of the Petroleum Exporting Countries
OU	Open University
PIU	Performance and Innovation Unit - now the Prime Minister's Strategy Unit, UK Government Cabinet Office
PV	Photovoltaic - apparatus that transforms sunlight into electricity
p/kWh	Pence per kWh, the common unit of pricing energy sold to consumers
RIIA	Royal Institute of International Affairs (Chatham House)
R&D	Research and Development
SD	Standard Deviation
Thermal Plant	Conventional steam-raising electricity generators - this includes coal, gas, oil and nuclear plant
TPA	Technology and Policy Assessment Function (of the UKERC)
TNUoS	Transmission Network Use of System charges
TSO	Transmission System Operator - in the UK, this is National Grid
TW	Terawatt - a measure of power, one thousand GW
TWh	Terawatt Hour - unit of electrical energy, one thousand GW of power provided for one hour
UCD	University College Dublin
UKERC	UK Energy Research Centre
Watt (W)	The standard (SI) unit to measure the rate of flow of energy
WECS	Wind Energy Conversion Systems - in practice, a wind turbine

[8]NB. National Grid plc (formerly National Grid Transco plc) is the parent company of NGET

List of tables and figures



1

Introduction

Overview

This report reviews and assesses the evidence on the costs and supply system impacts of intermittent generation (wind, wave, tidal and solar power). Its focus is on the UK and on the immediate future – changes and developments anticipated within the next two decades or so. Its findings are based upon a systematic search of the international literature which revealed more than two hundred reports and studies. It seeks to draw conclusions about a complex and much debated topic that are accessible to the non-technical reader.

1.1 What is this report about?

Some forms of renewable electricity generation exhibit what is often referred to as 'intermittent'[9] output. The output of these kinds of electricity generators depends upon environmental conditions that may be predictable to some degree but are outside the control of plant owners or system operators. For example, the amount of electricity generated by a wind turbine fluctuates as wind speed changes and that of a photovoltaic array with the intensity of sunlight. Their output is controllable only insofar as operators can *curtail* or reduce the potential output of such generators. When such devices are connected to electricity networks in significant numbers this will affect the operation of the network, actions within electricity markets, and the need for and output of other forms of generation. The impacts of intermittent generation on system operation and reliability and the extent of any new costs (relative to costs and impacts imposed on the system by other generating options) are the subjects of this report.

The report focuses on the UK[10], but draws upon experience and analysis from several countries. The focus is also largely upon issues raised by existing renewable energy targets or goals, and changes that might therefore be required in the period to around 2020. This time period was considered to be most relevant to policymakers and other industry stakeholders[11]. The report therefore draws on literature that is largely concerned with incremental change to existing electricity systems, rather than with the design or conceptualisation of radically different systems – such as those that might be conceived for the more distant future[12]. The report addresses this question:

What is the evidence on the costs and impacts of intermittent generation on the UK electricity network, and how are these costs assigned?

[9]This report refers to such generators as 'intermittent'. Other terms such as 'variable' have been proposed, and are arguably more accurate (Grubb 1991). But 'intermittent' is common parlance, despite its limitations and the fact that alternative descriptors were first mooted more than a decade ago. All terms have limitations and 'intermittent', though perhaps unsatisfactory, is widely utilised.

[10]More specifically the main focus of the report is the Great Britain (GB) electricity network, since Northern Ireland has rather different regulatory arrangements. See Ch. 3 for more details.

[11]See the UKERC User Needs Assessment http://www.ukerc.ac.uk/content/view/124/105/

[12]Some participants in the stakeholder workshop on this report propounded a more 'visionary' approach, and an idealised electricity system designed for maximum penetration of sustainable energy. In the longer term it is possible to envisage a system that is designed to optimise the use of intermittent supplies, at lower cost than would be the case for the current system. However, in keeping with the requirements of the principal audience for this report, and reflecting the issues that appear to be most controversial, we believe a shorter term and more incremental focus is justified.

1.2 Why is this report needed?

A substantial fraction of the UK's 2010 and 2015 targets for renewable energy will be met by intermittent generation, particularly wind power. The Government's aspiration is that renewables will meet 20% of electricity demand by 2020. This, and any subsequent renewable energy targets, is likely to increase the role of intermittent sources still further (DTI 2003). Managing intermittency may have important implications for the costs of meeting these targets, and/or affect security of electricity supply. It is important to note that intermittent generators are not alone in imposing system costs, nor are other technologies without security of supply implications. The report therefore focuses upon what is *different* about intermittency, and what *changes* are needed to deal with the integration of intermittent renewables.

Although there have been numerous engineering and economic studies of intermittency in many countries[13], the topic remains contentious with a wide range of cost estimates in the literature[14]. As a result, stakeholders interviewed by UKERC prior to the initiation of this assessment suggested that intermittency is a key controversy in the energy field[15]. Intermittency is also a high profile topic, often linked to a wider debate over the future of wind power that has caught the media's attention[16].

This report attempts to show where the balance of evidence lies and explain the reasons for the disparities in the literature. It is important to note that there are a range of issues where evidence is limited or research is ongoing, it is also impossible for this report to cover each and every aspect of integrating renewables in to electricity networks. Where possible we highlight evidence gaps and topics for further research.

1.3 How is this report different?

The object of this report is not to undertake new research on intermittency. Rather, it is to provide a thorough review of the current state of knowledge on the subject, guided by experts and in consultation with a range of stakeholders. It also aims to explain its findings in a way that is accessible to non-technical readers and is useful to policymakers. A key goal is to explain controversies, where they arise.

To do this the UKERC undertook a systematic search for every report and paper related to the costs and impacts of intermittent generation. This highly specified search revealed over two hundred reports and papers on the subject, each of which was categorised and assessed in terms of the issues covered and the methodology of the analysis. Experts from all sides of the debate and a wide range of stakeholders were invited to comment and contribute through an expert group and stakeholder workshop. Each stage of the process has been documented so that readers and reviewers can identify the origins of our findings and how the literature we consider and discuss was revealed. We describe this in a *review protocol*, published on UKERC's website. Relevant materials were also posted on the website as work progressed, including the project scoping note, discussion paper and workshop proceedings[17].

The complexity of the subject matter and confusion surrounding the debate were highlighted in our interactions with stakeholders. Our research also revealed a relatively limited attention to accessible *exposition of principles* in the literature. This report therefore provides an introduction to some key principles of electricity network operation and explains the factors affected when intermittent generation is added to it. Finally, the review team undertook its own analysis using statistical first principles to inform the exposition and assist in assessment of the findings revealed in the literature[18].

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[13]UK research dates back to the late 1970s. Recent work was undertaken for the UK Energy Review (Milborrow 2001), Energy White Paper (Ilex and Strbac 2002) and Carbon Trust/DTI Network Impacts Study (Mott MacDonald 2003). Similar research has been conducted in most countries with renewables programmes.
[14]See Ch 3 for the range of estimates.
[15]UKERC User Needs Assessment http://www.ukerc.ac.uk/content/view/124/105/
[16]See Wind Power Monthly, September 2004 for a review of media coverage of wind energy
[17]See UKERC website http://www.ukerc.ac.uk/content/view/124/105/
[18]See Anderson, 2005, Power System Reserves and Costs with Intermittent Generation http://www.ukerc.ac.uk/content/view/55/67/

The project team was drawn from the Supergen *Future Network Technologies* Consortium. The Expert Group was chosen to provide economic, policy and engineering expertise and a diversity of perspectives. It provided advice and scrutiny at a series of meetings throughout the project. Peer review was provided in January 2006 by international experts[19]. Databases, bibliographies, catalogues, and other sources, together with key words, were agreed with the expert group, refined in collaboration with stakeholders and published in the *Scoping Note and Protocol.*

The approach aims to provide a comprehensive, transparent and replicable assessment of *the balance of evidence* on the intermittency debate. As a result this assessment is able to draw firm conclusions about what is known, what remains uncertain and where more research is needed. We hope that this serves to overcome some of the controversy and facilitates a better informed debate.

1.4 The structure of this report

Ch. 2 provides an introduction to the principles of network operation relevant to integration of intermittent generators, what changes when intermittent sources are added to the network, and the techniques used to assess their impacts. It also provides an overview of key controversies related to each impact. These issues are explored further in Ch. 3 and Ch. 4.

Ch. 3 provides analysis of the evidence on each impact. In each case it provides the reasons that findings differ and discusses the implications of the quantitative evidence.

Ch. 4 draws out the principal findings, conclusions, implications for policy and discusses areas where further work is needed.

Box 1.1 Overview of the TPA approach

The approach the TPA takes to all its work seeks to learn from a range of techniques referred to as *evidence based policy and practice*, including the practice of *systematic review*. This aspires to provide more convincing evidence for policymakers, avoid duplication of research, encourage higher research standards and identify research gaps. Energy policy gives rise to a number of difficulties for prospective systematic review practitioners and the approach has in any case been criticised for excessive methodological rigidity in some policy areas. UKERC has therefore set up a process that is inspired by the approach described above, but that is not bound to any narrowly defined method or technique. This is explained in more detail in Annex 5.

Assessment activities:

The process carried out for this assessment has ten key components:
- Publication of Scoping Note and Protocol
- Establishment of a project team with a diversity of expertise
- Production of a discussion paper (key issues)
- Convening an Expert Group with a diversity of opinion and perspective
- Stakeholder consultation
- Systematic searching of clearly defined evidence base using keywords
- Categorisation and assessment of evidence
- Synthesis, review and drafting
- Expert feedback on initial drafts
- Peer review of final draft

[19] See Annex 1 for a full list of all contributors

2

Understanding the impacts of intermittent generation

Overview

This chapter explains the operation of electricity networks in terms of the provisions that are in place to deal with demand fluctuations and potential faults with conventional generators. It then considers the characteristics of intermittent generation, and the changes that they introduce when installed in electricity systems. It shows how the key impacts are quantified, outlines some important areas of controversy and introduces the topics that we explore empirically in Ch. 3.

2.1 Introduction

This chapter provides an introduction to the operation of technically mature electricity supply systems, such as that of the UK. It explains how a combination of market mechanisms and actions by the body responsible for the technical operation of the transmission system – the transmission system operator (TSO) – ensure that supply and demand are kept in balance. This includes the provisions that are made in case conventional generators fail or demand is higher than expected. All forms of generation have the potential to increase or decrease system costs. The chapter therefore explores the additional issues introduced when intermittent supplies are introduced and their implications for system composition, operation and cost.

The chapter deals with a range of concepts for understanding the impacts of intermittency, and the generic tools used to assess and maintain standards for reliable and secure operation of electricity networks. Some of these techniques and tools are themselves the subject of ongoing research and development, as we explain further in Section 2.3 and elsewhere. There is also ongoing research on the characteristics of intermittent resources and the best techniques for managing them. This chapter (and Ch. 3) provides in some respects a 'snapshot' of current understanding.

What follows is intended to provide an overview accessible to a non-technical reader. It attempts to ensure consistency with the processes and practices in place within the current UK market and regulatory arrangements[20]. Terminology can give rise to misunderstanding as terms are used differently in different countries, or have changed over time. We discuss potential for misunderstanding due to terminology below and a review of the technical terms we use in this chapter is provided in Box 2.1. Full details are in Annex 6.

[20] For the most part the chapter uses the terminology of the British Electricity Trading and Transmission Arrangements (BETTA) Grid Code, which covers Great Britain, and the contracts and services put in place by the British transmission system operator, National Grid. Arrangements in Northern Ireland, managed by Northern Ireland Electric, are somewhat different, characterised by a more 'traditional' vertically integrated structure. However there is little or no difference in the technical issues relating to system balancing and reliability.

Box 2.1: Terminology

In many cases the issues in this report are described using particular words or phrases. Terms have changed over the years as a result of liberalisation and are used in different ways in different contexts, for example in moving from engineering to regulatory or commercial practice or in different countries. As a result, confusion can arise. Annex 6 provides a comprehensive discussion of terminology. We briefly review here a few key terms, unlikely to be familiar to the lay reader, but essential to understanding this chapter and those that follow. Where terms differ between sources the specific definition used in this report is provided. These follow the GB Grid Code.

Term	Definition
Balancing mechanism	Set of arrangements in place after *gate closure* (see below) in which the system operator can take bids and offers to balance the system. The prices of bids and offers are determined by market participants and, once accepted, are firm contracts, paid at the bid price. These bilateral contracts are between market participants and the system operator.
Balancing services	Services purchased from balancing service providers by the system operator. Includes Balancing Mechanism bids & offers, other energy trades, Response, Reserve, and other system services.
BETTA	British Electricity Trading and Transmission Arrangements. The market rules under which generators, suppliers and the system operator operate. These include the GB **Grid Code, Balancing & Settlement Code and Connection & Use of System Code** which contains detailed definitions of contracts and rules relevant to this section.
Capacity credit	A measure of the amount of load that can be served on an electricity system by intermittent plant with no increase in the loss-of-load probability (LOLP), which is often expressed in terms of conventional thermal capacity that an intermittent generator can replace.
Capacity factor	Energy produced by a generator as a percentage of that which would be achieved if the generator were to operate at maximum output 100% of the time. Capacity factor for baseload thermal generators can be around 85%. Wind turbines achieve capacity factors of 20% - 40%.*
Gate closure	The point in time (one hour before real time under BETTA) at which the energy volumes in bilateral contracts between electricity market participants must be notified to the central settlement system. Between gate-closure and real-time the TSO is the sole counter-party for contracts to balance demand and supply. Also see 'balancing mechanism'.
Ramping rates	A measure of how quickly any plant on the system can increase or decrease its output – normally measured in MW/h.
Response and reserve services	Reserve and response services are purchased by the system operator in order to ensure there is sufficient capability in the short-term to undertake system balancing actions and frequency control. **Response** (frequency response) may be utilised in seconds through automatic controls on generators or loads. Steam generators may be held below maximum output to facilitate this. **Reserve** is a capability to change output to meet system operator requests within a few minutes. Utilisation of this capability may be subject to payment in the Balancing Mechanism or through other balancing service agreements. There are various categories of reserve depending on speed of delivery and the nature of its provision: **Fast Reserve** can be provided by demand reduction, pump storage or part loaded steam plant connected to the system. **Standing Reserve** is ready for action within twenty minutes. As well as demand reductions it might consist of fast starting gas turbines, or backup diesel generation. **Residual Reserve** - This is the capability provided in the Balancing Mechanism (i.e. reserves that can be dispatched in response to market prices rather than contracted by the TSO). **Contingency Reserve** - This is the capacity that should be established in the 24 hour ahead period by the market. It is not usually purchased by the TSO but is monitored to ensure adequate short-term reserves will be available.
System margin	The difference between installed capacity, including imports and exports, and peak demand. Operating margin is the difference between available generation and actual demand.
System operator (or transmission system operator – TSO)	The company or body responsible for the technical operation of the electricity transmission network. In Britain National Grid undertake this role, subject to regulation.

* Capacity factor is sometimes conflated with a related term, *load factor*. Load factor differs from capacity factor in that it is a measure of *actual* utilisation rather than *maximum* output.

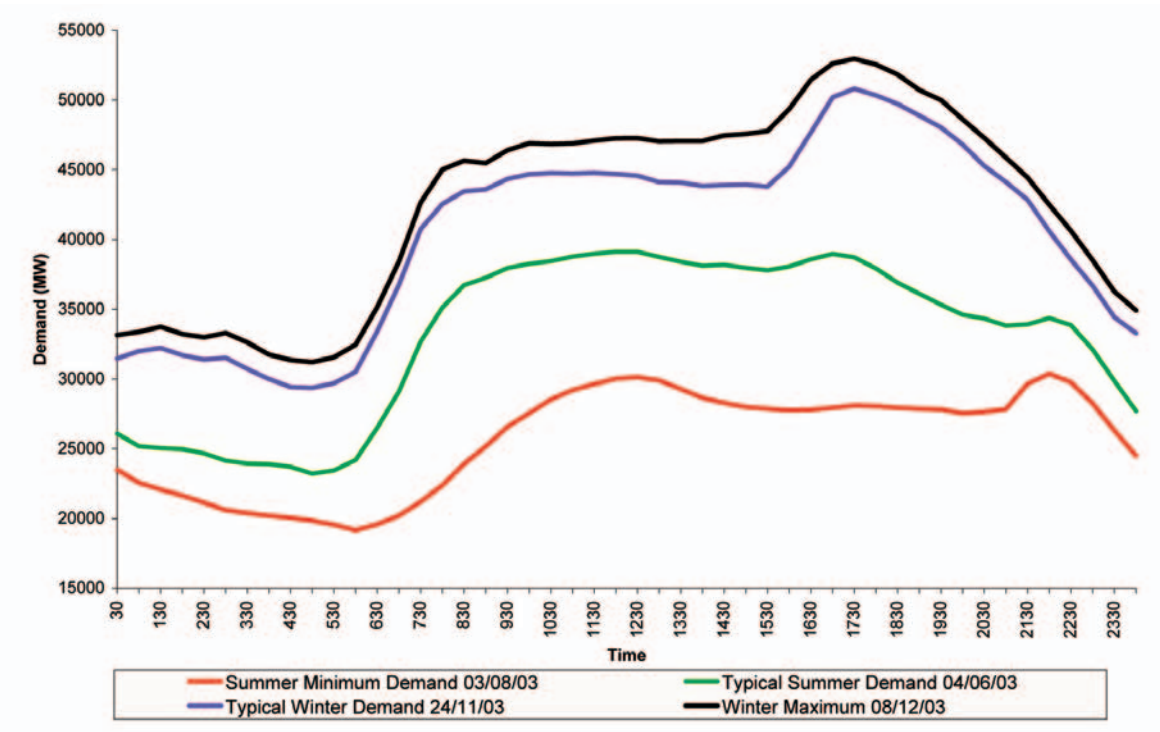
2.2 Context: managing fluctuations in demand and supply

2.2.1 Introduction

Electricity demand changes continuously. It fluctuates from second to second and also goes through very large swings over a few hours. Most consumers are not under the control of system operators nor are they direct participants in wholesale electricity markets[21], so the system operator and market mechanisms must ensure increased electricity generation as demand increases, and reductions as demand falls. To prevent serious problems this adjustment must be continuous, and almost instantaneous. Figure 2.1 illustrates the extent of diurnal variations in electricity demand, and how these vary by time of year, reflecting seasonal effects.

Some forms of generation can vary their output rapidly, others only over a longer time period. Some are largely inflexible and must operate at a fixed and constant level. Figure 2.2 in section 2.2.3 shows an example 24 hour 'load profile' and the operation of different types of plant to meet demand. However no plant is able to operate 100% of the time; all types of generator require periodic maintenance, and every power station will suffer occasional unplanned outages due to a breakdown or fault. As a result, power systems are engineered to cope with both demand fluctuations and periods when several power stations are unavailable due to planned maintenance or unexpected breakdowns. We explore the processes through which demand fluctuations and supply side failures are managed in the following sections.

Figure 2.1. Seasonal variation in daily demand patterns[22]



[21]Some very large consumers (such as steel works or chemical plants) can reduce demands in response to high prices or enter into contracts with the system operator such that they are paid to be disconnected when demand is very high.
[22]From the National Grid Seven Year Statement 2004 (data for England and Wales), Available from http://www.nationalgrid.com/uk/library/documents/sys_04/default.asp?action=mnch2_7.htm&Node=SYS&Snode=2_7&Exp=Y#Demand_Profiles

2.2.2 Basic principles - meeting demand fluctuations and ensuring reliability

Section 2.2.3 provides an overview of the way that the UK's electricity market helps keep electricity demand and supply in balance, as well as current provisions for reserves and contingencies to deal with unpredictable events. Market mechanisms have replaced the centrally planned electricity system that used to exist in the UK. However, the way the market relates to the technical operation of the electricity system is complex. By way of background, we first revisit the basic principles of electricity system operation in an historical context.

In the very early days of electricity, single generating stations provided individual local networks with electricity. These generators had to be inherently flexible in output, and/or variations in demand had to be restricted. They needed 100% 'back up' to ensure reliability in case of a fault. As interconnection between local networks expanded – first on a municipal scale, then nationally – two changes occurred. First, risks of breakdown could be shared across many plants, so the amount of 'back up' could be reduced without compromising reliability. Second, demands were aggregated which tended to smooth fluctuations and also meant that a range of types of generation could be used – some more flexible than others. In very simple terms, the following principles of operation apply to all large, advanced networks:

– A range of plants are used to meet different portions of the daily demand curves seen in Figures 2.1 and 2.2 - from very flexible plant designed to meet rapid swings in demand to inflexible (but cheap to operate) plant that runs all the time. A process for 'dispatching' plant to meet demand is needed, historically this was under the direct control of the system operator/owner, and used least cost criteria.

– System balancing reserves are needed to deal with unexpected short term fluctuations (minutes to hours) caused by either demand changes or faults at power stations or power lines. These reserves are sized on a statistical basis according to the range of unpredicted variation in demand, reliability of conventional generators and the scale of potential faults. The aim is to meet specific criteria for operational reliability – that is to ensure that the risk of demand being unmet is small.

– In addition to the short term reserves made available each day a larger 'system margin'[23] of maximum possible supply over peak demand is provided for when planning the development of the system. The size of this margin can be determined using statistical principles to do with the number and reliability of generators and the variability of demands. Previous UK practice was to ensure installed capacity should be approximately 20% larger than expected peak demand. Current practice is to monitor and report on this margin. Again, such criteria are aimed at ensuring a specific measure of reliability is sustained, and the risk of demand being unmet is small (e.g. the LOLP of the pre-privatised electricity system in Great Britain was planned not to exceed 9% - nine winters per century).

Any new generating plant can contribute to system margin (to varying extent) and may increase or decrease reserve requirements. In very broad terms, very large, less reliable, and unpredictable or inflexible generators tend to increase system costs[24]. Smaller, reliable, predictable and flexible generators tend to reduce system costs.

Nowadays the central planner is gone. Many of its functions are taken care of by markets, and key technical duties now rest with the transmission system operator (TSO). Nevertheless the same basic actions must be undertaken and requirements met. We explain how this is achieved in the section that follows, and then consider what changes when intermittent generators are added to the system.

[23]System margin is the current UK Grid Code term. The concept has been referred to historically as variously 'capacity margin' 'system reserves' and 'plant margin'.

[24]A recent example of a new non-renewable generator affecting reserve requirements is that of the pressurised water reactor being installed in Finland. The Finnish System Operator (Fingrid) has agreements with a number of major industrial electricity users for demand-side management actions to provide what they term 'disturbance reserves'. These agreements needed to take into account the very large size of the new nuclear unit (1600MW, larger than any existing single generation unit). See Fingrid press release 7th July 2004 available from http://www.fingrid.fi/portal/in_english/news_and_publications/news/?id=520

2.2.3 Short term balancing and long term capacity provision

Short term balancing
Short term balancing is achieved in part through actions of the system operator, but also through decisions taken in markets.

Balancing through the market
Currently, in the UK and many other countries, most of the variation illustrated in section 2.2.1 is handled by markets. Demand variation is reflected in market prices and/or supply contracts that ensure more generation when demand is high and less when it is low. Markets operate under different rules in different countries. The UK market arrangements 'BETTA' (see Box 2.1) are reflected in the following forms of contract and market activity:

- Firstly, generators and wholesalers/suppliers enter into bilateral contracts – more than 90% of UK electricity is traded in this way. Such contracts can be long term – months or even years ahead of real time. Contracts incorporate time of day variations.

- Second, small amounts of electricity trade through a number of spot markets (known as 'power exchanges') that allow market players to buy and sell electricity for rolling half hourly time periods. These markets operate from a couple of days until one hour ahead of real time. At the one hour point in time bilateral trading between generators and consumers is suspended and the energy volume of bilateral trades between generators and suppliers is notified to the settlement system. This is known as 'gate closure'.

- After gate closure, a balancing mechanism operates in the period from one hour ahead of real time and allows anticipated shortfalls or excesses – perhaps as the result of a known fault at a power station – to be accommodated through direct trades between the system operator and large consumers or generators of electricity[25].

- Finally (also after gate closure), the system operator can instruct plant with which it has contracts for balancing services to increase or decrease output and frequency response will occur automatically due to the action of a range of automatic controls. These reserve and response provisions for system are quite complex, and highly important to the intermittency debate. They are discussed below.

Balancing by the system operator
The market activities described reflect anticipated demand and supply. In addition, over short timescales, relatively small (but crucial) adjustments are made by the system operator. These allow residual market errors and events occurring post gate-closure, such as demand prediction errors or sudden failures at power stations, to be managed. Adjustments are made through automatic controls on power stations and by the system operator calling upon fast responding reserve plants. It does this through the balancing mechanism and directly with operators with which it has entered into reserve service contracts. These actions are described below, using terminology defined in terms of the range of services that the system operator contracts for, and the *grid code* issued by the electricity market operator[26].

Output from plant contracted to provide *response* may be delivered within seconds and its utilisation is controlled by automatic control systems sensitive to system frequency. Contracted *fast reserve* can be brought into operation within seconds to minutes. Contracted *standing reserve* can be brought into operation within 20 minutes and must be able to sustain its output for some hours. Some reserve capacity (called residual reserve) may be provided by part-loaded generation that participates in the market but is not contracted by the system operator. The sum of contracted and residual reserves are called operating reserves. Reserves in excess of operating reserves that appear available prior to gate-closure are referred to as *contingency reserves*. The system operator will monitor such reserves as real-time is approached to ensure the required operating and contingency reserves are maintained.

[25]A degree of under- or over- supply relative to contracted positions is inevitable. Payments are made after generation, through a set of arrangements known as 'settlement' - see annex 6.
[26]Ofgem Grid Code Glossary http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/7189_9904b.pdf

In some cases, the reserve provided by the market, together with that contracted in advance by the system operator may be insufficient and so additional reserve must be established by 'warming' unsynchronised generation, which requires several hours to achieve (a 'warming' payment may be made to generators by the TSO).

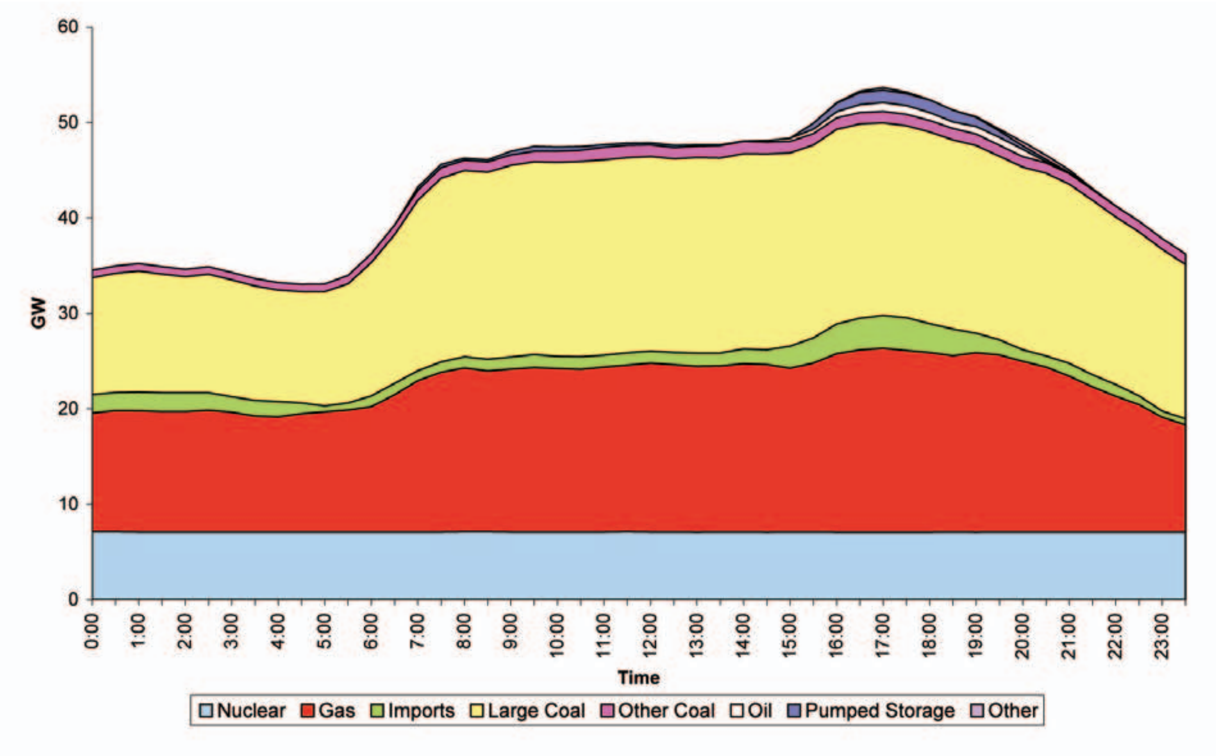
It is important to note that the strict definition of reserves described here may differ from international or historic norms. In particular, these definitions encompass all *system balancing reserves*, but do not include what have sometimes been referred to as 'capacity' or 'system' reserves which relate to system margin (see below).

System balancing reserves contracted by the British TSO (National Grid) currently stand at around 2.5 GW[28]. Reserves are sized in relation to three factors:

– The largest single credible generation in-feed loss on the system[29]
– The expected availability of all conventional plant on the system
– A given amount of demand prediction errors

The effect of the latter two factors is determined statistically. We discuss the way this is done in Section 2.3. In the sections that follow we explain how intermittent supplies impact on the activity of electricity markets and the need for reserve and response services.

Figure 2.2. Winter 24 hour load profile on National Grid system[27]



[28]Winter Outlook Report, 2005/6 Published by National Grid Plc and available at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/12493_214_05.pdf?wtfrom=/ofgem/index.jsp

[29]Reserves are sized to cover the sudden loss of the single largest generating unit (a criteria known as n-1, where n is the number of plants and 1 the single largest plant, currently either Sizewell B nuclear power station at 1260MW, or one bipole of the interconnector with France at 1000MW, or generators subject to instantaneous tripping for system purposes of up to 1320MW). May be referred to as disturbance or sizing reserve.

[27]From National Grid Seven Year Statement 2004 (data for England and Wales) Available from http://www.nationalgrid.com/uk/library/documents/sys_04/default.asp?action=mnch5_12.htm&Node=SYS&Snode=5_12&Exp=Y#Demand_Profiles

Box 2.2: Time horizons

The activities described in section 2.2.3 operate over different time horizons. In the very long term – several years in most systems – system operators, regulators and power companies assess the implications of changing demand patterns, government policies, technical and market developments. They can then make provision for (for example) incentives that affect location of new transmission lines or of new power plant. System operators also look ahead several months in order to assess system margin. National Grid does this each autumn, because peak demands occur in winter. Closer to real time market participants will determine the balance of demand and supply through long term contracts, shorter term contracts, spot markets and the balancing market. Contracts are also placed for different types of reserve. A day ahead of real time the system operator will determine exactly how much reserve needs to be ready for rapid action. Reserve plant is used in the sub-hourly timescale, and automatic controls operate in response to immediate events.

Timeframe (period ahead of real time)	Actions by market participants	Actions of system operator
Years	Planning and construction of new plant Long term bilateral contracts Purchase of transmission entry capacity	Seven year statement Transmission system pricing New transmission capacity
Months	Generation maintenance schedules Return of mothballed plant Purchase of short-term transmission entry capacity Bilateral contracts	Transmission maintenance schedules Winter outlook report Monitoring and reporting of system margin Contracts for fast and standing reserve services and frequency response
Weeks	Bilateral contracts	Refinement of reserve contracts Updates of system margin reports
Days	Short term bilateral contracts Commitment of inflexible generating units	Continued margin information to market Notification of Inadequate System Margin (NISM)
Hours	Participation in balancing mechanism Commitment of less flexible generating units Variation in output from flexible/load following plant to maintain contracted positions Registration of energy volumes at gate closure Notification of intended physical positions to System Operator	Establishment of required response and reserve capacity Operation of balancing mechanism Utilisation of other balancing service contracts
Minutes	Variation in output from flexible/load following plant to maintain contracted positions. Adjustments to reflect accepted balancing mechanism bids & offers or as contracted by system operator (reserve services)	Utilisation of fast reserve Operation of balancing mechanism
Seconds	Automatic frequency response on plant, as contracted by system operator	Utilisation of automatic frequency controls

Ensuring reliability through capacity provision – system margin

In addition to the short term operational requirements of the system, reliable supply of electricity also requires that electricity markets deliver enough capacity to meet expected peak demands. To be confident of reliable supplies a *system margin* by which installed capacity exceeds peak demand is desirable. This is because there are bound to be some plants that have to be taken out of service for maintenance, some that break down, or times when peak demand is higher than anticipated.

The relationship between system margin and reliability can be quantified. It is a function of potential errors in demand prediction, outages in generation and is normally estimated using concepts such as the Loss of Load Probability (LOLP, see box 2.3).

Historically these calculations led directly to the planning of generation capacity by system owners and operators. This is no longer the case in the UK where the system margin emerges from decentralised market-based investment decisions. At present, in the UK, the system operator *monitors*, but does not contract for, system margin. Since it takes time to build new plant or repair plant that has been taken out of service ('mothballed'), system margin is monitored from a time horizon of several months to years before real time.

The British system operator compares market notified margin with an 'indicative' level of desired system margin, and publishes market participant estimates of expected system margin at winter peak periods[30]. These statements highlight periods when system margin is expected to be smaller than desired[31]. They provide the market with detailed information about the level of system margin, and are used by market participants to determine expected future prices. This has proved effective as a mechanism to incentivise generation plant owners to bring mothballed plant back into operation[32].

It is important to note that system margin is not the same as the reserve described above. Dedicated reserves are purchased in order to react to unexpected events quickly, whereas system margin provides a more general contingency. System margin is much larger than dedicated reserve: in the UK, around 2.5GW[33] of dedicated reserve is kept available, whilst National Grid's indicative level of adequate system margin is around 20% above peak demand or 12 - 14GW[34]. Under current arrangements system margin is estimated net of the response and reserve services contracted by National Grid.

Close to real time the amount of system margin over peaks will normally become smaller, as breakdowns, maintenance and decisions to remove generation for commercial reasons become manifest. *Expected* and *actual* system margins are monitored by the system operator which can take a range of actions if the margin is smaller than it believes it should be to ensure reliability. The primary mechanism is Notification of Inadequate System Margin (NISM)[35]. In the sections that follow we explain how intermittent generation can contribute to reliability, and how we assess the extent of this contribution. We also discuss the controversy related to the costs of maintaining reliable supplies when intermittent generation is added to the system.

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[30]See Seven Year Statement and Winter Outlook Report, 2005/6 Published by National Grid Plc

[31]See Ibid. Note that system margin is actually monitored by the system operator (National Grid) on behalf of a team of experts drawn from the TSO, the DTI and Ofgem (the JESS committee).

[32]The TSO provides information on a range of factors. For example, it shows scenarios for demand in both 'normal' and exceptionally cold winters. The information that the system operator provides also takes into consideration the likely availability of plant. For 2006/6 National Grid provide scenarios that also show the available margin assuming 91% availability (Ibid)

[33]See Winter Outlook Report, 2005/6 Published by National Grid Plc

[34]Current expected peak demand, including export to NI 61.9GW, 2005 anticipated winter capacity 72 - 74 GW (Ibid)

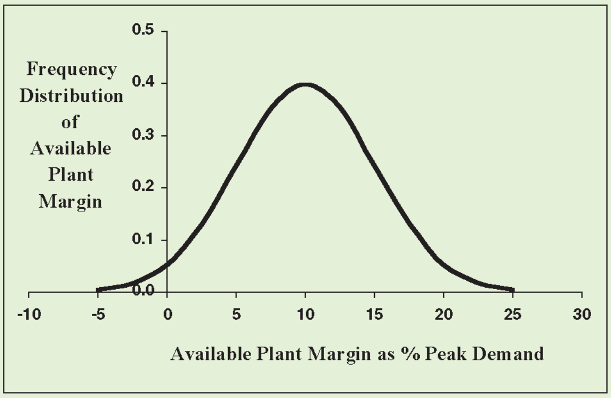
[35]See http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/7189_9904b.pdf

Box 2.3 Measures of reliability and the concept of system margin

Electricity supply systems operate with high but not 100% reliability; occasionally some customers are not supplied. Some interruptions of supply arise from equipment failures or storm damage in the transmission and distribution networks. Some can arise from inadequate generation capacity. There are many ways of measuring and estimating reliability and the measure used depends on circumstance. The measure most often used when assessing the impact of generation reliability on customers are measures of loss-of-load. **Loss-of-load probability (LOLP)** expresses the risk that a load will need to be shed (forced to disconnect from the system) because insufficient generation is present. This is expressed as a percentage that is the maximum number of years per century in which load shedding may occur.

LOLP is determined statistically and is directly related to system margins (slightly different concepts are used to determine the need for balancing reserves – see Box 2.5). System margin is a statistical quantity, and follows an approximately normal distribution when thermal plants dominate supply capacity (as in the figure below for example, which represents the probability of any particular level of plant margin for a given system, which depends on the probabilities of plant failure and load levels). Demands can be met when they are exceeded by the available capacity, but have to be shed of course when there are shortfalls; the area when the available margin is negative provides a measure of what is called the *loss of load probability.*

The 'spread' of the distribution shown is measured by its standard deviation*, denoted here by σ_m, and there is a simple statistical relationship between this quantity and the standard deviations of variations in demand (relative to expected demand) and plant availability (failure rate), denoted by σ_d and σ_s respectively (the square of such quantities is called the variance): $\sigma_m^2 = \sigma_d^2 + \sigma_s^2$.
The greater the supply uncertainties the greater the system margin needs to be (whether determined by market forces or otherwise) if the reliability of supply is to be maintained. Intermittent plants change the spread and the shape of this distribution, as we explain in Box 2.7.



It is important to note the LOLP provides for a simplified comparison of the reliability of prospective generation systems as it does not provide any indication of the frequency, duration and the severity of potential shortages. These factors have been identified as an important area of further research relevant to future electric system development in the UK (Ernst & Young 2005).

*Standard deviation is a measure that tells you how tightly clustered a set of values are around the mean value of a set of data. When the standard deviation is small the 'bell curve' depicted above is steep and narrow. When it is large the curve broadens and flattens out.

2.3 Introducing intermittent supplies – what changes?

2.3.1 Introduction

As we have seen, regardless of any intermittent generation that might be installed on an electricity network, provision must be in place to respond to changes in demand and failures in supply. Large demand fluctuations are normal, and no form of generation is 100% reliable. These are handled through market mechanisms and actions taken by the system operator. Quantifying the implications of adding intermittent generation to a network is therefore primarily a matter of understanding the extent to which a number of factors change when such generation is installed.

2.3.2 What is different about intermittent plant?

Intermittent renewable generation has a range of characteristics that distinguish it from conventional generation plant. Intermittent generators can provide energy, have zero fuel costs and can reduce emissions. It would usually make sense to operate such plant whenever it is available.

The energy supplied by an intermittent generator is a function of the resource available to it, and the amount of generation capacity installed. Taking wind energy as an example, in aggregate, the average *capacity factor* of all British wind farms is in the region of 27% - 30%[36]. Capacity factor is a measure of the average power output relative to the installed capacity. Generally speaking the capacity factor that can be achieved by intermittent generators is low relative to that of conventional generators. This means that a larger amount of intermittent capacity is required to replace the energy from a given capacity of conventional stations. This has implications for important concepts related to keeping electricity supply reliable (such as system margin) and for the maximum amount of 'back up' that might be required as a result of adding intermittent generators to the system. These are discussed later in this chapter. Intermittent renewable plants also show a wide variation of output, indeed for much of the time the output of a wind farm or other installation might be less than half of its maximum potential output. The nature of the outputs of intermittent generators varies markedly, depending on the nature of the technology and where it is located. It might be largely predictable (solar power in sunny regions), entirely predictable (tidal power) or much more stochastic (wind power in some regions, solar in UK). But all forms of intermittent renewable energy contrast with a conventional generator which (if required) would be expected to operate close to its maximum output for most of the time, with a relatively narrow range of output variation – even allowing for unplanned outages. Whilst all plant is intermittent, insofar as it will suffer occasional outages, intermittent renewables fluctuate to a much greater degree. Depending upon technology, location and timing of demand peaks, their output may or may not be available during peak demand periods. In many cases, the contribution to reliability is lower than for conventional stations, because there is more uncertainty surrounding the contribution of intermittent stations to meeting peak demands than there is for conventional generators contributing a similar amount of energy.

These factors can be quantified and give rise to changes to provisions for system balancing and reliability, which we explore and explain later in this chapter.

2.3.3 Limitations

There are a range of important issues that relate to the integration of renewables, and may be affected by intermittency, which are beyond the scope of this report or only dealt with relatively briefly. Examples include: the impacts of renewables on transmission infrastructure, particularly if generation is concentrated in limited geographical areas; the costs and impacts of supply interruptions; the role of demand side management and bulk storage systems in accommodating intermittent energy; the impact of generation system flexibility on the ability of electricity systems to absorb wind energy. Moreover, the sections that follow and the evidence presented in Ch. 3 tend to focus on a particular set of issues, and a particular approach to ensuring reliability (see Boxes 2.3 and 2.7). These approaches have limitations, some of which we discuss (see section 2.3.5), and are still under development through ongoing research. It is also important to note that there are areas where empirical evidence can improve understanding, examples include: a more detailed understanding of a range of intermittent resources; impact of extreme weather conditions; the effects of geographical clustering; understanding and quantifying the impacts of different nature of off-shore and on-shore generation.

[36] Figure for overall British wind generated output, this varies within a range, as some years are windier than others (Digest of UK Energy Statistics 2005).

Box 2.4 Popular misconceptions

Two related assertions that receive regular airings in the mainstream media are paraphrased below:

*'Wind turbines only operate 30% of the time, therefore we must provide 70% backup'**
*'Wind turbines need back up so they don't save any CO_2'**

Both these assertions are incorrect. In both, the use of the term 'back up' may in itself give rise to misunderstanding. Irrespective of terminological issues, the assertions are in error for the following reasons:

- The former assertion confuses the *capacity factor* (see above and Annex 6) that might be achieved by a typical UK wind farm (which would indeed be around 30% in a location with good wind conditions), with the amount of time it is operational. In fact, most wind turbines will be operational for around 80% of the time – *but usually operate at less than their rated capacity*. This is because the rated capacity of a wind turbine is its *maximum* output, which is typically associated with wind speeds in excess of 11-15 m/s (40-54 km/h). Yet most wind turbines operate in a range of wind speeds from around 4 m/s to around 25 m/s.
- The capacity factor of renewable energy does not tell us anything about 'back up' requirements. The capacity factor simply provides an indication of the amount of energy, on average, a given capacity of renewable plant would be expected to provide. The actions needed to manage intermittency are derived statistically, as this chapter explains.
- However, capacity factor does indicate the size of the *comparator* plant against which intermittent generators should be assessed when determining what is required to maintain reliability. A 1000MW wind farm with a 30% load factor delivers the same energy as a 350MW modern gas power station, allowing for the 15% outage rate of such generators. Hence, even if the intermittent station cannot contribute anything to reliability, its 'back up' in this example won't exceed 35% of installed capacity. This is why claims that renewable generators need 100% (or even 60% or 70%) 'back up' per MW installed are muddled and incorrect.
- The latter assertion conflates energy and power. Intermittent sources are unlikely to be able to provide the same level of reliable *power* output during demand peaks as a conventional generator. This *will usually* give rise to a need for additional capacity to maintain reliability (see Ch. 2 for full details), particularly at larger penetrations of intermittent sources. However, CO_2 reductions are a function of the *total energy* provided by intermittent stations, and hence fossil fuel use avoided, not output at peak demand periods.
- Confusion arises because the share of total *energy* provided by an intermittent station may be larger than its contribution to reliability. In fact, even if the contribution of an intermittent source at peak periods is expected to be zero (as would be the case for PV power in the UK for example), its contribution to CO_2 savings are still a direct function of its energy output.

Actual CO_2 savings are dependant on what fossil fuel plant is displaced, reduced by efficiency losses in thermal plant affected by intermittency and additional use of reserve and response. As we show in Ch. 3, these losses are a small proportion of the energy provided. Links to other grids can mean that CO_2 savings are 'exported' so might not be realised in the country of origin. But the CO_2 savings are, within a few percentage points, directly linked to the energy that renewable stations generate.

* e.g. "wind turbines are completely effete because they need backup all the time and help to produce CO_2, not reduce it" (David Bellamy, BBC Radio 4 Today programme, 18th November 2005), see also http://www.countryguardian.net/ for further examples.

2.3.4 Principal impacts of intermittent generation on electricity networks

The principal impacts that we discuss in this section fall into two broad categories[37]:

1. System balancing impacts

The primary benefit (indeed purpose) of adding intermittent generation to an electricity system is to save fuel and hence reduce emissions as fossil fuel stations are used less. Direct economic benefits might be made available to renewable energy developers through polices such as (for example) the Renewables Obligation. These savings will be reduced to the extent that intermittent plant gives rise to an increase in:

– Response and reserve requirements contracted for by the system operator, to manage unpredicted short term fluctuations and referred to here as *response and reserve impacts*.

– Effects on the utilisation of other plants in the electricity market which are termed here *system efficiency impacts*. Examples include losses due to increased variation in the output of thermal plant and wasted energy if intermittent output exceeds the ability of the system to use it.

2. Effects on capacity requirements to ensure reliability

If intermittent generators can make a contribution to reliability – that is if there is some probability of them generating during peak periods – they may be able to displace (or avoid future investment in) thermal plant without reducing system reliability. This is a benefit of intermittent generation over and above their role as a 'fuel saver'. However, the contribution of intermittent generators to reliability is often lower than a conventional generator that can deliver the same amount of energy. Hence there are two, counterpoised, impacts, the allocation of which can give rise to confusion and controversy, as we explain later in this chapter:

– Capital cost savings from any conventional plant that can be replaced or retired without compromising reliability

– Capital costs of conventional plant retained or constructed to maintain reliability at peak demand.

We now consider how each of these categories of impact is measured and assessed. For each category we consider:

– The *range* of impacts

– The *information* needed to quantify each impact

– The *techniques* used to assess the scale of each impact

– The *implications* of each impact

It is important to note that any new generator has the potential to increase or decrease reserve requirements or reliability. It is therefore important to assess impacts, and in particular *costs* through a comparison with a given alternative form of generation that can provide the same amount of energy.

[37]Potentially important impacts that we do not discuss in great detail here include:
– A reduction in transmission costs if the plant is close to demand
– Increased transmission losses or upgrading if the plant is in remote locations
– Increased diversity of supply, hence supply risk mitigation (for example the risk of supply interruptions or fuel price spikes)
– Changes to grid code requirements to ensure reliability - e.g. fault ride through from wind turbines

2.3.5 System balancing 1: Response and reserve services

Key issues

Intermittent plants can increase the short run unpredictable fluctuations that have to be managed by system operators. As a result they require that additional system balancing plant is held in readiness. Reserve and response service needs are calculated statistically and must deal with demand swings and breakdown of conventional plants as well as any additional fluctuations due to intermittency.

Range of impacts

Additional short run fluctuations in output can increase the utilisation of automatic controls on the output of conventional power stations. It is also necessary to have more part loaded plant running that can rapidly *ramp up or ramp down* i.e. increase or reduce its output as intermittent stations pick up or drop off. Fluctuations over minutes to several hours can require increased fast and standing reserve.

It is important to note that *predictable* variations will have implications for the utilisation of non-reserve plant, and are discussed in the section on system efficiency impacts, below. This section is restricted to unpredicted variations.

Information needed

Three interrelated factors determine the amount of extra reserve required when intermittent generation is added to the system.

1. The extent of rapid and unpredicted variations in intermittent plant output, which has two aspects: Firstly, how *rapidly* the outputs of different penetrations of different types of intermittent plant will fluctuate. This is sometimes called the *ramping rate*. Secondly, the possible scale of *total*, system-wide, changes in a given period. The system may cover a large area. Hence, this requires a representation of the aggregated behaviour of individual intermittent plants, based on weather data, size of units, inertia, the scope for 'smoothing' of outputs – for example by geographical dispersion – and a range of other factors. This data provides an indication of the variability of intermittent supplies. Historical data on forecasting can then be used to determine the extent of *unpredicted* variation.

2. How accurately fluctuations over the minutes-to-hours timescale can be forecast. This is important because the more accurate the forecasting the greater the opportunity to use (lower cost) *planned* changes as opposed to holding reserve plant in readiness – in particular reserves comprised of extra part loaded plant, which can be costly and less efficient. In market terms, the effects of predicted fluctuations can be contractually committed prior to gate closure, which should permit the market to reveal the most cost effective means to manage these variations. Again, it is the prediction accuracy of total aggregated intermittent generation that is relevant, forecasting for a large amount of distributed resources reduces forecast errors.

3. How existing variations of demand or load compare with that of intermittent output and the reserve capabilities that already exist on the system. These existing reserve capabilities are a function of the variability of demand, the reliability of existing plant, the number of plants on the system, and the size of the largest single unit.

Box 2.5 Reserve and response services for short term system balancing

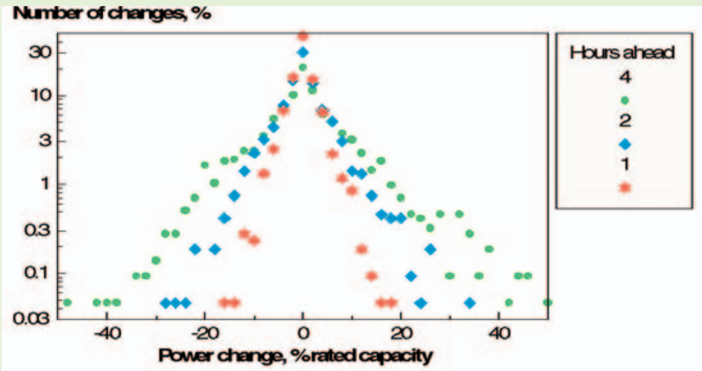
The amount of reserve needed to handle unpredicted short term variations – either due to demand prediction errors or generation failures – is worked out through analytical techniques using statistical principles or simulation models based on statistical principles. The objective is to ensure that operating reserves are available that can deal with almost all the unpredicted fluctuations that can be envisaged. The analytic techniques presented here provide approximate results but simulations are needed to deal with more complex situations, for example where correlations between variables exist. We present the analytical approach in order to provide an explanation of principles that come into play.

Historically, reserves have been sized to cover approx. ±3 standard deviations of the potential uncertain fluctuations that arise from this combined demand prediction error and generation plant failure, plus provision for the sudden loss of the largest single unit (n-1 criteria, or disturbance reserve). The ±3 criteria ensure 99% of unpredicted demand or supply fluctuations are covered by reserves: Reserves = $\pm 3\sqrt{(\sigma_d^2 + \sigma_s^2)}$ (plus disturbance reserve) where $\sigma_d\,\sigma_s$ represent the standard deviations* of fluctuations demand and supply. When intermittent generation is added the variance* of the supply side term increases. This is usually estimated by adding the effect of intermittence to existing reserve requirements – that is to say, adding the squared standard deviation of unpredicted fluctuations in intermittent supply to the sum of squared standard deviations of demand and conventional supply.

Two factors are notable: First that even for a relatively unpredictable intermittent source like wind power the standard deviation of fluctuations in the period from minutes to a few hours is relatively modest. This is because there is considerable smoothing of outputs in the sub-hourly timeframe, and considerable prediction accuracy over a few hours (see figure below). Secondly, variance of intermittent fluctuations must be combined statistically with the variance of demand and conventional supply. These factors suggest that reserve impacts from intermittence will be relatively modest.

The SCAR report (Ilex and Strbac 2002) provides a simple example of this in practice. The standard deviations of wind fluctuations at half hourly and four hourly time horizons were chosen by SCAR to represent different categories of reserve (roughly according to fast response and standing reserve in the discussion above). They were found to be 1.4% and 9.3% of installed wind capacity respectively. SCAR assumed 10GW of wind was installed, hence these SDs are 140 MW and 930 MW. This means that the range of possible changes (99% or 3 SDs) would be ±420 MW and ±2730 MW. The report notes that the SD of conventional generation and demand $(\sigma_d^2 + \sigma_s^2)$ is around 340 MW at the half hour period. Therefore the SD with wind would be $\sqrt{(340^2 + 140^2)}$ or 368 MW - a minor addition. Response and fast reserve requirements would be ±3√368 or 1143 MW – compared to 1040 MW without wind. In both cases total GB reserves would also require 1.1 GW 'sizing' reserve – hence in this example 10 GW wind accounts for around 130 MW reserve needs out of approx 2.2 GW total reserves needs. A related example, in this case from Denmark, is provided graphically below.

Wind fluctuation and time horizons (from Milborrow, 2001)



* See Box 2.3 for definitions

How do we work it out?

The relationship of interest to analysts is that between intermittent fluctuation and load variability. Statistical principles (and simulation models based upon them) can be used to assess the total unpredicted fluctuation that the system operator might have to manage over different timeframes.

System operators are concerned with the *total* amount by which the system might be out of balance. As a result, reserve requirements are a function of *both* the unpredicted load variation and unpredicted intermittency. Fluctuations in load and intermittent output might amplify each other, be completely unrelated to each other, or they may cancel each other out[38].

Hourly variations in wind farm output are also a function of geographical dispersion. Even extreme fluctuations fall from ±30% of installed capacity when the area is in the order of 40,000 km^2 (about the size of Denmark) to about ±20% for an area of 160,000 km^2 (e.g. Germany or the state of Iowa) and then to about ±10% in larger areas covering several countries e.g. the Nordic states (Holttinen 2005). Normal fluctuations are much more modest.

For this reason we need to know the degree to which variations might correlate. If demand increases tend to occur at the same time as decreases in intermittent output then the amount of reserves needed tend to increase. The obverse might also be the case, or loads and intermittent output might show no correlation.

In all cases analysis requires a statistical treatment of both demand and intermittent generation, since we are dealing with *probabilities* rather than determinate functions. At its simplest this might take the form of a statistical 'rule' – such as a sum of squares rule (see Box 2.5). Statistical algorithms and computer models can also capture more complex inter-relationships and correlations.

Implications

Reserve requirements tend to represent relatively small proportions of the intermittent generation capacity installed; the evidence from many studies bears this out – see Ch. 3. This is because the short run fluctuations and prediction errors associated with wind capacity are comparable to other variations in the supply-demand balance and so little increase in reserve provision is called for. The reasons for this are explained in more detail in Box 2.5. A statistical derivation of system balancing requirements is also provided in the working paper that accompanies this report[39].

Another reason reserve additions tend to be modest is that reserves are determined by two aspects: unpredicted fluctuations described above and a 'dimensioning' factor that allows for the failure of the largest single generating unit. This can be a major determinant of reserve margins. Even large wind farms are much smaller than large conventional stations. Hence, there may already be more than sufficient reserve capacity on the system to deal with intermittency – particularly if the amount of intermittent generation is a small proportion of total supply (this varies according to system characteristics but might be defined as below 10% of energy – see Ch. 3).

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[38]Since many wind farms are embedded in distribution networks, in practical terms the TSO is aware only of their impact only in terms of net demands, once wind output has been absorbed by distribution networks.
[39]See Anderson, 2005, Power System Reserves and Costs with Intermittent Generation http://www.ukerc.ac.uk/content/view/124/105/

Box 2.6 Confusion arising from use of terminology

Reserves, back up, stand by have all been used to denote conventional plants held in readiness to respond to fluctuations from intermittent stations. Each term gives rise to some problems. There are two important areas of misunderstanding.

The first problem reflects a fundamental misunderstanding often associated with the use of terms such as 'back up' or 'stand by' generation. This misunderstanding arises when these terms become linked with the idea that intermittent sources need *dedicated* back up. This is incorrect for the following reasons:

- Actions to manage short term fluctuations and maintain reliability of electrical networks should be assessed on the basis of plants interconnected and operated as a *system*. Dedicated 'back up' is not required. Rather, intermittent plants may increase the amount of reserves and response needed for balancing the system, may impact on the efficiency of other plants, and may increase the amount of capacity on the system required to maintain reliability.
- The additional actions needed to manage fluctuations from intermittent plants are also affected by the nature of fluctuations resulting from demand and conventional stations on the system. This is because the fluctuations from intermittent plants can be expected to diversify with these other fluctuations to some extent, depending on their relative magnitudes as well as correlations. Failure to assess these requirements in a *systemic* fashion would only be consistent if it were applied to all generation, since all experience unplanned outages. In this case the benefits of interconnected networks, which share reserve and reliability across all plants, would be lost.

The second problem is associated with the use of the term 'reserves'. The term is used for quite different types of function, on different timescales. Two broad categories of usage can be found in the literature:

1. *Reserves* has a strict and narrow sense, restricted to the requirements for fast responding reserves for short term *system balancing* that are contracted for by the system operator. These are the only reserves for which the system operator has a responsibility for establishing and for which the system operator may directly purchase in the UK (see Box 2.1).

2. A broader definition also encompasses the additional capacity that may be required to ensure *reliability* when viewed from a long term, or planning, time horizon. *System margin* is the current terminology used to refer to this capacity, and in Britain there is no mechanism for direct procurement of system margin. Yet historically, and in other regions, capacity over and above peak demand has also been referred to as capacity reserves (see Annex 6).

This gives rise to confusion, and may mean that comparisons are drawn between studies that are using the term differently. For example:

- Some studies of the 'cost of intermittency' in fact only quantify the cost of *additional system balancing* – the capacity to maintain reliability may be neglected, or not directly addressed. This may give rise to a 'reserve cost' estimate that understates the full cost of intermittency.
- However, where the term 'reserves' is used to refer to *both* capacity provision to maintain reliability *and* short term reserves, this too can create confusion – since it leads to cost estimates considerably larger than those directly attributable to the only reserve services actually purchased by the system operator.

We highlight the implications of these terminological issues in Ch 3. As far as possible, in this report, we try to use terms consistently and in line with current UK practice.

2.3.6 System balancing 2: Other system efficiency impacts

Key issues

Intermittent renewable energy plants can save fossil fuel, but may also increase the amount that conventional plants must vary their output, operating in response to market signals. This change in utilisation of generation is a separate issue from the need to establish additional reserves. These effects can be quantified using time series data on intermittent outputs and demand, and the implications for the operation of conventional stations assessed.

Range of impacts

As mentioned previously, the principal impact of intermittent generation on the operation of other plant on the system is to replace the output of fossil fuel stations and hence secure fuel and emissions savings[40]. However fuel saving may be partially offset by a range of *efficiency* impacts:

– More frequent changes in the output of load-following plant and/or greater use of flexible plant to manage predicted variations. This may decrease the efficiency of thermal plant and cause more fuel to be burnt. Frequent start up and shut down of certain types of plant can use a lot of fuel to 'warm' plant, without generating any electricity. The way such changes are provided for is also affected by the accuracy with which fluctuations can be forecast. In general terms better forecasting results in fewer losses, since the most efficient changes can be planned. However improved forecasting does not eliminate these costs, since the need to manage predicted fluctuations will still lead to the effects described above.

– If maximum output of intermittent plants exceeds the ability of the system to absorb its energy (normally determined by the minimum output, for either technical or economic reasons, of conventional plant at periods of low demand) it may be necessary, particularly at large penetrations of intermittent generation, to curtail output or 'spill' energy.

– Depending on the location and size of intermittent plant it may increase or decrease transmission investment and operating costs.

Information needed

Estimating these impacts requires quantification of four factors:

1. Average energy provision (e.g. per year) by intermittent plant. This is the maximum prospective fuel saving, neglecting all losses, efficiency impacts and curtailment.

2. A time of day representation of the typical (or actual) output of the intermittent generators, since different plants can be displaced at different times of the day and/or year. Different plants have different fuels, efficiencies and emission levels.

3. Assessment of the nature of the plants used to manage variability (the primary load-following plant) and what changes in the operation of all plants result from the addition of intermittent generation.

4. Assessment of the difference between minimum demand and the minimum output of inflexible plant.

[40]Current UK government convention for emissions savings is that average generation mix is displaced (see DUKES 2005). This includes both fossil and non-fossil plant. Wind and other renewables are in practice likely to displace coal generation, not baseload plant. There has been debate on this topic, see Ch. 3.

How do we work it out?

Analysts need to identify the impact of intermittent output on the commitment of other plant. The main technique used to assess impacts of this nature is a time series assessment of the behaviour of all the plant on the system, and demand, at each hour of the day, throughout the year.

Averages may also be used to quantify some impacts, depending on the degree of accuracy needed. For example, energy spilling may be calculated using data that indicates the average overall amount of wind output each year that is coincident with periods of low demand. More complex assessments would normally make use of time series simulation models, which represent the commitment of all the plant on the system. Getting the unit commitment 'right' is an economic issue, and other factors such as robust markets can also play into the unit commitment decision. Some models look ahead with perfect foresight, both in regards to load and weather forecasting, and may need some modification to take the effect of intermittency into account.

Implications

We explore the scale of these impacts in Ch. 3. The extent to which overall generation efficiency is reduced due to the need for other generators to vary their outputs more, or because energy is 'spilled' will depend on both the nature and penetration of intermittent sources, and on the nature of conventional plant on the system. In general terms, smaller and more flexible generators can assist the accommodation of intermittent sources, whereas larger and less flexible generators make efficient integration of renewables more challenging. These impacts are mediated through market signals, and it is therefore important that the benefits of flexibility and high efficiency at a range of outputs are captured in market rewards.

2.3.7 Capacity requirements to ensure system reliability

> **Key issues**
>
> How much conventional capacity can intermittent stations replace without compromising system reliability? This is a function of the probable availability of the intermittent source at peak periods and, like additional reserves for short term system balancing, it is assessed using statistical techniques.

Range of impacts

Intermittent generation may be able to replace some conventional plant. The extent to which intermittent generation can replace thermal plant without compromising system reliability is referred to as its '*capacity credit*'. It is important to note that capacity credit is a derived term because it can only be calculated in the context of a more general assessment of reliability across peaks[41]. See Boxes 2.3 and 2.7.

It might be thought that intermittent plant cannot contribute to reliability at all since in most cases we cannot be certain that it will be available at times of peak demand (there are exceptions, see later in this section). However, there is a possibility that *any* plant on the system will fail unexpectedly, so reliability is always calculated using probabilities. Intermittent plant can contribute to reliability provided there is some probability that it will be operational during peak periods.

Put another way, it is possible that intermittent plant will be running when a conventional plant breaks down and demand is high, so it can contribute to reliability. However, intermittent plant is usually less predictable than conventional generation, so the capacity credit of intermittent plant is usually lower, per unit of energy delivered, than it is for conventional generation. This means that there must be more installed capacity on the system than there would be without intermittent generators.

Information needed

How much capacity can be replaced by intermittent plant without compromising reliability is determined by the probability of intermittent generation providing electricity at periods when demands are high. Quantifying this depends upon the behaviour of demand, conventional stations and intermittent generators during the times of the year when demand is at its highest level. We need information about:

1. The timing and duration of demand peaks.

2. The variability of demand during peak periods (expected demand and range of possible demand levels).

3. The expected output and possible range of outputs from conventional stations during peak periods.

4. The range of possible outputs from intermittent stations during peak periods. In principle the output of aggregated intermittent stations can fluctuate from near zero to almost 100% of installed capacity. We need to know both the *expected* (most likely) output at peak periods and the probabilities of the *range* of potential output at peak periods. Note that wider geographical dispersion will tend to reduce, possibly eliminate, the probabilities of either near zero or maximum output, and the evidence from several countries indicates that aggregated fluctuations lie within a well defined range that reaches neither zero nor maximum output[42].

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[41] Some commentators have noted that although the risk of capacity shortages is highest at times of peak demand it may not be much lower within a few GW of peak because the standard deviation of available thermal capacity at peak can be nearly 2 GW.

[42] e.g. see http://www.nrel.gov/docs/fy04osti/36551.pdf

How do we work it out?

The complex relationship between the range and average output of intermittent and conventional plants, and the range and expected level of demand at peak times can be assessed using statistical algorithms or models based on statistical principles. The key determinants of capacity credit are as follows:

1. The degree of *correlation* between demand peaks and intermittent output.

   – Positive correlation between high output and high demand will tend to increase the capacity credit of intermittent stations; the obverse will have the opposite effect.

   – For this reason, capacity credit varies considerably according to the interplay between demand and renewable resource. For example, in the UK photovoltaic panels are unable to provide any contribution to peak demands, because these peaks occur in winter evenings, when it is dark. This does not detract from the prospective benefits of PV as an energy provider. However, in some regions demand peaks are driven by air conditioning loads that are highest on hot sunny days, in which case there is a very high probability of significant PV output that is highly correlated with demand. PV has zero capacity credit in the UK, but can have a high capacity credit in warmer regions.

   – Correlation occurs where both diurnal and seasonal fluctuations in demand and output show a strong coincidence, or indeed have the same cause (solar radiation in the PV example above). However, a partial relationship between demand and renewable output does not necessarily imply a meaningful correlation. Wind energy in Northern Europe tends to have higher availability and higher average output in winter, when peak demand also occurs. However, wind does not exhibit any meaningful diurnal pattern in winter months (being driven largely be weather fronts), and demand and wind output are therefore assumed in most studies to be uncorrelated on a day to day basis.

2. The *range* of intermittent outputs.

   – Where demand and intermittent output are largely uncorrelated, for example in the case of wind energy in Britain, a decrease in the range of intermittent outputs will tend to increase capacity credit. In statistical terms this is because the *variance* decreases. Taking wind as the example again, more *consistent* wind regimes decrease variance and increase capacity credit.

   – Variance can be reduced through geographical dispersion of plants. This has the effect of smoothing outputs such that overall variation decreases as geographical dispersion increases. We explore this relationship empirically in Ch. 3.

   – Having different types of intermittent plant on a system can also decrease variance and increase overall capacity credit. This is because different types of renewable resource fluctuate over different timescales, which also has the effect of smoothing outputs such that overall variation decreases.

3. The *average* level of output. A higher level of average output over peak periods will tend to increase capacity credit. Again, taking UK wind as an example, there is little correlation between wind output and demand. However, wind farm outputs are generally higher in winter than they are in summer. For this reason analysts use winter quarter wind output to calculate capacity credit.

Box 2.7 Calculating the capacity credit of intermittent generators

Capacity credit is a measure of the amount of load that can be served on an electricity system by intermittent plant with no increase in the loss-of-load probability (LOLP). In simple terms there must be minimal probability of coincident high demand, failure of conventional stations and low output from intermittent stations. Since the risk of low output from intermittent stations during high demand is often larger than for conventional generators it is necessary to hold more capacity on the system in order to maintain LOLP.

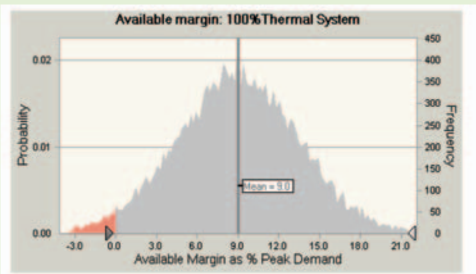
Box 2.3 explains how LOLP can be calculated statistically from the standard deviations of unpredicted demand fluctuations and supply failures: ($\sigma^2 = \sigma_d^2 + \sigma_s^2$). Intermittent generation increases the variance of the supply side of this term and as we show in the figures below, also changes the shape of the distribution, 'skewing' it away from a normal distribution. These changes can be estimated arithmetically and assessed more thoroughly using probabilistic analysis of the availability of thermal units and time series data for intermittent outputs.

Capacity credit is determined by considering the total variance of both supply and demand, including intermittent options on the supply side, and then comparing this to a 'without intermittency' case. It is calculated through three basic steps, which we explain more fully in Annex 7. Start from the amount of thermal capacity required to maintain a given loss of load probability (see Figure 2.7a). 1. Assess the change to the overall distribution introduced by adding intermittent generation which flattens and widens the frequency distribution first shown in Box 2.3 and increases the loss of load probability. 2. Calculate the capacity of thermal generation required to return LOLP to the desired level. 3. Calculate the amount of thermal capacity that has been displaced in moving from the scenario with no intermittent generators to the scenario with intermittent stations and LOLP as per an all thermal system. This is capacity credit.

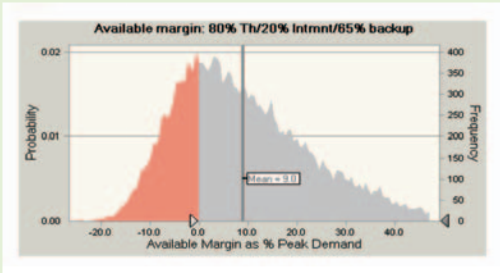
Because the variance at peak demand is larger than for conventional stations, the capacity credit of intermittent sources tends to be lower than their installed capacity, their availability and at larger penetrations is also less than capacity factor.

Annex 7 provides a detailed discussion of the principles used to calculate capacity credit. The following figures are reproduced from Annex 7 in order to illustrate the need for thermal capacity to maintain LOLP as described above. This also illustrates the changing *shape* of the area of lost load – demonstrating that the LOLP does not capture changes to the nature of any unmet demand (see text).

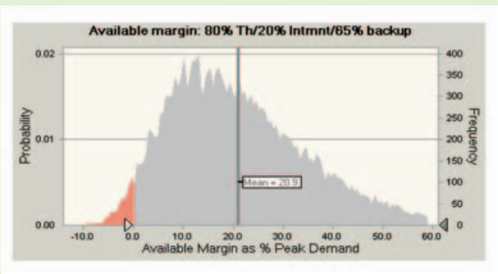
Fig 2.7a Distribution and LOLP, all thermal



2.7b Distribution and LOLP, 20% intermittent



2.7c Distribution and LOLP, 20% intermittent + thermal capacity to maintain LOLP



Implications

The primary implication of the above is that more plant will be needed to ensure reliability than would be the case without intermittent stations. The need to retain or construct plant alongside renewable generators, in order to ensure reliability, will give rise to a cost. In Ch. 3 we review the range of findings on capacity credit, and hence the scale of its contribution to reliability, requirements for 'back up' and costs.

Redefining system margin

The second implication is that 'system margin' as defined in Section 2.3.2, becomes less meaningful when intermittent generation is introduced onto a system. The difference between installed capacity and expected peak demand is no longer a good indicator of how reliable supplies are likely to be. Intermittent generators will be generating at full capacity for only a small percentage of the time, and only at 30% or less of their capacity (assuming a 30% capacity factor) for half the time, and at 15% for one quarter of the time (see Annex 7). Yet they can contribute to meeting peak loads and sometimes do this when 'conventional' generation is down; i.e. they have a 'capacity credit'. From the definitions given earlier, the following relationships can be derived:

(i) For a system comprised entirely of 'conventional' plant the system margin as a percentage of peak demand is defined as:

System margin = Capacity on the system – Peak demand[43]

(ii) When intermittent generation is added to the system, it is:

System margin = 'Conventional' capacity on the system + Capacity credit of intermittent generation – Peak demand

If the capacity credit is estimated such that the loss-of-load probability with intermittent generation is the same as that on a thermal only system then system margin is the same in the two cases. This provides a familiar yardstick by which the adequacy of system margins may be assessed.

Limitations to LOLP

It is important to note that the LOLP function is *one tool* by which reliability may be measured. There are others (see Annex 6). LOLP may not capture the full range of impacts associated with intermittent generation – for example the chronology and duration of lost loads. There are a range of metrics (see Annex 6) and there has been extensive research into measures of reliability, but this is an important area of ongoing and future research.

As illustrated in the figures in Box 2.7 and Annex 7, the shape of the area where load is not served may change in a system with intermittent generation. The impact of intermittency on reliability is determined by the distribution of intermittent outputs. Impacts range from low probability events with significant impact, to more frequent, but less severe, fluctuations. For example, output from a very large number of intermittent stations may be either zero or low. This 'high impact' event typically has very low probability, but can have a significant impact on capacity credit at large penetrations. 'Low impact' events, where there is a small capacity shortage, have a much higher probability but little effect of security of supply.

[43]NB system margin can be estimated either in terms of rated capacity or net of unplanned outages of conventional units. For simplicity we refer to rated capacity in these expressions, greater accuracy (and consistency) can be achieved if a measure such as UCAP (unforced capacity) is used for conventional units alongside the measure of capacity credit for intermittent options.

Box 2.8 The effect of the 'low wind cold snap' scenario

Some commentators have questioned the validity of allocating any capacity credit to wind generation in particular. This is because of concerns about weather events that affect much of mainland Britain and result in low wind output coincident with high demand. The following quotes were provided by Graham Sinden for his presentation to the workshop on this project on 5th July 2005. (See http://www.ukerc.ac.uk/content/view/124/105/):

- *"There are several periods during a year when the UK is covered by an anti-cyclone and there is no wind and often no waves."* (Fells 2004)
- *"… we must not lose sight of the fact that wind only blows a third of the time." (Foulkes 2003)*

It is important to note that intermittent output need not fall to zero, but need only to be very low in most areas of the country for this concern to have significance. Two important observations can be made about the 'cold snap low wind' issue; the first relates to the implications of such events for capacity credit, the second to the empirical evidence that such events occur.

Capacity credit is a function of probabilities, and no plant is 100% reliable. Even if low wind events occur with regularity, capacity credit need not be zero, provided there is no direct correlation between high demand and low output. The reason is that no plant can be 100% guaranteed available – that's why probabilities are used. If this argument is applied to conventional plant but with 'cold clear spell' substituted by 'unplanned outage' which has the same result of a plant not generating when it's wanted, then it would follow that capacity credit of any plant is zero and would require 100% 'back up'. The studies reviewed in Ch. 3 provide a wide range of capacity credit estimates, but most UK studies suggest that capacity credit at penetrations in excess of 10% of energy from wind are 15% - 25% of the installed capacity of wind energy. Several studies have observed that capacity credit would increase if resources were more diverse. It is important to note however, that existing estimates of capacity credit generally use LOLP as a measure of reliability. As we note in the text in Section 2.2 this measure may not capture all the impacts from intermittent generation. This is an important area of ongoing research.

Some existing studies use relatively short term weather data sets. Capacity credit is estimated most accurately using multiple years of data. If such 'cold snap low wind' events occur with greater regularity than has been allowed for in existing studies of the capacity credit of the UK system, it would follow that existing estimates of capacity credit may be wrong. Recent evidence using long term weather data suggests that very low or very high wind speeds affecting significant parts of Britain simultaneously are very rare (Sinden 2005). German and Danish experience indicates that wind energy does have a capacity credit. In Germany the relatively poor wind regime and more limited geographical dispersion result in capacity credits around half that estimated for the UK (DENA Project Steering Group 2005; E.ON Netz 2005). This illustrates that weather is an important determinant of capacity credit, but even in this case, capacity credit is not zero and 100% 'back up' is not required.

The final point to note with regard to capacity credit and weather data is that *even if capacity credit is zero* intermittent stations can still save fossil fuel, contribute to diversity and security of supply and reduce emissions from fossil fuel generators. The cost implications of low and zero capacity credit have been considered by several authors e.g. (Dale et al 2003; Ilex and Strbac 2002) and are discussed in Ch 3.

2.4 Calculating costs

Costs can be calculated by assessing the capital and operating costs of the impacts described in section 2.3, and may also be revealed by market prices. In all cases, costs can only be properly assessed from a system-wide perspective. It is relatively straightforward to account for some costs, such as response and reserve additions, and allocate these to intermittent stations. Other system effects, such as the costs associated with the lower capacity credit of intermittent stations, can be more complex to account for and allocate.

2.4.1 Introduction

As described in section 2.3 intermittent generation brings a range of changes; these can also be differentiated in terms of benefits and costs relative to conventional technologies[44]:

Prospective benefits:

- Fuel and other variable cost savings and emissions reduction as fossil fuel stations are used less
- Capital and other fixed cost savings from any conventional plant that can be displaced

Prospective costs:

- Capital and operating costs of intermittent generation plant itself
- Additional response and reserve to manage unpredicted short term fluctuations
- Additional fuel burn due to increased variation in the output of load following plants
- Conventional plant retained or new plant constructed to maintain reliability at peak demand
- Wasted energy if intermittent output exceeds demand[45]

We have now shown that the scale of each of these impacts can be quantified, which provides the basis for a cost (and benefit) assessment. This is highly context specific, for example, fuel costs (and hence the value of fuel savings), plant mix, plant margin and cost of reserve provision vary markedly between regions, countries or systems. In addition, short run marginal costs will differ from long run marginal costs. There may be opportunities to reoptimise the system in the longer run, which may reduce long run costs. On the other hand, short run costs may be held down through the use of older plant (for example to provide system margin) that will eventually need to be retired and replaced.

This means that these costs can only be assessed from a systemic perspective. Quantification of the costs of intermittency requires a comparison of the capital, operating and fuel costs of a system *with* new intermittent generation against a credible counterfactual scenario *without* intermittent plant. Both scenarios must provide the same level of energy, power quality and reliability.

Some costs (for example, additions to short term reserves) are sufficiently self-contained to permit a relatively straightforward assessment of the *additional costs* associated with intermittent plant. Whilst the costs in question are system specific, and accrue at a system (as opposed to individual plant) level, it is relatively easy to determine the cost in question and 'attach' these costs to intermittent plant. Other system costs – such as the implications of a lower capacity credit[46] – appear to be more difficult to account for. We explain this below.

A system wide approach may also be thought to militate against a traditional 'like with like' cost comparison between new generating options – usually based upon a 'factory gate' average cost figure (£/MWh). However, there is a clear balance of evidence for this approach – see Ch. 3 for details. As we discuss in the following section, most of the problems associated with system-wide analysis are tractable. In what follows we provide a brief description of the approaches taken to costing system balancing impacts, and consider the issues surrounding the costs of maintaining reliability.

[44]Transmission losses also will either be reduced or increased depending on how wind power is sited related to load centres. For higher penetrations these losses will probably increase. We do not deal with transmission losses in this report.
[45]Strictly speaking lost intermittent output is not itself a cost, since marginal cost of production is zero. However, the need to spill output gives rise to additional total costs, since it implies that utilisation of capacity will fall, and hence a larger amount of capacity/fixed cost will be required to deliver the same amount of energy.
[46]'Lower' in relation to a conventional generator providing the same amount of energy per year, since intermittent stations cannot usually be relied upon at peak periods to the same extent as a thermal plant.

2.4.2 System balancing costs

1. Response and Reserves

Operating and capital costs for reserve plant used for system balancing can be calculated in a relatively straightforward fashion once the additional reserves associated with intermittent generation have been assessed as described in section 2.3.3. The usual approach is to determine the least cost option for provision of such reserves. An alternative approach is to use market prices for reserve services. Both the need for and cost of provision will vary from system to system - for example depending on the size and nature of existing reserves. The principal problem with estimating costs of reserve and response services arises from terminological, operational and regulatory differences between countries. Reserve costs vary according to which actions fall to system operators and which are dealt with by markets. We provide a range of estimates from the literature in Ch. 3.

2. System efficiency impacts

The time series approach described previously allows fuel savings and efficiency losses to be accounted for. There is no other means by which these overarching aspects can have their costs quantified. It is important to note that in those electricity networks that operate through market processes, there is no single body with responsibility for optimising efficiency but rather each market participant optimises their own position such that, in an efficient market design, overall efficiency is achieved. Total system efficiency impacts and the costs thereof, are therefore something of an abstract concept for individual market participants but, nonetheless, can be monitored in terms of total fuel burn. It is important to consider the *potential* difference between central optimisation of fuel and emission savings and those delivered by the decentralised market. This provides a comparator against which market solutions can be judged, both in terms of costs and in terms of other impacts.

2.4.3 Costs related to capacity required to maintain system reliability

In many cases adding intermittent generators to an electricity network will tend to increase the amount of plant required to provide a given measure of reliability if compared to delivering the same energy, or meeting the same loads, with thermal plant. This is because the capacity credit of intermittent generation tends to be smaller than the contribution to reliability of a thermal generation that delivers the same energy output.

The *total change* in costs can be assessed by comparing a system that contains intermittent generators with one that meets the same reliability criteria without those intermittent generators – assuming that both systems have the same energy output. It is important to note, however, that in the UK at present there is no explicit payment for 'reliability services'. Unlike the additional reserve and response services that intermittency might give rise to, the system operator does not contract for plant in order to maintain system margin or to act as 'back up' to intermittent generators.

Two distinct strands of thought can be found in the literature on how to conceptualise the costs associated with any additional capacity required to maintain reliability when intermittent generators are added to an electricity network. The first does not explicitly define a 'capacity cost' rather it assesses the overall change in system costs that arises from additional capacity. More plant is required than would be the case in the absence of intermittent stations. The approach depends upon an estimate of the additional capacity needed to maintain reliability in order to derive capacity credit. However, this approach does not attempt to directly attribute a cost of 'capacity reserves' or 'stand by' due to intermittent stations (Dale et al 2003; Milborrow 2001). The reason for this is that there is no explicit market for, or central procurer of, such services.

Some commentators note that it is possible to derive the cost of maintaining reliability using the above approach by assessing the impact on system load factors (Dale et al 2003). This is because one effect of adding intermittent generators is that the load factor of the remaining conventional stations on the system will fall, since additional capacity is needed to provide a given energy output. All new generators have the potential to affect system load factors. Quantification of these impacts is an important topic of ongoing research. However it is unlikely that intermittency will affect each type of generator equally. In fact, it is possible that particular categories of generating plant might be used to maintain reliability. These include plants used for peak demand such as oil fired stations and open-cycle gas turbines and/or older plant retained and maintained only for peaking duty. This has led other commentators to suggest that 'stand by' generation provides the basis for estimating the cost of intermittency (Ilex and Strbac 2002).

The second line of thought directly costs the additional 'capacity reserve' put in place to ensure reliability. Using this approach, costs are assessed by costing the provision of 'back up' or 'capacity reserve' sufficient to close any gap between the capacity credit of intermittent stations and that of conventional generation that would provide the same amount of energy. Costs will vary depending upon what form of generation is assumed to provide 'back up'. This can give rise to a degree of uncertainty, since there is no market for this 'back up' and the nature and cost of available 'back up' may vary according to system circumstance and technology. It is also not clear that we can know the *long run marginal cost* of such capacity, as this will be a product of future system optimisation (market based or otherwise), which will be affected by new technologies or practices.

In a working paper that accompanies this report a simple algebraic exposition is developed which allows both techniques to be reconciled[47]. In principle both approaches should arrive at the *same* change in total system costs. Therefore, a simple identity can be derived that can be rearranged to allow the derivation of the capacity credit related cost of intermittency. Algebraic derivation of this term is provided in a working paper that accompanies this report. We provide a short description in Annex 2. This shows that the system reliability cost of intermittency = fixed cost of energy-equivalent thermal plant (e.g. CCGT) minus avoided fixed cost of thermal plant (e.g. CCGT) displaced by capacity credit of wind[48]. The benefit of this approach is that it allows the capacity credit related costs associated with adding intermittent plant to the system to be made explicit in a way that is consistent with systemic principles, making no judgement about the nature of the plant that *actually* provides capacity to maintain reliability. Instead, all that is required is determination of the *least cost energy equivalent comparator*, i.e. the thermal plant that would supply the same energy in the absence of intermittent generation (normally assumed to be CCGT). This approach is used in Ch. 3 to consider the range of costs implied by the range of capacity credit estimates we found in the literature that are relevant to the British electricity network.

2.5 Summary

This section has explored the principles of electricity supply system operation, and the provisions that are made through regulation and market actions to ensure that electricity demand is met by supply. We have seen how reliability is measured and maintained, and requirements estimated for a variety of reserve and response services. Demand fluctuations are substantial and not entirely predictable, whilst all forms of generation suffer occasional unplanned outages.

In all cases, the effects on system reliability and efficiency can only be quantified using a system wide, and essentially statistical, approach. The principal impacts of intermittency, and their implications, are as follows:

– System balancing impacts. These include both the additional response and reserve requirements that must be purchased by the system operator and the effects on market participants. They reflect the need to manage and accommodate fluctuations over the period from seconds to hours.

– Capacity to ensure system reliability. This relates to the capacity that must be built or retained on the system with intermittent generation to ensure that a defined measure of reliability of supply during peak demand is maintained.

Ch. 3 reviews the empirical evidence on each of these issues and the history and nature of the studies that have been undertaken into intermittency. It seeks evidence on the following questions:

– *What is the scale, and range of estimates, of additional reserves that are required to accommodate intermittent generation?*
– *Can we quantify other impacts, such as efficiency losses?*
– *How much does this cost?*
– *What is the scale, and range of estimates, of the capacity credit of intermittent renewables?*
– *What are the reasons for this range?*
– *What are the implications for the UK?*

There are important issues relevant to the integration of renewables that this report deals with only briefly. Others lie entirely outside its scope. The impacts of supply interruptions and of various scenarios of renewables development are both examples. There are also limitations to existing approaches to estimating the impacts of intermittent generation, for example, the range of impacts captured in the reliability measure LOLP. In many areas research is ongoing, both empirical and analytical.

[47]UKERC Working paper available at http://www.ukerc.ac.uk/content/view/124/105/
[48]Note that avoided can be taken to mean either retired (short run marginal costs change) or not replaced (long run marginal cost effect).

3

Evidence on the costs and impacts of intermittency

3.1 Introduction

This section provides an overview of the findings from the in-depth review of the literature on intermittency undertaken for this assessment. It seeks to identify where the weight of evidence lies, and understand the origins of contention. Ch. 1 and Annex 5 describe the protocol, search terms and databases used to gather data. As noted, these are derived from best practice in systematic review and informed by the stakeholder workshop and expert group.

A total of 212 documents were reviewed, of which 58 were excluded because they were irrelevant or duplicative. The remaining 154 documents were categorised according to the major issue which each document addresses and the approach adopted by the authors. The categories and numbers of documents falling into each category are summarised in Table 3.1.

The remainder of this chapter provides the following information:

- Overview of historical developments in research on intermittency
- Quantitative findings:
  - Additional reserve and response services for system balancing;
  - Other system balancing impacts
  - The capacity requirements to ensure reliability
  - Implications for costs
- Discussion of key issues
- Conclusions

Table 3.1: Overview of the evidence base

Primary aspect covered	Method/approach	Number of documents
Reliability, reserves and balancing	Statistical and/or time series simulation	64
	Review	57
	Other	1
	Sub-total	**122**
Connection, transmission and network issues	N/A	19
Resource characteristics	N/A	13
	Total included documents	**154**
	Total excluded documents	**58**
	Total all documents	**212**

3.2 Historical development of research on intermittency

The systematic search undertaken for this assessment revealed a rich and technically detailed literature spanning more than 25 years. The focus of work has changed over time, reflecting the evolution of understanding, the development of wind power in several countries and changing market and regulatory context. This section provides a short review and lists some key studies by way of example. It is important to note that the most recent period revealed by far the largest number of reports, and we include only a short excerpt here.

Early studies: 1978 - 1989

The literature uncovered in our review dates from 1978, with an initial cluster of reports dating from this time until 1987. Many studies were carried out by, or for, what were then state owned utilities and in response to the OPEC induced oil price shocks. Many studies focus on the basic principles of how to represent intermittent generators on an integrated network. Most are concerned with transmission system level reliability, reserve and balancing issues, with a particular focus on the role of wind and other renewables as 'fuel savers'. In all cases the 'context' is very different, in that centralised operation of electricity networks was still extant in all countries. As a result 'optimisation' of networks with intermittent sources is conceptualised in rather different terms than it is currently. However, the technical issues are largely unchanged. Many reports are concerned with development of methodological principles and apply these only to relatively simple – and obviously at that time hypothetical – scenarios.

Table 3.2: Example studies 1978 - 1989

Date	Author	Title
1978	Johanson E, Goldenblatt M	An economic model to establish the value of WECS to a utility system.
1979	General Electric; W D Marsh	Requirement assessment of wind power plants in utility systems
1979	Rockingham A	A probabilistic simulation model for the calculation of the value of wind energy to electric utilities
1980	Farmer ED, Newman VG, Ashmole PH	Economic and operational implications of a complex of wind-driven power generators on a power system
1980	Rockingham AP	System economic theory for WECS
1980	Zaininger Engineering Co.	Wind power generation dynamic impacts on electric utility systems
1981	Whittle G	The effects of wind power and pumped storage in an electricity generating system
1982	Gardner GE, Thorpe A	System integration of wind power generation in Great Britain
1982	Meier RC, Macklis SL	Interfacing wind energy conversion equipment with utility systems
1982	Moretti PM, Jones BW	Analysis method for non-schedulable generation in electric systems
1983	Danish Energy Ministry	Vindkraft I Elsystemet
1983	Brian Martin, John Carlin	Wind-load correlation and estimates of the capacity credit of wind power: An empirical investigation
1983	Brian Martin, Mark Diesendorf	The economics of large-scale wind power in the UK, a model of an optimally mixed CEGB electricity grid
1983	Halliday JA, Lipman NH, Bossanyi EA, Musgrove PJ	Studies of wind energy integration for the UK national electricity grid
1983	Yamayee ZA, Ma FS	Effect of size and location of conventional and intermittent generation on system reliability
1984	Halliday JA	Analysis of wind speed data recorded at 14 widely dispersed U.K meteorological stations
1987	Swift-Hook DT	Firm power from the wind
1987	Thorpe A	A computer model for the evaluation of plant and system operating regime
1988	Grubb MJ	On capacity credits and wind - load correlations in Britain

Methodological development: 1990 - 1999
During the 1990s some differences of emphasis emerged relative to the earlier analyses. There was a marked decrease in the number of utility studies compared to the early 1980s, though academic work continued in the US, UK and Nordic countries. One notable addition to the body of knowledge in this period was a series of ten country studies sponsored by the European Commission. The break up of national monopolies is possibly reflected in a marked reduction in emphasis on the *benefits* of wind and other renewables (fuel saving and system optimisation). Instead, work in this period has a noticeable focus on detailed methodological issues and in particular *costs* of system balancing and calculation of capacity credit. Several studies pay attention to methodological refinement and development, for example, through incorporation of stochastic variables into simulation models.

Table 3.3: Example studies 1990 - 1999

Date	Author	Title
1990	Holt, Milborrow, Thorpe	Assessment of the impact of wind energy on the CEGB system
1991	Grubb	The integration of renewable electricity sources
1991	Grubb	Value of variable sources on power systems
1992	EC Commission	Wind Power Penetration Study, The Case of Denmark
1992	EC Commission	Wind Power Penetration Study, The Case of Germany
1992	EC Commission	Wind Power Penetration Study, The Case of Greece
1992	EC Commission	Wind Power Penetration Study, The Case of Italy
1992	EC Commission	Wind Power Penetration Study, The Case of Portugal
1992	EC Commission	Wind Power Penetration Study, The Case of Spain
1992	EC Commission	Wind Power Penetration Study, The Case of the Netherlands
1993	Billinton & Gan	Wind power modelling and application in generating adequacy assessment
1993	Bouzguenda, Rahman	Value analysis of intermittent generation sources from the system operations perspective
1993	Soder	Reserve margin planning in a wind-hydro-thermal power system
1993	Watson SJ, Landberg L, Halliday JA	Wind speed forecasting and its application to wind power integration
1993	Yih-huei Wan, Brian K.Parsons	Factors Relevant to Utility Integration of Intermittent Renewable Technologies
1994	South Western Electricity plc	Interaction of Delabole wind farm and South Western Electricity's Distribution system
1994	Watson SJ, Landberg L, Halliday JA	Application of Wind speed forecasting to the integration of wind energy into a large scale power system
1995	Michael R.Milligan, Alan Miller, Francis Chapman	Estimating the Economic Value of Wind Forecasting to Utilities
1996	Reconnect Ltd	Wind turbines and load management on weak networks
1996	Milborrow D	Capacity credits - Clarifying the issues
1996	Wind energy weekly	How Difficult is it to Integrate Wind Turbines With Utilities?
1997	Michael Milligan, Brian Parsons	A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators
1999	RJ Fairborn	Electricity network limitations on large scale deployment of wind energy

Renaissance: 21st century research

The beginning of the 21st century saw a very significant increase in research activity on intermittency. References for the last five years outnumber those from both the previous decades by more than two to one. Whilst most utilities have been privatised, system operators, regulators and governments have funded a significant number of studies. Attention to methodological issues has been sustained and extended. In addition, an increasing amount of empirical data has been combined with increasingly sophisticated scenarios of wind power and other intermittent generation installation.

Table 3.4: Example studies from 2003 & 2004[49]

Date	Author	Title
2003	Dale, Milborrow, Slark, Strbac	A shift to wind is not unfeasible (Total Cost Estimates for Large scale Wind Scenarios in UK)
2003	Doherty R, O'Malley M	Quantifying reserve demands due to increasing wind power penetration
2003	Dragoon K (PacifiCorp), Milligan M (NREL)	Assessing Wind Integration Costs with Dispatch Models: A Case Study of PacifiCorp
2003	Environmental Change Institute University of Oxford	The Practicalities of Developing Renewable Energy Stand-by Capacity and Intermittency Submission to The Science and Technology Select Committee of the House of Lords
2003	Milligan M	Wind Power Plants and System Operation in the Hourly Time Domain
2003	Mott MacDonald	The Carbon Trust & DTI Renewables Network Impact Study Annex 4: Intermittency Literature Survey & Roadmap
2003	Seck T	GRE wind integration study
2003	Sveca J, Soder L	Wind power integration in power systems with bottleneck problems
2003	Xcel Energy	Characterizing the impacts of significant wind generation facilities on bulk power systems operations planning
2004	Auer H	Modelling system operation cost and grid extension cost for different wind penetrations based on GreenNet
2004	Bach P	Costs of wind power Integration into Electricity Grids: Integration of Wind Power into Electricity Grids Economic and Reliability Impacts
2004	Brooks D L, Anthony J, Lo E, Higgins B	Quantifying System Operation Impacts of Integrating Bulk Wind Generation at We Energies
2004	Doherty R, Denny E, O'Malley M	System operation with a significant wind power penetration
2004	E.ON- Net Z	Wind report 2004
2004	Electric Systems Consulting ABB Inc.	Integration of Wind Energy into the Alberta Electric System Stage 4: Operations Impact
2004	EnerNex Corporation, Wind Logics	Xcel Energy and the Minnesota Department of Commerce Wind Integration Study - Final Report
2004	Holttinen H	The impact of large scale wind power production on the Nordic electricity system
2004	Ilex, The Electricity Research Centre (ERC), The Electric Power and Energy Systems Research Group (EPESRG)	Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System
2004	KEMA-XENERGY for California energy commission	Intermittent wind generation: Summary report of impacts on grid system operations
2004	Milborrow D	Assimilation of wind energy into the Irish electricity network
2004	Royal Academy of Engineering, PB Power	The Costs of Generating Electricity
2004	Soder L	Simulation of wind speed forecast errors for operation planning of multi-area power systems
2004	Usaola et al	Benefits for Wind Energy in Electricity Markets from Using Short Term Wind Power Prediction Tools; a Simulation Study

[49]NB database includes a further 80+ studies from the period 2000 to 2005 on - see Annex 3

3.3 Quantitative findings

Overview

This section provides a detailed and quantitative account of the evidence revealed through the literature search undertaken for this assessment. It reviews the range of findings on system balancing impacts and costs, and on capacity credit, through a series of graphs and tables. It explains the range of metrics used to measure these impacts, and provides an explanation of both the main findings and the differences between studies. Finally, the key issues and conclusions for the UK are discussed.

3.3.1 Introduction

This section provides an overview and discussion of the principal quantitative findings from the literature, through meta-analysis of the included studies and reports. It discusses the main ranges and the reasons for differences between studies. It also provides a review of the different measures, or metrics, utilised in different studies and considers the potential for confusion that might arise from this and other factors.

The main issues identified in Ch. 2 provide the basis for the following categorisation of findings, described in the principal sub-sections below:

- *System balancing part 1: Response and reserve services (impacts and costs)*
- *System balancing part 2: Other system efficiency impacts*
- *Capacity requirements to ensure reliability*

We begin with a general overview of the characteristics of the literature and limitations to the search.

3.3.2 Overview of the evidence base

Sixty-seven documents were found to contain quantitative data under one or more of the headings above[50]. It should be noted that this number does not include those documents which presented results of other studies (provided that these other studies had been captured by the search process). The number does, however, include those reports which presented data from other studies *and* introduced additional new data (care was required to ensure that in these cases findings were not double counted). Relatively few studies attempted to measure the cost attributable to the (usually) relatively low capacity credit of intermittent generation.

Of the sixty-seven documents, twenty-four are academic research papers, six are collaborative studies undertaken by academic and industry representatives, two commissioned by a learned society, sixteen are reports by industry participants (generating/supply companies, network operators or trade bodies), and nineteen are from/by government or government bodies such as regulators and executive agencies. Nearly all of the studies reviewed focused exclusively on wind generation rather than intermittent renewable generation as a whole, which reflects the relatively advanced penetration of wind power relative to other emerging renewables.

Limitations

The search may have a number of limitations:

- The principal focus was on English language references and those commonly translated into English. This (along with the success of wind energy in these countries) may explain the predominance of Nordic, US, UK and Irish studies. There are relatively few studies from Spain.
- The search engines utilised may not have revealed the full range of government and industry reports in all countries.
- Whilst citation trails were followed, notably from key references highlighted by the expert group, it was not possible to follow each and every citation and reference in the time available.

Hence, whilst every attempt has been made to be extensive, the review is by no means exhaustive. Nevertheless, this review provides by far the most extensive assessment of this nature that has been undertaken to date in the mainstream literature.

[50]This is a subset of the 122 documents on reliability, reserves and balancing listed in table 3.1

General observations

One striking characteristic of the data is the range of different metrics used to assess the impacts. This means that for each of the categories of impact identified above, the numbers are presented in several different formats. This creates the potential for confusion and the risk that comparisons between results is not on a genuinely like for like basis. Attempts to normalise data from a range of studies to facilitate comparison run the risk of losing important detail or, at worst, suggesting that figures are comparable when they are not. The differing methods of presentation of data within each heading are identified in tabular form for each of our categories of impact, described below – see Tables 3.6 to 3.10. We present the principal/most common metrics in graphical form.

Even where studies have used ostensibly the same metric it is not always possible to compare the results because a study has focussed on a particular element[51] of a metric, or other system dimensions are not declared. Examples include studies which do not identify the extent to which intermittent generation displaces existing plant[52]. Other studies are not explicit regarding total intermittent generation levels, total system capacity, or total system demand, all of which hamper the derivation of the penetration level.

These issues do not imply a criticism of the studies reviewed – they are used to illustrate that it is prudent to exercise caution when drawing comparisons between results. These risks not withstanding, the remainder of this section presents the quantitative findings through a combination of charts and tables. Where there is a particular issue of comparability, this is identified.

It is also notable that attention to capacity credit tends to focus on the *scale* of the impact (i.e. calculation of capacity credit), with limited attention to costs thereof. By contrast more studies that consider system balancing provide cost estimates than provide an indication of the scale of the impact. Finally, a relatively small number of studies provide quantitative evidence on system efficiency effects such as fuel saving. We discuss each of these points in more detail below.

[51]For example, some studies include only the reserve requirement for frequency regulation and at the other extreme some appear to include an element of system margin for reliability requirements.

[52]If a paper expresses penetration level using a metric based on system capacity and the capacity credit is not specified, what assumption should be made about how much thermal plant is be retired (which we need to know to calculate the penetration level in percentage terms)? E.g. (Doherty and O'Malley 2005) model a system with 7.5GW capacity and adding 2GW of wind to that system, so is the penetration level 2/7.5 = 26.7%, or at the other extreme 2/(7.5+2) = 21.1%? In such cases we have used the latter as this gives the most conservative assessment of the intermittent generation penetration level.

3.3.3 System balancing part 1: response and reserve services

Impacts (MW and % additions to reserve requirements)

The additional reserve and response requirements attributable to intermittency are presented in Figure 3.1. In this figure we present findings which estimate additions to reserves in two ways:

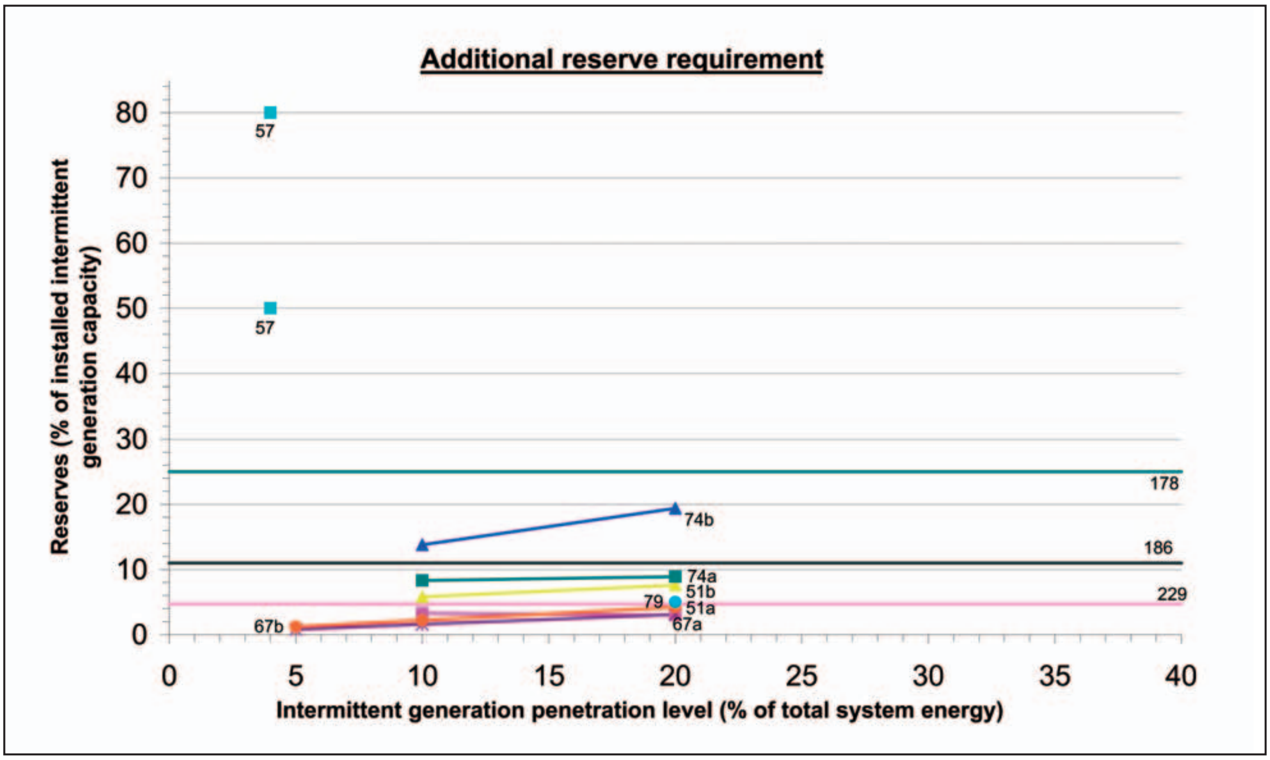
- As a percentage of installed intermittent generation capacity at given levels of intermittent generation penetration, and where penetration level is expressed as the percentage of *total system energy* provided from intermittent generation. These appear as a point or series of points in Figure 3.1.
- As a percentage of installed intermittent generation capacity, but *no penetration level given*. These appear as a horizontal line in Figure 3.1.

Out of a total of 18 studies that provide quantitative evidence on the additional reserve services associated with increasing penetrations of intermittent generation, ten use these two metrics, although two of the studies do so in a way which means that they cannot be represented on the chart.

Two other types of presentation were found in the literature. These findings are presented in Table 3.6 at the end of this chapter:

- Reserves expressed as a percentage of installed intermittent generation capacity at given levels of intermittent generation penetration, where penetration level is expressed as the percentage of *total system installed capacity* provided from intermittent generation (four studies use this formulation).
- Expressed as a percentage of installed intermittent generation capacity at given levels of intermittent generation penetration, where penetration level is expressed as the installed intermittent generation capacity as a percentage of *peak system load* (four studies use this formulation).

Figure 3.1 Range of findings related to additional reserves with increasing penetration of intermittent supplies



Key: 51(Mott MacDonald 2003), 57(E.ON Netz 2004), 67(Holttinen 2004), 74(DENA Project Steering Group 2005), 79(Dale et al 2003), 178(Doherty et al 2004a), 186(Milligan 2001), 229(Hudson et al 2001)

Comments on the range of values for reserve requirements[53]

5% penetration level

There are only four data points at this penetration level, representing data from just two studies. The striking characteristic is the very high outliers from a German study (E.ON Netz 2004) (reference number 57) which are two orders of magnitude greater than the other values (Holttinen 2004) (ref.67). The wording of the Eon Netz report is such that it is not clear whether the 'reserve' costs that they cite refer to balancing services only, or also include an element of capacity provision that reflects the relatively low capacity credit of German wind farms[54]. Moreover, particular difficulties are faced within the Eon Netz region, which has extensive wind energy developments:

- Factors which tend to exacerbate the scale of swings in output: Low average wind speeds and low capacity factor for wind output (see Ch. 2 for an explanation of the relationship between these factors and capacity credit); and substantial 'clustering' of wind farms in the North West of the control area which limits potential smoothing of short to medium term fluctuations.

- Limited interconnection with regions to the East and West.

- 'Gate closure' 24 hours ahead of real time, which means that the forecasting error that must be managed by reserve plants is much larger than it would be in the UK and other countries with a much shorter period between scheduled unit commitment and real time. E.ON 'firms' up the wind based on day ahead wind forecasts, independently of the load forecast errors. This increases the reserve requirement, and associated costs.

By contrast Holttinen covers a large area (4 countries) and only considers the sub-hour variations of wind power.

10% penetration level

There are eight data points at this penetration level, which lie in the range between approximately 2% and 8%. The high value is from the Dena Grid Study (DENA Project Steering Group 2005) (ref.74) - another report based on the German electricity system.

20% penetration level

At this level of intermittent generation, six of the seven data points are in the range between approximately 3% and 9%. There are no low outliers, but one higher value of 19% (DENA Project Steering Group 2005) (ref.74).

Penetration level not specified

These values are represented in Figure 3.1 as horizontal lines, since it is unclear what penetration level they represent. Two studies, (Milligan 2001) and (Hudson et al 2001) (refs.186 and 229) lie within the normal range of the 10% and 20% penetration levels described above. A third (Doherty et al 2004a) (ref.178), at 25%, is above the trend. This finding reflects Ireland's small system size and limited interconnection.

Other comments

Different analysts use different definitions of 'reserves', which means that a range of impacts are captured. For example, some studies look exclusively at 'spinning' reserve (part loaded plant), and so have not included the impact of intermittent generation on other system balancing services such as the level of standing reserve. Others identify figures for frequency control and load following reserve but do not analyse the impact on generating unit commitment (the requirement to instruct plant in advance of when it is required to allow sufficient time for it to be brought into operation).

Within the data on reserve impacts and costs we have included (but not shown on figure 3.1) a notable outlier (Royal Academy of Engineering and PB Power 2004) (ref.239). This report is difficult to categorise. This is because the report does not use the systemic approach to estimating system costs common to other studies, but works on the premise that wind generation requires dedicated back up. Since this back up would be expected to provide both balancing and reliability, the data in this study are therefore a combination of *system balancing* reserves and capacity installed to maintain reliability. This highlights the scale of the implications of methodological differences and the importance of terminology to estimates of the impacts of intermittency.

[53]Penetration levels are rounded for the purposes of these comments e.g. 19% would be in the 20% level.
[54]Eon Netz introduce the term 'shadow capacity', which is not used in any other literature and its precise meaning is unclear.

Response and reserve services costs

Twenty-three studies provide quantitative evidence on costs associated with additional reserve and response requirements attributable to the addition of intermittency. The main findings are represented in Figure 3.2. In this figure we present findings which used the following approach:

– Cost per MWh of electricity from intermittent generation at given levels of intermittent generation penetration, where penetration level is expressed as the percentage of *total system energy* provided from intermittent generation (as in figure 3.1). Fifteen studies use this approach.

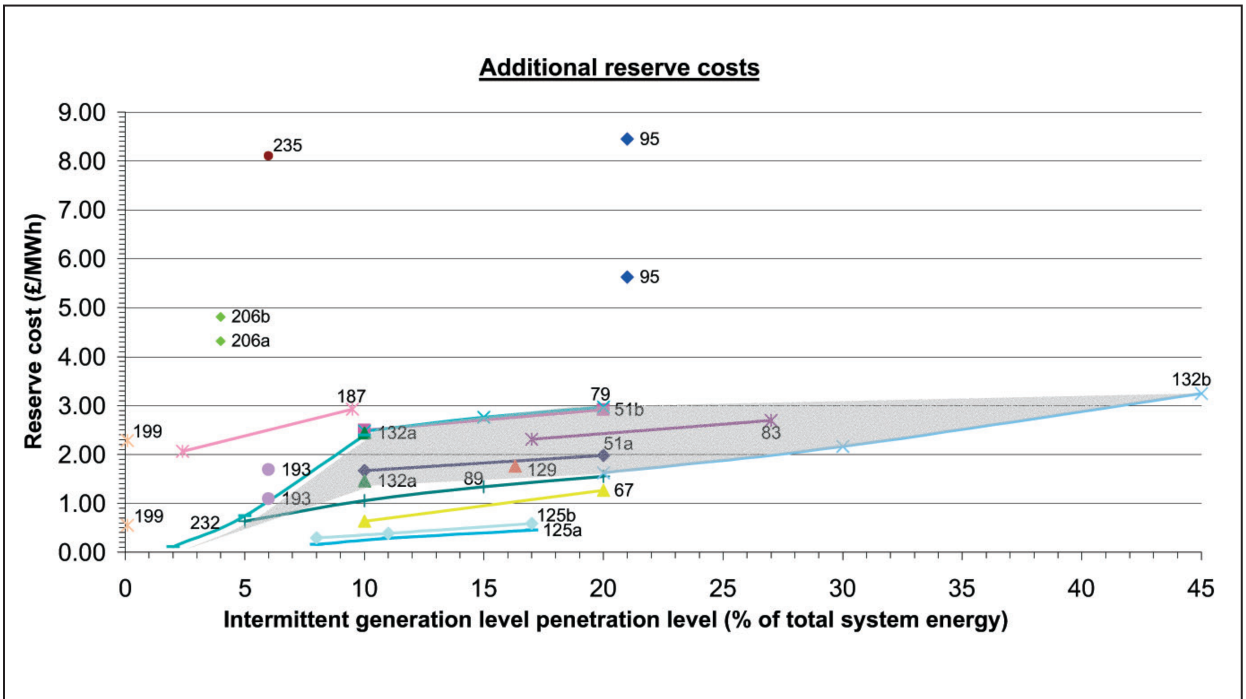
The database contains a further eight studies, summarised in Table 3.7 and discussed below, which used the following metrics:

– Cost per MWh of electricity from intermittent generation at given levels of intermittent generation penetration, where penetration level is expressed as the percentage of *total system installed capacity* provided from intermittent generation. Four studies use this approach.

– Cost per MWh of electricity from intermittent generation at given levels of intermittent generation penetration, where penetration level is expressed as the installed intermittent generation capacity as a percentage of *peak system load* (three studies use this formulation).

– Cost per MWh of electricity from intermittent generation, but *no penetration level given*. One study use this approach.

Figure 3.2 Range of findings on the cost of additional reserve requirements[55]



Key: 51(Mott MacDonald 2003), 67(Holttinen 2004), 79(Dale et al 2003), 83(Ilex and Strbac 2002), 89(Milborrow 2004), 95(Bach 2004), 125(Ilex et al 2004), 129(Pedersen et al 2002), 132(Milborrow 2001), 187(Seck 2003), 193(Hirst 2002), 199(Hirst 2001), 206(Fabbri et al 2005), 232(Dale 2002), 235(Milborrow 2005)

Shaded area represents the range of values for UK studies.

[55]Costs have been converted to Sterling using exchange rates at the date of publication and values inflated to 2005 using producer price index. All values are per MWh of intermittent output.

Comments on the range of values for costs of additional reserve requirements with intermittent generation[56]

5% penetration level[57]

Four of the seven data points lie in the range between £0.6 and £1.7/MWh. There is one very high outlier, which presents interpretation and analysis of data from the Eon Netz 2004 report – a value of £8.1/MWh (Milborrow 2005) (ref.235). It is worth noting that this report also highlighted some of the particular difficulties faced within the Eon Netz region (discussed previously in section 3.3.3). The other relatively high figure of £4.3-£4.8/MWh, from (Fabbri et al 2005) (ref. 206), reflects the price of procuring electricity in the Spanish market to cover the difference between predicted and actual generation from wind plant.

10% penetration level

At this level of intermittent generation, there are eleven data points with values ranging from £0.2 to £2.9/MWh. There are no clear outlying values at either the upper or lower end of this (wide) range.

15% penetration level

Values range from £0.5 to £2.8/MWh, with seven data points, again with no clear outliers.

20% penetration level

There are eight data points, six of which lie in the range £1.3 to £3/MWh, with two high outliers of £5.6 and £8.4/MWh from one of the studies relating to the Danish Eltra system (Bach 2004) (ref.95). We note that there is a disparity between the numbers presented in this study and the other study based on the Eltra system (Pedersen et al 2002) (ref.129).

Other comments

Studies which refer to the share of installed capacity, rather than energy, have costs in the range £0.4 and £4.81/MWh.

Twenty studies, out of a total of twenty-three, conclude that additional costs are less than £5.0/MWh of intermittent output at penetration levels of up to 20%, with estimates ranging between £0.2 and £4.81/MWh. One study suggests costs remain in this range at much higher penetrations. All studies find that reserve costs tend to rise as penetration level increases, but the range of costs across studies is broadly similar at each penetration level, that is, there is no appreciable convergence or divergence as penetration rises. The difference *between* individual studies is typically larger than the increase in costs *within* each study resulting from increasing penetration levels. This suggests that the reserve cost is particularly sensitive to assumptions about system characteristics, existing reserves, and what is included within the definition of reserve requirements (see Ch. 3). The study that does not show a penetration level (Royal Academy of Engineering and PB Power 2004) (ref.239) is an extremely high outlier at a cost of £17/MWh. This report has the unusual characteristics noted previously, and appears to be an amalgamation of balancing and reliability costs.

3.3.4 System balancing part 2: other system efficiency impacts

Intermittent stations will affect the operation of generating plant other than, and in addition to, operating reserves (see Ch. 2 for further details). Load following plant may be required to respond to variations in intermittent generation, which may affect efficiency. In addition, if the output of intermittent plants cannot be absorbed by the system energy may need to be discarded. Both factors will serve to decrease the potential value of intermittent generation in terms of its ability to deliver fuel savings and emissions reductions. This sub-section considers these two factors, and discusses the quantitative evidence available on the scale of their impacts. There is limited evidence on these impacts, in part reflecting the influence of market rules, available transmission to neighbouring countries and flexible demand on the results.

[56]Penetration levels are rounded for the purposes of these comments e.g. 19% would be in the 20% level.

[57]Comments under each of the penetration levels relate to those studies that have used the metric shown in Figure 3.2.

Fuel and carbon dioxide emissions savings

In the UK's electricity system, output from renewable generators would normally be expected to displace electricity generated in conventional plants burning coal and natural gas (usually coal plants). The theoretical maximum fuel and emissions savings would be realised where each MWh of renewable electricity displaces a MWh of fossil fuel electricity and where the conventional plant fuel burn is reduced accordingly (i.e. where there is no loss of operating efficiency resulting from the conventional plant's reduced output).

In practice, the theoretical savings are reduced because the efficiency of conventional plant can be affected by intermittent renewable generation in two ways:

– Through an increase in the variability of generation (increasing losses as plant is more frequently shutdown and restarted, or output is ramped up or down).

– As a result of a lower overall load factor, even if output is relatively stable at the lower load factor (because generating plant fuel efficiency is typically maximised at close to a plant's designed output).

This section is concerned with the extent to which the theoretical fuel and carbon dioxide emissions savings are reduced as a result of these potential efficiency losses. There are a number of factors which can influence the net savings:

The operational mode of the conventional generating plant on the system is key. At one extreme is the 'fuel saver' mode in which all of the conventional thermal plant that would be operated if there had been no intermittent renewable generation is left running but output (and therefore fuel burn) is reduced when intermittent generation is able to supply electricity. The result is that there will tend to be more part-loaded conventional plant running than is really needed, which will exacerbate efficiency losses. A closer to optimal approach is the 'forecast' mode in which renewable electricity generation is predicted (for example, based on forecast wind speeds) and surplus conventional plant is stood down. The remaining conventional plant on the system is therefore used more intensively, which minimises efficiency losses. A number of studies e.g. (Doherty et al 2004b) (ref.22), (Watson et al 1994) (ref, 26), (Ilex et al 2004) (ref.125), (Holt et al 1990) (ref.160), (Denny and O'Malley 2005) (ref.181) conclude that better forecasting of intermittent resource availability will maximise fuel and carbon dioxide emission savings.

Some commentators have argued that the design and operation of the electricity market can affect the potential fuel and carbon dioxide savings. If the market penalties for intermittent generation significantly exceed the true system cost, as may be the case in the UK (BWEA 2005) (ref.50), (Milborrow 2001) (ref.132), then generators with a mix of conventional plant and intermittent renewables may keep more conventional generation on-line than is theoretically required (from a whole-system perspective). They do this in order to avoid the market penalties which they would otherwise be exposed to as a result of their intermittent generation. The consequence may be a system that as a whole is operated sub-optimally (with the attendant efficiency losses).

The type of conventional thermal plant that is displaced by intermittent generation has a major effect on carbon dioxide savings. This is a consequence of the much higher carbon content of coal (per kWh of energy) compared to natural gas, and the greater thermal efficiency of combined cycle gas turbines. Strictly, this is not a pure intermittency issue, but is related to it because the operating characteristics of different conventional plant may make it more or less likely to be displaced by intermittent renewable generation. If coal fired plant is displaced then the carbon dioxide savings will be greater than if gas-fired plant is displaced. The issue of displacement can be assessed analytically based on the operating characteristics of existing (or planned) generating units. However, there appears to be a continuing debate as to what type of conventional plant is displaced by wind generation in the UK, e.g. (BWEA 2005) (ref.50), (Milborrow 2004) (ref.89).

A small number of studies have explicitly addressed the efficiency losses of thermal plant resulting from intermittent renewable generation (those that use the C2 and C5 metrics described in table 3.8 at the end of this chapter). There is no evidence to suggest that efficiency is reduced to such a degree as to significantly undermine fuel and carbon dioxide emissions savings:

– The fuel savings not realised because of the reduced efficiency tend to increase as intermittent generation penetration level rises but the actual losses are generally small - up to the 20% penetration level, the studies present efficiency losses ranging between a negligible level and 7% (as a percentage of theoretical maximum fuel savings).

Energy Spilling

Energy spilling will occur when the available renewable generation from installed plant at a particular point in time exceeds the ability of the system to absorb it, or when it is not economic to continue operating the intermittent generation. The circumstances under which energy may have to be spilt are dependant on a range of system characteristics (Denny and O'Malley 2005) (ref.181) (Sveca and Soder 2003) (ref.18), (Holttinen 2004) (ref.67), (Bach 2004) (ref.95):

– The point at which intermittent renewable generation capability is not fully utilised will be lower on systems with a high proportion of inflexible plant. This inflexibility may be a result of technical constraints (such as in the case of nuclear generation, or Combined Heat and Power plants bound to the heat demand), or policy constraints (such as the 'must-run' peat fuel plants in Ireland).

– It is important to note, however, that all systems will require some minimum quantity of plant that can provide the full range of frequency response, reactive power and other essential system services and that some types of intermittent renewable plant do not supply such services.

– The degree of correlation between the renewable resource availability and demand will have a major impact on the threshold at which energy spilling will occur. The threshold will be lower for those systems where high resource availability is positively correlated with periods of low demand.

– The level of spare capacity on the transmission lines between areas of high resource availability and areas of high demand will also influence energy spilling. If the resource is remote from demand and the transmission system has little spare capacity, the likelihood of transmission bottlenecks will be higher. Such bottlenecks could require that generation capacity is constrained off the system, and potential electricity generation would be lost.

The studies identified in table 3.9 show that the proportion of energy spilt tends to increase as the intermittent generation penetration level rises. The conclusion is that:

– At penetration levels up to approximately 20%, the spilt energy ranges between zero and less than 7% for five out of the six studies. The remaining study (which relates to the transmission network-constrained Swedish system) concludes that energy spill levels would reach 16.7% at an 11% penetration level, assuming all the new wind capacity was located in the north of the country and there were no grid reinforcements to the south.

3.3.5 Capacity requirements to ensure reliability: the capacity credit of intermittent generation

Twenty-nine studies provide quantitative evidence on the capacity credit of intermittent generators. All use a statistical or simulation approach based upon a measure of reliability such as LOLP[58]. The main findings are represented in Figures 3.3 and 3.4. In this figure we present findings which use the following metric:

– Capacity credit expressed as a percentage of installed intermittent generation capacity at given levels of penetration, where penetration level is expressed as the percentage of total system energy provided from intermittent generation. Nineteen studies use this approach.

[58] The techniques used are not always transparent and we have not attempted to undertake any form of methodological assessment to ascertain the relative merits of different analytic approaches.

The database contains a further ten studies, summarised in Table 3.10 and discussed below, which use the following metrics:

– Percentage of installed intermittent generation capacity, where penetration level is expressed as intermittent generation capacity as a percentage of peak system load. Three studies use this approach.

– Percentage of installed intermittent generation capacity, where penetration level is expressed as the percentage of total system installed capacity provided by intermittent generation. Four studies use this approach.

– Percentage of installed intermittent generation capacity, but no penetration level given. Three studies use this approach.

Comments on the range of values for capacity credit[59]

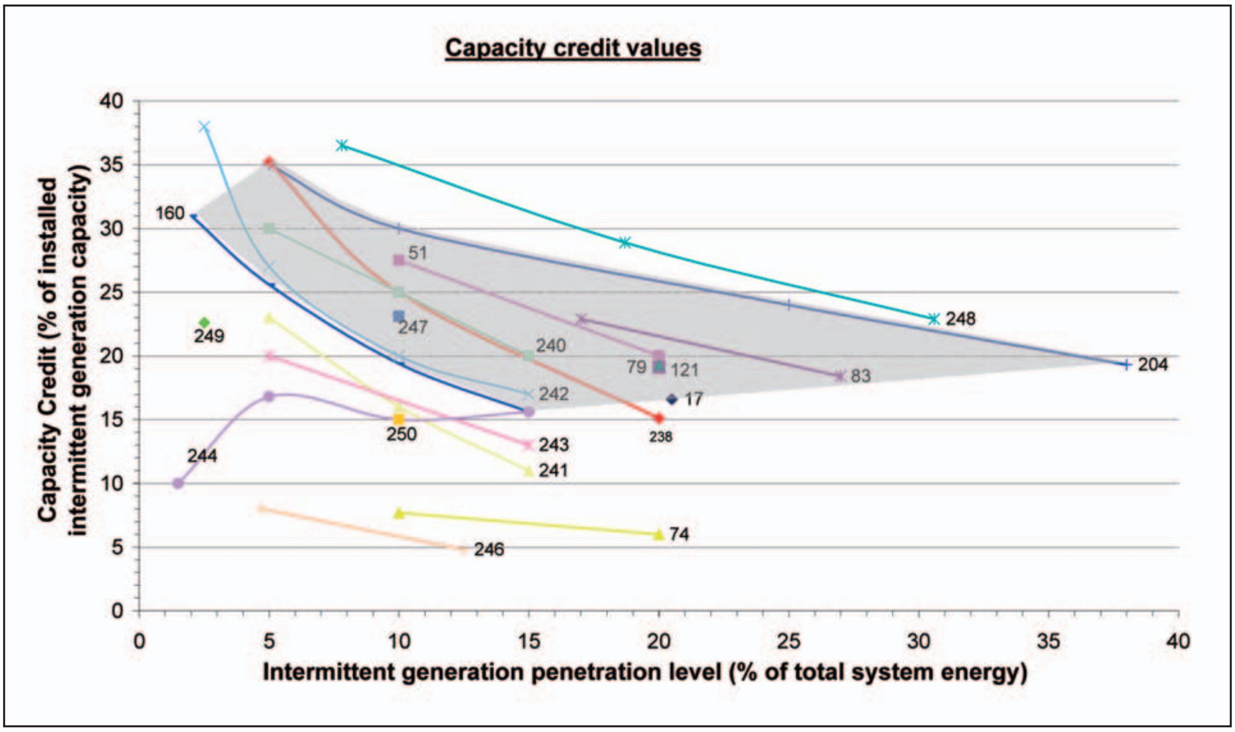
5% penetration level

At this level of intermittent generation the capacity credit values lie in a range between 17% and 35% for all but one of the ten studies which provided data points at this penetration level. There are no particularly marked outlying values at the upper end of the range. The one clear low outlier (E.ON Netz 2005) (ref.246) has a value at 8% capacity credit that is less than half that of the next lowest value.

10% penetration level

At this penetration level, eleven of the twelve data points lie in the range 15% to 30%. The values follow a similar pattern to those at the 5% penetration level with no clear upper outliers, but one low outlier (DENA Project Steering Group 2005) (ref.74), with a value that is half that of the next lowest.

Figure 3.3: Range of findings on capacity credit of intermittent generation



Key for studies used in figure 3.3: 17(Watson 2001), 51(Mott MacDonald 2003), 74(DENA Project Steering Group 2005), 79(Dale et al 2003), 83(Ilex and Strbac 2002), 121(Giebel 2000), 160(Holt et al 1990), 204(Grubb 1991), 238(Martin and Carlin 1983), 240(Commission of the European Union 1992b), 241(Danish Energy Ministry 1983), 242(Commission of the European Union 1992d), 243(Commission of the European Union 1992a), 244(Commission of the European Union 1992g) 246(E.ON Netz 2005), 247(Sinden 2005), 248(Commission of the European Union 1992f), 249(Commission of the European Union 1992e), 250(Commission of the European Union 1992c).

Shaded area indicates the range of values for UK studies.

[59]Penetration levels are rounded for the purposes of these comments e.g. 19% would be in the 20% level.

15% penetration level
At this penetration level, seven of the eight data points lie in the range 11% to 20%. The one low outlier (E.ON Netz 2005) (ref.246), has a value that is well under half that of the next lowest. There are no upper outliers.

20% penetration level
At this penetration level, six of the seven data points lie in the range 15% to 20%. The lower boundary of this range, at 15% capacity credit, runs counter to the general trend that capacity credit falls as penetration level rises (the corresponding value at 15% penetration was 11% capacity credit). This is because the studies which tended to provide the lower boundary numbers at the 5%-15% penetration levels do not extend as far as the 20% penetration level. The trend for one low outlying value continues in line with other penetration levels, with the low outlier (DENA Project Steering Group 2005) (ref.74) value being considerably less than half the next lowest.

Other comments

The capacity credit data in Figure 3.3 have two clear messages - firstly that all these studies conclude that intermittent generation does have a capacity credit value greater than zero, and secondly that capacity credit expressed as a percentage of intermittent capacity declines as the penetration of intermittent generation rises[60]. Findings from other capacity credit metrics (see Table 3.10) show the same trends.

There is a moderate amount of convergence within the data available - that is to say that the range of findings narrows slightly as renewables penetration increases.

One study (Commission of the European Union 1992g) (ref.244) does not follow the progressive downward trend of all others. This is thought to be caused by the methodology adopted by this particular study, which displaced specific conventional installations of varying size as more wind generation was modelled on the system.

The findings also demonstrate the sensitivity of the capacity credit to resource availability and the degree of correlation between resource availability and periods of high demand. Capacity credit values are adversely affected where there is a low degree of correlation between resource availability and peak loads. This is particularly well illustrated in an early US study (General Electric and Marsh 1979) (ref.217), which used data from four separate sites in the US. The lowest capacity credit value in this study was from a site with negative correlation between resource availability and load *and* a mismatch between actual wind speeds and wind turbine design speeds. Studies relevant to British conditions, all of which focus on wind power, indicate that output and demand are largely uncorrelated.

The relationship between resource and capacity credit is also demonstrated by studies using data from operating wind farms in a region with low average wind speeds. At each of the penetration levels described above, the low outlying values are from the German studies (DENA Project Steering Group 2005) (ref.74) and (E.ON Netz 2005) (ref.246). The results show the effect that the relatively weak wind resource in Germany has on the capacity credit value (see Ch. 3 for an overview of the relationship between average output and capacity credit). It is not clear why two other German studies - (Auer 2004) (ref.84) and (Commission of the European Union 1992c) (ref.250), produced results that lie within the normal range.

Figure 3.4 presents the distribution of findings at the 10% penetration level. It shows a cluster of findings in the 20 - 25% range, which accords well with recent UK studies reviewed in detail in the UKERC working paper that accompanies this assessment (see Box 3.1). It also indicates that 80% of the findings reviewed here provide estimates of capacity credit in the range 15% - 30%.

It is important to note that there is a direct relationship between the capacity credit and the amount of additional thermal capacity required to maintain reliability. This is because capacity credit is calculated by adding thermal plant in order to maintain a defined standard for reliability such as LOLP (see Ch. 2, box 2.7). The amount of capacity required is also a function of the capacity factor of conventional plant and of intermittent generators[61]. We explore the range of capacities, and associated costs, under a set of assumptions relevant to British conditions in the following section.

[60]Capacity credit will always rise in absolute (or MW) terms, albeit at a declining rate, as wind capacity increases. The declining trend becomes manifest when capacity credit is expressed as the percentage of wind capacity installed.
[61]Additional capacity can be calculated as follows: Additional capacity = (capacity factor intermittent/capacity factor thermal) - (capacity credit intermittent) x 100, %.

3.3.6 The costs and capacities of maintaining reliability with intermittent generation

Defining a convention for cost allocation

There is some controversy over the means by which the cost implications of the relatively low capacity credit of intermittent stations should be calculated. As we discuss in Ch. 2, some analysts consider such costs as manifesting themselves through a reduction in system load factor[62], whilst others have assessed the cost of various forms of 'back up' capacity. In contrast to the system balancing costs discussed in Section 3.3.3, there does not appear to be a generally accepted approach to calculating 'reliability costs'. In fact, many assessments note capacity credit, but do not attempt to derive an associated cost term at all, which is why we are unable to report a cost range in the analysis above.

In order to overcome this difficulty, UKERC have developed a simple formula that makes explicit the additional costs of maintaining reliability[63]. This can be added to the balancing costs discussed in Section 3.3.3 in order to provide a total 'cost of intermittency'.

The formula can be expressed in words as follows:

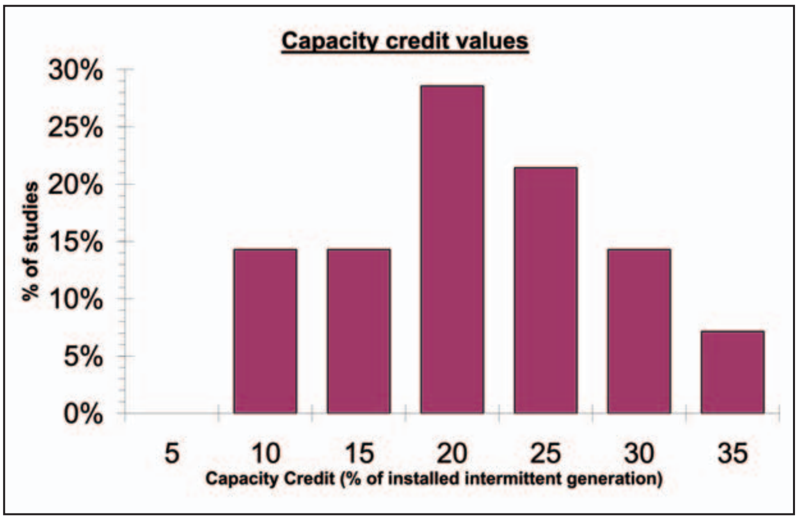
Reliability cost of intermittent generation = Fixed costs of energy equivalent thermal plant minus the avoided fix costs of thermal plant that is displaced by the capacity credit of wind.

In what follows we use this formulation to provide an indication of the range of capacity costs that are associated with a sub-set of the range of capacity credits reported in Section 3.3.5.

Reliability costs under UK conditions

The table below takes a range of capacity credits for 10% and 20% penetration of wind energy from the data assembled in Table 3.10. The range is chosen to represent UK relevant findings, and is also close to the centre of the range of the findings in Figure 3.3. We combined this range of capacity credits with fixed data for total system size, thermal equivalent capacity costs, thermal equivalent capacity factor, and wind capacity factor. These data represent a future least cost thermal comparator, GB electricity system and wind output[64]. In each illustration, the only figures changed are the capacity credit and total wind[65].

Figure 3.4: Frequency distribution of findings for capacity credit where intermittent generation provides 10% of energy



[62]Further work is needed on the means by which these impacts can be quantified in order to allow a transparent comparison of the effects on incumbent generation of adding various types of new generation plant.
[63]See Annex 2 and Ch 2 for the derivation of this formulation.
[64]The data are derived from a recent and widely cited UK study (Dale et al 2003).
[65]This is a simplification, since capacity factor and capacity credit are related variables. Nevertheless the range of capacity credits in Table 3.5 is consistent with the capacity factors and other characteristics reported in the table. It is illustrative of the likely range relevant to UK conditions, and assuming that the predominant intermittent source is wind power. A more thoroughgoing assessment would need to take the relationship between capacity factor and capacity credit into account, see Annex 2 for a more detailed discussion.

This analysis is predicated on the principle that the reliability component of the costs of intermittency can be determined only through a comparison between the contribution of an intermittent generator to reliability and that of a thermal generator which provides the same amount of energy. The *actual* cost of providing system reliability will always be system and context specific. Dedicated peaking plant, maintaining older power stations that can be made available for a small number of peak hours each year, storage, and demand management may all offer the most cost effective means to provide system margin.

Implications for additions to thermal capacity

There is a MW corollary of these cost ranges. The formulation noted in Section 3.3.5[68] would provide the following ranges of additional thermal capacity, expressed as a percent of installed intermittent capacity, assuming the capacity factors and capacity credits as per Table 3.5.

Additional thermal capacity (10% energy from intermittents): 11.2% - 21.8%
Additional thermal capacity (20% energy from intermittents): 15.2% - 22.1%

Zero and low capacity credits

There is widespread consensus about the range of capacity credit relevant to UK conditions. However some British studies explore the possibility of very low or zero capacity credit in recognition of the concerns highlighted in Box 2.8 (Dale et al 2003; Ilex and Strbac 2002). *If capacity credit were zero* and all other characteristics held as per Table 3.5, costs of maintaining reliability would rise to *£9/MWh of wind energy*.

It is also important to note that capacity credits and capacity factors are linked, reflecting the fact that a lower capacity factor is usually associated with a lower capacity credit. Lower capacity factor results in higher costs per unit of output. Non-UK studies, particularly those from Germany noted above, exhibit low capacity factors relative to Britain, and commensurately lower capacity credits. Such conditions result in modest increases in reliability costs - however this is because much larger capacities are needed to supply an equivalent amount of energy, hence *generating costs* and *total costs* rise considerably (we explore a range of capacity factors in annex 2).

Table 3.5: Relationship between capacity credit and reliability cost, GB relevant capacity credits and system characteristics

Wind energy penetration level	**Capacity credit range**	**Reliability cost (£/MWh of wind)**
10% (40 TWh of wind energy, 13 GW of wind installed)	19.4%	£4.76
	30%	£2.44
20% (80 TWh of wind energy, 26.1 GW of wind installed)	19.1%	£4.82
	26%	£3.32
System characteristics[66]		
Total system energy	400 TWh/yr	
Wind capacity factor	35%	
Thermal equivalent capacity factor[67]	85%	
Thermal equivalent cost	£67,000/MW/year	

[66]Assumptions taken from Dale et al 2003, and seeking to represent a future GB electricity system with demand of 400 TWh/yr, a mix of on and off-shore wind, and where CCGT continues to provide the least cost form of new electricity generation plant.

[67]A key principle of this approach is that comparator plant is assumed to be lowest cost new generation. Such plant would be operated at maximum capacity factor (CF), and is assumed here to be CCGT. We use 85% CF as an approximation; in fact some new plant exceeds this. Availability at peak demand is probably higher (above 90%, see National Grid winter outlook report), whilst system load factor (typically around 58%) or that of the entire fleet of CCGT as operated at present (typically around 60%, and affected by gas prices and other market factors) are both lower. The methodology is predicated on a 'like with like' comparison between a new thermal station and intermittent plant, both of which operate at maximum output.

[68]Additional capacity can be calculated as follows: Additional capacity = (capacity factor intermittent/capacity factor thermal) - (capacity credit intermittent) x 100, %.

Implications for the cost of intermittency

This analysis suggests that adding intermittent generation to the British electricity network will impose a capacity/reliability cost of less than £5/MWh with a 20% penetration of intermittent generation, with a range that starts a little above £3/MWh[69]. Section 3.3.2 indicates that the majority of estimates of system balancing costs are also less than £5/MWh, in many cases substantially less, and the range for UK studies is £2 - £3/MWh. Section 3.3.4 also indicates that there may be an efficiency reduction mediated through the electricity market of the order of 1% of the electrical output of intermittent generators. The impact of this on overall costs is likely to be negligible.

Hence, the total cost of intermittency at a 20% penetration on the British electricity network is likely to be in the range of a little under £5/MWh up to around £8/MWh. This range accords well with a range of UK studies reported in Box 3.1.

[69]Assuming that the predominant intermittent option is wind power, and with the other system characteristics described above

Box 3.1 Case study comparison of Capacity and Balancing Costs: Estimates of four well known studies compared to estimates from first principles

A comparative assessment between four key UK studies and the work from first principles undertaken in support of this assessment*. This work provides a review of the statistical approach to estimating provisions for both system balancing and long term reliability. This box is taken from the working paper. It compares the key estimates in the case where there is a high level of wind energy on the system (in the range 15% to 20%).

	Dale et al	SCAR report	Carbon Trust	R.A. Eng.	UKERC working paper
Capacity Factor for Wind, %[a]	35	35	35	35	35
Capacity creidt for wind, MW/MW					
wind capacity, %	19.2	22.9	20.0	Not estd	22.1
Capacity required to ensure reliability					
MW thermal/MW wind, %[d]	18.9	18.3	21.2	65.0	19.1
Cost of this capacity	0.39	0.26	0.45	1.86	0.44
Energy costs of increased variability	0.08	Not estd	Not estd	Not estd	0.05[c]
Balancing costs	0.27	0.22	0.20	Not estd	0.25[b]
Total costs, p/kWh	**0.74**	**0.48[f]**	**0.65**	**1.86**	**0.74**

Source data used in the UKERC working paper is from: (Dale et al 2003), (Ilex and Strbac 2002), (Mott Macdonald 2003), (Royal Academy of Engineering and PB Power 2004). In order to provide a consistent data set adjustments have been made to some variables – for example all figures are presented at a 10% discount rate, which may vary from figures in the originals.

*See Anderson, 2005, Power System Reserves and Costs with Inermittent Generation
http://www.ukerc.ac.uk/content/view/124/105/
Notes: The estimates in each report have been converted to a 10% discount rate: the tables attached to the working paper provide the original estimates at the discount rates thay have used plus further footnotes on assumptions. All costs are in p/kWh.

a Capacity factors for wind are based upon the assumption that roughly half the capacity will be offshore.
b Not an independent estimate, as discussed above, but based on the estimates of the first three eports (the upper estimate in the case of the Carbon Trust).
c The report by Dale et al is based on 20% energy market share for wind, that shown here for the present study is 15%, which partly accounts for the higher estimate in the former.
d Estimated directly by the R.A. Eng. and the present study, and for the other studies inferred from the identity between capacity credit and capacity costs of intermittency presented above. The working paper refers to capacity reserves, terminology has been adapted to ensure consistency with the rest of this report.
f Represents the incremental cost of an increase in from 10% to 20%.

There is reasonable agreement among four of the above five studies. Estimates of the capacity credit range from 19% to 23% of wind capacity. The range of estimates of the overall costs of providing for capacity margin and balancing is from 0.65 to 0.74p/kWh of electricity generated by wind after allowing for transmission losses.

3.4 Discussion of key issues from the quantitative evidence

General comments

Unless the assumptions and characteristics of the system being analysed are very clearly understood there is a danger that the results are misinterpreted, or that invalid comparisons are drawn. It is apparent from analysis of each study that the results of any individual work are sensitive to a set of system characteristics:

- The existing generation mix (in particular the degree of flexibility of existing plant and suitability for part loading, and the rate at which existing plant can increase or decrease output).
- Existing requirements for reserve services for system balancing.
- The spatial distribution of intermittent generation plant.
- The mix of intermittent generation technologies.
- Transmission network constraints and size of links to other networks.
- The absolute level of renewable resource available and the degree of correlation of resource availability with demand peaks and troughs.
- Generating unit commitment time horizon and accuracy of renewable resource forecasting.
- The overall system reliability/security target level.

It is important to note that data limitations, methodological details and scope of impacts/costs may differ between studies. It is only possible for this report to highlight significant outliers and general trends.

Relevance of simulation and empirical studies

The majority of the studies reviewed use simulated data, real data extrapolated or real data run through a range of models. The main exception is experience from Germany's Eon Netz, which tends to show relatively high costs for reserves. Moreover, it has been contended that experience in Denmark and Germany suggests that simulation studies in the UK may have failed to capture the extent of prospective fluctuations[70]. However, it is also important to note that experience cannot supersede simulation if the experience is not directly relevant. We would not conclude (for example) that PV should have a significant capacity credit in the UK because of experience with solar plants in California. It is also important to note that there are important differences between Denmark, Germany and the UK:

- Denmark is a small country and the scope for geographical dispersion is limited. The system must also integrate output from heat demand-constrained CHP plant, and has very high penetration level of wind energy. (Bach 2004; Holttinen 2004; Pedersen et al 2002)
- Denmark is heavily interconnected to both the Nordel and German electricity systems and hence able to manage intermittency in ways unavailable to the UK.
- We have discussed some of the differences between Britain and Germany (most notably the lower capacity factor of German wind farms) and the specific issues that relate to the geography and operating practices of the Eon Netz region. It is also clear that the DENA Grid Study, which looks at a wider geographical area, takes a more optimistic view than Eon Netz.

It is important that key problems are not 'assumed away'. Some existing studies explicitly explore key effects, such as regional concentration of some renewables (Ilex and Strbac 2002). However, others have assumed that wind energy will be geographically dispersed and hence may have failed to identify an important prospective cost. It has been suggested that wind developments tend to cluster in areas with good wind resources, and that in future large individual offshore developments may present problems for system operators[71]. These impacts must be explored in analytic research and monitored as empirical evidence increases.

[70]Hugh Sharman, presentation to the UKERC stakeholder workshop available from http://www.ukerc.ac.uk/content/view/55/67

[71]Ibid and Pers. comm. Hannele Holttinen, 2006

3.5 Summary of key findings

Exactly where in each range of values a particular study falls depends on the penetration level of intermittent generation, the characteristics of the system being modelled, and the methodology adopted by the study.

Summary of impacts on system balancing reserves

The majority of the studies which are applicable to the UK find that up to an intermittent generation penetration level of 20%, the additional reserve requirements imposed on the system are generally less than 10% of the installed capacity of the intermittent generators. The studies which present higher reserve requirements either represent systems which are not directly comparable to the UK or use a methodological approach which is not consistent with widely accepted practice. Different system operation principles, such as determining reserves from day-ahead prediction errors as in Germany, are also relevant. All the studies that present reserve requirements over a range of intermittent generation penetration levels show that the reserve requirement, expressed as a percentage of intermittent generation capacity, will rise as the penetration level increases.

Summary of impacts on system efficiency

Only a small number of studies explicitly address the efficiency losses of thermal plant resulting from intermittent renewable generation. Losses tend to increase as the intermittent generation penetration level rises but the actual losses are small. At the 20% penetration level, the studies present efficiency losses ranging between a negligible level and 7% of intermittent output.

The studies which address energy spilling show that the proportion of energy spilt tends to increase as intermittent generation penetration level rises, but the proportion of energy spilt is relatively small - at penetration levels up to approximately 20%, the spilt energy ranges between zero and less than 7% for all but one of the studies. The remaining study relates to a transmission network-constrained system and concludes that it may be more economic under some circumstances to spill energy rather than dimension the transmission network to cope with extreme generation peaks.

Summary of capacity requirements to ensure reliability: capacity credit

All the studies show that intermittent generation does contribute to system reliability through a positive capacity credit, and that capacity credit expressed as a percentage of intermittent output declines as intermittent generation penetration level rises. The capacity credit value is, however, particularly sensitive to the degree of correlation between resource availability and peak demand periods and to geographical dispersion. This is reflected in the relatively wide range of results at each penetration level. Nevertheless, 80% of the studies concluded that, at the 10% penetration level, the capacity credit lies in the range between 15% and 30%. A significant proportion of the studies do not extend to the 20% penetration range, but most of the studies that do present a capacity credit range between 15% and 20%. Those studies that present lower capacity credit values relate to systems with relatively low resource availability (compared to UK conditions), poor correlation between peak demand and intermittent output, or both.

Summary findings on costs

Over 80% of the studies concluded that the cost of providing additional reserves would be less (and in many cases substantially less) than £5 per MWh of intermittent generation at intermittent generation penetration levels up to, and in some cases exceeding, 20%. British relevant studies fall into the range £2 - £3/MWh. Those studies which present higher costs relate either to systems with much higher penetration levels, or where resource availability is not comparable with Britain, or are based on methodology that is inconsistent with UK regulatory and system operation practices. Costs of maintaining reliability fall into the range £3 - £5/MWh for penetrations up to 20% and under British electricity system and weather conditions.

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3.6 Summary of all findings and data used in Ch. 3

Table 3.6 Summary of additional reserve requirements with intermittent generation

Document reference, author, date and title	Metric type and notes	Penetration level range	Reserve range
26, Watson et al, 1994, Application of wind speed forecasting to the integration of wind energy into a large scale power system	R1, spinning reserve only so numbers not in figure 3.1 Report also has values for higher penetration levels but excluded due to the influence of discarded energy	**9.9-37.9%**	**6.6-24.5%**
51, Mott MacDonald, 2003, Carbon Trust and DTI intermittency survey & roadmap	R1	**10-20%**	**3.3-7.6%**
57, E.ON Netz, 2004, Wind report 2004	R1, appears to include system plant margin requirements	**4%**	**50-80%**
67, Holttinen, 2004, The impact of large scale wind power production on the Nordic electricity system	R1	**5-20%**	**0.8-4.2%**
74, Dena, 2005, Dena grid study	R1	**10-20%**	**8.3-19.4%**
79, Dale et al, 2003, A shift to wind is not unfeasible	R1	**20%**	**5%**
6, Doherty, 2005, A new approach to quantifyreserve demand in systems with significant installed wind capacity	R2	**6-21%**	**3-8.5%**
14, Doherty & O'Malley, 2003, Quantifying reserve demands due to increasing wind power penetration	R2	**13-31%**	**3-7%**
42, Dragoon and Milligan, 2003, Assessing wind integration costs with dispatch models: A case study with PacifiCorp	R2 (figure is for % increase in reserve)	**3-23.8%**	**2-103%**
117, Kema-xenergy, 2004, Intermittent wind generation: summary of report of impacts on grid system operations	R2	**10%**	**0.6%**
178, Doherty, 2004, Wind penetration studies on the island of Ireland	R3	**N/A**	**25%**
186, Milligan, 2001, A chronological reliability model to assess operating reserve allocation to wind power plants	R3	**N/A**	**11-20%**
219, Farmer at al, 1980, Economic and operational implications of a complex of wind-driven generators on a power system	R3, values based on 5-10GW of wind capacity. UK total capacity in 1980 was approximately 63GW	**N/A**	**7-16%**
239, Royal Academy of Engineering & PB Power, 2004, The cost of generating electricity	R3, appears to include system plant margin requirements	**N/A**	**65%**
104, GE Energy Consulting, 2005, The effects integrating wind power on transmission system planning, reliability and operations	R4, figures based on of hourly variation	**10%**	**4.7%**

173, Electric Systems Consulting ABB Inc, 2004, Integration of wind energy into the Alberta electric system - stage 4: operations impact	R4, report described as preliminary analysis and does not use the 'sum of squares' rule to combine demand and wind variance	**13.3%**	**10-40%**
191, Milligan, 2003, Wind power plants and system operation in the hourly time domain	R4, values are for the additional load following requirement imposed by having wind generators on the system	**5.7-22.7%**	**3.4-12.4%**
229, Hudson at al, 2001, The impact of wind generation on system regulation requirements	R4, value is for 'regulation' only (frequency response)	**4.5%**	**0.2%**

Metric description	Number of studies
R1: Percentage of installed intermittent generation capacity, where intermittent penetration level is expressed as the percentage of *total system energy* from intermittent generation.	6
R2: Percentage of installed intermittent generation capacity, where intermittent penetration level is expressed as the percentage of *total system installed capacity* from intermittent generation.	4
R3: Percentage of installed intermittent generation capacity, but *no penetration level given*.	4
R4: Percentage of installed intermittent generation capacity, where intermittent penetration level is expressed as the installed intermittent generation capacity as a percentage of *peak system load*.	4
Total	18

Table 3.7 Summary of findings relating to reserve costs

Document reference, author, date and title	Metric type and notes	Penetration level range	Reserve cost range
51, Mott MacDonald, 2003, Carbon Trust and DTI intermittency survey & roadmap	RC1	**10-20%**	**£1.7-£2.9**
67, Holttinen, 2004, The impact of large scale wind power production on the Nordic electricity system	RC1	**10-20%**	**£0.6-£1.3**
79, Dale et al, 2003, A shift to wind is not unfeasible	RC1	**10-20%**	**£2.5-£3.0**
83, Ilex & Strbac, 2002, Quantifying the system costs of additional renewables in 2020	RC1, incremental cost of moving from 7% to 17% & 27%, figures are for reserve costs but this report does have figures for capacity costs as well. Figures are for the 'north wind, high demand' scenario.	**17-27%**	**£2.3-£2.7**
89, Milborrow, 2004, Assimilation of wind energy into the Irish electricity network	RC1	**5-20%**	**£0.6-£1.6**
95, Bach, 2004, Costs of wind power Integration into Electricity Grids: Integration of Wind Power into Electricity Grids Economic and Reliability Impacts	RC1	**21%**	**£5.6-£8.5**
125, Ilex at al, 2004, Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System	RC1, figures derived from modelling individual days, not whole year - these are the highest cost days (for some scenarios the cost is negative)	**8-17%**	**£0.15-£0.6**
129, Pedersen, 2002, Present and future integration of large scale wind power into Eltra's power system	RC1	**16.3%**	**£1.8**
132, Milborrow, 2001, Penalties for intermittent generation sources	RC1	**10-45%**	**£1.5-£3.3**
187, Seck, 2003, GRE wind integration study	RC1	**2.4-9.5%**	**£2.1-£2.9**
193, Hirst, 2002, Integrating wind energy with the BPA power system: preliminary study	RC1	**6%**	**£1.1-£1.7**
199, Hirst, 2001, Interactions of wind farms with bulk-power operations and markets	RC1, numbers are for 'regulation' (frequency response) and load following only	**0.1%**	**£0.6-£2.3**
206, Fabbri et al, 2005, Assessment of the Cost Associated With Wind Generation Prediction Errors in a Liberalized Electricity Market	RC1, figures are the market costs of procuring the difference between predicted and actual generation	**4%**	**£4.3-£4.8**
232, Dale, 2002, NETA and wind	RC1	**2-10%**	**£0.1-£2.4**
235, Milborrow, 2005, Windstats newsletter	RC1, figure derived from analysis of the E.ON Netz study	**6%**	**£8.1**
22, Doherty et al, 2004, System operation with a significant wind power penetration	RC2	**17.6%**	**£0.18-£0.89**

42, Dragoon and Milligan, 2003, Assessing wind integration costs with dispatch models: A case study with PacifiCorp	RC2, numbers are for load following and unit commitment only	**20%**	**£3.5**
45, EnerNex and Wind Logics, 2004, Xcel Energy and the Minnesota Department of Commerce Wind Integration Study - Final Report Wind integration study - final report	RC2	**13.1%**	**£2.6**
46, Xcel Energy, 2003, Characterizing the impacts of significant wind generation facilities on bulk power systems operations planning	RC2	**3.5%**	**£1.2**
239, Royal Academy of Engineering & PB Power, 2004, The cost of generating electricity	RC3, appears to include system plant margin requirements	**N/A**	**£17.5**
84, Auer, 2004, Modelling system operation cost and grid extension cost for different wind penetrations based on GreenNet	RC4, figures are for reserve costs but this report does have figures for capacity costs as well	**5.1-30.4%**	**£0.04-£1.0**
151, Brooks et al, 2004, Quantifying System Operation Impacts of Integrating Bulk Wind Generation at We Energies	RC4	**4-289%**	**£1.1-£1.6**
229, Hudson at al, 2001, The impact of wind generation on system regulation requirements	RC4, value is for ‘regulation’ only (frequency response)	**4.5%**	**£0.04**

Metric description	Number of studies
RC1: Cost per MWh of electricity from intermittent generation, where penetration level is expressed as the percentage of *total system energy* provided from intermittent generation.	15
RC2: Cost per MWh of electricity from intermittent generation, where penetration level is expressed as the percentage of *total system installed capacity* from intermittent generation.	4
RC3: Cost per MWh of electricity from intermittent generation, but *no penetration level given*.	1
RC4: Cost per MWh of electricity from intermittent generation, where intermittent penetration level is expressed as the installed intermittent capacity as a percentage of *peak system load*.	3
Total	23

Table 3.8 range of findings for fuel and carbon dioxide savings metrics

Document reference, author, date and title	Metric type and notes	Penetration level range	Fuel/CO2 savings
22, Doherty et al, 2004, System operation with a significant wind power penetration	C1, lower value is for fuel saver mode, higher value is for forecast mode	**17.6%**	**9-20%**
181, Denny and O'Malley, 2005, Wind Generation, Power System Operation and Emissions Reduction	C1	**5.4-10.5%**	**3.5-9%**
26, Watson et al, 1994, Application of wind speed forecasting to the integration of wind energy into a large scale power system	C2	**9.9-48.3%**	**0-48%**
79, Dale et al, 2003, A shift to wind is not unfeasible	C2	**20%**	**1%**
221, Whittle, 1981, Effects of wind power and pumped storage in an electricity generating system	C2	**2.5%**	**5%**
50, BWEA, 2005, Blowing Away the Myths	C3	**N/A**	**860g/kWh**
125, Ilex at al, 2004, Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System	C4, figures derived from modelling individual days, not whole year - these are the peak demand days	**8-17%**	**4.4-10.2%**
222, Halliday et al, 1983, Studies of wind energy integration for the UK national electricity grid	C5	**15-42%**	**5-7%**
223, Gardener and Thorpe, 1983, System integration of wind power generation in Great Britain	C6	**20-60%**	**16-34%**
67, Holttinen, 2004, The impact of large scale wind power production on the Nordic electricity system	C7, lower figure is based on wind displacing mainly CCGT plant, higher figure based on displacing mainly coal plant	**4-12%**	**300-700g/kWh**

Metric description	Number of studies
C1: Total CO2 savings in percentage terms, where penetration level is expressed as the percentage of *total system installed capacity* provided from intermittent generation.	2
C2: Reduction in CO2 savings (when compared to theoretical maximum savings), where penetration level is expressed as the percentage of *total system energy* provided from intermittent generation.	3
C3: CO2 savings per kWh of electricity from intermittent generation, but *no penetration level given*.	1
C4: Total CO2 savings in percentage terms, where penetration level is expressed as the percentage of *total system energy* provided from intermittent generation.	1
C5: Reduction in CO2 savings (when compared to theoretical maximum savings), where penetration level is expressed as the percentage of *total system installed capacity* provided from intermittent generation.	1
C6: Total CO2 savings in percentage terms, where penetration level is expressed as the percentage of *peak system energy demand* provided from intermittent generation.	1
C7: CO2 savings per kWh of electricity from intermittent generation, where penetration level is expressed as the percentage of *total system energy* provided from intermittent generation.	1
Total	10

Table 3.9 range of findings for energy spilling metrics

Document reference, author, date and title	Metric type and notes	Penetration level range	Energy Spilt
18, Sveca and Soder, 2003, Wind Power Integration in Power Systems with Bottleneck Problems	ES1	**3-11%**	**1.9-16.7%**
178, Doherty, 2004, Wind penetration studies on the island of Ireland	ES1	**13-38%**	**0-40%**
222, Halliday et al, 1983, Studies of wind energy integration for the UK national electricity grid	ES1	**15-42%**	**2-45%**
26, Watson et al, 1994, Application of wind speed forecasting to the integration of wind energy into a large scale power system	ES2	**9.9-48.3%**	**0-39.2%**
132, Milborrow, 2001, Penalties for intermittent generation sources	ES2	**10-15%**	**0.1-0.7%**
223, Gardener and Thorpe, 1983, System integration of wind power generation in Great Britain	ES3	**20-60%**	**2-56%**

Metric description	Number of studies
ES1: Percentage of intermittent generation output which must be spilled, where penetration level is expressed as the percentage of *total system installed capacity* provided from intermittent generation.	3
ES2: Percentage of intermittent generation output which must be spilled, where penetration level is expressed as the percentage of *total system energy* provided from intermittent generation.	2
ES3: Percentage of intermittent generation output which must be spilled, where penetration level is expressed as the percentage of *peak system energy* demand provided from intermittent generation	1
Total	6

Table 3.10 Range of findings for capacity credit

Document reference, author, date and title	Metric type and notes	Penetration level range	Capacity credit range
17, Watson, 2001, Large scale integration of wind power in an island utility - an assessment of the likely variability of wind power production in Ireland	CC1	**20.5%**	**16.6%**
51, Mott MacDonald, 2003, Carbon Trust and DTI intermittency survey & roadmap	CC1	**10-20%**	**27.5-20%**
74, Dena, 2005, Dena grid study	CC1	**10-20%**	**7.7-6%**
79, Dale et al, 2003, A shift to wind is not unfeasible	CC1	**20%**	**19.1%**
83, Ilex & Strbac, 2002, Quantifying the system costs of additional renewables in 2020	CC1, Figures are for the 'north wind, high demand' scenario.	**17-27%**	**22.9-18.4%**
121, Giebel, 2000, The capacity credit of wind energy in Europe, estimated from reanalysis data	CC1	**20%**	**19.3%**
160, Holt et al, 1990, CEC Wind energy penetration study	CC1	**2-15%**	**31-15.6%**
204, Grubb, 1991, The integration of renewable electricity sources	CC1	**5-38%**	**35-19.3%**
238, Martin & Carlin, 1983, Wind-load correlation and estimates of the capacity credit of wind power: An empirical investigation.	CC1	**5-20%**	**35.2-15.1%**
240, EC, 1992, Wind power penetration study, the case of Denmark[72]	CC1	**5-15%**	**30-20%**
241, Danish Energy Ministry, 1983, Vindkraft I Elsystemet	CC1	**5-15%**	**23-11%**
242, EC, 1992, Wind power penetration study, the case of Greece	CC1	**2.5-15%**	**38-17%**
243, EC, 1992, Wind power penetration study, the case of The Netherlands	CC1	**5-15%**	**20-13%**
244, EC, 1992, Wind power penetration study, the case of Spain	CC1	**1.5-15%**	**10-15.6%**
246, E.ON Netz, 2005, Wind report 2005	CC1	**4.7-12.5%**	**8-4.8%**
247, Sinden, 2005, Wind power and the resource	CC1	**10%**	**23.1%**
248, EC, 1992, Wind power penetration study, case of Portugal	CC1	**7.8-30.6%**	**36.5-22.9%the**
249, EC, 1992, Wind power penetration study, the case of Italy	CC1	**2.5%**	**22.6%**
250, EC, 1992, Wind power penetration study, the case of Germany	CC1	**10%**	**15%**
84, Auer, 2004, Modelling system operation cost and grid extension cost for different wind penetrations based on GreenNet	CC2	**5.1-30.4%**	**35.2-22.9%**

[72]Numbers for the EC Commission and Danish Energy Ministry reports were taken from (Giebel 2005), their derivation checked with the author of that study, and cross-checked to the corresponding UK study (Holt et al 1990).

104, GE Energy Consulting, 2005, The effects of integrating wind power on transmission system planning, reliability and operations	CC2, the report has a much higher capacity credit value of 36% for a single offshore site	**10%**	**10%**
203, Wan & Parsons, 1993, Factors relevant to utility integration of intermittent	CC2	**1-10%**	**41-15%**
45, EnerNex and Wind Logics, 2004, Xcel Energy and the Minnesota Department of Commerce Wind Integration Study - Final Report Wind integration study - final report	CC3	**3.5-13.1%**	**33.8-26.7%**
59, Royal Academy of Engineering, 2003, Response to the House of Lords Science and Technology committee inquiry into the practicalities of developing renewable energy	CC3	**11.6-31.3%**	**26.7-16%**
117, Kema-xenergy, 2004, Intermittent wind generation: summary of report of impacts on grid system operations	CC3	**4.8%**	**25.9-0%**
217, GE & Marsh, 1979, Requirements assessment of wind power plants in electric utility systems	CC3, covers 4 different sites	**5-20%**	**5-2%** **22-6%** **37-17%** **47-28%**
133, Garrad Hassan and Partners, 2003, The impacts of increased levels of wind penetration on the electricity systems of the Republic of Ireland and Northern Ireland	CC4, value based on up to 800MW of wind capacity. Island of Ireland systems total capacity is approximately 7.5GW	**N/A**	**20%**
137, Milligan, 2001, Factors relevant to incorporating wind power plants into the generating mix in restructured electricity markets	CC4	**N/A**	**21-51%**
212, Milborrow, 1996, Capacity credits - clarifying the issues	CC4, results from several earlier studies	**N/A**	**58-7%**

Metric description	Number of studies
CC1: Percentage of installed intermittent generation capacity, where penetration level is expressed as the percentage of *total system energy* provided from intermittent generation.	19
CC2: Percentage of installed intermittent generation capacity, where penetration level is expressed as intermittent generation capacity as a percentage of *peak system load*.	3
CC3: Percentage of installed intermittent generation capacity, where penetration level is expressed as the percentage of *total system installed capacity* provided from intermittent generation.	4
CC4: Percentage of installed intermittent generation capacity, but *no penetration level given.*	3
Total	29

Conclusion

This report is the product of a systematic review of the literature on the costs and impacts of intermittent generation. It seeks to provide an overview of the main results of the review, together with a non-technical exposition of the key principles of electricity network operation. It is international in scope but draws out the key findings relevant to the British electricity network. It assesses the integration of intermittent renewables in the immediate future and on the basis of incremental change to electricity network design and operation. Its principal conclusions are summarised below.

4.1 The impacts of integrating intermittent generation

None of the studies reviewed in our assessment suggest that intermittency is a major obstacle to the integration of renewable sources of electricity supply.

Almost all of the literature deals with the impacts of intermittency using a statistical representation of the main factors, or through simulation models based upon statistical principles. At the levels of penetration foreseeable in the next 20 years, it is neither necessary nor appropriate to allocate dedicated 'back up' or reserve plant to individual renewable generators when these are integrated into modern electricity networks. Nevertheless additional capacity is likely to be needed, and operational changes will need to be made.

The primary impacts and costs introduced through connecting increasing amounts of intermittent supply arise from *additional system balancing actions* and the need to install or maintain *capacity to ensure reliability of supplies*. Such costs cannot be assessed without a *counterfactual* that permits the costs of intermittent sources to be compared to those imposed by conventional generation making an equivalent contribution to energy and reliability.

4.2 The costs of integrating intermittent generation

System balancing costs

For intermittent penetrations of up to 20% of electricity supply most studies estimate that costs are less than £5/MWh of intermittent output, in some cases very substantially less. The range in studies relevant to Britain is £2 - £3/MWh. These costs arise from the need to schedule additional response and reserve plant to manage unpredicted fluctuations on the timescale from minutes to hours. Additional system balancing reserves represent no more than 5-10% of installed wind capacity in the vast majority of cases. System balancing services are purchased directly by the system operator, and additions can be calculated directly using statistical techniques. They are not controversial, and although there is a range of estimates in the literature the reasons for the range are well understood.

System balancing will also be undertaken by market participants as prices change in response to predicted fluctuations in intermittent output. This, together with the additional system balancing actions under the control of the system operator, may affect the efficiency with which thermal generators operate and hence give rise to costs. These costs may be revealed through markets or calculated using system simulations. Most studies find that efficiency losses are a small fraction of the energy output of intermittent generators; typically no more than a few percent.

The costs of maintaining reliability

Our analysis suggests that adding intermittent generation to the British electricity network will impose a capacity/reliability cost of less than £5/MWh with a 20% penetration of intermittent generation, with a range that starts a little above £3/MWh. This range is based upon results relevant to Britain revealed in our review of the literature, and uses the convention for costing the impact of intermittency on reliability that we describe in section 4.4 below.

These costs arise because the amount of capacity required to meet a given measure of reliability will increase when intermittent generation is added to an electricity network. Intermittent generators are, generally speaking, less certain to be generating power at times of peak demand than conventional generators. *Capacity credit* is a measure of the contribution that intermittent generation can make to available capacity at times of peak demand. It is expressed as a percentage of the maximum instantaneous output of the generators. There is a range of estimates for capacity credits in the literature and the reasons for there being a range are well understood. The range of findings relevant to British conditions is approximately 20 - 30% of installed capacity when up to 20% of electricity is sourced from intermittent supplies. In percentage terms, capacity credit falls as the intermittent generation penetration level rises.

Capacity credit and additional conventional capacity required to maintain a given level of reliability are corollaries. The smaller the capacity credit, the more capacity will be needed to maintain reliability. This in turn determines the reliability costs highlighted above. In addition, capacity credit expressed as a percentage of installed intermittent capacity declines as the share of electricity supplied by intermittent sources increases. For this reason costs also increase as penetration of intermittent generation rises.

The total costs

Total costs of intermittency comprise system balancing costs plus the costs of maintaining reliability. In Britain these are likely to lie in the range £5 - £8/MWh (0.5p - 0.8p/kWh) of intermittent output. This range is sensitive to a number of factors, as we discuss below.

4.3 Factors that affect the costs of integrating intermittent generation

System balancing

Smoothing through aggregation and better forecasting decreases costs:
System balancing costs will tend to be higher if the output of intermittent generators fluctuates more rapidly or more substantially over short time periods, if fluctuations are less predictable or if decreases in renewable output and increases in consumer demand correlate strongly. System operators are concerned primarily with *aggregate* fluctuation, potentially from large numbers of generators. Decreasing the correlation between the output of individual generators decreases aggregate fluctuation, effectively *smoothing* outputs. This means that wide geographical dispersion and a diversity of renewable sources tends to decrease system balancing costs. Interconnection between regions can further decrease costs. Conversely, geographical concentration will increase cost, and it may be that wind developments tend to cluster in regions with the best resource. Much larger individual wind farms could be developed, particularly offshore, increasing the fluctuation seen at an individual connection point. Both factors need further research.

The nature of conventional plant and regulatory practice affect costs:
The characteristics of renewable sources are not the only determinant of system balancing impacts. The nature of thermal plants operating on the system and regulatory practices are also relevant.

– If system balancing actions are determined close to real time (known as 'gate closure', which occurs one hour before time in Britain) system balancing costs are minimised, since intermittent output can be forecast with a high degree of accuracy at such timescales. In countries where balancing decisions are made a long period ahead of time (gate closure is up to a day ahead in some regions) forecasting, and indeed demand fluctuations and failures of conventional plants, is much less accurate. Reserve costs rise as a result.

– In general terms, relatively small and flexible plants assist the integration of intermittent renewables and reduce balancing costs. A large penetration of inflexible thermal generating units would make it more difficult to absorb large amounts of renewable output and increase the likelihood of intermittent output being curtailed. Large single generating units can also have a significant impact on reserve requirements, since the system needs to be able to cope with the sudden failure of the largest generating unit. This requirement will usually have a much larger impact on system balancing reserves than the fluctuations introduced by renewable generators.

Capacity to maintain reliability

Output over peak periods is the principal determinant of the cost to maintain reliability:
The costs for maintaining reliability at times of peak demand are determined by the capacity credit of intermittent generators. This depends upon average output during peak periods, the geographical dispersion of generators and the relationship between fluctuations in electricity demand and intermittent output.

Correlations between peak output and peak demand can either increase or decrease capacity credit:
Strong positive correlations can lead to high capacity credit. At the other extreme, if peak demand always correlates with low or zero output, capacity credit would be very low or zero.

Where demand and intermittent output are uncorrelated, average output and the distribution of output over peak periods determines capacity credit:
Other things being equal, higher average output will lead to higher capacity credit. The wider the variance of output the lower the capacity credit. Variance is reduced through geographical dispersion and diversifying the range of intermittent sources utilised.

In all cases, capacity credit is a *derived term* and cannot be calculated independently of a wider assessment of system reliability. It is context and system specific.

It is also important to note that *all types* of generating plant have the potential to affect the utilisation of incumbent generation plant. More work is needed to provide a transparent methodology for assessing these impacts and how they differ between technology types.

4.4 Confusion and controversy

A number of factors give rise to confusion in the literature, and may be one reason for ongoing debate on the subject of intermittency.

There is a widespread tendency for terminology to be used in different ways:
Words can be given multiple meanings. A good example is the use of 'reserve'. In some studies 'reserve' is specifically operational reserve, used for short term balancing. In others it also denotes the 'back up' capacity required to maintain reliability because intermittent generators have capacity credits lower than their capacity factors. We contend that this confusion over language gives rise to widespread misunderstanding. It can result in inappropriate cost comparisons across studies and give rise to ongoing confusion and disagreement.

The literature also exhibits a wide range of metrics through which the costs and impacts of reserve and balancing issues are expressed. This makes cross comparison hazardous, which also serves to perpetuate conflict and debate.

There has been some controversy over how to estimate the costs associated with the additional thermal capacity required to maintain reliability:
Some studies have assessed the costs of the capacity required to maintain reliability based on assumptions about the nature of plant providing 'system reserves'. Others have assessed only the change in the total costs of the electricity system as a whole. There is broad agreement between both approaches on the total change to system costs[73].

We recommend that the 'reliability cost of intermittency' be defined as follows:
The additional cost of adding a unit of intermittent generation to an electricity system, over and above the direct costs of investing in and operating the intermittent generator, compared with the cost of building and operating conventional generating plant at base load. This can also be expressed as: Reliability cost equals the fixed cost of energy-equivalent thermal plant (e.g. CCGT) minus the avoided fixed cost of thermal plant (e.g. CCGT) displaced by capacity credit of wind[74].

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[73]There is a range of costs associated with 'back up' and the range arises from differing assumptions on the nature of the plant that provides reliability. Analysts have also assessed the impact on system load factors and used this to derive an estimate of costs. Both approaches are based upon a systemic approach, not dedicated 'back up' for individual intermittent generators. Studies that assume 'dedicated' back up is needed give rise to much higher costs.

[74]This range uses the cost allocation methodology described in Ch 3 and Annex 2, assumes that the predominant intermittent option is wind power, and with the other system characteristics as described in Ch 3.

The comparison with conventional generating plant at baseload is crucial to the calculation. Policymakers and others often seek to compare the average costs of different types of generating plant on a 'like with like' basis – for example the cost of wind power compared to the cost of coal power. This usually uses levelised costs (£/MWh). If intermittency costs are calculated any other way meaningful comparisons of this nature are impossible.

4.5 Recommendations for policy

We recommend that additional steps are put in place to continuously monitor the effect of intermittent generation on system margin and existing measures of reliability. The effectiveness of market mechanisms in delivering adequate system margin also need to be kept under review.

Policies need to encourage widespread geographical distribution of intermittent generators if the costs of intermittency are to be minimised. A judgement is needed on the relative costs of intermittency and transmission upgrading. This cannot be done without the development of detailed scenarios recommended below.

Intermittent generation can make a valuable contribution to energy supplies but, to ensure reliability of supply, investment in thermal capacity is also required. In the short run older plant may provide system margin but, in the long run, investment in new capacity will be needed. Flexible and reliable generation is an ideal complement to intermittent renewables. Policy should encourage and not impede investment in plant that is well suited to complement renewable energy sources and contribute to both reliable operation and efficient system balancing.

4.6 Issues for further research

In some countries wind development has clustered in specific geographical regions, and problems have been highlighted recently by some system operators. Some of the literature *assumes* wide geographical dispersion. The impacts of geographical clustering, its likelihood and interaction with transmission cost issues needs to be better understood. Related to this, much larger individual wind farms are envisaged, particularly offshore. The implications of their fluctuations need to be better understood.

The risk of demand being unmet is characterised statistically, and the measure commonly used to quantify this risk is called Loss of Load Probability (LOLP). This measure defines the likelihood that some load is not served, and the normal convention in advanced electricity networks is that LOLP is kept very small. This is done by ensuring that the generation capacity on the system exceeds peak demand by some amount, known as the system margin.

There is some debate over the extent to which existing measures of reliability, particularly LOLP, fully capture the changes that arise when intermittent sources are added to the network. This is because intermittent generation changes the nature of the statistics used to calculate risk, and not all of these changes are represented within existing measures of reliability.

Most of the studies reviewed in this report take an incremental approach and assess the impacts of intermittent generation on existing electricity networks. Optimisation of operating practices, development of electricity systems and new technologies designed to facilitate the integration of intermittent sources could radically reduce the costs of integrating intermittent generation. Conversely, some technologies and practices are not well suited to the efficient integration of intermittent generation. Analysis through modelling and scenarios could assist our understanding of the prospects for this.

We recommend that more research is therefore undertaken on the following topics:

– Renewable energy deployment scenarios in which intermittent generation is clustered in particular regions of the UK and analysis of the impacts on electricity networks of very large individual wind farms.

– Measures of reliability appropriate to intermittent sources. In particular the merits of, and options for, going beyond 'loss of load probability' (LOLP) in characterising the reliability of an electricity system at high levels of intermittent generation. LOLP measures the likelihood of a capacity shortfall rather than its severity.

– Using these improved measures of reliability, there is a need for on-going monitoring of the British electricity market to assess how actual market response (i.e. decisions to invest in new generation or maintain existing generation in-service) compare to those that would be consistent with the improved reliability measures.

– The definition of an agreed convention for reporting the costs associated with maintaining system reliability.

– Further work on the development of methodologies for assessing the system cost implications of new generating technologies (intermittent or otherwise), in terms of the impacts on the utilisation of incumbent generation.

– The extent to which intervention may be needed to ensure that adequate investment in appropriate thermal plant to maintain reliability is delivered, and the policy options available to do so.

– The implications of different combinations of thermal plant on the costs and impacts of integrating renewable energy in the short to medium term. In particular, the relative impacts of different sizes and types of thermal generation, and of inflexible versus flexible plant, on efficiency of system operation and integration of wind and other renewables.

– Options for managing the additional power fluctuations on the system due to intermittency – including new supply technologies, the role of load management, energy storage etc.

– Opportunities and challenges for re-optimisation of the electricity system in the long term to cope with intermittent generation, including research on much higher penetrations of renewable sources than the relatively modest levels considered in this report.

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Annex 1: Project team, expert group and contributors

Project team

The team was drawn from the EPSRC-funded Supergen Future Network Technologies Consortium, operating under the management of ICEPT at Imperial College, who run the TPA function of the UKERC. The team is as follows:

Director: Jim Skea, UKERC Research Director
Project Manager: Robert Gross, TPA Manager
Principal Contributors: Dennis Anderson, Tim Green, Matt Leach
Researchers: Philip Heptonstall, Sree Payyala

Expert group

The expert group was chosen for its combination of economic, energy policy and engineering expertise and to provide a diverse perspective. It met three times during the course of the project, providing input to the initial framing of the issues, literature search, synthesis and drafting. Several members of the group made additional contributions in the form of reference provision, invited submissions on particular issues and through bilateral interviews on specific areas of expertise.

Nick Hartley, Oxera - Expert Group Chair
Lewis Dale, National Grid Plc
Michael Laughton, QMW College & The Royal Academy of Engineering
David Milborrow, independent consultant
Mark O'Malley, University College Dublin
Phil Ruffles, The Royal Academy of Engineering
Goran Strbac, University of Manchester (since joined Imperial College London)

Peer reviewers

Hannele Holttinen, VTT Finland
Michael Milligan, National Renewable Energy Laboratory, USA

Stakeholder workshop attendees

Adrian Bull	BNFL
Richard Ford	BWEA
Michael Grubb	Cambridge/Carbon Trust/Imperial College
Karsten Neuhoff	Cambridge University
David Vincent	Carbon Trust
Andrew Henderson	Ceasa, Spain
Simon Watson	CREST, Loughborough University
Fred Starr	DG-JRC Institute of Energy, NL
Janusz Bialek	Edinburgh University
Nick Eyre	EST
Doug Parr	Greenpeace
Tim Green	Imperial College
Sree Payyala	Imperial College
Matthew Leach	Imperial College
Dennis Anderson	Imperial College/UKERC

Robert Gross	Imperial College/UKERC
Hugh Sharman[75]	Incoteco
David Milborrow	Independent
Antony Price	Institute of Civil Engineers
Ronnie Belmans (sent sub.)	Katholieke Universiteit Leuven, Belgium
Lewis Dale (sent sub.)	National Grid
Ben Willis	Npower
Steven Argent	Ofgem
Bob Everett	OU
Nick Hartley	Oxera
Graham Sinden[76]	Oxford University
Nick Mabey	Prime Minister's Strategy Unit
Michael Laughton	QMW College London
Richard Plozchek	RAEng
Gaynor Hartnell	Renewable Power Association
Walt Patterson	RIIA
Alan Laird	Scottish Power
Chris Bronsdon	Scottish, Executive, Estrata Ltd
Mark Barrett	SENCO
Jim McDonald (sent sub.)	Strathclyde University
Gordon MacKerron	Sussex Energy Group
Steve Sorrell	Sussex Energy Group/UKERC
Mark O'Malley	UCD, Ireland
Jim Skea	UKERC
Goran Strbac	University of Manchester
David Andrews	Wessex Water

[75]Delivered a presentation 'Planning for intermittency', available on the UKERC website http://www.ukerc.ac.uk/content/view/124/105/

[76]Delivered a presentation 'Assessing the costs of intermittent power generation', available on the UKERC website http://www.ukerc.ac.uk/content/view/124/105/

Annex 2: Costs of maintaining system reliability

Two distinct strands of thought can be found in the literature on how to conceptualise the costs associated with any additional capacity required to maintain reliability when intermittent generators are added to an electricity network. The first does not explicitly define a 'capacity cost' rather it assesses the overall change in system costs that arises from additional capacity. The second includes an explicit 'capacity cost', which can be estimated provided we know or make an assumption about the nature of the plant that provides 'back up'. In a working paper that accompanies this report a simple algebraic exposition is developed of both configurations which allows both techniques to be reconciled[77]. We provide a short description here:

1. Total system cost approach. This approach compares a *system* with intermittent stations with an equivalent (same energy output, same reliability) system without such generation in place. On this view the cost of accommodating the lower capacity credit of intermittent stations is manifest through a depression of the load factors of the conventional plant on the system. Whilst more plant (intermittent plus conventional) is required than would be the case in the absence of intermittent stations, this approach does not attempt to directly attribute 'capacity reserves' due to intermittent stations (Dale et al 2003; Milborrow 2001).

This approach is fully consistent with the systematic approach explained earlier in Ch. 2, and provides an estimate of the total cost of intermittent generators without being drawn into any controversy about the nature or need for any 'reliability back up' plant and the attribution of costs to particular aspects of intermittency. The approach derives the *total* change in system costs which result from replacing a proportion of thermal generating plant (e.g. CCGT) with intermittent generation (e.g. wind). It can be expressed in the simplest terms as follows:

<u>Change in system costs = cost of building and operating intermittent plant - fuel saved by wind - avoided fixed cost of thermal plant displaced by capacity credit of intermittent plant</u>

The procedure is:

i. Start with the fixed and variable costs of the intermittent generating plant
ii. Add system balancing costs, and any efficiency losses caused by intermittency
iii. Subtract the thermal generation variable costs avoided (primarily fuel cost savings)
iv. Subtract the fixed costs avoided due to being able to retire[78] some of the thermal plant (this is the *benefit* of the capacity credit of the wind)
v. The remainder is the change in system cost

The main limitation of the approach is that it produces a figure for the change in total system costs that includes but does not specifically identify the costs attributable to the lower capacity credit of intermittent compared to conventional stations. In other words, it does not explicitly identify the 'capacity deficit' cost. An alternative approach does attempt to derive this cost:

2. Capacity reserve approach. This approach conceptualises the impact of the lower capacity credit in the form of additional 'capacity reserve' put in place to ensure reliability. Using this approach, costs are assessed by costing the provision of 'back up' or 'capacity reserve' sufficient to close any gap between the capacity credit of intermittent stations and that of conventional generation that would provide the same amount of energy. This approach may be expressed in the most simple terms as follows:

<u>Change in system costs = cost of building and operating wind + cost of intermittency - fixed cost and variable cost of energy-equivalent CCGT</u>[79]

i. Start with the fixed and variable costs of the wind generating plant
ii. Add system balancing costs, and any efficiency losses caused by intermittency
iii. Add the capacity cost (this is the *cost* that will arise if the capacity credit of wind is lower than its capacity factor[80])
iv. Subtract the fixed and variable costs of energy-equivalent CCGT generation
v. = Change in system cost

[77]UKERC Working paper available at http://www.ukerc.ac.uk/content/view/124/105/

[78]To use precise economic terms; the long run marginal costs saved by non-replacement of existing capital stock.

[79]This is the thermal plant that would provide the same amount of energy as the wind plant at minimum cost. As an approximation we assume this is CCGT operating at baseload capacity factor - see UKERC Working paper available at http://www.ukerc.ac.uk/content/view/124/105/

[80]NB this is *usually* the case, but it is not necessarily true, since it is possible to imagine intermittent stations with outputs at peak periods that are both highly dependable and higher than average annual output.

This approach may give rise to controversy because line (iii) may be derived using a range of methods and assumptions about the nature and amount of 'back up' that is needed. This is because cost estimates provided will vary according to assumptions about the nature of the plant that provides 'back up'. Also, in the absence of a central planner, it is not clear by what means such plant is provided. Different assumptions are found in the literature, ranging from, for example, the capital and operating costs of new gas-fired peaking plant, projected future costs of storage devices, or the maintenance and operating costs of retaining old power stations that would otherwise be retired. (Ilex and Strbac 2002; Milborrow 2001; Royal Academy of Engineering and PB Power 2004).

3. Reconciliation. In principle both approaches should arrive at the *same* change in system costs. Therefore, a simple identity can be derived that can be rearranged in order to allow the derivation of the capacity credit related cost of intermittency. Algebraic derivation of this term is provided in a working paper that accompanies this report, in which it is shown that the change in variable costs cancel. Simplified, this term is as follows:

<u>System reliabilty or capacity cost = fixed cost of energy-equivalent thermal plant (e.g. CCGT) - avoided fixed cost of thermal plant (e.g. CCGT) displaced by capacity credit of wind.</u>

The benefit of this approach is that it allows the capacity credit related costs associated with adding intermittent plant to the system to be made explicit in a way that is consistent with systemic principles, without making any judgement about the nature of any 'back up'. Instead, all that is required is determination of the least cost *energy equivalent comparator*, i.e. the thermal plant that would supply the same energy in the absence of intermittent generation (normally assumed to be CCGT).

In section 3.3.6 we used this simplified term to demonstrate the effect of different capacity credit values on the capacity cost (i.e. the cost of maintaining reliability), whilst keeping all other system characteristics unchanged. These characteristics were chosen to be representative of a future British electricity network and expected capacity credit for wind power. However, capacity credit and capacity factor are related variables and relatively low capacity credit values tend to be associated with relatively low capacity factors. We therefore also explored the sensitivity of the cost of maintaining reliability to a range of capacity credit *and* capacity factor values, the results of which are shown in table A2.1. As in section 3.3.6, the system characteristics are derived from (Dale et al 2003). The only changes in each calculation are the wind capacity factor and wind capacity credit.

The lower wind capacity factors require proportionately more installed wind capacity to deliver the same amount of energy. In isolation, this has no impact on the reliability cost[81]. This is illustrated by the reliability cost being the same for each capacity factor where the capacity credit is the same fraction of capacity factor (e.g. capacity factor/capacity credit combinations of 20%/10%, 30%/15%, 40%/20%).

For any given capacity factor the reliability cost reduces as the wind capacity credit increases. It is the size of capacity credit *relative to* capacity factor which determines the cost of maintaining reliability - low capacity credit relative to capacity factor gives rise to higher reliability costs.

[81]It would of course have very significant implications for the capital, operating and maintenance costs incurred for a given energy contribution from wind.

Table A2.1 The sensitivity of reliability cost to capacity factor and capacity credit

Wind capacity factor (% of installed wind capacity)	Wind capacity required to deliver 20% of electricity (GW)	Wind capacity credit (% of installed wind capacity)	Reliability cost (£/MWh)
20%	45.7	10%	£5.17
		15%	£3.26
		20%	£1.35
30%	30.4	10%	£6.45
		15%	£5.17
		20%	£3.90
		25%	£2.62
		30%	£1.35
40%	22.8	10%	£7.09
		15%	£6.13
		20%	£5.17
		25%	£4.22
		30%	£3.26
		35%	£2.31
		40%	£1.35
System characteristics			
Total system energy	400 TWh/yr		
Wind energy	80 TWh/yr		
Thermal equivalent capacity factor	85%		
Thermal equivalent cost	£67,000/MW/year		

Annex 3: Full list of included documents

Author	Title	Year	Ref.	Source
Ackermann T	Wind power in power systems	2005	94	John Wiley & Sons Ltd, England
Auer H	Modelling system operation cost and grid extension cost for different wind penetrations based on GreenNet	2004	84	IEA Workshop on Wind Integration, Paris
Bach P	Costs of wind power Integration into Electricity Grids: Integration of Wind Power into Electricity Grids Economic and Reliability Impacts	2004	95	IEA Workshop on Wind Integration, Paris
Bathurst G, Strbac G	The value of Intermittent Renewable Sources in the first week of NETA	2001	198	Tyndall centre for Climate Change
Billinton R, Gan L	Wind power modelling and application in generating adequacy assessment	1993	9	http://ieeexplore.ieee.org/iel2/702/6717/00270560.pdf?tp=&arnumber=270560&isnumber=6717
Boone A	Simulation of Short-term Wind Speed Forecast Errors using a Multi-variate ARMA(1,1) Time-series Model	2005	163	Royal Institute of Technology, Dept of Electrical Engineering Electric Power Systems Stockholm, Sweden
Bouzguenda M, Rahman S	Value analysis of intermittent generation sources from the system operations perspective	1993	34	IEEE Transactions on Energy Conversion
Brooks D L, Anthony J, Lo E, Higgins B	Quantifying System Operation Impacts of Integrating Bulk Wind Generation at We Energies	2004	151	http://www.epri-peac.com/wind/files/We_Energies OpImpacts.pdf
Brooks D L, Lo E, Smith J W, Pease J H, McGree M	Assessing the impact of wind generation on system operations at Xcel energy and BPA	2002	158	http://www.uwig.org/opimpactspaper.pdf
Bryans A G, O'Malley M, Crossley P	Impact of Tidal Generation on Power System Operation In Ireland	2005	182	IEEE Transactions on M, Power Systems 2005:
BWEA	Blowing Away the Myths - A critique of the Renewable Energy Foundation's report: Reduction in carbon dioxide emissions: estimating the potential contribution from wind power	2005	50	British Wind Energy Association, London
Caldwell J H	Overview of Issues in Modelling Wind Energy	2003	100	AWEA
California Wind Energy Collaborative for California Energy Commission	California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis PHASE III: recommendations for implementation	2004	168	http://www.energy.ca.gov/reports/500-04-054.PDF
Dale L	Neta and wind	2002	232	EPSRC 'Blowing' workshop, UMIST
Dale, Milborrow, Slark, Strbac	A shift to wind is not unfeasible (Total Cost Estimates for Large-scale Wind Scenarios in UK)	2003	79	Power UK
Danish Energy Ministry	Vindkraft I Elsystemet	1983	241	See ref. 245
Dany G	Power reserve in interconnected systems with high wind power production	2001	20	2001 IEEE Power Tech Conference Proceedings, Porto, Portugal

DeCarolis J F	The Economics and Environmental Impacts of Large-Scale Wind Power in a Carbon Constrained World	2004	169	Carnegie Mellon University, Pittsburgh, Pennsylvania
DeCarolis J F, Keith D W	The Costs of Wind's Variability: Is There a Threshold?	2005	197	http://www.ucalgary.ca/~keith/papers/72.Decarolis.2005.Threshold.e.pdf
Dena Project Steering Group TGEAD	Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020(Dena Grid study)	2005	74	Deutsche Energie-Agentur, Berlin
Denny E, O'Malley M	Wind Generation, Power System Operation and Emissions Reduction	2005	181	IEEE TRANSACTIONS ON POWER SYSTEMS
Deutsches Windenergie-Institut GmbH Germany, Tech-wise A/S Denmark, DM Energy United Kingdom	Wind Turbine Grid Connection and Interaction	2001	63	http://europa.eu.int/comm/energy/res/sectors/doc/wind_energy/maxi brochure_final_version.pdf
Doherty R, Bryans L, Gardner P, O'Malley M	Wind Penetration Studies on the Island of Ireland	2004	178	Wind Engineering
Doherty R, Denny E, O'Malley M	System operation with a significant wind power penetration	2004	22	Power Engineering Society General Meeting, 2004. IEEE
Doherty R, O'Malley M	Quantifying reserve demands due to increasing wind power penetration	2003	14	http://ieeexplore.ieee.org/iel5/9135/28975/01304288.pdf?tp=&arnumber=1304288&isnumber=28975
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Dragoon K (PacifiCorp),	Assessing Wind Integration Costs with Dispatch Models: A Case Study of PacifiCorp	2003	42	WINDPOWER 2003, Austin, Texas
E.ON- Net Z	Wind Report 2005	2005	246	E.ON Netz, Germany
E.ON- Net Z	Wind report 2004	2004	57	E.ON Netz, Germany
EC Commission	Wind Power Penetration Study, The Case of Italy	1992	249	CEC, Brussels, Luxembourg - see ref. 245
EC Commission	Wind Power Penetration Study, The Case of the Netherlands	1992	243	CEC, Brussels, Luxembourg - see ref. 245
EC Commission	Wind Power Penetration Study, The Case of Greece	1992	242	CEC, Brussels, Luxembourg - see ref. 245
EC Commission	Wind Power Penetration Study, The Case of Portugal	1992	248	CEC, Brussels, Luxembourg - see ref. 245
EC Commission	Wind Power Penetration Study, The Case of Spain	1992	244	CEC, Brussels, Luxembourg - see ref. 245
EC Commission	Wind Power Penetration Study, The Case of Denmark	1992	240	CEC, Brussels, Luxembourg - see ref. 245
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Foulkes	Press Release - 'ICE delight at wind investment, but not in isolation'	2003	254	Institution of Civil Engineers
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Milborrow D	Wind and gas - the gap narrows	2005	236	Power UK
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Milborrow D	The real costs and problems of integrating wind	2001	73	Blowing work shop, Belfast
Milborrow D	Penalties for intermittent sources of energy	2001	132	Working Paper for PIU Energy Review
Milborrow D	False alarm	2005	207	Power Engineer
Milborrow D	Integrating wind: Ofgem discussion day	2004	66	www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/7749_DavidMilborrow_may04.pdf
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Rockingham A P	System economic theory for WECS	1980	220	2nd British Wind Energy Association Workshop, Cranfield
Royal Academy of Engineering	Response to the House of Lords Science and Technology select committee inquiry into the practicalities of developing renewable energy	2003	59	The Royal Academy of Engineering, London
Royal Academy of Engineering, PB Power	The Costs of Generating Electricity	2004	239	The Royal Academy of Engineering, London
Salman SK, Teo ALJ	Windmill modelling consideration and factors influencing the stability of a grid-connected wind power based embedded generator	2003	15	IEEE Transactions on Power Systems
Seck T	GRE wind integration study	2003	187	Great River Energy, UWIG technical wind workshop
Sinden G	Wind Power and the UK Resource	2005	247	Environmental Change Institute, University of Oxford
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Soder L	Imbalance management and reserve requirements	2002	155	Wind power and the impact on power systems IEEE-Cigre workshop, Oslo
Soder L	Simulation of wind speed forecast errors for operation planning of multiarea power systems	2004	23	2004 International Conference on Probabilistic Methods Applied to Power Systems
South Western Electricity plc	Interaction of Delabole wind farm and SouthWestern Electricity's Distribution system	1994	225	Document sourced from British Library
Strbac G, Jenkins N	Network security of the future UK electricity system (Report to PIU)	2001	196	MANCHESTER CENTRE FOR ELECTRICAL ENERGY Department of Electrical Engineering &Electronics PO Box 88, Manchester, M60 1QD
Sustainable Development Commission	Wind Power in the UK: A guide to the key issues surrounding onshore wind power development in the UK	2005	92	Sustainable development commission
Sveca J, Soder L	Wind power integration in power systems with bottleneck problems	2003	18	2003 IEEE Power Tech Conference Proceedings, Bologna
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The Large-Scale Wind Integration Working Group to the NEM Entry Coordination Group	Integration of Large-Scale Wind Generation	2004	98	http://systemcontroller.transend.com.au/public.asp
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Watson R	Large scale integration of wind power in an island utility-an assessment of the likely variability of wind power production in Ireland	2001	17	2001 IEEE Power Tech Conference Proceedings, Porto, Portugal
Watson S J, Landberg L, Halliday J A	Wind speed forecasting and its application to wind power integration	1993	215	Proceedings of 16th British wind energy association conference, York
Watson SJ, Landberg L, Halliday JA	Application of Wind speed forecasting to the integration of wind energy into a large scale power system	1994	26	Generation, Transmission and Distribution, IEE Proceedings
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Wind Energy Weekly	How Difficult is it to Integrate Wind Turbines With Utilities?	1996	202	Wind Energy Weekly #680
Xcel Energy	Characterizing the impacts of significant wind generation facilities on bulk power systems operations planning	2003	46	http://www.uwig.org/UWIGOpImpactsFinal7-15-03.pdf
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Annex 4: Full list of excluded documents

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Bazilian M, Denny E, O'Malley M	Challenges of Increased Wind Energy Penetration in Ireland	2004	183	Wind engineering
Billinton R, Karki R	Reliability/cost implications of utilizing photovoltaics in small isolated power systems	2003	40	Reliability Engineering & System Safety, Univ Saskatchewan, Dept Elect Engn, Power Syst Res Grp, Saskatoon, SK S7N 5A9, Canada
Blair N, Short W, Heimiller D	Reduced Form of Detailed Modelling of Wind Transmission and Intermittency for Use in Other Models	2005	171	WindPower 2005, Denver, Colorado
Brobak B, Jones L	Real time data acquisition from wind farms in power systems	2002	29	Power Engineering Society Summer Meeting, 2002 IEEE
Brocklehurst F	A Review of the UK Onshore Wind Energy Resource	1997	210	ETSU, Harwell, Oxfordshire
Brown A, Ellison C, Porter K	Transmitting Wind Energy Issues and Options in Competitive Electric Markets	1999	176	National Wind Coordinating Committee: NREL
Burges K	Dynamic modelling of wind farms in transmission networks	2004	118	http://www.irish-energy.ie/uploads/documents/upload/publications/technical_paper_modelling_wind_KBu_mar_04.pdf
Castronuovo ED, Lopes JAP	Bounding active power generation of a wind-hydro power plant	2004	25	2004 International Conference on Probabilistic Methods Applied to Power Systems
Catunda SYC, Pessanha JEO, FonsecaNeto JV,	Uncertainty analysis for defining a wind power density measurement system structure	2004	32	Instrumentation and Measurement Technology Camelo NJ, Silva PRM Conference, 2004. IMTC 04. Proceedings of the 21st IEEE
Christiansen P, Jørgensen K, Sørensen A	Grid Connection and Remote Control for the Horns Rev 150 MW Offshore Wind Farm in Denmark	2002	180	http://www.owen.eru.rl.ac.uk/workshop_4/pdfs/owen_Christiansen.pdf
Danish wind turbine manufacturers association	The energy balance of modern wind turbines	1997	81	Vindmïlleindustrien Vester Voldgade 106DK 1552 Copenhagen K
Dragoon K, Milligan M	Assessing Wind Integration Costs with Dispatch Models: A Case Study of PacifiCorp	2003	108	NREL

DTI	The UK wind resource: Wind energy fact sheet 8	2001	53	www.dti.gov.uk/renewables/publications/pdfs/windfs8.pdf
DTI	Wind fact sheet 11	2000	56	http://www.dti.gov.uk/renewables/publications/pdfs/windfs11.pdf
DTI	Energy White Paper	2003	251	DTI, London
EnerNex Corporation	Wind Generation Forecasting: Status and Prospects for Improving System Integration, California Energy Commission Workshop on Renewables Operational Integration Issues #2	2005	165	UWIG Workshop on Renewables Operational Integration Issues #2, Sacramento, California
EnerNex Corporation, WindLogics	Characterization of the Wind Resource in the Upper Midwest Wind Integration Study Task 1	2004	105	Xcel Energy and the Minnesota Department of Commerce
ESB national grid	Wind dynamic modelling update August 2004	2004	119	ESB national grid
ETSU	Renewables in Power Generation: Towards a Better Environment Appendix on Wind	1997	115	http://spider.iea.org/pubs/studies/files/benign/pubs/append3d.pdf
European Commission Directorate-General for Energy	Wind energy - the facts: costs, prices and values (Volume 2)	2003	82	http://www.ewea.org/fileadmin/ewea_documents/documents/publications/WETF/WETF.pdf
EWEA, Forum for energy and development, Green peace International	Wind force 10. A blueprint to achieve 10% of the world's electricity from wind power by 2020	1999	62	http://www.inforse.dk/doc/Windforce10.pdf
Flaim T	Avoided costs for solar facilities	1985	10	Energy Policy
Giebel G	The State-of-the-Art in Short-Term Prediction of Wind Power From a Danish Perspective	2003	195	http://anemos.cma.fr/download/publications/pub_2003_paper_BILLUND_SOTAGiebel.pdf
Gow G	Forecasting short-term wind farm production	2003	214	http://www.regie-energie.qc.ca/audiences/3526-04/MemoiresParticip3526/Memoire_CCVK_24_W4500572.pdf
Holttinen H	Impact of hourly wind power variations on the system operation in the Nordic countries.	2005	75	Wind energy, Wiley & Sons Ltd
Holttinen H, Hirvonen R	Power system requirements for wind power.	2005	76	John Wiley & Sons Ltd
Holttinen H, Hirvonen R, Botterud A, Vogstad K.-O.	Effects of large scale wind production on the Nordic electricity market	2001	72	Proceedings of European Wind Energy Conference, Wind Energy for the New Millennium, EWEC 2001, Copenhagen, Denmark
Jangamshetti SH, Guruprasada Rau V	Height extrapolation of capacity factors for wind turbine generators	1999	27	Power Engineering Review, IEEE
Justus D	Wind Power Integration into Electricity Systems	2005	142	http://www.oecd.org/dataoecd/22/37/34878740.pdf
Kariniotakis G et al	ANEMOS: Development of a Next Generation Wind Power Forecasting System for the Large-Scale Integration of Onshore & Offshore Wind Farms.	2003	192	European wind energy conference, Madrid

Kariniotakis GN, Pinson P	Uncertainty of short-term wind power forecasts a methodology for on-line assessment	2004	24	2004 International Conference on Probabilistic Methods Applied to Power Systems
King D	Environment: Climate Change Science: Adapt, Mitigate, or Ignore?	2004	35	Science
Kjaer C	Comments on the Preliminary Draft Vision Document of the High Level Group on Hydrogen and Fuel Cells	2003	190	http://www.ewea.org/documents/11_EWEA_hydrogen_response.pdf
Kosoric KR, Katancevic AR	Wind changes influence on control of power systems with high percentage of wind power	2003	30	Power Engineering Society General Meeting, 2003, IEEE
Milborrow D	Hydrogen myths and renewables reality	2003	233	Windpower Monthly
Milborrow D	Revolutionary potential	2000	228	Windpower Monthly
Minnesota Department of Commerce	Wind resource analysis program 2002	2002	47	http://www.state.mn.us/mn/externalDocs/WRAP_Report_110702040352_WRAP2002.pdf
Morgan C A (HMSNCSfDCT)	Offshore wind economies of scale, engineering resource and load factors	2003	61	http://www.dti.gov.uk/renewables/policy/garradhassanoffshorewind.pdf
Mott MacDonald, Bourton Group	Renewable Energy Industry Gap Analysis: Summary Report	2005	114	Department of Trade and Industry
National Grid Company;	Evidence to House of Lords' Select Committee on 'Electricity from Renewables'.	1999	227	The Stationery Office
NECA	Code change panel: Intermittent generation forecasting obligations	2004	97	http://www.neca.com.au/Files%5CC_CCP_intermittent_generation_forecasting_obligations_Sep2004.pdf
Obersteiner C, Auer H	Modelling additional system operation cost due to large-scale wind generation	2004	86	GreenNet Dissemination Workshop Prague
Oxera	What is the potential for commercially	2005	60	http://www.oxera.com/cmsDocuments/Reports/DTI%20The%20potential%20for%20commercially%20viable%20renewable%20generation%20technologies%20February%202005.pdf
Park SJ, Kang BB, Yoon JP, Cha IS, Lim JY system	A study on the stand-alone operating or photovoltaic/wind power hybrid generation	2004	36	http://ieeexplore.ieee.org/iel5/9371/29761/01355441.pdf?tp= &arnumber=1355441&isnumber=29761
Renewable energy research lab UoM	Wind power resource assessment: wind power on the community scale	2005	54	RERL- MTC Community wind power fact sheet 5
Renewable energy research lab UoM	Wind power: Interpreting your wind resource data	2005	55	RERL - MTC community wind power fact sheet 6
Royal Academy of Engineering	Inquiry into the practicalities of developing renewable energy: Memorandum submitted by The Royal Academy of Engineering	2003	153	The Royal Academy of Engineering, London
Slark R	The costs imposed by intermittent renewables on the electricity system	2002	113	http://www.eci.ox.ac.uk/lowercf/intermittency/richardslark.pdf

Slootweg J G, Kling W L	Aggregated Modelling of Wind Parks in Power System Dynamics Simulations	2003	177	IEEE Bologna PowerTech Conference
Snodin H	Scotland's renewable resource 2001 executive summary	2001	80	http://www.scotland.gov.uk/library5/environment/SRS2001ExecSumm.pdf
Soder L	Integration of Wind Power into Electricity Grids: Economic and Reliability Impacts'	2004	103	IEA
Soder L	Integration study of small amounts of wind power in the power system	1994	156	www.icomm.ca/ee/folkkampanjen/soder/lennart_report_mars94.html
SP Transmission Ltd, Scottish Hydro-Electric Transmission Ltd	Consultation on Technical Requirements for Windfarms Scottish grid code review panel consultations SA/2004	2004	128	http://www.scottish-southern.co.uk/ssegroup/KeyDocumentsPDFs/SA%202004%20Consultation.pdf
Stefanakis J	Crete: an ideal study case for increased wind power penetration in medium sized autonomous power systems	2002	28	http://ieeexplore.ieee.org/iel5/7733/21228/00985007.pdf?tp=&arnumber=985007&isnumber=2122
Swift-Hook DT	Wind power for the UK-conclusions and recommendations	1988	33	IEE Colloquium on Wind Power for the UK
van Werven M, Beurskens L, Pierik J	Integrating wind power in EU electricity systems: Economic and technical issues	2005	87	http://www.greennet.at/downloads/WP4%20Report%20GreenNet.pd

Annex 5: Technical annex to Ch. 1: search terms and databases used

Literature search

Following consultations with the expert group the following databases, bibliographies, catalogues, and other sources were utilised. A preliminary list was published in the Scoping Note and Protocol. A number of relevant papers were accessed through expert recommendations, in particular older studies and important pieces of 'grey' literature, as well as international sources.

- Manual searching of key recent documents' bibliographies
  - the DTI 'SCAR' Report and Network Impacts Study and PIU Working Papers

- Recommendations from the expert group and stakeholders
  - In particular international technical reports/consultations/case studies produced by transmission system operators and regional electricity companies.

- Database searches, using key words and search terms (see below). Databases included:
  - 'ESTAR', the British Library's Electronic Storage and Retrieval System
  - 'SIGLE', the system for Information on Grey Literature in Europe - citations to reports and non-conventional literature published across EU member states since 1980
  - Elsevier's 'Science Direct'
  - Academic Working Paper Series available online
  - PhD theses available online
  - Engineering databases - IEEE Explore and IEE Inspec

- Specific journal archives not covered in the above, in particular for older papers not available in on-line databases
  - Electrical engineering journals, IEE conference proceedings

- Website searches using the keyword combinations (as below). Example sites:
  - DTI
  - National Grid and Ofgem
  - Google
  - IEA
  - Wind energy associations
  - US DoE
  - NREL

Search terms

Key words were determined and refined in collaboration with the expert group and stakeholders. They are listed below:

Wind + network	Wind + system costs
Assessing + impact + wind generation + system operations	Wind + intermittency + impact assessment
Forecasting	Wind variation + system operation
Intermittency + generation	Wind + transmission network + impact assessment
Intermittency + networks	Renewable + network
Intermittency costs	Intermittency + electricity
Intermittent generation + network + issue	Intermittent generation + network + impacts
Intermittent power + costs	Quantifying + system costs + renewables
System costs + power generation	Intermittency + renewable
Wind + integration costs	Wind + capacity credit
Wind power + intermittency	Wind power + network integration
Wind power + modelling	Wind integration + transmission reliability
Wind power	Wind + grid impacts

Inclusion and categorisation criteria

The literature was included and categorised according to relevance. It is not uncommon for systematic reviews to exclude the majority of studies found during the search period on 'quality' grounds – for example the exclusion of all non-empirical work[82]. The approach taken in this report is to include studies and comment on their quality rather than exclude large numbers of reports a priori. A categorisation matrix was developed, which captured key data from the 154 included references. The range of data captured on each reference is summarised in the table below:

Box A5.1 Summary of document information captured in database

- Title
- Author
- Date published
- Journal where published if applicable
- Who the work was undertaken for or commissioned by
- Country or region the paper is applicable to
- Abstract
- Primary aspect covered e.g. reserves and balancing or resource characteristics
- Method and approach adopted e.g. statistical approach or forecasting
- Secondary aspects for those papers that cover more than one aspect of the issue
- Secondary or supplementary approaches
- Notes by the TPA team, identifying the major areas covered by the paper and any conclusions drawn
- Summary of usable outputs identified
- Decision by the TPA team to include or exclude in study

In addition, the following information has been captured for those papers which provide relevant quantitative data:

- Capacity credit
- Additional reserve requirements
- Additional reserve costs
- Impact on fuel savings, CO2 reductions and energy spill levels

[82]See for example Smith and Skea, 2003, Resource Productivity Innovation: Systematic Review. DTI, London

Annex 6: Technical annex to Ch. 2: terminology

To make an accurate assessment of the costs of using intermittent sources of generation in an electricity network one must be careful to properly describe the problem and to use terms consistently. The issues are under discussion in many parts of the world and amongst many groups of people (the general public, economists, engineers and others). Here we define the terms we use, and where relevant how they relate to terms used elsewhere.

Energy, Power, Average Power and Rated Power

Energy is the ability to do work or is work done. It is, for instance, the work done by an electric motor or a heater. The scientific unit of energy is the joule (J), or its multiples such the megajoule (1,000,000 joules) and the gigajoule (1,000,000,000 joules). It is more normal when discussing electricity systems to measure energy in kilowatt-hours, kWh (domestic electricity tariffs are quoted in p/kWh) or megawatt-hours (wholesale electricity prices are quoted in £/MWh). Power is the rate at which energy is delivered and its scientific unit is watts (W), and is equivalent to joules per second, J/s. When a power quantity is multiplied by a time it gives an energy quantity. So, a kilowatt-hour is 1000 watts for 3600 seconds and is therefore 3,600,000 joules or 3.6MJ.

It is also common to discuss the energy per annum. This is actually a power because it is an energy transfer rate (energy per unit time). This is an example of an **average power** using a year as the period over which the average is taken. For instance, the predicted UK electricity consumption in 2020 is 400,000 GWh per annum. If this is divided by the number of hours in a year (8760) it gives the average power (the average rate of energy delivery) which is 45.6 GW.

Most items of generating plant or electrical network equipment have a maximum power capability known as their **rated power**. This will be determined by its maximum voltage and maximum current or perhaps by a mechanical limitation. Sometimes these limitations depend on air temperature so there can be different rated powers for summer and winter conditions. In alternating current (AC) systems we must also account for reactive power which expresses how much energy per second is stored in and released from the magnetic fields or electric fields of various parts of the system. This energy is not consumed, merely shuffled back and forth. It need not be generated through the burning of fuel but it does need to be present for the proper functioning of the system.

Intermittency and Variability

Intermittency has become a short hand term for power sources that do not produce a constant output. In every day language the term intermittent would be interpreted as something that turns on and off. All types of power generation are intermittent in this sense. Coal or nuclear power generation plants that are designed to run at full power continuously are still subject to planned shut-downs for maintenance and unplanned shut-downs because of equipment failures.

Variability is an alternative term to describe power sources such as the wind whose output is not constant and varies between zero and full power. That variation might be on any or all of the timescales of seconds, minutes, hours, days, seasons and years. The variation may be in part regular (such as tides or patterns of evening on shore winds), it may be predictable, subject to forecast errors (and dependent on weather patterns, sea and air temperatures, or other factors) or it may be random. The variability can be characterised in terms of the changes in the amount of power generation, the frequency of the changes and the rapidity with which the changes occur.

System Balancing Gate Closure, Balancinh Mechanism, Balancing Systems Charges and System Frequency

The supply of electricity is unlike the supply of other goods. Electricity cannot be readily stored in large amounts and so the supply system relies on exact second-by-second matching of the power generation to the power consumption. Some demand falls into a special category and can be manipulated by being reduced or moved in time. Most demand, and virtually all domestic demand, expects to be met at all times. It is the supply that is adjusted to maintain the balance between supply and demand in a process known as **system balancing**. There are several aspects of system balancing. In the UK system, contracts will be placed between suppliers and customers (with the electricity wholesalers buying for small customers on the basis of predicted demand) for selling half hour blocks of generation to matching blocks of consumption. These contracts can be long standing or spot contracts. An hour ahead of time these contract positions must be notified to the system operator which in Great Britain is National Grid Electricity Transmission Limited. This hour-ahead point (some countries use as much as twenty-four hour ahead) is known as gate closure. At gate closure the two-sided market of suppliers and consumers ceases. (National Grid becomes the only purchaser of generation capability after gate closure and its purpose in doing so is to ensure secure operation of the system.) What actually happens when the time comes to supply the contracted power will be somewhat different to the contracted positions declared at **gate closure**. Generators that over or under supply will be obliged to make good the difference at the end of the half hour period by selling or buying at the system sell price or system buy price. Similar rules apply to customers who under or over consume. This is known as the **balancing mechanism** and the charges as **balancing system charges**. This resolves the contractual issues of being out-of-balance but not the technical problems. If more power is consumed than generated then all of the generators (which are synchronised such that they all spin at the same speed) will begin to slow down. Similarly, if the generated power exceeds consumption then the speed will increase. The generator speeds are related to the **system frequency**. Although the system is described as operating at 50 Hz, in reality it operates in a narrow range of frequency centred on 50 Hz. It is National Grid's responsibility to maintain this frequency using "primary response" plant (defined below). This plant will increase or decrease its power output so that supply follows demand and the frequency remains in its allowed band. The cost of running the primary response plant can be recovered from the balancing charges levied on those demand or supply customers who did not exactly meet their contracted positions. It is possible that a generator or load meets its contract position by consuming the right amount of energy over the half hour period but within that period its power varied about the correct average value. Thus the contract is satisfied but the technical issue of second-by-second system balancing remains.

Back-up and Reserve

The term **back-up** power is sometimes used to describe the need for additional power to be available to cover for when intermittent or variable sources are not available. It is important that back-up is matched to the problem it is intended to cover and therefore a classification system is required. Just as the variability of some sources and the intermittency of others need to be described in terms of a timescale, so too is the back-up described in terms of timescales. Generally, the sort of flexible generation plant that can produce power at short notice is not the type of plant that it is desirable (economically or otherwise) to run for long term energy supply. There is therefore a hierarchy of measures on different timescales. Because this is a study of the UK system, we will follow the classification used by the British transmission system operator, National Grid. The preferred terminology is for **reserve generation** and this is split into several categories as defined in the following sections.

Operating Reserve, Primary Response and Secondary Response

Operating reserve is generation capability that is put in place following gate closure to ensure that differences in generation and consumption can be corrected. The task falls first to **primary response**. This is largely made up of generating plant that is able to run at much less than its rated power and is able to very quickly increase or decrease its power generation in response to changes in system frequency. Small differences between predicted and actual demand are presently the main factor that requires the provision of primary response. There can also be very large but infrequent factors that need primary response such as a fault at a large power station suddenly removing some generation or an unpredicted event on TV changing domestic consumption patterns. The primary response plant will respond to these large events but will not then be in a position to respond to another event unless the **secondary response** plant comes in to deal with the first problem and allow the primary response plant to resume its normal condition of readiness. Primary response is a mixture of measures. Some generating plant can be configured to automatically respond to changes in frequency. In addition some loads naturally respond to frequency and other loads can be disconnected (shed) according to prior agreement with the customers concerned in response to frequency changes. Secondary response is normally instructed in what actions to take by the system operator and will have been contracted ahead by the system operator. The secondary reserve might be formed of open-cycle gas-turbine power stations that can start and synchronise to the system in minutes. In the past in the UK and presently in other parts of the world, the term spinning reserve has been used to describe a generator that is spinning and ready at very short notice to contribute power to the system. Spinning reserve is one example of what in this report is called primary response. Primary response also includes the demand side actions noted in discussing system frequency.

Standing Reserve, Contingency Reserve and Capacity Reserve

To provide cover for unavailable generating plant over a period of hours requires **standing reserve**. This might be in the form of thermal plant (such as coal fired power stations) that are kept at operating temperature but without their steam turbines and generators running. In the past this has been known as thermal reserve but the term used here will be standing reserve. It is necessary to keep them warm because they can take several hours to heat up from cold to operating temperature. This type of reserve has to be contracted 24 hours ahead by the system operator. Such notice is termed 'warming' and payments are made once warming commences. **Contingency reserve** consists of the margin of generation over forecast demand which is required in the period from 24 hours ahead down to real time to cover against uncertainties in large power station availability and against both weather forecast and demand forecast errors. It includes generation that the system operator has contracted for but not issued a notice to warm.

If a generator has to be taken out of service for a prolonged period then it is expected that there will be a reaction in the pre-gate-closure market. If the out-of-service generator would have been offered in the spot market then there will be a shortage there. If it was part of a long term contract then its owner will seek to cover that contract position by purchasing output from other generators. Other plant owners might now offer generators that would not otherwise have been offered. These plants can be described as **capacity reserve**. Provision of this capacity reserve is left to the market but because National Grid makes regular statements on system adequacy, the market has signals about when moth-balled plant might become needed to form capacity reserve.

Reliability, LOLP, LOLE, LOEE

Electricity supply systems operate with high **reliability** but are not perfectly reliable in that occasionally some customers are not supplied. Some interruptions of supply arise from equipment failures or storm damage in the transmission and distribution networks. Some can arise from inadequate generation capacity. There are many ways of measuring and estimating reliability and the measure used depends on circumstance. The measure used when assessing the impact of generation reliability on customers are measures of loss-of-load. **Loss-of-load probability, LOLP** expresses how likely it is that a load will be needed to be shed (forced to disconnect from the system) because insufficient generation is present. This is expressed as a percentage that is the number of years per century in which load shedding will occur. LOLP does not inform us of how much load will be shed or for how long. **Loss-of-load expectation, LOLE** is slightly different and accounts for how much time would be spent without the load being served. **Loss-of-energy expectation, LOEE** accounts for how large a collection of load, in terms of its power, is not served and over what time period by measuring how much energy is not supplied (energy being the product of power and time).

Capacity, Installed Capacity, Availability, Technical Availability, System Margin, Reserve Capacity and Capacity Credit

The **capacity** of a system is the amount of the generation plant connected to the system. The **installed capacity** would be all of the connected generation accounted for at its rated power. However, we know that plant is not always available to generate because of planned maintenance, unplanned maintenance or unavailability of the energy source. **Technical availability** accounts for maintenance only and **availability** will include the energy source availability too. Statistical methods are needed to assess how much of the plant connected to a system is likely to be available at any time and from this the LOLP can be calculated for a given combination of plant and peak demand. A simple measure of the safety margin in a system is the **system margin** which is the difference between the installed capacity and the peak demand but one needs to know the type of plant (or the mix of types of plant) in question before this can be interpreted in terms of a system reliability. Capacity margins in the region of 20% peak demand have been common in the UK and because the generation mix has been dominated by thermal (gas turbine and coal) plant of similar probability of availability it has been possible to use this as a simple indication of whether the system was adequate to meet peak demand.

When a new generation technology with a quite different availability probability is introduced (or substituted for existing plant) one can reassess the LOLP using statistical methods. A simple representation of the outcome of this assessment is to assign the new generation plant a **capacity credit**. The capacity credit is defined as the capacity of incumbent generation that makes the same contribution to capacity available at peak load (the same contribution to LOLP) as the new generation.

If the new generation is less likely to be available at peak demand than the incumbent generation then its capacity credit will be less than its installed capacity.

Cut-in Speed and Cut-out Speed

At low wind speeds, a wind turbine will barely turn and does not produce enough energy to cover its own internal needs for electrical control. Therefore the turbine is not used (and is held stationary) at wind speeds below the **cut-in speed** (typically 4 m/s). For wind speeds above the cut-in speed the power output rises with wind speed until eventually the maximum power rating of the electrical generator is reached. If the wind speed rises further (to above about 15 m/s), measures are taken to limit the generated power to the rated power. At very high wind speeds, above the **cut-out speed** (typically 25 m/s), this is no longer possible without endangering the wind turbine structure and the turbine is stopped. In principle the turbine could be designed for a higher cut-out speed but the expense of doing so is judged to not be justified in terms of the additional energy generated during the infrequent periods of very high wind speeds.

Efficiency, Load Factor and Capacity Factor

Generators take an original energy source and convert it into electrical power through one or more transformations. Even where the original energy is essentially free (such as sunlight or wind) it is important that the plant is used to maximum advantage and a high proportion of the available energy is converted to electrical form. For a wind turbine, the available energy is the kinetic energy in the air mass that passes through the swept area of the turbine blades. The **efficiency** is defined as the electrical energy output divided by the available kinetic energy. It has been established (and this is known as the Betz limit) that not all of the energy in the air mass can be captured (since this would require bringing that portion of air to a standstill). The theoretical limit on wind turbine efficiency is 59% and practical wind turbines achieve somewhat less than this because of aerodynamic, mechanical and electrical inefficiencies. It must then be recognised that since the wind speed is variable, the turbine produces less than rated power for some of the time and that the average power is less than the rated power. The ratio of average generated power to delivered output is known as the **load factor**. The average power is assessed with a long term average of one or more years, it is effected by demand side issues - for example the load factor of CCGTs on the GB system has fallen in recent years, as a result of changes to the regulatory regime, electricity prices and gas prices. The **maximum** ratio of generated power to rated power is known as **capacity factor**. This represents the maximum number of load hours per year net of both planned and unplanned outages, independent of actual utilisation.

Use of System Charges

The requirement on generators (at least those above a certain size) to pay charges to cover the cost of the balancing mechanism has already been discussed. There are other charges levied on generators including intermittent generators. In using the electrical network to convey power, the generator will be charged transmission network **use-of-system** charges, TNUoS for use of the high voltage network and be charged distribution network use-of-system, DNUoS for use of the medium and low voltage networks. There is a further charge levied for making the connection to the system known as the connection charge.

Ancillary Services

Some generators are contracted by the system operator to provide **ancillary services** to the gird. The provision of reserve has already been discussed. Providing control of the grid voltage (through provision of reactive power) is also required and some plant will be contracted to do this. A small number of plants are also contracted to supply black-start capability such that should all of the system collapse following a very serious problem, these black-start generators can restart without the assistance of an external electricity supply.

Grid Code

A **grid code** is a document that defines obligatory features of a power generator that is to be connected to the electricity transmission or distribution system. An item recently added to the UK grid code is a requirement for fault ride-through from large wind farms. Fault ride-through is the ability of a generator to stay connected to the grid even when the grid is experiencing a fault condition so that once the fault is cleared (and normally the faulted item can be disconnected in less than a second) the wind farm will be available to resume delivering power.

Annex 7: Comparing the system margin and loss of load probabilities with and without intermittent generation: an illustrative example

The following figures compare the system margins for three systems. In the first, all the energy is generated by conventional plant, and the system margin is such that the loss-of-load probability (LOLP) is 2.5%. The LOLP is indicated by the area shaded red, where demand is greater than available capacity. The maximum available capacity on this system would be about 20% of the peak demand - slightly higher than the sum of the rated capacities of the plant on the system, since for short periods operating the plant above rated capacity is possible.

In the second example 80% of the energy output is provided by conventional and 20% by intermittent generation. In this example the mean capacity of the system is the same as that for the conventional system of Figure A7.1. There is no extra investment in thermal capacity to maintain reliability (sometimes termed 'back up' or 'capacity reserves').The effects are a marked increase in the loss of load probability, from roughly 2.5% to nearly 30% - and also a marked increase in the variance of the margin:

In the third example, the increase of LOLP is neutralised by investment in extra capacity ('backup'), which shifts the distribution to the right. As shown, an increase in the mean capacity on the system is such that the mean available margin rises from 9.0% (see Fig A7.2) to 20.9%, and is sufficient to restore the LOLP to the same level as that for the conventional system. The increased investment is approximately 12% of peak demand or 20% of the capacity of the intermittent plant. (See Figure A7.4 below, which shows the frequency distribution of the available capacity of conventional generation.) The capacity credit is 19.2%. These estimates are similar to those estimated using statistical formula (and also those of several other studies), though for slightly different parameters.

Figure A7.1: Frequency Distribution of System Margin When Conventional Generation Supplies 100% of the Energy. Loss-of-Load Probability ≈ 2.5 %

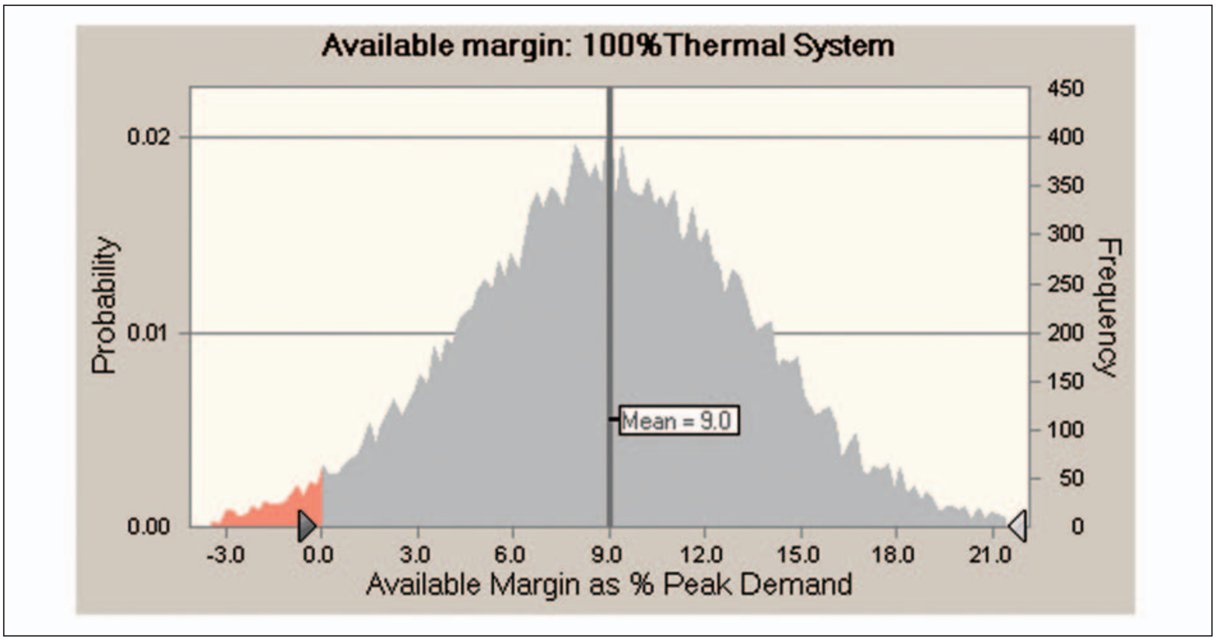


Figure A7.2: Frequency Distribution of System Margin When Conventional Generation Supplies 80% of Energy and Intermittent Generation 20%, but with no Additional Investment in Capacity to Maintain LOLP. (LOLP rises to 30%)

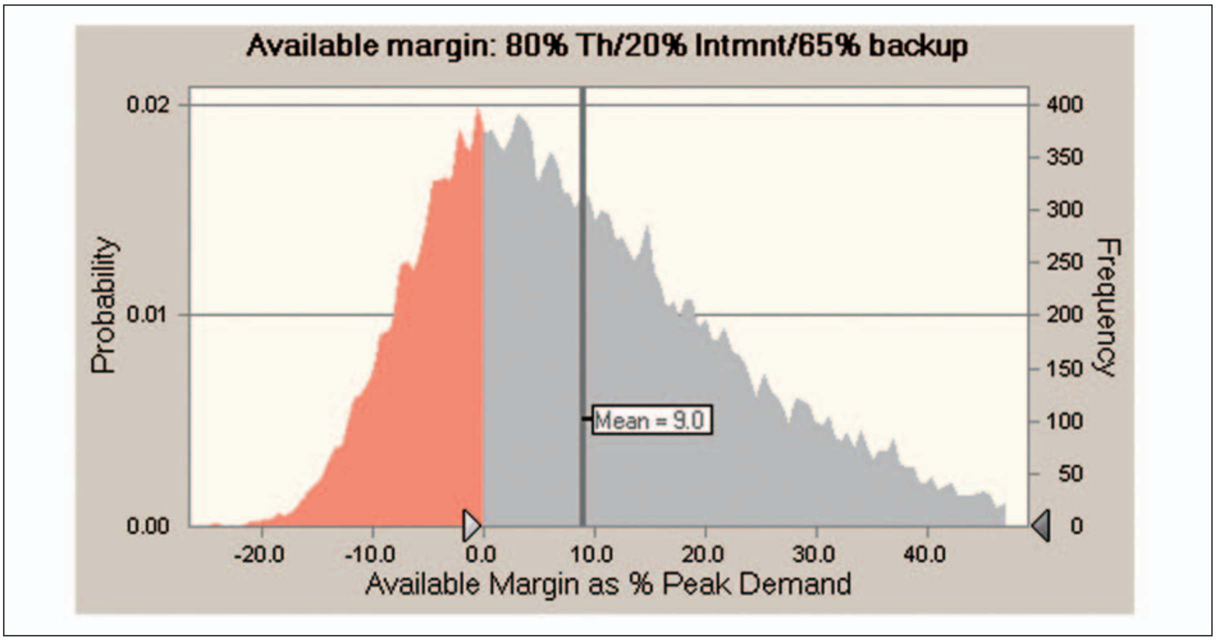


Figure A7.3: Frequency Distribution of System Margin When Conventional Generation Supplies 80% of the Energy, Intermittent Generation 20%, and Backup Capacity is Installed to Maintain Loss-of-Load probability to ≈ 2.5%.

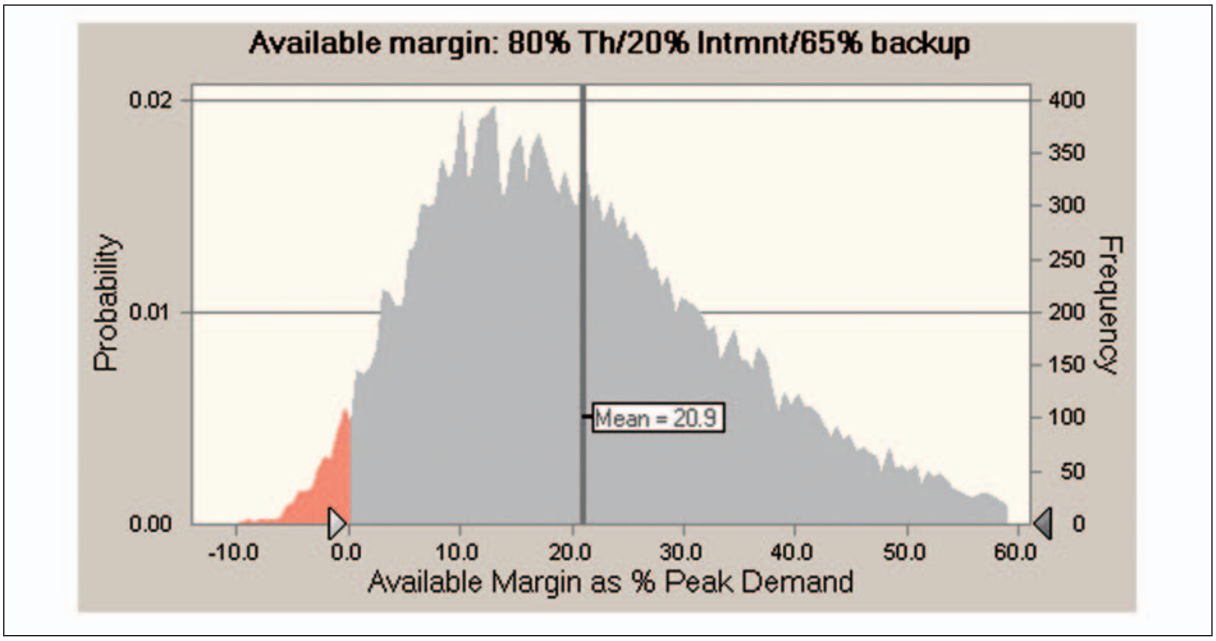
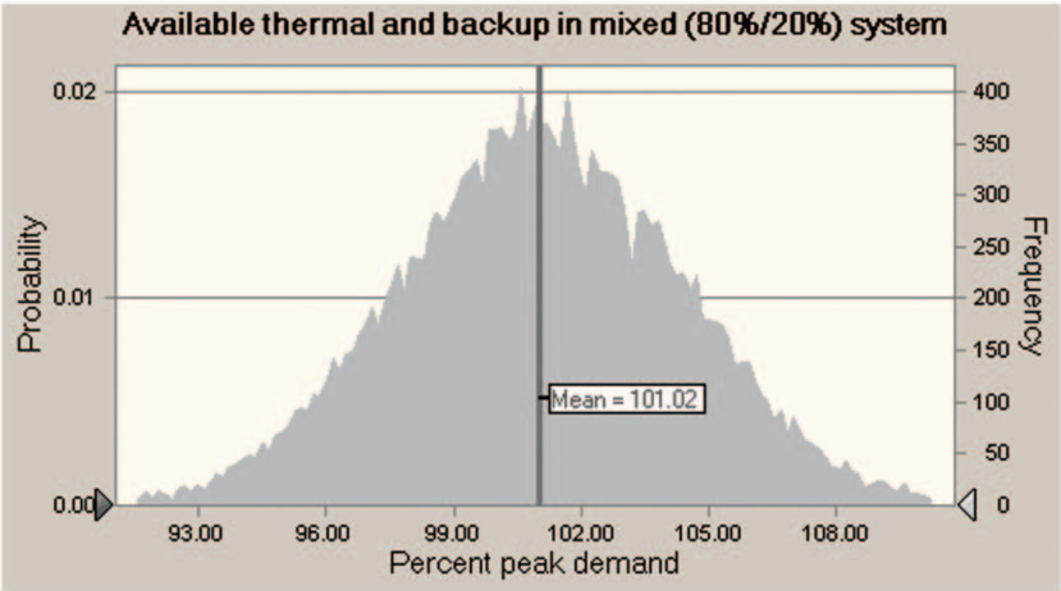


Figure A7.4. Available conventional capacity (including backup) corresponding to Figure A7.3: 80% of energy is supplied by thermal and 20% by intermittent generation; backup capacity 20% (19.2% capacity credit).



Further points:

1. The spread in the margin increases significantly (note the difference in the scales in the axes of Figures A7.1, A7.2 and A7.3) when intermittent generation is added, which of course is a reflection of the greater volatility of output.

2. Although the loss-of-load probability is similar in both cases, in extreme situations (<0.5%) the cuts in supply would be deeper with intermittent generation (compare the red areas in Figures A7.1 and A7.3). The nature and depth of the outages is an important aspect of the problem.
3. In extreme cases the loss-of-load levels due to capacity shortages would be within the compass of demand management practices. As illustrated in Figure A7.4, the capacity of conventional plant on the system would be 108% of peak demand, the average available capacity 101% and the lower probability limit of available capacity 94%.

4. There are significant periods (during times of peak demand) when the output from the intermittent generators raises the available capacity to very high levels; these are periods when the fuel savings over the peak will be large.

Assumptions for Preceding Results

Monte Carlo simulations using Crystal Ball. No. of trials: 20,000. Calculations compare 20% energy addition from conventional capacity with 20% from intermittent capacity. Demand: Mean value normalised to 100%; Standard deviation, 3.0% of expected value. Thermal capacity: Normal distributions with means 2 standard deviations below installed capacity and standard deviations of 4.0% of mean capacity. Backup capacity: means 2 s.ds below capacity with s.ds = 5.0% of mean capacity. Intermittent capacity: Weibull distribution with mean of 20.0% of expected peak demand, s.d. 12.8% of mean; max. capacity 60% of expected peak demand, min. capacity 0%.

Annex 8: Background documents and working papers

The following documents were produced as part of the process that contributed to this assessment report. Hard copies are available from the UKERC HQ on request:

58 Prince's Gate
Exhibition Road
London SW7 2PG

Tel: +44 (0) 207 594 1574
Fax: +44 (0) 207 594 1576
Email: admin@ukerc.ac.uk

They are also available from the intermittency project pages of the UKERC website (http://www.ukerc.ac.uk/content/view/77/60).

- Scoping note and assessment protocol
- Discussion paper on key questions
- Stakeholder workshop report
- Workshop presentations

The following Working Papers are also relevant to this assessment report, and/or the wider work of the TPA. They are available from the TPA pages of the UKERC website (http://www.ukerc.ac.uk/content/view/55/67).

- TNA User Needs Assessment
- Working paper on energy and evidence based policy and practice
- Power System Reserves and Costs with Intermittent generation, Anderson 2005
- Allocating costs arising from the capacity credit of intermittent options, UKERC 2005

UK ENERGY RESEARCH CENTRE
58 Prince's Gate
Exhibition Road
London SW7 2PG

tel: +44 (0)20 7594 1574
email: admin@ukerc.ac.uk

www.ukerc.ac.uk
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