The Carbon Trust & DTI

Renewables Network Impact Study

Annex 4:

Intermittency Literature Survey &

November 2003

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Summary

Intermittency, in the context of power generation, refers to the inability to sustain a steady and consistent output. This inability is due to the intermittent availability of the primary energy source employed by the renewable generator and is distinctively characteristic of renewable energy sources such as solar, wind, wave, and tidal generation.

Mott MacDonald has undertaken a literature review covering intermittency issues for renewable power sources, such as wind. We have then analysed the findings from this review in order to present a roadmap of the key intermittency issues and how they might be addressed. Our key findings are summarised below.

- Overall, there is good agreement between studies in the UK, Denmark, Germany and the US on the key issues such as power fluctuations from wind plant, the benefits of aggregation, strategies for dealing with intermittent sources, the amount and cost of extra balancing and capacity credits.

  However, comparisons must be made with care, and the absence of key data sometimes inhibits this process; relatively few studies explicitly tabulate all the key parameters, assumptions and methodology.

- The cost of extra balancing associated with intermittent renewables has been estimated by NGC at around £1.5/MWh for 5% wind, rising to £2.38/MWh for 10% wind. Other studies have derived lower values.

- There is reasonable agreement on the magnitude of the costs for providing additional contracted reserves on a £/MWh basis, although relatively few studies have quantified the amount of extra reserve capacity potentially required

- With an installed wind capacity of 3 000 MW, an extra 200 MW of spinning reserve would be required, or just under 7% of the rated wind capacity. With 6 000 MW of installed wind capacity the extra spinning reserve rises to 480 MW of thermal power, or just over 8% of the rated wind capacity.

- Storage should be seen as a system-wide issue rather than be associated with individual intermittent generators
- Reliable and stable system operation calls for modest additional thermal generation or energy storage (whichever is cheaper) to compensate for both predicted and unpredicted power shortfalls
- It is possible that large penetrations of renewable generation may displace conventional plants that provide ancillary services required to manage the system securely. A separate paper on Generator Characterisation discusses the ability of renewable technologies to provide such services.

- Aggregation reduces the net impact and load fluctuations which a transmission system might see from numerous wind farms

- Improvements in wind predictability could allow system operators to have more confidence in scheduling the extra reserves needed to cope with intermittency, thus reducing the extra costs

- We recommend that wind data and production data is gathered from as many operational UK wind farms as possible in order to provide a detailed analysis of wind/power fluctuations within the context of wind predictability and reliability

- NETA has brought additional complexities to the issues above, although resolution of these additional complexities is ongoing within the UK.

Table S-1: Summary of Intermittency Key Issues

Key Issues	UK Power System.	
Penetration of Intermittent Renewable Power Sources.	**10%**	**20%**
Dispatched Intermittent Wind Generation in MW.	About 12 000 MW	About 24-26 000 MW
Requirements for extra Operating Generation Reserve.	Between 400 MW to 700 MW	In the range between 3% to 7.6% of intermittent dispatched generation.
Estimated Operating Generation Reserve Costs. (Based on present-day UK market prices)	Reserve = £3-6/MWh Frequency Control = £4.5/MWh Note that other utilities report lower prices	Reserve = £3-6/MWh Frequency Control = £4.5/MWh
Estimated Operating Generation Balancing Costs.	£1.6-2.4/ MWh	£1.9-2.8/MWh
Capacity Credits (displaced thermal plant in MW).	3 300 MW	c.5 000 MW, or about 25% of intermittent dispatched generation.
Distribution Networks.	The Distribution Networks Operators (DNOs) claim that without proper investment to reinforce distribution networks, the government's target to generate 10% of the UK electricity needs based on renewable energy sources by 2010 could be affected. In an increasingly dynamic operating environment the DNOs will have to control generation more effectively. For that reason DNOs may have to engage in • Dispatch of local generation • Management of Reactive power • Co-ordination of voltage control	

1 Introduction

This paper is Annex 4 of the Renewables Network Impact Study for the Carbon Trust and the DTI, and summarises the capacity mapping exercise and scenarios undertaken as part of the overall study. It should be read in conjunction with Volume 1 of this study, which summarises the findings from each separate Annex within a single short report.

The individual annexes to Volume 1 of the Renewables Network Impact Study comprise the following five parts:

Annex 1: Capacity Mapping and Scenarios

Annex 2: Transmission Network Topography Analysis

Annex 3: Distribution Network Topography Analysis

Annex 4: Intermittency Literature Survey and Roadmap (this paper)

Annex 5: Grid Code Compliance

This study was commissioned by the Carbon Trust and the DTI in June 2003 on behalf of the DTI's Renewables Advisory Board to assess the ability of the electricity networks to accommodate the Government's target to have 10% of electricity generated from renewable energy sources by 2010 and its aspiration to double that percentage by 2020.

Objectives of the Renewables Network Impact Study

The study's key objectives, as set by the Renewables Advisory Board, the Carbon Trust and DTI, are as follows:

- To undertake a forward renewables capacity mapping exercise derived from the generation companies' investment plans to 2010, and if the capacity mapping exercise indicates that the planned level of activity is unlikely to meet the 2010 target, to devise and consider a small number of scenarios whereby the 10% target could be achieved.
- To determine how the transmission and distribution networks need to evolve to enable the Government's 2010 target of 10% of electricity supplied from renewable sources and the aspiration to double that percentage.
- To investigate the network issues regarding the intermittent nature of renewable generation and the characterisation of renewable generation with regard to grid code compliance.
- To provide insights into the actions and the stepping stones required between now and 2020 for the key decisions and investments relating to the transformation of the transmission and distribution network, and those issues likely to affect the rate of progress toward the targets.

The study also analyses whether there are potential network impacts on renewables expansion from a simultaneous expansion of the UK's CHP capacity to meet the Government target of 10GW of CHP by 2010. The study's terms of reference were finalised in June 2003. It therefore has based its considerations on the then renewables targets as set down in the Energy White Paper. The majority of the research had been carried out and completed by the time the Government announced in November

2003 its decision to set a new target of 15% of renewables electricity sales by 2015 and to extend the Renewables Obligation to 2015. However, the impact of this important development in the stimulation of more renewables generation capacity is considered briefly as they impact on the key conclusions reported.

All aspects of this paper were consulted with the project's Advisory Group. This was created by the Carbon Trust and the DTI and it comprises representatives from the following entities:

- Ofgem
- the Renewable Power Association (RPA)
- the British Wind Energy Association (BWEA)
- the Distribution Network Operators (DNOs)
- the Technical Steering Group (TSG) of the Distributed Generation and Co-ordination Group (DGCG).

1.1 The Intermittency Literature Survey and Roadmap

As part of its overall study into actual and potential network impacts from meeting the 2010 target and 2020 aspirational target for renewable power in the UK, Mott MacDonald has undertaken a literature review covering intermittency issues for renewable power sources, such as wind. This paper summarises the findings of the literature review and presents an analysis of the results, indicating where there is consensus between different studies and where knowledge gaps still exists for this particular topic. We then go on to develop a roadmap of suggested actions required to identify the key issues discussed in this paper.

Intermittency, in the context of power generation, refers to the inability to sustain a steady and consistent output. This inability is due to the intermittent availability of the primary energy source employed by the renewable generator. This feature is distinctively characteristic of renewable energy sources such as solar, wind, wave, and tidal generation.

Consequently, to maintain reliable and stable operations network operators require additional generation or energy storage to compensate for both predicted and unpredicted shortfalls in output from intermittent sources.

Numerous utility studies have examined the feasibility of operating power systems with substantial amounts of intermittent sources, usually wind, in the UK, Europe and the United States. Most studies have concluded that there are no insuperable technical problems in assimilating wind energy. As the wind capacity rises, however, measures must be taken to ensure the wind variations do not reduce the reliability with which demand is met and that frequency and voltage tolerances are not exceeded.

When wind is introduced on a utility network measures must be taken to ensure that the additional uncertainties in meeting the supply/demand balance are mitigated by measures such as the provision of additional reserve (possibly including existing pumped storage plant) or demand-side management. At low penetration levels the cost of these measures is small. However, as the amount of intermittent production increases, these additional costs can also be expected to increase. Most studies to date suggest that the costs of these services add up to approximately £0.5/MWh with 2% wind, rising to around £1-2/MWh at 10% penetration.

In this paper, all the extra operating costs are debited to the intermittent generation source. It should be noted that some studies spread the cost over all electricity generated and hence arrive at apparently lower figures.

When the wind capacity reaches around 15% to 20% of system peak demand, the costs are more significant and actions are likely to be needed to ensure sufficient system flexibility is available. In addition, there may be times when not all the available wind energy can be assimilated on to the system, as the most economic option for the network operator is to reduce the output of some wind plant.

This paper concentrates particularly on analyses of wind intermittency and its impacts, simply because there is a wealth of data on this topic, and very few, if any, corresponding studies exist for other technologies. However, the findings of this study can be read across to other intermittent sources with care.

Institutional changes, such as privatisation and introduction of the New Electricity Trading Arrangements (NETA) have not altered the technical parameters influencing efficient operation of the electricity network, and so technical conclusions drawn from earlier studies remain valid. Similarly, comparisons with studies of other electricity networks can be made, provided wind and plant characteristics are similar. Post-NETA, intermittent generators tend to be viewed in isolation, rather than as part of an integrated network, although the financial penalties are now less severe than at the start of NETA. The renewables industry in Great Britain is lobbying to eliminate this anomaly and similar problems have now been resolved in Northern Ireland and the United States.

2 Aim and Scope

The objectives of this paper are to: -

- Critically review well-founded studies of wind integration relevant to the UK, identifying strengths and weaknesses and (particularly for early studies) assumptions which have become dated
- Compare and contrast key results
- Identify gaps in knowledge and uncertainties
- Develop a roadmap identifying how the key issues can be addressed.

The aim has been to cover the following issues during the literature survey:

(a) The technical issues and costs for handling intermittency, as a function of the quantity of generation and the other parameters which influence these costs, including:

  – the potential role of pumped storage generation in managing intermittency

  – the potential for customers to manage demand, and the practical challenges of such demand management (remote control of loads, costs of rewiring customers' premises to segregate loads, likely resistance to change)

  – the potential for use of existing standby generation to manage troughs in intermittent generation, including technical barriers and costs

  – the potential (if any) for new storage technologies to reduce costs

(b) The level of firm capacity that can be attributed to a portfolio of intermittent generators.

3 Characteristics of Electrical Transmission and Distribution Systems

Power systems are stochastically dynamic in nature. That is, the behaviour of electricity consumers is characterised by a random distribution of power consumption profiles. On the other hand, current technology is unable to store large volumes of electrical energy cost-effectively. The above implies that the deployment of multiple generators supplying consumer needs, through an intricate grid of distribution and transmission networks necessitates a continuously harmonised balance between power production and demand.

In addition, the consumers' electrical equipment, machinery and appliances are designed to function at restricted values of voltage, current, power factor and frequency. Accordingly, the operation of power systems is regulated by a set of stringent operating codes and standards. These aim at maintaining the adequate balance between electrical demand and supply while keeping the values of the above electro-technical parameters within acceptable values. Generators therefore require a certain degree of flexibility in their operation to ensure compliance with grid code requirements.

In consequence, power systems operation needs the controlled co-ordination of generators deployed to satisfy electricity demand, along with the provision of ancillary services essential to sustain the delivery of power in a continuous, secure, reliable, and safe way.

The changes introduced by the deregulation of the electricity industry and the growing numbers of generators driven by non-conventional primary energy sources have the potential to alter the traditional operational philosophy of the networks.

3.1 Distribution

Historically, distribution systems have facilitated the delivery of electricity from centralised large generators connected via the high voltage transmission system, thus playing a mostly passive role. The distribution companies' chief responsibilities have been that of maintaining voltage variations within limits, as specified in industry standards, and to ensure that the appropriate level of power quality is sustained. For this purpose, distribution systems are designed, protected, and operated on the premise that there is a single source of electric power on each distribution feeder at any given time.

With the introduction of embedded generation, some of which is based on renewable sources, and the existing competitive environment, this passive role is developing into a more dynamic one. Strbac and Jenkins (ref. 1) have indicated that distribution systems in the UK are becoming facilitators of competition in generation and supply, thus moving away from the traditional, centralised approach to the production and delivery of power. This new function of distribution systems calls for adjustments in the current regulatory framework to encourage subsequent changes in the distribution systems' operation, protection and design philosophies so as to tie in with the major responsibilities of the distribution companies mentioned above. For instance, the voltage profile could involve the dispatch of local embedded generation and reactive power management and/or a co-ordination of both. Likewise, to sustain the appropriate level of power quality new equipment and requirements will be needed.

3.2 Transmission

International experience [(ref. 2) to (ref. 9)] seems to agree that as the penetration of large (transmission-connected) wind farms increases care is needed in operating the transmission network. Although the bulk of renewable power (especially in the form of photovoltaic cells, biomass technology and small scale wind farms) and CHP (including micro-CHP) is expected to be delivered to distribution systems, large on- and off-shore wind installations, and any large-scale CHP and biomass plants, may be connected directly to transmission networks. Imbalances in generation and customer load may affect system stability. Similarly, power flows across power systems components (generators, transformers, transmission and distribution lines, motors, electrical appliances and equipment, etc.) cause a reduction of voltage levels. This voltage reduction brings about the need to compensate in the way of reactive power the losses originated (primarily, by magnetic and electric fields formed around these components).

Therefore, system operators need to optimise of the balance of generation and demand on the transmission system. This requires the operator to instruct generators to produce more or less power to follow changes in load and unscheduled generation. Also, the operator should make provisions to keep enough reserve to be able to respond quickly to a sudden loss of a system component.

Consequently, there are a number of technical issues to take into account when considering the connection of intermittent generation to distribution or transmission systems.

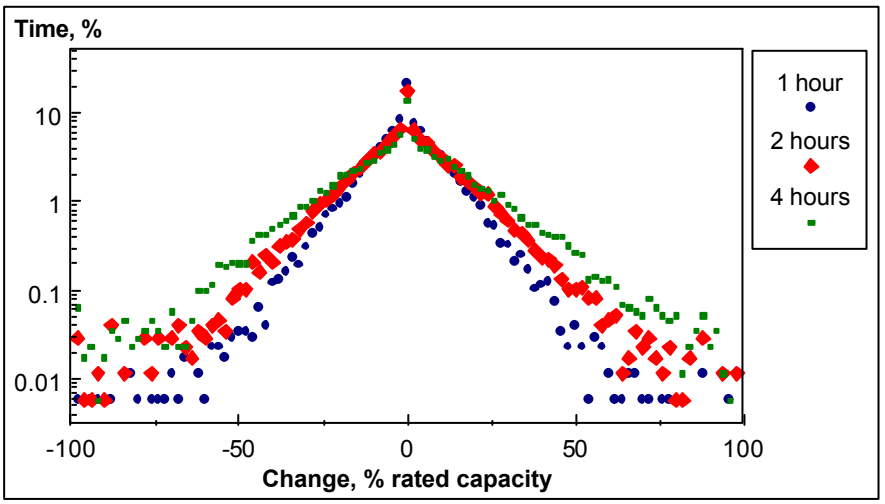
4 The Nature of Intermittency

Four intermittent renewable energy sources are variable, both in time and space – wind, wave, tidal (barrage and stream), and solar. Of these, only tidal variations are totally predictable, but more is known about wind variations and their impact on electricity systems than is known about wave and solar energy. The focus on wind stems from its increasing utilisation, by autumn 2003 there was over 34 000 MW operational, worldwide, including 13 000 MW in Germany. Nevertheless it is Western Denmark that supports the highest concentration of wind energy in the world, as it contributed 19% of the electricity consumption there in 2002.

In pace with the rising development of wind energy, numerous studies of intermittency issues have been carried out, dating back over some 25 years. As a result, the nature of wind fluctuations, or more importantly the power output fluctuations from wind plant, is now well characterised. With some exceptions, they are not location-dependent. Although temporal fluctuations occur on timescales down to a second or so, they are of relatively small size and, in any case are smoothed by wind turbine rotors. It is the fluctuations in timescales ranging from minutes to a few hours that influence the absorption of wind energy within integrated electricity systems. There are also variations on timescales of days, months and even years; it tends to be more windy during the day than the night and, in Britain it is more windy in the winter than the summer. Variations on these longer timescales impact on the extent to which wind can supplant the conventional thermal sources; the "capacity credit".

To illustrate the way that wind variations generate power fluctuations from a typical wind farm, Figure 1 depicts an analysis of data from a 5 MW wind farm in Northern Ireland (ref. 9). The data shows half hourly averages and it may be observed that, within an hour, the wind farm output changed by a maximum of the full rated output (downwards) on one half-hour in a year (0.0057% of the time); the maximum upward change was 90% of rated output, again in one half hour only. At the other end of the scale, the half hourly output varied by less than 2% of the rated power for 21% of the time. As the timescale is extended, the fluctuations increase; on the 4-hour timescale, for example, 100% changes were observed on about 10 occasions per year, and the output changed by less than 2% for 14% of the time.

Figure 1: Fluctuations measured on a 5 MW wind farm.

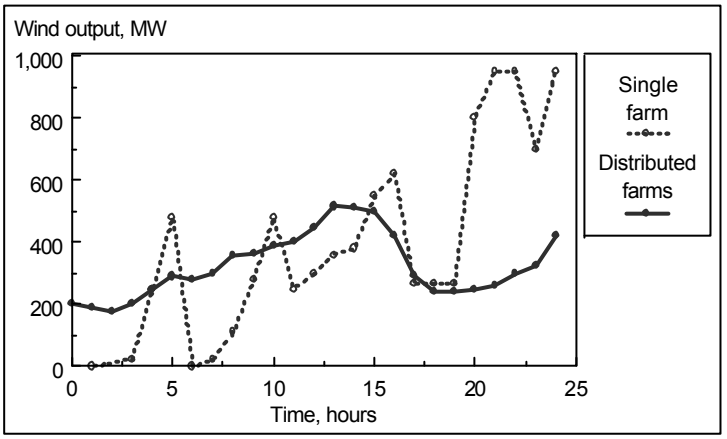


Similar results have been reported from 350 MW of wind plant in Germany (ref. 10), although the maximum fluctuations were slightly less on the 1-hour timescale, about 80% of rated output, but almost identical on the 4-hour timescale. No data of this kind, i.e. measured data from numerous wind farms, are available for the UK, although simulations by NGC have yielded similar trends (ref. 11).

4.1 Aggregation

Just as aggregation of consumer loads in an integrated electricity network smooths the total demands, so aggregation of wind plant smooths, in proportion, wind fluctuations. Although based on a simulation exercise, Figure 2 illustrates this point (ref. 12). During a 24-hour period, the output from a 1 000 MW wind farm might fluctuate from zero to close to its rated output, but the output from 1 000 MW of distributed wind would only vary between 200 and 500 MW, approximately. However, there appears to be less data available on the incidences of extremes in fluctuation which could then indicate what a possible worst case situation may look like in terms of a shortfall in output across several wind farms.

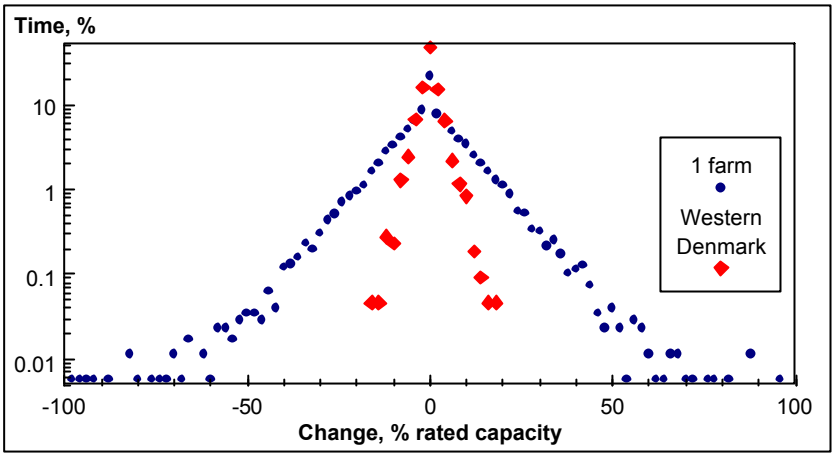
Figure 2: The smoothing effects of geographical dispersion: the "single farm" and the "distributed farms" are both rated at 1 000 MW.



The smoothing occurs because wind fluctuations are not perfectly correlated across the country, and the work reported by NGC to the Energy Review (ref. 11) suggests that the correlation coefficient falls to around 0.5 at a distance of 300 km, and to 0.2 at 800 km. Another way of demonstrating this smoothing effect is to compare the pattern of fluctuations from all the wind plant in Western Denmark (ref. 9) with those of the single wind farm shown in Figure 1.

This comparison is made in Figure 3. It shows that the maximum power swing within an hour comes down from nearly 100% to 18% and that, for 47% of the time, the power variation within an hour was less than 2% of the rated output. In other words, the maximum hourly power swing from the Danish plant (1 860 MW) was 335 MW, and for 47% of the time it was less than 37 MW.

Figure 3: The smoothing effects of geographical dispersion: a single wind farm of 5 MW, and all the wind plant in Western Denmark.



Again, data from Germany shows very similar characteristics, with the maximum power swings, reported in reference 2, being +18% and –20%.

Another measure of the variability of wind power is the standard deviation of the fluctuations and Table 4-1 shows how this is reduced with large numbers of wind plant. It also compares the modelling carried out by NGC and the analysis of Danish data. On a one-hour lead time, the agreement is good, although less so four hours. However, as England and Wales are several times the area of Western Denmark, it might be expected that the greater geographical diversity will lead to lower standard deviations. Allowing, also, for the fact that NGC calculated the standard deviation for 3.5 hours, and it would be slightly higher at four hours, the results seem reasonably consistent.

It should be noted that while England and Wales are larger than Western Denmark, most of the UK's wind power is currently concentrated in the south half of Scotland, which does raise issues regarding standard deviations which warrant further attention.

Table 4-1: Standard deviation of wind power fluctuations (%)

Lead time, hr	**1**	**2**	**4**
Single wind farm	11.8	16.0	20.8
Aggregations			
Farmer et al (ref. 17)	9.4	13	17
NGC, (ref. 11)(5600 MW)	3.1		6.0 (at 3.5 hr)
Danish data, (ref. 9)	3	5.6	10

The table includes data from an early analysis by Farmer et al, and this yields higher standard deviations for aggregated wind than quoted by NGC, or derived from Danish data. This is due to the study using meteorological data, combined with wind turbine performance characteristics, to produce simulations of wind output. This tends to overstate wind fluctuations, as meteorological measurements are made at a single point, whereas wind farms respond to average winds over a large area. This study is discussed further in Appendix A.

5 Integration of Intermittent Sources into Electricity Systems

5.1 Electricity network considerations

Aggregation of demands, as noted above, smooths fluctuations, and aggregation of wind generation has the same effect, so aggregation of generation and demand further simplifies the operation of utility networks:

> *"The uncontrollable, unpredictable, and variable nature of wind output is not analyzed in isolation. Rather, as is true for all loads and resources, the wind output is aggregated with all the other resources and loads to analyze the net effects of wind on the power system. Aggregation is a powerful mechanism used by the electricity industry to lower costs to all consumers. Such aggregation means that the system operator need not offset wind output on a megawatt-for-megawatt basis. Rather, all the operator need do, when unscheduled wind output appears on its system, is maintain its average reliability performance at the same level it would have without the wind resource"(ref. 18).*

The "demand prediction error" is a measure of the accuracy with which demand can be predicted and the standard error is about 1.3% (ref. 19). On the generation side, the prediction error is similar, and so the total error in mismatch between supply and demand, which is a "sum of squares" calculation, is about 1.6%.

These uncertainties have a strong influence on the scheduling of reserves, although another factor, the need to make provision for breakdown of the largest single unit on the system, is also important. In the UK, this is usually one circuit of the Cross-Channel link or Sizewell B power station, with the result that (ref. 19) shows that the average level of fast and regulating reserve is about 1 000 MW.

It can be appreciated that the variable nature of intermittent generation presents the operator with new challenges. These are mainly associated with the short-term (up to four hours, say) uncertainty of power available to correspond continuously to system demand. This also involves keeping enough generation reserve to cater for ancillary services required to compensate the supply-demand imbalances and voltage drops.

The difficulties associated with intermittent generation can be categorised into operational and interface issues. Operational issues comprise operating reserve, unit commitment, economic dispatch, and system stability. Interface issues include power quality issues and network requirements (reactive power supply, voltage regulation and frequency control). However, the impact of intermittent generation will vary depending on the particular power system and power market under consideration. For instance, where network systems are heavily loaded or not well meshed, then congestion may present a hurdle to the delivery of back-up power to support intermittent generation. Also, power systems with a large hydro-generation component might be more receptive to intermittent generation as they can deliver back-up power more rapidly.

Consequently, the impact of intermittent generators depends strongly upon the power system to which they are connected. Some of the main issues that have been identified internationally [(ref. 2) to (ref. 7)] concerning the connection of intermittent generation to the power system include forecast of dispatchable generation, network management, frequency and voltage control ancillary services, and regulatory issues.

The above difficulties and challenges introduced by intermittent generation onto the system bring with them associated costs. For instance, Danish environmental and energy policies with ambitious goals have resulted in large subsidies for constructing and running small-scale CHP and wind plants. Thus, the model chosen for conditions of connection to the grid places a greater responsibility (and cost) on to the system operator rather than the developer, and for example requires Eltra in Western Denmark to build the land grid connection for offshore wind farms.

5.2 Integrating intermittent sources - General considerations

Deployment of renewable generation is expected to grow as environmental concerns cause a move towards a cleaner production of electricity and reduction in use of fossil fuels. It is envisaged (ref. 1) that renewable generation will displace conventional power plants in increasing numbers. As seen earlier, some renewable generation is inherently intermittent by nature. It is expected, as a result of the propagation of intermittent generation to the power system, that changes in philosophy of operation will be needed. These changes will vary according to the location of the connection of intermittent generation.

The new considerations can be classified into issues concerning the Distribution and Transmission systems respectively.

5.2.1 Transmission Networks

In assessing the impact of renewable generation on the operation of the transmission system it is relevant to bear in mind different time horizons.

Balancing of supply and demand will require an insight into long-term, seasonal, daily and real time load behaviour in order to anticipate required generation and adequate levels of reserve. Market arrangements play a significant role in this respect as some functions are intertwined with the operation of the system.

The long-term time horizon analyses of load variations must be considered by the system operator's planning office in order to anticipate the network expansion and reinforcement required, though in the UK actual connections and disconnections may be made on much shorter timescales. Planning criteria require the capability to supply peak demand. It also incorporates the calculation of reserve generation required by the system to provide ancillary services needed to sustain system security. In the UK these services are purchased by NGT from the market; there needs to be sufficient long term incentive for providers to offer them.

The additional margin of generating plant above peak demand is correlated to the desired level of security. The level of required security varies from system to system based on the potential risk of interruptions acceptable to the system operator. However, in market based operation of the electricity system, there is no universal standard for the margin and the need for new plant is dictated by market forces.

To reduce the uncertainty inherent to intermittent generation the generic approach conventionally accepted by some utilities internationally has been to neglect any contribution made by these generators (ref. 5). This is because intermittency equates to opposite variations in demand. Therefore, significant increases in the levels of renewable generation translate into an increase in the uncertainty of the expected demand. The National Electricity Market Management Company (NEMMCO)

experience in Australia (ref. 2) shows a correlation in inaccurate load forecast and intermittent generation variations. They have concluded:

> *"Increased penetration of intermittent generation will create additional uncertainty in national electricity market price and reserve forecasting processes, and will therefore impact their accuracy. Changes to those processes may therefore be required to recognise the variable nature of some generation sources. Such changes would most likely require the provision of availability data and operational metering data to NEMMCO from significant non-scheduled and intermittent generation sources".*

(i) Operating Reserve.

Operating reserve is required to assure adequate system performance and to protect against the sudden loss of generation or a transmission line and, also, a significant fluctuation of load. Operating reserve can be instantaneous, spinning and standing reserve.

Instantaneous reserve is output capability immediately realisable via the Automatic Generation Control (AGC). This reserve can sustain energy requirements for a few minutes until spinning reserve becomes effective. Spinning reserve refers to the additional output which part-loaded generators can make available and sustain within 5 minutes notice. Spinning reserve generation is synchronised to the system and spinning in air (thermal plant) or water (hydro plant) prepared to pick up output. Standing reserve is output from plant at a standstill and is able to supply sustainable output within 5 minutes. This is usually covered by pumped-storage and gas turbine plants.

The system operator's planning criterion to determine the amount of spinning reserve varies upon system conditions. Traditionally, this criterion has been to consider the most likely event of the sudden loss of; a) the largest individual generating set, b) the largest generating plant or c) the most significant interconnector (link between two independent systems).

Spinning reserve guiding principles are also affected by load shedding capabilities in place and any international interconnections of the system. However, the amount of spinning reserve will also be influenced by electricity market regulations. In places where the emphasis is on customers' satisfaction rather than the economics of the system, load shedding or curtailments can be unacceptable.

It is anticipated that large penetrations of renewable generation may displace conventional plants that provide ancillary services required to manage the system securely (ref. 1). Significant increases in the levels of intermittent generation, especially unscheduled generation, bring additional uncertainty of expected peak demand and/or generation availability, therefore affecting the accuracy in the operator's estimate of additional generation needed to meet spinning reserve requirements. Furthermore, renewable generation technology is not currently adequately equipped to provide some of these ancillary services, namely frequency and voltage regulation, although design improvements are addressing these to a limited extent.

The experience of NEMMCO (ref. 2) suggests that there is a need to model the contribution of non-scheduled generation sources. Conversely, in Denmark where wind generation has a substantial share of dispatch generation, spinning reserve is made available from neighbouring countries via international interconnector.

Statistical analyses to determine the amount of spinning reserve in a scenario where intermittent generation is considerable requires the scrutiny of historical data. At present, the UK lacks historical data, but as penetration of intermittent generation gradually increases, enough data could be collected to carry out a more accurate statistical study.

(ii) Unit commitment and Generation Dispatch

The Unit Commitment concept implicates the appointment of electricity generation units that should be running in each period so as to satisfy a predictably varying demand for electricity. Economic Dispatch refers to the set of instructions for a generating unit to achieve specified load and/or target voltage levels.

Given the mixture of units available for generating electricity and their corresponding techno-economic characteristic, the units are scheduled (committed & dispatched) to run based on their start-up costs, seasonal availability of primary energy sources (hydro and wind), shutdown costs, and maintenance schedules and they are loaded based on their operating costs.

Because seasonal and daily load forecasts are associated with weather changes, then models correlating the weather forecast are widely used world-wide to predict load profiles to assist in producing the corresponding unit commitment and dispatch schedules. The approach taken by some utilities in scheduling and dispatching plant in the face of the indeterminate variations of renewable generation has been to discount their output (ref. 7).

However, NEMMCO recognises that given the expected growth of highly variable generation, specific mechanisms may need to be developed to incorporate intermittent generation in forecast processes. These include:

(a) accounting for the contribution of intermittent generation in the forecasting process using a statistical approach

(b) monitoring the contributions of non-scheduled generation and eventually separate it from other components of demand

(c) accumulating records of the actual production levels from non-scheduled generation. For this purpose they suggest appropriate operational metering be put in place.

Several sources ((ref. 2) to (ref. 7)) agree that wind power output could be included in the forecast processes.

Load and generation imbalances in the UK are managed by dispatching half-hourly the generators which participate in the balancing mechanism. Limited literature has been published on wind data analysis and corresponding wind generation output at sub-hourly timescales. Yet, real time dispatch requires the operator to realign the generation profile recurrently to follow changes in load and unscheduled generation every several minutes.

International experience differs in the treatment of real time imbalances. In Australia where real-time dispatch operates every 5 minutes, the operator simply assumes that intermittent generation will not materially change over that period. In places where storage plant is available, then real-time balancing can be rapidly achieved by storage facilities.

It has been explained that the combined output variations of intermittent generation geo-electrically scattered in the system (aggregated generation) would be reasonably smooth. This is because all

renewable generators cannot be synchronously disturbed at one single time. However, the study carried out by GH&P (ref. 3) emphasises that failure of all wind generation in an area the size of Northern Ireland due to low wind is considered credible.

Therefore, NEMMCO's proposal to accumulate records on production levels of non-scheduled generation should be considered and can be extended to include intermittent generation.

On the other hand, GH&P has reported limits imposed on positive and negative rate of change of power. Limits on positive and negative rate of change of power have to be established for situations when the system operator has instructed other plants to reduce or increase output in response to variations in demand (e.g. peak demand). Also, limits will be needed in future when wind ramp rates (in MW/s) reach the levels of the maximum ramp rates from conventional generation. Figures found during the literature review for limits of positive ramp rates include 0.1 of rated power output (defined as "P_{nom}") per minute in Germany and 0.07 P_{nom} per minute in Scotland. The negative ramp rates (during shutdowns only) in Scotland requires a phased reduction of output over 30 minutes.

(iii) System Stability

Stability refers to the system's ability to remain stable in terms of voltage and frequency. Operational actions (operation of switches, connection of equipment, dispatch of generators, etc) and abnormal system actions/events cause the generators to accelerate or decelerate. When generators run at different speeds, then power flows erratically. Two issues are relevant: firstly, the generators are required to remain synchronous. Secondly, voltage varies when power flows over the system components, and it is therefore necessary to ensure that voltage will not collapse.

For generators to withstand nearby faults, protection clearance times should be set properly, thus avoiding further system disturbances. Protection settings are usually obtained from the Grid Operator. Generally, disturbances will be more noticeable when the grid is less integrated.

Because erratic power flows may cause the transmission system protection to operate unduly, then limits and/or requirements are enforced on the amounts of power allowed to transfer across the transmission lines. In addition, voltage may collapse in seconds if the incident is critical. Voltage stability is determined by the characteristics of the grid and the operating procedures implemented. The critical issue is the intensity and time interval of the voltage drop.

Some requirements imposed on generators stipulate that these must remain operating during and after a fault occurs in electrically close proximity. Some system operators are more demanding than others; in Scotland the grid code is onerous for wind turbines (see Appendix A).

Technically there are no obstacles to achieve the requirements, yet there may be regulatory, design or costs implications to take into account. Grid Code requirements are key issues for wind plant developers, and these are being analysed separately within Mott MacDonald's overall work for the Carbon Trust. Grid Code compliance issues are therefore the subject of a detailed discussion elsewhere within our Generator Characterisation Report. Deployment of wind turbines in California (ref. 7) has not led to system stability problems due to wind speed fluctuations or network disturbances.

5.2.2 Distribution Networks

It is recognised that electricity produced at distribution level provides benefits including the reduction of electricity losses and the corresponding improvements in voltage levels. This in turn may defer investment in assets needed to reinforce the system. Certainly, this will depend on the numbers of MW that will be injected and the connection voltage at which generation will be attached. However, even if there is scope for the presence of generation to defer or obviate the need for Distribution Network Operators (DNOs) to reinforce their system, DNOs will need reassurance that generation will actually be available when the system needs the support.

Consequently, despite the benefits of locally produced electricity, the production of electricity at distribution levels also introduces operational challenges, which are exacerbated if electricity generation comes from intermittent sources. Thus, the operation of distribution networks calls for a change in philosophy in consideration of the new challenges and difficulties introduced by the growing level of electricity production at distribution level.

In such an increasingly dynamic operating environment the DNOs would have to control generation more effectively. For that reason DNOs may have to engage in

- Dispatch of local generation
- Management of Reactive power
- Co-ordination of voltage control

These issues are similar in nature to those facing the transmission system. Consequently, the same topics discussed for transmission systems (forecast, operating reserve, generation dispatch, system stability) are also relevant to distribution systems.

5.3 Interface Issues

The interface issues relate to the technical requirements faced by the plant when connecting to the system, before the plant can be made operational and export power, and also include power quality requirements.

5.3.1 Connection

Jensen's study (ref. 4) has shown that with the penetration of renewable generation the production of electricity in Western Denmark is now moving towards lower voltage levels of the grid and he believes that this tendency will continue. The study reveals that in 2001 half of the power generating capacity in Western Denmark was connected to distribution networks.

At that time there were 17 local plants and 50 wind turbines connected at 60 kV voltage level with a total capacity of 568 MW and 32 MW correspondingly. At 10 to 20 kV voltage levels there are 711 local plants and 4 938 wind turbines with a total capacity of 1 053 MW and 1 868 MW respectively. In Ireland (ref. 3) most wind farms are connected to 33kV voltage level, however, in the absence of 33kV voltage level in Western Denmark, these are mostly connected to the 10 to 20 kV networks.

The penetration of generation into distribution networks will mostly come from scattered generators whose location and amount is not known in advance either to the Transmission or Distribution Operators. Therefore, a question that comes to light is whether distribution networks capacity can cope

with forthcoming generation and if not, then who will assume the costs involved considering the government's intentions to promote renewable generation. Strbac's (ref. 1) study has mentioned that DNOs in the UK anticipate that there is a limited capacity to integrate generation at distribution level. The DNOs envisage that without proper investment to reinforce distribution networks, the government's target to generate 10% of UK electricity sales based on renewable energy sources by 2010 could be affected, although this must be seen within the context of the DNOs' own priorities. Determining what these barriers are, at transmission level as well as distribution level, and estimating the range of costs to reduce them sufficiently or to remove them altogether, is one of the key tasks of Mott MacDonald's study for the Carbon Trust.

5.3.2 Power Quality

One of the most important technical issues associated with the connection of intermittent generation to the grid is the Voltage Quality. For any grid-connected system, power factor and harmonic consideration are important. Some renewable generation can introduce non-sinusoidal currents, thus degrading voltage quality by causing harmonic voltage distortions. This is because these power generating technologies do not produce 50Hz AC and thus they need semiconductor-based power converters to connect to the grid. Any power electronic converter will result in some harmonic voltages. However, these can be controlled to acceptable levels.

However, advanced converter systems can produce output with very little harmonic distortions. The arrangement of new generating technology supplemented by these advanced converter systems should not cause any concern to the network. It is advised that the design of generating technology include filters to reduce harmonics to acceptable levels.

A study (ref. 47) of a ten-machine, 4 MW wind farm connected into an 11 kV system in Cornwall, England has provided valuable information on local issues. The study concluded "the wind farm caused surprisingly little disturbance to the network or its consumers". In particular: -

- Voltage dips on start-up were well within the limits prescribed There were no problems with flicker during any operating conditions
- During periods of low local load, the output from the farm was fed "backwards" through the distribution network, but no problems were reported.
- Reduced activity of the automatic tap-changers at the adjacent 33/11 kV transformers was significant and would lead to lower maintenance costs.

Large current fluctuations were sometimes observed although there was a possibility that these originated elsewhere within the distribution system.

However, for larger wind farms or in places concentrating several wind farms within the same area, it would require close analysis, as data becomes available from operator records.

Literature on international experience has not reported troubles on the control of harmonics from generating technology.

5.3.3 Voltage Control

Voltage falls across transmission and distribution lines as a result of power transfers across network elements. This brings about the need to compensate voltage in the way of generating reactive power.

Voltage control is an imposed action, usually through an external adjustment, for the purpose of increasing or decreasing "terminal voltage". Voltage control methods can produce stepped or continuous voltage changes. The former encompasses the deployment of transformer tapping and capacitor bank (and reactor) switching and it is not suitable for frequent changes in voltage due to intermittent generation. The latter includes synchronous and static compensators as well as generating unit excitation systems (manually or automatically). In most cases the process involves changing the resistance of the field (excitation) circuit. By changing the field circuit resistance, the field current is controlled. Controlling the field current permits control of the output voltage. An automatic voltage control device "senses" changes in output voltage and causes a change in field resistance to keep output voltage constant

The penetration of large amounts of intermittent generation in distribution networks may cause significant variation of local voltage. Local voltage control in distribution networks is generally accomplished by means of transformer tapping and capacitor banks.

If voltage control is needed in transmission networks, then given the number of customers that could be potentially affected, the system operator requires a balancing contribution from conventional generation to make up for the voltage variations. Displacement of conventional generation, which provides this voltage support function, by intermittent generation may expose the voltage control abilities of the system.

In the US (ref. 7) the Southern California Edison Co. (SCE) has experienced difficulties at 66 kV voltage networks. The solutions considered by SCE included new transmission lines, alternative line arrangements, the addition of static or adaptive VAR controllers, and wind plant curtailment. However, the least-cost option is to curtail wind plant production and to compensate the wind plant operators.

In Australia, NEMMCO (ref. 2) suggests that intermittent generation should be able to provide a share of the reactive power requirements in a continuously acting form. Garrad Hassan (ref. 3) have brought to light that Eltra in Denmark requires the wind farm to operate close to unity power factor, while in Scotland the system operator requires a range of 0.95 lead to 0.85 lag and to be able to control local voltage.

5.3.4 Frequency Control

Frequency changes are the direct measurement of demand/supply balances. Drops in frequency equal to greater demand, vice-versa rises in frequency are indications of reductions of customer loads. Quality standards require a frequency variation of no more than ± 1%.

Frequency control is provided by flexible output of conventional plants and usually supplemented by fine-tuning of hydro plants (refer to Appendix A for bands of timescale of action for frequency control).

In systems where wind energy has an important share of dispatched generation, system frequency varies when gusting winds increase the output of wind plants. An analysis carried out by NEMMCO (ref. 2) suggests that within a 5 minute interval (real time dispatch) the output of an existing wind farm can vary up or down by up to 50% of nameplate rating. Therefore, other generation plant may be needed to counteract this variation in generation in real time. This may prove problematic for weak isolated systems.

In the US (ref. 7) a study showed that a reduction in capacity (increase in demand) of 10 MW per minute on the Hawai Electric Light Company (HELCO), would cause a particular load-following plant to trip, thus resulting in a loss of ability to regulate system frequency within acceptable limits. The study concluded that HELCO system would require the use of modern, variable-speed wind turbines with power electronic control and interface to the grid and/or automatic generation control with additional spinning reserve.

Although these international views are worthy of interest, the UK power system is strong and well integrated, and thus the above is not presently of concern within a British context.

NEMMCO (ref. 2) has found that the amount of ancillary service needed for regulating frequency for a single wind farm may be of the order of 30% of nameplate rating. However, the aggregation of physically separate wind plants can reduce this figure. NEMMCO's analysis suggests that two wind plants of the same rated output but located at different locations will reduce the requirements for ancillary services for regulating frequency to 20% of total wind name plate rating. Three wind plants will further reduce this figure to 15% of total combined nameplate rating.

NEMMCO judges that for large amounts of diverse wind generation at various locations will require ancillary services for regulating frequency in the order of 5% to 10% of the total wind generation nameplate rating. This is consistent with the findings from other studies.

NEMMCO has concluded that intermittent generation may result in a greater usage of frequency control ancillary services to manage power system frequency and that revised monitoring arrangements may be required to identify the party causing the need for regulating ancillary services, in order to recover the associated costs.

In Denmark (ref. 9) Eltra requires disconnection of the wind turbine at frequencies below 47.0 Hz and above 53 Hz. No time constraints are placed for underfrequencies above 49.0 HZ and overfrequencies below 50. However, the response to overfrequency must be such that output power is reduced from 100% to 20% in 5 seconds (ref. 3).

To provide an increase of output to counterbalance a drop in system frequency would require the wind turbines to be operating at below the power level possible in the wind conditions. This would cause a waste of energy, which according to Garrad Hassan (ref. 3) will not be acceptable in Germany.

It can be concluded that provided sufficient frequency control ancillary services are in place to meet frequency variations, this issue should not impose a threat to the system. The issue is more about who should fund the increase of additional ancillary service to regulate frequency as a result of increased wind power penetration; a "causer pays" policy may discourage renewable generation.

5.3.5 Additional Requirements (Metering, Automated Dispatch and Control Systems, Protection and Control Equipment, Remote Monitoring)

To improve results from key areas of forecasting, frequency control, voltage control and overall network management the availability of operational metering data from all relevant generating plant, including intermittent generation, is required. Analaysis of historical operational metering data will help the operator to understand the impacts of intermittent generation as they arise.

Availability of operational metering data will:

- provide a better understanding of the impact to the system of intermittent generation;

- help monitor intermittent generation and its effects on long and short term forecasting processes;

Additionally, monitoring of operational metering data will require co-ordinated arrangements to manage the cut-out operation of wind farms.

Projections foresee power electronics components becoming the key to allowing a greater use of renewable generation within distribution and transmission networks.

Revolutionary advancements in communication technology may be at the forefront of interface changes in the implementation of intermittent generation. Little A.D (ref. 14) explains how new communication systems may be expanded to allow control and dispatch of distributed generation.

With power electronics becoming increasingly appealing we may see small DC distribution systems used to connect remote loads to the grid without having to install high-voltage AC transmission systems. This might lead to a dramatic change to DC systems and eventually modifying in the old paradigm of grid control through frequency stability.

5.4 Extra costs incurred due to the additional uncertainty imposed on System Operators

A key issue when considering the impacts of intermittent renewable energy sources is that extra costs are incurred due to the additional uncertainty imposed on System Operators by the variability. This additional uncertainty translates to a need for additional reserves, which cost money. The cost of these additions, per kWh of generation from the intermittent source, is examined first.

A separate, and equally important, issue in the context of economic appraisals of intermittent sources, is the "capacity credit" of the source.

In essence, the value of intermittent sources may be specified as:

<u>(fuel saving value) + (capacity saving value) - (costs associated with intermittency)</u>

Although the scope of this analysis does not include economic appraisals, it is important to quantify the capacity credit, from which the capacity saving value can be specified. This is examined in the next section.

Relatively few studies have quantified and explained all the key parameters in the analysis, but sufficient information is available to build up a fairly clear and broadly consistent picture.

The analysis of Farmer et al (ref. 20): "Economic and operational implications of a complex of wind-driven generators on a power system", laid the foundations for an analytical approach to the question of wind integration. It is widely quoted and respected. The authors simulated the operation of up to 10 000 MW of wind (17% of generation) on the CEGB system, using hourly wind, demand and generation data. They formulated a number of key conclusions, most of which are still valid, and in particular argued that the “sum of squares” approach to uncertainties in matching supply and demand can be extended to include wind generation, as follows:

> *"There was a small positive correlation coefficient of 0.23 between the wind power output variations and the fluctuations in system demand. As a result there is negligible error in*

compounding the uncertainties in wind output and demand, as if they were statistically independent".

The National Grid Company has summarised the fluctuations from generation and demand currently managed, as a guide to levels, or "thresholds" for renewable energy, above which significant extra costs may be incurred. NGC notes (ref. 11), however, that *"any new fluctuations, even if smaller than those currently managed, will require some change in response and reserve holdings, potentially increasing their costs"*. The thresholds and the mitigation options are set out in Table 5-1. Additional background material was provided in an earlier submission to a House of Lords Select Committee (ref. 21):

Table 5-1: Factors influencing absorption of renewable energy

Nature of fluctuation	Maximum accommodated	Mitigation options
Predictable daily cycle	Fluctuation<20% of peak demand, i.e. 10 000 MW	Purchase additional controllable output as Balancing Services
Unpredictable instantaneous reduction in output	Instantaneous loss of 1 320 MW	Purchase additional frequency control services
Unpredictable 1 hour notice generation-demand imbalance	Potential generation loss or demand forecast error of 1 500 MW	Purchase additional reserve services

As far as wind is concerned, the third threshold appears to be more stringent. Using actual power data from Western Denmark, it was noted in Section 4.1 that the maximum power excursion in an hour was 18% of the rated wind capacity, and that German data showed similar characteristics. As the UK is bigger than Western Denmark, the assumption that the maximum UK swings will be 18% is probably conservative. If 18% corresponds to 1500 MW (from Table 5-1), then the corresponding rated power will be 8330 MW. It must be emphasised that these thresholds are not ceilings; merely markers. More wind can be accommodated, but at increased cost.

NGC has also observed "Sufficient fast response and reserve services will be available for a situation in which the entire 2010 renewables target is met by wind" (ref. 22). This message is reinforced in the current (2003/4) Seven-year Statement:-

"Current levels of frequency response are sufficient even if the goal of 10% of electricity ...were all met by wind"

"...If more response and reserve services is required, our ancillary service markets should encourage their cost effective provision"

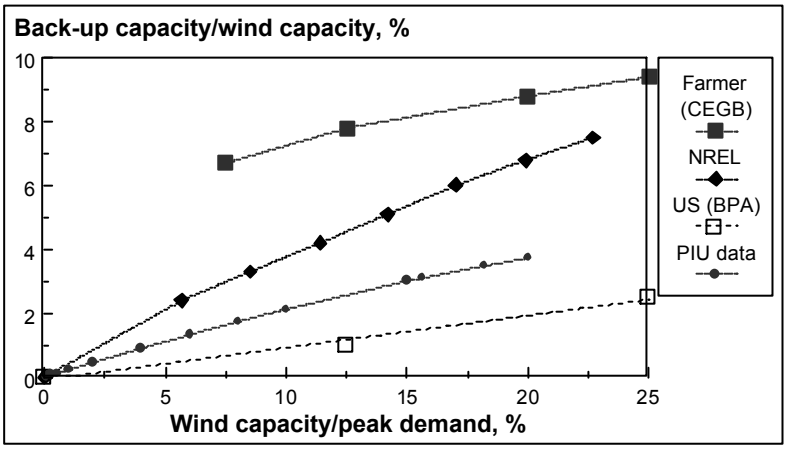
"We do not foresee any significant technical problems.. accommodating the government's targets for renewables and CHP by 2010"

6 Key Issues, and their treatment in the Literature

6.1 The amount and cost of extra reserve

The study by Farmer et al (ref. 17) optimised the amount of thermal reserve needed for increasing amounts of wind energy and the results are shown in Figure 4, below. With 5% wind energy (3 000 MW)[1], an extra 200 MW of spinning reserve was required (just under 7% of the rated wind capacity), with 10% wind (6 000 MW) the extra spinning reserve rises to just over 8% of the rated wind capacity (480 MW of thermal power). These results are broadly consistent with those quantified by NEMMCO (ref. 2). Data from more recent studies that present the information in this way is also shown on the graph. The Farmer study exaggerated for extra reserve, partly because it was completed just before Sizewell B power station was completed, (which necessitated extra reserve due to being the largest single unit) and partly because it overstated the wind fluctuations. More details are given in Appendix A.

Figure 4: Estimates of the extra back-up needs for wind energy



The study carried out by the National Renewable Energy Laboratory (ref. 23) used actual wind data from four sites and so did not benefit from the greater geographical dispersion appropriate to more widespread sites. This may be why the predicted backup needs are higher than those calculated for the analysis carried out for the UK PIU Energy Review (ref. 9). On the other hand, the predictions from the study carried out for the Bonneville Power Administration (ref. 24) are significantly lower than both of these, and it is not entirely clear why this is so.

Estimates made for the Scandinavian network are within the same range. A study carried out by Nordel (ref. 25) suggested that 9% wind (capacity/peak demand, consistent Figure 4) would require regulating power between 2.75% and 7.3% of the wind capacity. 25% wind would need between 3% and 7.6% of wind capacity. In Australia the study carried out by NEMMCO (ref. 2) has derived similar values. As noted earlier, NEMMCO estimated that backup regulating power needed was in the range of 5% to 10% for large amounts of diverse wind generation at various locations.

A.1.1 [1] It should be noted that the relationship between wind capacity and wind energy varies between different studies, as it depends on the assumed capacity factor of the wind plant.

There seems little doubt that the extra reserve in the UK (which amounts to between 400 and 700 MW for 10% wind) would be readily available, since,

- Suppliers are using extra spinning reserve post-NETA (ref. 26), to limit their exposure to the balancing market
- NGC has observed "sufficient fast response and reserve services will be available for a situation in which the entire 2010 renewables target is met by wind (ref. 27)".

On the other hand, recent plant closures and "mothballing" means that the capacity margin is now lower, so the situation may change.

6.2 Balancing costs

NGC has indicated the magnitude of the extra balancing costs likely to be incurred by wind energy (ref. 28) range from £0.67/MWh at 2% wind, to £2.38/MWh at 10% wind. Details of the analysis behind these estimates were reported in the paper prepared for the Energy Policy Review (ref. 9). In a more recent paper (ref. 29), NGC estimated the extra cost of balancing for 20% wind, from which a wind-related cost of £2.85/MWh can be derived. This data is shown Figure 5. Balancing costs differ from Reserve costs in that the latter is contracted for in advance in order to ensure support is available if called upon, while balancing costs are applied as a result of actual system balancing activities and are on the whole charged to those causing the imbalances.

The overall costs of balancing estimated by NGC are higher than those calculated by Milborrow (ref. 9) for the Performance and Innovation Unit, using a "first principles" approach to the calculation of the relevant costs. Figure 6 is drawn from this study. The calculation used the principles set out by Farmer, but with recent prices for reserve plant (ref. 30). NGC assumed equal amounts of frequency response and reserve plant would be needed, which is why its estimates are about 80% higher.

The graph also includes the penalty recently quoted by the Danish grid operator, Eltra, who absorbed 16.3% of wind energy on its system in 2000 at a cost of £1.58/MWh (ref. 31). This figure has not been challenged by the Danish wind industry. It may be noted that this estimate appears to be consistent with the calculations for the UK system. As mentioned before, Western Denmark is connected to Norway, Sweden and Germany although the grid operator pays market rates for balancing services. These may, however, be lower than market rates in the UK.

Figure 5: Extra balancing costs for wind energy (NGC data)

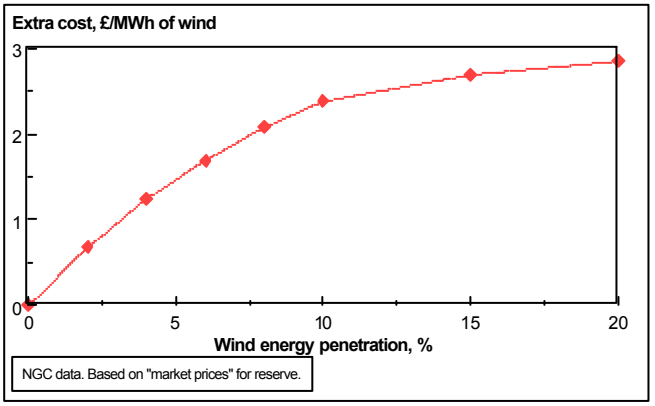
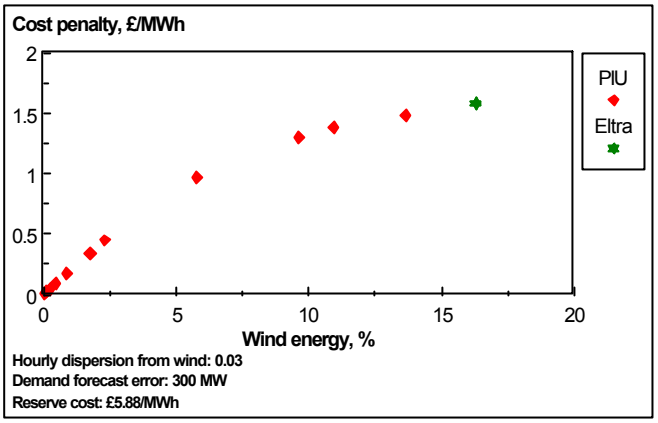


Figure 6: Estimates of balancing costs made for the PIU



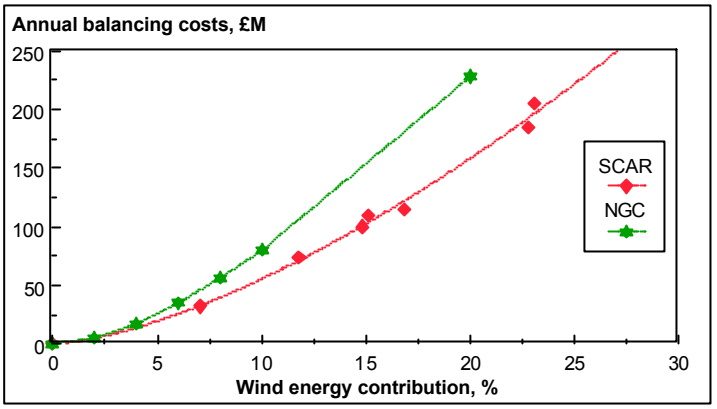
A third estimate of extra balancing costs for the UK system was made in the "SCAR" report (ref. 32). These are compared with NGC estimates in Figure 7. They are lower than NGC's estimates (by about 33%) and this is may be partly due to the use of lower estimates for the market costs of reserve. The magnitude of these costs has a critical bearing on the estimates of balancing costs and so the values used in each of the studies have been compared in Table 6-1. A comparison with market rates in the United States is also included in the table. The SCAR report also includes a good description of the trade-off between synchronized and standing reserve. The costs of the former tend to be dominant.

Table 6-1: Comparison of reserve costs

Source	Reserve	Frequency response
NGC (ref 3)	£5/MWh	£5/MWh
SCAR (ref 20)	£1-3/MWh	Add £4.5/MWh to reserve cost
Milborrow (ref 1)	£5.88/MWh	Not included
New York (Ref 6)	$2.56/MWh	Not quoted
Texas (estimate, from a graph)	$5/MWh	Not quoted

It appears that market rates fell in the intervening period between the NGC estimates of balancing costs being made and the SCAR study. They still seem to be higher than some other market rates in the United States and the latter may be more cost-reflective. Given that wholesale prices are low in the UK at present, it would not be surprising if generators sought to boost revenues through the ancillary services markets. This is what appears to be happening in some parts of the United States (ref. 33).

Figure 7: Comparison of extra balancing costs



It should be noted that, in practice, reserve prices vary with time and with demand. The use of average prices is a simplification, but more sophisticated methods of calculating the extra balancing costs are much more demanding in terms of complexity. They would necessitate a time-series analysis, but would inevitably be subject to criticism, as it would be difficult to demonstrate that any particular time series, with time-dependent market rates for reserve (and all other parameters), was totally representative of long-term conditions. The SCAR report discusses this dichotomy, concluding that analytical methods give acceptable results.

In conclusion, the upper and lower-bound and estimates for the costs of extra balancing may be taken from the NGC and PIU estimates, respectively. The former are based on conservative estimates of market rates, and the latter are closer to actual costs. These analyses suggest that the present-day technical level of wind penalty in the UK (for around 500 MW of wind) is between £0.09 and £0.18/MWh. With 10% wind energy, the penalty is between £1.35/MWh and £2.25/MWh.

6.3 Future developments

The growth of wind power, particularly in Denmark, is leading to developments that could make a significant difference to the costs of extra frequency control and reserve for wind energy. Eltra's (Western System Operator in Denmark) experience (ref. 4) shows that despite the ample international (Germany, Sweden and Norway) interconnection, balancing the system with large penetrations of non-dispatchable generation has sometimes proved to be problematical and on a few occasions it has threatened system stability. Jensen (ref. 4), has brought to light an event that occurred in April 2001 where changes of forecasted wind profiles indicated an 800 MW of surplus generation. At the time the interconnection to Norway and Sweden was in use to capacity, and Germany could not take surplus production from wind plants in Denmark, because of the level of output from its own wind power. The operator decided to regulate down 350 MW of CHP plants, to stop two local plants of 100 MW, and to overload the cables to Norway and Sweden to 70 MW. The remaining 180 MW of excess wind power could not be dispatched. The wind profiles then rapidly went back to the original forecast and the critical excess output situation reversed into a deficit situation of 300 MW.

In a separate incident, Eltra was forced to close down wind turbines to balance the system and avoid critical overflows. Regardless of the ability to import or export power across the interconnection with neighbouring countries, which strengthens the ability to balance the system, the Danish operator has revealed that the imbalances are often in the order of 800 to 1000 MW. When these numbers are compared to the maximum (3 650 MW) and minimum (1 150 MW) values of demand, then it is not

difficult to realise the potential problems. In percentage terms, the imbalances represent 22 to 27 % during peak load conditions and 70 to 87 % at minimum load conditions. It can be seen that the most onerous impact of intermittency at high penetrations is associated with low load conditions, if the bulk of the demand is being met by wind during such low demand situations.

It should be noted, however, that wind provides around 20% of electricity consumption in western Denmark, which also has a substantial amount of inflexible CHP plant, although considerable interconnection capacity is available for energy imports. Translated to UK conditions, this corresponds to 25 000 MW of wind and a similar amount of CHP plant. While this does not therefore represent a considerable risk to the UK situation, it does present a contingency for which system operators should plan, once the level of wind penetration in the UK has increased above 10%. It may also be noted that wind power forecasts in western Denmark are made 12 to 36 hours in advance and that better accuracy can be obtained at shorter timescales.

In the US (ref. 7), despite the fact that the state of California had not experienced major reserve requirements due to the variability of wind plant output, they acknowledged that further studies were needed to determine the point when intermittency begins to degrade system economics.

Other issues also need to be addressed. The recently-completed 120 MW Horns Rev offshore wind farm, (west of Jutland) for example, includes a number of characteristics including frequency control on the turbines, the ability to provide a limited amount of reserve and constraints on the ramping rates (ref. 34). Discussions on grid code modifications in the UK may lead to similar requirements, and these issues are discussed in our separate report on Generator Characterisation. These requirements may impose extra costs on wind turbine projects, but these would be offset by reductions in the cost of balancing penalties.

6.3.1 Curtailment costs

The provision of extra reserve enables generation shortfalls due to intermittency to be made up, but the converse problem of excess wind may necessitate deloading some wind plant on occasions, particularly windy summer nights. The Farmer paper suggested this might happen with a wind energy penetration of around 13%, and the SCAR study found it might happen at a level around 15% - although neither study quoted a threshold. The costs are, however, very small. The maximum level in the SCAR report is £0.1/MWh, with 27% wind energy.

6.3.2 Storage

Storage is often seen as a "solution" to the difficulties of coping with intermittency. However, results from the studies already cited show that the additional system costs of coping with intermittency are quite modest. Storage is simply one possible way of providing additional reserve, but generally has no intrinsic merit for "levelling" the output from intermittent sources - simply because it is very unlikely that the increased value will exceed the extra cost.

The Farmer study (ref. 17) made this point as follows: *"...there is no operational necessity in associating storage plant with wind-power generation, up to a wind output capacity of at least 20% of system peak demand".* A later American study made the same point (ref. 35): *"Storage may increase the value of intermittent generation. However, studies generally show that dedicated storage systems for renewables are not viable options for utilities because of added capital costs of current storage*

technologies. Storage can add flexibility and value to utility operations, but it should generally be a system-wide consideration, based on the merit of the storage system".

It may be concluded, therefore, that storage may or may not be the most effective way of providing additional spinning reserve, *for the system*, depending on its costs. However, with the possible exception of pumped storage, large-scale storage of electricity is generally too expensive or too demanding of specific site requirements. Sites for new pumped storage systems in the UK are unlikely to be found. It may also be noted that the existing pumped-storage facilities operate with a low load factor, perhaps indicating that plentiful storage is already available. However, it should be noted that low load factors do not necessarily indicate the frequency for which such plants are used for ancillary services, which does not normally require significant levels of output. The SCAR report (ref. 32) suggests that the value of the existing pumped storage facilities would be improved if they were able to provide frequency response in pumping mode and this would be likely to further facilitate the assimilation of intermittent renewables.

With capital costs of large scale storage systems generally in the range £500-1000/kW, fuel costs (based on current wholesale prices) around £15/MWh and annual load factors unlikely to exceed around 65% (taking into account the "round-trip" efficiency), generation costs from storage devices are unlikely to be lower than those from combined cycle or open cycle gas turbine plant. Using pool prices as a guide, it has been suggested that the cost target for storage with low maintenance costs is around £700/kW, assuming a 15 year life and a discount rate of 8% (ref. 36). The break-even costs for storage plants will depend on the trading gains they can make.

(i) Regenesys

At one stage the prospects for a new reversible "flow battery", being built at Little Barford Power Station, looked very promising, but Innogy scrapped the project in December 2003. Innogy claimed it had the potential to bring about a revolution in the power industry. The claim was made at a presentation in London to launch "Regenesys," as it is known. Regenesys is a reversible fuel cell and, following successful trials of a pilot project at Aberthaw Power station in Wales; the first plant was to have a rated output of 15 MW and a storage capacity of 120 MWh.

The prototype Regenesys plant appeared to be able to store power at a price which is close to commercial viability in a competitive electricity market such as that of the UK. The target cost for storage is controlled by the pattern of electricity prices, the lifetime of the device and the rate of return required by the owner. The higher the difference between peak and off-peak electricity prices, the more one can afford to pay for storage. In England the break-even cost, as noted above, may be around £700/kW - possibly higher if there are added benefits from ancillary services. Innogy expected the cost of its first commercial prototype to be around £1000/kW.

(ii) Fuel cells

There is considerable discussion over the emergence of the "hydrogen economy" and the impacts this might have on the assimilation of the intermittent renewables. However, the generation of hydrogen by electrolysis and its subsequent conversion to electricity is both inefficient and costly and somewhat uncertain at present. It is therefore unlikely to be an attractive proposition as an alternative storage mechanism for some time to come, based on the literature reviewed to date (ref. 37) and (ref. 38).

6.4 Capacity credits

6.4.1 CEGB studies

All the key studies of the UK network have concluded that wind plant has a capacity credit. The Farmer study (ref. 17), for example concluded:-

> *"If a definition of capacity credit is adopted, that maintains the existing level of security of supply, it can be shown that for low levels of wind-power penetration, a substantial proportion of the output can be ascribed as firm power".*

The paper endorsed the findings of an earlier study (ref. 39), noting, "Even at higher levels of penetration, the capacity credit could approach 20% of the rated output". On the basis of a mathematical analysis, Swift-Hook (ref. 40) also of the CEGB, later suggested, that, to first-order, the capacity credit was equal to the annual capacity factor. In practice, as winds are stronger in the winter than in the summer, and the availability of wind power at times of peak demand carries some weight, Milborrow (ref. 41) later suggested that the "winter quarter capacity factor" was more accurate at low penetrations. This was based on an analysis of a number of different studies.

The 1988 CEGB study (ref. 16) also addressed the issue, suggesting that the capacity credit declined from 31% with 2% wind energy to around 16% with 15% wind energy. That study was one of ten such analyses of European electricity networks, all part-funded by the European Commission. A comparison of the values of capacity credit derived from them is shown in Figure 8.

It should be noted that the values of capacity credit depend on the assumptions made about the average capacity factor of the wind plant. To facilitate comparisons between the studies, Figure 9 compares normalised values of capacity credit between some of the studies. (It was not possible to analyse all the data in this manner). Although the normalised capacity credits all fell with increasing wind energy penetration, and the general form of the curves is similar, clearly other factors affect the precise form of the relationship.

Figure 8: Capacity credits from 8 CEC-funded integration studies

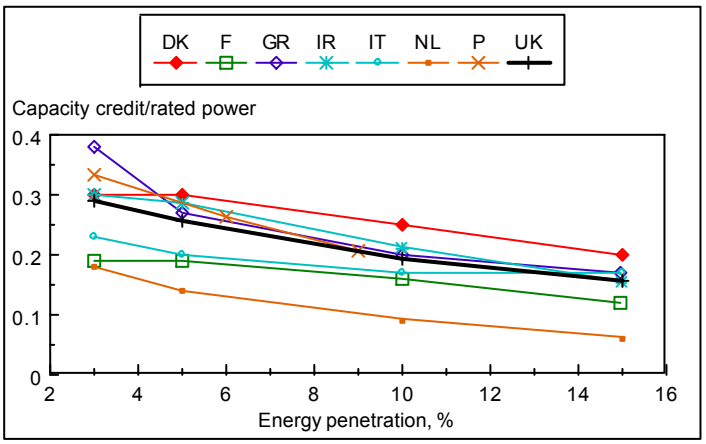
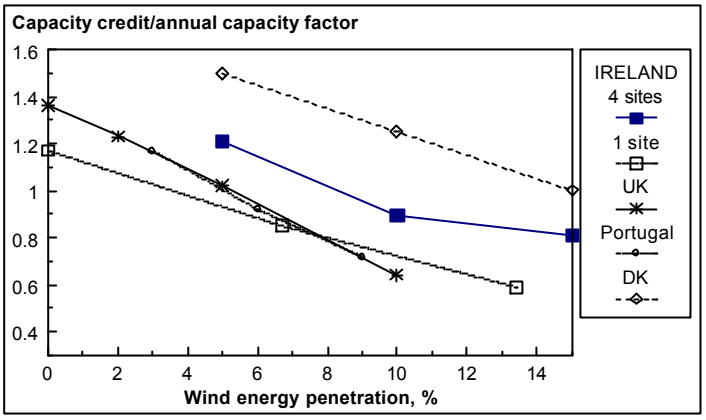


Figure 9: Normalised values of capacity credit as a function of wind energy penetration.



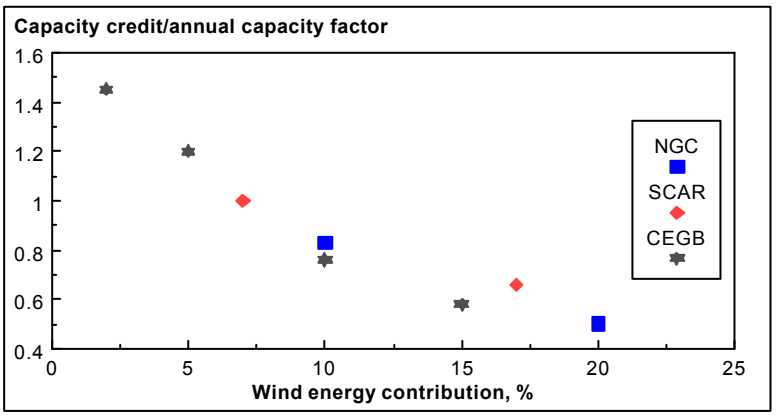
6.4.2 NGC Work

NGC has published estimates for the capacity credit of 10% and 20% wind energy penetration (ref. 42). NGC indicates that 7 500 MW of wind would displace about 2 000 MW of conventional plant and 25 000 MW of wind would displace about 4 000 MW of conventional plant. This decline of capacity credit with increased penetration is in line with most other studies that have been published and their values compared with those derived by other sources in the next paragraph.

6.4.3 The "SCAR" report

The "SCAR" report also made assessments of capacity credit for wind plant and these are compared with data from NGC and the earlier CEGB study in . The agreement between the three studies is good, suggesting that the capacity credit is around 1.5 times the annual capacity factor at low wind energy penetrations, falling to around 50% of the annual capacity factor with 20% of wind energy.

Figure 10: Comparison of estimates of capacity credit



6.4.4 Implications of NETA

If wind power can generally be relied on to generate at a higher capacity factor during the winter months then wind power could be given a higher value during the winter than its annual average price. However, imbalance costs during the winter months can be higher than at other times and so the potential risk of giving wind power a higher value during the winter is that imbalance penalties are potentially higher.

The issue of higher penalties could be particularly problematic for wind if the Balancing and Settlement Code (BSC) adopts either of the two modifications now being put forward regarding calculation of imbalance prices in the Balancing Mechanism (BM).

Initially, the BM started with imbalance prices which were calculated from the weighted average of offers (to supply) and bids (to take energy) which gave us the System Buy Price (SBP) and System Sell Price (SSP) respectively.

This was changed in March 2003 to a net imbalance method, were the bids and offers were offset against each other to provide net of offers or bids which was then used to provide a SBP or SSP depending on whether the system had called more offers than bids respectively. The remaining cash-out price was then calculated from a prompt market index. This had the effect of substantially reducing the buy-sell spread and hence the penalty for imbalance.

The situation is expected to shift again back toward more punitive pricing. There are two proposals to adopt marginal pricing rather than weighted average prices. The claimed rationale for this is that this will encourage generators to provide flexible reserve plant. The negative side of this is that inflexible and intermittent plant is heavily penalised in contract its energy in forward markets.

If the BM does move the marginal pricing this will effectively provide a hefty discount on the value of intermittent energy in the market. However, this value cannot be quantified without an increase in the available detailed data on wind availabilities.

Given the paramount importance of sharing reliable data to scrutinise wind variations for the pre-dispatch (long and medium term), and dispatch (including real time dispatch) processes we would recommend that the UK wind industry assemble wind fluctuation data. Of particular importance is data covering the number of days when wind speeds were insufficient or were above operating limits. NGT has apparently investigated this situation in order to calculate incidents when estimated reserves based on the standard approach may not be sufficient, although this work is not in the public domain.

6.5 Better Wind predictability

Methods of improving wind predictability, specifically geared towards wind-generated electricity, have been developed in both Europe and America and further studies are in progress. The Danish grid operator, for example, uses wind prediction methods and a small levy has recently been agreed with Californian wind developers to fund further studies. As an indication of the improvements that can be secured, a British study has estimated that the needs for extra spinning reserve can be reduced by over 30% (with 10% of wind) using these methods (ref. 43). If the conclusions from this study are reflected across to the system penalties, it is estimated that these could be reduced by about £0.45/MWh at the 10% wind energy penetration level.

Another study has estimated that revenues under NETA could be increased by up to 7.5% by appropriate forecasting methods (ref. 44).

6.6 Demand-side Management

The potential for load management, i.e. active control of customer loads, in association with wind energy has been investigated and found to be a viable way of increasing the amount of wind generation which can be accepted onto a weak network (ref. 45). It follows that load management could attenuate the power fluctuations "seen" by a supplier or grid operator and these techniques can also be used to reduce the magnitude of the technical penalties.

6.7 Wind-induced demands ("The cooling power of the wind")

It is known that a rise in wind speed may be accompanied by rising demand and one estimate for the link between heating load and wind velocity suggests a linear relationship (ref. 46). If so, this would enhance the value of wind energy. However, predictions of increased heating loads due to wind are empirical in nature. Given the difficulty of establishing precise estimates for rates of air leakage, together with the variations between different types of building, means that it is not practical to devise rigorous theoretical estimates, but the form of the equation used by the UK electricity industry, suggests a square root function. This is broadly consistent with what might be expected from an examination of the underlying physical processes. Although some authors have failed to find evidence of a correlation, this does not necessarily imply that the phenomenon does not exist. One recent study appears to indicate that some correlations can be detected at the local level (ref. 47).

6.8 Other Issues

6.8.1 Wind-diesel and other hybrid systems

Although there is considerable interest in the potential of wind-diesel systems for small isolated networks (ref. 48), it is unlikely that such systems would be economically viable within a large integrated network. Some Distribution Network Operators have installed diesel generators to improve security of supply, mostly in rural areas with relatively few network connections. However, the economic case for installing such units depends on assessments of the network security is a whole, and they have not specifically been linked with renewable energy installations. On Orkney (before it was connected to the mainland) and Shetland, wind plant have been used to save the cost of diesel fuel and so have backed-up the diesel plant, rather than the reverse. On the mainland, diesel plant could, in theory, be used for peak lopping, provided it delivered energy at lower cost than the open-cycle gas turbines often used for this purpose. Diesel plant have lower capital costs but higher fuel costs and so, at a time when the future fuel costs are uncertain, they are unlikely to find favour.

Wind-solar and wind-hydro systems are also used in small systems but not currently within large integrated systems, and there is unlikely to be many opportunities for linking the technologies to provide improved output characteristics. There are two problems: in the first place there is no guarantee that significant improvements in output characteristics can be achieved. Although average winds are highest in winter and average solar generation is highest in summer, this does not mean that a steady combined output could be guaranteed on any particular day. Secondly, achieving such an

output would inevitably mean that some generation would need to be rejected and this would have an adverse effect on generation costs.

The economics of island systems are quite different from those of large integrated networks and so hybrid system economics tend to be very site-specific. Island systems often rely on imported fuel and so the generation costs tend to be higher, which improves the prospects for hybrid systems.

6.8.2 Micro-grids

With increased interest in small-scale distributed generation, there is increasing interest on the extent to which this may influence the future structure of electricity networks. Some commentators suggest that the era of centralised generation may soon be over and that distributed generation will play a major role in the near future (ref. 49). However, these projections often lack detailed examination of the underlying technical and economic issues and, in particular, the vital influence that aggregation plays in keeping down costs. An American study (ref. 50), however, has examined the concept of "Micro grids" which would operate in conjunction with existing systems. Their definition of such a system is: --

> *"The Consortium for Electric Reliability Technology Solutions (CERTS) MicroGrid concept assumes an aggregation of loads and microsources operating as a single system providing both power and heat. The majority of the microsources must be power electronic based to provide the required flexibility to insure operation as a single aggregated system. This control flexibility allows the CERTS MicroGrid to present itself to the bulk power system as a single controlled unit that meets local needs for reliability and security."*

A key feature of the concept is that the MicroGrid would be designed to operate either separate from the grid or in conjunction with it. It would appear to the grid as indistinguishable from other consumer sites. The study focused on generation sources less than 500 kW, including microturbines, fuel cells and other emerging technologies, but the role that MicroGrids might play as elements of larger power parks whose total installed capacity is measures in the tens of MW was also illustrated.

From the grid's perspective, the key advantage of a MicroGrid is that it can be regarded as a controlled entity within the power system that can be operated as a single aggregated load.

The study tended to focus on the electro-technical and control system issues, rather than the economics, although these do attract limited attention. What appears to be missing is any evaluation of improvements (if any) in the overall economics of the total power system. The study is of limited value to UK conditions, inasmuch as it only considers small (10 kW) wind turbines.

Ofgem's proposed concept of "Power Zones" has some similarities with the Micro grid concept, but Ofgem's emphasis is different, as the emphasis is on encouraging distributed generation to be located where it can best be managed within a DNO, and to provide to some extent a "proving ground" for new technologies and ideas. There is also an institutional dimension, whereby some modification of price controls may be allowed within the zones.

7 Other Technologies

The capacity credit for some tidal barrage schemes has been estimated as part of the assessments of the Severn barrage. Although tidal energy is predictable, which means that management of the variability is subject to less uncertainty than for wind, it is actually less likely to contribute to peak power demands, which strongly influence the value of capacity credit and so the capacity credit of the Severn barrage has been assessed as 15.3% (ref. 51). This, it may be noted, is lower than the capacity factor, which at the time was estimated to be 20%. The value may, however, be a function of the large size of the installation, as the capacity credit of the Mersey scheme (500 to 600 MW) was quoted as being around 28%. From this rather limited database, it may be inferred that capacity credits decline more rapidly with increasing penetration than for wind. Similar considerations may be expected to apply to tidal stream technology.

The capacity credit of solar PV installations may be expected to be quite low. The contribution of the power source at times of system peak demand plays a dominant role in the calculations. System peak demands tend to occur around 17:30 on January weekdays, at which time the contribution from PV may be confidently taken as zero. Studies in California have concluded that PV can realise significant capacity credits, but there the system peak demands occur during the summer. The increasing use of air-conditioning in the UK, due to increases in mean summer temperatures, may mean that PV is capable of making some contribution to capacity needs during the summer, but the annual average is still likely to be very low. It should also be noted that the capacity factor of PV installations is significantly lower than those of wind plant.

The system costs associated with the assimilation of wave energy are likely to be generally similar to those for wind. Although the capacity factor of the early wind energy devices was generally low (around 20%) it is claimed that new devices currently under development will deliver values up to around 60% (ref. 52). There is little information about the precise way in which power outputs will vary, although it is claimed that the overall power variations will be significantly smoother than is the case with wind energy. It is also argued that wave energy outputs are likely to be more predictable, with six-hour forecasts being possible (ref. 53).

8 Key Literature Survey Findings

8.1 Principal technical issues

(a) Overall, there is good agreement between studies in the UK, Denmark, Germany and the US, on the key issues of

- Power fluctuations from wind plant
- Strategies for dealing with intermittent sources
- The role of storage
- The amount and cost of extra balancing
- Capacity credits

However, comparisons must be made with care, and the absence of key data sometimes inhibits this process; relatively few studies explicitly tabulate all the key parameters, assumptions and methodology.

(b) Wind variability: as NGT is on record (in several places) suggesting that the assimilation of 10% of wind energy on the system is likely to incur no significant operational problems, it may be inferred that it considers sufficient information is available on wind variability. As it has also quoted estimates of the balancing costs associated with 20% of wind energy, it appears that there are no serious technical issues associated with this level of intermittent generation.

(c) Electro-Technical Issues: There are no major technical barriers to the implementation of dispersed intermittent generating systems connected to the networks. Technical research is needed in some specific areas, although the outstanding barriers are essentially cost sharing, pricing and policy.

(d) Attenuating intermittency: All the studies which have been reviewed have analysed the impact of intermittent renewables on the electricity network as a whole, and several emphasise the importance of this approach. The concept of "levelling the outputs" from sources such as wind energy receives scant attention, simply because the cost of such action is likely to exceed the additional value. The provision of extra balancing services (see next bullet point) to cater for the additional uncertainty associated with intermittent sources is technically straightforward and only incurs modest costs when compared to wind power costs of between £35 and £60/MWh. Additional balancing services are therefore likely to be the most cost-effective way of integrating the intermittent sources into the UK electricity network.

(e) Cost of extra balancing: estimates produced by NGC suggest are around £1.5/MWh for 5% wind, rising to £2.38/MWh for 10% wind. These costs are higher than those coming from other analyses; and the most likely cause appears to be the exact prices used for reserve and frequency response plant. It is difficult to quantify cost reflective values with precision but they may be lower than current market rates. Table 8-1 summarises the key estimates for possible wind penetration levels that may be realised, based on Mott MacDonald's analysis, the benchmark levels of 10% and Mott MacDonald's estimate of the wind contribution to the 20% "aspirational" target.

Figures for the range of costs, quoted in the Summary, use the SCAR data to define the lower end of the range. It is more recent than the PIU data, and is based on market prices, whereas the former aimed to use cost-reflective figures for balancing costs, which are difficult to specify with precision. The differences between the two datasets, are, in any case, quite small.

Table 8-1 Costs of extra balancing

Wind penetration, %	5.3	7.6	10	14.2
	(72% compliance with 2010 target)	100% compliance with 2010 target)		(MM estimate for 2020)
Total cost, £M p.a.				
Lower bound (PIU)	18	31	46	84
Median (SCAR)	20	38	56	100
Upper (NGT)	30	55	83	150
Cost, £/MWh of wind				
Lower bound (PIU)	0.9	1.1	1.3	1.5
Median (SCAR)	1.0	1.4	1.6	1.7
Upper bound (NGT)	1.5	2	2.4	2.6

(f) Storage: storage needs to be considered on its commercial merits as a means of reducing system costs as a whole. Although the availability of storage aids the assimilation of renewables, it is not an essential prerequisite and there are other options for providing extra reserve, including the retention of coal-fired plant, CCGT, or OGT. There do not appear to be any storage technologies with the right combination of energy capability and price which can compete with "traditional" methods of providing reserve. [It may also be noted that the existing pumped-storage facilities operate with a low load factor, perhaps indicating that sufficient hydro storage is already available].

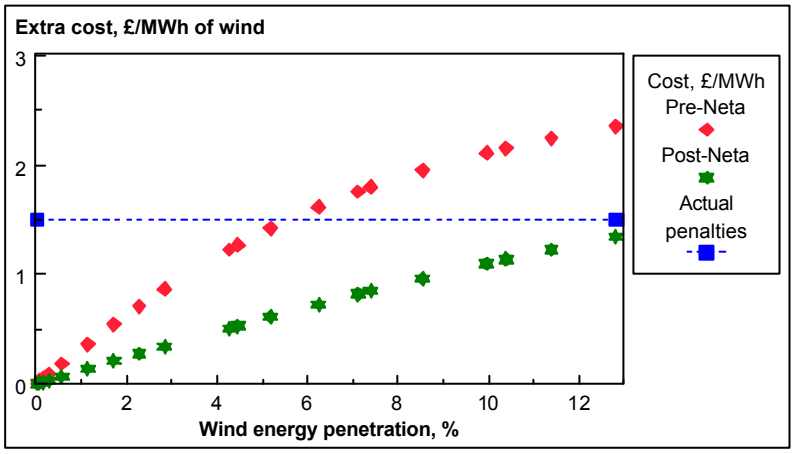
(g) Capacity credit: As there is a good measure of agreement between three independent wind energy studies of this question, the issue appears to be relatively settled for that technology. The credit is about 50% higher than the average capacity factor at low penetrations, falling to about 80% of the average capacity factor for 10% wind. Capacity credits for other intermittent technologies under UK conditions do not appear to have been studied, although further literature searches and discussions with appropriate experts may uncover information. However we wish to explore further whether extreme conditions (still conditions on cold days) were factored into this analysis adequately, and also the impact of declining reserve margins for the British Isles as a whole.

(h) There may be further, and significant, opportunities for Demand-Side Management (DSM) to be implemented alongside the growth of intermittent renewables. For this to be effective the incentives offered would need to be less than the cost of additional reserve. As this is quite modest (c0.2p/kWh, for 10% of wind energy), this might be difficult to implement. However it should be noted that load shedding is already a reserve service which NGT contracts for and which can compete with the reserves offered by generators.

(i) Implications of the New Electricity Trading Arrangements: most analyses in this review assume that the power system is operated as an integrated whole. With the introduction of NETA, there has been a tendency to look at the performance of intermittent renewables in isolation. In the early days of NETA, this resulted in high penalties for intermittent generators. An analysis of the value of wind energy during the first week of NETA concluded, "the most profitable way of operating wind farms was to switch them off (ref. 54). Since the early days of NETA, the differential between System Buy and System Sell Price has narrowed and so the penalties are much lower. Ironically, the demand prediction error has increased (ref. 55) and so the amount and cost of spinning reserve being used has risen to well above the economic optimum. This makes the assimilation of intermittent sources much easier and reduces the extra costs.

These issues are illustrated in Figure 11. This shows that the current penalties (for around 550 MW of wind) are actually more appropriate to around 22 500 MW, when the post-Neta demand prediction error is taken into account. This graph is based on reserve levels and Balancing Market prices in Summer 2003, and changes in these parameters (which are volatile) will influence the exact values at any given time.

Figure 11: Pre and post-NETA technical costs of intermittency compared with current levels actually being paid.



8.2 Issues requiring further searches or analysis

Some analysis has already been undertaken to facilitate comparisons between the studies that have been reviewed, but further analysis could derive a better understanding in the following areas: -

(a) Extra reserve capacity: although there is reasonable agreement on the magnitude of the costs for providing reserves on a £/MWh basis, relatively few studies have quantified amount of extra reserve capacity potentially required. Further analysis of the existing data should provide additional information on this point.

(b) Cost of reserve: NGC's estimates of the cost of absorbing increasing amounts of wind energy are based on "market prices" for reserve. The Ilex/UMIST study (ref. 32) yielded lower costs, possibly due to the use of lower market prices.

(c) American work: a number of American studies have been cited, but it has proved difficult to correlate the results with British studies, in several instances, as insufficient background information has been provided. Further analysis may enable better comparisons to be made. Recent proposals put before the Federal Regulatory Electricity Commission (ref. 56) may indicate ways of overcoming the anomalies thrown up by the NETA.

(d) Wind prediction: a number of studies of the impacts of better prediction methods have been made, or are in progress, but few of these appear to present their conclusions in a way that enables the impact on balancing costs to be assessed. The indications are that worthwhile savings in extra balancing costs, perhaps up to 50%, may be realised.

(e) DSM: Fewer studies have been undertaken, and, as with wind prediction, further analysis may yield better insights into the potential.

(f) Capacity Credit: the extreme case of still conditions on a cold day is repeatedly raised as an issue. No evidence has yet been provided to show it is a serious concern, but further examination of the question would resolve the doubts which exist.

8.3 Gaps in knowledge and issues needing further consideration

Several of the possible constraints on the uptake of intermittent renewables are institutional rather than technical, as follows.

(a) Impacts of NETA: there are two market distortions which may inhibit the growth of the intermittent sources and/or result excessive prices being paid by the consumer for renewable energy:

- The high balancing market penalties incurred by intermittent renewables under NETA do not reflect the technical costs.
- Setting balancing market penalties aside, prices for reserve seem likely to fluctuate and may or may not settle down and be cost-reflective.

At some time in the future it is quite possible that the generation costs of wind energy could start to undercut those of gas-find generation[1]. If wind is burdened with unrealistic penalties, it will not be built in preference to gas, and so electricity prices will be dearer than they need be.

Similar dichotomies have been recognised by the regulators in California (ref. 56) and Northern Ireland (ref. 57), who have acted to correct the anomalies. The approaches are similar, inasmuch as imbalances are no longer accounted for on an hour-by-hour basis, but averaged over longer periods, up to a year. This reduces the penalties considerably and, in each case, any residual costs are spread across all consumers. The principles of the Californian scheme seem likely to be adopted by the Federal Electricity Regulatory Commission.

No specific actions have yet been taken into the UK.

A.1.2 [1] Depending upon allocation and pricing of CO2 emissions allowances

(b) Will capacity credit be recognised under NETA? At a time when there is a debate over the ability of NETA to deliver capacity signals, this is uncertain. However, if wind plant is on-line during times of peak demand, this will reduce the magnitude of price spikes, and so signal that extra plant is not needed. If this does not happen, then, as noted above, (previous bullet point) lack of cost-reflectivity may artificially inhibit the growth of intermittent sources and result in unnecessarily high prices.

(c) Local and regional issues: most of the studies which have been reviewed have considered the assimilation of wind from the standpoint of the system as a whole. A few studies have examined local issues, although generally with only one wind farm. It is possible that constraints may arise if significant amounts of intermittent renewables are concentrated in particular areas, which may mean that the full "capacity credit" may not be realised. This issue therefore needs further examination, particularly for parts of the British Isles with high renewables build that are weakly connected to the core transmission system (eg Scotland).

(d) Use of Demand Side Management (DSM): Few studies have been undertaken and the key issue is whether increased use of DSM is a viable option to the provision of extra reserve. As with other topics, such as storage, the conclusion is that this issue should be examined from the point of view of the system as a whole, and not specifically linked to intermittent renewable generation.

(e) If wind power can generally be relied on to generate at a higher capacity factor during the winter months then wind power could be given a higher value during the winter than its annual average price. However, imbalance costs during the winter months can be higher than at other times and so the potential risk of giving wind power a higher value during the winter is that imbalance penalties are potentially higher. Proposed changes to the BSC/BM may increase likely imbalance penalties.

(f) More detailed wind data is required for the UK, combined with operational data from wind farms, to allow the issues discussed above to be analysed in greater depth, with a view to improving the predictability of wind power and addressing the associated balancing and reserve issues.

9 Intermittency Roadmap

9.1 A Road Map for the Future

Although there may be few technical problems at present, there are some institutional issues that may inhibit the development of the intermittent renewable energy sources. Resolution of these should enable developments to proceed on a "level playing field" basis, that is, one where the costs associated with intermittency are properly reflected. In addition, there are a number of areas where further research may enable the costs associated with intermittency to be better understood, or reduced. The key areas are:-

- Balancing cost reduction, which, in turn, may come about through –
  - Improved information on wind variability
  - Improved wind forecasts, and/or
  - Lower costs for reserve.
- Post-NETA institutional problems, other than those associated with the costs of reserve, particularly,
  - Balancing market penalties
  - Treatment of capacity credit

Lower costs for reserve would, of course, reduce costs for all electricity consumers, but it would enhance the competitive position of intermittent renewable sources relative to the thermal sources.

9.1.1 Balancing costs

Accurate estimation of extra balancing costs is important. There are two elements to the calculation. Firstly, estimates need to be made of the demand prediction error of the electricity system and of the additional dispersion introduced by wind energy. Secondly, estimates of the extra balancing costs need to be made, ideally using cost-reflective values for reserve prices.

9.1.2 Use of accurate data on wind fluctuations

NGT accepts that its method of estimating wind dispersion is conservative, i.e. it may underestimate the smoothing effects of geographic dispersion. In particular, it does not account for the extra geographical smoothing that may be realised once substantial amounts of offshore wind are commissioned. A measurement programme involving a number of well-dispersed wind farms would help to quantify the key parameters more accurately.

9.1.3 Wind prediction

The importance of good predictions of wind availability has been recognised for some time and there are now numerous research projects in progress in Europe and the United States, including a large EU-

funded project (ref. 63). Despite the technical difficulties there are indications that accuracy is improving. It should be noted, however, that even if 100% accuracy were achieved, there would still be operational penalties associated with the variability of wind. Improvements in accuracy, however, mean that the current levels of operational penalty may be reduced in future.

There are four possible ways that electricity system operators with significant amounts of wind on their network may cater for wind variations:

(g) "No prediction" - the system takes wind as it comes

(h) "Persistence"- it is assumed that the power output from a wind plant at, say, 12:00 hours will be the same as it was at 11:00 hours. This tends to be the "default" approach and has been used in the PIU and NGT studies.

(i) More sophisticated models than "persistence", which examine climatological forecasts and attempt to produce, first, estimates of wind strength as a function of time in particular locations or regions and then second, use this to produce estimates of power generation. The yardstick against which improvements in accuracy are assessed is sometimes Persistence.

(j) "Perfect Prediction". Although this is not achievable, it is used as a useful benchmark.

With the levels of wind currently operating in the UK, around 600 MW, sophisticated prediction is probably not worthwhile. It is worth noting that the economic value of Perfect Prediction - compared with "no prediction" is not large. In a CEGB study, the break-even value of wind power came down by about 10% between No Prediction and Perfect Prediction (for 10% wind). In a second UK study (ref. 64), Perfect Prediction realised additional fuel cost savings of 2%, compared with Persistence. In terms of the reduced requirements for back up capacity, a recent American study (ref. 65) suggested that the requirements for back up reserve capacity, when the wind capacity amounts to 22.6% of peak demand, might be reduced from 7.6% of the wind capacity to 2.6%. This suggests that the costs of extra balancing might be reduced by a factor of about three, although a realistic target may be a halving of capacity requirements and costs. The value of wind forecasting becomes more significant with high wind penetrations.

9.1.4 UK research

An EPSRC-funded project at the Rutherford Appleton Laboratory aims to develop new methods for the improved prediction of wind power production in the UK (ref. 66). The development will concentrate on improving short-term predictive methods based on statistical analysis of wind speed and power time series data relevant to onshore sites to address the current needs of the wind energy industry. These techniques will be extended to prediction of wind power at offshore sites. The value of longer-range wind power forecasting based on the latest numerical weather prediction models in facilitating future large-scale integration of wind energy in the UK national grid will also be assessed. An economic evaluation of the methods for short-range onshore power prediction using a simple price forecasting model will be made.

9.1.5 Impacts of NETA

The emergence of "market mechanisms" complicates the issue somewhat. It becomes more difficult to make generalised estimates of the improvements associated with better wind prediction, as prices in the Balancing Market have varied. One study was completed before the implementation of NETA (ref. 67), although it did forecast Balancing Market prices reasonably accurately. This suggested that

wind farm revenues might be increased by around 6%, using available forecasting techniques. The study was carried out before reduction of the Gate closure time to one hour and this may mean that the potential gains are now less.

A later, DTI-funded study also concluded that the use of forecasting techniques could improve the accuracy with which power output from wind farms could be specified (ref. 68). The work suggested that the improvement over persistence might be in the range 40 to 60%. The monetary value of such forecasting is critically dependent on the assumptions made about Wholesale, System Buy and System Sell Prices. For a number of reasons, the analysis concluded that the value of forecasting under the current market framework within the UK is quite small. This comes from the standpoint of a wind developer selling to a supplier trading under NETA, but the situation could change if the differentials between Wholesale, System Buy and System Sell Price should change. The analysis did not quantify the value of forecasting to the System Operator, but noted that the SO might benefit from forecasts on a longer timescale (e.g., 12 hours) than those needed for operation in the market. Although this is relatively unimportant at the present time, the value of such forecasts will increase as the penetration of wind energy increases.

9.1.6 Reserve costs

Calculation of the extra balancing costs that have been made by NGT relied on market prices for frequency response plant and for reserve. As these have been subject to some fluctuation, any estimates of the extra costs are likely to depend on the date that the calculations were made. The discrepancy between extra balancing costs from the SCAR Report and the NGT values (Table 1) may be due to these variations. To illustrate the point further, prices for standing reserve increased by a factor of three in 2000 (ref. 69). Moreover, comparisons with similar prices for reserve in America indicate that levels in the UK under NETA may be on the high side and therefore not cost-reflective.

In practice, the costs of extra balancing tend to be dominated by the costs of regulating reserve, which can be estimated reasonably accurately. It comprises the extra costs associated with the reduced efficiency of thermal plant below rated output, plus a capital cost element. A reasonably accurate estimate appears to be £5/MWh (close to the value used in the SCAR report) and is close to the value used in the PIU report. The other elements of additional balancing costs are more difficult to quantify, but have less weight.

The situation needs to be kept under review. This is, in any case, desirable from the standpoint of aiming to make prices under NETA cost-reflective. There may be a case for agreeing a reference level of additional balancing costs that would be cost-reflective and so independent of any volatility in prices for reserve. Without this, in the longer term, the uncertainty could harm the prospects for the development of wind and other intermittent renewable sources.

It may be noted that not all of this extra reserve, which would be procured through NGT's normal tendering processes, need necessarily be new thermal plant. Some may be provided by rarely used plant and some might not be physical plant at all. Demand-side management, whereby consumers allow their demands to be interrupted in return for a lower tariff, might fulfil some of the requirements. In other words, demand may be reduced, rather than generation increased, to achieve balance. Research in America aims to make this option more attractive to System Operators by providing more sophisticated controls over certain types of commercial and industrial demand.

9.1.7 New options for reserve

The source and type of the additional reserves needed to cope with the additional uncertainty introduced by wind energy, or any other intermittent renewable source, is a matter for the market. NGT holds periodic tendering rounds for various types of reserve and, as noted earlier, sees no difficulty in meeting the additional requirements for the 2010 renewable energy target, even if it were provided entirely by wind. There is no case for providing "dedicated" reserves for the intermittent sources, nor for linking storage to them.

9.1.8 Storage

Storage is simply another possible source of providing reserve although, generally speaking, high capital costs mean that it is unlikely that much new plant will be built. Similarly, the potential for the use of hydrogen, which is essentially a storage technology, appears less attractive than some of its advocates imply. The European Wind Energy Association argues that any assessments of its benefits should consider the complete cycle and that its introduction will not necessarily increase the renewable energy supply (ref. 70).

The "flow battery" system under development by Regenesys Technologies, when commissioned, is likely to earn revenue by a mixture of energy trading, provision of black start facilities and other ancillary services. It is unlikely that constraining this, or any other technology, specifically to operate in conjunction with intermittent renewables would enable revenue to be maximized. It may also be noted that the distribution of wholesale prices is “flatter”, post-NETA (i.e., less spread between the high and low ends of the curve), which makes it more difficult for storage to maximise revenue through energy trading.

The SCAR report queried whether the existing storage was being used as effectively as it might be, but this is a system-related issue, rather than one particularly relevant to wind. The role of pumped storage is likely to be more or less unchanged, unless the bidding strategy changes, or NGT’s tendering yields cheaper ways of providing fast reserve. Intermittency is unlikely to add significantly to the needs for this reserve. The literature survey showed that, however much wind is integrated into the system, the variability will never impose "jolts" on the system that are more severe than the loss of a large power station. In fact, the distribution of hour-by-hour demand changes is much the same with 20% wind (based on analysis of Danish data) as it is without wind. There appears to be no significant difference in the "tails" of the distribution.

The most likely source of reserve in the short term is coal plant, but combined cycle gas turbine plant will increasingly be used for this purpose in future. At the present time, there is over-provision of reserve on the electricity network, due to the introduction of NETA. It therefore seems unlikely that there will be any difficulties with assimilating wind for some time in the future. Even if reserves fall back towards the technically optimum level, any additional requirements due to intermittent generation will build up slowly, giving time for the market to respond.

A new approach to providing spinning reserve through responsive loads is being investigated and may result in lower costs. As it is a demand-side technology it is considered below.

9.1.9 Demand-side management

DMS, like storage, generally acts to improve the efficiency of the electricity network as a whole. As in the case of reserve, the System Operator issues invitations to tender on a periodic basis. However, in certain circumstances, it may help to improve the local penetration of wind energy on electricity networks. This was the conclusion of an analysis which examined the feasibility and economics of load management in Northern Electric's area (ref. 71). The study concluded that such techniques might increase the uptake of onshore wind energy by around 1 600 MW.

Any reduction in the cost of frequency control measures would reduce the extra balancing costs for intermittent renewables and it has recently been suggested that responsive loads might be able to act as spinning reserve (ref. 72). It could be argued that, by implication, this happens anyway, but the study advocates the use of better controls to secure a more positive link. The study focused on air conditioning loads in particular but identified other possible sources that would be equally suitable.

Given that demand-side management acts to reduce the overall costs of operating the electricity network, further encouragement should be given to its promotion. Indeed, this is already an area of activity for groups such as the TSG, who are well placed to investigate the key issues for this particular topic. Reduced costs for balancing intermittent renewable sources would not necessarily be the prime motivation, but a useful side effect.

9.1.10 Local issues

There are fewer studies of the effects of intermittent renewables at the local level, although a detailed assessment of the performance of one wind farm showed that its impact on the distribution network was generally positive. However, there are concerns that specific sections of weak distribution networks may possibly be vulnerable to concentrations of renewables. Wind turbine manufacturers are aware of these issues, and many now provide generators with power factor control. In addition, wind farm controls may be provided with means to limit ramping rates, so as to mitigate possible problems with voltage swings or flicker (ref. 73) This may be more to do with problems of voltage control, rather than intermittency and the issues are currently being addressed. Initial results from the DTI-funded research are encouraging, suggesting that suitable controls within the distribution network may enable the installed capacity of wind generators to be "more than doubled" (ref. 73). This work appears to be potentially valuable and results from the demonstration projects are awaited.

9.2 Institutional Issues

9.2.1 Balancing costs

All small generators, and the intermittent sources in particular, tend to be disadvantaged by NETA. Intermittent renewable generation continues to suffer from Balancing Market penalties. If output increases after Gate Closure, the "surplus" is sold at a low price (SSP), if it decreases, the deficit is made good at a higher (SBP) price. Adjustments to the rules, since the start of NETA, mean that these penalties are now smaller, but they remain out of line with the actual impact of wind on the integrated electricity network. Typical penalties are currently around £0.1-0.2/MWh, around 10 times the technical penalty for 600 MW of wind. Although modest, this penalty could rise due to volatility in Balancing Market Prices, or further modifications to the rules.

The renewable generators (and the CHP industry) have consistently argued for rule changes that would make the penalties more cost-reflective. The solution most commonly advocated is the "single cashout price", i.e, abolishing the distinction between "System Buy Price" and "System Sell Price". This modification is also advocated outside the renewables industry.

The option of a single cashout price has the advantage of simplicity and, given that wind power outputs, for example, are as likely to increase as decrease after Gate Closure, would reduce penalties to a very low level.

The second option that would reduce penalties for intermittency would be a modification that allowed aggregation with demand on a wider basis. At present this is only allowed "downstream" of a Grid Supply Point. Even then, it is at the discretion of the Supplier. Aggregation has the advantage of being technically logical, and would also go some way to eliminating imbalances in both generation and demand which occur due to unexpected changes in wind speed. As noted in the Literature Survey, increases in wind are usually accompanied by increases in demand, especially in cold weather.

Neither of the above options needs to be taken as providing special treatment for intermittent renewables, since they would bring benefits to the system as a whole. Solutions which give some special status to renewables are not favoured by Ofgem, even though their impacts on the trading system as a whole would be negligible. Possibly for this reason, the "Californian solution", assessing imbalance penalties over a longer period such as a month, has not been strongly advocated in Great Britain. This is despite the fact that a similar solution has been adopted in Northern Ireland.

Industry groups continue to lobby on this issue. The BWEA, for example, accepts the logic of wind bearing the costs that arise from the need to schedule extra reserve on an integrated system. It, and the Renewable Power Association, confirm that they will continue to press for solutions which combine simplicity with technical logic. The first and second options above (single cashout price, or more opportunities for aggregation) meet this criterion.

Although some argue that the additional balancing costs associated with intermittency should be borne by all electricity consumers, this is not technically logical and is unlikely to appeal to economists. As noted above, the wind industry accepts the validity of adding additional balancing costs, based on the impact of wind on an integrated electricity system, to its generation costs and it appears that the DTI accepts this view (ref. 74), although the exact details of its approach may not be agreed by the industry.

As the amount of wind energy increases, with its generation costs possibly converging with those from natural gas plant, it is important that there is an accepted way of estimating the extra balancing costs and a cost-reflective value would seem to be appropriate. This is consistent with the premise that market distortions may arise if cost reflectivity is not achieved. The wind industry, Ofgem and the DTI therefore need to monitor the costs of frequency response and reserve, to ensure that they do not drift too far from being cost-reflective.

9.3 Conclusions

To conclude, there are several issues which warrant ongoing attention and investigation in order to remove or reduce potential barriers to renewable power development resulting from the intermittent nature of many renewable energy sources.

These issues include:

- Allowing balancing costs to be more cost-reflective, which is difficult in the current market-based environment. Alternatively, an agreed method of estimating extra balancing costs for intermittent renewables may need to be established.
- Encourage further improvements in the use of wind prediction by both generators and system operators. Such a move could result in reducing the costs of additional balancing to between one half and one third of current costs. The value of accurate wind prediction increases as wind penetration increases.
- Storage, reserve and DMS should be seen as system-wide issues, as they provide system-wide benefits and dedicating specific reserves or storage facilities to renewables is unlikely to be economic. In any event, the level of reserve required for wind power is modest, with one pessimistic study advising that 840 MW of thermal reserve is needed to cover 12 000MW of installed wind power capacity.

Overall, balancing penalties need to become more cost-reflective for renewable generators. Aggregation of plant outputs across wider areas of the network can also provide real benefits, rather than allowing aggregation of output only below a single GSP. Extending the reconciliation period for balancing penalties, as has been done in Northern Ireland, also presents a way of improving the situation for renewable power while not necessarily having a materially detrimental effect on the operation and balancing of the system itself.

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Appendix A Commentaries on Key Integration Studies

Farmer et al (1980)

Farmer's analysis of the CEGB network (ref. 17) was essentially technical in nature and most of the methodology is valid today, due to the generic nature of his approach. The conclusions of the work may be regarded as conservative, that is, they paint a pessimistic picture of the effects of wind on a utility network, for the following reasons: -

(a) The study used meteorological data, combined with wind turbine performance characteristics, to produce simulations of wind output. This tends to overstate wind fluctuations, as meteorological measurements are made at a single point, whereas wind farms respond to average winds over a large area.

(b) Simulation of the combined output of large amounts of wind was made using data from only four meteorological stations (2 in Wales, 2 in East Anglia). Use of more locations would have reflected the greater geographical diversity appropriate for widely dispersed wind plant.

(c) Completion of Sizewell B power station, subsequent to the analysis, has meant that the requirements for system reserve have increased, as the need to "cover" for the loss of this station tends to have a significant impact on reserve needs. The fact that additional reserve is operated eases the assimilation of intermittent renewable sources.

Later CEGB work

Subsequently, two very detailed assessments of the impact of wind energy on the CEGB system were made (both with CEC support), by Gardner & Thorpe (ref. 58) and Holt, Milborrow & Thorpe (ref. 16) - "*Assessment of the impact of wind energy on the CEGB system*". Each of the later studies yielded similar results to those of Farmer's original analysis and the last was completed in the run-up to privatisation.

The latter study (Holt et al) used wind data from 12 coastal and upland sites - mostly close to locations where wind farms have subsequently been built - in Cornwall, mid-Wales, the Pennines, East Anglia and elsewhere - to obtain a time series of "wind farm" power outputs - for onshore and offshore locations - at hourly intervals over a year. Using similar time series for the system demand, and plant characteristics for the nuclear, coal and other units, the "system" was operated with increasing amounts of wind, up to 16 GW.

The study concluded:-

(a) 5% of wind energy could easily be assimilated. At the 10% level[1] , economic operation led to a tiny amount of wind being rejected (0.07%), and the need for extra part-loading of the thermal plant incurred extra operational costs which, if debited to the wind plant, equated to about £1.2/MWh.

A.1.3 [1] As the load factor of wind plant is roughly half that of a thermal power station, 10% of wind, on an energy basis, corresponds to about 20% of wind on a capacity basis. Wind plant capacity is often quoted, for system studies, relative to maximum demand on a power system.

(b) "The available energy from storage will be more economic than scheduled thermal reserve, however, the inherent part-loaded thermal plant will be the most economic source of reserve, thus reducing the use of pump-storage for reserve needs".

(c) The degree to which wind output can be predicted has a significant effect on its economic value.

(d) The capacity credit of wind plant declined from 1.5 times the annual average capacity factor at 2% penetration to 0.3 times the capacity factor at 10% penetration.

The variations in output from the wind plant were derived by simulation, which means that, as noted above; they may be exaggerated, although the smoothing effect of using 12 sites may ameliorate this to some extent. The baseline capacity factor assumed for the wind plant was 26%, which may be a little low by present-day standards. As noted in section 3.1, the commissioning of Sizewell power station after the study probably means that the results are conservative. The operational penalties associated with increasing wind energy penetration were not explicitly tabulated and need to be derived. They may therefore be subject to slight uncertainty.

On the positive side, it may be noted that the study was completed just before privatisation and so reflects realistic costs for the various generation sources and ancillary services, such as reserve. The subsequent studies carried out by the National Grid Company have used market prices for reserve, which may or may not reflect costs accurately.

Other early studies by non-CEGB authors:

A feature of several early studies of wind integration is that they examined very high penetrations of wind energy [(ref. 59) and (ref. 60)]. Most were, in practice, carried out with the co-operation of the CEGB and the conclusions generally are consistent with those derived by the CEGB authors. Apart from system studies, Grubb's analysis of capacity credits contains an authoritative and detailed review of the topic (ref. 59).

NGC work

Although NGC's results [(ref. 11) and (ref. 28)] rely on a simulation of wind fluctuations, they took into account "real" data on wind fluctuations, derived from the German wind energy programme. Moreover, an analysis carried out for the Performance and Innovation Unit showed that the magnitude of the wind fluctuations predicted by NGC, including the extreme excursions, was in line with data derived from 1800 MW of wind in Western Denmark (ref. 9). Since the United Kingdom is significantly bigger than western Denmark, this suggests that the additional geographical diversity may mean that the results are conservative. NGC themselves note that their simulation techniques -- which effectively places offshore wind sites close to the coast -introduce an element of conservatism, inasmuch as offshore sites are likely to be sited at increasing distances from the shore.

NGC is well placed to assess the uncertainties in matching supply and demand on the electricity network (in the absence of wind), but it should be noted that it has used "market rates" for balancing and frequency response plant. These may or may not reflect the base costs of providing these services, and this point needs to be examined further.

Study carried out for the Performance and Innovation Unit

The primary objective of the study carried out for the PIU was to examine whether the penalties imposed on the intermittent renewable sources by the New Electricity Trading Arrangements were out

of line with those appropriate to an integrated electricity network. Since that time, modifications to the Balancing and Settlement Code mean that the penalties are now much less, although they are still viewed as unrepresentative by many parties within the industry.

The "SCAR" report

The SCAR report is a useful contribution to the literature on the additional cost associated with increased contributions from renewables and it describes the procedures used for estimation of the additional balancing costs clearly. It does not, however, make any comment about whether or not the market prices for reserve and frequency response are cost-reflective or not. It is quite likely that the lower prices (than NGC) quoted for additional balancing simply represents changes in the market rates.

One aspect of the report was, however, more controversial. It introduced a new concept "Capacity costs", which appears to be a new, and does not seem to be found in any other integration study over the past 25 years, including those carried out by utilities across Europe and America, and by respected organisations such as EPRI.

The "Capacity costs" in the report appear to be calculated assuming that the low capacity factor of wind plant means that there is a "capacity deficit" which needs to be restored. The reasoning seems to be based on the assumption that the rated capacity of wind is taken into account when assessing the plant margin, but this is not the case. The plant margin would be assessed including wind's capacity credit, using standard procedures. There is only an additional system cost if wind results in an increase in the total costs of achieving acceptable LOLE. This can be argued another way. The addition of wind to a network improves, i.e. reduces, the LOLE, and thermal plant can then be notionally "subtracted" to restore the desired LOLE. This is the capacity credit. Irrespective of the exact level of capacity credit, the target LOLE has been restored, so it is difficult to foresee why any extra plant is required. (Apart from small amounts needed to provide balancing services).

The validity of this "Capacity Costs" approach requires further investigation before it could be relied on in any way. As noted, it has only been used once and in isolation.

Appendix B Technical Requirements

System Stability

Generators attached to the transmission system in Scotland are required to withstand dips to zero voltage for 0.140 seconds. According to GH&P (ref. 3) at present only one wind turbine manufacturer anticipates achieving this requirement, but his details have not been given.

NEMMCO (ref. 2) states that requirements in Australia include:

- Tolerance of a voltage dip to zero volts for up to 0.175 seconds in any one phase or combination of phases.
- A further period of 10 seconds where voltage may vary in the range 80 – 110 % of rated voltage, and
- A further period of 3 min. where voltage may vary within the range 90 – 110 % of rated voltage.

Limits to Flicker

Limits to flicker contributions from wind farms in Denmark (ref. 9) include:

- Flicker Severity Factor (Pst) < 0.30, calculated a s a weighted average of the flicker contribution during ten minutes.
- Long-Term Flicker Severity Factor (Plt) < 0.20, calculated as a weighted average of the flicker contribution during two hours.

The flicker contributions Pst and Plt are defined in IEC 868 and IEC 1000-3-7.

Limits to Voltage Steps

Limits imposed in Denmark (ref. 9) for the permissible maximum values for rapid voltage changes in the connection point of wind farms include:

- General limit < 3%
- Until a frequency of 10 per hour <2.5%
- Until a frequency of 100 per hour <1.5%

Frequency Control

Four bands of timescale of action for frequency control are conventionally accepted:

- Primary Operating Reserve 5 – 15 seconds.
- Secondary Operating Reserve 15 – 90 seconds
- Tertiary Operating Reserve 90 – 1200 seconds
- Standby Reserve 20min to 4 hours.