POWER SYSTEM RESERVES AND COSTS WITH INTERMITTENT GENERATION

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1. Purposes of the Paper and Questions Addressed

Estimates of reserve capacity requirements for electric power systems have long been based on statistical analyses of the frequency distributions of projected electricity demands and availabilities of generating plant.[1] The earlier studies of Farmer, Milborrow and Ashmole (1980) and Grubb (1989) showed how statistical methods can be adapted to the case when highly variable forms of supply such as wind energy are introduced on a system. Several recent studies in the UK, Germany, the Nordic Countries and the US continue in this mould using simulation methods based on historical data on wind patterns and power system characteristics.

The size and complexity of the models and data sets, however, make it difficult to assess how the underlying assumptions and parameters influence the estimates of reserve requirements when increasing amounts of intermittent generation are added to an electrical system. Indeed the details of the models, let alone data on the parameters, are often not published and remain a 'black box' to the readers. Perhaps for this reason some recent studies have departed from the statistical approach and used engineering rules-of-thumb to estimate system reserve requirements and costs. For the case where wind is the main intermittent resource the results depart from those of the 'modellers' appreciably, to such an extent that that it is worth revisiting the elements of the statistical approach to see where the differences arise. This is the main purpose of this paper.

The following analysis revisits the relationships between the reserve requirements, the capacity margins needed to maintain the reliability of supplies, the costs of intermittency, the capacity credit for intermittent generation, and several other quantities. It is not put forward as a substitute for full-blown modelling studies, but does provide a reminder of principles and an independent means of checking results. It rests on a few key parameters, principally the means, standard deviations and ranges of the frequency distributions of the various quantities. Whilst this is a simplification, it helps to make the underlying relationships more transparent and enables the analyst to explore the effects of changes in assumptions. It begins with a basic case and then relaxes the assumptions.

There are three questions which recur throughout the paper:

1. What are the required additions to reserves to maintain the reliability of supplies when intermittent generation is substituted for thermal generation? It is unquestionable that the margin will need to rise when the variance of the

[1] They date back to the statistical work of the late Frank Jenkin of the CEGB in the 1960s.

supplies increases if supply reliability is to be maintained—but by how much? An alternative way of putting the question is what is the 'capacity credit' (defined below) that can be given to intermittent generation?

2. What is the associated increase in system costs that would result from building more wind and less thermal generation?

3. At the project level, how can we compare the costs of a large wind farm say with the thermal alternative? To answer this, we need to know the answer to (1) above—how much extra 'reserve' or 'backup' capacity is required for the intermittent resource, and of course what its costs will be.

The paper does *not* answer questions as to what the optimum reserve margin should be or how it should be determined. There is a long debate on the role of markets and regulation for determining reserve margins which this paper does not get into. Suffice it to say that whatever policy position is taken: (a) in actuality there is at all times a reserve margin, which is the difference between available capacity and demand; (b) this quantity is of interest and needs to be monitored since when it declines the probability of losing load increases; (c) when for policy purposes estimates of the costs of introducing intermittent resources onto the system are being made it is necessary to compare like-with-like such that the costs of introducing them, including the costs of maintaining the reliability of supplies, can be compared with the costs of the alternatives.

2. Reserve Margin and System Size, Neglecting Demand Uncertainties

It is sometimes argued that every wind generator needs 100% backup to allow for the possibility of zero output in high demand periods. The same argument could also be applied however to all generators on an electrical system, fossil-fired or otherwise, since any generator may suffer an unplanned outage. However, this is to ignore the advantages of interconnection. When companies first supplied only their own municipalities it was common practice to have 100% backup in case of failure of the main generator; however, it was recognised that with interconnection reserve generators could be shared between them and further that, as the number of generators on their systems increased to meet demand growth, it was not necessary to allow, when planning for reserves, for all the generators to fail simultaneously. In fact, to maintain the reliability of supply at a constant level, the reserve margin as a percentage or per unit of system size declines inversely with the square root of system size (the statistical law of large numbers). The system reserve margin today is around 20%, about a fifth of its value a century or so ago.

Statistically, the reserve margin per unit of demand is given by $m = k\sigma_i / \sqrt{n}$, where n is the number of generators and σ_i is the standard deviation of the availability of individual generators divided by their average available capacity; k is a constant. [2] If the margin is normally distributed, a value of k = 4 (four standard deviations) would imply a roughly 95% chance that demand over the peak period would be met, and of k = 3.3 a 90% chance. Adding intermittent sources of generation, whose frequency distributions for plant availability are appreciably broader, will lead to a significant increase in the reserves required to maintain the reliability of supply; however, the principle remains that any source of generation on the grid, whether fossil, nuclear, wind or other will benefit from the pool of reserve capacity on an interconnected system.

[2] Such expressions make the simplification that all generators are the same size and have identical frequency distributions for plant availability; however, the law of large numbers still applies. If the generator sizes differ but otherwise have similar frequency distributions, $\sigma_m = \sigma_i (\mu_{rms} / \mu_{ave}) / \sqrt{n}$, where μ_{rms} is the root mean square average plant size, i.e. $\mu_{rms}^2 = \left(\sum \mu_i^2\right) / n$, and $\mu_{ave} = \text{system size} / n$. This expression logically places more weight on the larger units on the system, which act to increase the required reserve margin.

3. System Reserves with a Single Type of Generation

Denote the demand and supply by *D* and *S* respectively, the means of these quantities by μ_d and μ_s, the standard deviations by s_d and s_s, and the normalised values of the standard deviations by $\sigma_d = s_d / \mu_d$ and $\sigma_s = s_s / \mu_s$. Then the margin of spare capacity for any particular value of *D* and *S* is *S* – *D* and the standard deviation of the margin (denoted by s_m), assuming the co-variance between *D* and *S* is small, is given by $s_m{}^2 = s_d{}^2 + s_s{}^2$. The standard deviation of the margin can be normalised by dividing by the mean expected demand; denoting this by $\sigma_m = s_m / \mu_d$ and substituting for s_d and s_s leads to:

$$\sigma_m = \left(\frac{\mu_s{}^2}{\mu_d{}^2} \cdot \sigma_s{}^2 + \sigma_d{}^2 \right)^{1/2} \tag{1}$$

The margin of reserve capacity required, per unit of demand is again $m = k \cdot \sigma_m$, where *k* is a constant. Working to a value of *k* ≈ 4.0 for a normal distribution implies a supply reliability of around 95% over the peak period; it is of course much higher than this over the whole year. The peak capacity relative to the expected peak demand is 1+*m*, and $\mu_s / \mu_d = 1 + m/2$ is the average available capacity over the peak.

4. System Reserves with Thermal and Intermittent Generation

4.1 Reserves required to maintain supply reliability

The aim of this section is to determine how much investment in reserve capacity is required to keep the reliability of supply intact once intermittent generation is introduced. Let the μ_f, μ_r and μ_s refer to the mean expected capacities of fossil-fired stations, renewable energy and total supplies respectively, s_f , s_r and s_s to the standard deviations of their frequency distributions of availability, and σ_f (= s_f / μ_f), σ_r (= s_r / μ_r)and σ_s (= s_f / μ_s) their normalised values. Then since the availabilities of fossil and renewable energy power plant are independent $s_s{}^2 = s_f{}^2 + s_r{}^2$, from which:

$$\sigma_s{}^2 = \left(\frac{\mu_f}{\mu_s}\right)^2 \sigma_f{}^2 + \left(\frac{\mu_r}{\mu_s}\right)^2 \sigma_r{}^2$$

Let $\lambda = \mu_r / \mu_d$. Since the marginal running cost of using the intermittent resource is small, it will always be used when it available, such that μ_r times hours of generation over the peak also equals the share of energy output provided by the resource over the peak; hence λ is also a measure of energy market share of intermittent renewable energy on the system. [3] To a first approximation[4] $\mu_f / \mu_d = 1 - \lambda$, hence:

$$\left(\frac{\mu_s}{\mu_d}\right)^2 \sigma_s{}^2 = (1-\lambda)^2 \sigma_f{}^2 + \lambda^2 \sigma_r{}^2 \qquad \text{(2a)}$$

For reasons discussed above (in Section 2), the variances of thermal and renewable energy plant decline with their aggregate capacity. For thermal plant the aggregate capacity is proportional to 1/(1 – λ), and for intermittent generators to 1/λ. Allowing for this leads to:

$$\left(\frac{\mu_s}{\mu_d}\right)^2 \sigma_s{}^2 = (1-\lambda)\sigma_{f0}{}^2 + \lambda \sigma_{r0}{}^2 \qquad \text{(2b)}$$

Where $\sigma_{f0}{}^2$ is the variance of system plant availability when λ = 0, i.e. for a conventional system, $\sigma_{r0}{}^2 = k^2 \sigma_{f0}{}^2$ and k is the ratio of the plant-level variances of intermittent to conventional plant.[5]

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[3] λ may also differ between seasons so strictly a seasonal function is needed but is neglected below.

[4] A better approximation is $\mu_f / \mu_d \approx (1-\lambda)(1+m_0/2)$ and is used in the calculations for the figures shown below.

[5] $\sigma_{f0}{}^2$, the aggregate variance of system plant availabilities (normalised), is a familiar quantity from the history of systems with conventional plant. We also have some evidence on the relative variances of

Hence: $$\sigma_m \approx \left\{\sigma_d^{\,2} + (1-\lambda)\sigma_{f0}^{\,2} + \lambda\sigma_{r0}^{\,2}\right\}^{1/2} \qquad (3)$$

There is an important qualification to this relationship, which is that, depending on the correlations of the outputs of intermittent generators in a country, the variance of their aggregate output may not decline as rapidly as the expression $\sigma_r^{\,2} = \sigma_{r0}^{\,2} / \lambda$ implies on account of the co-variance of outputs between the generators. In this case an upward correction would need to be applied to the term $\lambda\sigma_{r0}^{\,2}$ in (3).[6] In the calculations discussed later a crude allowance is made for this based on observations of σ_{r0} at intermediate values of λ.

The standard deviation of available output from intermittent generators is three or more times greater than that of thermal plant, and the variance roughly ten times greater. Hence a rising share of intermittent generation on the system will significantly increase the variance of the margin between available capacity and expected demand. To restore system reliability to the same level of reliability as a system without intermittent generation on it additional capacity reserves will therefore be needed.

Denote these reserves by β, again per unit of peak demand. In the near future in the UK the most likely kind of backup plant will be fossil fired—open cycle gas turbines for instance, or old thermal plant retained for the purposes of providing backup. Short-term storage technologies and demand management are further possibilities; in countries with significant hydro resources, increasing the MW capacity/MWh output ratio through installing extra turbine capacity is yet another. Assuming it will be fossil-fired, it is likely to have a similar variance term to other fossil-fired plant such that the new standard deviation (normalised) of the margin between supply capacity and demand is:

$$\sigma_m \approx \left\{\sigma_d^{\,2} + (1-\lambda+\beta)\sigma_{f0}^{\,2} + \lambda\sigma_{r0}^{\,2}\right\}^{1/2} \qquad (4)$$

This expression provides an approximate basis for estimating the additional reserves required. The mean expected capacity on the system is given by:

$$\mu_s = \mu_f + \mu_r + \mu_{reserves}$$

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intermittent and conventional plant and some predictions of the likely variance for larger aggregates of intermittent plant. Equation (2b) can be derived by reformulating (2a) in terms of plant variances, $\sigma_{fi}^{\,2}$ and $\sigma_{ri}^{\,2}$. $s_s^{\,2} = \mu_f \sigma_{fi}^{\,2} + \mu_r \sigma_{ri}^{\,2}$. But $\sigma_s^{\,2} = s_s^{\,2} / \mu_s^{\,2}$, $1-\lambda = \mu_f / \mu_s$ and $\lambda = \mu_r / \mu_s$ which lead to $\sigma_s^{\,2} = \{(1-\lambda)\sigma_{fi}^{\,2} + \lambda\sigma_{ri}^{\,2}\} / \mu_s$. Also, when λ = 0 $\sigma_{f0}^{\,2} = \sigma_{fi}^{\,2} / \mu_f$ (the 'large numbers' effect again). Substituting for these various quantities and rearranging leads to *k* and (2b).

[6] The adjustment would take the form of multiplying $\sigma_{r0}^{\,2}$ by the factor $(1+\lambda\overline{\sigma}_{ij} / \sigma_{ri}^{\,2})$, where $\overline{\sigma}_{ij}$ (*j* ≠ *i*) is the mean covariance of outputs between the generators.

But to maintain the reliability of supplies at a constant level, the mean expected capacity needs to be approximately 2 standard deviations above the mean expected peak demand, i.e. $\mu_s / \mu_d = 1 + 2\sigma_m$; also $\mu_f / \mu_d = (1 + 2\sigma_{m0})(1-\lambda)$, $\mu_r / \mu_d = \lambda$ and the mean capacity of the new reserves per unit of demand $\mu_{reserves} / \mu_d = \beta$. Substituting for μ_s, μ_f and $\mu_{reserves}$ in the preceding expression for μ_s leads to:

$$\beta = 2(\sigma_m - \sigma_{m0}) + 2\sigma_{m0} \cdot \lambda \qquad (5)$$

The subscript m_0 denotes the s.d. of the reserve margin of the system without intermittent generation. The first term on the right hand side of (5) represents an allowance for the added variability of having the intermittent resource on the system, the second term an allowance for the loss of reserves arising from thermal plant being taken off the system.

Expressions (4) and (5) are easily solved iteratively or simultaneously for σ_m and β. To recall once more: β is the amount of reserve capacity, per unit of expected peak demand, required to maintain the reliability of supply at the same level as that of a system without intermittent generation.

There are five further quantities of interest:

1. *The peak capacity of the intermittent renewable energy plant on the system* ($\hat{R}$). By definition, this equals the average output over the peak (μ_r) divided by the capacity factor (CF_r). But $\mu_r / \mu_d = \lambda$, the above measure of the market penetration of intermittent renewable energy on the system. Hence:

$$\hat{R} = \lambda \cdot \mu_d / CF_r \qquad (6)$$

2. *The capacity of the thermal plant displaced by the intermittent generation, excluding provisions for new reserves.* Denote this by ΔF. It is the capacity of the thermal plant capable of providing the same amount of *energy* as the intermittent generators; this is equal to the capacity of the renewable energy generators times their capacity factor:

$$\Delta F = \hat{R} \cdot CF_r / a_f \qquad (7)$$

Where a_f is the availability of the thermal plant.[7]

3. The peak capacity of the thermal plant remaining on the system, excluding new additions to reserves. This is denoted by $\hat{F}$. Per unit of expected demand it is given by:

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[7] $a_f \approx 1 - 4\sigma_{f0}$

$$\hat{F} = (1 + m_0)\mu_d - \Delta F \qquad (8)$$

4. *The peak capacity of the new reserves per unit of expected demand*. This is taken to be two standard deviations above the mean capacity of the reserves:

$$\hat{\beta} = (1 + 2\sigma_f)\beta \qquad (9)$$

5. *The capacity requirements of intermittency per unit of intermittent capacity installed.* Denoting this quantity by CI_r:

$$CI_r = \hat{\beta} \cdot \mu_d / \hat{R} \qquad (10)$$

4.2 The capacity credit and reserve requirements of intermittent generation

The capacity credit of intermittent generation (denoted here by CC_r) is concept that can be used for estimating and monitoring the adequacy of reserve margins, and as an alternative basis for estimating the costs of providing reserves. It is defined by Ruffles and Ploszek as follows:[8]

> "The amount of conventional capacity that a given amount of wind [or other intermittent] generator capacity can replace on an electricity system with no change in system security based on Loss of Load Probability analysis."

Since the capacity of the new reserves ($\hat{\beta}$) to provide for intermittency can be identically defined such that the reserve capacity to support intermittent generation leads to no change in loss of load probability, there is an identity relating CC_r to CI_r. Specifically, the capacity credit is given by the original size of the system, $(1+m_0)$, minus the capacity of thermal plant remaining on the system (expression 8) minus the capacity of the new reserves (expression 10), all divided by the capacity of the intermittent renewable energy plant (expression 7):

$$CC_r = \left((1 + m_0)\mu_d - \hat{F} - \hat{\beta} \cdot \mu_d\right) / \hat{R} \qquad (11)$$

From 8: $$CC_r = (\Delta F - \hat{\beta} \cdot \mu_d) / \hat{R} \qquad (12)$$

Or from 7 and 10: $$CC_r = CF_r / a_f - CI_r \qquad (13)$$

Some studies (Dale et al and SCAR) estimate the capacity credit directly rather than the additional reserve requirements as above. In this case the latter can be

[8] Paper submitted to the working group.

estimated from the former using (13). Provided mutually consistent statistical methods and criteria are used the method chosen is a matter of computational convenience, not one of principle. In practice estimates of both quantities are needed.

4.3 valuing the capacity credit and costing reserve requirements

Expression (13) has also been arrived at in an intuitively appealing way by Jim Skea[9], who compared two ways of estimating the change in system costs when intermittent generation is substituted for thermal plant:

(a) Change in system cost =	+ Capital cost of intermittent plant[10]
	+ Balancing costs
	- Capital cost of the thermal plant displaced
	+ Capital cost of thermal or other provisions for reserves needed to provide for intermittency (= capacity cost of intermittency)
	- Fuel cost savings of intermittent plant

(b) Change in system cost =	+ Capital cost of intermittent plant
	+ Balancing costs
	- Value of capacity credit
	- Fuel cost savings of intermittent plant

Equating (a) and (b) leads to an identity corresponding to that on MW in (13):

(c) Value of capacity credit =	+ Capital costs of thermal plant displaced
	– Capital cost of intermittency

Or: (d) Capacity cost of intermittency =

	+ Capital costs of thermal plant displaced
	– Value of capacity credit

In capacity units (c) is the same as (13):

(e) Capacity credit (MW) =	+ MW of thermal plant displaced
	– MW provisions for intermittency

Once again, for such identities to be valid the capacity credit and the additional capacity required to provide for intermittency need to be calculated on the same statistical basis.

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[9] Note written for the working group. November 2005

[10] O&M costs are assumed to be capitalised and included in the capital costs in the above.

4.4 capacity margins and system reserves

Estimates of the capacity credit provide a basis for assessing the adequacy of the system capacity margin. As a Report of the House of Lords (2004 paragraph 7.16)[11] on *Renewable Energy: Practicalities* commented, the greater the share of intermittent generation on a system the more important it will be to assess whether the capacity of system reserve is sufficient to maintain the reliability of supplies:

> *With the introduction of increasing quantities of intermittent renewable power the provision of an adequate level of capacity margin will become increasingly critical to the reliability of power supplies. Indeed the level will have to rise to reflect the intermittency of wind and other renewable energy sources. Without anyone managing security of supply, and with a Regulator committed to market incentives alone, increasing volatility appears likely, with the possibility of shortages and resulting price shocks.*

As the level of intermittent generation on the system is increased, the new margin can be estimated from the original capacity of the thermal plant on the system, minus the capacity displaced by the intermittent generation, plus the capacity credit of the latter, plus the additional provisions for reserves. Per unit of expected peak demand:

$$1 + m = \{1 + m_0 - \Delta F / \mu_d + \hat{\beta}\} + CC_r \hat{R} / \mu_d$$

Or:

$$m = \{m_0 - \Delta F / \mu_d + \hat{\beta}\} + CC_r \hat{R} / \mu_d - 1 \qquad (14)$$

The first three terms (bracketed) on the right hand side equal the 'conventional' capacity on the system; hence as a percentage of expected demand:

The new margin = the 'conventional' capacity + the capacity credit – 100 (15)

If the capacity credit and the provisions for reserves are estimated such that there is no change in the loss of load probability when intermittent generation is added to the system, then the right hand side of (14) equals the old margin and $m = m_0$, as can be seen by substituting (11) in (14). In other words, if the reliability of supplies is to be maintained, the new margin, based on the sum of the conventional capacity on the system and the capacity credit for intermittent generation, should be the same as the margin that obtained when there was no intermittent generation on the system. The convenience of the idea of the capacity credit therefore is that it allows us to work with a long-familiar and trusted measure for monitoring the adequacy of system capacity.

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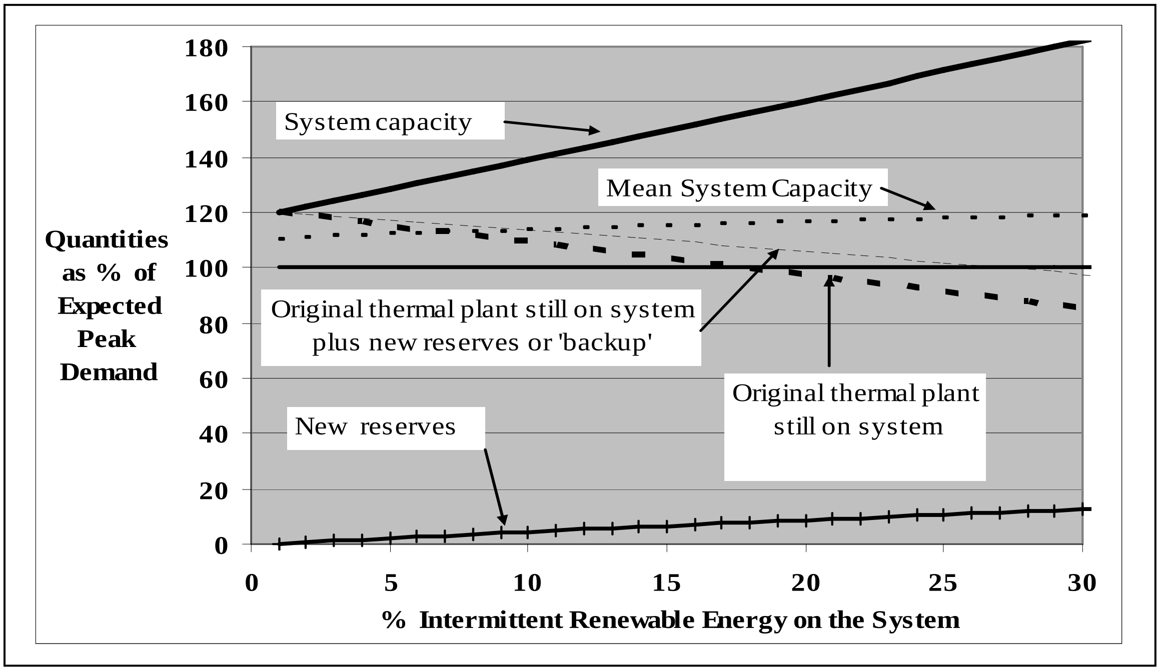
[11] Science and Technology Committee, 4th Report of Session 2003-04, HL Paper 126-I

4.5 Results

Figure 1 shows some results for a particular set of parameters footnoted below. Interpretations of are provided in the following sections:

Figure 1: New Investment in Reserves and other Quantities as a Function of Intermittent Renewable Energy on the System



Parameters: Demand uncertainties are taken to be ± 5%; assuming this to be roughly ± two standard deviations, gives a value of σ_d = 0.025. For thermal plant σ_d = 0.04 (approximately ± 8% around an availability of 90%). For renewables, minimum capacity is considered to be two standard deviations below the mean expected capacity; it is put at 0.0 percent of installed capacity and the capacity factor is 30%, giving a value of σ_r = (0.3-0.0)/2 = 0.15; note that value of σ_r is used *only* for deviations *below* the mean expected capacity level; the installed capacity of renewables is obtained by dividing the mean output by the capacity factor, which in the present case would be 3.3 times the mean output. The initial plant margin is 20%. The spreadsheet is to be put on the ICEPT website accompanying the papers to this report for others to explore alternative assumptions and review the approach.

5. Fuel Consumption Arising from Intermittency (other than that incurred through short run balancing policies)

Having intermittent renewable energy on the system has three effects on fuel consumption:

i) A reduction in fossil fuel use proportional to the energy output of the renewable generators.

ii) The added fuel costs of balancing the system in the face of increased short-term volatility of supplies, on a scale ranging from a few seconds to a few hours. These costs are incurred throughout the year and not simply over the peak period; they are discussed in Section 7.

iii) Use of the new reserve or backup capacity over the peak period. This is different to the extra fuel used for balancing, which does not entail an increase in energy production but in energy consumption by the thermal plant, on account of a loss of thermal efficiency.

This section is concerned with the third effect. One way of estimating it is first to consider what would happen if the new reserves were not used, as if no new reserves were added, such that meeting demand depended only on the thermal plant remaining on the system and the new intermittent generation. There will still be a reserve margin, but managing the system in this way will increase in the loss-of-load probability. It is then possible to estimate the output required from new reserves to restore the loss-of-load probability to its original level.

Reserve or backup capacity is used at any time t when the outputs from the thermal plant (excluding that used for reserves) and renewable energy plant (F_t and R_t respectively) fall short of demand (D_t); i.e. when:

$$F_t + R_t - D_t < 0 \tag{16}$$

The left hand side tells us what the *actual* margin would be at any point of time in the absence of additions to and use of reserve capacity. Its mean value (denoted by μ_m) is that of the expected output from the renewable energy and thermal plant minus the mean expected demand. Relative to the expected demand, this is given by:

$$\mu_m / \mu_d = (1 + m_0 / 2)(1 - \lambda) + \lambda - 1 = (1 - \lambda) m_0 / 2 \tag{17}$$

The expression for the standard deviation of the left hand side of (16) is the same as that given earlier in equation (3):

$$\sigma_m \approx \left\{\sigma_d^{\ 2} + (1-\lambda)\sigma_{f0}^{\ 2} + \lambda\sigma_{r0}^{\ 2}\right\}^{1/2} \qquad (3)$$

Hence the lower probability limit of the actual margin (excluding the use of new reserve capacity), taking it to be approximately 2 standard deviations below the mean, is given by:

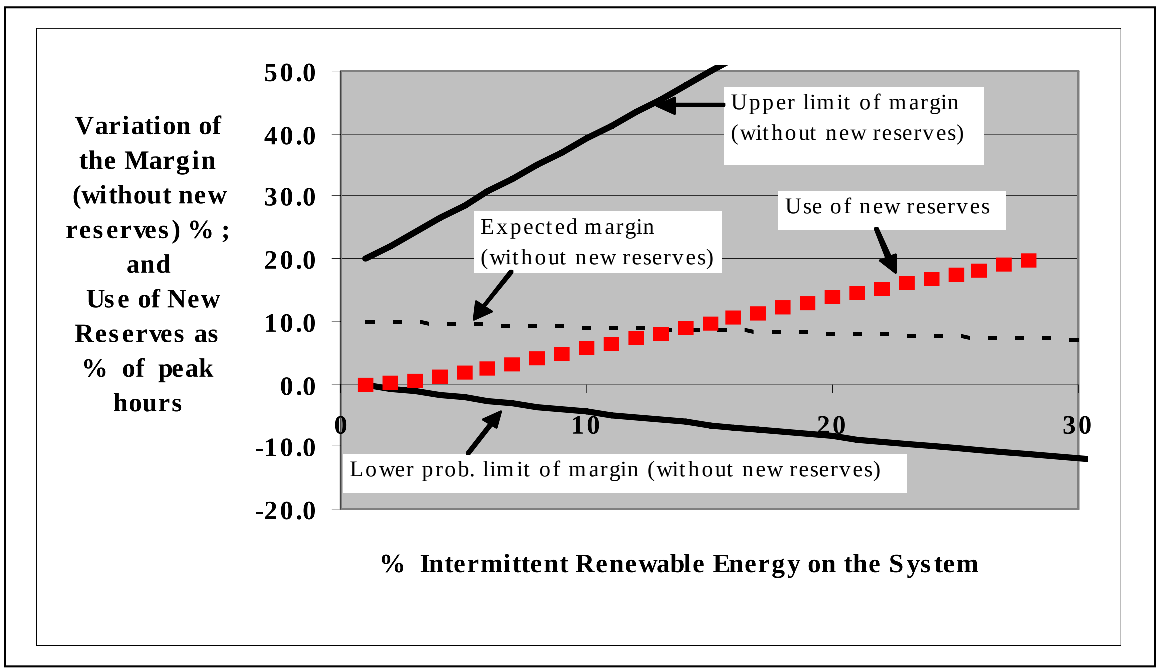
$$\mu_m / \mu_d - 2\sigma_m = (1-\lambda)m_0 / 2 - 2\sigma_m \qquad (18)$$

Lastly, the upper limit of the margin (again excluding new reserves) is given by the capacity of the thermal and intermittent renewable energy plant (expressions 6 plus 7):

$$\hat{F} / \mu_d + \hat{R} / \mu_d = (1-\lambda)(1+m_0) + \lambda / CF_r \qquad (19)$$

Expressions 18 and 19 show that the range of possibilities fans out appreciably as intermittent energy is added to the system, and that there is an increasing likelihood, in the absence of the provisions for and use of new reserves, of loss-of-load. The situation is illustrated by the calculations displayed in Figure 2, which are based on the same parameters as those noted in Figure 1 above:

Figure 2: Range of Variation of the Actual Margin in the Absence of New Reserves; Use of New Reserves Required to Stem Increases in the Loss-of-Load Probability



Same parameters as those noted in Figure 1

For there to be no increase in the loss-of-load probability investments in reserve capacity are needed to preclude the lower probability limit of the margin from going below the axis. The additions to reserve capacity to avoid this happening were discussed in the preceding section—see equations 4 and 5. However, these equations only tell us how much *capacity* is needed; in addition, we also need to know how much it will be *used*. This is not quite measured by the vertical distance between the horizontal axis and the curve representing the lower probability limit in Figure 2 since the frequency distribution of *output* possibilities is not uniform; the extreme points, for instance, are much less common than those in the mid range. A simple linear approximation[12] leads to the following expression for the fraction of peak hours (denoted by β_{use}) during which the new reserve capacity is in use:

$$\beta_{use} = \frac{b^2}{8\sigma_b^{\ 2}} \tag{20}$$

where $b = 2\sigma_m - (1-\lambda)m_0 / 2$ is the aforementioned vertical distance between the axis and the lower probability limit of the actual margin in the absence of new reserves. The value of β_{use} as a percentage of peak hours is shown by the square-dotted curve in Figure 4. For 20% energy market penetration by renewables, it would be around 15% for the parameters indicated, with a range of 12-19% based on the other parameters discussed in figures 2 and 3. The fuel cost associated with this effect, per kWh of intermittent energy generated, is given by:

$$\text{Extra fuel cost} = \frac{\beta_{use} \text{ x hours of peak x capacity of new reserves x unit fuel cost}}{\text{Energy generated by intermittent resource}} \tag{21}$$

[12] Using a triangular approximation to the sorts of frequency distributions shown in Figure 3 below

6. Balancing Costs

The fanning out of the reserve margin illustrated in Figure 2 is indicative of the scale of the added volatility of supplies on the system as the share or penetration of intermittent energy is increased. Many studies have noted that for up to 20% penetration, the amplitude of the volatility would be no more than that already experienced in the form of diurnal and weekly variations in demand. However, the following would all increase: the variance of the difference between demand and supply; the ramping and de-ramping rates of the plant responsible for keeping the system in balance; the frequency of output increases and decreases; and the frequency of startups and shutdowns of reserve plant.[13] All this will add to fuel—and to some extent maintenance—costs in several ways:

a) A larger proportion of the thermal plant or other standby generation will remain connected to the system (synchronous standby) on part load such that unexpected shortfalls in intermittent energy may be accommodated within the range of a few minutes to half an hour or so; and conversely such that unexpected surpluses from the intermittent generation may be accommodated by reducing the output of the thermal plant. This means that thermal plant providing the balancing will be operating at lower thermal efficiencies, which will increase average fuel costs.

b) The more frequent start-ups and shutdowns of backup plant on the system likewise will also add to fuel costs.

c) Very short term fluctuations will be absorbed by the mechanical inertia of the generators on the system and through the governors on selected plant. This too will have some effect on efficiency and thus on fuel costs. Further, it is estimated that this will add to wear and tear and thus to:

d) Added O&M costs.

A full discussion is provided in the SCAR report, and indeed in the earlier papers of Grubb, Farmer et al and others, while reports by the Carbon Trust and the International Energy Agency provide reviews. Estimates of the effects on fuel costs differ between parties, but they fall within a fairly small range with no apparent outliers. Most fall in the range 0.16-0.28 p/kWh if there were to be 20% wind energy on the system, and compare well with experience in other countries, including Denmark and the US. The following are the estimates of the SCAR report, which provides a detailed analysis:

[13] Grubb (1990) provides an extensive analysis and is much cited on this subject.

Table 1: Estimates of Incremental Balancing Costs, Relative to a System Without Wind Energy, p/kWh

Balancing cost item:	17% Wind on system (20% renewables)	27% Wind on system (30% renewables)
Dynamic response	0.03	0.04
Synchronised reserves	0.12	0.14
Standing reserves	0.03	0.03
Startup	0.04	0.04
Curtailment (shed wind energy if too much wind)	0.00	0.01
Total, p/kWh	0.22	0.26

Source: SCAR report. Definitions: Dynamic response = response provided by the turbine governors and the inertia of generators. Synchronised reserves = part loaded thermal plant or pumped storage connected to the system. Standing reserves—thermal plant on 'hot standby' or OCGTs that can be started up and connected to the system at short notice. Startup = added fuel costs of starting up plant not connected to the system.

A simple check can be made by looking at the change in the standard deviation of the difference between predicted demand and supplies within any one hour period and multiplying this by the marginal fuel costs of the plant responsible for the balancing. The Carbon Trust reports that the s.d. for such short-period demand predictions is 1.3% of demand, while that for thermal plant is of a similar order; the s.d. for 5000MW of wind farms for any one hour period is 3.1%[14], and may be slightly lower (say 3%) for larger capacities. Thus the *change* in the s.d. of the difference between predicted demand and supplies is $(1.3^2 + 0.8x1.3^2 + 0.2x3^2)^{0.5} - \sqrt{2}x1.3 = 0.362\,\%$ for the case where 20% of energy is supplied from wind.

In such short periods, the operators are managing the system such that there is a very high probability of meeting demand (better than 99%), which implies that they need to cope with possible variations of ± 3s.d.'s of the (short-period) prediction margin between demand and supplies. Thus the addition to balancing costs in the present case would be around 6 x 0.362 = 2.17% of the expected fuel costs of balancing. At full load the fuel costs of thermal plant are estimated to be 1.5p/kWh, but may rise to 2.5p/kWh or more at part load. On this basis the extra fuel costs would be 0.0217x2.5/0.2 = 0.27p per kWh supplied by wind which compares well with the estimates in Table 1.

[14] See Carbon Trust Report, Annex 4, pp 9-10

7. A Comparison of Selected Studies

The five tables attached summarise the key results and assumptions of five studies: the simulations reported by Dale, Milborrow, Stark and Strbac; the SCAR report; the review of the Carbon Trust; the study of the Royal Academy of Engineering; and the present report. The first two of these studies are based on systems analysis using statistical methods to handle uncertainties, while the latter two take a project approach. The findings of all five can be compared, however, if they are put on project basis in which the systems effects on costs are added to or subtracted from project costs as appropriate. This is what is attempted in the attached tables.[15] All five also focus on the consequences of having high levels (15-20%) intermittent energy on the system.

7.1 Reserves and Balancing costs

The following table compares the key estimates. They relate to the case where there is a high level of wind energy on the system (in the range 15-20%):

Table 2: Reserve and Balancing Costs: Estimates of five studies. Costs in p/kWh

	Dale et al	SCAR report	Carbon Trust	R. A. Eng.	Present Study
Capacity Factor for Wind, % [a/]	35	35	35	35	35
Capacity credit for wind, MW/MW wind capacity, %	19.2	22.9	20.0	Not estd[e/]	22.1
Backup capacity for Wind, MW additional reserves/MW wind, % [f/]	18.9	18.3	21.2	65.0	19.1
Capital and O&M costs of reserves	0.32	0.26	0.45	1.86	0.43
Energy costs of using reserves	0.08 [d/]	Not estd.	Not estd.	Not estd.	0.05 [d/]
Balancing costs	0.25	0.22	0.20	Not estd.[c/]	0.25 [b/]
Total costs, p/kWh	**0.65**	**0.48**	**0.65**	**1.86**	**0.73**

Nb: The estimates in each report have been converted to a 10% discount rate; the attached tables provide the original estimates at the discount rates they have used plus further footnotes on assumptions.

a/ These seemingly high capacity factors for wind are justified in the various studies by assuming that roughly half the capacity will be offshore.

b/ Not an independent estimate, as discussed above, but based on the estimates of the first three reports (the 'upper estimate' in the case of the Carbon Trust).

[15] The spreadsheets will be made available on the UKERC and ICEPT websites.

c/ The report does not discuss balancing, but as the report's assumptions on the capital and maintenance costs of backup capacity lead precisely to its total estimated cost of reserves, it appears that this component of costs has been omitted.

d/ The report by Dale et al is based on 20% energy market share for wind, that shown here for the present study is 15%, which partly accounts for the higher estimate in the former.

e/ This could be inferred using the identity between the capacity factor, the capacity credit and the capacity requirements of intermittency, which in this case would give a negative capacity credit of *minus* 28.2%. However, this identity has been rejected by the authors of the report, so this estimate is not given here.

f/ Estimated directly by the R.A.Eng and the present study, and for the other studies inferred from the identity between capacity credit and capacity costs of intermittency presented in Sections 4.2 and 4.3 above.

There is reasonable agreement among the studies of Dale et al, the SCAR report, the Carbon Trust and the present paper. Estimates of the capacity credit range from 19 to 23% of wind capacity, and of the required provisions for reserves from 18 to 22%. The range of estimates of the overall costs of providing for reserves and balancing is somewhat broader mainly on account of differences in capital cost assumptions; they range from 0.48 to 0.65p/kWh of electricity generated by wind after allowing for transmission losses.

The estimates of the RAEng are outliers. Some lesser reasons for this also arise from differences as to unit costs and in the treatment of losses[16]. The major difference, however, arises in the estimated capacity costs of intermittency. It is assumed that each 100 MW of wind energy would require 65 MW of thermal backup on the grounds that, since wind has only a 35% capacity factor, thermal energy would have to supply the balance. The study is especially concerned that wind energy might not be available for long periods when demand is unusually high—the 'cold snap-no wind' scenario—since it is remarked that:

> "For planning purposes, it is traditional to take a pessimistic or worst-case view of intermittent generation so ensuring that there is a high level of confidence that demand can be met even under extra-ordinary climatic circumstances."

For these reasons the study's estimates of the capital costs of providing backup are three to six times those of other studies—in round numbers, 1.9p/kWh as compared with 0.3-0.5 p/kWh in the latter. Had the costs of providing balancing and the use of fuel by the backup generation been included, the study's estimates of the overall costs of providing backup capacity and balancing would have exceeded 2.2p/kWh.

[16] The report assumed that the backup plant would also have to supply the transmission losses associated with wind when the wind wasn't blowing and the reserves were provided centrally on the grid system, not at the locations of the wind turbines.

The authors of the Academy's report have objected to the above comparison of its estimates with those of the other studies shown[17], arguing that the report was concerned with much higher levels of market penetration by wind than 15-20%, and with the need to cope with daily and other fluctuations of the demand. In addition, it eschewed the 'statistical approach' to estimating reserve requirements followed by the other studies although this has, in fact, been the traditional approach for many years.

The study's assumptions necessarily limit its applicability to the UK. Its assumptions imply extra-ordinary expenditures on reserves—in round numbers, 2 MW of backup capacity for each MW of thermal plant displaced. But intermittent renewable energy is intended to displace a thermal plant that would deliver the same amount of energy, not the same amount of capacity as a thermal plant, though it does, of course, have a capacity credit too. Thus 3000 MW of wind farms with a capacity factor of 30% would be intended to displace the energy that could be provided by 1000 MW of thermal plant. Even if, in the extreme case, *no capacity credit* were to be given to the wind farms, on the assumption that they would *never* be available over the peak period, the *maximum* amount of thermal backup that would be needed to avoid an increase in loss-of-load probability would be 1000 MW not 2000 MW. (In practice it would have a capacity value of around 600MW.) Put another way, it would not be cost-effective to replace a 1000MW thermal plant by 3000MW of wind plus 2000MW of thermal plant as backup.

The Academy's concerns about 'worst case' situations are both legitimate and shared by all involved in the present study. A further discussion is provided in section 7.2 below. However, it does seem to the present writer that the statistical approach to estimating reserves is the better one, and that UK policies would be better guided by the SCAR report, Dale et al and the Carbon Trust. The pooling of reserves was one of the main reasons why grids were formed in the first place, and is statistical in philosophy.[18] The approach allows for a wide distribution of possibilities while respecting the ineluctable fact that no system can be 100% secure 100% of the time.

7.2 The 'cold-snap-no-wind-power' scenario

The possibility of unusually high electricity demands coinciding with zero wind energy has been raised by many engineers. The following are two of several views compiled by Graham Sinden for his presentation to a Workshop on this project on July 5:

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[17] Correspondence between the UKERC team and Dr Ruffles.
[18] As Grubb (1991) observed wind farms may also contribute to the pool of reserves, and will sometimes be generating when demands are unusually high and supplies from 'conventional' stations are unavailable, as has happened in the Nordpool.

- *"There are several periods during a year when the UK is covered by an anti-cyclone and there is no wind and consequently no waves."* Professor Ian Fells (Fells and Associates, Submission to House of Lords Inquiry into Renewable Energy, 2003)

- *"… we must not lose sight of the fact that wind only blows part of the time."* Tom Foulkes (Director General of the Institute of Civil Engineers, 2003)

On the other hand, Sinden's statistical analysis of wind wave patterns in the UK comes to different conclusions:

- *"Wind power sites typically generate electricity for around 85% of all hours, (and) a diversified UK wind power system would generate electricity for 100% all hours.*

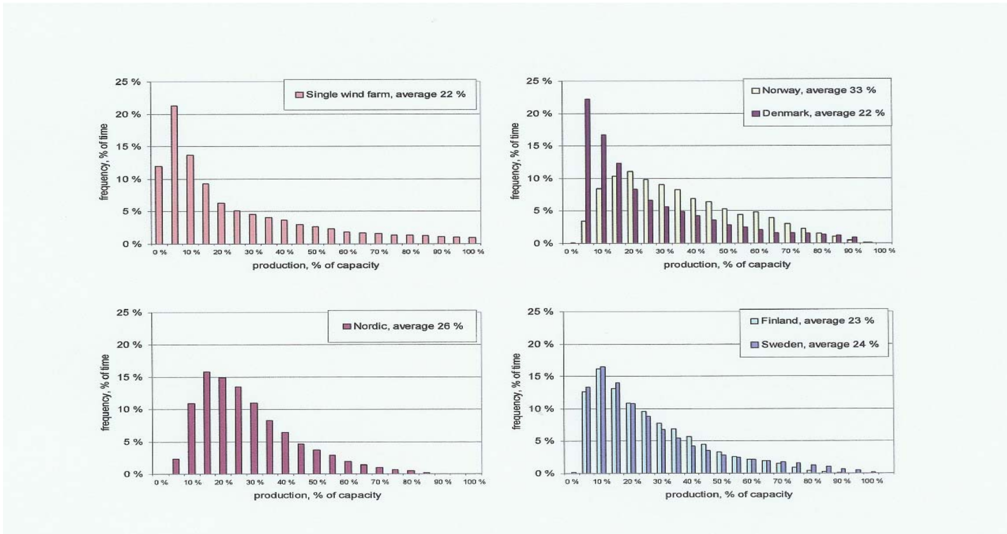
- *"Between 1970 and 2003 there was not an hour, let alone a day or week, with no wind across the UK.*

- *"Waves may be present or absent during windy conditions, and during low wind conditions."*

These conclusions are based on the same data set used in the report by OXERA (2002) sponsored by BNFL, which estimated that with 14.2 GW of new wind generating capacity on the system there might be 6 hours of shortage in 2020. However this estimate assumes 14.9 GW of new investment in open cycle gas turbine capacity, or a backup capacity of 105%, so the study actually serves to reveal the importance of having backup capacity on the system.

Evidence from Denmark provided by Sharman shows that there have been periods ranging from two to seven days (December 30-31, 2003, 13-20 February, 2003) when there was no energy available from wind. However, the analysis by Holttinen (2005) of wind energy data in the Nordic countries shows that wind regimes differ appreciably between countries, with Denmark showing an unusually high probability of having poor wind conditions (Figure 3 below).

Figure 3: Estimated Frequency Distributions of Output from Wind Farms in the Nordic Region



Source: Holttinen (2005)

As to the probability of outages in the UK arising during a 'cold-snap-high-demand' situation, consider the results summarised in Figure 1 above for the case where the energy market share of intermittent renewables is 20%:

> The capacity of thermal plant on the system would still be 95% of expected system demand, excluding new investment in reserves and/or old thermal plant retained on the system for the purpose of maintaining reserves, and 110% of expected system demand including new investment in reserves.

Hence even if there were no wind power available there would have to be a combination of power failures with thermal generation *and* an unusually high demand for a small portion of the load to be shed; suggestions of the 'lights going out' all round the country on account of capacity shortages are alarmist. Furthermore, if capacity shortages were to occur there is a long list of well-known demand management and supply options for mitigating the effects: they include switching devices, supported by tariff policies to shift loads to off-peak or the shoulders of the peak; interruptible loads, again supported by tariff policies; the use of emergency reserves held by many industrial and other consumers; and many others. [19]

In sum, a cold-snap-high-demand situation could be provided for through a reasonable provision for investment in reserve capacity, and the main issue is how

[19] A useful summary is provided in the paper by Mike Grubb (1990). With advances in information technologies and the possibilities for electronic metering, the options have widened appreciably since then.

much reserve capacity will be needed. The statistically-based studies discussed above have come up with an estimate in the range 19 to 26% of the installed capacity of wind energy, and have observed that the amount would be less if resources were more diverse.

7.3 The fuel costs of using reserves

As the share of intermittent generation on a system rises extra fuel is used over the peak period when winds are below average. The effect, which is separate from—and additional to—the extra fuel used for system balancing measures, increases with the amount of intermittent generation on the system. The simulation studies of Dale et al estimate this effect implicitly; their results point to a cost of around 0.08p/kWh of the total energy supplied by wind. The present study (using the formula discussed in Section 5) comes up with a similarly small estimate of around 0.06p/kWh if 20% of the energy on the system were supplied by wind farms.

7.4 Other differences between studies

Further differences in the cost-estimates arise from assumptions regarding

- *The choice of reserve plant*. Some studies assume that extending the lifetimes of existing thermal plant will provide the required reserves, others assume OCGTs will be installed, and others a mix of technologies. New options for providing reserves, including micro-generation, small and large scale storage devices, and technologies and practices for demand management are not a feature of the studies discussed, but can be expected to become important in future.
- *The capital and fuel costs of backup plant*.
- *The incremental costs of transmission, including losses*. Some studies allow for these, others do not. Estimates of incremental losses in studies that do provide for them are in fact quite high, in the range 12-14%.
- *The balancing costs for conventional plant*. When comparing the costs of wind with those of conventional plant, some studies ignore the balancing costs associated with the latter, and thus over-estimate the balancing costs of adding to intermittent generation on the system.
- *Seasonal fluctuations in the availability of wind energy*. These are not treated explicitly in many studies, including the present one.
- *Uncertainties as to the variance and higher moments of the frequency distributions of the projected outputs of intermittent generation*. These exert a large influence on the required reserve margin and investment in reserve

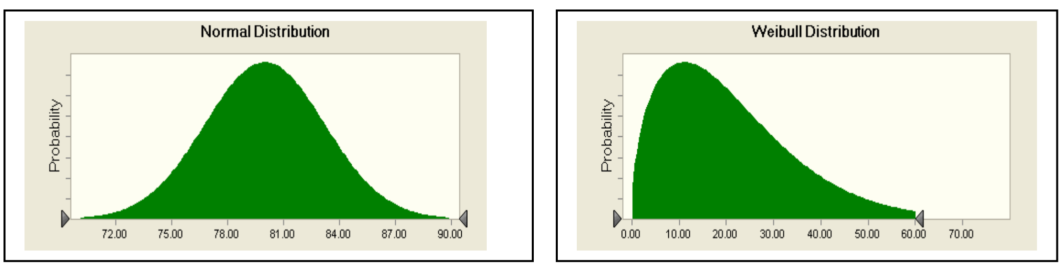
capacity, as shown in Figures 2 and 3 above. Few studies specify their assumptions, even about the variance.

There is inevitably a spread in the estimates of reserves and costs. However, the main differences between studies arise over estimates of backup capacity.

8. A Further Check Using Monte Carlo Methods

The statistical calculations discussed above can be checked using Monte Carlo methods, which provide a numerical method for combining the frequency distributions of multiple inputs to find the frequency distributions of the outputs. In the present case we are interested in finding the resulting distribution of the available system plant margin for the the case where 20% of the energy is provided by intermittent plant. For large numbers of thermal plant the binomial distributions of individual plant availabilities aggregate to a normal distribution with a mean of 80% of system capacity and a 95% probability range of approximately ± 7%. See the chart on the left of Figure 4 below. For wind plant, in contrast, the distribution of possibilities are heavily skewed about a mean of 20% of system capacity, with a range from 0.0% up to 60%, as shown on the right hand side of the figure. There is also a probability distribution for the availability of reserve capacity; the mean value of this quantity (x, say) is not known before the calculations, but is determined such that it consistent with a defined loss of load probability. For backup plant this is typically x(1 ± 10%). Finally, there are demand uncertainties to take into account, which are normally distributed; in the present case they are put at 100% with a probability range of ± 6%.

Figure 4: Characteristic Probability Distributions for the Availability of the Aggregates of Thermal Plant (left figure) **and Wind Farms** (right figure)**.**

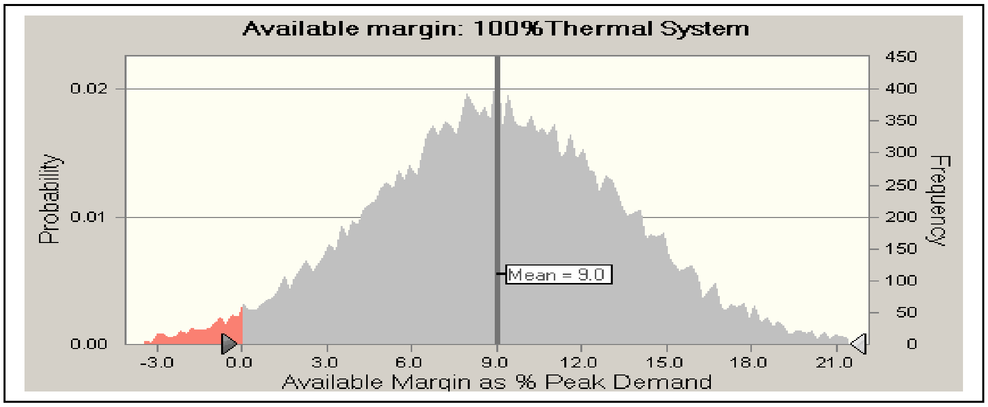


To calculate the frequency distribution of the system margin it is necessary to consider particular values of availability the thermal, reserve and intermittent plant, and of the peak demand (the inputs to the calculation) and calculate the resulting available plant margin (the output). The calculations are then repeated many times (in the examples below 20,000 times or 'trials'), with the frequency of the input assumptions chosen for the calculation being determined by their probability distributions (shown in Figure 4), until a picture of the final probability distribution is developed. [20] There are then three steps to finding the reserve capacity requirements:

[20] The following calculations use the Crystal Ball software, which is excellent for analyses using spreadsheets.

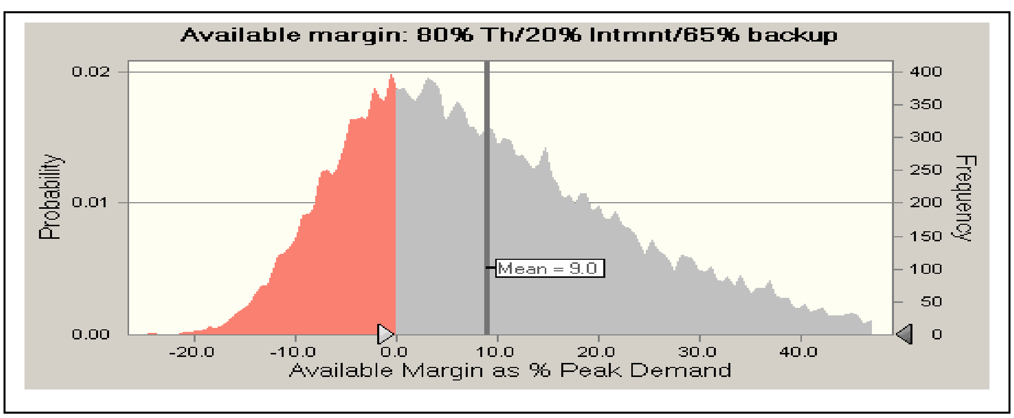
First, the system margin is estimated for a system where all the energy is generated by 'conventional' plant, the system margin being adjusted (by assumptions of investment in reserve capacity) until, in this example, the loss-of-load probability (LOLP, shown by the red-shaded area) is approximately 2.5%. The results are shown in Figure 5. Note that the system capacity margin in this case is approximately 20% above the LOLP threshold, which is not untypical for thermal systems.

Figure 5: Frequency Distribution of System Margin When Conventional Generation Supplies 100% of the Energy. Loss-of-Load Probability ≈ 2.5 %



Second, a system is considered in which 80% of the energy output is provided by conventional and 20% by intermittent generation. In this example, however, there is no extra investment in reserves on account of intermittent generation such that the investment in reserves is the same as that for the conventional system of Figure 5 and the mean capacity of the system is the same in both cases. Not surprisingly given the variance of the intermittent plant on the system, the effects are a marked increase in the loss of load probability, from roughly 2.5% to nearly 30%--and also a marked increase in the variance of the margin:

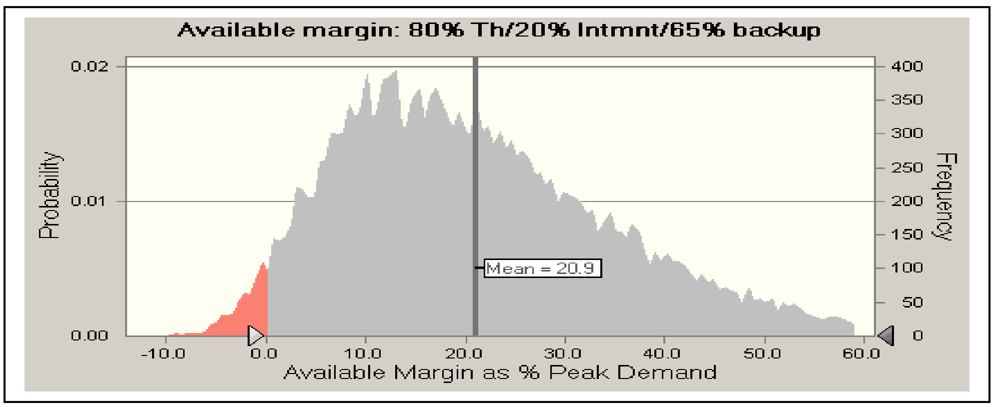
Figure 6: Frequency Distribution of System Margin: Conventional Generation Supplies 80% of Energy and Intermittent Generation 20%; no Additional Investment in Reserves.



The third step is to neutralise increase of LOLP by extra investment in backup capacity, which shifts the distribution shown in Figure 6 to the right. Inspection of Figure 6 suggests that an increment of reserve capacity, equal to about 12% would restore the loss of load probability to about the same level as that for the conventional system in figure 5; and the more precise calculations (see Figure 7) show this to be the case. As shown, an increase in the mean capacity on the system is such that the mean available margin rises from 9.0% (see Fig 6) to 20.9% is sufficient to restore the LOLP to the same level as that for the conventional system.

The capacity credit can be inferred directly from such calculations by comparing the capacity of the conventional system (including backup) with the conventional capacity on the system (including backup) with intermittent generation on it.

Figure 7: Frequency Distribution of System Margin: Conventional Generation Supplies 80% of the Energy, Intermittent Generation 20%, and Backup Capacity is Installed to Restore Loss-of-Load probability to ≈ 2.5%.



The increased investment in reserves is approximately 12 % of peak demand or 20% of the capacity of the intermittent plant. The capacity credit is 19.2%. These estimates are very to those estimated above using statistical formula, and also those of SCAR, Dale et al and the Carbon Trust, which capacity credits in the range 19.2-21.2% and backup capacity in the range 18.9-21.2% (see table 2).

Further points:

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

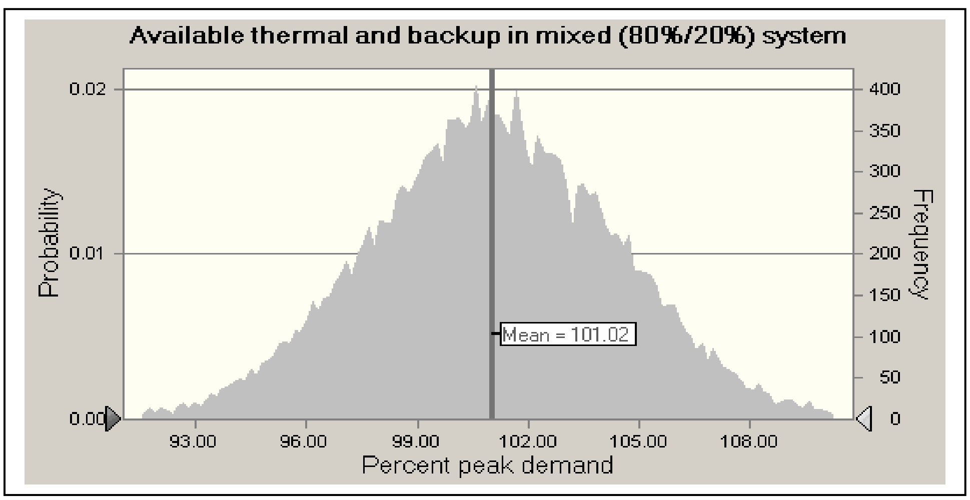
2. Although the loss-of-load probability is similar in both cases, in extreme situations (<0.5%) the cuts in supply would be deeper with intermittent generation (compare the red areas in Figures 1 and 3). As Professor Strbac has commented to us, the nature and depth of the outages is an important aspect of the problem.

3. Even in the extreme cases the loss-of-load levels due to capacity shortages would be within the compass of demand management practices. As illustrated in Figure 4, the capacity of conventional plant on the system would be 108% of peak demand, the average available capacity 101% and the lower probability limit of available capacity 94%.

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

5. Returning to the 'cold-snap' no wind scenario, Figure 8 shows the availability of 'conventional' capacity on the system if there were a total absence of wind. It is apparent that, for there to be a loss-of-load, three things would have to happen not one: there would be no output from wind; thermal plant, including backup would, have to be below average availability; and demand would also have to be unusually high.

Figure 8. Available conventional capacity (including backup) corresponding to Figure 3: 80% of energy is supplied by thermal and 20% by intermittent generation; backup capacity 20% (➔ 19.2% capacity credit).



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

9. Variation of Capacity Credit with Market Share of Intermittent Generation

A decrease in the aggregate standard deviation or variance of system supplies will act to decrease—and an increase to increase—the capacity margin required to maintain the reliability of supplies. On these grounds it might be expected that, as the market share of intermittent generation on a system rises, the capacity credit should increase. In fact, system simulation studies have consistently predicted that the opposite will be the case, that increases in market share would likely *decrease not increase* the value of the capacity credit. While this remains a prediction, it is worth reviewing why this might be the case, if only because the possibility points once again to the importance of updating system level studies and monitoring the margin regularly.

Recalling expression (3), the relation between the standard deviation of the plant margin and the standard deviations of demand and system supplies before investments in reserve capacity are introduced:

$$\sigma_m \approx \left\{\sigma_d^{\ 2} + (1-\lambda)\sigma_{f0}^{\ 2} + \lambda\sigma_{r0}^{\ 2}\right\}^{1/2} \tag{3}$$

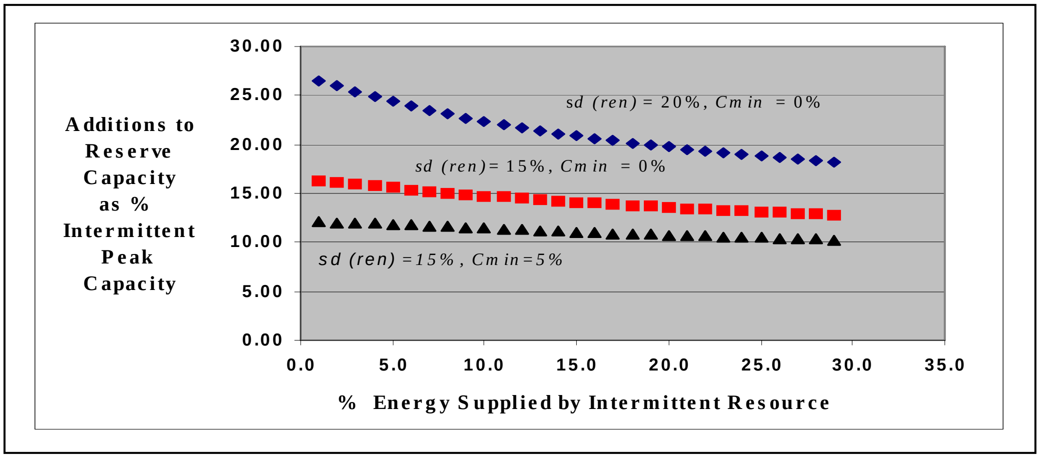
It was noted that for a given level of reliability the required margin $m = k\sigma_m$, where $k \approx 4$ for 95% reliability over the peak period. It follows from this that:

$$\frac{\Delta m}{m} = \frac{\Delta\sigma_m}{\sigma_m} \approx \frac{\sigma_{r0}^{\ 2} - \sigma_{f0}^{\ 2}}{2\sigma_m^{\ 2}} \cdot \Delta\lambda \tag{15}$$

If the available output from intermittent generators had the same variance as that of thermal plant no change in the margin would be needed, as one would expect. In practice, however, $\sigma_{r0}^{\ 2} > \sigma_{f0}^{\ 2}$ by a factor of 10, so even small changes in energy market share require significant investments in reserve capacity, even when the initial share is small.

It was the purpose of Section 4 to show how reserve requirements and the capacity credit may vary with λ. Figure 9 illustrates the effects; the reserve requirements per unit of intermittent capacity installed decrease as the market share increases. For the central case, the corresponding values of the capacity credit (not shown on the graph) rise from around 20% to 23% as the market share rises from 0 to 20%.

Figure 9: Reserve Capacity Requirements of Intermittent Energy as a Function of Energy Market Share



Note: Parameters and assumptions as for Figure 1, except those for the standard deviations, which are indicated in the above figure. *Sd (ren)* denotes standard deviation of renewable energy source, *Cmin* is the lower probability limit of its output.

A theoretical argument why the capacity credit may be initially high has been put forward on many occasions over the past 25 years, going back to the much cited paper by Farmer et al (1979) and the recent report of the Carbon Trust. It is however, unpersuasive.

The theoretical argument

This is that adding intermittent to a system is initially equivalent to adding 'firm' capacity to a system in the equivalent amount of the intermittent capacity installed times the capacity factor (after allowing for losses). This has sometimes been expressed more strongly: at small market penetrations "the capacity of any source is independent of its actual reliability and equals that of a completely reliable plant generating the same average power at times when the system is at risk." [21] The argument is as follows.[22] Suppose we have a system of conventional plant of firm capacity *Y*. The 'firmness' *Y* is expressed as a probability, *P*(*Y*), that all loads ≤ *Y* will be met. A plant of capacity x is added to it. But *x* is intermittent, with a probability *p* that it will be generating at full capacity and (1-*p*) that its output will be zero; its capacity factor is therefore $p \cdot x$. Then the probability the expected output of the new system is given by $(1-p)P(Y) + p \cdot P(Y+x)$. After expanding the second term using

[21] Grubb (1991a) See also Grubb (1991 b) and Swift-Hook (1987). I should add that while the following departs from their papers on this point no-one can read these papers without benefit. Grubb's are remarkable in scope, 15 years ahead of their time; the following relate only to one aspect of his analysis.
[22] This follows Swift-Hook's paper.

Taylor's series, taking first order terms on the assumption that x is small, then simplifying, this expression reduces to:[23]

$$P(Y + p \cdot x) \qquad (16)$$

According to this the probability of meeting all loads of less than Y plus the average capacity of the intermittent plant added to the system is the same as that which obtains when the system consists only of conventional plant. In other words, the capacity credit equals the capacity factor for small additions of size x.

The crucial assumption is that the frequency distribution of possibilities is unchanged when generation is added to a system. The distribution is assumed to shift by an amount equal to the capacity credit times the increment of capacity. However, adding intermittent generation also changes the *shape* of the probability distribution. It is more appropriate to write the functional form for the probability of meeting a load Y as $P(Y, \sigma)$; if σ increases with additions to capacity, as it does when intermittent generation is added, the probability distribution becomes flatter and broader.[24] It is necessary to reformulate the problem is as follows: [25]

Let $F_1\{Y + x_f\}$ and $F_2\{Y + x_r\}$ be the respective frequency distributions of system plant availabilities when conventional and intermittent plants with capacities x_f and x_r are added to the system. Then for the two alternatives to meet a demand of D or less with the same probability:

$\Pr\{Y + x_f \leq D\} = \Pr\{Y + x_r \leq D\}$ = the loss-of-load probability.

Means: $\mu_1 = \overline{Y} + \overline{x}_f$

$\mu_2 = \overline{Y} + \overline{x}_r$, with $\overline{x}_f = \overline{x}_r = \overline{x}$ (say) for the same expansion

Variances, with the subscripts *fi* and *ri* denoting plant level variances as before:

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[23] The second term becomes $p\{P(Y) + xP'(Y)\}$; adding this to the first gives $P(Y) + p \cdot xP'(Y)$, which is the first order Taylor series for (16). The result holds even if the probability distribution for x is given a more complex form.

[24] A prescient paper by Rockingham (c1979) is often cited in the present context. It contains a neat derivation of the aggregate variance of system plant availability when intermittent plants are introduced, using the same principles as those used in the present analysis. I could not find, however, any reference by him to a conclusion that for small levels of market penetration the effects of the variance of the new resource are insignificant in relation to the amount of investment in the resource.

[25] The analysis could also proceed by rewriting the change in the distribution as the effects of a shift in the mean by an incremental amount x and a shift $\Delta\sigma$ in the standard deviation:

$$x \cdot P'_{\overline{Y}}(\overline{Y}, \sigma) + \Delta\sigma \cdot P'_{\sigma}(\overline{Y}, \sigma)$$

The second term, which is negative, represents the effects of the change in variance when intermittent plant are added, and could be used as another basis for estimating the capacity cost of intermittency.

$$s_1^{\ 2} \approx s_Y^{\ 2} + \bar{x}\sigma_{fi}^{\ 2} \tag{17}$$

$$s_2^{\ 2} \approx s_Y^{\ 2} + \bar{x}\sigma_{ri}^{\ 2} \tag{18}$$

Putting[26] $\sigma_{f0}^{\ 2} \propto \sigma_{fi}^{\ 2} / (\bar{Y} + \bar{x})$, expressing the variance of the intermittent resource relative to that of conventional plant by $\sigma_{r0} = (\sigma_{ri} / \sigma_{fi})\sigma_{f0}$, noting that the variance of the margin, $\sigma_m^{\ 2} = Var(s_2)$, and also noting that $\bar{x} / (\bar{Y} + \bar{x}) = \Delta\lambda$, and finally taking the difference between (18) and (17) and rearranging, leads us back to an expression for the per unit change in margin identical to the one derived above:

$$\frac{\Delta m}{m} = \frac{s_2 - s_1}{s_1} \approx \frac{\sigma_r^{\ 2} - \sigma_f^{\ 2}}{2\sigma_m^{\ 2}} \cdot \Delta\lambda \tag{19}$$

In relation to the size of the system, the effects of adding, say up to 5% of intermittent supplies to it may be 'lost in the noise'. Nevertheless the effects exist, and the capacity credits of new intermittent plant are less than their capacity factors. In other words, it is not too soon to be making allowances for additions to reserve capacity in the UK as new intermittent capacity is being introduced on the grid.

Other Reasons Why the Capacity Credit May Decline with Market Penetration

One reason may be that, as the share of any new source of generation rises on a system, it will need to be available over an increasing number of peak hours. This is apparent from the curvature of the load duration curve at the peak, which widens very rapidly near the peak. Initially the contribution of the resource to available capacity will only be crucial over, perhaps, a few hundred hours per year; but this may rise to several hundred and then to over a thousand hours as the levels of market penetration increases. In the case of an intermittent resource, this would act to increase its 'exposure' over an ever-expanding critical period. In turn, this would decrease its capacity credit if the effect were greater than that stemming from reductions in variance as market penetration increases. It is difficult to estimate the net effect on loss-of-load-probability however without recourse to system simulation methods.

A second possibility is that the co-variance of outputs between intermittent generators may diminish the 'large numbers' effect noted earlier; a third may stem from the sites having the best capacity credits being used up first. Once again such effects are difficult to estimate without recourse to simulation models.

[26] Recall that the aggregate variance declines in proportion to the number of plants on the system.

10. Full System Simulation Methods and Monitoring of the Capacity Margin

The statistical methods outlined in this paper are useful for conveying the main issues and for providing ball-park estimates. But there are complications that cannot be dealt with using the aggregate statistical formula outlined above, for which full system simulations are required respecting the full frequency distributions of plant availabilities and demand profiles for the actual system. These distributions are complex for all plant. For wind farms the frequency distribution has a range of 0-100% of capacity but is mostly concentrated in a range of 10-50% (see Figure 3 above). Even for conventional plants, however, the frequency distributions are not symmetrical. The possibility of unplanned outages means that the full range of the frequency distribution of the availability of any thermal plant is from 0 to 100% capacity, just as it is with any wind plant, even if the distribution is heavily concentrated in the range 85-100%, and within this range resembles a normal distribution. The existence of large plant on a system also makes a difference to the estimates of the aggregate frequency distributions.

System simulation based on engineering and statistical methods is the approach taken by Dale, Strbac and colleagues and is the best way of obtaining reliable estimates of required reserve margins consistent with any defined level of system reliability. Even then (as Professor Strbac has pointed out to us) there is still much research to be done, for example to estimate the likely possible chronology of losses of load and their magnitudes, the effects of changes in the geographical spread of wind farms as investment proceeds, and more generally of changes in the mix of generation on the system.

Given the uncertainties as to the underlying parameters of the frequency distributions, however, it will be operational experience that will ultimately determine what level of capacity margin is appropriate. The required reserve margin will change with the way the system evolves and the geographical locations of both the wind farms and other plant. The actual parameters will only become apparent with operational experience, and the margin will need to be re-estimated periodically as experience is accumulated.

11. Conclusions and Recommendations

1. *The incremental costs of adding intermittent generation to a system*. These have the following components:

a) The capital and O&M costs of the intermittent generation itself, plus any incremental costs arising from associated investments and losses in transmission.

b) The capital and O&M costs of adding to the reserve capacity.

c) The additional fuel costs of using reserve capacity in peak periods. This is a small effect, which is likely to become significant only when the energy market share of intermittent generation is in the range 15-20% and above.

d) The additional fuel and maintenance costs of keeping the system in balance.

The studies reviewed above are in general agreement about a), c) and d), aside from differences in the unit fuel and capital cost assumptions, which are within acknowledged margins of uncertainty. Major disagreements arise over the treatment of b), however, concerning estimates of reserve capacity requirements.

2. *Estimates of reserve capacity requirements and costs*. Most estimates in the UK are concerned with the penetration of wind energy in the electricity market:

- The estimated additions to reserves if wind energy were to account for 10-20% of electricity supplies are in the range 19-26 % of the capacity of the aggregate capacity of the wind farms. The corresponding estimates of the capacity credit are 15-22%. These ranges correspond to a capacity factor of wind, adjusted for losses in transmission, of around 32% of installed capacity. These ranges are quite broad; but it is unlikely they will be narrowed much until more information is obtained from operating experience; much will also depend on the locations of future wind farms.
- The total incremental cost of providing capacity reserves and balancing, of which roughly two-thirds is for the reserves and one-third for balancing, is in the range 0.65-0.75 p/kWh.

These estimates imply that each MW of thermal plant capacity replaced by a wind plant would require approximately 3 MW wind capacity plus 0.6-0.7 MW of reserves in the form of OCGTs or delayed retirements of thermal plant. The reserves would of course be used when wind energy is not available, but the fuel consumption in such periods would be offset by the higher outputs (up to 3 times that of the thermal plant replaced) in windy periods, such that the *net effects* on fuel costs would be small.

An influential report by the Royal Academy of Engineering assumed that the required backup capacity should be 65% of wind energy capacity, such that each MW of thermal plant capacity replaced would require 3 MW of wind plus 2 MW of backup capacity. This ignores the benefits of the pooling of reserves on the grid. They might be justified for isolated systems, or for very high levels of energy market penetration by wind energy (>>30%). But they are not relevant for grid-connected investments in the UK.

3. *Monitoring the capacity reserve margin*. The capacity reserve margin in the UK is an outcome of private investment decisions taken within the context of current regulatory arrangements and electricity prices. However, Ofgem, DTI, NGC and industry observers monitor the reserve margin closely if only to assess whether the markets are likely to 'deliver' reliable supplies over peak periods, and for such purposes we need a means of for estimating the adequacy of the margin. For systems comprising only of 'conventional' plant the margin is simply the difference between installed capacity and the peak demand; when intermittent generation is on the system, however, installed capacity is no longer a reliable indicator of reserves, and instead the contribution of intermittent generators to system capacity requirements is better thought of in terms of their capacity credit.

There is broad agreement that there is a capacity credit to be attributed to intermittent energy. For a system comprising entirely of conventional plant the capacity margin as a percentage of expected peak demand is defined as:

Reserve margin = Capacity on the system – 100

When intermittent generation is added to the system, it is:

Reserve margin = 'Conventional' capacity on the system
+ Capacity credit of intermittent generation – 100

If the capacity credit is estimated by statistical methods such that the loss-of-load probability with intermittent generation is the same as that on a system comprising conventional capacity only, then the required reserve margin—and the reliability of supply—is the same in the two cases. This provides a familiar yardstick by which the adequacy of current reserve margins may be assessed.

4. *The cold-snap-no-wind scenario*. Many people have rightly pressed for provisions for such a situation to be made as the share of wind energy on the UK system rises. An additional investment in reserves equal to about 20-25% of the installed wind capacity should be ample to achieve this. For the example provided in the text (Figure 1), in which 20% of the system's energy supplies over the year being are provided by wind:

- The capacity of conventional thermal plant remaining on the system would still be 95% of expected system demand, excluding new investment in reserves and/or old thermal plant retained on the system for the purpose of maintaining reserves. Including such reserves, the conventional capacity on the system would be:
- 110 % of expected system demand if the added backup capacity were 20% of the installed capacity of wind and 115% if it were 25%. Even ignoring the capacity credit of wind the reserve margin would still be 10-15% of expected peak demand.

New options for providing reserves are also emerging in the form of micro-generation, small- and large-scale storage technologies, and new technologies, practices and pricing policies for demand management.

In sum, there is no reason why a cold-snap-no-wind situation could not be provided for *if* the system reserve margin were kept to a level commensurate with the amount of intermittent generation capacity on the system.

5. *Identities between the capacity credit and the capacity costs of intermittency.* The capacity needed to backup intermittent generators can be inferred from the capacity credit, since:

Capacity credit, in MW units = *+ Mean MW output of the intermittent plant*
– MW reserve provisions for intermittency

The mean MW output of the intermittent plant equals the mean MW of thermal plant that it is capable of displacing *before* providing for intermittency. *If* there were no intermittency the MW provisions for intermittency would be zero and the mean MW of thermal plant displaced would be the capacity credit (in MW units). The upper limit to the reserve provisions for intermittency can also be inferred from this identity, since in the extreme case the capacity credit is zero, in which case each MW of thermal plant displaced by intermittent generation would require a maximum of 1.0 MW of reserves.

This identity follows from the statistical practice of dividing the probability distribution of the available capacity of the intermittent plant into its mean or expected value, and terms representing its variability, i.e. the variance and higher moments. (The same practice has long-been applied to thermal plant; the distinguishing characteristics of intermittent plant is that the variance is greater and the distribution is more skewed.) The larger the variability, the greater need to provide for reserves to cope with it. In the case of intermittent generators the mean available capacity equals their mean MW output.

The above identity can also be used for costing purposes. The costs of providing the reserves—the 'capacity costs of intermittency'—can be based on the capital and other fixed costs of a suitable backup plant, an OCGT for example. The corresponding cost identity is:

Value of capacity credit = *+ Capital costs of thermal plant displaced (corresponding to the mean MW output of the intermittent plant)*
– Capacity cost of intermittency

6. *Cost criterion for investment*. This criterion also follows from the above. Investment in intermittent generation is economically justified if:

Capacity costs of intermittent generator ≤ Value of capacity credit
+ Fuel cost savings
+ Balancing costs

The value of the capacity credit and fuel cost savings can be based on the capacity costs of the thermal generators displaced and their fuel costs.

7. *Variation of the capacity credit and provisions for reserves with energy market penetration by intermittent energy*. When intermittent energy is added to a system there are two effects on the frequency distribution of available capacity:

- The *mean value* of the distribution shifts by an amount equal to the capacity credit times the amount of intermittent capacity installed.

- The *variance* and higher moments of the distribution also increase, again by an amount related to the intermittent capacity installed.

Several early studies, which have deservedly been influential in all other respects, had counted the first but overlooked the second effect, and had concluded that adding intermittent generation was equivalent to adding firm capacity to the system, whatever its degree of intermittency. This conclusion is not valid. The UK will need to provide for intermittency even when intermittent resources account for small market shares. The identity between the capacity credit, the capacity factor and capacity reserves requirements, discussed above, provides a good basis for making estimates; alternatively the same estimates could be inferred from the reserve margin estimated as outlined in conclusion 5 above if there is agreement on the capacity credit and the required margin.

Increasing the amount and geographical spread of intermittent generation on the system should, by reducing the aggregate variance of the available supply, reduce the costs of intermittency and increase the capacity credit. Many studies however have suggested that the opposite will be the case. One explanation may be that, as the share of intermittent generation on a system rises, it is exposed to peak loads over an increasing number of peak hours, which in turn may increase the probability of supplies not being available; the co-variance of outputs between intermittent generators may be another explanation, and the sites with the highest capacity credit being used first yet another. How far such effects would offset the benefits of the reductions in variance with scale can only be estimated through system-wide simulation methods.

8. *Methods for estimating reserve requirements and costs.* Estimating reserve margins and costs requires the use of a full system simulation model of the main generating plant on the system; evidence on the costs, operating characteristics and frequency distributions of the availability of the generating plant on the system; daily demand profiles throughout the year together with some way of characterising of both very short- and longer-term fluctuations of system demand and supply response; a statistical basis for estimating the full frequency distributions of the margin between the total available capacity and demand on the system throughout the peak period, and thus for estimating loss-of-load probabilities. Such models are available and have been developed in the UK and several other countries. The statistical formulae outlined in this paper are *not* a substitute for full-blown simulation analyses of this kind, but do provide a simple and convenient way of checking the results of full-blown models using a few familiar parameters.

9. *Recommendations for future work*. Over recent decades, views on what comprises a *desirable* margin for a large, predominantly thermal system with pooled reserves had settled down to a value of around 20%. This view has been challenged by market liberalisation and the new regulatory policies introduced over the past 15 years. In testimonies to the House of Lords Committee on Science and Technology[27] Ofgem and others have argued that the optimum margin (whatever it is) is best determined by market forces. However, the points remain that

a) For monitoring the performance of the industry, government departments and informed observers of the industry are keeping their eyes on the actual margin, and report on it annually. As noted above, Ofgem, DTI, NGC and others all pay very close attention to plant margin, and through their reports send signals to the market that have proved effective in bringing capacity back to the system.

b) For policy making purposes, e.g. on the future of nuclear power, of renewable energy, of micro-generation or other, some estimate of the reserve margin is indispensable, whether it is based on assessments of 'what the markets decide' or on economic calculation;

[27] *Renewable Energy: Practicalities.* 4th Report of Session 2003-04. HL Paper 126-I

c) Estimates of required reserves will change appreciably over the next two decades with the growth, locations and types of intermittent generation on the system; with changes in the composition and performance of thermal plant on the system; with the possible emergence of new storage technologies both large and small scale; with new opportunities for demand management through advances in metering and information technology; and with improved pricing regimes.

The current situation is that reserve margins are estimated from time-to-time through *ad hoc* studies. But the disputes reviewed in the present report, the testimonies provided to the House of Lord's Committee, the report of the Committee itself, and the technological changes now taking place—all show that a more continuous effort is merited, supported by industry, Ofgem, DTI or all three. Ideally this would be supported by research to improve methods and to gather evidence as the system evolves.

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13. Supplementary Tables—cost estimates from various studies

1. Generation Costs with 20% Wind Energy on System--Dale, Milborrow, Stark and Strbac

	Wind	Thermal (CCGT)
Assumptions:		
Method: system simulations with and without wind		
Capital costs, £/kW	540.0[a/]	400.0
O&M costs, £/kW/year	20.0	20.0
Efficiency of thermal plant, %	n.a.	50.0
Cost of gas, (p/kWh output)	n.a.	1.30[b/]
Availability, %	[c/]	85.0
Capacity Factor, %	35.0	58.7
Backup capacity for wind, MW thermal/MW wind, %	18.9[d/]	n.a.
Capacity credit, MW/MW wind,%	19.2	
Discount rate, %	10.0	10.0
Plant lifetime, yrs	20.0	30.0
Annuity rate,%	11.7	10.6
Losses, %	8.0	8.0
Derived costs, p / kWh of plant output:		
Capital costs, p/kWh	2.07	0.57
O&M costs, p/kWh	0.65	0.27
Fuel costs, p/kWh		1.30
Subtotal, p/kWh	**2.72**	**2.14**
Costs of reserves and balancing:		
Backup capacity, p/kWh	0.32[e/]	[f/]
Thermal energy to support wind (see text, section 5)	0.08[g/]	n.a.
Balancing costs, p/kWh	0.25	0.09
Subtotal, p/kWh	**0.65**	**0.09**
Total, including losses, p/kWh	**3.65**	**2.41**
Incremental network costs with wind p/kWh	0.30	
Total cost/kWh	**3.95**	**2.41**

Source: These estimates are derived from Table 2 and supporting text in the paper by Dale et al. Their estimates were of total system costs, which have been translated into total incremental costs per unit of wind and thermal energy to facilitate comparison with other studies. Note that the costs of wind with these procedures are 1.54 p/kWh of wind energy, which is almost identical to the difference in system costs, per kWh of wind energy, estimated by the authors.

Notes: na. = not applicable or otherwise allowed for elsewhere.

a/ Based on 60% offshore and 40% onshore wind

b/ Corresponds to gas price of 27 p per therm and 50% thermal efficiency

c/ Included in capacity factor

d/ Using the identity between capacity credit, the capacity factor and provisions for reserves, discussed in the text.

e/ Equals the backup capacity (MW/MW wind) times annual capital and O&M costs of thermal per kWh of output from wind.

f/ Mostly included in availability factor (there should also be an adjustment for demand uncertainties).

g/ This cost seems to have been picked up implicitly in the simulations, which actually indicate that the share of thermal energy in sales is 81.5% not 80%; so 1.5% extra is generated for reasons discussed in the text. This estimate is based on the additional 1.5% of thermal plant fuel costs estimated by Dale et al, divided by the output from the wind plant. Note that the unit fuel cost for this duty would be higher than for base-load thermal plant.

2. Incremental *system* costs of a system with 17% and 27% wind (20% and 30% renewables) relative to a baseline system with 7% wind (10% renewables)--SCAR report [a/]

	Baseline, 7% Wind	17% Wind	27% Wind
Assumptions:			
Method: System simulations comparing wind scenarios with the baseline scenario			
Capital costs of OCGT (the reserve plant)			
Annualised capital and O&M costs of OCGT (13% d.rate)	47.0	47.0	47.0
Efficiency of OCGT			
Cost of Fuel (p/kWh of output)			
Availability of thermal plant	85.0	85.0	85.0
Capacity factor of wind, %	35.0	35.0	35.0
Incremental backup capacity for wind, MW OCGT/MW wind, % [b/]	5.9	18.3	22.8
Capacity credit, MW/MW wind capacity, % [c/]	35.3	22.9	18.4
Discount rate,%	13.0	13.0	13.0
Plant lifetime of OCGT	15.0	15.0	15.0
Other data:			
Peak demand, GW	75.7	75.7	75.7
Capacity of wind, GW	9.9	24.0	38.0
Capacity of Conventional Plant (incl. reserves) GW	74.0	72.0	70.5
Capacity of other plant, GW	13.6	13.6	13.6
Energy demand, TWh/yr	427.0	427.0	427.0
Output of wind, TWh/yr	30.1	72.8	115.6
Output of thermal, TWh/yr			
Incremental costs of reserves and balancing, p/kWh of increment of wind:			
Balancing: [d/]			
Response		0.03	0.04
Synchronised reserves		0.12	0.14
Standing reserves		0.03	0.03
Start-up		0.04	0.04
Wind curtailment		0.00	0.01
Capacity costs *		0.28	0.35
Incremental costs of reserves and balancing, p/kWh		**0.50**	**0.60**
Further incremental costs:			
Transmission and distribution: capital costs & losses		0.27	0.35
Capital and operating costs of wind plant	Not estd.	Not estd.	Not estd.
Total *system* incremental costs , p/kWh of output [e/]		**0.77**	**0.95**
* N.b.: At 10% discount rate capacity costs are:		0.26	0.32

a/ The estimates are for the high demand scenarios in the report
b/ This equals the capacity of wind times its capacity factor divided by the availability of the thermal plant (giving the amount of thermal plant capable of producing the same amount of energy) , minus the capacity credit times the capacity of wind, all divided by the capacity of wind.

c/ Based on the estimates in table 9, p 32 of the SCAR report. Note that the peak demand estimates in this table are lower than those in the Annex tables and reported below; they appear to be peak demand minus the contribution of micro-CHP, energy from wastes and other renewables.
d/ The difference between the annual costs in the baseline scenario divided by the difference in kWh of wind generation
e/ I.e. excluding capital and O&M costs of wind.

3. Estimates of Reserve and Balancing Costs--The Carbon Trust

	10% Wind on System	20% Wind on System
Assumptions		
Method: survey of results of others plus supplementary calculations		
Capital and O&M costs of thermal and plant		
Capital and O&M costs wind farms		
Wind capacity, GW	12.0	25.0
Capacity Factor, % [a/]	35.0	35.0
Capacity credit, GW	3.3	5.0
Capacity credit, % of wind capacity	27.5	20.0
Implied incremental backup capacity for wind, MW OCGT/MW wind, % [b/]	13.7	21.2
Estimated Reserve and Balancing Costs, p/kWh		
Generation Reserves Costs (average of range)	0.45 [c/]	0.45 [c/]
Balancing costs	0.20 [d/]	0.24 [e/]
Total	**0.65**	**0.69**

a/ Not given in the report, but taken to be the same as in the SCAR report.
b/ Estimated from the identity between the reserve requirements, the capacity factor and the capacity credit, discussed in the text.
c/ Actual range is £3-6/MWh
d/ Actual range is £1.6-2.4/kWh
e/ Actual range is £1.9-2.8/MWh

4. The Royal Academy of Engineering: *The Costs of Generating Electricity*. (The following are their estimates for wind, CCGT and OCGT only.)

	Onshore Wind	Offshore Wind	CCGT
Assumptions:			
Method: Project analysis using rule of thumb to estimate reserve requirements			
Capital Costs, £/kW [a/]	740.0	920.0	300.0
O & M Costs, £/kW [b/]	24.0	57.0	25.0
Fuel costs, p/kWh			1.53
Availability of CCGT, %			85.0
Capacity factor of wind, %	35.0	35.0	
Transmission losses (relative to conventional plant), %	14.0	12.0	0.0
Economic lifetime, yrs	20.0	20.0	25.0
Construction time, yrs	2.0	2.0	2.0
Discount rate, %	7.5	7.5	7.5
Annuity rate,%	9.81	9.81	8.97
Subtotal: project costs excl. balancing and resrvs, p/kWh [c/d/]	**3.68**	**5.40**	**2.25**
Data on OCGT (for estimating costs of reserves):			**OCGT**
Capital Costs, £/kW			330.0
O & M Costs, £/kW			34.0
Fuel costs, p/kWh (@ 39% efficiency)			2.25
Availability of CCGT, %			85.0
Economic lifetime, yrs			20.0
Construction time, yrs			1.0
Incrmtl. backup capacity for wind, MW OCGT/MW wind, %	65.0	65.0	
Estimated Reserve and Balancing Costs, p/kWh			
Generation Reserves: Capital and O&M Costs [c/]	1.69	1.69	
Balancing costs (including fuel used by OCGTs)	Not estd.	Not estd.	
Subtotal: reserves and balancing, p/kWh	**1.69**	**1.69**	**0.00**
Total costs, p/kWh	**5.37**	**7.09**	**2.25**
Supplementary estimates (this study, not of RAE):			
Costs at 10 discount rate, p/kWh: -- reserves and balancing	1.86	1.86	
--Total costs	**6.2**	**8.06**	**2.35**
Costs at 13 discount rate, p/kWh: -- reserves and balancing	2.1	2.1	
--Total costs	**7.3**	**9.36**	**2.49**

a/ Future estimates are £630/kW and £780/kW for onshore and offshore wind respectively.
b/ O & M costs include allowances for overheads (listed separately in the RAE report)
c/ Includes interest during construction, here assumed to be interest on the full capital cost for half the construction period.
d/ The actual project costs excluding balancing and reserves in the RAE study are slightly different for offshore wind and CCGT, being 5.5 and 2.2 p/kWh respectively.

5. Present Study: estimated costs of reserves and balancing	**Wind on System**		
Assumptions:	**5%**	**15%**	**OCGT**
Method: project analysis using statistical approach to estimate reserves and costs			
Peak demand on system GW	75.0	75.0	
Reserve margin, %	20.0	20.0	
Energy demand, TWh/yr	420.5	420.5	
Capacity factor for wind	35.0	35.0	
Incremental losses associated with wind generation	10.0	10.0	
Energy output of wind before deductions for losses, TWh/yr	23.1	69.4	
Capacity of wind on system before deductions for losses, GW	7.5	22.6	
Backup capacity for wind, MW OCGT/MW wind, % [a/]	22.3	19.1	
Implied capacity credit for wind, % wind capacity [b/]	18.9	22.1	
Capital and fuel cost data for OCGTs: [c/]			
Capital Costs, £/kW			330.0
O & M Costs, £/kW/yr			20.0
Fuel costs, p/kWh (sporadic use over peak) [d/]			5.2
Availability of CCGT, %			85.0
Economic lifetime, yrs			20.0
Construction time, yrs			1.0
Discount rate, %			10.0
Annuity rate, %			11.7
Fraction of peak hours over which backup capacity is used,%	3.1	14.0	
No of peak hours	1000	1000	
Estimated reserve and balancing costs, p/kWh			
Generation Reserve: Capital and O&M Costs [e/]	0.50	0.43	
Expected fuel costs of using reserves [f/]	0.012	0.045	
Balancing costs (spinning reserves etc) [g/]	0.20	0.25	
Total reserve and balancing costs, p/kWh	**0.72**	**0.73**	

a/ See text for basis. These estimates assume an s.d. of 20 % for wind farms and that the lower probability limit of output is zero. The estimates are per unit of capacity supplied to the grid, as the OCGTs would not have to provide backup for the losses associated with the wind.
b/ Energy output of wind, net of losses, divided by availability factor for conventional plant (assumed to be 85%) minus the added backup capacity requirements to avoid increases in loss-of-load probability.
c/ Estimates of the unit costs are those of the RAEng report.
d/ The RAEng report estimates that the fuel costs of operating OCGTs for long periods are approximately 2.1 p/kWh, but would rise by 3.1 p/kWh when operated for peaking duty.
e/ Equals fuel cost*backup cap*(annual capty. and O&M costs)/8760*availability of OCGT*capacity factor of wind.
f/ Equals the new backup capacity of OCGTs times the no. of peak hours, times fraction of peak hours over which the OCGTs are used, times the fuel costs of OCGT divided by wind energy output. (Figure 5 in text gives an example, though for slightly different parameters.)
g/ These are the estimates (rounded) of the SCAR report, Dale et al and the Carbon Trust ('upper estimate' in the latter case), which are in close agreement.