Integrating renewables

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Summary

There is a widespread, but mistaken, belief that operation of an electricity system with inputs from variable renewable sources, such as wind, causes operational problems. An objective assessment of the impacts needs, however, to consider how integrated electricity systems are managed. It is shown that modest amounts of input from sources such as wind into a network pose no operational difficulties because they do not add significantly to the uncertainties in the prediction of the supply/demand balance. The way that geographical diversity smooths the output from wind farms is also examined. A review of integration studies, worldwide, suggests that the additional costs of integrating wind are around £2/MWh with 10% wind, rising to £3/MWh with 20% wind. There is also a consensus that wind plant does have a “capacity credit”, and so can displace thermal plant. This paper includes a discussion of the costs for intermittent renewables that arose from the New Trading Arrangements (NETA) in England and Wales and concludes with a brief review of transmission and distribution system issues.

1. Introduction

There is a widespread, but mistaken, belief that operation of an electricity system with wind energy - or the other intermittent renewables - causes problems. Misunderstandings arise as, unlike the output from, say, coal-fired plant, the output from wind farms is variable. A common misconception is that other plant must be held in readiness, to come on-line when the output from wind plant falls. This may be true in an island situation, with wind the principal source of supply, but modest amounts of wind within an integrated electricity system pose no threat. They do not add significantly to the uncertainties in predicting the balance between supply and demand, and so changes in their output only marginally influence the need for reserves.

Misconceptions over the role of wind have been reinforced by the fact that intermittent sources of energy incur penalties under the UK's New Electricity Trading Arrangements (Neta). These do not, however, reflect the real operational penalties incurred by wind energy in an integrated system. This has been recognised in California, where modifications to (similar) trading arrangements have been implemented.

2. Electricity system characteristics

2.1 Aggregation

The efficiency of integrated electricity systems depends on the aggregation of demand and generation. At one end of the spectrum, the minimum demand from a single house is a few watts, the average is about 0.5 kW and the maximum is 5 to 10 kW - 10 to 20 times the average. If each household met its own maximum demand - 5 kW, say, 100 GW of plant would be needed for this sector alone. Aggregation smooths variations in demand from all sectors so, nationally, the maximum demand is around 60 GW, about 1.5 times the average demand. As demands are added and smoothed, savings in generating plant are realised and load prediction becomes easier.

Aggregation can be illustrated using random number strings to simulate consumer demands. The "demand" from one of 10 consumers, together with the total, is illustrated in figure 1. The single consumer’s demand varies between 1 and 9 kW, but, when added together, 10 consumers combine to produce fluctuations between 40 and 70 kW.

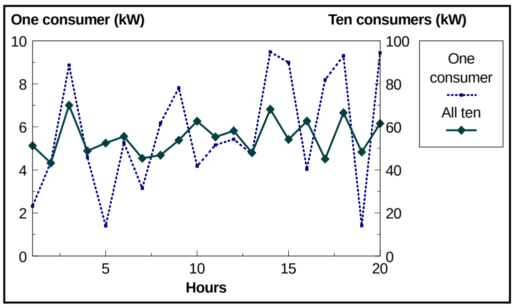

Figure 1 Illustration of the smoothing effects of aggregation, using ten "consumers", with random demands between 0 and 10 kW

2.2 *Operational issues*

It is often suggested that more "spinning reserve" (part-loaded thermal generation, whose output can be increased or decreased) needs to be scheduled to "cover" for fluctuations in output from wind plant. This is true up to a point, but the reserve only needs to cover the *extra* uncertainty, not the whole of the uncertainty due to the wind. It is important to note two key, linked factors: -

- Uncertainty margins do not add arithmetically, and
- All uncertainty margins come with a spectrum of probabilities

A System Operator with a network similar in size to that managed by the California ISO might have a forecast demand for one hour ahead of, say, 25,000 MW, plus or minus 300 MW. That is the "central estimate" of the error. It might be plus 600 MW, but with a lower probability. The Operator then schedules 25,000 MW of generation, plus about 900 MW of reserve (Three times the standard error – to cover a "worst case" scenario). These reserves are discussed in Section 4.1.

The average daily errors in demand in a typical week on the English system are shown in figure 2; during this period the maximum error in prediction was just under 4% and on 15 days it was less than 1%. The standard error during this week was 1.6% and, as the average demand was about 32 GW, this corresponds to about 500 MW.

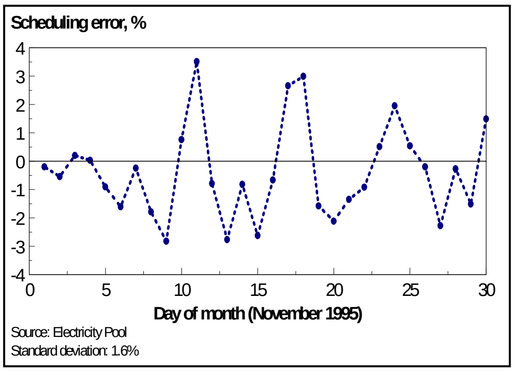

Figure 2 Typical scheduling errors on the network in England and Wales

2.3 *Power system defences*

Large interconnected electricity systems have a number of robust defences against unexpected changes in the balance between demand and generation, including: -

- Inertia of the Generating Plant. The mechanical and thermal inertia in the boilers and turbines of coal and nuclear power stations help keep the power system stable. The contribution is small, passive, and is the first line of defence, but
- "Frequency response" plant responds to frequency changes, automatically increasing or reducing output.
- Reserve - This refers to various types of plant. Some is operating at part-load; some is off-line, but able to start up within a short time.
- Pumped Storage - These can respond very rapidly to counteract any loss of generation, or surge in demand. The UK power system, for example, has rapid response output from four systems, with a maximum output of 2859 MW.
- "Hot standby" plant, able to provide generation on timescales ranging from a few minutes (in the case of gas turbines) to a few hours (in the case of steam plant).
- Voltage changes - System voltage, like system frequency is rarely "spot on" its prescribed value but varies within controlled limits. One response to a loss of generation, which may occur due to manual intervention or automatically, is a reduction of system voltage.

Voltage and frequency reductions can cope with demand or generation changes up to 7.5%[1], although only in exceptional circumstances would both be allowed to reach their minimum or maximum values.

The levels of reserve required at any given time depend partly on uncertainties in the predictions of demand, but also on the need to deal with the sudden loss of substantial amounts of generation, either due to power station faults or the loss of transmission circuits. In England and Wales, for example, key criteria are possible loss of one circuit of the cross-Channel link (1000 MW), or of Sizewell B nuclear power station (1320 MW).

When scheduling reserves, System Operators take into account the uncertainties in demand and generation on various timescales. Uncertainty increases with the time horizon, but broadly speaking, the costs of the appropriate reserve decrease. "Standing reserve", for example, may cost around £1/MW-h, but fast response plant may cost up to £5/MW-h, or more.

3 Wind characteristics

System operators simply cannot detect the variations in output from small amounts of wind plant since they are swamped by numerous other fluctuations of similar magnitude. The output from a 4 MW wind farm might be curtailed in high winds over a period of a few minutes, but a Eurostar train which shuts off power and coasts may "switch off" a 4 MW load – or more - in a matter of seconds.

3.1 Wind variability

Just as combining the demands from more and more consumers smooths the electricity demand on the network, so bringing increasing numbers of wind farms together smooths the overall output. As the amount of wind energy on a network increases, the wind farms are likely to be spread more widely over the country. The greater the distances involved, the greater the smoothing, as the correlation between wind speeds from different sites decreases with distance.

Whilst the loss of 1000 MW of thermal plant is a real risk, it is inconceivable that 1000 MW of dispersed wind will disappear instantaneously, due to wind variations. The more wind that is installed, the more widely it is spread, and sudden changes of wind output across the whole country simply do not occur.

The way that increased geographical spread reduces the wind fluctuations, is illustrated in Figure 3[2], and a more sophisticated way of presenting the information in shown in figure 4. As the capacity of wind on a network increases, however, the wind fluctuations gradually increase the uncertainty in the supply/demand balance and this point is discussed later.

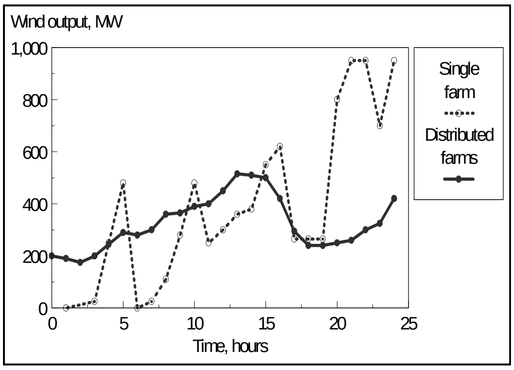

Figure 3. The smoothing effects of geographical dispersion: the "single farm" and the "distributed farms" both have 1000 MW of capacity

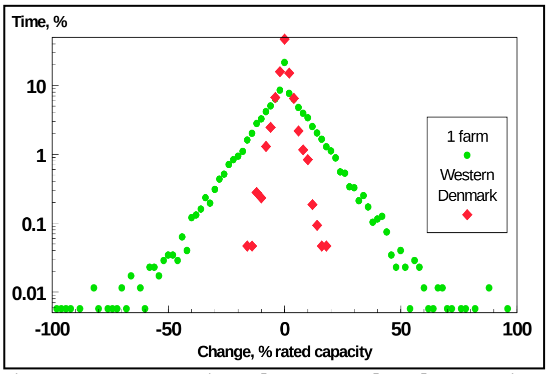

Figure 4. Comparison between the changes in output within an hour measured on a single wind farm, and over the whole of western Denmark in 1Q01[3].

Figures 3 and 4 both illustrate the dramatic impact of geographical diversity. The data from western Denmark show that, for 78% of the time, the power changes within one hour by less than plus or -3% of its initial value. At the other end of the scale, the output from a single wind farm may, very occasionally, change by 100% within an hour. In western Denmark, on the other hand, there were no changes greater than 16% in 2004.

This discussion has focused on power changes within an hour, since these that tend to have the strongest influence on the "costs of variability." System Operators also take into account the additional uncertainty on longer timescales.

In the UK, National Grid Transco has summarised the key issues relating to "smoothing" as follows[4].

"However, based on recent analysis of the incidence and variation of wind speed we have found that the expected intermittency of wind does not pose such a major problem for stability and we are confident that this can be adequately managed…

It is a property of the interconnected transmission system that individual and local independent fluctuations in output are diversified and averaged out across the system."

4 Managing a network with wind

The reason that modest amounts of wind cause few problems (or costs) for System Operators is that the extra uncertainty imposed on a System Operator by wind energy is not equal to the uncertainty of the wind generation, but to the combined uncertainty of wind, demand and thermal generation. This combined uncertainty is determined from a "sum of squares" calculation. To illustrate the point, the requirements for operating reserve in England and Wales at the winter peak is about 3500 MW, based on uncertainties in demand and generation four hours ahead[5]. As System Operators tend to schedule reserve taking into account "worst-case" scenarios, this figure is probably based on three times the standard deviation of the uncertainty, which is likely to be around 1200 MW. The corresponding standard deviation in the uncertainty of wind generation, four hours ahead, is around 6% and so, when Britain has 5000 MW of wind generation, the standard error, four hours ahead, will be around 300 MW. It follows that the additional standard error at the peak -- using the sum of squares calculation -- will be around 37 MW. It will clearly be higher at times of lower demand, but still modest.

4.1 Extra reserve and costs

The characteristics of most electricity systems tend to be similar, so estimates of the extra reserve needed to cope with wind energy are also similar. With wind supplying 10% of the electricity, estimates of the additional reserve capacity are in the range 3 to 6% of the rated capacity of wind plant. With 20% wind, the range is 4 to 8%, approximately. Estimates of the "extra costs of intermittency" are mostly close to National Grid's figures: accommodating 10% wind on the UK system would increase balancing costs by £40 million per annum (£2/MWh of wind), and 20% wind would increase those costs by around £200 million per annum (£3/MWh of wind)[6]. Estimates from other studies, including work by or for PacifiCorp, the Bonneville Power authority and the Electric Power Research Institute yield similar results[7], shown in figure 5. With 5% wind, the extra costs are within the range $1.7-3/MWh, and with 10% wind the range is $3-5/MWh.

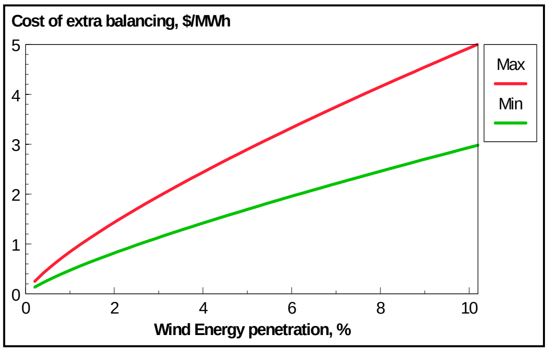

Figure 5. Estimates of the cost of extra balancing needed for wind. (Most of the studies are American, so values have been left in dollars)

4.2 Wind Prediction

Considerable efforts are being made to improve the accuracy of wind forecasting, as this has the potential to make significant reductions in the costs of extra balancing. Researchers claim that these can possibly be halved[8]. The precise savings depend, however, on the operational rules of the particular utility concerned.

For example, in Western Denmark the system operator, Eltra, commits itself to purchasing energy based on forecasts made up to 36 hours ahead. The longer term forecast can be inaccurate. In general, errors in Eltra's forecasts aren't to do with the expected amount of wind generation – these predictions are fairly accurate. The inaccuracies arise when the expected increases and decreases in wind generation arrive earlier or later than predicted.

Clearly shorter term forecasts would be more accurate and would reduce the cost to Eltra of operating the system.

In the UK, under NETA, generators commit themselves to predictions of generator output only 1 ½ hours ahead. This allows UK wind farm operators to predict their output with greater confidence than their Danish counterparts.

4.3 Frequency Spectrum of Wind Energy

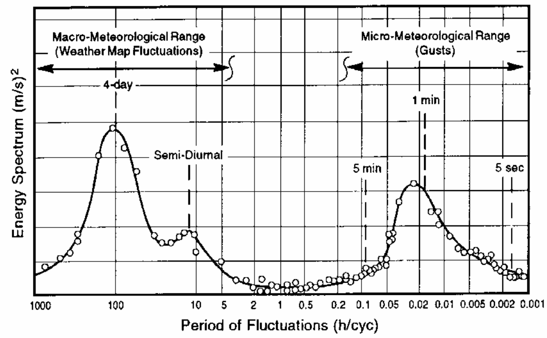

Figure 6. Variability of wind energy in different timescales. This graph courtesy of AMS Truewind.

Figure 6 demonstrates the variability of wind energy in different timescales. This feature of wind was first described by Isaac Van der Hoven in 1957[9]

What it shows is three distinct time periods where there is volatility in wind speeds form period to period. The first of these is in the 1 minute range and is caused by gusting. The second is a 12 hourly period which is due to the day/night variation of wind speed. The largest peak on this graph is at a period of approximately 4 days which is related to the average time it takes for a storm system to pass over a wind farm.

The 2 longer term variabilities do not cause additional system costs as they occur on a longer timeframe than the provision of generation predictions to the system operator.

The timescales of most interest to a system operator are the few hours before real-time and as can be seen, windspeed variations are low in this timescale.

Variations in generator output due to gusting however deserve to be considered in more detail.

4.4 Gusting

Whilst the output of an individual turbine will fluctuate in response to gusts of wind, the output fluctuations of a wind farm will be less pronounced. This is because of the time it takes for a gust of wind to pass from the first to last turbine in its path. For example a gust of 20 m/s passing across a line of 5 turbines will take 80 seconds to travel the 1600m between the front and back turbine.

Nor is it the case that a gust of wind will necessarily result in a short pulse of energy from an individual turbine. The impact of the gust is smoothed due to the inertia of the blades and generator. The turbine technology also has a part to play as some designs can capture the energy in wind gusts. For example, Enercon machines operate at variable rotor speeds and can capture the increased energy in a gust to be released slowly as additional electrical energy. The Optispeed® design of some Vestas machines have a similar impact.

When the further aggregation effects of the geographical dispersion of wind farms (as described above) is taken into account, the impact of wind gusts on the UK electricity system becomes negligible and cannot be discerned form the minute to minute variations in demand There is therefore no impact on system operation costs due to short term fluctuations of wind speed.

5 Storage

When it comes to sourcing the most economic method of providing reserve, System Operators choose the least cost options, provided it meets their technical requirements. Storage has no intrinsic merits for coupling with wind energy, as an early analysis by Farmer et al[10] made clear: -

"...there is no operational necessity in associating storage plant with wind-power generation, up to a wind output capacity of at least 20% of system peak demand".

This quote implicitly deals with the idea that storage might help "level the output" from intermittent renewables. That is possible, but it simply adds to wind's costs – unless the added value exceeds the extra cost. Storage may or may not be the most effective way of providing additional spinning reserve, *for the system* – that, again, depends on its costs.

The breakeven cost for storage is controlled by the pattern of electricity prices, the lifetime of the device and the rate of return required by the owner. The higher the difference between peak and off-peak electricity prices, the more one can afford to pay for storage. Studies suggest that the break-even cost is in the range £500-700/kW - possibly higher if the technology can provide a range of services. No large-scale technology currently appears able to match this cost.

5.1 Demand-side Management

Demand-side management has a similar role to storage - it may be the most economical way for System Operators to provide reserve. It is an area of increasing interest and ideas for remote control of non-essential consumer loads are being investigated. As with storage, there may be opportunities for links with wind energy developments -- depending on the economics. It may be a viable way of increasing the amount of wind generation, which can be accepted onto a weak network[11].

6 Capacity credits

A separate issue in the context of economic appraisals of intermittent renewable sources is the "capacity credit" of the source. The capacity credit of any power plant may be defined as a measure of the ability of the plant to contribute to the peak demands of a power system. Capacity credit here is defined as the ratio (capacity of thermal plant displaced)/(rated output of wind plant).

Numerous utility studies have concluded that wind can displace thermal plant. The capacity credit of wind in northern Europe is roughly equal to the capacity factor in the winter quarter[12]. Results from ten European studies are compared in Figure 7, showing credits declining from 20-40% at low wind penetrations to 10-20% with 15% wind. It should be noted that the values of capacity credit depend on the capacity factor of the wind plant.

Numerous studies of the UK network have concluded that wind plant has a capacity credit. An early study, already cited (10) concluded: -
"If a definition of capacity credit is adopted, that maintains the existing level of security of supply, it can be shown that for low levels of wind-power penetration, a substantial proportion of the output can be ascribed as firm power…even at higher levels of penetration, the capacity credit could approach 20% of the rated output".

NGT has estimated that 8,000 MW of wind might displace about 3,000 MW of conventional plant and 25,000 MW of wind, (20% penetration), would displace about 5,000 MW of such plant.

To facilitate comparisons between UK studies, Figure 8 compares normalised values of capacity credit and shows a good measure of agreement.

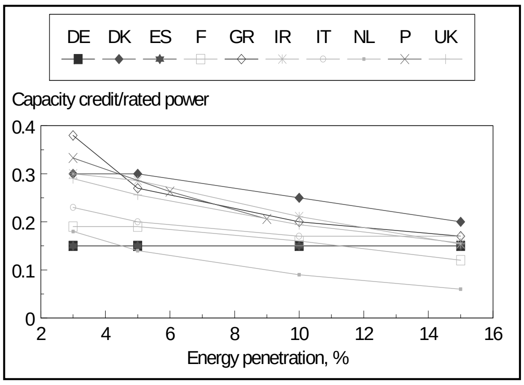

Figure 7 Comparison of results from 10 utility studies of capacity credit. Note that some made arbitrary assumptions.

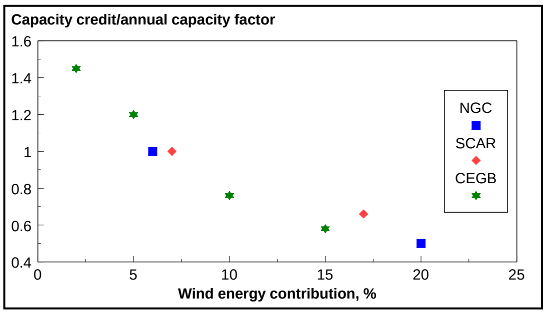

Figure 8. Normalised values of capacity credit from three studies of NGC system. The data labelled "SCAR" come from ref[13]

No evidence appears to exist to demonstrate that the conclusions set out above are inaccurate. Although there are periods of calm during the summer, the loss of load probability at such times is low. The non-availability of wind during such periods therefore makes little difference to the year-round probability. It may be noted that the capacity credit of solar plant in the UK would be very low, and that of tidal barrage plant is lower than the average capacity factor.

7. Impacts of NETA

The New Electricity Trading Arrangements in England and Wales (NETA), introduced in 2001, require each supplier to achieve a balance and so, to a certain extent, they ignore the benefits of aggregation. Shortfalls in power, after "gate closure", (when the likely power output must be quantified) are made good at the "top up price" (System Buy Price under NETA) and surpluses are sold at the lower "spill price" (System Sell Price under NETA).

Suppliers initially tended to view wind plant in isolation, as they were likely to incur significant penalties due to changes in output after gate closure. Concern that NETA would unfairly penalise the intermittent renewable energy sources by undervaluing their contribution surfaced before the system started and "penalties" in the region 0.3-0.5 p/kWh were quoted.[14] In practice, they were initially far higher than this, due to the vagaries of the "Balancing Market". An analysis of the value of wind energy during the first week of NETA concluded, "the most profitable way of operating wind farms was to switch them off[15]".

A summation of all the cash inputs and outputs from surpluses and efficiencies enables typical penalties to be determined. Estimates are shown in Figure 9, assuming:

- Constant values of SSP and SBP.
- All the expected output from wind is traded at gate closure and no attempt is made to reduce imbalance payments by reducing exposure to the higher SBP at the expense of more spill at SSP.

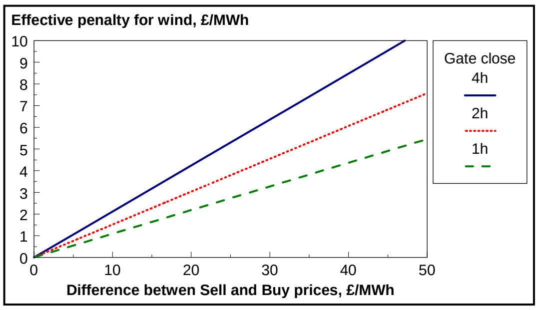

Figure 9. Estimates of the penalties payable by a single wind farm, as a function of gate closure time and balancing prices

The gate closure time has now been reduced from 3.5 hours at the outset, to one hour, which has the effect of reducing penalties significantly. The spread between SBP and SSP has also come down, which again is beneficial. The preferred solution (according to the Regulator) for wind operators is "consolidation" -- meaning they "club together", but this is only a partial solution.

Similar problems have surfaced in California and elsewhere in United States where contract-based electricity trading systems are causing difficulties for wind energy developers. In California, exemption from imbalance penalties has been agreed, along with other measures to ease the assimilation of wind energy[16].

8 Regional and Local Issues

Transmission limitations may sometimes impose tighter constraints[17] on the assimilation of wind than system-wide issues. In the UK, large concentrations of wind in Scotland and the North of England, - where wind speeds are higher than those further south - will have an adverse effect on the north-south power flows, which are already substantial[18]. Substantial reinforcement costs for the transmission networks may also be incurred, depending on the timing and precise location of the new renewable generation. Studies carried out by the network operators suggest that 6000 MW of new and renewable capacity in Scotland might trigger reinforcement costs up to £1500 million[19]. By contrast, the connection of similar amounts in England would trigger much lower transmission reinforcement costs.

In practice, higher transmission connection charges in the North of England and Scotland may dampen the enthusiasm for wind projects. These are annual charges, paid by generators, which reflect the fixed costs of the transmission system associated with their plant. The indicative charge for plant in the Scottish Hydro zone is £20/kW[20], whereas plant in the southwest is paid £9/kW -- reflecting the shortage of generation in that region. It should be noted that substantial reinforcement of the north to south transmission links might also take several years to implement.

Local issues are a complex issue[21] as they vary both regionally and locally. It is important to recognise that concentrations of embedded generation can increase distribution losses in rural areas where demand is low and so should be avoided. A study of a ten-machine, 4 MW wind farm connected into an 11 kV system in Cornwall, England has provided valuable information on local issues[22]. The study concluded "the wind farm caused surprisingly little disturbance to the network or its consumers". In particular: -

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

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

9 Other renewables

Similar methods can be used to determine the impact of other renewable energy sources although it may be noted that their performance characteristics differ and may qualitatively be described under five headings:-

- The "steady" sources such as energy from waste, landfill gas, energy crops and geothermal energy are capable of producing a steady supply of electricity; their capacity credit will be close to (75-85%) the rated power, and no extra balancing costs will be incurred

- Wind and wave energy are, broadly speaking, random in nature, although there are frequently seasonal and diurnal trends superimposed. (European winds do not exhibit the strong diurnal trends found in the Californian passes). The random nature of wind is both temporal and spatial although the movement of large-scale weather systems may mean that there are often underlying trends over a wide geographical area.

- Solar energy is, broadly speaking, less random than wind, as the underlying seasonal and diurnal trends are accurately predictable. Randomness is, however, introduced by the variations in cloud cover. The capacity credit of solar photovoltaic installations in the UK is likely to be very low, given that the output from PV plant around the times of peak demand -- generally 17:30 on a January weekday -- may confidently be stated to be zero.

- Tidal energy is in a unique category as it is related to the Lunar, rather than the solar cycle. It is highly predictable but the peak generation from a tidal scheme will rarely coincide with peak demand on an electricity system. Detailed studies of the proposed Severn barrage concluded that the capacity credit of the installation was around 15% of rated power, whereas the capacity factor was estimated at 22%[23]. If a number of tidal barrage schemes were installed, the effects of geographical diversity might be expected to improve the capacity credit, in much the same way as for wind. Similar considerations apply to tidal stream devices.

- Hydro power capacity credits depend on the amount of rainfall in the area where they are installed. Many Swedish and Norwegian schemes have high load factors but some of the schemes in southern Europe are highly dependent on the amount of rainfall, have lower load factors and a more variable output.

Sinden[24] has argued that a combination of renewable energy technologies will substantially reduce the needs for additional reserve on the UK electricity network.

10 Concluding discussion

Much of the early work on wind integration involved simulation studies and the results are now being tested against actual operational data. These comparisons strongly indicate that some of the early estimates of wind fluctuations were on the high side, and so some early estimates of the “costs of intermittency” are likely to be pessimistic.

The overwhelming consensus, from the studies cited in this paper, from the UK System Operator, and from a wide-ranging review of the relevant literature, worldwide[25], is that there are no major technical barriers to the implementation of dispersed intermittent generating systems connected to the network. The costs of managing the additional uncertainty associated with the variability are in the range £1.6-2.4/MWh with 10% wind energy, rising to £2-3/MWh with 20% wind energy.

A number of factors are likely to reduce the impacts of intermittency, Better wind prediction methods are a key issue[26] will reduce the uncertainty – and hence the cost – of absorbing wind energy and research is under way in both America and Europe to develop better techniques. The importance of this work will increase in the future, as the proportion of wind energy in electricity networks increases. Although the monetary savings depend on the costs of reserve, they are of the order £0.5-1/MWh of wind at low wind energy penetrations (2-4%), rising to around £1.2-1.7/MWh with 10% wind energy

Market mechanisms that require individual suppliers to "balance their own positions" can introduce cost penalties for wind energy that are not cost reflective. It is difficult to quantify typical monetary levels, as the relevant prices in the market are rarely cost-reflective and vary with time, and across electricity jurisdictions. The penalties incurred by wind are not due to any real technical problem, but to the vagaries of a particular set of market rules. However, there is a growing trend, particularly in United States, towards exempting wind from balancing market penalties, often by averaging imbalances over a month, and concentrating on providing System Operators with good forecasting tools – for which the wind plant operators pay a levy. The magnitude of the levy roughly corresponds to the costs of the extra balancing that is required -- from the standpoint of the system as a whole.

One of the key requirements for effective and fair utilisation of wind energy is that the advantages of an integrated electricity system are exploited to the full. This does not amount to "special pleading" for renewables, as low-cost electricity, even without renewables, also demands this. To illustrate the point, "side-effects" such as the increased (and unnecessary) part loading that has occurred in the UK since the introduction of the New Electricity Trading Arrangements are unacceptable. This pushes up both costs and carbon dioxide emissions, and is a consequence of the “compartmentalising” of the industry.

Considerable worldwide interest in the potential of demand-side management techniques has the potential of reducing balancing costs for system operators and so, as a side effect, reducing the additional costs of intermittent renewables. Looking to the future, there is now considerable interest in exploring the possibilities of high penetrations of wind energy into electricity networks. The cost implications at the higher penetration levels are inevitably somewhat less certain, but NGT has suggested (6): -

"In the longer term, we do not think it is likely that there will be a technical limit on the amount of wind that may be accommodated as a result of short-term balancing issues but economic and market factors will become increasingly important."

Given the recent increases in the price of gas and the strong downward trend in wind energy prices that has been evident for some time, the overall conclusion that can be drawn is that the future prospects for wind energy are bright.

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