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Contracting for wind generation

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Abstract The UK Government proposes offering long-term Feed-in-Tariffs (FiTs) to low-carbon generation to reduce risk and encourage new entrants. Their preference is for a Contract-for-Difference (CfD) or a premium FiT (pFiT) for all generation regardless of type. I argue that neither is suitable for on-shore wind, where a fixed FiT appears less risky. The estimated extra trading and balancing costs of a CfD for on-shore wind might be £70 million/yr by 2020, while the cost of the increased risk incurred by a pFiT might add another £180 m/yr. If similar savings were made to projected off-shore wind investments the savings might be three times as high.

Keywords wind power, long-term contracts, balancing costs

JEL Classification Q42, L14, L94

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Contracting for wind generation

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Introduction

The consultation on Electricity Market Reform (DECC, 2010) proposed that low-carbon electricity generators should be offered long-term contracts, loosely described as Feed-in-Tariffs (FiTs), to reduce their financial risk and hence allow new entrants and new sources of finance to be tapped for the massive electricity investments required by 2020 – some £75 billion in generation alone. The Government's preference appears to be for a single type of contract for all forms of generation, despite the evident differences between nuclear on the one hand (base-load, reliable and predictable) and wind on the other (intermittent and hard to predict much ahead of time).[1] Their preference is for either a two-sided Contract for Difference (CfD) or a premium FiT, pFiT. The CfD entitles the generator to receive (or pay) the strike price *less* a reference price (which could be negative, requiring the generator to make a payment), but the generator must sell the power for whatever price can be secured in the market place. The pFiT is an agreed fixed payment per MWh produced that supplements the generator's sales in the market.

These should be contrasted with the classic FiT in which the generator receives a fixed amount per MWh regardless of the market price and is automatically dispatched without the need to secure a buyer, and the current system of supporting renewables in the UK, which is a via Renewable Obligation Certificate, ROC. Under the ROC scheme an on-shore wind generator would be issued one ROC per MWh that they could sell in the market for ROCs, as well as selling their power. Suppliers would be required to secure and surrender a certain number of ROCs proportional to their sales, or pay a buy-out price that would be returned to generators in proportion to their ROCs, amplifying the value of these ROCs to the generator. Figure 1 shows the evolution of the ROC value and the wholesale (day-ahead) price, which together provide the return to on-shore wind. (Off-shore wind receives two ROCs/MWh, reflecting the need for greater subsidies to cover the higher cost.) It shows that the ROC scheme looks rather like a pFiT, in that the ROC price, corresponding to the pFiT premium, is fairly stable, although its future predictability and credibility may be lower.

Comparing support mechanisms for wind

This note compares the various subsidy mechanisms for on-shore wind (the story is similar for off-shore wind), and questions the extent to which they would reduce the financial risk facing new entrants to the electricity market seeking new sources of funds. Nuclear power

[1] This has been criticised by the House of Commons Energy and Climate Change Committee (2011, p4)

raises different issues, where the risks are primarily in construction cost and time, and where a classic CfD appears a suitable support/risk-reducing instrument that provides suitable incentives for availability.

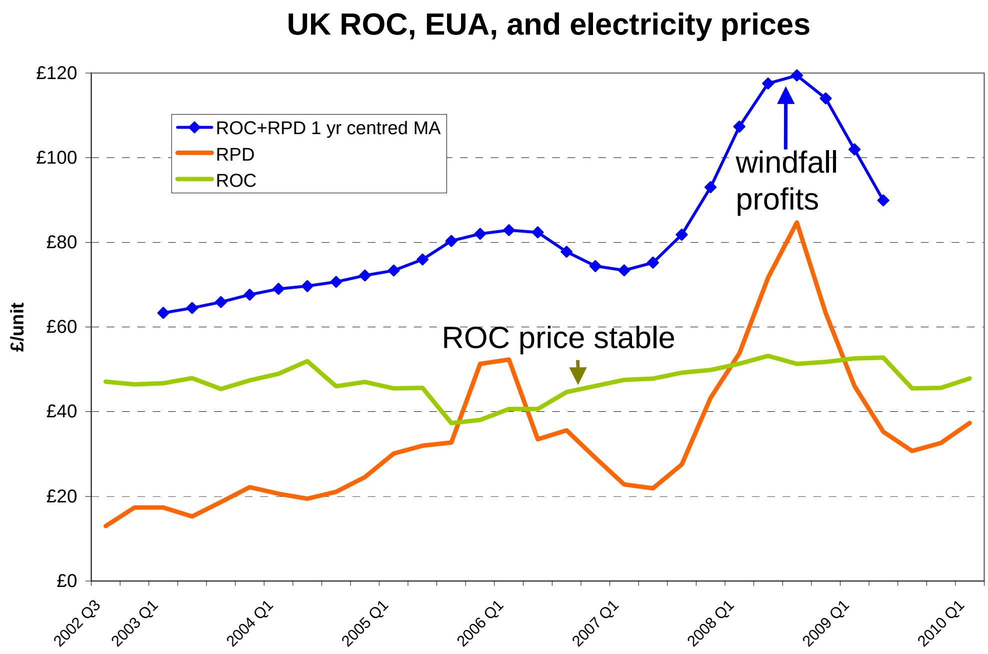

Figure 1 The value of ROCs and of selling electricity with a ROC, 2002-9
Sources: UKPX and Ofgem

If a small independent on-shore wind farm developer holds a two-sided CfD for his wind, then he is responsible for selling his output to achieve the best price in the market place, and in return will receive the difference between the strike price and the reference price, which for wind is likely to be the day-ahead average price, based on the LEBA index and N2EX. The wind farm is unlikely to be able to sell at the reference price because of the special characteristics of wind – intermittency and unpredictability ahead of dispatch. The relevant question is how large the penalty for these factors might be, given the current design of the wholesale market and especially of the Balancing Mechanism, and how this penalty might be reduced by better contract (and market) design.

Alternatively he could sell the wind to another generator or an aggregator on a Power Purchase Agreement (PPA) in return for a fixed payment per MWh of metered output, indexed to the strike price. The issuer of the PPA would then hold the CfD and be responsible for selling the power in the market. At present the Balancing Mechanism (BM) confers an advantage on the Big Six[2] as they can reduce their balancing costs by some internal balancing rather than offering such services to the market and buying them back as needed, risking exposure to the two-price structure of the BM. However, if the market for

[2] These are the six vertically integrated utilities: British Gas, npower, Scottish and Southern, Scottish Power, EDF and E.ON who collectively supply over 99% of the domestic market.

such PPAs is not very competitive, the counter-party might just offer the outside option to the wind farm, in which case we are back to the first calculation – the value of selling in the market compared to the reference price, or the *basis risk*.

Three important characteristics of wind affect their contract risk. First, their capacity factor is quite low - on-shore averages around 25% and lower nearer to demand centres, while off-shore averages 36%. Second, wind is volatile and so needs flexible fast response back-up generation to maintain balance. Third, wind is difficult to forecast reliably at the time when the power needs to be contracted.

Figure 2 shows the capacity factor (CF) duration schedule for two years for on- and off-shore wind (2005 was particularly windy, 2003 was an average year) using data from Green and Vasilakos (2010).[3] For more than half the time the on-shore wind CF was less than 20% on-shore and less than 30% off-shore and for only 10% of the time was the CF more than 66% on-shore and 75% off-shore. As these are averages over wide areas the proportion of low (< 20%) output from a single wind farm will be higher than 50% and that of high (>75%) output will be higher than 10%.

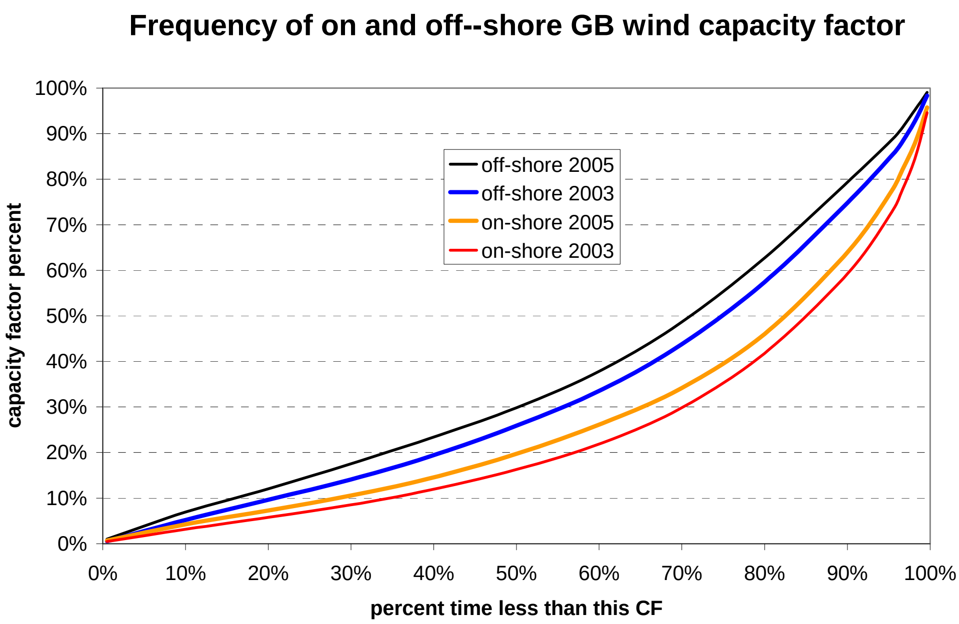

Figure 2 Average GB on and off-shore capacity factor for two selected years
Source: data from Green and Vasilakos (2010).

Although wind output is variable, there are systematic variations over hours of the day and months of the year that are relevant to valuing its output. Figure 3 shows GB average hourly averages of wind for three different months, and the pattern of hourly

[3] I am indebted to Richard Green for this data. The off-shore wind data is based on coastal conditions scaled to produce off-shore CFs.

demand in winter and summer, using the Green and Vasilakos (2010) data for 2003 wind conditions. It shows that, conveniently, wind power increases with the morning peak increase in demand, and peaks in the afternoon around 3pm, but then falls, just when winter demand is rising.

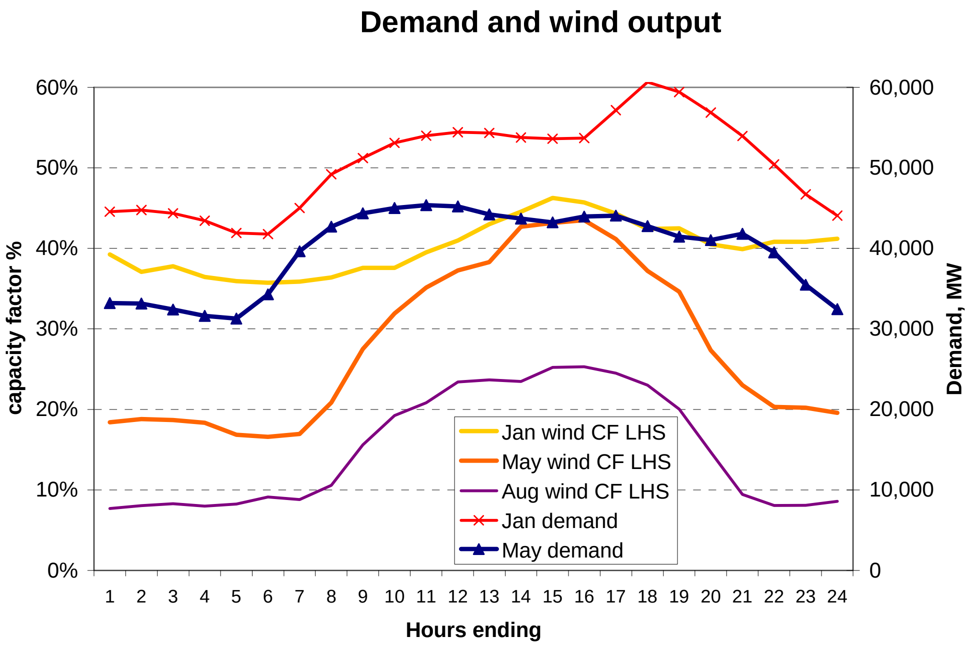

Figure 3 Average on-shore wind capacity factor by hour and month, 2003 wind
Source: Green and Vasilakos (2010).

There is clearly a strong seasonal effect, which is demonstrated more obviously in Figure 4, which looks at seasonality in a range of years' wind output. Output is lower in the summer when demand is also lower, confirming the diurnal positive correlation between wind output and demand. This positive correlation should help in that if the reference price is a daily or annual time-weighted average price, at least provided output is higher when prices are higher. If so, then on average wind farms will earn more than a time-weighted average reference price.

Short-term variability and unpredictability

Figure 5 shows the variation in the average simulated GB-wide on-shore wind output over a three-day period in October 2003, for a hypothetical 11 GW of wind power, using Green and Vasilakos (2010) data. Output rises from a capacity factor of 20% to reach a high of nearly 90% some 27 hours later.

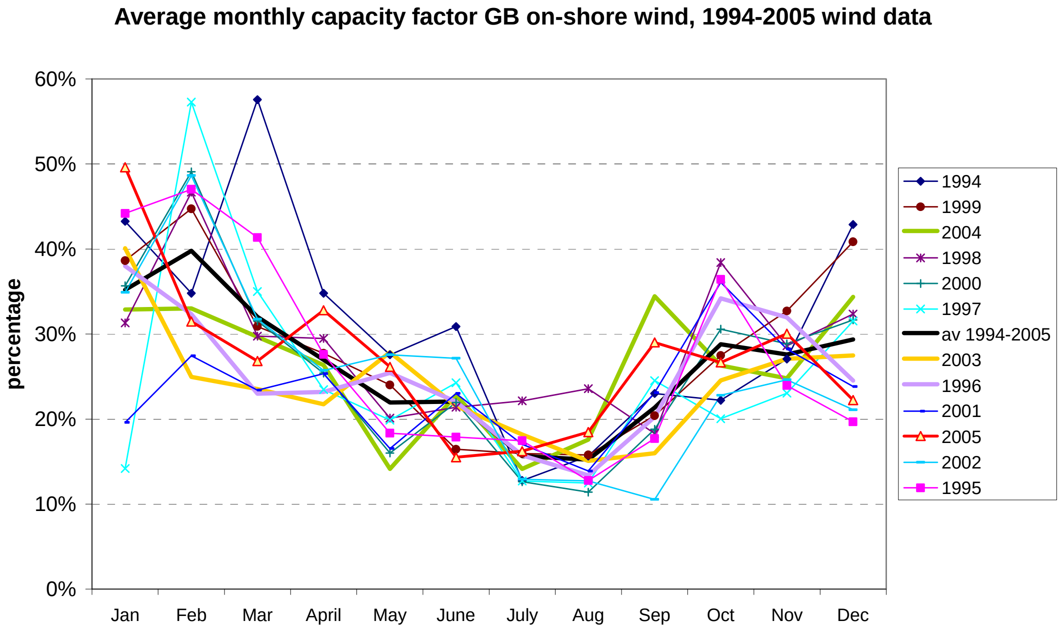

Figure 4 Average on-shore wind capacity factor by month and year.
Source: Green and Vasilakos (2010).

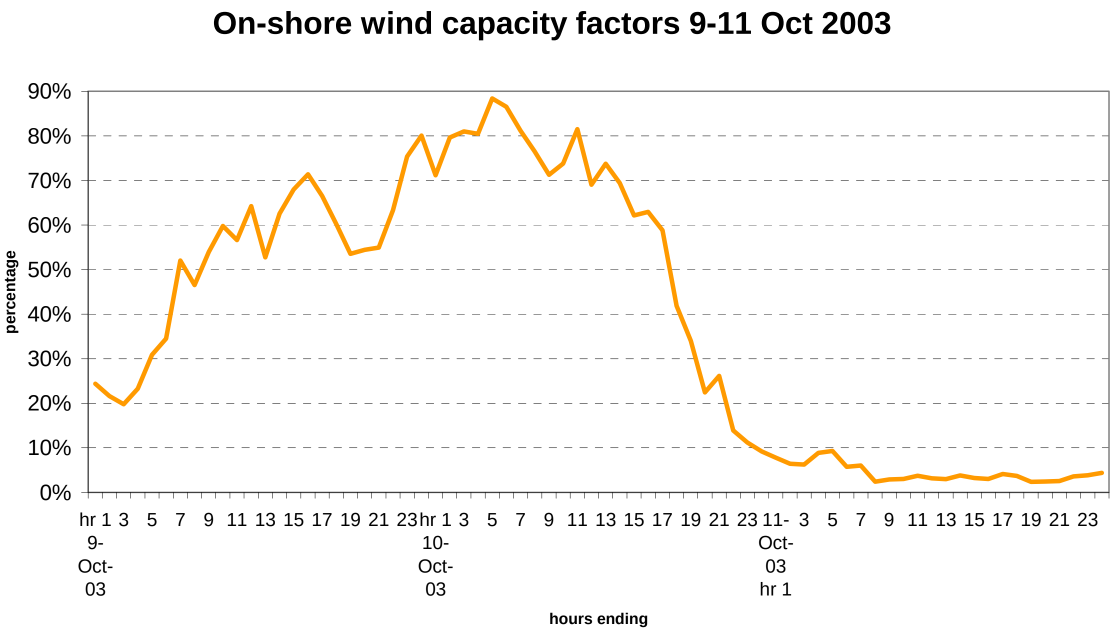

Figure 5 Variability of GB average on-shore wind over a three day period
Source: data from Green and Vasilakos (2010).

More dramatically, peak output at 5am on 10th October of 9.7 GW falls to 680 MW less than 24 hours later, and falls by 1,870 MW in one hour (at 6pm). If the simulated off-shore wind power is included then total wind output (11 GW on-shore and 19 GW off-shore) would fall from 22.5GW to 2.4 GW by 8am on 11th, a fall of 20GW in 18 hrs, and a peak rate of change of over 6GW/hr, requiring very rapid reserve responses.[4]

This wind power is simulated over a wide area and therefore takes advantage of the decreasing correlation of wind output with distance apart of different turbines. Such variability over a short period is remarkable (admittedly for these particular days), and would be higher for individual wind farms. Figure 6 provides another view of GB wind volatility.[5]

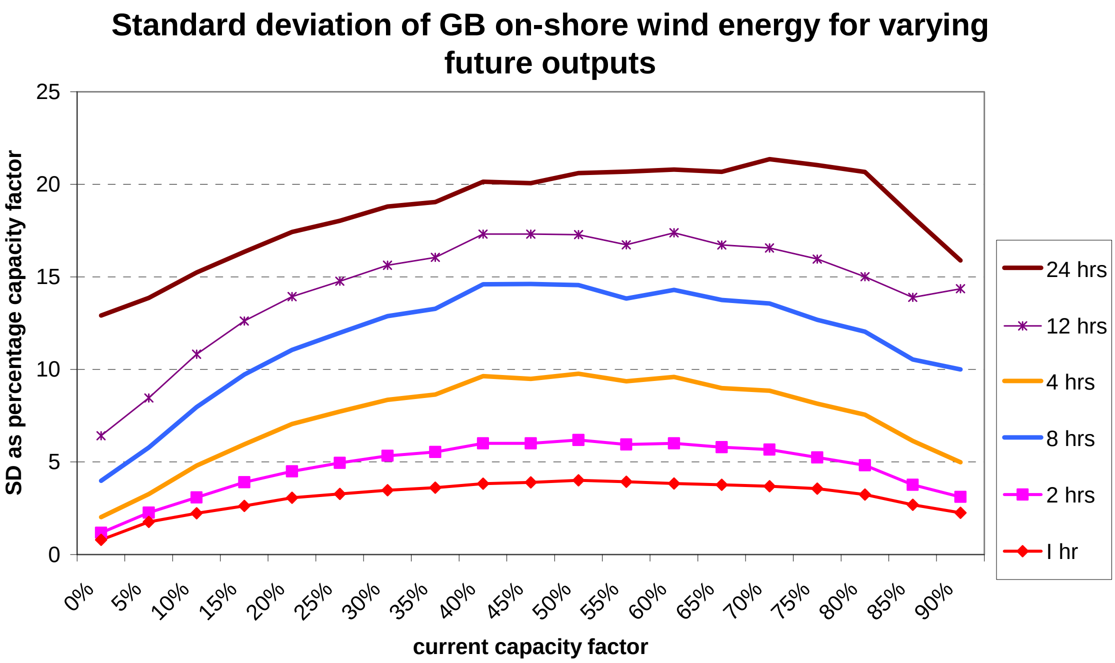

Figure 6 Standard deviation of GB on-shore wind output for varying numbers of hours later
Source: National Grid

Figure 6 shows the variability of wind output starting from a known current level of output (measured by capacity factor, CF) for varying hours ahead for GB average wind conditions. It shows that there is considerable variability over quite short time periods, so that starting with a current output of 25%, the output day-ahead might be on average similar, but the standard deviation (SD) is 18%. Again, variability is likely to be somewhat higher over smaller areas. The distribution of possible future outputs has fatter tails than a normal distribution, with a higher chance of extreme variations, as shown in figure 7 (although bounded below by zero and above by 100%). Thus 24 hours after a current CF of 25% there is a 5% chance that the output will be more than 60%, or 35% more than today,

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4 The Green and Vasilakos wind data set for off-shore is based on rather few near-shore observations and these are quite closely correlated with the on-shore wind over this three-day period, but with a wider distribution of off-shore wind the correlation might be lower and the falls less dramatic.

5 I am indebted to Lewis Dale of National Grid for this data, supplied from James Cox of Pöyry (see Cox, 2009), and based on wind conditions between 1st Jan 2000 to 31st Jan 2009.

whereas a normal distribution would give this only a 2.5% chance. The median output is only slightly less than present output for a 25% CF.[6]

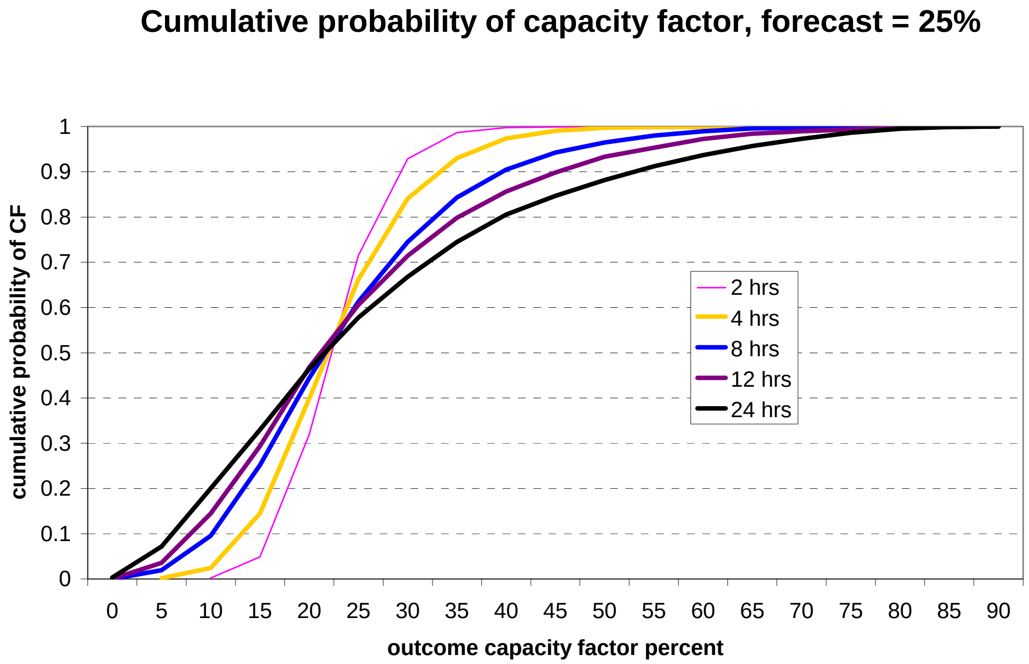

Figure 7 Cumulative distributions of later output outcomes starting from 25% output[7]
Source: as for fig 6

Variability is not the same as unpredictability, and figure 8 gives evidence on forecast accuracy for German wind power. Note that accuracy is considerably lower for transmission zones that only cover a part of the country, and that averaging over wider areas increases forecast accuracy.

If all wind were dispatched by a single System Operator (SO) then the country-wide average would be the relevant measure of the cost of inaccuracy, but if each wind farm has to contract ahead and bear the risks of inaccuracy then the individual forecast accuracy is relevant and will be considerably higher. Just how much higher has been carefully surveyed by Giebel et al (2011). Thus looking at the mean absolute error (MAE) 24 hours ahead the error is 16% for a single wind farm but only 10% for four wind farms together (Giebel et al; 2011, fig 40 for wind data in Finland).[8] Similarly, the standard deviation of the error (and presumably the MAE) rises by 60% as the distance decreases by a factor of 5 (from a diameter of 730km down to 140km, Giebel et al fig 37 using German data).

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[6] There is regression to the mean output so for outputs of 20% or less the later outputs tend to be higher, and for 30% and above they tend to be lower.

[7] The probability distribution from which the distributions are constructed is given in the appendix

[8] The source discusses the difference between RMSE and MAE. For our purposes MAE is more immediately useful, as discussed below, although RMSE attaches more weight to large disturbances and these will be more costly to deal with. Roughly speaking MAE is 66%-75% of the RMSE, depending on the shape of the distribution.

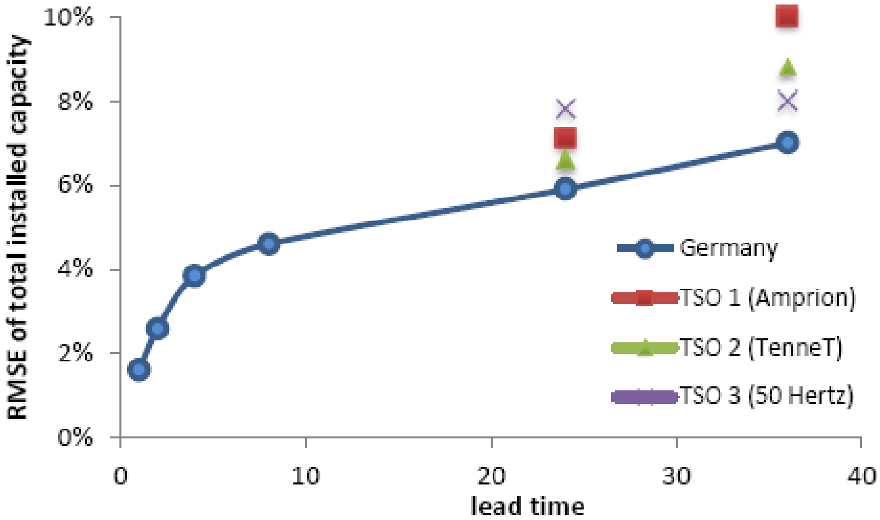

Figure 8 Accuracy of wind forecasts for Germany and three transmission zones
Source: Borggrefe and Neuhoff (2011)

Forecast accuracy also depends on the terrain, so while day-ahead inaccuracy is about 10% (MAE), it rises for 12-14% for complex terrain and over 20% for highly complex terrain (Giebel et al fig 9). Perhaps surprisingly, the RMS error for a single wind farm increases only slightly from 15% of capacity from about 4 hours ahead to 18% 36 hours ahead (Giebel et al fig 4). The evidence on forecast accuracy at the individual wind farm level therefore suggests a plausible MAE of about 10-12% of nominal capacity from 4 hours to a day ahead, provided the site is not too complex (rugged terrain).

Valuing the risks under a Contract for Difference

A classic two-sided CfD for a defined number, *M*, MW obliges the generator to deliver *M* MW of power by generating or buying it in the market, in exchange for the strike price. This works well with high capacity factor plant like nuclear power, but would be quite inappropriate for the capacity of a wind farm, as roughly 75% of the time it would be buying power to sell at the strike price, and as such merely acting as a trader. If the strike price were normally above the average wholesale price, this would not be a problem, and might act as an appealing hedge to the generation company that had rights over the wind farm (via the PPA mechanism above), but this would surely constitute a subsidy to fossil generation.

Presumably such a CfD would be sized to accommodate the low capacity factor (CF). Consider, for example, a 4 MW turbine with a CF of 25% with an average effective output of 1 MW. This might be achieved by running at 4, 3, 2 or 1 MW each for 10% of the time, and at zero for 60% of the time. A CfD for 1 MW would lead to average surplus sales of 2 MW for 30% of the time and purchases of 1 MW for 60% of the time, on average zero. A CfD for actual output would only pay the difference between the strike price and reference price for actual output, but would still be responsible for nominating output into the market ahead of time and resorting to the Balancing Mechanism for any errors.

If the wind farm held a CfD for actual output, then we can estimate the size of the *basis*, that is the difference in successfully selling the actual output at the spot price but being paid the reference price, using the simulated data available with current and projected future prices. Suppose the reference price is a time-weighed average price, while transactions take place at the half-hourly price. If the sales were in higher valued hours than the purchases, then there would be a modest contribution from this extra trading (essentially arbitraging between the cheaper less windy periods and the windier and costlier periods). This hypothesis can be tested using the simulated data available. First we can consider the trading wind at recent market prices (when wind has a relatively low share). Table 1 shows the value of successfully selling at the half-hourly day-ahead price rather than selling at the time-weighted day-ahead price over the course of the year. The price data are all post NETA, for which the first full year is 2002, so in table 1 the first date is the date of the hourly average GB wind and the second is the (non-leap) year of the day-ahead price data, where these are different. Note that the wind outputs in 2003 and 2005 are negatively correlated with 2005 prices but the 2005 wind is positively correlated with 2009 prices.

Table 1 Average prices received selling spot vs. selling at daily base-load average

	1999/2006	2001/2007	2002	2003	2005	2005/2009
weighted av. on-shore	£38.45	£29.64	£15.78	£18.14	£34.54	£39.30
weighted av. off-shore	£37.81	£29.28	£15.75	£18.69	£35.89	£38.92
time average	£37.75	£28.53	£15.23	£18.36	£36.49	£36.92
ratio on-shore	101.9%	103.9%	103.6%	98.8%	94.6%	106.4%
ratio off-shore	100.2%	102.7%	103.4%	101.8%	98.3%	105.4%

Source: wind data from Green and Vasilakos (2010); prices from UKPX RPD

Table 1 suggests that the basis risk is modest most years although quite high looking at 2005 wind conditions at 2009 prices. Green and Vasilakos (2010) have gone considerably further in estimating the possible impact of large-scale wind power on the spot prices, where high wind is likely to depress prices. Table 2 shows the results, confirming that large volumes of wind can depress prices when wind output is high and as a result gives rise to a shortfall in revenues compared with the daily average base-load price.

Table 2 Average prices received selling spot vs. at 2020 predicted daily averages

	1999	2001	2002	2003	2005
weighted average on-shore	£24.18	£37.04	£25.13	£24.59	£24.20
weighted average off-shore	£24.50	£35.87	£25.14	£24.77	£24.67
time average	£25.88	£35.22	£26.49	£26.56	£26.12
ratio on-shore	93.50%	105.10%	94.90%	92.60%	92.70%
ratio off-shore	94.70%	101.80%	94.90%	93.30%	94.40%

Source: wind and price data from Green and Vasilakos (2010)

The conclusion is that a contract signed for the period from say 2014 for 15 years could encounter a system with increasing volumes of wind, and this would be a risk factor over the life of the CfD, as the basis would change from slightly favourable to rather unfavourable most of the time.

Even a variable CfD covering metered (not a pre-specified) output faces an additional risk, as it may be risky to leave selling into the spot market until the last moment. Presumably the wind farm would contract ahead and sell the unpredictable part into the Balancing Mechanism (BM) or buy to make up short-falls when the contracted amount exceeds the actual output.

Figure 9 shows that trading in the BM is risky in that there is a margin between the System Sell Price, SSP, and the System Buy Price, SBP. Note that when the market is long, as it is 70% of the time (the yellow thick line shows the cumulative volume of activity in the BM on the right hand y-axis), the SBP reverts to the spot price (i.e. the day-ahead price for that half hour) and when the system is short the SSP reverts to the spot price. In each case the agent on the side opposite to the overall BM position who is helping to reduce the imbalance, is not penalized for so doing (relative to the day-ahead market), but nor are they rewarded for their help.

The average price difference of the SBP-SSP was £13.32 in 2006-7 and £16.51 in 2007-8, but this is not the same as the exposure to the BM, as 70% of the time selling in the BM it is no worse than selling in the day-ahead market. A better measure is the opportunity cost of selling surplus when the system is long (71% of the time), and buying the shortfall when the system is short (29% of the time).

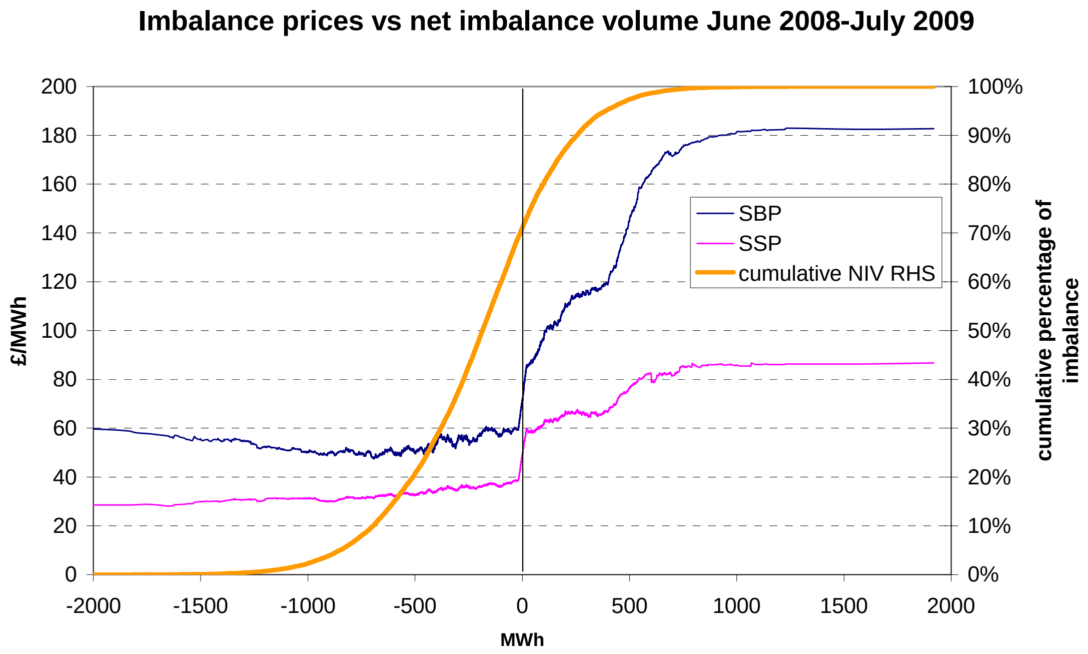

Figure 9 Moving average of the System Buy and Sell prices 2008-9
Source: Elexon data[9]

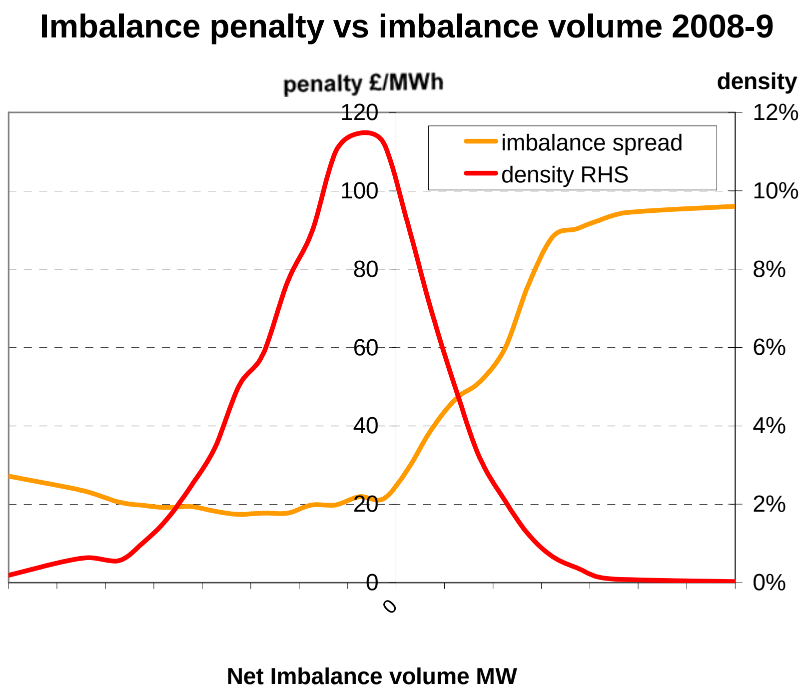

Figure 10 Spread in the GB Balancing Mechanism 2008-9, SBP-SSP
Source: as figure 9

[9] I am indebted to Nigel Cornwall for supplying this data

Figure 10 shows that most of the time the exposure to the spread is modest, but a small fraction of the time it becomes large. The next step is to work out the exposure from mis-estimating sales. Suppose again we have a 4 MW wind turbine with an average capacity factor of 1 MW. The evidence on forecasting accuracy for a single wind farm suggests a Mean Absolute Error of 10% of capacity 4-24 hours ahead, which would translate into an average error of 0.4 MW. The first question to address is whether to contract ahead for the forecast output or to be cautious and contract for somewhat less than the forecast output, and if so how much to contract.

Table 5 shows that the penalty of being short is considerably higher than that of being long, so this might suggest that it were better to be long than short, but the table also shows that the probability that the system is long is considerably higher than that of being short. If the forecast errors are uncorrelated with the system imbalance, then appendix 2 shows that it is the *expected* cost that matters, that is the product of the probability of being short or long times the price when short or long. More to the point, if the forecast errors are symmetrically distributed about the mean of zero, then what matters is the ratio of these costs, shown in the last line of table 5.

Table 5 Average GB BM spreads when short and long

	shares	2006/7	shares	2008/9
overall	100%	£13.32/MWh	100%	£26.83/MWh
average long	71%	£7.22/MWh	71%	£19.80/MWh
average short	29%	£28.26/MWh	29%	£44.02/MWh
Expected long cost/short cost		0.63		1.1

Appendix 2 shows how to calculate the optimal contract position given an estimate of these expected costs, and if the ratio of the expected long to short costs is greater than 1, it is better to be short, i.e. to over-contract, and conversely if the ratio is less than 1. The two sample years chosen show that either case is possible, but if anything under-contracting seems better. In addition, the downside cost of being long is bounded below as prices ought not to go negative (although with poorly designed wind support mechanisms they can) but the upside risk is very high (the SBP could reach £9,999/MWh).[10] It therefore seems defensible to argue that contracting ahead for somewhat less than the forecast output is a reasonable strategy.

In the 71% of hours in which the system is long, selling incurs a loss relative to the day ahead price in 2006-7 of £7.22/MWh but this only applies to 50% of the hours and only to 0.4MW so the expected cost when long is 71% x 50% x £7.22 x 0.4 = £1.03, but in 2008/9 this rises to £2.81. In the 29% of the hours in which the system is short, buying incurs an

[10] With very inflexible plant it can be desirable for them to bid negative prices to remain under load, but with the GM generation mix this would be a rare occurrence except for negative wind offers.

extra cost of 29% x 50% x £28.26 x 0.4 = £1.64 in 2006/7 and £2.55 in 2008/9, giving a total imbalance exposure of £2.67 at 2006/7 imbalance prices or £4.31 at 2008/9 imbalance prices, each per MW of average output, i.e. per MWh.

These imbalance charges that are borne by individual wind farmers are somewhat higher than the estimated costs of handling intermittency at the country level. That may reflect the inefficiency of the Balancing Mechanism, which exaggerates the apparent cost of balancing by foregoing the benefits of system aggregations as well as better advance wind forecasting that a properly incentivized System Operator might achieve. It is worth noting that of the varying estimates of the increase in system costs of wind power presented in EWEA (2009, figure 3.1) the UK is the highest (at 20% wind energy share at €4/MWh (averaged over the range from €2.6-4.7/MWh) while the Nordic market, with access to convenient hydro storage, is only €2/MWh, and Germany in between at an estimated €2.7/MWh, reflecting the earlier estimates summarized in UKERC (2006). To repeat, when considering contracting for wind the question is not so much what the system cost to the country is, but what costs are visited upon the contract holder through exposure to the GB Balancing Mechanism.

In the recent past the average ROC value has been around £50/MWh and the average ROC plus wholesale price has varied between £70/MWh and a peak of £120/MWh, but perhaps we can take £80/MWh as an average (as shown in figure 1). If the Big Six are asking a premium of 10% of this to provide the aggregation and balancing services, then these would amount to £8/MWh, somewhat higher than the £2.6-4.3/MWh estimated above.[11] Given the considerable uncertainties in the annual variation in these balancing costs that is not obviously unreasonable, but it suggests that the Big Six are not transferring any of their gains from internal balancing in such contracts. Nevertheless, if the excess of balancing charges of £5/MWh compared to the extra system costs of perhaps £3/MWh are applied to an on-shore wind output of 35 TWh by 2020, the extra contracting costs might amount to £70 million per year. If similar savings were made for offshore wind the sum might be more than doubled. The conclusion is that it is costly to place volume risk on the wind generators, and at the least any wind CfD should be on metered volume, not a fixed amount.

Faced with a choice between a CfD on metered output with a strike price set at the reference day-ahead daily average price and a classic fixed FiT, the remaining differences are the basis risk, which looking ahead for on-shore wind might cost £1/MWh, and any risk attached to the uncertainty surrounding the determination of the reference price. In addition generators have to undertake the costs of selling a fraction of their power into the spot market before gate closure in a market that is currently illiquid, or selling on contract

[11] It is rather difficult to obtain good evidence on the discount offered to small wind farms, but it might even be as high as 15-20%. These figures may also reflect risk surrounding ROC prices, which although apparently stable, are subject to political and credibility risk.

ahead of time and risking imbalance charges. The alternative of a fixed FiT with the dispatch entrusted to a System Operator charged to minimize the cost of dispatching and balancing the wind then looks more attractive, both in terms of minimizing system operation costs and providing the assurance of a low cost contract with no uncertainties to alarm bankers.

Credibility, risk and the cost of capital

Figure 1 also shows that the ROC price is moderately stable, and so the risks of the current system are arguably similar to those of a premium FiT, although there is at least one obvious difference. The ROC mechanism is vulnerable to changes in the volume of ROC-eligible generation, which may be hard to predict, although the Government has tried to reassure investors that the mechanism will be preserved, perhaps through adjustments to the headroom.[12] But a wary banker might attach low weight to the future public commitment to such an unsatisfactory mechanism; in contrast to the premium FiT payment that would be contractually enforced.

Both the premium FiT and the ROC system suffer from exposure to both the wholesale market and the balancing market, and these risks are best handled by the vertically integrated Big Six. Although they are well-placed to bear these risks, and can charge for them in any PPA they offer, their capacity to increase their intermittent portfolio and also take on other generation investment must be limited. The EMR is specifically designed to address barriers to entry to encourage new generators with access to new forms of finance, and these new entrants will eventually have to live with the market risks, both in the wholesale and balancing markets, at least with standard CfDs. Again the strong implication is that any CfD for intermittent generation (wind) should be on metered volume, not on a pre-determined volume, to remove the balancing risks, but the underlying problems of selling unpredictable volumes into the wholesale market remains.

These market risks are perceived to be considerable, certainly by financial institutions observing the rather turbulent experience of the GB wholesale and balancing markets. They will note that the balancing mechanism has had several hundred modifications to date, and there must be some chance that the wholesale market will either be reformed, or transformed by the large increase in low variable cost generation that might come on stream from 2018 onwards. Even without that, the EC Target Electricity Model that is driven by the EC Third Energy Package that came into effect in March 2011 is likely to require Britain to couple with Europe and adopt price zones that may lead to different prices in England and Scotland. The reference price in Scotland is likely then to fall below

[12] The headroom is the amount by which the requirement for suppliers to buy ROCs exceeds their supply, which determines the amount of penalty payment that is recycled back to the issuers of ROCs and hence amplifies their value.

that in England and there will be concerns as to which reference price will apply. Selling in the Scottish market and receiving the English reference price would be very unattractive.

A considerable part of the value of the intermittent generation will thus be vulnerable to markets that need, and are likely to experience, reforms and considerable changes. As more wind comes onto the system the average imbalance will increase and figures 9 and 10 show that this will increase the spread, perhaps considerably, making imbalance charges higher. Further, more wind will mean that the positive correlation between wind output and wholesale price becomes negative as wind drives down prices in the hours of surplus.

The obvious answer to the risk in the markets and the barriers to entry and/or the limited capacity of the Big Six is to replace CfDs for intermittent generation with fixed price FiTs on the standard Continental model. This would require two institutions – one to design and negotiate the FiTs (and also any CfDs that continue to make sense, e.g. for nuclear power) and another to be the counterparty to the wind FiTs with the ability to sell or dispatch that wind. The logical institution for the latter would be the System Operator, who might find it attractive to offer a voluntary centrally dispatched single price pool model to handle all the wind, all the balancing services (STOR, new flexible generation that the EMR envisages) and any other plant that is flexible and which would like to avoid trading and scheduling costs. This institution would have the legal power to charge consumers for the extra cost of honouring the contracts, just as Ofgem can pass through the regulated costs of transmission and distribution and recover the cost of the ROC scheme.

Such a guaranteed revenue stream would have a small annual variability (Danish on-shore wind turbines in the size range 1-2 MW have an annual capacity factor of 22.7% with a standard deviation over the years averaging 2%). As such they should be financeable with a high debt share compared to the current ROC system or its counterpart, the pFiT. Further, if their FIT is indexed to the CPI, perhaps with two tiers as in Germany, with a higher payment for the first 7 years and a lower indexed payment for the next 13 years, the cost of indexed debt might be lower (3.5% real instead of 6.5% nominal or an expected 4% real). On-shore wind is a mature technology so that construction risk is low (after site acquisition and permitting) and banks are familiar with financing such at a low cost of debt (6.5% nominal) and quite high gearing – perhaps 70+%. Off-shore wind has higher construction risks and therefore a higher cost of debt (7.5%) and lower gearing (60%). The construction risks remain for off-shore, so the estimate below is just for on-shore wind. Here the reduction in market risk (through the contract with an SO or equivalent, avoiding balancing and sale risk) and the presence of an indexed contract could attract in new investors and new forms of finance, and perhaps allow the share of debt to rise from 70% to 80%. Table 5 shows the effect on the weighted average cost of capital (WACC) when equity has a post-tax cost of 16%.

Table 5: WACC illustration for onshore wind – current regime

Component	ROC	Fixed FiT
Cost of debt, pre-tax	6.50%	6%
Tax *	28%	28%
Cost of debt, post tax	4.70%	4.30%
Cost of equity, post-tax	16%	16%
Gearing	70%	80%
Post tax WACC, nominal	8.10%	6.70%

* *note that 28% tax rate is the historical UK corporation tax rate*

The effect of the FiT (+ sales to an SO) replacing a ROC or pFIT (selling in the market) is to reduce the post-tax WACC from 8.1% (nominal equivalent) to 6.7% (from 5.6% real to 4.2% real) saving nearly 1½% p.a. If we were to build an additional 12 GW of on-shore wind capacity by 2020 and if the cost were as low as £1,000/kW, the investment cost would be £12 billion and the capital cost saving would rise to £180 million/yr by 2020. Any savings to the capital cost of off-shore wind, which is considerably more expensive, would considerably increase this amount.

Conclusion

Wind power has high capital costs and low variable costs, so the cost of capital is the main determinant of the cost of wind power and the cost of meeting our 2020 renewables target. The aim is therefore to reduce risk as far as possible. This paper has argued that even a CfD on metered output will still leave basis risk and volatility risk (having to contract ahead of knowing actual output) on the wind developers, while a classic fixed FiT would transfer all those risks to an agency better placed to bear them, and at lower cost. The financial benefits of this risk reduction and reduced cost of capital for on-shore wind alone might together be £250 million per year by 2020, and could be two-three times as large if similar savings were made to projected off-shore wind investments if the choice is between a fixed FiT and a pFiT, and perhaps £70 million per year by 2020 for on-shore wind if the choice is between a fixed FiT and a CfD on metered volume.

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Appendix 1 Additional graphs

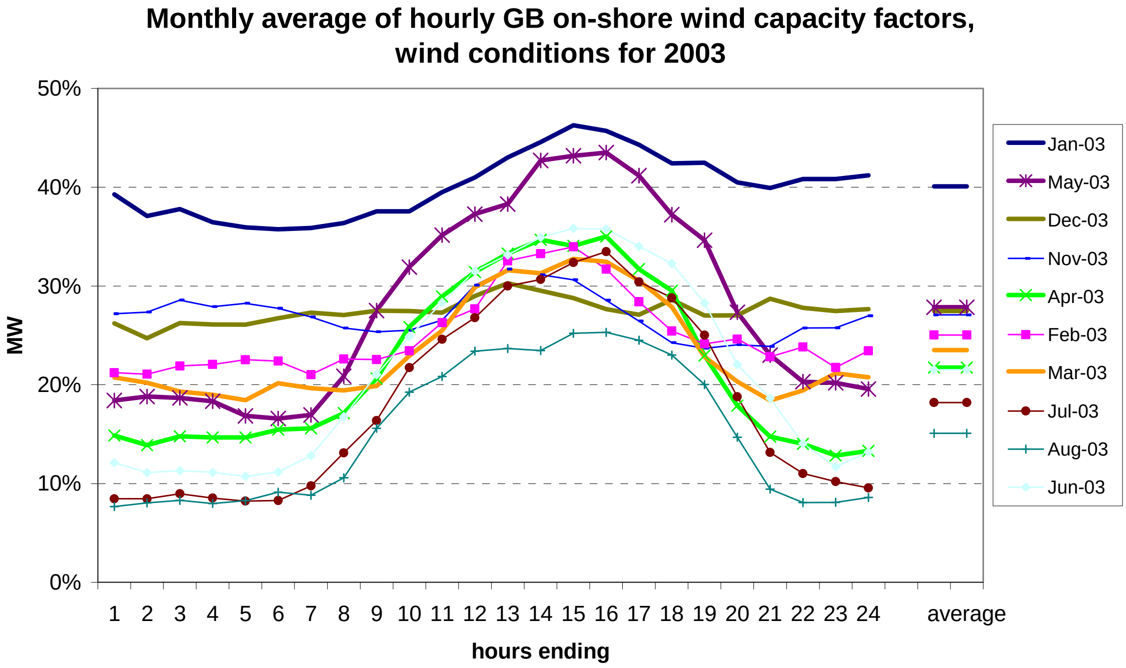

Figure A1 Average on-shore wind capacity factor by hour and month, 2003 wind
Source: Green and Vasilakos (2010).

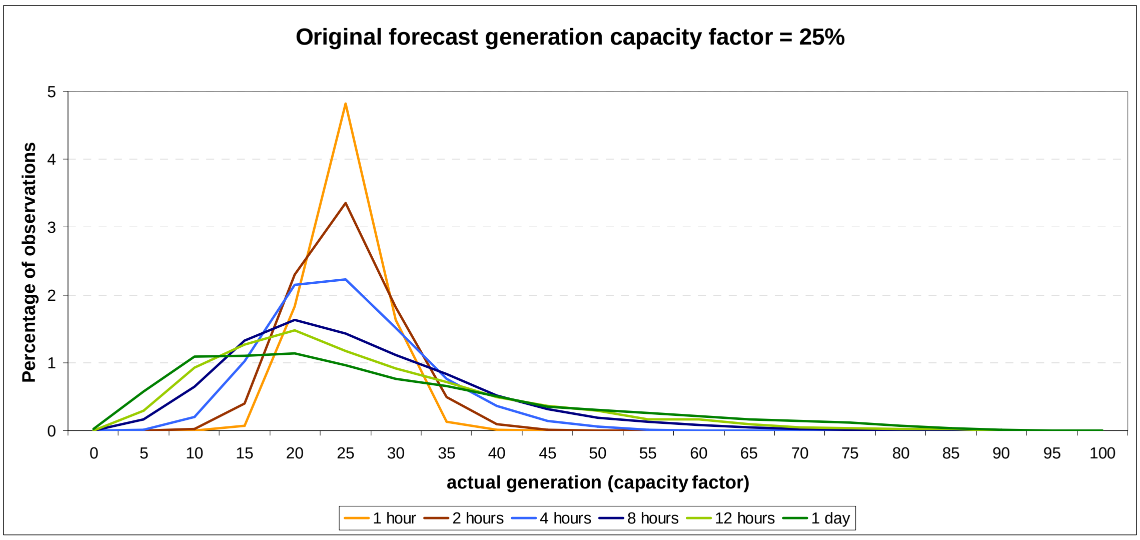

Figure A2 Probability distributions of future outputs starting from current output of 25%
Note: Probabilities are over all output levels; the probability of an output of 25% is 8.5%.

Appendix 2: Optimal wind contracting*

May 27, 2011

Abstract

From four hours out the error in predicting wind output typically exceeds 10% MAE (perhaps 15% RMSE). Given the asymmetry in imbalance penalties from being short or long, the optimal forward contract of wind might be expected to be less than the expected output. This note derives the optimal ex ante contract position and finds that if wind is uncorrelated with the system imbalance, this argument does not necessarily hold. For a symmetric error distribution whether to under or over-contract depends on whether the expected long penalty exceeds the expected short penalty for a risk-neutral producer.

1 The GB Balancing Mechanism

In the GB Balancing Mechanism, balancing parties who are short (i.e. have contracted to deliver more than they actually produce, or have consumed more than they contracted to buy) will pay the System Buy Price (SBP). If the system as a whole is short, the SBP will be higher than the spot price (SP, i.e. the day-ahead price for that half-hour). If the system is long when the balancing party is short, the party is helping to reduce the imbalance, and consequently is not penalised (but nor is he rewarded) and buys at the spot price, SP. He therefore faces a penalty equal to SBP-SP $= P_S$ if short when the system is short, and otherwise zero.

Conversely, if the balancing party is long he receives the System Sell Price (SSP), and if the system is also long, the SSP will be below the SP, but if the system is short and the balancing party is helping reduce the shortage, he is paid the SP and so faces no penalty (and again no reward). The relevant penalty is thus SP-SSP $= P_L$ if long when the system is long, and otherwise zero. The penalty when short is considerably higher than when long (i.e. $P_S > P_L$) and the ratio of P_S/P_L was nearly 4 in 2006/7 and over 2 in 2008/9. One might expect that as it is more costly to be short than long, balancing parties would aim to be long, and that is what we find,

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as the system is long roughly 70% of the time. We might therefore expect wind generators to be similarly cautious and contract ahead less than their expected output, to avoid having to pay the more penal shortage imbalance price. This note explores whether (and when) this might be correct.

2 Selecting the contract position

Suppose the predicted output of a wind generator of nominal capacity 4 MW is 1 MW at the moment of contracting (as it will be for on-shore wind in GB on average), and the probability density function of output x is $p(x)$, $0 \leq x \leq 4$, $\int_0^4 xp(x)dx = 1$, $\int_0^y p(x)dx = F(y)$, where $F(y)$ is the distribution function of output. The Mean Absolute Error, MAE, M, of the forecast output is

$$M = \int_0^1 (1 - x)p(x)dx + \int_1^4 (x - 1)p(x)dx.$$

If the contracted amount is $y < 1$, the expected size of the shortfall (net imbalance purchases) will be

$$S = \int_0^y (y - x)p(x)dx, \tag{1}$$

and the excess (net imbalance sales) will be

$$L = \int_y^4 (x - y)p(x)dx. \tag{2}$$

In each case its value will depend on whether the system is long or short.

Suppose the fraction of the time the system is long is θ (roughly 70%) and that whether or not the wind is higher or lower than expected is uncorrelated with the system imbalance. The probability of the wind turbine (or farm) being short is $F(y)$, and of being long is $1 - F(y)$.

The expected penalty when the system is short and the wind farm has a negative imbalance (is also short) is SP_S and this occurs with joint probability $1 - \theta$ and $F(y)$, while the penalty if long and the wind farm has a positive imbalance is LP_L, which occurs with joint probability θ and $1 - F(y)$. The total expected penalty cost is then

$$C(y) = F(y)(1 - \theta)P_S S + (1 - F(y))\theta P_L L. \tag{3}$$

For an individual contractor, P_S, P_L and θ are given and it is convenient to define new variables $\pi_S = (1 - \theta)P_S$, the expected short penalty, and $\pi_L = \theta P_L$, the expected long penalty, so that

$$C(y) = F(y)\pi_S \int_0^y (y - x)p(x)dx + (1 - F(y))\pi_L \int_y^4 (x - y)p(x)dx. \tag{4}$$

The problem facing the wind owner is to choose the contract level y to minimise this cost, given values for P_S, P_L and θ. (A further complication is that all these are also random variables, which we can assume are independent of contract positions, so to a first approximation we can take them as their expected values for a risk-neutral generator.) The first order condition will give a value of y that satisfies the equation

$$\frac{dC}{dy} = 0 = F(y)\pi_S \frac{dS}{dy} + (1 - F(y))\pi_L \frac{dL}{dy} + p(y)\left[\pi_S S - \pi_L L\right], \tag{5}$$

as differentiating with respect to the limits produces zero values. As set up $dS/dy > 0,\ dL/dy < 0$, as the more the wind farm contracts ahead the greater the amount that he might fall short of meeting that contract.

We can characterise the location of the solution by solving for the end points and the mean for a mass-less symmetric distribution for which $F(1) = \frac{1}{2},\ p(0) = p(4) = 0$, as follows:

$$\frac{dC(0)}{dy} = \pi_L \frac{dL}{dy} < 0, \quad \frac{dC(4)}{dy} = \pi_S \frac{dS}{dy} > 0.$$

The graph of dC/dy is thus increasing from negative to positive values and we need to establish whether it reaches zero before or after $y = 1$. If $dC(1)/dy > 0$, then the solution to the first order condition must be $y < 1$, and conversely if $dC(1)/dy > 0$. To evaluate $dC(1)/dy$ differentiate (4) as follows:

$$\begin{aligned}
\frac{dC}{dy} &= F(y)\pi_S \int_0^y (1-x)p(x)dx + (1-F(y))\pi_L \int_y^4 (x-1)p(x)dx + p(y)\left[\pi_S S - \pi_L L\right], \\
\frac{dC(1)}{dy} &= F(1)\pi_S \left[F(1) - \int_0^1 xp(x)dx\right] + (1-F(1))\pi_L \left[\int_1^4 xp(x)dx - (1-F(1)\right] \\
&\quad + p(1)(\pi_S - \pi_L)\frac{M}{2}, \\
&= \frac{1}{4}\left[\pi_S(1-M) + \pi_L(M-1)\right] + p(1)(\pi_S - \pi_L)\frac{M}{2}.
\end{aligned}$$

$$\frac{dC(1)}{dy} = \frac{1}{4}(\pi_S - \pi_L)\left[2p(1)M + (1-M)\right]. \tag{6}$$

Thus the sign of $dC(1)/dy$ is the same as the sign of $(\pi_S - \pi_L)$. If $\pi_S < \pi_L$, the expected penalty when short is less than when long and the first order condition where $dC(y)/dy = 0$ will have $y > 1$, so the wind farm will choose to be over-contracted, or on average short in the Balancing Mechanism. Converseley, if $\pi_S > \pi_L$, the first order condition will have $y < 1$, and the wind farm will choose to be under-contracted or on average long to aavoid the higher expected short penalty price.

2.1 Numerical example

If we consider the GB imbalance prices for 2008/9, $\theta = 71\%$, $P_L = £19.80$/MWh, and $P_S = £44.02$/MWh, so that, assuming no correlation between wind output and imbalance volumes, $\pi_L = £14.06 > \pi_S = £12.77$, $\pi_S - \pi_L = -£1.29$, which is negative, so the contract position involves being on average short: $y > 1$. If we take the prices for 2006/7, $\pi_L = £5.13 < \pi_S = £8.2$, so that $\pi_S - \pi_L = £3.07$, and the derivative is positive so the contract position is on average long. Clearly both possibilities are demonstrated in the recent data. One might therefore argue that contracting the expected output might not be an obviously wrong strategy, given the *ex ante* uncertainty about the relative size of π_S and π_L.

2.2 Qualifications and discussion

If wind becomes a significant fraction of total power supply, as it would need to be to meet the Renewables Directive targets, then if wind were higher than expected, and wind farms had contracted ahead the expected volume, the system as a whole would be more likely to be long, and conversely when wind were less than contracted. This would introduce a correlation between wind forecast errors and imbalance volumes. One rather crude way of taking this into account is to assume that the probability that the wind farm is short when the system is short has joint probability $(1 - F(y)\theta\phi,\ \phi > 1$, while the probability that the wind farm is long when the system is long is $(1 - \theta)F(y)\psi,\ \psi > 1$. These can be inserted into (3) and new variables $\Pi_S = (1-\theta)\phi P_S,\ \Pi_L = \theta\psi P_L$ defined to replace $\pi_{S,}\ \pi_L$. The contract position will now be more than expected output $(y > 1)$ if

$$\frac{dC(1)}{dy} < 0, \text{ or if } \frac{\Pi_L}{\Pi_S} = \frac{\psi\pi_L}{\phi\pi_S} > 1.$$

To reverse the 2006/7 outcome so that the wind farm is then short, $\psi/\phi > 1.6$, which seems unlikely, while to reverse the 2008/9 outcome so that wind tends to under-contract, $\psi/\phi < 0.91$ or $\phi/\psi > 1.1$, which seems quite probable. Thus one might expect wind if anything to be under-contracted, tending to be long, provided that in turn does not greatly increase the probability that the system as a whole is long.

Given that generators might choose to be short, why then is the system systematically long on average? The obvious answer is that the risk is primarily on the buyers of wholesale power who supply the retail market. As they have agreed retail prices ahead, their downside cost of being long is limited as the SSP cannot go negative, while the upside cost of having to buy at the SBP is potentially far higher, as the SBP could reach as high as £9,999/MWh. Risk aversion may thus drive suppliers to overcontract to buy, driving the system long on average. Of course, generators also face a very low risk of a very high imbalance cost, so they may similarly be wary of being overcontracted, but the pressure to be significantly undercontracted does not seem strong, given the imbalance prices in the recent past.

2.3 Example: triangular error distribution

As an example consider the symmetric triangular distribution between $1-b$ and $1+b$, so that $p(x) = \frac{1}{b^2}(x+b-1)$, $1-b \leq x \leq 1$. $F(x) = \frac{1}{2b^2}(x+b-1)^2$, $1-b \leq x \leq 1$, and symmetrically above 1. The MAE is $M = b/3$ and the RMSE is $\sigma = b/\sqrt{6} = 0.41b$, so $M/\sigma = 82\%$, rather higher than the actual error distributions observed (for the normal distribution it would be 68%, and wind errors have slightly fatter tails but are truncated above by capacity and below as output cannot be negative).

It is convenient to measure everything relative to the mean output, which we can normalise to 0, with the range $[-b, b]$ and the *shortfall* in contract is t, (so in the previous terminology $t = 1-y$). If z is relative output, $z = x-1$, $z \in [-b, b]$, then $|z|$ is the absolute deviation from the expected output. The imbalance is $z+t$, positive if $z > -t$ (net sales) and negative (net buying) if $z < -t$. It is convenient to distinguish the probability density $p_-(z)$ as the density for $z < 0$ and $p_+(z)$ for $z > 0$. Consider first the case in which the contracted amount is less than the expected amount, i.e. $y < 1, \quad t > 0$.

We can now calculate the imbalances. Net purchases (as a positive amount) are:

$$S(t) = -\int_{-b}^{-t}(t+z)p_-(z)dz = \int_t^b (z-t)p_+(z)dz = \frac{1}{b^2}\int_t^b (z-t)(b-z)dz,$$

where the second integral comes from symmetry and is simpler. Integrating

$$\begin{aligned} S &= \frac{1}{6b^2}\left[-2z^3 - 6tbz + 3(b+t)z^2\right]_t^b, \\ S(t) &= \frac{(b-t)^3}{6b^2}. \end{aligned} \tag{7}$$

The net long position is

$$\begin{aligned} L(t) &= \int_{-t}^{b}(z+t)p(z)dz = \int_{-t}^{0}(z+t)p_-(z)dz + \int_0^b (z+t)p_+(z)dz, && (8) \\ &= \frac{1}{b^2}\left[\int_{-t}^{0}(z+t)(z+b)dz + \int_0^b (z+t)(b-z)dz\right], \\ &= \frac{1}{6b^2}\left[\left[2z^3 + 3(b+t)z^2 + 6btz\right]_{-t}^{0} + \left[-2z^3 + 3(b-t)z^2 + 6btz\right]_0^b\right], && (9) \\ &= \frac{1}{6b^2}\left[b^3 + 3tb^2 + 3bt^2 - t^3\right] = \frac{1}{6b^2}\left[(b+t)^3 - 2t^3\right]. && (10) \end{aligned}$$

If we now wish to evaluate the terms dS/dy and dL/dy:

$$\begin{aligned} \frac{dS}{dy} &= -\frac{dS}{dt} = \frac{(b-t)^2}{2b^2} = \frac{(b+y-1)^2}{2b^2}, \quad \frac{dS(1)}{dy} = \frac{1}{2}, \\ \frac{dL}{dy} &= -\frac{dL}{dt} = \frac{-1}{2b^2}\left[b^2 + 2bt - t^2\right] \\ &= \frac{y^2 + 2b(y-1) + 1 - 2b - b^2}{2b^2}, \quad \frac{dL(1)}{dy} = -\frac{1}{2}. \end{aligned}$$

These values can be substituted into (5) to solve for the contract position y provided $y \leq 1$. If $y > 1$ so that the wind farm is over-contracted relative to expected output, the integrals will need re-evaluation as $t < 0$:

$$
\begin{aligned}
S(t) &= \int_{-b}^{-t} (t+z)p(z)dz = \int_{-b}^{0} (t+z)p_{-}(z)dz + \int_{0}^{-t} (z+t)p_{+}(z)dz, \\
S(t) &= \int_{0}^{b} (t+z)p_{+}(z)dz + \int_{-t}^{0} (z+t)p_{-}(z)dz, \ t < 0. \\
&= L(-t), \quad -t > 0.
\end{aligned}
$$

By symmetry,

$$L(t) = S(-t), \quad -t > 0.$$