BECOMING RESPECTABLE IN SERIOUS CIRCLES

The wind industry has delivered impressive reductions in cost along with serious increases in productivity over the past 20 years. Wind generation prices—tracked by WINDPOWER MONTHLY in a series of annual articles starting in 1999—are today almost level with those of fossil fuels and have long since beaten nuclear. Further wind price reductions are highly likely, while increases in gas and oil prices are projected across the board

COSTS COMPARED

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Two-thousand-and-three looks as if it will go down in history as the year in which wind energy became economically respectable. In past months it has appeared with increasing frequency as a resource option in the energy plans of governments, utilities and investment banks—a significant step up from its more cautious categorisation as a rising star with potential.

A new wealth of data on wind energy costs has accompanied its entry into the ranks of the respectable. Even the tradition-bound International Energy Agency includes a positive analysis of wind power in its report on Renewables for Power Generation—Status and Prospect, pointing out that wind's cost is near enough to being fully competitive with traditional generation technologies to be forcing policy makers to sit up and take notice.

There are two reasons for wind energy's new found status. First, with installed wind plant capacity now exceeding 37 GW worldwide—and capacity doubling every three years—the database on performance and cost is becoming increasingly robust. As a result, energy professionals are more inclined to view wind as less of a one-off wonder. Second, electricity markets are becoming increasingly nervous about the future price of gas, the most popular and cheapest generation resource in recent times.

Even if wind prices, against all projections, failed to continue their downward progress, the generation cost from gas could well be higher than that from wind by 2010. The uncertainty accompanying the rise in gas prices is also pushing up the level of risk—and risk adds cost. Uncertainty can be overcome by negotiating long term contracts, but the premium needed to fix gas prices within contracts over a ten year period is around $5/MWh, according to two recent reports from the respected Lawrence Berkley Laboratory in the United States.

There were no marked changes in 2002-03 in the various parameters from which the cost of wind power is derived. Overall, the cost of installing a complete wind plant continued to hover a little above last year's targets—$1000/kW for onshore and $1500/kW for offshore. The slowing of the downward trend in wind's installed costs, however, is more a reflection of the dollar's fall relative to European currencies, than lack of progress by the wind industry. A cheap dollar has the effect of making European technology—and most wind turbines are made and installed in Europe—appear more expensive.

A similar standstill in the fall in installed costs for thermal plant is for several more fundamental reasons, including higher insurance costs, more stringent utility connection requirements—and tighter limits on emissions. The net effect is to leave the competitive position of wind today in much the same place as it was last year—cheaper than nuclear, frequently on a par with coal, and knocking on

Facts from the real world
Installed cost of sample wind plant this year

LOCATION	NO. OF UNITS/KW	TOTAL MW	COST (MILLIONS)	COST $/KW
Onshore				
Canada, Magrath	20x1500	30	C$48	1194
Spain, Gavilanca/Bucy	15x1500/ 23x850	42	€40	1142
Spain, Fonsegrana	155x660	75.9	€65	950
Tunisia, Sidi Daoud	660/850/ 1300	8.8	€7.8	886
N.Ireland, Altahullion	20x1300	26	£18	1170
Texas, Desert Sky	107x1500	160	$174	1090
Offshore				
Denmark, Middlegrunden	20x2000	40	€50	1250
Denmark, Horns Rev	80x2000	160	€268	1993
Denmark, Nysted	72x2.3	166	€245	1771
UK, North Hoyle	30x2	60	£74	2121
UK, Kentish Flats	30x2.75	82.5	DKK 1100	1844
Sweden, Yttre Stengrund	5x2000	10	SEK 120	1150

the door of gas or, in the US, competing with gas (box). Future prospects still have wind steadily edging its way down the price scale faster than its competitors.

The average turnover per megawatt of turbines sold by Danish manufacturers is virtually unchanged between 2002 and 2003, after allowing for inflation, and stands at just over DKK 6 million/MW ($1000/kW). But while an indicator of the trend in wind power's cost, the figure includes both large and small orders, as well as spares and servicing contracts, so it is not a precise measure for establishing the installed cost of a typical wind plant today.

A more reflective measure is to consider the cost of a range of larger wind stations (table previous page), since it is these that are in increasingly close competition with the conventional sources of electricity generation. There are wide variations, from $886/kW in Tunisia to $1194/kW in Canada, but the average installed price for onshore wind farms remains at just over $1000/kW. For offshore wind, the increased installation activity this year provides an extended range of installed prices for the first time. In sheltered waters, prices start as low as $1150/kW, with the upper end of the range at a little over $2000/kW, with the costs of grid connection often accounting for a significant (10-15%) proportion of the total cost.

COSTS COMPARED WIND POWER

PUBLIC OR PRIVATE

Institutional factors are responsible for the spread of values for wind's installed costs and the even wider spread of generation costs. In Denmark, utilities almost invariably use public sector test discount rates and depreciation periods, typically 6% and 20 to 25 years, respectively. In Britain and the United States, however, there are no fixed criteria and project developers are at the mercy of financiers operating in a tough commercial world.

In the private sector, the overall interest rate on a wind plant loan is in practice dependent on the relative proportions of debt and equity and the appropriate interest rates. A weighted average, appropriate for the project as a whole, tends to be around 11%, although higher and lower values are found. Depreciation periods also vary, but are generally in the region of 12 to 15 years.

Taking into account all the possible options is impractical and generation cost calculations are more sensibly calculated using two alternative criteria for public and private sector projects (table). The public sector criteria—6% project discount rate and 15-20 year depreciation—are consistent with those being used by the International Energy Agency (IEA). As well as taking account of financing parameters, appropriate values for capital cost, load factor, thermal efficiency and operation and maintenance are also taken into account to arrive at generation costs.

The effect of moving all the generation sources from public to private sector financial criteria is dramatic. All the prices move up, but the impact on capital intensive generation sources, such as wind and nuclear, which cost a lot to build but not much to run, is far more pronounced. Moving from public to private sector typically pushes the price of gas fired generation up by around $5/MWh (say from $33/MWh to $38/MWh), but the corresponding increase in the price of offshore wind is five times greater at $25/MWh (from $49 to $74/MWh). While a study by Danish utility Energi E2 suggests the prices of offshore wind and gas may be roughly equal, these are based on public sector financing, a good wind site and a high gas price. It could not be repeated under private sector terms.

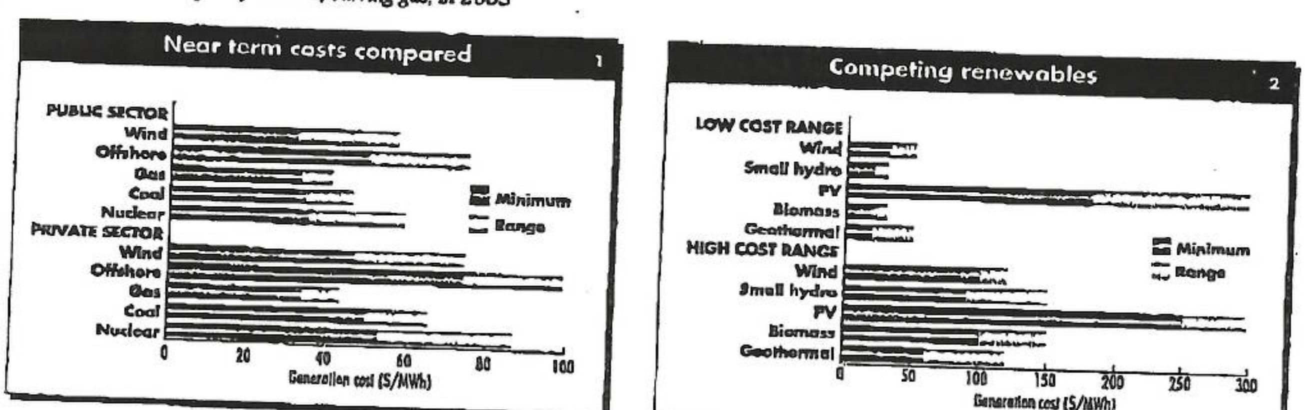
Onshore wind and gas are neck and neck under public sector criteria, coming in at just under $32/MWh at the low end of the price range. The wider spread of prices for wind compared with gas reflects the wider spread of wind's capital cost estimates (Fig 1).

Under private sector criteria, wind at $47/MWh undercuts coal at the low end of the scale, which comes in at around $50/MWh. Wind is comfortably below nuclear at 53-87/MWh, by around $5/MWh. But private sector

The impact of financing parameters
Wind's private sector disadvantages as a capital intensive technology

	PUBLIC SECTOR	PRIVATE SECTOR
Project discount rate	6%	11%
Depreciation	15-20 years	15 years
Comments	20 year life used for lowest price estimates in range	12% discount rate used for nuclear high estimate, reflecting higher perceived risk

Looking for least cost generation
Wind was the cheapest of them all, barring gas, in 2003



ʒas-generation is cheaper than wind power. The price of ʒas, both in Europe and America, has fallen back from the ıigh levels observed in 2000-01. With fuel purchases of ʒas now costing around $13/MWh, gas-fired generation once again becomes the cheapest option within a price range of $34-$44/MWh. Higher gas prices are encountered in some regions.

THE OTHER RENEWABLES

In its report, the IEA includes both a high and a ow range of costs for a series of renewable energy technologies (fig 2). At first sight, wind in the ow range at $30-$50/MWh seems to face stiff competition from small hydro and biomass power, which start at $20/MWh. Geothermal also starts at $20/MWh, although it upper low-range cost of $50/MWh is on a par with wind.

Potential for small hydro, however, is restricted by a very limited resource. Geothermal resources are more widespread, but the amount of energy that can be produced at a rock bottom prices is extremely limited—few places have steam issuing from the earth. Biomass is only cheaper than wind for generation plant built where the resource is available on site, such as forestry residue in Scandinavia or bagasse in warmer climates.

Energy crops are another potential renewable energy source, but their economic potential continues to be uncertain. Energy crop economics are linked with those of farming and farming subsidies, while the development of commercial high-efficiency generating plant is proceeding more slowly than expected. The UK government has a starting price for energy crops of $80/MWh.

The IEA ignores wave energy, currently the subject of increasing research activity in the UK and elsewhere, probably because its commercial costs are unknown. The wave energy community suggests that a near-term generation cost target is around $80/MWh.

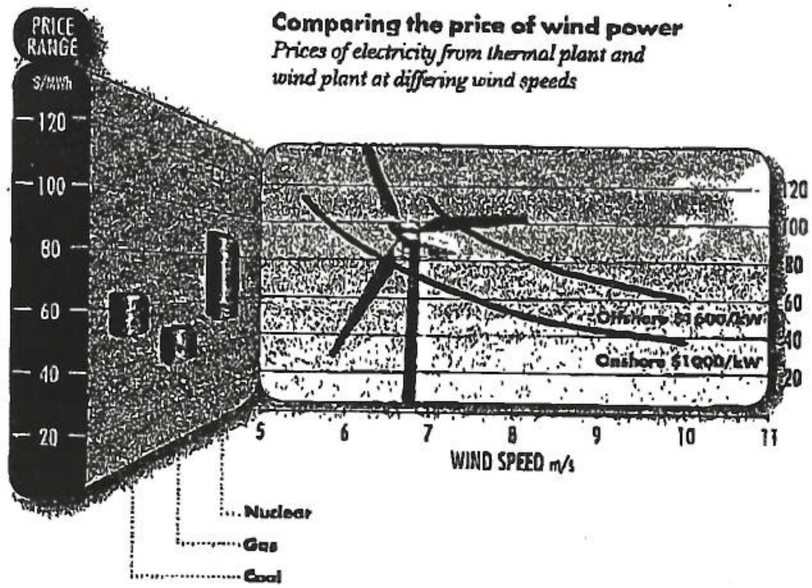
FUTURE PRICES—ONSHORE

Looking forward to 2010, few analysts expect dramatic changes in generating costs from the thermal sources. The big imponderable is the price of gas. Estimates for gas rise with each successive edition of the US Department of Energy's Annual Outlook. Gas fired generation, however, at $49/MWh in 2010, will remain cheaper than coal at $53/MWh, even though coal prices are set to decline, according to the Department of Energy (DOE). Nuclear comes in at around $65/MWh.

To beat a target of $49/MWh, installed costs of wind on a moderately windy onshore site need to be around $900/kW. Some plant are being built today at below that price, but not all. Taking a conservative estimate of $1100/kW for current wind plant costs, an 18% reduction by 2010 seems to be well within the bounds of feasibility. Five independent analyses have suggested that the reduction in costs per doubling of worldwide wind capacity, based on a learning curve ratio, lies between 12% and 18%. Even if the current rate of global wind plant installation (a doubling of capacity every three years) is not maintained, capacity is likely to increase by a factor of at least four by 2010. Accepting the pessimistic 12% end of learning curve reductions, a fourfold increase in capacity will lead to wind plant costs coming down by around 24% by 2010. As this is significantly higher than the target of 18%, that also leaves room for pessimism in the rate of growth.

Accepting a 24% rate of decline in wind power costs and using data for gas prices drawn from the US Department of Energy, the crossover point with gas comes around 2009 for a wind plant using today's typical installed cost of $1000/kW on a site with winds blowing at a healthy 8 m/s (figure next page). With a more rapid decline in wind costs, or at sites with higher wind speeds, or with lower interest rates, the crossover date may be significantly earlier. The crossover point with coal comes much earlier—around 2005. In locations with good wind regimes, wind is already cheaper than coal.

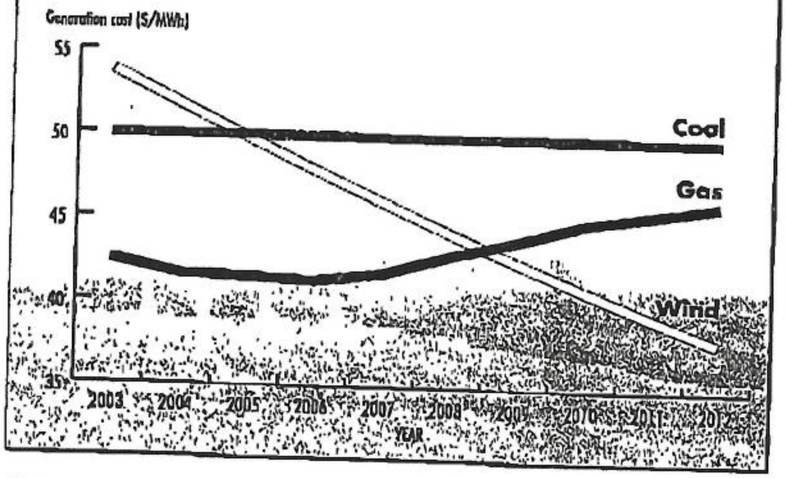
The IEA report enables 2010 price projections to be made by another route. IEA data reveal that wind turbine prices fell by about 16% each time the average size of wind turbines doubled, to reach about $800/kW for 750



Comparing the price of wind power
Prices of electricity from thermal plant and wind plant at differing wind speeds

Differential costs: *Wind energy generation prices are critically dependent on the wind speed at the site of the plant and price estimates above are given for a range of wind speeds from 5.5 metres per second to 10 m/s. The installed cost of a wind plant also differs from site to site and from technology to technology. A typical price per kilowatt of generation for a wind plant station built on land is $1000/kW. Offshore, a typical price is $1600/kW.*

For a land based wind farm, prices of the electricity generated fall from $115/MWh on a low wind speed site of 5.5 m/s, to $54/MWh at 8 m/s, and $38/MWh at 10 m/s. Offshore prices are just under 60% higher than these levels, reflecting the higher installed costs.



The crossover points
Plotting likely trends of future generation costs

kW machines. Given that 1500-2000 kW machines are already standard items and that larger sizes are coming onto the market, another 16% reduction by 2010 seems a very modest target.

FUTURE PRICES—OFFSHORE

Offshore, a $49/MWh cost target is tougher. Offshore wind turbines are typically 10-15% more expensive than their onshore counterparts and foundations, installation and grid connection are usually significantly more expensive. Onshore, "balance of plant" costs typically add 25-50% to machine costs, but offshore the additional costs can almost double the turbine costs, bringing the total to $1800-2100/kW.

Significant offshore cost benefits are likely to come from the much larger sizes of offshore wind farm now in planning—with a 40% cost reduction on the cards for 2012, with energy yields up by 20% as construction moves further offshore (WINDPOWER MONTHLY, April 2003). Meantime, an analysis by the University of Utrecht in the Netherlands suggests that generation costs for offshore wind might fall by around 25% by 2010.

NO CHALLENGE

Drawing the various generation cost estimates together, it is hard to see wind on good sites being challenged come 2010. The most optimistic projection for onshore wind for 2010 ($20/MWh) comes from the IEA, but uses public sector financing assumptions. Using the same installed cost ($700/kW) and a slightly less optimistic capacity factor, brings the figure to just under $40/MWh in the private sector.

Although the American DOE suggests $49/MWh to be appropriate for gas-fired generation, if the price of the fuel does not rise as expected, then $40/MWh may be a more appropriate figure—the same as anticipated for wind. Offshore wind is likely to cost in the range $60-80/MWh, unless the development of large scale wind farms gets underway within the next six years. After 2010, the prospects for both onshore and offshore wind become increasingly brighter.

Wind is already competing with coal, it is cheaper than nuclear, and cheaper to exploit at large scale than any of the other renewable energy sources. In some regions it can be competitive with gas-fired generation today. By 2010 it is likely to be a serious competitor to gas. This projection is based on a conservative view of how steeply the curve for wind plant costs will fall—and on kind assumptions on behalf of gas generation that its fuel prices will not rise as the very latest projections suggest.

Data sources: *Data on generation costs used for this article (main story) come from a wide variety of sources, including the International Energy Agency, the United States Department of Energy, the UK Department of Trade and Industry, a recent analysis by Energi E2 of Denmark, and an analysis by the Deutsche Bank. Other data are drawn from conference publications for the thermal and renewable energy sectors. Private information gathered in personal conversations with members of the power generation industry, including wind generators, forms a major part of the assessment. The application of internal knowledge to assessment of specific project costs is vital for ironing out data inconsistencies which would otherwise contribute to a skewed picture of the comparative costs of power generation. Prices are expressed in dollars since much of the data originated in the United States, which was one of the most active markets for wind plant development over the past year.*

THE OTHER FACTORS

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Should the thermal sources be required to pay for at least some of their external costs—such as those of pollution and protecting oil supplies—wind in comparison will start to look cheap. Further restrictions in Europe on the output of emissions from generation plant, coupled with a cap and trade system for control of carbon emissions, are on the way. Although the premiums on electricity cost from carbon trading will be small, they will probably be enough to tilt the balance firmly in favour of wind.

Another factor to be taken into account is that many wind installations on shore feed electricity into local distribution networks rather than the main transmission system. Numerous studies are in progress to put a price on the added value to an electricity network of local generation—and wind power should end up being financially rewarded for its contribution to limiting the transmission losses that customers otherwise pay for.

Last, as the penetration of wind power into electricity systems increases, fluctuating wind output at some point will start adding extra costs to the far bigger overall bill for keeping power supply and consumer demand in balance. Though wind's contribution to that bill will only be small, it will have to bear its costs.

RESPONSE TO CNF-62

WIND

THE REAL COST OF INTEGRATING WIND

CNF-1027

Integration of wind into power systems is as much an economic as a technical challenge. A clear understanding of how much reserve generation is needed to maintain system security is a vital part of that exercise. Competitive markets, with their focus on cost, are leading the way in discovering how little reserve it takes and thus how cheap wind integration can be. The real cost, however, is being inflated by poor market structures everywhere

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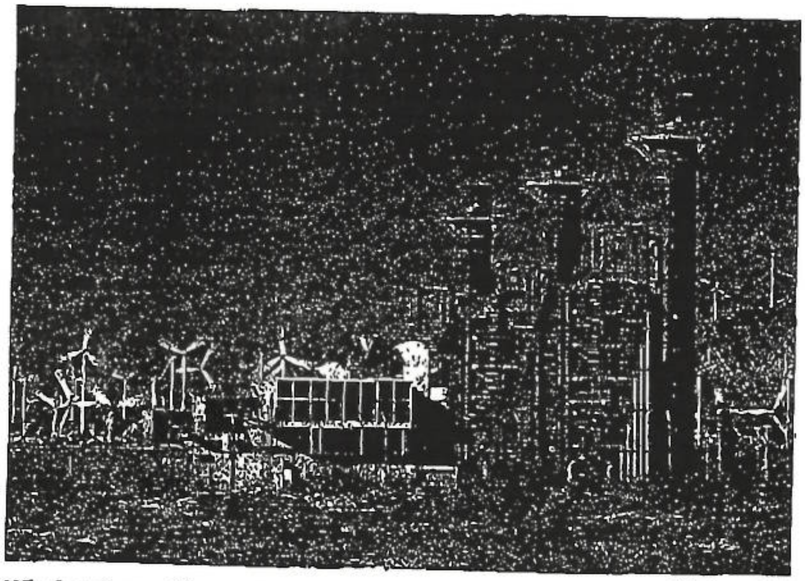
The good news about integrating ever larger amounts of wind power into the power systems of today is that it can be done without putting security of supply at risk—and without costing an arm and a leg. Mounting evidence in support of these facts is flowing in from markets where wind meets up to 20% of consumer demand for electricity and from detailed studies of the issue on both sides of the Atlantic. Wind's tendency to blow (or not) at will and thus the inability of wind plant operators to precisely schedule generation is proving to be neither a technical nor economic barrier to getting large proportions of our electricity from this freely available natural resource.

The bad news about wind integration is that the ongoing energy market revolution is obscuring the good news. The struggle to increase efficiency and bring down costs by applying market economics to the business of electricity supply is still in its infancy. The new competitive markets, particularly the very new "balancing markets," are fraught with structural errors that work against the aim of increasing the overall efficiency (reducing the cost) of power systems. Hundreds of amendments to market regulations are being made, but wind, forced in the main part to abide by rules designed for thermal generators, is a particular victim of the process. Its calls for better rules tend to get lost among the clamouring of the fossil fuel and nuclear giants.

NO FAVOURS NEEDED

Fortunately, the criteria for efficient integration of wind energy are the same as those for efficient operation of power systems in general. The key to efficiency is rules and regulations that recognise and support the inherent benefits of the huge and tightly integrated systems that today serve the Western world. Within these systems, fluctuating input from wind power plant is no greater and no more difficult to cope with technically than fluctuating demand from consumers (WINDPOWER MONTHLY, July 2001).

By their nature, integrated systems absorb all the variations in demand from all sectors—domestic, commercial and industrial. The bigger the system, the more likely a trough in demand from one sector can even out a spike from another. So while the demand of an individual consumer can vary wildly, across a large system the maximum demand is typically about one and a half times the year-round average demand. An individual wind station's output, just like an individual consumer's consumption, will fluctuate. But this does not imply the need to match each



Wind and gas: *The cost of reserve power requirements for both wind and gas, here pictured together in California, must be included in any comparison of electricity production costs*

PHOTO: PAUL GIPE

CNF Undertaking #62

STRAINS ON THE SYSTEM

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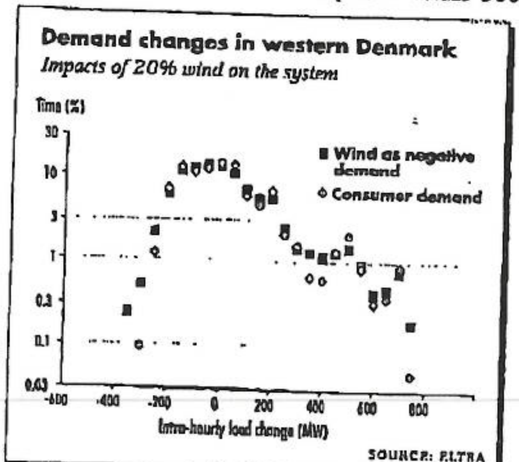
Logic would indicate that introducing a fluctuating supply of power to an electricity network already burdened by fluctuating consumer demand would put an intolerable strain on system stability. The evidence from western Denmark, however, is that wind power imposes only modest extra strains on utility operations.

Wind's impact on a power system can be assessed by examining demand swings from all consumers, first by pretending there is no wind in western Denmark and then by netting off the wind output. During this exercise, wind is treated as "negative demand." The largest power swings (750 MW and above) do occur more frequently with wind included, but the numbers are small—0.18% (16 hours a year) of the time with wind, and 0.05% in its absence (fig). Information of this kind is essential for estimating the additional spinning reserves needed for wind so they can cover expected fluctuations.

Operating utility networks is all about managing probability and risk. Greater probability of power swings means more uncertainty and the need for more reserves to cover the uncertainty. Margins for uncertainty do not, however, pile up on top of one another. Instead, the statistical laws of probability come into play.

A system operator managing a network the size of that run 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. (All uncertainty margins include a range of estimates, each with its own probability). The operator will aim to schedule 26,000 MW of generation. If it has 10,000 MW of wind capacity on its system, generating 5000 MW, the best estimate of wind generation one hour ahead will also be 5000 MW. That leaves a need to schedule 20,000 MW of conventional generation. One of those units might trip during the hour and so that estimate also has error bands. The generation clearly will not be more, but might be deficient by, say 400 MW with a probability of 1%, or by 600 MW with a probability of 0.1%.

As for wind, data from Denmark, Germany and Britain all suggest the uncertainty margin on the estimate of generation (5000 MW) one hour ahead is plus or minus 300 MW—the "standard error." The wind output might be minus 1700 MW, but with a very low probability. Based on these numbers and probability laws, the extra uncertainty due to wind, used to determine spinning reserve, does not call for 300 MW, but for about 60-80 MW.



Little effect: *Hour-to-hour demand changes and those apparent to the system operator when the output from the wind plant, looked at as negative demand, is subtracted*

wind plant with an equivalent level of conventional generating capacity. The variations are absorbed in the whole.

This theory is being proved in practice and by utility studies. In Britain, the National Grid Company has recently looked at the implications of operating its power system in England and Wales with wind energy meeting up to 20% of demand for electricity. It sees no technical or economic barriers that make wind a problem at that level. Several recent American studies have come to the same conclusion. Relying on wind power for 20% of generation will cost a mere $5/MWh, at most.

So much for the good news. In regions where understanding of the issues is still in its infancy, or where the rules explicitly work against efficiency, these facts are ignored and wind is regarded as a major headache. The transmission system operator in the Irish Republic has asked the electricity regulator to set a 700 MW limit on wind power (11% of total generation capacity) until concerns over operating difficulties are resolved (page 29). In Spain, the system operator says 17% wind is the limit (WINDPOWER MONTHLY, December 2003), while in Germany the experts are saying that huge reserves will be needed to cover future wind expansion (page 45). Meanwhile, western Denmark is coping just fine with 21% of its electricity from wind power, but the market structure inflicts costs that bedevil the system operator (page 41).

In none of these countries which label wind power as problematic or expensive to integrate have technical issues been identified that would inhibit satisfactory operation of a network with up to 20% of its generation coming from wind power. Indeed, electricity networks can assimilate far more than 20% of wind power without de-stabilising modern power systems and at reasonable cost—the cost curve per unit of wind energy rises gradually and at a slower rate than the increased wind penetration.

AGGREGATION

Applying market economics to a commodity which cannot be stored calls for a whole new set of rules. In place of warehouse logistics, rule-makers should be working on how to aggregate as much generation and demand as possible for maximum efficiency. Aggregation not only increases the probability that supply will balance demand, it also increases the precision with which a transmission system operator can predict a match between the two, although some uncertainty often remains.

Much greater uncertainty for the stability of any network is the threat of a sudden loss of output from one of its power stations. This can account for anything up to 10% of total generation. Changes of this kind are unlikely ever to be associated with wind energy, due to its distribution over a wide geographic area. Wind variations can be treated in the same way as those of consumer demand. A sudden surge in demand at the end of an unexpectedly popular television program is the kind of daily fluctuation that systems are set up to cope with.

To cater for changes in the balance between supply and demand, system operators contract for various types of regulating reserve (box page 38). These are power plants that operate at less than full output, so that power can be increased if there is a shortage of generation. Conversely, if there is a surplus of generation, the output of ome plant can be reduced. System operators must pay :enerators for this provision, since plant not operating at ull capacity is less efficient so costs more to run.

When it comes to wind power, aggregation means lealing with all the wind production in a utility area, not he output from individual plant. The power output from a ingle wind farm fluctuates significantly with several agged peaks and troughs in the production curve, but the ower output from several wind farms fluctuates less; the vider the geographic spread, the lower the fluctuations. In he case of western Denmark, the fluctuations from the enire 2360 MW of wind are less severe than those from a ingle wind farm by a factor of about three.

THE REAL COSTS

Data from western Denmark, from Germany, and from a rand new study just completed in New York state all sug:est that the average hourly output from distributed wind nergy will rarely, if ever, change in the next hour by more han 20% of the rated capacity of the wind plant. So the utput from 10,000 MW of wind is unlikely to change by nore than 2000 MW in an hour. On a system the size of ie UK network, this is typical of changes in consumer deland that the operator copes with several times a day—nd demand variations can be far larger. Smaller systems learly experience lower demand swings, but can cope ith similar proportions of wind.

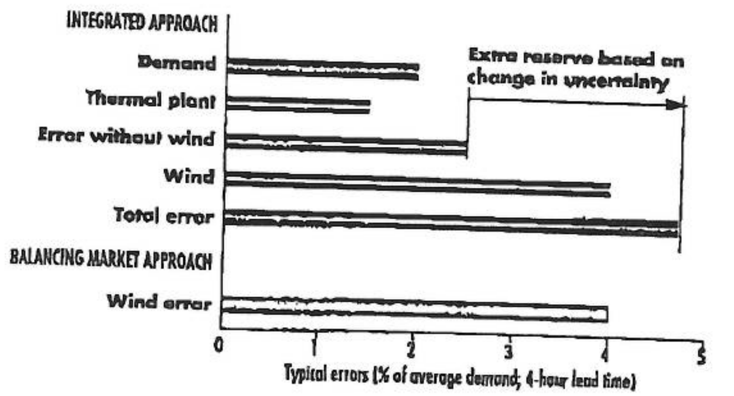
As the amount of wind energy on a network increas-, so does the uncertainty in matching supply and deland. To cover that uncertainty, more regulating reserve iust be made available—and paid for. But it is only the ost of the extra reserve that determines the cost of inteating an intermittent resource, not the costs associated ith a system's entire imbalance (fig 1). And if wind generors are allowed to adjust their production schedules ose to the time of delivery, as is the case in some Ameri- states and in Britain, far less uncertainty is introduced anks to modern wind forecasting techniques.

Determining how much extra regulating reserve capacity is needed for each megawatt of wind capacity is a fundamental first step in establishing (and controlling) cost. Surprisingly, many utilities with wind on their systems, including operators in Denmark, Germany and Spain, claim not to know the volume of the extra reserve they use for wind. Others, however, have examined the implications of increasing wind capacity, providing data which enables the cost of reserves to be established and from there the cost per unit of wind energy generated.

Data from the US National Renewable Energy Laboratory reveals that only modest extra reserves are required (fig 2). With wind capacity equal to 5% of peak demand, the extra reserve capacity is around 3% of the wind capacity; with 10% wind capacity the extra reserve needs are around 5% of the wind capacity, and with 20% wind, just

Assessing reserves for wind 1

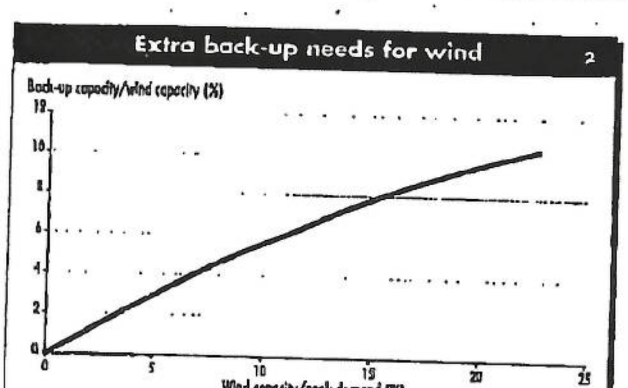
The failure of balancing markets to arrive at true costs



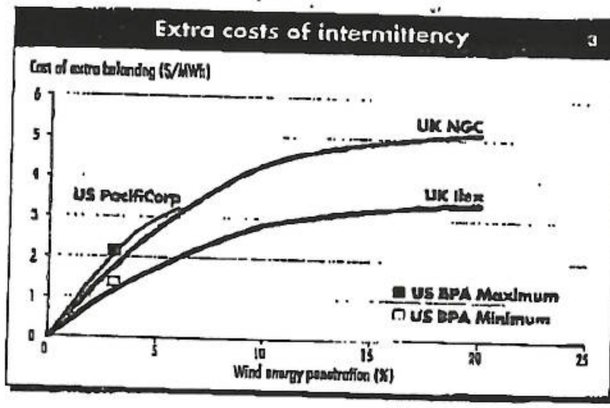
Penalties: *The uncertainty associated with 10% of demand being met by wind is far less on an entire system than if wind is looked at in isolation. But the approach of the new balancing markets is to penalise individual scheduling errors*

Not as much nor as costly as commonly believed

Assessing the level of extra reserve on the system needed to cover wind fluctuations—and its cost



The growing consensus of system operators is that wind adds only modestly to the general need for reserves to balance supply and demand



The costs of intermittent supply, the results of studies by the industry in both the United States and the United Kingdom under 10% of extra reserve is needed. Other studies have yielded even lower estimates.

The cost of reserve capacity in America, Britain and elsewhere differs, but not vastly so. There is a reasonable degree of consistency between estimates of the overall extra costs of intermittency from several sources (fig 3), including two analyses of the UK system, an analysis for the Bonneville Power Administration in the US Northwest, and one for utility PacifiCorp, also in the Northwest, with an installed capacity of 8000 MW. The studies report that 5% wind energy (as a proportion of total electricity production) is likely to attract an additional cost of between \$1.5/MWh and \$2.6/MWh, rising to \$2.8-4.3/MWh with 10% wind, and \$3.4-5.1/MWh with 20% wind. At the high end of the scale, the difference between two estimates for the British network is probably just a question of timing. The lower estimates were made at a later date and the prices for reserve had fallen in the interim.

DEBITING THE COST

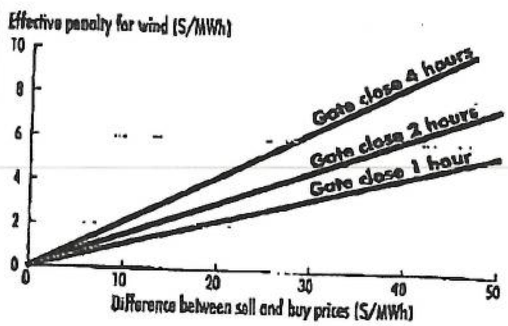
The exact way in which the actual cost of intermittency is to be debited to wind plant operators has received little attention anywhere, although there is broad acknowledgement that the costs need to be taken into account when assessing the relative competitiveness of wind, particularly against its principal competitor, gas (WINDPOWER MONTHLY, January 2004). Another school of thought argues that wind is desirable from an environmental standpoint—and that since the additional costs of integration are relatively small they should be borne by the electricity consumer without more ado. Whether this argument will stand the test of time as wind's growth raises the requirements for reserves remains to be seen.

The aim of the new markets for trading electricity, aside from the quest for greater efficiency, is that they should take account of all the costs associated with all generation. No market structure has achieved that as yet. Most have unintentionally created fictitious power system costs, particularly connected with wind power.

In Denmark, any departures from wind production forecasts made 12 to 36 hours in advance are treated as "energy imbalances" and charged accordingly (page 41). The whole of the difference is charged, not just the extra uncertainty introduced to the system. New trading markets in America and Britain also follow this approach, although the interval between "gate closure" and actual delivery is much shorter—down to 20 minutes—lessening the uncertainty of wind forecasts dramatically. Gate closure is the point when generation and demand schedules are notified to the system operator. After that, surpluses and deficits are traded at "balancing market" prices and the system operator takes control.

Balancing market punishment 4

The dire effects of longer gate closure in the UK



Better: *Gate closure—the last chance for generators to schedule their output—is down to one hour in England and there is no longer a big difference in buy and sell prices for balancing power; effective penalties are down to around \$1/MWh, or less*

BALANCING BUNGLES

The intention of these markets is to make generators and retailers produce accurate generation and demand schedules—and stick to them—by inflicting financial punishment if they do not. But as is often the case with first stabs at regulation, undesirable side-effects have emerged.

First has been the tendency for suppliers to schedule their own regulating reserve in order to limit their exposure to the risk of volatile and unpredictable prices on balancing markets, rather than rely on the system operator for reserves. The unnecessary extra reserves that result push costs and carbon dioxide emissions up—though they incidentally make assimilation of wind easier.

A second undesireable effect has been to inflict "virtual" cost punishment on individual players for deviations from scheduled production, a cost that is not incurred on the system because individual deviations are absorbed in the whole. Since the output from wind plant is liable to change after generation schedules have been settled, they cannot avoid getting punished: deficits must be made good at the "system buy" price and any surpluses sold at the (lower) "system sell" price. Wind energy loses out, despite the fact that wind plant tend to over-generate as much as they under-generate after gate closure.

The cost of intermittency under this type of market mechanism is independent of the volume of wind energy. It has little to do with real costs to the system, but a lot to do with the difference between the "buy" and "sell" prices, and the gate closure time. Provided the difference between the "buy" and "sell" prices is small, the penalties will be small, but as this difference increases, the penalties in-

THREE TYPES OF RESERVES

DAVID MILBORROW
Windpower Monthly Technical Consultant

"Regulating reserve" actually comprises several types of generation plant. "Frequency response" plant act automatically, increasing or decreasing output in response to changes in system frequency. A fall in frequency means demand exceeds supply, so more power is needed. A rise in frequency indicates supply is exceeding demand.

"Spinning reserve," as the name implies, is operational, but at less than full output. "Standing reserve" is not generating, but ready to do so.

The requirements for each type of reserve depend on the uncertainty margins in scheduled production and estimated demand at various timescales. The way the requirements for reserves are calculated is based on statistical principles (see box page 36: Strains on the System).

crease. Furthermore, the longer the gap between gate closure and delivery, the further wind power output is likely to be from its scheduled output (fig 4).

Although these penalties are lower if several wind farms aggregate their output, they may still be significantly higher than the costs actually incurred by a system operator aggregating all generation and demand.

WAYS FORWARD

One solution to this difficulty has been to allow wind generators to pay penalties based on their average imbalances over, say, a month. This reduces them significantly. In Britain, wind generators are tending to secure agreements that allow their output to be consolidated with other generation—although with the shortening of gate closure and reductions in the difference between sell and buy, penalties have dropped significantly (page 46)

The problem of the new market structures effectively undermining attempts to operate efficient electricity systems remains, however. Market forces are spawning a new breed of "consolidator," businesses that aim to make a living from taking a share of the financial benefits of efficiency improvements they introduce by bringing together as much demand and generation as possible. Perhaps that will be the route to higher efficiency—and also one that enables wind to take its rightful place in the generation mix, with intermittency penalties that are fair.

AN AMERICAN LESSON IN POSITIVE PRAGMATISM

MIKE O'BRYANT
Windpower Monthly USA

A consistent policy across the US for how wind generation is integrated into utility systems, and how balancing markets treat wind resources, does not exist. A commendable attempt by the Federal Energy Regulatory Commission (FERC) to introduce a Standard Market Design (SMD) for the entire US power industry was stopped in its tracks last year when strong utility opposition killed the FERC's proposal. Policies for integration of wind, however, are being introduced, though in piecemeal fashion at regional levels.

The SMD, a market-friendly plan for open access to transmission and retail competition, would have adopted a California-like method of integrating wind power generation into power grids by removing the energy imbalance penalties from intermittent resources and averaging imbalances over a month. It also required the use of wind energy forecasting to ease the assimilation of wind on the power system.

Without such a singular policy, the owners of transmission lines across the US are left with a variety of rules—mostly their own—for integrating wind. Many are now struggling to understand the impact wind generators have on their system.

SIZE MATTERS

While most US system operators agree that intermittent resources place some burden on the power system, they do not always agree what penetration of wind is needed before impacts are significant. Jim Caldwell of the American Wind Energy Association (AWEA) says a system will not begin to feel a significant presence of wind until it is close to supplying 20% of demand, unless the system is small, inflexible and weakly linked to surrounding transmission control areas. Up to that 20% mark, says Caldwell, reserve requirements for wind should not be much different than for other resources on the system.

The Northwest Power Pool (NWPP) agrees. It recently estimated its reserve requirement for the 620 MW of wind in its region at 5% of the wind capacity. The pool operated by NWPP, a loose grouping of generating utilities serving a huge area covering the US Northwest and the Canadian provinces of British Columbia and Alberta, has a winter peak of about 50,000 MW. It assesses other resources making up the bulk of its capacity, including hydro and thermal generators, as needing reserves in the range of 5-7% of their load.

Conclusions about the cost of intermittent resources on a system, however, range widely depending on the parameters, from a negligible impact on the California system to estimates of \$5.50/MWh—\$2.50 for incremental reserves and \$3 for imbalance costs—at a 20% penetration for wind power for PacifiCorp in the Northwest. Other studies fall between these two marks:

- The impact of adding 2000 MW to the WeEnergies 8000 MW Midwest system is \$2-\$3/MWh.
- The Utility Wind Interest Group (UWIG) determines the impact of an existing 280 MW of wind generation on Xcel Energy's 7200 MW system in Minnesota is \$1.85/MWh, which includes intra-hour load-following reserves, intra-hour load-following energy and regulation reserves.
- Consultant Eric Hirst arrives at a cost of \$1.47 to \$2.27/MWh for the same three components when adding 1000 MW of wind to Bonneville Power Administration's 14,000 MW system.
- A first phase study completed in January for the New York Independent System Operator and New York State Energy Research and Development authority found that a 10% penetration of wind generation has little impact on New York's 33,000 MW system.

These studies have led UWIG to conclude that the higher the penetration of wind on a system, the higher the costs, that wind capacity does not need to be matched by reserves of an equal volume of dispatchable power as some system operators assert, and that the cost of reserves "is significantly less when the combined variations in load

The imperative for establishing how much it costs to integrate wind into the power systems of today has been much greater in the market economy of the United States than in mainland Europe. The emerging consensus in America is that wind's fluctuating supply adds very little cost—so little that in some cases it is being ignored

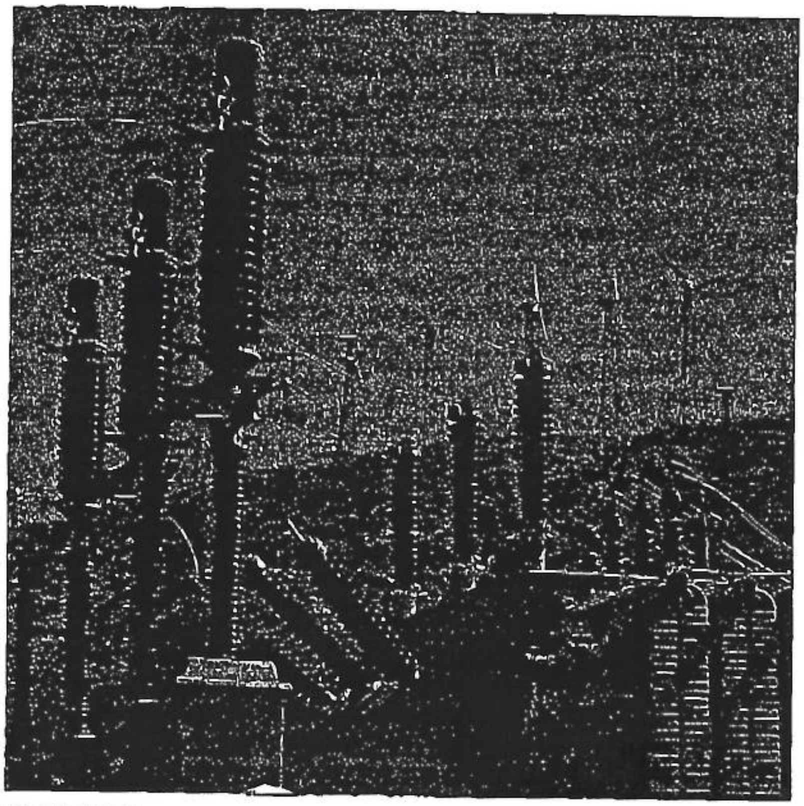


PHOTO: STEVE MSDO

Wind and the wires: *California has decided to protect wind from unfair punishment at the hands of the market because it recognises that wind variations cause minimal extra cost*

and wind plant output are considered, as opposed to considering the variations in wind plant output alone." UWIG also concludes that wind forecasting would mitigate some of these costs.

CARROTS AND STICKS

Without nationwide rules like SMD to govern balancing markets, there is a wide variety of carrot-and-stick financial incentives and penalties across the US for encouraging generators to do their best to match output with likely demand—and for dealing with wind in particular. In its treatment of wind, the Electric Reliability Council of Texas (ERCOT), which oversees 85% of transmission in the state, simply excludes the existing 1305 MW of wind generators from its current balancing market. This is because the state's renewables portfolio standard requirement of up to 2000 MW of wind capacity by 2008 requires ERCOT to get the renewable generation on the system, which peaks at 60,000 MW regardless of the impacts.

ERCOT's Ken Donohoo says the biggest problem with integrating wind into its network is transmission bottlenecks, not wind's impact on reserve requirements. He suspects, however, that wind generation does have an impact on the system and says ERCOT is completing modelling that will look at how the grid will be able to integrate the full 2000 MW of wind into its system.

In the Pacific Northwest, BPA's Steve Enyeart says his agency has removed generation imbalance penalties that amounted to as much as $0.10/kWh for wind (WINDPOWER MONTHLY, September 2002) and now charges the same fees to all generators, regardless of fuel source. If a wind facility, or any other generator, delivers less than what it scheduled (within 2 MW or 10%), then it will pay 110% of the cost of market power to make up the difference. Conversely, if it delivers more power, it will receive 90% of market price for the extra electricity. Because BPA allows generators to set their schedules one day ahead, however, and to true up that schedule 20 minutes before the actual hour, it has a system that is "near real time," says AWEA's Caldwell. The closer to real time that the market for balancing supply and demand is allowed to operate, the more likely that wind generators will supply the system with what it has been told to expect.

MARKET SOLUTIONS

With all Northwest wind projects now using wind forecasting, scheduling accuracy is on the rise (WINDPOWER MONTHLY, December 2003). While that adds the cost of a forecasting service and the cost of an automated scheduling system to the final cost of wind generation, it saves more on imbalance charges and cuts the amount of reserves necessary.

"If you don't know what you can provide 24 hours ahead, then you would need more reserve," says Michael Brower of TrueWind Solutions. The company is a US leader in wind energy forecasting, providing forecasting services for over 1500 MW of wind generation, or about 30% of the total US wind capacity. "To the extent you can reduce uncertainty through forecasting, then you can make scheduling more optimal," says Brower.

In California, the independent system operator requires a central wind forecasting service, which is provided by TrueWind. Even with that service, the California balancing market does not require an immediate truing up of a resource's balancing account. Instead, it allows wind projects to true up their accounts by averaging imbalances over a month, an approach which avoids the economic inequities of penalising wind for under-production one day and over-production the next. It is a good solution for an imperfect market, says Caldwell.

But he prefers real-time balancing on the spot market, as operated by PJM Interconnection (the Pennsylvania-New Jersey-Maryland Independent System Operator that touches on seven states). Here each generator, regardless of type, schedules its production 24 hours ahead, but it can true up 20 minutes ahead. Any imbalance that remains at the time of delivery is dealt with on the spot market at spot market prices. The PJM approach avoids the requirement of most systems for precise advance delivery schedules. "It sort of naturally allows wind into the system at the right cost," says Caldwell. The PJM comes closest in the US to a theoretically perfect solution to pricing wind imbalance, he adds.

Because the FERC's SMD proposal is so disliked by state governments and the US energy industry, it is unlikely it will be included in a 2004 United States energy bill, if there is a bill at all this year. The SMD would establish nationwide deregulation of electricity markets, something states are hesitant to embrace after the shocking failure of California's deregulation experiment. For its part, the energy industry dislikes having to join regional transmission organisations and perhaps giving up control over transmission assets.

Without any sign of the SMD coming into being, the wind industry is scrambling for other ways to ensure wind gets equal treatment by transmission organisations. AWEA, says Caldwell, is beefing up its regional efforts to get fair transmission tariffs for wind generators. Wind advocates are seeing some gains in the strategy. California, the PJM Interconnection and to some extent BPA area already taking steps to take account of wind in their market rules. As other regional transmission organisations, such as the Midwest ISO, get on their feet, the industry will be there on the ground floor to ensure the rules do not prevent wind from being able to compete in the market.

AWEA and other wind advocates are also going back to FERC to ask for a technical conference aimed at exposing integration issues for wind resources and then recommending a "best practices" document that would guide utilities under FERC's jurisdiction to deal fairly with wind power. Caldwell favours guidance in preference to force at this time. He warns that an attempt to draft mandatory rules for integrating wind generation would likely end up being so watered down it would not be worth the trouble.

INTEGRATED IN PRACTICE BUT NOT IN THEORY

With wind sometimes supplying all the electricity in western Denmark, balancing supply and demand is proving a costly exercise, says transmission system Eltra. But that cost seems to be a function of a market structured for convenience rather than efficiency. Another approach could greatly reduce those costs

JACK JACKSON
Windpower Monthly Special features

Western Denmark has long been an industry benchmark when it comes to integrating large proportions of wind energy into a modern power system. Wind penetration last year—the proportion of electricity supplied by wind power—was 21% says Eltra, the transmission system operator (TSO) for Denmark's main peninsula of Jutland and the big island of Funen. Yet while Eltra manages the technical job of providing its customers with secure supplies of electricity without so much as a whiff of a blackout, come wind or no wind, the structure of the market for balancing supply and demand places an extraordinary financial burden on the TSO for doing its job—a cost that gets passed on to consumers.

In the current market design, wind's added costs amount to tens of millions of Danish kroner every year for buying regulating power in the real-time imbalance power market. While Eltra tends to put the main blame for this on poor wind forecasting (Windpower Monthly, December 2003), industry observers and wind power producers point to balancing market failings and to inadequate interconnections to Denmark's neighbours.

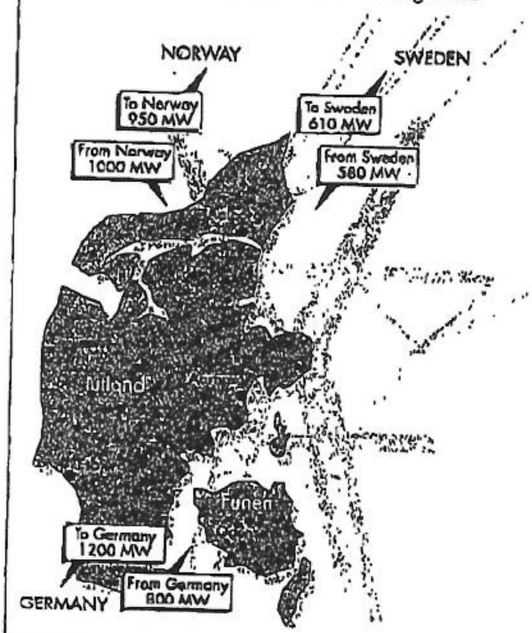
The main culprit for the extra cost placed on wind seems to be the requirement that all generation be scheduled on the Nordic electricity exchange, NordPool, way ahead of when it is needed. "Gate closure" is at noon for the following day, requiring generation to be accurately projected fully 12-36 hours ahead of time. For wind generation, accurate predictions of output a day ahead is almost impossible (Windpower Monthly, December 2003).

The early gate closure means that any deviations from scheduled production incur costs for Eltra. Either it has to offload generation it has already bought, because demand is less than scheduled or generation is more than scheduled, or it has to buy power to make up a deficit, because of greater demand or less generation than scheduled. Under the rules of supply and demand, Eltra will nearly always end up selling excess power at a loss and buying power at a premium to make up a deficit.

PRIORITY POWER

The situation in Denmark is exacerbated by the existence of a large number of distributed, communally owned, combined heat and power (CHP) plant run mainly on natural gas. Eltra is required to buy all electricity from these facilities and from all subsidised wind plant as "priority power," whether it needs it or not (fig 2). On a cold, windy day, CHP work overtime to meet demand for heat, with Eltra forced to buy the accompanying electricity—even though plenty of power is being delivered by the 2360 MW of wind plant on its system. Eltra's system is relatively

Not an isolated system
West Denmark's transmission links to its neighbours



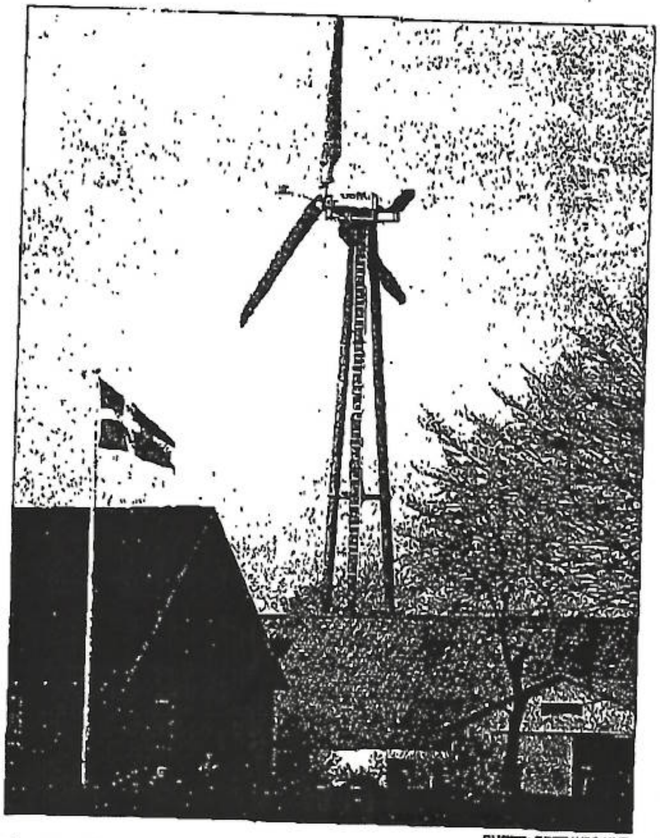


PHOTO: GERT WOLUND

The land of distributed wind: *With turbines well spread out, varying output from individual units is absorbed into the big picture*

small, with maximum and minimum loads of 3800 MW and 1150 MW. During 2003, about 40% of electricity was from wind and local (heavily subsidised) gas-fired CHP, with the remainder mainly from coal.

The designation of "priority power" wreaks havoc on market prices, directly affecting the one in five wind turbines which, because of their age, no longer receive subsidies and must sell their output on the open market. Recent Nordic power market research has found that a more flexible market design would cut regulation costs (for all generation) by up to 70% and increase net income by up to 8%, though Eltra is sceptical.

A DAY AHEAD

Market players in Eltra's area sell power through NordPool or trade bilaterally with German TSO E.on Netz, or among themselves. "Gate closure" for E.on Netz is 2:30 pm for the following 24 hour period, starting at midnight. For bilateral trade among themselves, bids must be in by 3 pm.

On average, in its day-ahead prediction for wind production, Eltra misses the mark 30-35% of the time. In 2002, the need to buy or sell power on the real-time imbalance power due to miscalculations of expected wind production, cost Eltra DKK 67.5 million, or DKK 19.4/MWh ($2.61/MWh) of wind power consumption, according to the TSO.

Wind power is responsible for most physical system imbalance 70-80% of the time, according to Eltra. For the remaining time, wind power counters any imbalance in the rest of the system.

The rigid market design means Eltra cannot put to use unscheduled windfalls of (clean) power from wind plant without a financial penalty—not unless they coincide with the need to cover other unexpected imbalances. Eltra's Paul Mortensen points to the evening of April 11, 2003 as a typical occurrence (fig 1). An unexpected 400 MW of wind hit the system for more than six hours. Since normal production had already been scheduled from other (largely dirty) sources the day before, most of the clean energy surplus was sent to Norway and Sweden as regulating power, replacing equally clean hydro, he says. In west Denmark the six-hour imbalance cost consumers between DKK 140,000-170,000 (€18,800-22,800).

"It is the prices on the regulating power market and the capacity in the grid that decide what gets regulated up or down—not the type of generating source used," explains Mortensen. A transmission bottleneck prevented all the overspill power on April 11 going to Norway. That is often the case, he says, requiring Eltra to regulate within its own region, bartering with suppliers, or to use the German interconnection. The only way that a 400 MW windfall could have saved the same amount of fossil fuel production without a financial penalty is if an exact wind power forecast had been made the day before production, says Mortensen. This would have allowed the correct amount to be traded on the market and thereby replace bids from coal.

RESERVE FOR ALL

Eltra does not know precisely how much reserve power it needs to have on standby due to deviations in scheduled wind production. Eltra's Gitte Agersbæk says there are too many moving variables—including market price and system imbalances—to get an exact figure. Eltra can say, however, that the average deviation from its day-ahead wind power forecasts is 170-200 MW. Occasional peaks of unexpected surplus or missing production can be as high as 800 MW or more. "You cannot buy for worst case scenarios—that's too much reserve to have for a little system like ours," Mortensen says. "It's a balancing of how big a risk are you willing to take in cases when big deviations do occur. Do you reckon you have the capacities on neighbouring systems?"

Eltra's average error in scheduling electricity demand—when estimated by noon the day before—is around 2-3%, or 40-50 MW. In January, Eltra awarded a contract for reserve power to the one large power producer in western Denmark, Elsam. This was the first time Eltra's manual and automatic reserve contract covered only three months—an attempt at reducing costs. Previously, the contracts have stretched for more than a year and included the summer months, when variations in loads and wind output are less.

For a total price of DKK 91.6 million (€12.3 million), Elsam is to supply three months of manual regulating re-

Further reading:
An article examining in detail how fluctuations in wind output impact a power system, *Fading Fears About Fluctuations*, was published in the July 2001 issue of WINDPOWER MONTHLY. It is available as a PDF document from the WindInsight section of our web site:
www.windpower-monthly.com

serve (370 MW upward and 300 MW downward), three months of automatic regulating reserve (100 MW up and down) and a year of upward regulating reserve/emergency start-up units for 37.5 MW. Added to this is the energy payment for using the automatic reserves: DKK 400/MWh for upward regulation and DKK 75/MWh for downward regulation. The cost of manual regulation reserve is dictated by the regulating power market. In 2002, the average use of upward regulation cost DKK 219/MWh and the average downward regulation was DKK 150/MWh.

POTENTIAL SAVINGS

According to new calculations that build on a paper from 2002 by Hannele Holttinen of VTT, the State Technical Research Centre of Finland, a more flexible market would allows bids for wind power to be updated four times daily, instead of the day ahead (box). Predictions of six to 12 hours ahead would reduce Eltra's regulation costs 30% and increase its net income by 4%. "There is no technical barrier in making the electricity market more flexible—that is, shortening the time between the clearing of the market and the delivery," says Holttinen.

While regulation costs would fall, Eltra's senior market economist, Henning Parbo, says an increase in transaction costs to market players makes this option undesirable. "The electricity market will be reserved to players that can afford 24-hour working positions," Parbo says. "Of course, there is a trade off between transaction costs and balance costs, but I am pretty sure that the definition of one point in time where the bulk of electricity trade is cleared [i.e., at noon every day] is the main reason for the success of the Nordic market model with a large number of market players. This gives another quality: price transparency."

Parbo stresses that changing gate closure time cannot be done in isolation. "The electricity markets in Europe are linked. You cannot change a significant design parameter in one country without affecting market conditions in the surrounding areas," he says.

MARKET INTERFERENCE

While wind power makes up a heavy portion of generation in Eltra's area—21% of total consumption in 2003—decentralised CHP plant produce even more; in 2003, they generated 31% of consumption. While four out of every five megawatts of wind is priority power, meaning market players are required to buy all production from these machines, every MW of local CHP is prioritised. In terms of income, the non-priority wind turbines suffer.

"Heat demand decides how much the local CHP produce," says Per Lauritsen, director of DV-Energi, which acts on behalf of the wind turbine owners who now trade their power on the open market. Their combined capacity in Eltra's area is about 150 MW. "If it's a cold, windy day, you can get a situation where the local CHP are producing too much electricity."

If, in its day ahead forecasts, Eltra anticipates more power coming onto the grid than it can export, NordPool sets the price to zero for players in Eltra's area. Parbo says that during the last year Eltra had 100 hours with zero prices, plus many more hours with spot prices close to zero due to the overflow problems.

If supply in specific hours still exceeds demand, NordPool "shortens the sales bid" in order to balance its schedules, informing every seller that they have sold less than their bid, regardless of the price of the bid. Thus, sellers

ANOTHER BALANCING MARKET OPTION

JACK JACKSON
Windpower Monthly Special features

A small electricity trading market in use in Sweden and Finland could improve the situation for Danish wind power producers who are otherwise forced to schedule their production on the Nordic power exchange a day ahead of delivery—a time span that makes accurate predictions of wind generation difficult to achieve. Called Elbas, it is a market where trade closes one hour before delivery. As Hannele Holttinen, of the Technical Research Centre of Finland, points out, if Denmark's transmission system operator (TSO) Eltra used this market it would reduce its expenditure in the big regulating market.

Just one hour before delivery, Elbas allows market players to check the likely deviation of their production/consumption from the spot bid made the day before. "As there are a lot of actors, you may well find someone wanting to buy your extra production at a price near the spot price, or sell production to cover your underproduction near spot price. This is the idea, to avoid the high (or too low) prices on the regulating market," says Holttinen.

INCREASING INCOME

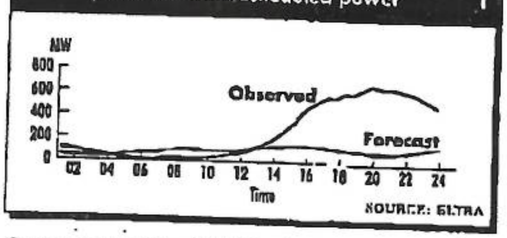
Elbas enables wind producers to forecast production one to two hours ahead of delivery. Using 2001 data, Holttinen says Elbas could reduce Eltra's regulation costs by 70% and increase its net income by 7%, assuming that wind power does not influence the Elbas price and the Swedish price level applies in Denmark. "A well working after [spot] sales market would help both wind power producers and the system operator in reducing the amount and cost of wind power production at the regulating market," she states.

Eltra's Henning Parbo says the TSO is not immediately interested in pursuing trade on Elbas, partially for the same reasons it is against working under a shorter gate closure (main story). "But the crucial question will be the price level in such a market," he says. "Will the prices be close to the spot prices or close to the regulating prices? And, indeed, if the regulating market prices without an intra-day-market in place are already close to the spot prices, there seems to be no economic room for an intra-day-market. To me, this is the case in Sweden and Finland, and the moderate turnover in Elbas seems to support my view."

Parbo concedes, however, that regulating prices in Denmark are quite "expensive" compared with the other Nordic countries. "This may speak in favour of experimenting with an intra-day-market," he states. Parbo stresses that Eltra is not against a concept when many more players enter the electricity market—particularly if German market players could be included.

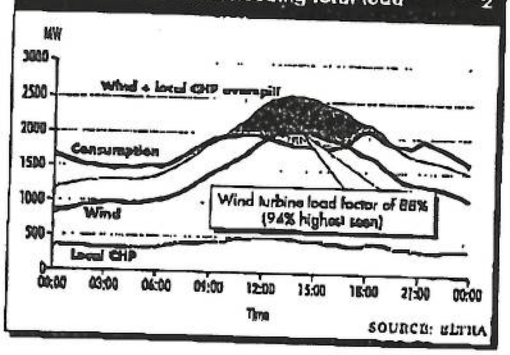
Dealing with wind
Western Denmark learning how

Deviation from scheduled power 1



On the evening of April 11, Eltra had to offload nearly 400 MW of production when the wind defied the forecast from the previous day. The TSO had already scheduled generation from other sources and lost money as a result.

Production exceeding total load 2



For more than a decade Eltra has complained that the mandate on it to buy all "priority power" results in overspills of production on which it makes a loss

are only able to get rid of, say, 90% of their production on the NordPool wholesale market, while the remaining 10% must be sent to the regulating market. Parbo recalls a shortening of 800 MW as maximum during 2003.

"We've gone from a market support system to a liberalised market, but not all the players are on the market at the same time," says Lauritsen. "They haven't taken the full stride in liberalisation. We can't choose the price. We produce when the wind blows. We want all market players to play by same rules."

POLITICAL HELP

Help is on the way. Parbo explains that a law proposal is currently being discussed to "deprioritise" local CHP and make it part of the open market. "CHP on the electricity market will mean that the plant owners can enter the spot market, the regulation market and the reserve market, which Eltra will be pleased about, improving competition in these markets," says Parbo. The proposal is scheduled to be handled in parliament in the spring.

This is music to the ears of DV-Energi. "Our hope is to get more suppliers in the market, so it's not just Elsam," says Nils DuPont of the company, referring to the main, near-monopoly power company in Eltra's area. "This will make it cheaper and easier to use the real market and not the balancing market."

NordPool will introduce negative prices in March as another way to help the overflow problem. Potentially, this could mean that wind producers on the free market will be forced to pay for the surplus power they generate when the price dips under zero. Ideally, however, the price will never go negative because it will encourage fossil fuel-fired plant to shut off production at zero prices, instead of keeping it running like they do today. "The argument is then that it would move a lot of production to the real market and away from the balancing market. It's sheer economics," says DuPont.

INTERCONNECTIONS

Another main area where wind power producers criticise the current market are the bottlenecks on the lines in and out of Eltra's area. Eltra activates regulating power where it is the cheapest, provided the transmission capacity is adequate. And this is the crux of the matter.

"There's not enough space on the system for the normal market when it is really blowing," says Lauritsen. "The biggest problem in the current balancing market are the cable connections to Norway, Sweden and Germany. They are not optimal. Stronger interconnections would make it easier to balance the Danish market with hydro—the fastest and cheapest standby reserve."

Lauritsen points out that balancing market costs of western Danish wind producers are double those of wind producers on Zealand, the big island of eastern Denmark which is not linked to the rest of Denmark, including Eltra's region. Part of the reason for the huge price difference is that western Denmark has 80% of the country's wind turbines. "But Zealand also has a good connection with Sweden, which helps to level things out," says Lauritsen.

A major power outage on Zealand and southern Sweden last summer has brought discussion of connecting the two Danish markets by cable to the forefront once again. There is also talk about bettering the connections from Eltra to Norway, Sweden and, particularly, to Germany.

Eltra is careful around the issue. Its 2003 System Report states: "Financially speaking, the optimum capacity is achieved if a certain congestion effect is maintained. The socio-economic advantages of an expansion will typically exceed the financial benefits to the company. The increased transit capacity can improve earnings for the power generators, as congestion will no longer force them to leave capacity unutilised. However, the power generators may also in some situations benefit from congestion as they often trigger a higher electricity price. Consumers will typically have to pay a lower price when the international interconnections allow for the cheapest electricity to be supplied."

Correction: Eltra did not save fuel costs on 400 MW of thermal generation on April 11, 2003, as stated in a caption to a series of figures, "Achieving a match on Eltra's system," in the December issue of WINDPOWER MONTHLY. Only some of the generation the wind power replaced was thermal power. The remaining power was sent to Norway and Sweden, where it replaced hydro power, as the article above explains.

WIND

SHOCKING CLAIMS ON RESERVE REQUIREMENTS

Transmission system experts in Germany charged with studying wind integration are claiming that the country's wind power plant need reserves equal to half their installed capacity. This is up to ten times more than needed in other countries and even defies the experts' own observations of wind's current demand on spinning reserve

SARA KNIGHT
Windpower Monthly
Germany

Surprisingly, the country operating the most wind power plant has yet to agree on hard and fast rules for calculating the volume of reserve generation needed to cover the extra uncertainty introduced by wind fluctuations. Germany, with 14.2 GW of wind power, has also only just started consideration of how to assess the actual cost of the reserves and how balancing markets should be structured to reflect that cost.

Studies of how to integrate wind have been initiated, however, and there is political recognition that the efficiency of what are now four balancing market zones needs to be improved. Debate on amendments to the German renewable energy law (WINDPOWER MONTHLY, December 2003) includes discussions on improvements that will not only benefit wind energy but other market players as well.

The two power system operators with networks bordering Germany's North Sea and Baltic Sea coastlines, E.on Netz and Vattenfall, take the bulk of the country's wind power, which meets about 4% of national demand for electricity. The huge E.on network runs from north to south through the centre of the country and Vattenfall's VE Transmission system covers the whole of eastern Germany. With expectations that wind capacity on their networks, particularly offshore, will more than double within seven years, they are both pressing for political action to pave the way for them to get a grip on how their systems will cope. E.on predicts it will need to cater for 12,800 MW of wind generation, 6000 MW of that offshore, by 2011. By the same year, Vattenfall is getting ready to operate 8650 MW, including 3250 MW offshore.

At those volumes and presuming the offshore stations get built, the demand met by wind generation could approach, and for Vattenfall exceed, 20% on their individual systems. In practice, the effective penetration will not be as high since the production feeds into the whole of Germany's integrated national network, which is also connected with its neighbours. The challenge now is to develop market rules that recognise that fact and do not unfairly punish wind by landing it with a fictional cost.

OUT ON A LIMB

Experts from the two utilities, working with more experts from research institutes RWTH in Aachen and FGH in Mannheim, agree that wind's demands on spinning reserve today (in Germany, reserves called up within 15 minutes) are minimal and place "no restrictions" on wind energy. But as wind penetration increases, E.on and Vattenfall say reserves must increase too.

By 2016, claims the expert group, wind's demand on spinning reserve will be four or five times greater than today. On E.on's northern network it will peak at 8 GW, they believe, or a huge 50% of the wind capacity in the region. A 50% reserve is five to ten times the level that system operators in America or Britain are expecting to provide (article page 35). It is apparently based on purely day-ahead forecasting of wind output and a claim that standard error in that forecasting is a high 12.5% (WINDPOWER MONTHLY, December 2003).

The group uses the same calculation basis for the VE Transmission area, concluding that maximum demand for spinning reserve will be 4 GW, again 50% of the wind capacity. In both cases, average spinning reserve over the year will be about half those levels, they say. This is still substantially more than experience with wind operation indicates, including their own experience with 4% wind penetration, and more than international studies maintain.

Not surprisingly, the expert group questions whether its calculations of the "extremely high reserve requirement of about 10 GW" can be covered by German resources alone. Spinning reserve in the whole of Germany today lies at just over 8 GW. The group concedes, however, that its analysis looks at the northern part of E.on's network and the VE Transmissions network in isolation, rather than at the sum of all four German high voltage transmission systems.

The group also expresses its calculations in terms of energy used by the reserve. On E.on's northern network, the experts claim the need for electricity reserve will rise from about 1.5 TWh in 2001 to around 6.5 TWh a year in 2016 and for VE Transmission from about 1 TWh to 3.5 TWh in 2011.

NO WORD ON COSTS

The actual cost of the reserve power is an issue the expert group avoids. Its only comment is on market prices for spinning reserve, which "are by no means stable and therefore difficult to estimate for the coming years." Network operators are not required to use the country's four separate markets for regulating wind power, which is barely traded on them.

As it is, both E.on and VE Transmission procure at least some of the needed reserve for wind energy internally rather than on the market after conducting their own wind forecasting and scheduling (WINDPOWER MONTHLY, December 2003). As a result, the actual costs of reserve are hidden away from external examination. E.on buys reserves for up to 60% of its wind capacity from sister company E.on Energie, which it says costs far less than buying the standard market product, used to cover some of the remaining 40% of its needs.

Vattenfall's trading division markets wind power on the EEX Leipzig electricity exchange based on day-ahead forecasts. It corrects deviations from the forecast on the delivery day with power bought internally and/or calls on spinning reserve procured the previous day to iron out discrepancies between projected and actual supply and demand, including wind fluctuations.

Federal economics minister Wolfgang Clement seems to have been made aware of the dark areas of wind integration costs. At a Handelsblatt/Euroforum conference in Berlin last month he stated that combining Germany's four balancing markets into one "in connection with wind energy" was part of discussions on amendments to the renewable energy law. The intention is to increase market liquidity with the aim of reducing prices. Liquidity is highly constrained by distribution of balancing services over four separate markets.

A new study, Energy and Economic Planning for Network Integration of Wind Energy in Germany on Land and Offshore to 2020, co-ordinated by German energy agency Dena, is due for publication by the summer. Representatives from a cross-section of wind and electricity companies, research institutions, lobby organisations and the federal economics ministry aim by then to have answers to the key issues of wind energy expansion. Dena assumes that wind capacity will grow from 14 GW in 2003 to 24.5 GW in 2010.

A DIRE START THAT GOT GRADUALLY BETTER

Among the hundreds of fixes to Britain's New Energy Trading Arrangements have been amendments to greatly lessen the penalties associated with settling wind's deviations from scheduled production on the balancing market

JANICE MASSY
Windpower Monthly UK

The introduction of new electricity trading arrangements (NETA) for England and Wales caused a furore in the renewables and combined heat and power (CHP) industries in the months after NETA came into force in March 2001. The problem for renewables revolved around the balancing mechanism at the heart of NETA that penalises generators when their output does not match their offer exactly. In particular, this hit small and intermittent generators like wind farms.

Output from renewable generators fell by around 25% and revenues fell by over 33%. Volatility in the power market in those early days with a high spread of prices meant that generators had to pay a high "system buy price" to make up shortfalls, while they received only a low "system sell price" for excess power. For months, some small generators could not find an electricity supplier willing to buy their power and incur the imbalance charges.

After that low point things could only get better. Two particular modifications to the rules governing the balancing mechanism—the balancing and settlement code (BSC)—improved matters for small generators. Reducing the period to gate closure, the time between notifying an offer of power and its later dispatch, from 3.5 hours ahead to just one hour ahead, and reducing the spread of system buy and sell prices have both combined to lower exposure of intermittent generation to imbalance charges.

Welcome though these modifications were, their effect on renewables pales when compared with that of the UK renewables obligation (RO), introduced in April 2002, which transformed the market for wind power. The RO requires electricity suppliers, known elsewhere as retailers, to supply a percentage of their power from renewables, starting at 3% in 2002-03, rising to 15.4% in 2015/16. Where once suppliers were reluctant to contract for wind power, they now vie to buy up wind generation, since the imbalance costs of wind are more than outweighed by the income gained through sales of the associated renewables obligation certificates (ROCs) and Climate Change Levy exemption certificates (LECs). Nearly all renewable electricity is sold directly to suppliers who add it to their energy portfolios, where the effect of any imbalances from individual projects is reduced through aggregation.

But while the RO cushions renewables from the effects of NETA, its problems have not gone away. "We still have a system which inherently works against smaller, intermittent and green generation," says Syed Ahmed from the Combined Heat and Power Association (CHPA). He points to the demise of large generator and supplier TXU as proof that no one is immune from the triple whammy of lower wholesale prices for power, imbalance costs, and loss of benefits for embedded generation in today's electricity market. "The big guys have been suffering, and smaller players have been suffering disproportionately more," he says. "The only people who are building new capacity are wind developers because they have the RO."

FIGHTING FOR A SAY

There is still room for improvement of NETA, says Ahmed, but changes will only come about if one of the signatories to the BSC—who are mostly large players—proposes a modification. This is then considered by the BSC panel and energy regulator Ofgem. A number of proposed modifications to help small generators have been rejected. "The problem is that NETA is a big boys' playing field," he says. "We have a very difficult time engaging our members in the NETA process because it is all so complex."

From Ofgem, Boaz Moselle claims the modifications already introduced have helped smaller intermittent generators. But if the balancing rules are still unfairly penalising them, Ofgem will consider further changes to the BSC, he says. "The aim is to have cost reflective charges and if we could see anything to make them more cost reflective, we would consider it." He points out, however, that intermittent sources such as wind can lessen their exposure to imbalance charges by pooling their output in a portfolio of generation, although he concedes that few renewable generators have so far opted to use consolidation services.