Implications of intermittency - market madness?

The Renewable Energy Strategy, published by the government in mid-July, confirms the UK's renewable targets for 2020 with an ambitious target of 15% of final energy use to be provided by renewables. This could mean that over 30% of electricity generation will have to be met by renewable power, with the government anticipating the majority of that coming from wind. As a result, there could be as much as 35GW of wind on line in the GB system by 2020 (33% of total installed capacity). In addition, the long-term reduction of 80% of CO_2 emissions by 2050 and a decarbonisation target of 70gCO_2/kWh by 2030 suggested by the Committee on Climate Change may lead to over 45GW of wind and marine installed by 2030. But what will the implications be for intermittency? James Cox* looks at the issues.

The intermittency of wind generation creates potential challenges for the electricity system to deal with.

However, it is not only wind generation that has the potential to change the shape of the electricity market. Much of the new generation that could be deployed in Great Britain in the next 20 years will be fundamentally different to existing generation in four main ways.

■ Price insensitive. Most new generation planned for a future low carbon world, such as nuclear, coal, carbon capture and storage (CCS) and biomass, is price insensitive. This means that the amount of plant that varies its generation in response to price and/or varying demand will decrease significantly.

■ Intermittent (unavailable when needed). Wind and marine technologies are highly variable in their output, with swings of 80% possible within a day.

■ Unpredictable. Wind and wave generation are both difficult to predict accurately – and the error in a forecast of wind generation increases dramatically as the time interval increases, in the same manner as any weather forecast. (Tidal generation, on the other hand, is extremely predictable – we know the time of high tides accurately for the next thousand years or so).

■ Subsidised. From an electricity system where about 5% of generation is subsidised, the proposals from DECC will lead to over 30% of generation receiving government support. Hence a system and market that is currently dominated by price sensitive, non-intermittent and predictable technologies that have no government funding could, within two decades, become completely inverted. The dominant technologies to be built would be baseload, intermittent and unpredictable, and a significant proportion would need to be subsidised.

So will the current market design survive? Can a market with 30% of generation subsidised be described as a market?

There is no doubt that this is a radical shift. Neta/Betta was introduced to make the wholesale electricity market more akin to other commodity markets: the emphasis was on de-centralisation, simplification and limitation of regulatory and government intervention.

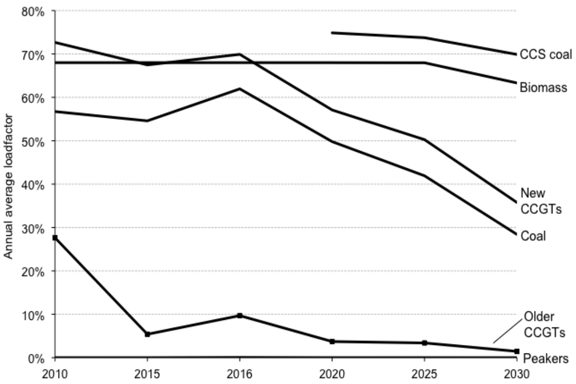
Generators were expected to self-balance, CO_2, emissions were low on the agenda, and it was envisaged that the bulk of new capacity would be fossil-fuelled. A market design that was fit for purpose when proposed and implemented in 2001 will have to deal with issues that were simply not foreseen when it was designed.

Some initial answers to this question have been established in a recent major multi-client study by Pöyry, a summary of which has recently been published.

The year-long study investigated how the future GB electricity market may look in 2020 and 2030 in a low carbon world, which required assembling an unprecedented quantity of wind data and building a highly sophisticated electricity market model.

The study is the first to look in detail at how aspects of the functioning of the market – such as prices and investment – may change, and the results suggest that it will not be an easy path over the next 10-20 years. A number of important findings on plant operation, market prices, investment and market design are highlighted in the rest of this article.

Figure 1 - Future plant load factors



Source : Pöyry

Plant operation

With large amounts of wind generation on the system, along with increasing nuclear, biomass and combined heat and power (CHP), load factors of conventional thermal plant are strongly affected (as shown in Figure 1).

In GB by 2020, load factors of older 1990s CCGTs are below 10%, and newer CCGTs are under 60% whilst coal is at 50%.

The main reason for this is the reducing 'space' for these plant to operate in – with rising volumes of baseload nuclear, carbon capture and storage (CCS) coal and biomass plant, and increasing volumes of low-cost intermittent generation, the running patterns of conventional plant by 2020 are increasingly dictated by the need to fill the gap when the wind is not blowing.

Market prices

With significant volumes of wind generation, a continuation of the Betta market rules will lead to prices becoming much more 'peaky' – increased periods with very high or very low prices.

This is because the system will alternate between having too much capacity – in periods with high wind speeds and high wind generation, and much tighter capacity when there are low wind speeds.

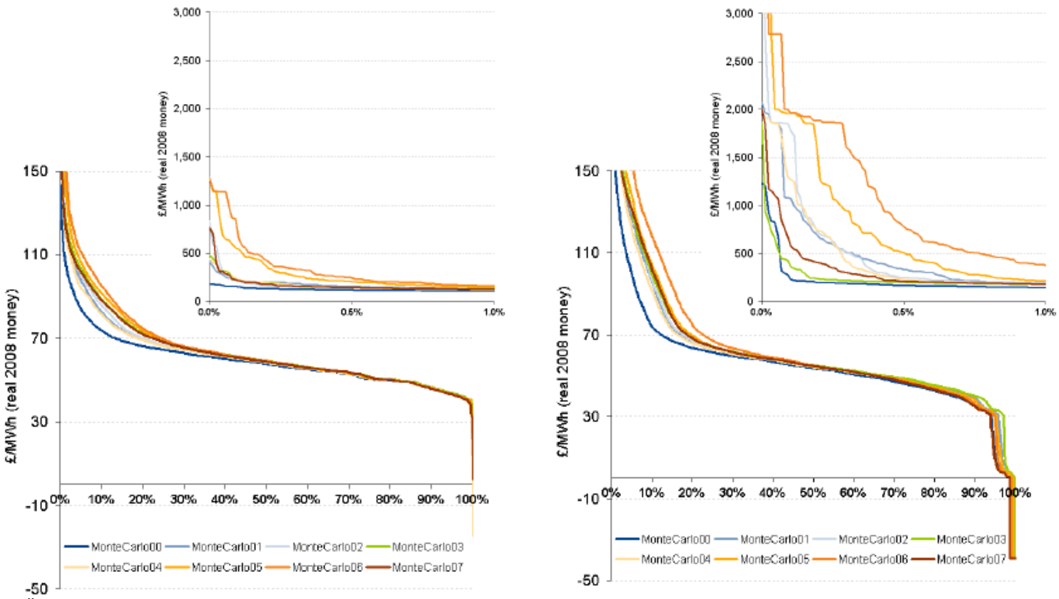
By 2030, with significant volumes of wind on the system, the distribution of prices will change, with periods of negative prices due to the wind generation bidding at its opportunity cost of between -1 and -2 Renewables Obligation Certificates (ROCs), periods with low or zero prices and some periods with very high prices above £1000/MWh.

However, these spikes in price are necessary for the market to operate. Without them, generators that only run a few hours each year cannot make sufficient returns.

These volatile and unpredictable prices significantly increase the commercial risk of operating in this market. It will be highly uncertain how high prices might rise, and depending on the interaction between wind and demand, in any given year these price spikes simply might not occur.

This is shown by the different lines in the price duration curves in Figure 2 – in some simulations

Figure 2 - Price duration curves for the British market



Source : Pöyry

there are quite low prices, whilst in others there are much more extreme prices. With increasing commercial risk will come a reluctance to invest or a need for higher returns to compensate for the additional risks that are borne.

Investment – peaking or baseload?

The contrast between the Single Electricity Market (SEM) in Northern Ireland and the Republic of Ireland and Betta in Great Britain highlights how different markets deliver different outcomes.

In the SEM, the most economic new build for a high-renewables world is peaking plant – primarily OCGT. This is due to the capacity payment mechanism that exists in the Irish market. Since all plant is paid for its available capacity as well as the energy it generates, it means that cheap, low load factor projects are much more commercially viable. In many ways these peakers are ideally suited to a world of significant wind generation, as they are highly flexible and designed to operate at low load factors.

In contrast, Betta largely only pays plant when it is operating. As a result, the most attractive conventional new build remains CCGT. However, as load factors are squeezed, prices become spiky and investments highly risky. Building expensive baseload plant to run at low load factors in response to variable wind generation is not necessarily an ideal outcome.

The differences between the market designs are emphasised by the generation queue in both countries. In GB, there is around 50GW of thermal plant awaiting connection by 2023, of which 30GW is CCGT with no open cycle gas turbines (OCGTs) at all. In the SEM, the figure is around 6.4GW, of which 2GW is peaking plant.

It should be noted that a capacity payment mechanism is not necessarily the right answer for the GB market – capacity payments often bring as many difficulties as benefits, and are politically difficult to maintain: there is an understandable feeling that consumers are overpaying companies to provide plant that is already fully depreciated. However, the difference between an energy-only market and one that also remunerates capacity provision is stark.

Double capacity conundrum

The study highlighted the important effect of forthcoming emissions regulation, and how this may interact with a new build programme of subsidised renewable generation.

The LCPD (Large Combustion Plant Directive) and the IED (Industrial Emissions Directive) appear likely to have very similar effects, each closing down around 10GW of older plant that does not meet emissions standards by the end of 2015 and a similar amount in 2023.

Although these closures create a significant requirement for new thermal plant build, the forthcoming wave of subsidised renewable generation means that the investment case for new thermal plant becomes increasingly difficult. For example, any generation built before 2016, conceivably to cover closure of existing coal fired power stations under emissions regulations, would only operate in a ‘stable’ market price regime for a small number of years. The revenues will be volatile and uncertain as load factors swing from one year to the next.

The same effect may recur a few years later with the IED. Again, large amounts of plant are required to close, but replacing these with conventional plant is difficult if you believe that further renewables growth is likely. Again the operating ‘space’ that these plant need will be eroded by further renewable new build.

Conclusion

The future vision outlined by the government in the Renewable Energy Strategy is one which will revolutionise electricity generation in striving to decarbonise the sector fully. The capacity mix will be transformed, with an influx of baseload, intermittent, unpredictable and subsidised generation.

The Betta market design seems to cope less well with these impending changes than might be hoped, with several issues that will need to be resolved. There are a number of potential solutions, including capacity payments, capacity obligations, payments for provision of flexibility and even perhaps power to a central body to mandate and direct investments.

It is not clear which of these measures, if any, might be adopted, but it appears increasingly likely that Betta will require changes, and possibly even a rethink, if the market is going to deliver the government’s goals.

** James Cox is a principal consultant at Pöyry Energy Consulting.*