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Agenda

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Towards better electricity trading and transmission arrangements

The UK is facing the significant challenge of integrating into its electricity market up to 30% of electricity from intermittent wind generation, much of it located far from demand centres. Richard Green, Oxera Associate and Professor of Energy Economics at the University of Birmingham, argues that the current trading arrangements are not fit for purpose in terms of providing efficient outcomes in such a market environment. The market design implemented in the north-eastern United States is likely to be more suitable

In Great Britain, electricity trading takes place within the framework of the British Electricity Trading and Transmission Arrangements (BETTA). The principle underlying BETTA is that electricity is traded like any other commodity, although the system does have special features to deal with its unique physical characteristics.

Under BETTA, most electricity in Great Britain is traded well in advance of real-time, with prices being agreed through bilateral trades between generators and retailers. Additional arrangements have been put into place to manage the non-storability of electricity and the need to ensure that generation matches demand on a second-by-second basis. Generation and demand levels may be out of balance when the physical volumes of electricity generated or demanded differ from the volumes contracted for in advance. Imbalances also arise due to constraints on the electricity transmission system, which mean that electricity cannot be transported from regions with excess generation to those with excess demand. The system operator, National Grid, is tasked with resolving these short-term imbalances between contracted and physical positions by buying and selling electricity.

The market has operated smoothly under BETTA for over eight years, with only one significant failure of generation to meet demand. However, the electricity market is now undergoing considerable changes as a result of the significant renewable energy targets faced by the UK. In order to meet these targets, it is likely that 30% of electricity consumed in the UK will have to come from renewable sources by 2020. Most of this renewable electricity is likely to come from wind energy, which is characterised by its variability given its dependence on changing wind speeds.

Substantial wind generation creates a number of challenges for electricity markets. First, the variability of wind output creates a requirement to ensure that output from conventional generators (eg, coal and gas) can change quickly in response to sudden changes in wind availability. Second, wind variability implies that very little wind capacity can be relied upon to meet peak demand. Conventional generators will need to be remunerated sufficiently to be available to operate for the few hours in the year when electricity demand is high and wind speed is low. Finally, with most new wind generation in Great Britain expected to be located in the north, and demand located further south, the likelihood of transmission constraints and associated constraint costs is expected to increase.[1]

This article asks whether BETTA is suited to meet these challenges. It finds that BETTA is unlikely to result in efficient outcomes—BETTA relies on high prices during periods of high demand to ensure that generators are remunerated sufficiently, but prices do not rise high enough to ensure that generators needed to run for short periods of time to meet peak demand are viable. Furthermore, under BETTA, generators receive the same electricity price irrespective of their location and are consequently not incentivised to reduce their impact on transmission costs.

The market design used in parts of the USA, incorporating explicit capacity markets and locational marginal pricing, is likely to provide more efficient signals for investment and generators' operations.

This article is based on Green, R. (2010), 'Are the British Electricity Trading and Transmission Arrangements Future-proof?', forthcoming in *Utilities Policy*.

Assessment of trading arrangements

To assess the suitability of BETTA and alternative trading arrangements, their ability to meet the following objectives is considered:

- ensuring efficient operation by generators connected to the system, such that generation is carried out by lowest-cost generators. At the same time, transmission constraints need to be respected, and adequate reserve generation capacity made available to deal with unexpected changes in demand (arising, for instance, due to changes in wind speed or failures in conventional generators);
- allowing generators to connect to the transmission network in a timely fashion, provided that the system can safely cope with additional generation capacity;
- giving generators the incentives to build new generators (or keep old ones open) if capacity is needed, and to close them if it is not.

Impact of renewables

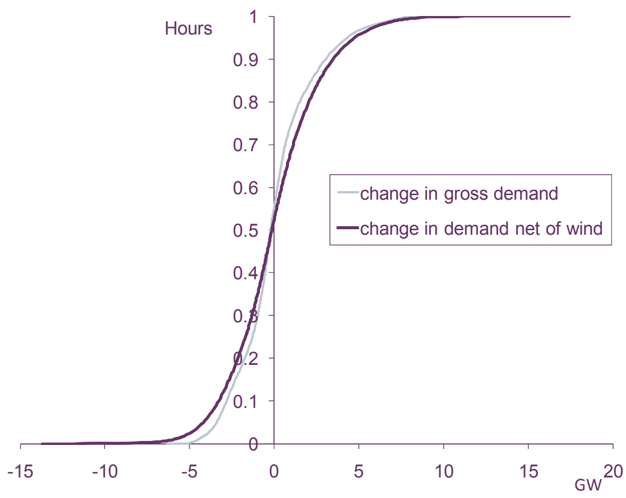
Penetration of up to 30GW of wind generation by 2020 (as compared with 5GW today) is likely to have significant implications for the electricity wholesale market. First, fluctuations in wind output imply that conventional and nuclear generators will face greater hour-to-hour changes in the demand that they will have to meet as wind generation increases (Figure 1).[2] The illustrative figures suggest that the greatest hourly changes in demand net of wind output (ie, demand to be met by conventional and nuclear generators) rise to –13.7GW and +17.4GW, compared with changes in gross demand of –6.3GW and +10.1GW.

Market rules will need to ensure that enough generators will change their outputs quickly to respond to these new demand patterns.

Second, variable wind generation also affects the number of hours that conventional and nuclear generators will be required to operate. Figure 2 shows the number of hours for which demand exceeds a given level, considering separately gross demand and demand net of wind output (ie, demand that will have to be met from conventional and nuclear generators). It highlights that although peak demand will remain almost unchanged due to wind output, the amount of capacity needed for only a few hours a year will increase. The key market design issue will be in ensuring that this capacity is remunerated sufficiently (or that greater demand-side response is incentivised).

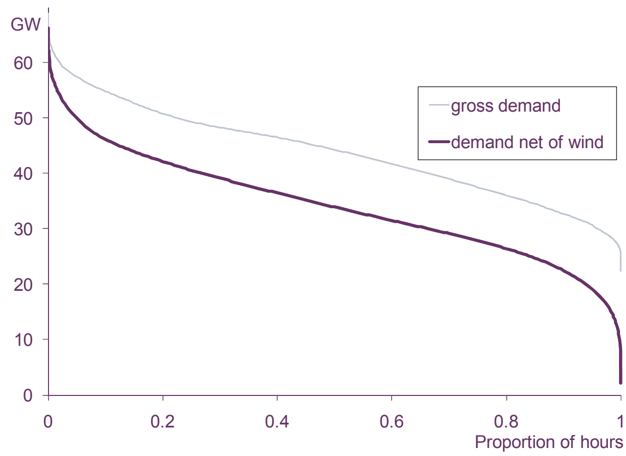
Third, given that renewables resources are not evenly distributed across the UK, the majority of new wind generators are likely to be built in the North Sea, a long way from centres of electricity demand in the Midlands and the south.

Figure 1 Simulated hour-to-hour changes in electricity demand in Great Britain in 2020



Note: The starting point of the demand and load–duration curves presented in this figure and Figure 2 are 13 years of hourly electricity demand data between 1993 and 2005, obtained from National Grid. Each year is scaled up to a predicted level for 2020, assuming future annual demand growth of 1.1%, and basing the scaling on annual weather-adjusted energy consumption. The simulated hourly wind outputs are based on wind speed data from the British Atmospheric Data Centre. Individual weather stations are used to represent 19 onshore and 11 offshore regions, with generation capacities assigned to them in proportion to the amount being planned (or built, or existing) in the British Wind Energy Association Database. The regional wind generation output is based on a standard wind turbine output curve. The simulated demand and load–duration curves for 'gross demand' are calculated by summing the scaled-up demand data for the 13 years. The 'demand net of wind' curve is obtained by subtracting the simulated wind output for each hour from the simulated demand in that hour.
Source: Green (2010).

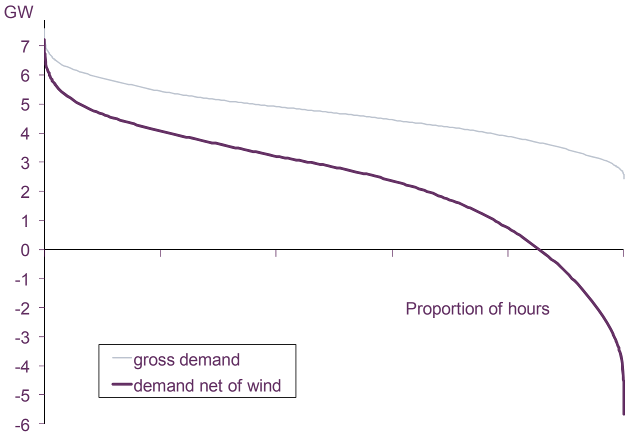
Figure 2 Simulated load–duration curve for Great Britain in 2020



Source: Green (2010).

Figure 3 below highlights that wind generation is likely to exceed demand in Scotland for a number of hours in a year, resulting in an increase in transmission constraints.[3] The system operator will have to manage this transmission congestion by constraining the output of some Scottish wind generators and buying extra power from generators further south.

Figure 3 Simulated load–duration curve for Scotland in 2020



Note: Based on four years of data from April 2001 as this is the earliest date for which National Grid publishes detailed data on Scottish demand.
Source: Green (2010).

Efficient operating decisions

How does BETTA perform in incentivising generators to operate efficiently? Efficient operation requires that the costs of generation are minimised, which involves ensuring both that the lowest-marginal-cost generators produce electricity and that the marginal costs of transmission are minimised. The latter include the costs of electrical losses during transmission and the opportunity costs of transmission constraints. The market that BETTA operates in works as follows.

- Generators commit much of their generating capacity through bilateral trades well in advance of real-time, facing a significant degree of uncertainty over outturn levels of electricity demand and generation input costs. This would not be a concern if higher-cost generators were able to find a lower-cost generator to replace them in short-term markets. Given the low liquidity of GB short-term markets, such cost-minimising trades are unlikely.

- Generators face high penalties (imbalance prices) for being out of balance. This incentivises them to produce at less than full capacity as protection against the risk of generator failure and consequent imbalance penalties, tending to increase production costs.

- Under BETTA, there are inefficiencies in the management of transmission costs by National Grid. Under the existing market arrangements, National Grid avoids arbitraging between high- and low-cost generators when managing constraints, and does not take account of the costs of transmission losses when determining which generators should generate. This tends to raise the overall system costs. Such costs are expected to rise further in future with increasing transmission constraints on the interconnector from Scotland to England as the level of renewable generation in Scotland increases.

While it would not be cost-effective to build so much transmission capacity that all constraints are eliminated, the target should be to use existing capacity as efficiently as possible. This may be achieved if generators are exposed to the costs they impose on the transmission system. This would require the introduction of a system of locational marginal prices, whereby the price of electricity and transmission constraint costs are calculated for every point on the system, instead of the current approach of a uniform price of electricity throughout Great Britain. With constraints on the transmission system, the locational marginal prices in exporting areas (where generation is greater than demand) will fall, and those in importing areas will rise. This will provide generators with the correct incentives to increase or reduce output during periods of transmission constraints, helping the system operator to manage those constraints.

Such a system of locational marginal prices (or nodal prices) has been operating in three markets in the north-eastern United States (New England, New York, and Pennsylvania Jersey Maryland, PJM) for over ten years (see box below), and could provide a model for pricing in Great Britain.

Efficient connection decisions

Under the recently introduced ‘connect and manage’ regime for connecting generators to the transmission system in Great Britain,[4] generators will be allowed to connect as soon as any local work required on the network has been completed, even if this worsens

Locational marginal pricing in the north-eastern United States

The system operators in New England, New York and PJM operate voluntary markets in which generators’ offers are used to calculate the marginal cost of electricity at each point (or node) in the network. The day-ahead market accepts bids to buy power and offers to generate and provide reserve capacity for the following day. The system operator calculates an operating schedule that maximises net benefits from trading (ie, the value of accepted bids less the value of accepted offers), while respecting transmission constraints. A real-time market allows for adjustments to the committed volumes at new prices calculated from revised bids and offers from companies able to adjust their positions in the short term.

Although much of the electricity is traded bilaterally in advance and markets are voluntary, there is sufficient liquidity for the markets to be attractive to generators. This ensures the minimisation of generation costs.

transmission constraints elsewhere. The objectives of this regime include ensuring that enough generators connect to the system to enable the achievement of renewables targets. However, this increase in renewables would also raise transmission constraint costs.

How would a regime enabling efficient connection decisions be characterised? Generators would make efficient connection decisions when they face the economic consequences of their location decisions, with net generation revenues being lower in transmission-constrained areas. This would arise because of higher transmission prices or lower electricity prices in such areas.

A system based on locational marginal pricing could give generators the correct incentives for their location decisions, with lower revenues being received for connecting in regions with frequent transmission constraints.

Locational pricing can pose potential risks to renewables generation because renewable resources are located far from demand centres and are likely to face higher costs with the pricing of transmission with locational marginal pricing. However, these risks can be mitigated as follows.

- Locational pricing can increase the level of financial support needed by renewable generators located in high transmission-cost areas. This would either reduce renewable investment or raise the cost of the renewables support scheme. The impact on support costs could be minimised with more targeted support schemes—for example, through tenders for specific contracts, as occurred in the 1990s. This would allow the amount of support to equal the amount actually needed to make specific projects viable. It would also reduce the rents received by generators in favourable locations and make it possible to target transmission costs on those generators that cause them without impeding the achievement of renewables targets.

- With locational pricing, generators already located in export-constrained areas will see their net revenues fall as generation capacity is added and constraints more frequently become binding. Long-term financial transmission rights may be issued to existing generators to allow them to lock in the prices they expected to receive before new entry took place.

Efficient capacity decisions

How does BETTA incentivise generators to make sufficient capacity available to meet peak demand?

This question is of particular concern because increasing wind generation will imply that some plant will need to operate for only a few hours a year (ie, in periods of high demand and low wind). Under BETTA, generators are remunerated for selling electricity. Alternative market arrangements exist where generators are explicitly remunerated for making capacity available, even when they are not generating electricity.

In theory, a market like BETTA may provide the right incentives for making generation capacity available, in particular if prices rise well above the variable costs of the most expensive generators at certain times, allowing generators to recover their fixed costs. Such high prices may be expected to arise when demand for output from conventional generators is high. However, with most trades taking place well in advance, generators will not be able to predict exactly when low wind and high demand create high demand for them. Consequently, they may not be able to adjust their price offers to maximise their revenues.

Ofgem's Project Discovery highlights that under the current market arrangements there are significant risks to security of supply in the period leading to 2020.[5] It has identified a range of reform options to enable investment to replace retiring power generators and to raise the level of renewables investment. These include an option to have long-term tenders for low-carbon generation and short-term tenders for conventional capacity, as is the case in certain US power markets (see box below).

In addition to its proposals for market-based solutions of tendering and capacity mechanisms, Ofgem has proposed more radical reform measures such as the possibility of setting up a central energy buyer that would determine the type and quantity of capacity to be built. Given the success of market-based solutions in the USA, it would be premature to consider such a sweeping departure from the market-based policies of the past 20 years.

Annual capacity markets: the US experience

In some US power markets, retailers buy capacity to cover their customers' demand, in annual auctions held three or four years in advance. These aim to ensure that generators have sufficient incentives to keep capacity available to meet expected demand and reserve requirements. The long-term time interval and potential for security of returns allow both incumbent and new entrant generators to bid to provide capacity.

In return for payments from the capacity market, generators provide a hedge on energy prices, ensuring that they do not gain from both capacity and energy markets, giving them a strong incentive to be available to generate when they are most needed.

Conclusions

The integration of a high proportion of intermittent renewable generation in the electricity market poses significant challenges for trading arrangements. Existing trading arrangements are inefficient in resolving transmission constraints, ensuring efficient location of new generation, and that sufficient capacity is made available to meet short-lived demand peaks.

A better approach might be to learn from US markets where trading arrangements address the problems facing the UK. A system of locational marginal pricing, whereby the price of electricity varies across the country, would provide incentives to reduce generation and investment in transmission-constrained areas. In addition, capacity markets might be introduced to increase incentives for the investment in generation needed to meet peak demand.

Richard Green

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[1] Transmission constraints arise when the amount of electricity flowing through the line is at the limit allowed by safety. In the presence of transmission constraints, a cheap but distant generator may have to be replaced with a more expensive but local generator to meet local demand. The opportunity cost of a transmission constraint may therefore be estimated as the cost of generation under a constrained system *less* the costs under an unconstrained system.
[2] The analysis of the impact of renewables draws on Green, R.J. and Vasilakos, N. (2009), ‘Market Behaviour with Large Amounts of Intermittent Generation’, *Energy Policy*, **38**:7, pp. 3211–20.
[3] The simulation results highlight that for around 1,250 hours a year, wind generation is likely to exceed demand in Scotland. This implies that some power will have to be exported across the interconnector with England. However, with the capacity of the interconnector due to rise to 3GW by 2020, and the existence of 2GW of nuclear capacity in Scotland in 2020, exports of power are likely to be constrained whenever wind output is greater than 1GW. In addition, constraints will be tightened further if some conventional generators need to be kept running to allow fast, local responses to changes on the system.
[4] Department of Energy and Climate Change (2010), ‘Government Response to the Technical Consultation on the Model for Improving Grid Access’, July 27th.
[5] Ofgem (2010), ‘Project Discovery: Options for Delivering Secure and Sustainable Energy Supplies’, February 3rd.