Lost in translation

COST REFLECTIVITY AND TRANSMISSION LOSSES IN BRITAIN'S ELECTRICITY MARKET

The history of how electricity generators and customers are charged for transmission losses in the British market has been long and painful. It may not be over yet. A new approach was implemented in April 2018, but it is not without its drawbacks, as this briefing explains.

While average losses in the electricity transmission system are typically low, they can increase materially when power plants generate a long way from load centres. In contrast, adding generating capacity near to load centres can cut losses by reducing the distance over which electricity is transported. While much depends on the context, there is an economic logic to assigning generation and load charges for losses which reflect such differences: knowing the potential costs will help private operators decide which sites to close and where to invest in the future. In doing so, they will tend to minimise the overall costs of the power system.

At privatisation of Britain's wholesale electricity industry in 1990, the competitive market that was established charged losses without regard to location. The shortcomings of this approach were recognised at the time, and so locational charging for losses was included in a post-privatisation "to do" list (the so-called Schedule 12 items).

Between 1990 and 2016, at least four attempts to introduce locational charging for transmission losses all failed - not least because it creates winners and losers, and hence resistance in some quarters. In 2016, as part of the conclusions of its inquiry into the sector, the Competition and Markets Authority (CMA) decided that losses should be charged locationally. Modification P350 to the Balancing and Settlement Code, which implemented this decision, took effect in April 2018.

This could have been the end of the story. But the approach taken, which is based on a methodology first developed in 2011, means that some plants do not face a cost-reflective signal. As a result, new investments may still not minimise overall system costs.

Lost in the details?

At the highest level, the approach now taken to charging for losses in Britain is quite simple: each transmission-connected generator and load has a loss factor which varies by location. This factor is set by modelling the additional losses which result from incremental generation in each location. This factor is then applied to metered production or consumption.

So, in broad terms, when an increase in generation leads to greater losses, generators are credited with less output than they actually produce; when it reduces losses, they are credited with more output. The same approach applies to load: customers are attributed a larger or smaller volume of power than they actually consume, depending on whether the incremental load increases losses or reduces them.

This means that in a power zone where generation increases losses, a generator may be credited with only 99 MWh even though they may produce 100 MWh. Conversely, in a part of the country where generation reduces losses, they may be credited with 101 MWh. In the former case, a generator loses out because they have less volume available to sell (post application of the loss factor). Similarly, a customer has to buy more power than they consume.

If you believe losses should be charged according to location, you may struggle to see the problem: indeed, for a conventional generator (or demand-side response provider), the approach makes sense.

Take the perspective of the operator of a conventional plant in a zone where incremental generation increases losses. They are credited with, say, 99 MWh for every 100 MWh they generate. On 100 MWh of actual generation, they face a "charge" of 1 MWh multiplied by their average achieved sale price during the period in question.

For conventional generators, this achieved sale price will be broadly similar to the value of electricity in that period. And since this value represents the market's view of the opportunity cost of lost energy, the system overall ensures that conventional generators face a sensible locational signal. The reverse applies if they are in a zone where incremental generation reduces losses. They effectively receive a credit based on their average achieved sale price.

However, more and more generation is subsidised on a per MWh basis. Whether it is from the sale of Renewable Obligation Certificates (ROCs), via a Contract for Difference (CfD), or maybe in the future via a Regulated Asset Base (RAB) model for nuclear plant, low carbon and renewables generators typically receive a price per MWh which reflects the value of electricity *plus* a subsidy element required to ensure that investors are willing to build more expensive plant in the first place.

However, when this higher average sale price is combined with the loss factors, it results in a price signal for losses which is arguably too strong. Put another way, a plant is overcharged for being in a location where generation increases losses and is overcompensated for being in a place where it reduces them.

Coming back to the example above, suppose the marginal value of electricity on the system for a particular period is £50/MWh. A conventional plant that produces 100 MWh and is credited with only 99 MWh will face an effective charge for losses of £0.50/MWh if its sale price is equal to the marginal value of electricity. In contrast, a renewables plant in the same location which sells power at £75/MWh because of a £25/MWh subsidy will face an effective losses charge of £0.75/MWh.

But the opportunity cost to society of the incremental losses is identical in these two examples. It does not matter if the losses are incurred by production from a remote thermal plant or a remote renewables plant. So the locational losses for a renewables plant are not cost-reflective.

Lost track?

In its recent decisions and consultations on network charges, Ofgem has assessed the implications of charges which are not cost-reflective in terms of *system costs.* Broadly speaking, these relate to the costs to the country overall of meeting demand. If lack of cost-reflectivity results in increased system costs, it means that as a society we are using more resources than necessary to satisfy demand.

This framework can be used to analyse the impact of locational signals from losses which are too strong. But the results of the analysis in the case of a new generator are different from those for an existing plant.

It is possible for a new renewables generator to include in its bid for a CfD subsidy the losses "charge" they will face. This means that bids from projects where loss factors are high and positive will be higher than they should be; conversely, if loss factors are high and negative bids will be lower than they should be.

This could increase system costs because if the effect is significant enough, relative to a situation in which all plants face the "right" losses charge, the "wrong" plants may clear in the auction. Put differently, because losses may make some projects look artificially cheap or expensive in the auction, as a society we may not buy the cheapest renewables plant. In technologically neutral auctions, this effect could even be powerful enough to lead to the "wrong" technology being chosen.

The scale of the effect depends on the loss factors themselves and the extent of subsidy. To give an indication, imagine a developer considering two sites for a potential plant, one of which faces the lowest loss factor on the system and the other the highest. For a conventional plant, assuming a wholesale price of £50/MWh, the worse site (from a losses perspective) would be around £1.60/MWh more expensive. For a renewables plant securing a CfD at £75/MWh, the disadvantage would be £2.43/MWh (both based on the latest data from Elexon and taking a simple average over seasons). In other words, the signal to the renewables developer would be around £0.80/MWh too high.

If the generator already has a CfD or is under the ROC scheme, then the plant may be unable to pass the higher locational charges on to end-customers. This is clearly a serious commercial issue: an excessive valuation of losses represents an unforeseen departure from the basis on which the original investments were made. It may also increase system costs if it accelerates the closure of existing renewables plants that are coming to the end of their lives but continue to earn a preferential price.

Lost for words?

Subsidies for renewables are falling as the cost of plant comes down. So time will ultimately reduce the distortions resulting from the problem of excessive loss valuations. That said, the scale of the distortions is not trivial and the problem is relatively easy to rectify. A simple solution would be to put a price on the losses and then charge (or pay) participants accordingly per MWh rather than making adjustments to volumes.

Charging for electricity transmission losses in Britain according to location has been a long-held ambition of many stakeholders. That ambition has finally been achieved, but in the process the devil appears to have crept into the detail. It should not be that hard to exorcise it.

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