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EU electricity markets: one of a kind?

The EU and its Member States are committed to decarbonisation, security of energy supply, and affordability. A step change in policies appears necessary in order to encourage the investments required to meet these objectives. The economic factors associated with creating a stable investment environment include encouraging efficient price formation, investment incentives, and mitigating adverse impacts of unintended consequences of electricity sector reforms

The electricity sector forms a key pillar of European policies aimed at climate change mitigation, both because it already represents a significant share of overall emissions, and because its share of future emissions might increase with electrification in other sectors, such as transport. There is a consensus that achieving a material reduction in carbon emissions requires a step change in mitigation efforts by the public and private sectors.

Without reform, there is a concern that electricity markets might fail to deliver a sufficient quantity of the 'right' investments. In particular:

- the decarbonisation objective may be threatened, since electricity markets and wider energy policies may not provide sufficient incentives to reduce carbon emissions;
- the security of supply objective is potentially threatened by a lack of investment in generation capacity to meet demand, particularly as greater penetration of intermittent generation (eg, wind) influences the economics of other, more flexible, generation technologies.[1]

Moreover, disruptions in electricity provision, by depriving consumers and users of electricity, can cause significant economic loss of welfare. Lack of investment in generation capacity (as well as network infrastructure) could raise the likelihood of disruptions to a socially unacceptable level.

Before considering the challenges facing electricity sector reform, it is worth looking at the economic features of electricity markets, as listed in the box overleaf.

Taken together, these features make electricity markets unusual, since the commodity is highly fungible, while it can also be difficult to substitute production or consumption over time. This implies that the returns on large, capital-intensive assets with economic lives typically of greater than, say, 25 years rely on market prices that potentially fluctuate significantly every hour. In turn, this makes investments in electricity generation highly dependent on price-formation processes, and economically inefficient prices—whether resulting from market or regulatory failures—would be expected to significantly disrupt the formation of fixed capital.

Carbon pricing and low-carbon investment

Central to the correction of the carbon externality associated with conventional electricity generation is the imposition of a cost-reflective carbon price. Common carbon pricing was imposed on certain European industries with the launch of the EU emissions trading system (EU ETS) in 2005. Introduced as a cap-and-trade scheme covering energy-intensive sectors including power generation, EU ETS carbon allowance prices are currently valued at around €7/tCO_2,[2] significantly below estimates of the lower benchmark for the social cost of carbon of over €40/tCO_2.[3]

While the low level of prices observed in the EU ETS reflects market perceptions that overall emissions will be below the cap, many, including the European Commission, believe that the scheme needs to be modified to provide sufficient low-carbon investment incentives.

Key economic features of electricity markets

The demand side

- ***Inelastic demand*—demand for electricity is typically not highly responsive to electricity prices, and the demand-side response to price changes over the short term is even less so. For example, large numbers of households are generally unaware of their demand or consumption patterns (although smart metering will make consumer demand more flexible in future) and industrial users may also have only limited opportunities to shift their demand in response to real-time prices.**
- ***Demand volatility*—demand for electricity, driven by factors such as macroeconomic conditions, climate, intraday consumption patterns and seasonal variations, varies substantially over time, potentially resulting in periods of very high peak demand.**
- ***Non-excludability*—given that suppliers are generally unable to disconnect users individually (especially households), the benefits of high system reliability are effectively shared by the majority of customers. This potentially undermines the incentive for individual customers to signal their willingness to pay for increased security of supply.**

The supply side

- ***Generation costs and risks*—costs and risks vary greatly across generation technologies. This is driven by differences in capital and operating costs, and differences in technical and market risk.**
- ***Sunk costs*—investments in generation capacity are usually irreversible and specific, increasing the risk of investors being left out of pocket if contracts are renegotiated or regulations changed after investments have been made.**
- ***Limited storability*—technological and economic limits to utility-scale electricity storage present significant challenges for market participants in matching demand and supply at specific points in time.**
- ***Intermittent output*—some technologies, such as wind generation, are inherently variable, potentially passing on the burden of meeting demand to other flexible generators whose output is controllable.**
- ***Carbon emissions*—as a byproduct of electricity generation technologies that rely on burning fossil fuels, carbon emissions can constitute an externality if their climate change impact is not reflected in prices.**

The current level of low prices (which encourages the use of relatively carbon-intensive generation) is reflective of the level of the cap relative to:

- the unforeseen decrease in economic growth (and emissions) as a result of the financial crisis;
- the development of significant renewables investment, incentivised by national support schemes, often independent of the carbon price;
- the prospect of national policies aimed at reducing overall levels of demand through improved energy efficiency.

The range of large-scale renewable incentive schemes across Europe reflects the desire to stimulate deployment in renewable technologies in order to meet the relatively near-term 2020 output targets embodied in the 2009 Renewables Directive.[4] However, while these targets and associated incentive schemes had previously formed the basis of confidence and the perception of relatively low risk in the sector, a number of countries (faced with increasing budget deficits as a result of the financial crisis, and concern over the impacts of renewable subsidies on customer bills and industry competitiveness) have reacted by:

- removing or reducing the level of subsidies on offer (as has happened in Spain);[5] and/or
- placing limits on the cumulative deployment of particular technologies (such as solar photovoltaics (PV) in Germany).[6]

Such reactions may still enable the 2020 renewables targets to be met (in which the target renewable output is expressed as a percentage of national energy consumption—which may remain depressed), but could increase perceptions of regulatory risk in the sector, and weaken investment and development in the supply chain. The reaction to this has been to consider further targets, as embodied in the Commission's consultation on the 2030 renewables targets.[7]

Fundamentally, the absence of an international climate change agreement serves to increase the uncertainty regarding carbon pricing within the EU, since the existence and nature of the EU ETS beyond 2020 is unclear. 'Carbon leakage'—the relocation of carbon-intensive industry to countries without carbon pricing—could reduce emissions in the EU, and hence the demand for European carbon allowances, although clearly it would not lower overall global emissions.

Renewable subsidy reforms

A common feature of the large-scale renewable support schemes adopted across EU Member States is to provide output-based support, given the focus of the 2020 renewables targets on energy consumption (as opposed to capacity). Despite the low marginal cost of many renewable technologies such as wind and solar, additional subsidies are required to make such projects viable, given the current and forecast levels of carbon, fossil fuel, and, ultimately, electricity prices.

Such output-based subsidies represent 'operating aid' within a state aid assessment—for which the Commission's state aid guidelines allow exception to the more widely applied principle that the duration of operating aid should be limited, and that aid itself should be targeted at the relevant market failure (in this case, insufficient carbon pricing or support for research and development).

Two basic models of output-based support have been adopted across Member States:

- **premium support payments**—renewable generators sell the electricity they generate into the energy market, as with other technologies, in addition to receiving a separate support revenue stream (which can be fixed in value or from the sale of renewables certificates). Renewable generators are exposed to electricity price risk and contracting incentives within such schemes;

- **full support payments**—renewable generators typically receive a predetermined support payment (or feed-in-tariff) for each unit of output, and are not exposed to power price risk; alternatively, they contract to sell their output (which is then delivered directly into the transmission grid). Renewable generators that are insulated from electricity prices are also insulated from any effect of carbon pricing.

The different nature of these support scheme designs has significant implications for both market operation and investment:

- full-support payments insulate the renewable generator from electricity price signals that provide important information about market conditions. Incentives to undertake maintenance during low-price off-peak periods are therefore reduced; and, in the case of wind generation, incentives are also reduced to develop more advanced wind forecasting techniques to allow more efficient contracting; and

- financing costs are typically lower under full-support payments, as these insulate the generators from electricity price risk, thereby reducing cash-flow volatility.

The proposed UK reforms[8] attempt to create contracting incentives and reduce financing costs by issuing support contracts structured as contracts for differences (CfDs) around the electricity price. The intention is therefore to introduce a variable premium payment that reduces cash-flow volatility while still imposing incentives on generators to contract to sell their electricity efficiently.

Furthermore, since the introduction of such schemes, there has been a question about the relative volumes of investment in each technology to which support is provided. Governments have been keen not to be seen to 'pick winners'—indeed, recent proposals in the UK set out a vision where different low-carbon technologies could compete in technology-neutral auctions for support contracts.

However, more recent concerns about the rapid uptake of certain technologies (such as solar in Germany), and the consequences for total subsidy levels and consumer costs, have led to the imposition of technology quotas or limits. (German law places a 52GW limit on deployment of solar PV, with a target annual growth corridor.)[9] Some have also started to question the impact that significant volumes of intermittent wind deployment could have on system operation, and whether similar limits should also be applied.

System reliability, and investment in 'flexibility'

The rapid introduction of significant volumes of low-marginal-cost renewables, and particularly intermittent, generation, has reduced the outlook for generation output of conventional thermal generation (ie, coal and gas plant)—generation technologies that are 'despatchable', and therefore useful for filling shortfalls in supply during periods when intermittent generation is not available.

This potential stranding of existing conventional technologies, and uncertainty over the future operating conditions of new conventional technologies, has raised the question of whether the associated flexibility and security of supply will be sufficiently reflected in market prices, or whether new mechanisms are needed. Capacity mechanisms, whereby eligible generating plant would receive payments for availability rather than output, can reduce the risk of such plant being dependent on infrequent and volatile prices achieved during periods of scarcity.

Two risks surround whether energy-only markets without a capacity mechanism will deliver sufficient investment incentives:

- the risk that system operators, regulators or governments may intervene in ways that depress scarcity prices in order to protect consumers;
- the risk of under-provision of flexible capacity by companies in the private sector, given the inability to exclude customers who are unwilling to pay for security (but who are able to free-ride on its provision).

In addition, these incentives are affected by the potential development of other sources of flexibility (storage, greater demand-side response, increased interconnection and cross-border network capacity).

Given the current process of Member State-led development of capacity mechanisms, alongside the prospect of increased interconnection between countries, there is further risk of uncoordinated market design, and the effects of potential free-riders across neighbouring countries.[10]

Capacity mechanisms

The focus on investment incentives has led many countries to consider redesigning electricity markets to move away from an 'energy-only' design in which generators receive one revenue stream based on output (and through which fixed and capital costs are recovered through prices in peak periods), to one in which generators are remunerated separately for the electricity they generate and the availability of capacity.

Given the high levels of capacity relative to demand across European power markets, there is some debate over the need and timing of the introduction of capacity mechanisms—although, in part, this relative surplus of capacity reflects a mix of capacity developed in earlier periods when different market arrangements may have been in place, as well as recent unexpected reductions in demand following the financial crisis.

Proponents of capacity markets argue that, without such markets, there may be underinvestment. This could be because system operators or regulators may take actions that limit prices reaching appropriately high scarcity levels, and that could distort investment signals. Furthermore, if system security can be regarded as something close to a public good (as suggested by the non-excludability feature of electricity markets discussed above), it is possible that private companies will contract for a sub-optimal amount of capacity relative to what a central planning agency would otherwise do.

If capacity markets are to be introduced in an increasing number of electricity markets across Europe, two high-level design considerations deserve attention.

First, some commentators have suggested that the design of capacity payments could be combined with support for low-carbon generators as a single instrument.[11] This raises the question of whether separate instruments are needed to encourage investment in different technologies that deliver a combination of security of supply, learning effects, and carbon abatement, or whether the payments within a common support structure could be differentiated to reflect those characteristics.

Second, there are potential distortive effects if capacity mechanisms are introduced in some countries but not others. If one country is designed as an energy-only market and has high peak prices compared with a neighbouring country with a capacity mechanism, energy flows (and hence security of supply) will effectively be imported from the country with the capacity mechanism, but the consumers in the energy-only country receiving that security will potentially not be charged for it.

Further work from the Commission is expected to focus on such harmonisation issues.[12]

Conclusion

The ambition for a rapid turnover of the existing capital stock in electricity generation to meet decarbonisation objectives has brought into focus the challenge of ensuring that system-wide security is maintained, and that such a large investment programme is delivered at least cost, or at least that it is affordable. Assuming that meeting these challenges is best done through the development of a single European market, this will continue to place greater limits on the development of idiosyncratic national policies and market frameworks.

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[1] Causes of outages include technological problems, bottlenecks in transmission capacity, and generation inadequacy. This article discusses only the latter, which is considered the main threat to security of supply.
[2] As reported by Point Carbon on November 16th 2012. Point Carbon is an organisation that provides news, analysis and consulting services for energy markets.
[3] Stockholm Environment Institute, Oxford (2005), 'Social Cost of Carbon: A Closer Look at Uncertainty', November, p. 33.
[4] European Commission (2009), 'Directive on the Promotion of the Use of Energy from Renewable Sources and Amending and Subsequently Repealing Directives 2001/77/EC and 2003/30/EC', April.
[5] Bloomberg (2012), 'Spain Halts Renewable Subsidies to Curb $31 billion of Debts', January 27th, available at www.bloomberg.com.
[6] PV Magazine (2012), 'Germany: Bundestag Approves new PV Subsidy Program', June 28th, available at www.pv-magazine.com.
[7] European Commission (2012), 'Renewable Energy: a Major Player in the European Energy Market', June.
[8] Department of Energy & Climate Change (2011), 'Planning our Electric Future: a White Paper for Secure, Affordable and Low-Carbon Energy', White Paper, July 12th.
[9] Auer, J. (2012), 'The German Feed-in Tariff: Recent Policy Changes', Deutsche Bank Research Paper, September.
[10] See European Commission (2012), 'Consultation Paper on Generation Adequacy, Capacity Mechanisms and the Internal Market in Electricity', November 15th.
[11] Helm, D. (2012), 'EMR and the Energy Bill: A critique', July, p. 13, available at www.dieterhelm.co.uk.
[12] European Commission (2012), 'Consultation Paper on Generation Adequacy, Capacity Mechanisms and the Internal Market in Electricity', November 15th.

If you have any questions regarding the issues raised in this article, please contact the editor, Dr Leonardo Mautino: tel +44 (0) 1865 253 000 or email l_mautino@oxera.com

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