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The EU electricity target model: the devil is in the details?

Creating an EU internal energy market requires both 'software' and 'hardware' solutions—ie, rules to allow trade across borders, and financing models to increase the physical capacity of interconnections. The EU target model defines a number of market design elements for this purpose, raising the question of whether the design options chosen will necessarily improve market efficiency, or could risk hindering it. We look at two examples: the management and pricing of congestions, and investment in interconnectors

According to Ofgem, the energy regulator for Great Britain:

> The electricity market in Great Britain (GB) is changing, driven by major reforms internally and in Europe. The interactions between GB and EU reforms will shape the future GB market.[1]

The free flow of energy across Europe and the effective functioning of an internal energy market are central to the European Commission's aim of achieving secure, sustainable and affordable energy supplies. The market integration process started in 1990–91 and has involved three legislative 'packages'. Yet significant obstacles remain to achieving European integration by 2014, namely:[2]

- **harmonised market rules**—the absence of harmonised rules across Member States can reinforce market segmentation and energy flows from high- to low-priced areas;
- **transmission investment**—having insufficient levels of interconnection between countries risks a number of geographic regions remaining isolated, particularly the UK and Ireland, with €104 billion in transmission investment needed before 2020.[3]

Together with the Commission, networks of regulators and system operators are developing the policy framework and operational details of a more integrated set of market arrangements—known as the 'target model'. This model defines a number of market design elements to facilitate integration and cross-border trade, while leaving several other important market design elements to the discretion of Member States.

According to Ofgem, the direct and indirect impact of the target model on Great Britain is likely to be significant. As well as changes to existing arrangements to remove obstacles to cross-border trading, efficient implementation could require:

> [the] development of liquidity in the day-ahead market, leading to a robust and trusted reference price for Great Britain, and consideration of appropriate price zones to manage internal constraints most efficiently. These changes could have material implications for ongoing GB reforms, particularly the Department of Energy and Climate Change's (DECC) Electricity Market Reform (EMR), Ofgem's liquidity project, and the potential reform of cash-out arrangement.[4]

This article considers whether the chosen design options will necessarily improve market efficiency, or could risk hindering it, by looking at two crucial areas:

- how transport capacity at interconnection points is allocated and priced, especially when demand exceeds available capacity, so that market participants can access and compete in the European market;
- how physical interconnections between countries can be developed in order to support the internal market with the necessary infrastructure.

Price zones—potential adverse effects on the management of network congestions

When one or more transmission lines are at maximum capacity (ie, when demand for transport capacity exceeds available capacity), transmission system operators (TSO) are responsible for managing the use of the (scarce) transmission capacity such that transmission constraints are not breached.

Transmission congestion can be managed through two contrasting models, with different effects on electricity prices:

- **zonal pricing**: based on zones, defined as portions of the power grid comprising a group of nodes;
- **nodal pricing**: based on electrical nodes, defined as points in the transmission system.

While in nodal pricing the 'fundamental units' of analysis are electrical nodes, in zonal pricing they are larger geographical zones. As such, zonal pricing is based on a technically simplified representation of the electricity system. The essential economic implication of this 'technical' difference is that, with nodal pricing, there will be a unique price at each *node*; while with zonal pricing there will be a unique price in each *zone*. The fact that in zonal pricing all the nodes within a zone will be priced at the same level would lead to the limitations discussed below. As illustrated in Figure 1, the way in which transmission congestion is managed influences both the operating and the investment decisions (through price signals) of generators, and the extent to which system operators have to implement counter-trading and/or re-despatching measures.[5] This may have perverse effects on congestion costs; on whether congestions are managed in a non-discriminatory manner; and on generators' market power.

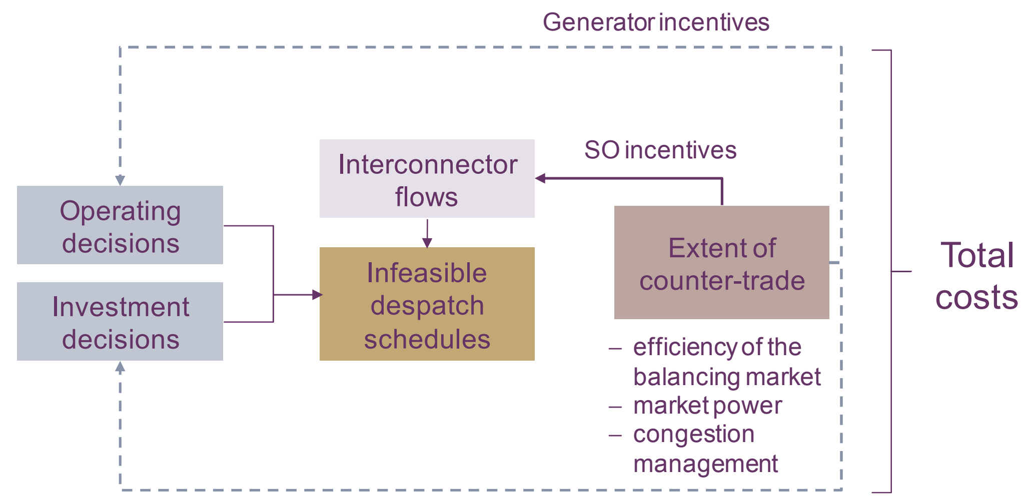
Possible risks associated with zonal pricing

The target model assumes the application of zonal pricing, which is largely considered to be theoretically inferior to nodal pricing, as explained below.[6] This is also supported by the successful experience with nodal pricing of PJM,[7] New England, California and New Zealand, where its feasibility and capacity to reduce or eliminate congestion costs has been demonstrated.

Why, then, did European energy regulators decide to adopt a theoretically and practically inferior solution? According to the regulators, it is 'important to consider the nodal approach as the ultimate goal and (technically and economically) optimal solution for capacity calculation within capacity allocation and congestion management, but at the same time to pursue the practical development and implementation based on the flow-based calculation [ie, zonal pricing]'.[8]

A nodal approach would require radical changes to the current market design, with a number of provisions needing to be additionally defined or redefined for TSOs, market participants and regulators. In addition, nodal pricing would normally imply multiple prices within one country, which could be politically difficult. This problem could, however, be resolved through regulatory measures such as those adopted in the Italian electricity market, where consumers are 'protected' from geographically different prices through a national average price, while distinct locational price signals are delivered to generators so that they can invest (and operate their plants) in the locations where it is most economically efficient.

Figure 1 How transmission congestion is managed, and possible risks



Source: Oxera.

The key implication of adopting a zonal approach is the need for national regulators to consider the appropriate definition of zones (or critical network elements), based on proposals from TSOs. Failure to achieve the optimal zonal definitions could:

- **increase the cost of relieving congestions**—in a zonal system, TSOs may need to alter the generation pattern (eg, by re-despatching) and/or to exchange energy across zones (eg, by counter-trading) in order to change physical flows in the transmission system and relieve a physical congestion.[9] In other words, the less the initial definition of zones reflects the economic reality of the local energy market, the more TSOs will have to implement corrective measures. Such measures are costly and affect consumers' tariffs. Moreover, the problem could be exacerbated by the increasing penetration of intermittent renewables because of the inherent uncertainties that this brings;

- **increase the risk of discrimination by system operators**—whereas, in a nodal pricing system, operators do not face any (or only minimal) congestion costs, in zonal pricing TSOs could have an incentive to move 'internal congestion to the border' to reduce national congestions, and the related costs. They could reduce the capacity auctioned to neighbouring customers in order to maximise the capacity for national customers—ie, satisfying the internal demand for transport capacity to the detriment of cross-border trades. To address the related concerns raised by the European Commission, in 2010 the Swedish TSO committed to split the national system into four bidding areas (ie, into four regional zones rather than a single national zone) to better reflect the 'network reality', thereby introducing different prices within the country.[10] Moving from pure zonal pricing to a more segmented zonal pricing, the Swedish system made a significant but incomplete step towards nodal pricing: reducing congestions and related costs and risks, delivering better price signals, and introducing distinct prices across four sub-national areas (but not across all the nodes that actually make up the system);

- **increase the potential scope for abuse of market power by generators**—as observed, the more inefficiently zones are defined (with respect to network topology and/or structural congestion), the more the TSO will be active in managing the resulting congestions. As a result, the potential for abusing a dominant position could extend from the main energy markets (day-ahead markets) to balancing markets. This is because balancing markets are where TSOs procure the 'corrections' needed from producers. Given that balancing markets typically have lower volumes and liquidity than day-ahead markets, this could increase the scope for potential abuse of market power by generators. For example, satisfying consumption at 'peak' hours will require most generators to produce as much electricity as they can. Some power plants (eg, nuclear and coal) cannot change their production pattern rapidly for technical reasons. This means that, during certain hours, TSOs will need to rely on a limited number of producers able to promptly increase or decrease their generation to keep the system in balance. When networks are congested, this number could be further reduced, thus potentially giving some producers a dominant position in specific zones (note that the same producers do not necessarily have the same position in energy—as opposed to balancing—markets).

The 'software' solutions discussed above are not without implications for the location and timing of investments, as these implications are influenced by price signals. The challenge of increasing cross-border transmission network capacity is addressed more directly below.

Addressing the investment gap—interconnector financing models

According to the European Commission,[11] around €200 billion of European energy infrastructure investment is required by 2020, of which €140 billion relates to electricity transmission, storage and smart grid applications.

This raises the question of who will deliver this investment and whether the proposed European regulatory approach to cross-border integration, as contained in the target model and in other related EU policy and legislative initiatives, is likely to facilitate or hinder it. Three financing models, and the investment conditions for each, are examined below.

The merchant investment model

The available cross-border transmission capacity in the EU could be increased through investment in merchant interconnectors, incentivised by market participants with an interest in capturing the value of price differentials between countries.

Merchant projects refer to arrangements whereby investors recover their costs through congestion charges rather than regulated transport tariffs. As they may still be built by TSOs, the main difference with a regulated approach lies in the party that finances the investment. For example, the BritNed interconnector was commissioned in 2011, is 260km long with a capacity of 1,000MW, and is funded and operated by National Grid and TenneT on a commercial basis, independent of their regulated businesses.[12]

From a theoretical perspective, all of the investments that are profitable under this model will also be efficient, being based exclusively on price signals. However, in practice the implementation of a merchant model could give rise to some issues once implemented, of which two are as follows:

- **failure to capture positive externalities**—the merchant model might be expected to lead to lower levels of interconnection compared with the social optimum when there are wider economic benefits to the investment that are not captured by the project sponsors (such as promoting market integration or increasing security of supply);

- **perverse incentives**—the same problem could be aggravated by strategic behaviour by potential merchant transmission investors that face incentives to underinvest in order to maximise congestion revenues—a concern raised by the Commission with regard to BritNed, as it was not convinced that the proposed size of the cable struck the optimal balance between rewarding the investors and benefiting consumers on both sides of the interconnector.[13]

In recent years, the Commission appears to have been adopting a progressively more stringent approach when reviewing the exemptions granted by national regulators to merchant interconnector projects from regulated third-party access, restrictions on the use of congestion revenues, and tariff regulation (eg, a cap on profits). In balancing the need to provide investors with greater control over cash flow and reduced risks, and mitigating the potential harm to competition, the Commission has imposed an increasing number of conditions on the four merchant projects (Estlink, BritNed, Imera, and Arnoldstein-Tarvisio), potentially hindering the development of merchant projects.[14]

The TSO-led model

The TSO-led model can address some of the weaknesses of the merchant model. For example, perverse incentives could be mitigated and positive externalities taken into account, conditional on the ability of regulators to get the incentives right.

However, in an EU-wide context, where transmission investments relate to multiple borders and national authorities, such a challenge is further complicated.

- **Common cost–benefit analysis (CBA) and cost-allocation methodologies**—building interconnectors through a TSO-led model often requires controversial cost allocations, as it implies the need for national regulators to agree on how the investment should be recovered from transmission tariffs charged at national level; in other words, how the cost of the investment should be split between different countries and their consumers. Moreover, some interconnections may clearly be beneficial for achieving EU policy objectives, but at the same time it is not straightforward to identify who should pay for these 'positive externalities'. It is therefore likely to be critical (but also extremely contentious) to develop common CBA methodologies to take into account these externalities, based on agreed scenarios of future trends and location of demand and supply. Interconnections also create winners and losers, and increase average prices and system balancing in one of the host countries. As at the national level, consumers living in high-consumption, low-production areas would be made worse off by the introduction of nodal pricing—so consumers living in a country where production is relatively cheap would be made worse off by an increase in interconnections allowing national generators to export electricity into countries with higher prices.

- **EU-led involvement in tarification**—an alternative approach to overcoming cost-allocation and funding issues would be to define tariffs directly at the EU level (ie, if national regulators/TSOs cannot agree on cost allocations). In 2010, the Commission established an inter-TSO compensation scheme to ensure that TSOs are compensated for the costs incurred on their systems due to hosting cross-border flows of electricity (about €225m in 2011), and at the same time to facilitate cross-border trade by avoiding 'tariff pancaking' (where users pay tariffs for every country they cross).[15] However, the inter-TSO compensation scheme, although it may help to eliminate negative barriers to trade, might not provide strong-enough incentives for investment in cross-border networks: it represents a 'negative integration' instrument (ie, eliminates restrictions and obstacles to trade) rather than a 'positive integration' one (ie, which actively supports the creation of the internal market).

Should further EU involvement be considered necessary, it would remain to be seen whether national governments and regulators would accept the transfer of such a sensitive competence to EU authorities.

Public funding

A CBA could be used to highlight projects where there are significant positive externalities, and to feed into a third approach to mitigate underinvestment in cross-border transmission investments—ie, the public financing of projects of European interest.

The Commission has proposed a draft regulation on guidelines for trans-European infrastructure which identifies 12 priority corridors and areas, and defines a procedure and criteria for projects to become projects of common interest (PCIs). PCIs should be eligible for financial support through the Connecting Europe Facility—which is expected to comprise a fund of

€9 billion as of 2014 and benefit from a more speedy permit-granting process, characterised by a maximum duration of three years and a 'one-stop shop'.[16]

Although certainly desirable, such financial support might be expected to play only a marginal role, given the scale of investment needed (€104 billion for electricity transmission only).[17]

Conclusion: the importance of the details

The target model is a framework that should help the transition to an internal energy market that is competitive, secure and sustainable. To address the need for cross-border harmonised rules for trading and increased interconnector capacity, both 'software' and 'hardware' solutions have been put forward.

This article has nonetheless shown how market design solutions characterised by good intentions could have adverse effects, depending on the details of how they are implemented in practice.

It therefore appears that a well-known expression used by Brussels civil servants—'the devil is in the details'—is appropriate for the potential unintended consequences that the EU electricity target model could have for generators and system operators, both within and outside Great Britain.

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[1] Ofgem (2012), 'Open Letter: Implementing the European Electricity Target Model in Great Britain', March 28th.
[2] European Commission (2011), 'The Internal Energy Market – Time to Switch to a Higher Gear', non-paper.
[3] European Network of Transmission System Operators for Electricity (2012), '10 Year Network Development Plan 2012', July 5th.
[4] Ofgem (2012), op. cit., p. 1.
[5] Counter-trading measures exchange energy across zones, while re-despatching measures alter the generation pattern.
[6] See Green, R. (2004), 'Electricity Transmission Pricing: How Much does it Cost to Get it Wrong?', the Cambridge-MIT Institute, working paper, September; and Neuhoff, K., Boyd, R., Grau, T., Barquin, J., Echavarren, F., Bialek, J., Dent, C., von Hirschhausen, C., Hobbs, B., Kunz, F., Weigt, H., Nabe, C., Papaefthymiou, G. and Weber, C. (2011), 'Renewable Electric Energy Integration: Quantifying the Value of Design of Markets for International Transmission Capacity', Climate Policy Initiative, January.
[7] 'PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia', http://www.pjm.com/about-pjm/who-we-are.aspx, accessed November 16th 2012.
[8] European Regulators' Group for Electricity and Gas (2010), 'IIA for the FG on Capacity Allocation and Congestion Management', E10-ENM-01-01-CM_FG_IIA, September 8th, p. 29.
[9] European Network of Transmission System Operators for Electricity (2012), 'Network Code on Capacity Allocation and Congestion Management', September 27th.
[10] European Commission (2010), 'Case COMP/39.351 — Swedish Interconnectors', 2010/C 142/07.
[11] European Commission (2011), 'Commission Staff Working Paper: Energy Infrastructure Investment Needs and Financing Requirements', June 6th.
[12] According to its licensing regime, as National Grid cannot include interconnectors in its regulatory asset base or cover its costs from tariffs, it has to recover costs by marketing the cable capacity. See Hancher, L. (2011), 'Cross-border Infrastructure Projects: the EU Exemption Regime', January 27th.
[13] European Commission (2007), 'BritNed Exemption Decision', para 11 (f).
[14] European Commission (2005), 'EstLink Exemption Decision'. European Commission (2007), 'BritNed Exemption Decision'. European Commission (2008), 'Imera Exemption Decision'. European Commission (2010), 'Arnoldstein-Tarvisio Exemption Decision'.
[15] European Commission (2010), 'Commission Regulation (EU) No 838/2010 of 23 September 2010 on Laying Down Guidelines relating to the Inter-transmission System Operator Compensation Mechanism and a Common Regulatory Approach to Transmission Charging'.
[16] European Commission (2011), 'Proposal for a Regulation of the European Parliament and of the Council on Guidelines for Trans-European Energy Infrastructure and Repealing Decision No 1364/2006/EC', October 19th.
[17] European Network of Transmission System Operators for Electricity (2012), '10 Year Network Development Plan 2012', July 5th.

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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