

A NERA Publication

Energy Regulation Insights

Issue No: 20

April 2004

From the Editor

When the UK introduced its New Electricity Trading Arrangements (NETA) in 2001, it was heralded as a new paradigm for electricity markets. Key features were decentralised despatch (“nominations”) and penalty prices for “cashing-out” imbalances (deviations from imbalances). In March 2004, energy regulator Ofgem announced a review of the electricity cash-out mechanisms (and the equivalent system for gas), having been prompted by concern over their impact on incentives to balance and on security of supply. Ofgem recognises that there are problems with the current arrangements. In particular, the current pricing arrangements do not send proper signals when there are supply shortages.¹ This brief examines why and what it means for electricity markets everywhere.

Graham Shuttleworth, Director

“Pay-As-Bid” Balancing Market Runs into Trouble in the UK

by Graham Shuttleworth and Former Special Consultant
Isabelle McKenzie

Within NETA the Balancing and Settlement Code (BSC) is a compulsory arrangement to which all market participants must sign up as a condition of trading in the market.² If participants produce insufficient or surplus electricity, the grid operator must take action to ensure the system remains secure. The BSC ensures that participants pay for any ‘extra’ electricity they consume and receive a modest payment for any ‘surplus’ electricity generated. These cash-out prices emerge from an administered process of calculation, rather than a market, but they are intended to signal the supply/demand balance in the market. Since they represent the ultimate outlet and source of electricity in real time, cash-out prices eventually feed through into market prices. Thus, if market prices are to signal a shortage of electricity, cash-out prices must rise to shortage values at such times.

Ofgem’s review demonstrates the difficulty of setting the rules for the administered price of imbalances and ensuring that participants receive the correct signals. The former Pool arrangements in England and Wales used a variant of the “system marginal price”, in which the price paid by consumers and received by generators is the cost of producing the most expensive unit of electricity in a least-cost despatch. In competitive conditions, marginal pricing encourages participants to submit prices that reflect their own costs,

¹ Ofgem (2004), Decision document on modifications P136 and P137, 30 March 2004

² All electricity and gas markets contain this compulsory element, although the design and scope of it varies.

³ Competing generators will submit offers in which the price reflects their marginal costs, because they will then be called to run when, and only when, the system marginal price is higher than their costs, so that they will maximise their profit from running.

The views in this issue represent the views of the authors and not necessarily those of NERA.

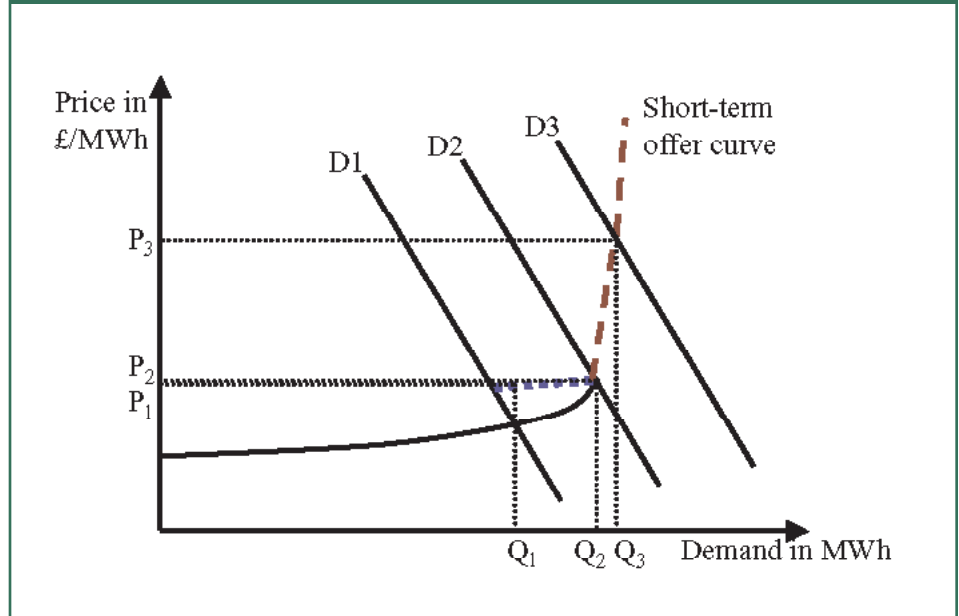


which ensures a least-cost despatch.³

Ofgem abandoned the old version of this system in favour of a “pay-as-bid” system, in which parties selling power to (or buying power from) the system operator receive (or pay) the prices in their own bids. The BSC rules then set cash-out prices as the volume-weighted *average* price of the system operator’s purchases (for cashing-out deficits) and sales (for cashing-out surpluses). In a pay-as-bid system, participants aim to submit prices equal to the system marginal price, rather than their own costs.

Using average prices for cashing out imbalances creates problems at times of system scarcity, when demand exceeds, or is in danger of exceeding, available generation capacity. On 10 December 2002, NGT (as system operator) issued a “Demand Control Imminent notice”. By this notice, NGT signalled a possible need to reduce demand by 5 percent, due to a combination of record demand levels and a number of generator failures. In the Balancing Mechanism, NGT bought extra power from a variety of sources and accepted prices up to and including £9,999 per MWh. However, the *average* price of accepted offers, which defined the System Buy Price charged to all those who were short of electricity, only reached £270 per MWh. This average price did not adequately reflect the scarcity in the market or the marginal value of additional

Figure 1



Box 1

Balancing Offers and the Average Cash-Out Price:

Suppose that, before the start of a settlement period, traders anticipate that demand will be D1 and arrange supplies of Q_1 to meet it, at which point the market-clearing price is P_1 . However, owing to a sudden change in conditions, demand rises to D2, or even to D3. The solid part of the supply curve shows the unit costs of generation in ascending order (a “marginal cost curve”). The dotted line (· · ·) shows how generators might offer additional units of output to meet the normal range of variation in demand, up to D2. In this case, generators anticipate reasonably accurately the market price at the higher level of demand and submit offers around the level of the system marginal price (P_2) at the higher level of output (Q_2). If demand rises to D2, the price for cashing-out imbalances is an average of prices in the range P_1 to P_2 , which is reasonably close to marginal costs at that level of output.

However, if demand rises to D3, the system operator must also accept offers dictated by sharply rising marginal costs, as shown by the dashed line (- -). The volume of such offers is relatively small (Q_3 minus Q_2), so the volume-weighted average price will be considerably lower than the marginal price (P_3). Hence, in times of shortage, the cash-out price is bound to understate the true market value of electricity.



capacity. Figure 1 shows how the average price rule fails to signal shortage conditions and Box 1 gives a detailed explanation.

A volume-weighted average of accepted offer prices will underestimate the true value of electricity during a shortage. That is what happened on 10 December 2002. If the cash-out price for imbalances does not reflect the real value of electricity, it will undercut other prices for electricity. By doing so, it will prevent the correct price signals from reaching the market and can eventually undermine the overall security of supply on the system. Ofgem therefore has genuine reasons to be concerned.

Old Reasons for the New Rules

Ofgem's main reason for moving from a marginal price system to an average price was concern over price manipulation by the generators. At the time, in the late 1990s, ownership of high-cost flexible generation was highly concentrated. Ofgem thought the marginal pricing system made it easier

for generators to raise cash-out prices than a pay-as-bid market, although no-one has ever shown precisely how.⁴ If the market for such generation is competitive, then generators will not manipulate the marginal price at times of moderate demand; at times of high demand, a high marginal price provides a useful spur to investment. Ofgem will therefore need to reconsider whether competition in this part of the market is now adequate for the marginal pricing system. If Ofgem favours the marginal pricing system, it might also act to prevent consolidation of this type of generation.

Markets with no explicit mechanism for remunerating capacity can only recover the fixed costs of power plant during periods of tight supply and demand. The market must be capable of sustaining high prices for prolonged periods, because supply shortages may persist until new capacity is built. However, sustained periods of high prices can result in regulatory and political problems, as consumers lobby government over the high prices and the perceived high level of profits by generators. Consumers may demand

price caps or a return to regulated prices in place of a liberalised electricity market.⁵ The threat of either outcome would eliminate the generators' belief that they will recover their fixed costs and hence undermine the incentives to invest.

Thinking Outside the Box (or, Rather, Outside Box 1)

Faced with the difficulties outlined above, Ofgem will no doubt consider a number of different ways to improve investment incentives. Below, we sketch out a range of possible solutions:

Marginal Pricing: Many electricity markets already set prices using the marginal pricing system. Ofgem departed from that rule when setting up NETA to minimise the impact of market concentration, but the market concentration that undermined confidence in marginal pricing is long gone. Ofgem might conclude that a return to marginal pricing is possible and advisable, given the desire to stimulate investment.

Restricted Average Pricing: If Ofgem remains set against marginal pricing,

⁴ Several studies have concluded that lower cost generators will offer lower prices, to increase their chance of running, so that the curve of offer prices rises up to the right, as in Figure 1. (See Fabra N (2003), *Tacit Collusion in Repeated Auctions: Uniform Versus Discriminatory*, Journal of Industrial Economics Vol 51, Number 3, pp 271-293.) This difference between prices would lower total payments to generators by a small amount. However, these models take no account of the prior contracting up to demand level Q_c , which removes the bulk of such arbitrage opportunities.

⁵ In terms of the economics of institutions, electricity markets are vulnerable to this kind of pressure if it is cheaper to avoid peak prices by lobbying, than by building a peaking generator.



it might nevertheless be advisable to modify the cash-out pricing rules to bring the outcomes closer to a marginal price signal. For instance, the current rules already “tag” (exclude) some offers as being related to transmission constraints and other localised problems. The rules could be adapted to exclude offers considered too far from the margin (i.e. those on the dotted section in Figure 1), or to take an average of only the three (say) most expensive offers accepted.

Contracts for New Capacity or Interruptible Demands: Several governments have considered offering special inducements to the builders of new capacity, in order to encourage more investment than the market is willing to provide. The latest such proposal comes from the Irish Commission for Energy Regulation.⁶ Although (as in the Irish case), such schemes are only intended for use if indepen-

dent investment has produced “too little” capacity, the effect is to make all future investment dependent on the award of such a special contract. This is because such contracts further reduce the incentives for investment by other independent operators, by increasing available capacity and reducing the frequency of shortage conditions. Thus, even if such schemes are not ruled out as being discriminatory, they will ultimately have to be applied to all generation. The same applies to special schemes which pay a limited number of customers a fee to make their demand interruptible at times of high prices, without paying such fees to generation capacity.

Capacity Payments and Obligations: If regulators respond to concerns about competition by imposing caps on energy prices, markets must (and do) offer other sources of revenue to reward investment and to ensure

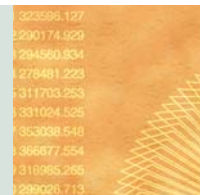
adequate security of supply. Capacity payments are difficult to define and to allocate, but they help to smooth out the high prices associated with capacity shortage. The Spanish and Italian systems currently use such centralised systems to allocate (a small amount of) revenue to generators. US regulators have so far preferred to decentralise payments for capacity, by imposing obligations on energy retailers to contract for capacity sufficient to meet their demand. However, the market price of capacity can fluctuate just as widely as prices in energy-only markets and has in some cases provoked its own price cap. The UK Department of Trade and Industry examined capacity obligations in 2003 and concluded (quoting research by NERA),⁷ that the case for them had “not been made”,⁸ but Ofgem might decide recent events have strengthened the case for such obligations, if no other solution seems better.

⁶ Commission for Energy Regulation (2003), *Key Design Issues: Generation adequacy, dominance and pricing*, 30 April 2003

About NERA

NERA Economic Consulting is an international firm of economists who understand how markets work. Our more than 40 years of practical experience creating strategies, studies, reports, expert testimony and policy recommendations reflects our specialization in industrial and financial economics. Our global team of 500 professionals operates in 16 offices across North and South America, Europe, Asia and Australia.

NERA Economic Consulting (www.nera.com), founded in 1961 as National Economic Research Associates, is a Marsh & McLennan company (MMC). MMC is a global professional services firm with approximately 60,000 employees who provide analysis, advice and transactional capabilities to clients in over 100 countries.



Summary

All electricity (and gas) markets require some kind of mechanism to charge for imbalances between amounts provided to the system and amounts taken from the system. If the prices of these imbalances is not high enough during shortages investment will suffer.

When announcing NETA, Ofgem publicised the degree to which it was moving away from the pricing principles inherent in the previous arrangements. The Ofgem review of cash-out prices highlights the difficulty of departing from the economic principle

that prices should reflect marginal costs. At times of system shortage, average prices accepted by the grid operator provide too little incentive for investment in generation capacity or demand management. Applying the marginal cost principle creates other problems and some electricity markets have adopted different ways to remunerate capacity. In the long term, if prices do not reflect real scarcity, the market rules must ensure prices reflect marginal costs, provide some alternative source of revenue for capacity, or else face the prospect of capacity shortages.

⁷ Falk J, Fraser H, Meehan E, Rosenzweig M, Shuttleworth G (2002), *Electricity Markets and Capacity Obligations: A Report for the Department of Trade and Industry*, NERA, 13 December 2002 (available at www.nera.com)

⁸ Department of Trade and Industry (2003), *Energy White Paper: Our energy future - creating a low carbon economy*, Para 6.43.

Our Practice

NERA is at the forefront of the continuing transformation of the energy industries worldwide. We have pioneered in developing approaches for introducing competition in segments such as power generation (where competition is workable) and for improving the regulation of sectors (where it is not). We work with companies and governmental bodies worldwide to design competitive power markets and to develop tariffs and rules of access for regulated transmission and distribution systems for electricity and gas and transport of oil and oil products. With industry restructuring, we also help companies develop strategies for exploring new opportunities and minimizing new risks, including issues related to climate change and other environmental initiatives.

We help our clients to develop new regulatory strategies and, when needed, support our clients with analysis and testimony before regulatory commissions, antitrust and competition policy agencies, and domestic and international courts. Our economists help clients to decide which lines of business to pursue; to divest assets no longer consistent with their strategy; to identify and evaluate opportunities for mergers, acquisitions and investment; and to develop bidding, trading, contracting, and marketing strategies and organizations. Our work also includes designing and conducting energy auctions, providing strategy and valuation, advice on mergers and acquisitions, the financing of energy companies, and the financial restructuring of distressed companies.