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Electricity Wholesale Markets: Designs for a low-carbon future

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Abstract

This paper compares electricity wholesale markets in the United States and Europe. The Standard Market Design in the US involves an independent system operator, nodal pricing with financial transmission rights, and integrated markets for capacity and ancillary services. In Europe, there are national, or occasionally zonal, spot markets run by companies independent of the transmission operator, and of the latter's purchases of ancillary services. As the amount of low-carbon generation increases, prices and transmission constraints are likely to become more volatile, increasing the need to adopt an efficient market design. In most respects, the US standard market design is likely to give better results than the European models.

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1. INTRODUCTION

The aim of this paper is to consider the designs used in electricity wholesale markets from around the world, and ask how much market design matters for the move to a low-carbon electricity system. Casual observation quickly reveals that many different market designs have been adopted around the world. For the purposes of this paper, I will compare two main families, which I will describe as the United States and the European market designs.

The differences between them include the choice between a compulsory centralised market (a gross pool) and a system where bilateral physical trading was allowed, and between markets in which short-term trades are settled at a uniform price and those with discriminatory pricing. The most important difference, however, is in the treatment of transmission effects. Broadly speaking, markets in Europe try to minimise the effect of transmission constraints on their prices, while markets in the United States treat them explicitly.

Both systems are clearly capable of working, in the sense of allowing companies to trade electricity and deliver it to customers with a high level of reliability. The question I want to ask is which system is likely to work better, promoting more efficient outcomes, not just now, but in the future. It is hard to predict the future shape of the electricity industry, but it seems clear that it will be dominated by the need to reduce carbon emissions. There is a centralised route to doing so, based on nuclear power and large fossil-fuelled stations with carbon capture and sequestration. There is also a decentralised route, with renewable generation, typically dispersed in the areas where renewable resources are found, and distributed generators using combined heat and power (CHP) technology. In practice, it is likely that a mix of centralised and decentralised generation will be required, but that the future system will contain much more decentralised generation than at present. Furthermore, many of the decentralised generators will be intermittent – wind, wave and tidal generators depend on the availability of their power source, while CHP generators are most (technically) efficient when their electrical output follows their heat demand.

What will this increasing intermittency mean for the performance of different wholesale market designs? In the next section, I discuss the principles that a good wholesale market design should achieve. Section 3 describes the model used (or planned) in the power markets of the United States. Section 4 describes power markets in Europe, which have a wider variety of designs, but some common features, while Section 5 shows how these market designs cope with the increasing cross-border flows of electricity. The challenges to be expected from increasing volumes of low-carbon electricity are discussed in Section 6, while Section 7 concludes by assessing the relative merits of these two models.

2. WHOLESALE MARKETS

First, however, we should define what we mean by the electricity wholesale market, and ask what we want it to do. “The wholesale market” is actually the combination of many separate ways of trading power, and the interactions between them are so important that no single market should be studied in isolation. In many countries, the key component, and the part that looks least like other commodities markets, is a day-ahead auction to sell power, run by an independent system operator. Running the auction one day in advance gives sufficient time to plan the operation of (relatively) inflexible power stations, while still allowing reasonably accurate forecasts of demand and plant availability. These forecasts will be wrong, however, and so other markets are frequently used to make adjustments in real time, although in some countries, these adjustments are procured by the grid operator without the use of a market. Day-ahead prices are typically volatile, and companies wanting to avoid this volatility will try to trade most of their power well in advance on a forward market, which typically operates through over-the-counter trades rather than an organised auction. Finally, there may be a long-term market for capacity or for other services that the grid operator wishes to procure well in advance.

How should we judge whether a market is successful? The Stanford Energy Modeling Forum set out six principles that should be followed when designing electricity transmission pricing. These were intended to cover both the use of system charges levied directly by the transmission owner, which normally provide the bulk of its revenues, and any transmission-related elements of wholesale prices. "The prices should:

1. promote the efficient day-to-day operation of the bulk power market;
2. signal locational advantages for investment in generation and demand;
3. signal the need for investment in the transmission system;
4. compensate the owners of existing transmission assets;
5. be simple and transparent; and
6. be politically implementable" (Green, 1997, p. 178).

The principles for wholesale markets would be similar, but the focus would shift from transmission to generation. Wholesale markets should:

1. ensure the efficient day-to-day operation of the generation sector;
2. signal the need for investment in generation and demand-side management;
3. promote efficient locational choices for these investments;
4. compensate (sufficiently) the owners of existing generation assets;
5. be as simple, transparent and stable as possible; and
6. be politically implementable.

The first criterion has been strengthened, compared to the Stanford list, since we are now considering the sum of wholesale trading arrangements, rather than a set of transmission pricing arrangements that might have only annual changes, and in a market-based system, if the market arrangements do not lead to efficient operation, there will be no plan B. This essentially requires that the markets send the correct signals for operation, either through prices to which market participants respond, or through direct instructions from the system operator, coupled with payments that make participants willing to accept those instructions. The second principle considers long-term signals, and the need to ensure that generators (and those who would need to invest in order to provide demand-side response) are given enough incentive to do so. Since investment in generation involves significant time lags and very long-lived assets, wholesale markets will rarely extend far enough forward to give investors much certainty about the future revenues of a given project. What they can do, however, is send a strong signal about when to close capacity (a decision with a much shorter lead time), and provide generators with confidence that they will earn sufficient revenue if the market is not suffering from excess capacity.

The third principle also relates to signalling, but to its spatial aspect, and has been downgraded slightly, since other mechanisms, and in particular charges paid to the transmission company, are also available to send these signals. Even so, if the wholesale market rules do not penalise a generator located on the wrong side of a transmission constraint – and some designs do not – then the transmission charges will have more work do to in providing the correct incentives. The fourth principle relates to the second function of prices, which is to distribute resources between economic agents, and refers to the need for generators (and others) to receive sufficient remuneration for the services they provide. Sufficient must be defined carefully, however, for revenues can be too high as well as too low. If generators are able to exert market power to increase their revenues, the industry is performing poorly, although the extent to which specific market designs can enhance or reduce market power is an open question (Newbery and McDaniel, 2003, Fabra *et al*, 2006). Similarly, if the market is grossly over-supplied with capacity, then not all of that capacity *should* be able to recover its full costs. If it were able to do so, the incentive for investment in that market would be too strong. There would be little incentive for investment, however, if stations that the market needed were unable to cover their costs from their market revenues.[1]

The fifth principle, that of simplicity and transparency, has been expanded to include stability, and an important rider added. The electricity industry is inherently complex, and no legislator can repeal Kirchhoff's laws. A trading system that ignores these complexities is doomed to failure, but one that is perceived to be more complicated than it needs to be will not be attractive to potential participants – which is important if the market is voluntary, or new investment is needed. Since overly frequent rule changes add to the complexity of the market, and can act as a deterrent to entry by smaller companies (Baldick and Niu, 2005), stability can be interpreted as applying to the market rules. It should not be too easy to change the rules of the market, but neither should it be too difficult, and this requires appropriate governance procedures. A second dimension of stability is in terms of market outcomes, and prices in particular. The challenge here is that when market conditions change, so should the outcomes. Hedging contracts, however, allow market participants to stabilise their costs and revenues while still facing efficient prices at the margin.

Finally, the market must be able to attract, and retain, the support of politicians and other stakeholders, which the Pool of England and Wales signally failed to do (Newbery, 1998). Prices that appear unnecessarily high or volatile will sacrifice political support, and may lead to unfortunate interventions, such as those in California (Blumstein et al, 2002). Since the Californian debacle, political support for liberalised power markets has been eroded in many states, with eight of them suspending their restructuring programs.[2] While the US approach to market design considered in the next section compares favourably to the European approach when measured against several of the principles above, it has been less successful on what may be the most important criterion, that of persuading politicians across a continent to adopt it.

3. MARKET DESIGN IN THE UNITED STATES

Power markets in the United States are organised along lines based on the work of Fred Schweppe and his co-authors (Bohn et al (1984), Schweppe et al (1988)). This showed how spot prices, varying over space and time, could reflect the marginal cost of generating power and delivering it to any point on the network. This gave the basis for an electricity wholesale market, even though their model of retail pricing, using a variety of adjustments to ensure that the industry recovered the amount of money actually due to it, was firmly within the paradigm of regulation. The Independent System Operators responsible for the major organised wholesale markets in the United States have either adopted, or plan to adopt, a market design which is based upon this model. In 2002, the Federal Energy Regulatory Commission attempted to make it compulsory across the country, calling it the standard

[1] An anonymous referee asked whether the use of the term "existing generators" was meant to imply a distinction between incumbents and entrants. It is not – the wording was chosen to mimic the earlier list, and retained on the basis that as soon as an entrant is in a position to earn wholesale market revenues, its plant can be counted as "existing".

[2] Fourteen states and the District of Columbia had active programs in April 2008, and twenty-eight had never implemented an active restructuring program (source: Energy Information Administration).

market design, but backed down in the face of opposition from states opposed to liberalisation.

The centrepiece of this design is a day-ahead market in which the Independent System Operator calculates the optimal dispatch, based upon generators' offers and bids from the demand side, and respecting security constraints on the transmission system (Helman et al, 2008). Generators and retailers that have already traded bilaterally can submit these trades to the ISO as part of the dispatch, but if they also submit prices at which they are willing to change their plans, the ISO may be able to find a more efficient solution. The quantities in the ISO's day-ahead dispatch are financially firm, in that generators (retailers) are committed to either deliver (accept) the power or to buy (sell) it back in the real-time market that runs the following day. The ISO will calculate a price for every point on the network, equal to the marginal cost (according to the generators' offers) of providing power there, either by generating it at that node, or generating it elsewhere and transmitting it to where it is needed. Transmission costs consist of marginal losses (not yet charged by some of these markets) and the cost of adjusting output from some generators if this is necessary to avoid sending more power down a transmission line than is safe.[3]

Traders without generation or physical demand are allowed to enter the day-ahead market, and so most of the ISOs run a reliability unit commitment to ensure that enough plant is started up to meet the expected demand (and need for reserve) on the following day. If the units committed at this stage do not earn enough from selling power to cover the cost of starting up, the ISO will compensate them. At some point before real time, generators and loads submit offers and bids to adjust their output or demand. In real time, the ISO dispatches plant to meet the actual load, given the resources actually available to it and the offers and bids it has received. These produce a set of real-time prices, which are used to settle the differences between the day-ahead positions and actual outcomes for each hour.

Companies trading in the ISO's markets face prices that vary across the region to reflect the local value of energy in the face of transmission costs. Companies can avoid these markets, making bilateral trades, but cannot avoid transmission costs. If a company schedules power at a low-priced node to meet demand at a high-priced node, it must make a payment to the ISO equal to the price difference multiplied by the amount traded. The price difference occurs because there is a constraint on the amount of power that can be exported from the low-price area, and so the company is paying for adding to the pressure on the constrained boundary. If the company were to generate at the high-priced node and take the power at the low-priced node, it would receive a payment for reducing the flow across the boundary.

As well as energy, the ISO is responsible for buying reserve from generators that are capable of providing more power at notice periods ranging from a few minutes to half an hour, and the automatic generation control that (usually) keeps the system frequency stable (known in the US as regulation). Experience in California exposed the flaws of trying to buy reserve in independent markets, in that the California ISO was required to buy a fixed quantity of low-quality (long notice) reserves even if high-quality (short notice) reserves were available at a lower price (Wolak *et al.*, 1998). Nowadays, ISOs calculate an optimal dispatch that includes both energy and the ancillary services of reserve and regulation.

While the day-ahead market is the centrepiece of this market design, it includes some longer-term arrangements. A capacity market provides additional revenue for generators, but requires them to make their plant available to sell into the corresponding region, or face financial penalties. Capacity markets are a response to the concern that energy market prices may not remunerate generators for the fixed costs of keeping plant available, and especially for the costs of peaking plant. In a "pure" market design, the price for energy would

[3] The usual problem is not that the line would be overloaded if more power flowed down it now, but that it would become so if some other line were to fail and flows on the rest of the system increased.

occasionally rise to whatever level was needed to keep demand down to the level of available generation, and this would pay for the cost of the optimal level of capacity. In the US markets, energy prices are capped to prevent the abuse of market power, and this may prevent them from rising high enough to cover generators' fixed costs. The capacity markets provide an alternative revenue stream.

A similar problem faces some generators in "load pockets", or other areas where they will frequently be required to run because of transmission constraints. These generators have enough market power to raise prices well above their costs, and therefore most of the US markets impose automatic bid caps, usually generator-specific, to keep their prices down. If these caps are set too close to variable cost, the generator will not be able to recover its fixed costs. Longer-term contracts are used to close the gap.

While all the main US markets are moving to a version of the standard market design, California and Texas both initially adopted zonal models. Each state was divided into a small number of zones, separated by those lines believed most likely to be constrained. Market participants would inform the independent system operator of their planned transactions – in California, this was mostly in terms of the outcomes of the day-ahead auction run by the California Power Exchange – and if there was no congestion, the same price could be set throughout the state. In the event of congestion on the inter-zonal boundary, a separate price would be set for each zone, and cross-boundary flows would be charged this price difference. Congestion inside a zone was handled by counter-trading – requiring some generators on the exporting side of a constrained line to produce less, and some on the importing side to produce more – and the costs recovered from all market participants.

The Californian experience is well-known (Joskow, 2001; Blumstein et al, 2002; Wolak, 2005). The fatal flaw was that retail prices were fixed, while an implicit hedge of wholesale prices would break down if they rose too far above their predicted level – which turned out to be well below the levels actually seen in the winter of 2000-1.[4] Weaknesses in the wholesale market design did not cause the problem, although they probably exacerbated the price rises. These problems included inconsistent price caps, which encouraged firms to switch an increasing proportion of their trade away from the Power Exchange, and the gaming opportunities created by the way in which transmission constraints were resolved. In particular, the "DEC game" encouraged firms to submit schedules that violated transmission constraints, which they would then amend through (very profitable) trading with the system operator. The Power Exchange collapsed, in part because of inappropriate regulatory interventions, and California is now designing a nodal market.

Texas started with a model in which all congestion costs would be socialised – recovered from all market participants – but this quickly proved unsustainable, and zonal prices were allowed to differ (Baldick and Niu, 2005). Intra-zonal congestion costs then became a significant issue, and in August 2003, the Texas Public Utilities Commission ordered the system operator to design a nodal market, which is expected to start operation at the end of 2008. According to the PUC, "the rule is expected to yield important benefits, such as a reduction in local congestion costs; reduced opportunities for gaming and manipulation in the wholesale electricity market; increased price transparency and liquidity in the wholesale electricity day-ahead energy market; increased locational price transparency for resources; more efficient and transparent dispatch of resources in real-time; improved siting of new resources; and a reduction in the amount of new transmission facilities needed to support the reliability of, and competition in, the wholesale electricity market (Texas PUC, 2003, p XX).

[4] The implicit hedge came from the Competitive Transition Charge, which would absorb the difference between the fixed retail rate (net of transmission and distribution charges) and the variable wholesale cost until the utilities' stranded costs had been paid off. Once this happened, retail rates were intended to vary with wholesale prices – although this proved politically untenable in San Diego in the summer of 2000.

4. MARKET DESIGN IN EUROPE

In Europe, electricity markets have followed a very different, and superficially much simpler, model. Electricity is typically traded at a single point in each country,[5] which is likely to be a notional market hub rather than an identifiable geographic location. With a single product, liquidity could be much higher than with the thousands of separate locations in each US market – although the discussion of financial markets, below, will show how the US markets get round this problem. The disadvantage of this model is that transmission congestion is not eliminated simply by deciding to trade at a notional location – if it potentially exists, it must be managed. In Europe, this is done by the grid operators, either through a formal market, or bilateral trading.

Most European countries have a voluntary day-ahead auction, coupled with bilateral trading and self-supply, as in the US. The British Isles contain the two main exceptions to this rule at the time of writing. Great Britain itself does not currently have a day-ahead auction, relying on continuous bilateral trading until Gate Closure when the system operator takes over the task of balancing the system, although the Futures and Options Association (2007), representing a large number of energy traders, is assessing proposals for the organisation of a clearing house and a day-ahead auction. The All-Island Market covering Northern Ireland and the Republic of Ireland is a mandatory market in which all generators above a *de minimis* size must participate. This market has many similarities to the Electricity Pool of England and Wales, in that generators are allowed multi-part offers, with prices for energy and for starting up their plant, which are rolled into the System Marginal Price.

The Spanish day-ahead market was formally a voluntary market, but in practice, almost all the country's power was traded there between 1998 and 2005. One unusual feature of the market was that companies could submit either simple price-quantity bids for individual hours or complex bids involving inter-temporal constraints. These could include limits on the change in output between two adjacent periods, or a requirement that a bid be accepted in full or not at all. Another condition, a minimum income level, allowed a station to set an offer price close to its marginal costs, but only run if the market price exceeded this offer by enough to cover the station's start-up costs. Prices on this market were also significantly affected by a competitive Transition Charge which effectively capped the generators' revenues (although their incentives were affected by mis-matches between their share of wholesale market revenues and CTC payments) until it was abolished in 2006.

Both Spain and the All-Island Market include capacity payments in their market designs. The original capacity payment, in England and Wales, was set each half-hour on the basis of half-hourly demand and generators' availability over the previous eight days, and was extremely volatile. In Spain, the capacity payment for consumers is set by the government, and then distributed among the generators participating in the day-ahead auction.[6] In the All-Island Market, the total payment is equal to the fixed cost of a peaking plant, less any revenues from ancillary services and from selling energy at more than its variable cost, multiplied by a capacity requirement based on the forecast peak demand (All Island Project, 2007). The annual sum is then allocated to months, and then to half hours on the basis of forecast demand, the forecast loss of load probability, and the ex-post loss of load probability.

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[5] Italy and Norway use a number of zones.

[6] Since only generators participating in this auction could receive capacity payments, it is not surprising that there was practically no bilateral trading in Spain (Crampes and Fabra, 2005) – at least until this rule was changed!

Half-hourly capacity prices are obtained by dividing the amount of money for that half-hour by the capacity available in it.

Most European markets operate without capacity payments. Implicitly or explicitly, they are based on the idea that generators will be able to recover enough revenue from energy prices, and payments for ancillary services, alone. For a peaking generator, considered as a separate unit, this requires either high peak prices or significant payments for being available as reserve capacity, as in the US model. Most European countries have just a few large generating firms at the moment, however, and these may be willing to consider their portfolios of plant as a whole. In this case, revenues for the portfolio may be adequate, even if some stations would not cover their costs from the wholesale market, given the pattern of prices. It remains to be seen whether this approach could be sustainable in a more fragmented market.

In most European countries, the day-ahead markets do not specify a geographical location for the delivery or acceptance of power – there is a single national price. The exceptions are Norway and Italy, which use a zonal model. In these markets, if the amount of power to be produced in a zone at a common national price exceeds the export capacity of the lines connecting that zone to the rest of the country, then the local price is reduced until the power flow is expected to respect transmission limits. Similarly, a higher local price will be set in zones that would have inadequate production at a common national price. Norway usually has three zones (which sometimes share a single price), with borders that are set from time to time by the system operator, reflecting anticipated constraints on the grid. Italy has seven geographical zones, with five running from north to south along the mainland, and the two islands of Sardinia and Corsica. In 2007, there was a single price for the whole country in about 23% of hours, and just two prices in 42%. There were three prices in 30% of hours, while five prices (the maximum) were seen in only a handful. The border between Calabria and Sicily was the most frequently congested (4593 hours in 2007), followed by that between the Northern and Central North zones (2927 hours), while the lines to Sardinia were congested in 2072 hours. The least congested border, the one between the Central South and the South, was congested in only 28 hours (and 65 in 2006). With any zonal system, the number of zones needs to be a compromise between capturing all the significant constraints (implying a large number) and producing a manageable system with liquid markets (implying a smaller number).

If the zones are too large, they will contain congested lines, and the system operator will have to respond in the same way as in the national markets without zones. Some generators will have to be ordered to increase generation (or loads to reduce demand), and other generators to produce less. The system operator will also need to change some generators' outputs to meet unanticipated changes in demand, and cope with unplanned outages. Most countries now run markets in which the system operator can compare bids and offers from different sources in a transparent manner. In the All-Island Market, offers to the main energy market are also used for counter-trading across constraints and for real-time balancing, and participants are paid their own offers for the energy involved. Participants are also paid their own bid in the Balancing Mechanism in Great Britain, although this exists only for real-time trading with the system operator.

The regulation market in the Nord Pool area is based on marginal pricing, so that all accepted offers for up- and down-regulation (providing more or less power to the system operator) receive the price of the most expensive accepted offer (Wibroe *et al.*, 2002). If there are transmission constraints, separate prices are set for each constrained area. These prices are also used to settle imbalances between market participants' contracted and physical positions, once the latter are determined. In Denmark and Norway, the up-regulation price (the more expensive of the two) is used for all imbalances if the system operator needs to buy power, while the down-regulation price is used if the system operator is a net seller. In Finland and Sweden, imbalances in the opposite direction to the system as a whole are cashed out at the Nord Pool spot price. This is less attractive than using the main imbalance price, since it involves, for example, selling power back to the market at a lower price than the up-regulation price if the system is short but a participant is long. However, it involves a lesser penalty than requiring the participant to trade at the opposite regulation price.

This is the method that was initially imposed under the New Electricity Trading Arrangements in England and Wales. Perversely, this penalty persuaded many participants to aim to have a surplus of power (rather than aiming to be in balance), for the cost of a shortage was potentially many times greater than that of a surplus.[7] The British market now follows the Swedish practice, cashing out helpful imbalances at a price based on short-term bilateral market trades for the relevant period (in the absence of a day-ahead auction). Imbalances in the same direction as the market as a whole are cashed out at a price based on the average of several marginal trades. Originally, the imbalance price was based on the average of all the system operator's purchases or all its sales, and the change was made to send a stronger signal of the marginal cost of power.

In France, RTE runs a balancing mechanism similar to the earlier version of the English system, using the average price of its sales or purchases for unhelpful imbalances, and the spot price for neutral imbalances. In the Netherlands, Tennet bases charges for both positive and negative imbalances on a marginal price. Buyers may need to pay an additional incentive price on top of this, while the price sellers receive is reduced by an incentive price, in order to penalise them for their imbalances, if these are at a level that makes the system hard to control. However, the incentive price, which is adjusted in line with system conditions and market performance, has been zero since mid-2003. In Germany, each of the four transmission system operators has its own imbalance price, set every fifteen minutes, which is used for both positive and negative imbalances. The prices are based on the cost of procuring balancing energy, which is done through a national internet-based market.

To sum up, electricity spot markets within most of the countries of Western Europe are now well-established and transparent. While the details vary, most countries have a voluntary day-ahead auction that sets a single national price, and imbalance pricing that is based on the cost of trades carried out close to real time. One area where significant challenges remain, however, is the question of what to do at national borders, and we now turn to this issue.

5. CROSS-BORDER TRADING IN EUROPE

In Europe, the electricity industry grew up on national lines, and although cross-border interconnectors were developed, the connections between national grids have typically been much weaker than those within the grids. At the same time, there are significant opportunities for cross-border trade. Neighbouring countries often have different demand patterns and generation mixes, and would have different marginal costs in autarky. Cross-border trade can arbitrage these potential price differences, but may be restricted by the limited cross-border capacities. The questions for policy-makers and market designers are how to allocate that capacity and set prices for its use.

[7] The penalty for acquiring power through a negative imbalance, rather than in advance, equals the System Buy Price, which can reach hundreds or even thousands of pounds per MWh, less the cost of the power in earlier trading, whereas the penalty for a surplus equals the price paid in earlier trading, less the System Sell Price. While this latter price can be negative, potentially creating a large penalty, in practice it has been much less volatile than the System Buy Price.

At first, capacity on cross-border interconnectors was typically reserved by incumbents, or the holders of long-term contracts, who could use it to sell power into the neighbouring market. A better, market-based, approach is to auction interconnector capacity. If no congestion is expected, the price should be zero, while risk-neutral traders should ensure that the price of using an interconnector where congestion is expected is equal to the profit from doing so – the expected difference in prices between two neighbouring markets. The problem with this, however, is that these relationships will only hold in expectation, and if the different markets – for power on either side of the interconnector, and for interconnector capacity – clear at different times, a trader may have sold power in a foreign market with no way of delivering it, or may be committed to export power from a cheap market to an expensive one. The European Commission (2007, figure 64) has documented trades between England and France where power flows from a higher priced area to a lower-priced one, and also between Germany and the Netherlands.[8] Furthermore, it is possible that trading transmission capacity separately from energy may create opportunities to exploit market power – particularly if it is possible to reserve capacity and then withhold it from the market (Joskow and Tirole, 2000; Gilbert *et al*, 2004).

The problem of incomplete or inappropriate trades can be resolved if transmission and energy are traded simultaneously, via market coupling. Separate national markets receive bids and offers from loads and generators within their borders, but then find a joint equilibrium which takes account of the possibility of trade between them. If conditions in the two markets are similar, in the sense that their prices would be close, even in the absence of trade, then the market coupling algorithm will calculate the level of export from one to the other that will equalise their prices. If the exports required to equalise prices exceed the capacity of the interconnector between the markets, then the algorithm will calculate a separate price for each market, based on the maximum possible trade between the two.

Market coupling between two (or more) independent markets is in many ways the equivalent of market splitting, which can be used to manage congestion within a single market. The difference is that in the market splitting system there is a single market operator, which receives all the bids and offers, rather than two. Market splitting has actually been used in Europe for longer than market coupling, because it is the method used by Nord Pool, the world's first multi-national electricity market.

Nord Pool covers Norway, Sweden, Finland and Denmark (in order of joining). Nord Pool runs a voluntary day-ahead auction that will set a single price for the whole region – if there is no congestion – but could otherwise set separate prices for two regions of Denmark, for Finland, for Sweden, and for three areas within Norway with boundaries chosen to reflect system conditions. If the prices differ between two areas, then electricity that is transmitted between them has to pay the price difference, as in the US model, whether or not it was traded in Nord Pool. After the day-ahead auction closes, there is an intra-day market, Elbas, based on continuous trading.[9] The regulating market, for real-time adjustments and the settlement of imbalances, covers the entire Nord Pool area, although local prices are calculated when there is congestion.

Most other European markets started on a national scale, but are becoming international. In October 2005, Nord Pool opened a "price area", Kontek, in Germany to allow traders to deliver power (for import or export) to the southern end of the interconnector with Eastern Denmark and Sweden, and have it priced according to Nord Pool rules. If the

[8] It is possible that in a meshed network, an efficient transaction in which power flowed from a low-price area to a high-price area would involve loop flows in which some power did move from a higher- to a lower-priced area. This could be the case on the border between Germany and the Netherlands, but cannot be the case on the Direct Current link between England and France, where the flows are actively controlled.

[9] At the time of writing, Elbas does not include Norway, but its coverage is due to be extended in 2008.

cable is not congested, the price at Kontek will be the same as in Eastern Denmark, while it will be set by local supply and demand (taking the net export into account) if the cable is congested. Companies wishing to use the interconnector between Germany and Western Denmark could use an optimisation service that would only schedule their trade if it was flowing from the lower-priced area to the higher-priced area, using the Kontek price as a proxy for the price in the German market.

A few months earlier, that market had become multi-national, when the German exchange EEX started to accept trades from companies in Austria, rather than requiring companies to make or take delivery at a point in the German grid and have a separate contract for access to the cross-border interconnector. EEX sets a single price covering both countries, implying that cross-border congestion will have to be managed by the grid companies involved. When EEX expanded its operations to Switzerland, however, in December 2006, it created a second price area.

Another multi-national market was created in November 2006, when the Trilateral Market Coupling between France, Belgium and The Netherlands started. France and The Netherlands had used voluntary day-ahead auctions (powernext and APX) for several years, while the Belgian market, Belpex, only started at this time. Each market closes at the same time, and the market operator then calculates the prices that would clear its market for each hour in the absence of trade. For each hour, the operator also derives the country's hourly net exports as a function of the local price. These net export curves are used to find the equilibrium across the three markets, following the same principles as Nord Pool. If there is no congestion, all three markets will have the same price, while if the transfer across one (or both) national borders needed to achieve this exceeds the available transfer capacity, then two (or three) different prices will be set.

Another multi-national market, covering the Iberian Peninsula, was established when Portugal joined the Spanish market in July 2007. At the time of writing, the western part of continental Europe thus has five electricity markets (or linked groups of markets), covering Iberia, France and the Low Countries, the Nordic countries, the German-speaking countries, and Italy. In the near future, however, this will fall to three, for EEX is to join in market-coupling arrangements with both Nord Pool (in June 2008) and the Trilateral Market. This offers the prospect of a market with 350 GW of generation capacity. This would significantly dilute the market power of even the largest generators, except when they are on the importing side of a congested border.

6. A LOW-CARBON ELECTRICITY SYSTEM

The European Union and some American States have adopted aggressive targets for reducing carbon emissions. Energy efficiency, heat from biomass and bio-fuels in transport can make significant contributions, but it seems inevitable that much of the reduction will have to come from the electricity industry. Fuel switching from coal to gas, building more efficient power stations, nuclear power and carbon capture and storage could all contribute to this reduction without changing the industry's current model of a largely centralised system. The European Union, however, has also set a target for 2020 of producing 20% of its energy from renewable sources. This could involve renewable electricity generation of 1250 TWh a year (Pöyry, 2008), nearly three times the current level of renewable generation in the EU (which was 440 TWh in 2005). Wind output might rise from around 60 TWh a year to nearly 350 TWh a year. Electricity generation from biomass, presently at a similar level to wind generation, might rise to nearly 450 TWh a year. Much of this could be in small plants, providing combined heat and power.

This increase in wind and other distributed generation poses significant challenges for the electricity system. Wind power is not controllable, except to the extent that electricity can be spilled by rotating a turbine's blades and reducing its efficiency if the system is unable to accept its full power output. The level of output depends on the wind, and this is highly variable. In Western Denmark, the total wind output during 2007 was equal to 26.3% of consumption, but for 10 per cent of the hours in the year, it was less than 2.7% of the consumption in that hour, and for 10 per cent, it was more than 61.8%. In 50 hours, wind output exceeded the local demand (source: Energinet). There can also be significant fluctuations from hour to hour – in Western Denmark, wind output changed by at least ten percent of capacity in 5 per cent of the hours in 2007. The Danish system operator is able to keep its system in balance by exporting power when it has a surplus, but this depends on its neighbours' ability to absorb the fluctuations. As the proportion of intermittent plant in neighbouring systems increases, each country will have to manage a greater share of its own fluctuations.

This means that the load on thermal plants becomes far more variable. At the operational level, more plants must be kept in reserve to cope with the risk of a sudden loss of power when wind speeds fall (or exceed the point at which the turbine must shut down for its own safety). This is exacerbated if the trading system requires generators to submit their plans a long time in advance. Bathurst *et al* (2002) show how the imbalance pricing regime under NETA penalised wind generators in England and Wales. Holttinen (2005) shows that a generator in the Nordic market, normally trading between 12 and 36 hours before delivery, would increase its net income by 4% if it could trade between 6 and 12 hours in advance, and by 8% (in total) if it could trade just one hour in advance. Müsgens and Neuhoff (2006) show that trading closer to real time would also reduce the cost of thermal power, since fewer stations would be started up, only to find that previously unexpected wind power substitutes for their output.

Moving to investment, more capacity is needed in total, to compensate for the risk that the wind stations are not producing at the times of the system peak. These costs are estimated in a number of studies, summarised by Gross *et al.* (2006). Their conclusion for Great Britain was that the cost of intermittency would be in the range of £5-8/MWh of intermittent output, at least while wind power supplied less than 20% of annual demand. In the market context, however, the volatility means that prices, and particularly peak prices, will become more volatile. This could well reduce the attractiveness of keeping peaking plant open at the very time when a greater reserve margin becomes necessary.

The other aspect of variable wind outputs is geographical. For obvious reasons, wind stations are mostly built in places with high average wind speeds, and these are not spread evenly over Europe. In Great Britain, most wind farms are in the north and west, remote from the load centres, with a few more helpfully located in East Anglia. Plans for future stations show an even stronger bias towards locations in Scotland. If these stations are built, then the transmission system in its present state will not be able to accommodate all of their output on a windy day. One approach (and that formally enshrined in the industry's rules) is not to connect any wind farms until the transmission system *can* accommodate all their output, but this has the weakness that constraints that might only bind for a few hours a year are then causing either a delay in generation investment or excessive investment in transmission.[10] Strbac *et al* (2007) estimate that with 10 GW of wind capacity in Scotland, the economic level of transmission capacity on the border with England would be 5.4 GW, compared to the 7.6

[10] In Great Britain, the difficulty of getting planning permission means that the consequence has generally been a delay in investment, but in Texas, generators were allowed to build wind farms in an area (McCamey) with good wind resources, but behind a local constraint that could only be relaxed with an investment of $150 million (Texas PUC, 2003).

GW that the present planning standards require. This would, however, entail a significant increase in transmission constraints – which has been accepted in Greece as the most efficient way to allow more wind power (Kabouris and Vournas, 2004).

Distributed CHP plants, unlike wind, are controllable, but achieve their maximum levels of technical efficiency if they are scheduled to run when there is a demand for heat, which need not coincide with the needs of the grid. Hawkes and Leach (2007) find that residential micro-CHP plants, with an electrical output of only 1 kWe, may find it most economic to follow the greater of the home's heat or electricity demands, and Peacock and Newborough (2007) show that these plants could be operated in a way that reduces loads on their local distribution system. Larger plants with heat storage can also synchronise their electricity generation with the grid's needs, but still need an incentive to do so. Gordijn and Akkermans (2007) discuss several business models for distributed generation (DG), highlighting the need for the model to be attractive both to the generator-customer and to the electricity industry. They find that the business case is significantly helped by regulatory stability and by the ability "to sell and trade directly on a power exchange market" (p. 1188). This contrasts with what Strbac (2007) calls the "'fit and forget' approach" to connecting distributed generation, in which "no real attempt has been made to integrate DG in system operation" (p. 1143). Strbac regards it as "an economic imperative that DG participates in the provision of ancillary services needed for secure and reliable operation of the power system" (p. 1147).

It is unlikely to be realistic for many distributed generators to participate directly in the market – many of the owners are small companies or individuals, without the capacity to actively engage in the electricity market. Instead, they should trade through intermediaries, presumably the companies that would also sell them power at times when their generation is inadequate for their own needs. This means that when we think about the requirement for the market to be as simple as possible, we can do so in relation to the capacity of a specialised participant, and not a typical individual. The market rules should allow many small sources to be aggregated (since system operators would be incapable of dealing with each individually). When the rules create an anomaly, such as (for example) paying very different prices for generators small enough to be treated as negative demand, and those large enough to be treated as generation, there must be clear boundaries to show how any given generator will be treated. These can minimise attempts at regulatory arbitrage, even though they may then influence investment decisions designed to stay on the more favourable side of the boundary.

But what about the main features of wholesale market design - what do the combination of high levels of wind energy and distributed CHP imply for the optimal wholesale trading system? First, there need to be genuine opportunities to trade power in a liquid market close to real time, so that wind generators can react to the latest weather forecasts. A market that is formally open, but illiquid, does not provide a low-cost opportunity to correct an earlier position. Real-time markets in the US meet this criterion, and some European systems include liquid short-term markets, but many do not.

Spatial issues are likely to become more important, and this will increase the differences between nodal and zonal prices. Nodal prices will lead to a more efficient dispatch, and can also signal an area that generators should avoid because of transmission constraints. The disadvantage of this feature is that generators already located in the area, which may not have been constrained in the past, will suffer from lower revenues. At the very least, the risk that this might happen will increase the cost of capital, while the worst case would be that some generators would close, unable to cover their (avoidable) costs. The advantage of avoiding investment in areas where excessive amounts of the power generated would be lost to transmission constraints should outweigh this risk, however.

Prices are likely to be more volatile, over both time and space. This will increase risks and hence the importance of hedging tools. Hedging in a zonal market may appear to be easier, because there are fewer products to trade. In a nodal market, however, financial transmission rights can allow market participants to hedge price differentials between zones, reducing their risks and those of the system operator, which is the natural counter-party to these instruments. In a zonal market, the costs of congestion do not disappear, being paid by the system operator and then passed on to market participants, but in a manner that may be hard to hedge.

The rules surrounding ancillary services will become more important, as the need for reserves increases, and there are fewer conventional generators able to provide them. Distributed generators must be able to provide these services, both to reduce the strain on (and cost of) conventional generation, and to increase their own commercial viability (Strbac, 2007). Under the US model, both the main energy markets and the purchase of ancillary services are the responsibility of the independent system operator. It could be easier for distributed generators to sell ancillary services in this setting than in Europe, where energy markets are operated by companies distinct from the transmission companies that procure ancillary services. The advantage of the European model, however, is that an asset-rich transmission company is in a position to accept higher-powered incentives than an independent system operator in the US, which owns few assets. If European regulators provide strong incentives to keep down the cost of ancillary services (as has happened in Great Britain, but is not inevitable) then transmission (and distribution) companies could be more pro-active in seeking services from distributed generators.

Finally, the need for rarely-used reserve capacity is likely to increase. Most European markets do not have formal markets for capacity, relying on energy prices to remunerate investment in generation. If energy prices become more volatile, however, these peak revenues will come from a smaller number of hours, increasing the risk that any individual generator will not be available during those hours, and hence that it will not recover its costs in that year. Capacity markets in the US will need to give a realistic amount of credit (neither too little nor too much) to intermittent generators, but will provide a more stable revenue stream to peaking generators, reducing their cost of capital.

7. CONCLUSIONS

How do the two stylised market designs measure up against the criteria set out in section 2? First, it is important to remember how much the designs have in common. In almost every case, participation in any centralised day-ahead market is voluntary, and most power is traded bilaterally through long-lasting contracts, or kept within an integrated company. In real time, generators respond to the system operator's instructions and are paid for doing so, receiving their own offered price or that of a more expensive unit that was also needed. The main differences are in the treatment of transmission effects (whether the markets are zonal or nodal), in the presence or absence of a capacity market, and in whether the main spot market is run by the system operator that also procures ancillary services.

To take the first principle from section 2, systems based around nodal pricing, with day-ahead markets that are repeated close to real time, will lead to more efficient operations. Green (2007) found that moving from one to thirteen prices in a simplified model of England and Wales would improve social welfare by 1.3% of generators' annual revenues. Most of these gains came from the signals sent to consumers, since the system operator had to change generators' outputs in response to constraints, in ways that reduced transmission losses, whether or not most generators received locational price signals. The US markets set zonal, rather than nodal, prices for demand, but even if the signals to consumers are muted, the impacts on generation efficiency are worth having. Price (2007) reports a study that simulated the Californian system, comparing the current market rules with a nodal market which was also aided by the adoption of better tools to estimate the state of the transmission system. The combination of better price signals and a greater use of the available capacity led to more response from generators and a reduction in congestion costs.

Considering signals for investment, each design has advantages. The price caps imposed upon most US markets can stop peak prices rising to the level needed to remunerate generators' fixed costs, but the capacity markets that are also part of the standard design provide an alternative revenue source. Most European systems lack a formal capacity market, and therefore rely on the expected prices for energy and ancillary services (particularly reserve) rising to levels sufficient to encourage investment when this is needed – if this does not happen, there could be shortages of capacity. Forward trading may help to hedge the risks involved in investment, although contract markets will only be liquid for a few years into the future – a very small proportion of a power plant's life. The apparently simpler structure of most European markets might help to encourage forward (or futures) trading, compared to the complexities of nodal pricing. In practice, futures trading in the US is mostly based around trading hubs, weighted averages of the nodal prices at many locations, and liquid markets have grown up. In 2007, the volume of financial contracts traded against the PJM market was 3.4 times the final sales of power in the area, and while this was below the level of Nord Pool (5.6 times), it was hardly illiquid.[11]

The US system is clearly better than a zonal design when it comes to sending signals about the best location for new generation or demand (the third principle). However, there is a danger that generators sited in a region that becomes export-constrained region could suffer from lower prices under a nodal system than a zonal system. To that extent, the nodal system may be worse when assessed against the fourth principle, that of compensating generators. If a generator could buy a (very) long term financial transmission right, ensuring that it could sell its power at the price of the system's trading hub, whatever happened to local congestion in future, this potential weakness would be less of a problem.

The fifth principle calls for markets to be simple, transparent, and stable. The European design is superficially simpler, and an energy market based upon a simple stack of bids and offers within each zone could appear more transparent than the complexities of nodal pricing. The problem is that ancillary services, constraint management and system balancing are still needed in the European system, and are the responsibility of the transmission company rather than the market operator. What is a complex process within an independent system operator may become an opaque one within a transmission company. If the transmission company is integrated with generation, it may be hard to dispel the suspicion that the affiliated generators are being favoured. As for stability, this is linked to the perceived performance of the market. Markets in England and Wales, in California and in Texas were re-designed because they were perceived to have failed. Europe's zonal model is likely to deliver a less efficient outcome than a nodal market would have done, but if this performance is deemed to be adequate (since the counter-factual nodal results would not be visible), the model could still be stable.

The final principle for market design recognises that there is no point in designing a perfect market that is never implemented because it cannot get political support. Every EU Member State is moving towards liberalisation, whereas many US states are not, but this is not related to market design questions, as these are settled after the decision on whether or not

[11] The figure for PJM refers to financial contracts traded by the ICE and Nymex (source: ICE), while the figure for Nord Pool includes financial contracts traded on its futures market, and those contracts submitted to the company for clearing (source: Nord Pool).

to liberalise. However, the European Commission has not been able to push Member States too hard, and in the proposed third electricity directive, for example, still gives the creation of an independent system operator as an alternative to full ownership unbundling of transmission. In the absence of either, it would have been very undesirable for the main electricity market to have been run by a transmission company integrated with generation, thereby making the US market model infeasible. If Member States accept the proposed directive, however, and create independent system operators, then establishing nodal markets becomes feasible. This does not mean that it would be easy – generators with plants located in areas that would see lower prices are likely to be aware of this, and to lobby against the change. Nonetheless, nodal markets, run by an independent system operator, provide for more efficient operation than alternative designs. Increasing amounts of low-carbon electricity generation will make system operation a more challenging task, and we should use the best tools available for it.

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