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Electricity Transmission Pricing: How much does it cost to get it wrong?

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Economists know how to calculate optimal prices for electricity transmission. These are rarely applied in practice. This paper develops a thirteen node model, based on the transmission system in England and Wales, incorporating losses and transmission constraints. It is solved with optimal prices, and with uniform prices for demand and for generation, but re-dispatching to take account of transmission constraints. Counting consumer surplus and generators' operating costs alone, moving from optimal prices to uniform prices reduces welfare by 0.6% of the generators' revenue. A less efficient re-dispatch could raise these costs significantly.

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I. Introduction

The economic theory of electricity transmission pricing is now well-known. The first-best price of electricity at each point on a network (node) equals the marginal cost of providing electricity at that node. The electricity must not only be generated, but it must also be delivered to that node, taking account of transmission constraints and electrical losses. If transmission constraints are binding, so that the amount of power flowing through a line is at the limit which safety allows, then cheap but distant generation may have to be replaced with more expensive local generation, in order to reduce power flows. In the constrained area, the optimal price of electricity rises to the marginal cost of the local generation, or to the level needed to ration demand to the amount of electricity available. Even if there are no constraints, some power will be lost in the transmission system (dissipated as heat), and prices should reflect the fact that it is more expensive to provide electricity at the far end of a heavily loaded line than close to a power station. Transmission Congestion Contracts (Hogan, 1992) could be used to hedge spatial price differentials, and to help coordinate investment.

These principles are well-known, but few electricity systems have adopted them. New Zealand and a small number of US power pools have markets which are based upon nodal spot prices, but almost every other country in the world uses a simplified system of transmission pricing. Nodes may be grouped together into zones, and the price differentials between zones are calculated from simplified models. Other systems still see transmission as an “overhead” cost, and use simple “wheeling rates” to calculate payments if one company imports power from a second over the lines of a third. These payments are typically based upon the volume of the flow and the length of its contracted route (the MW-mile approach), and frequently ignore the fact that any transaction in an interconnected system will affect power flows on all the other networks in that system. A special issue of *Utilities Policy* (1997) discusses the pricing rules adopted in eight electricity systems, assessing them against economic and political criteria. One common theme is that these rules tend to produce lower price differentials than would be associated with optimal spot prices.

How important are the differences between the relatively simple rules adopted in practice, and the prices which an optimal system would produce? One of the main economic functions of a price system is to signal the opportunity cost of alternative courses of action. On the demand side, an agent should buy something if it is valued at more than its price, while a supplier should produce it if this can be done for less than its price. If buyers and suppliers face the same prices, their independent decisions will ensure that the value of output at the margin is just equal to its marginal cost, which is optimal. If prices are above marginal costs, then too little of a good will be consumed and produced, while too much will be produced if prices are below marginal costs.[1] The wrong prices can also lead to inefficient "bypass" as agents have an incentive to leave the market, and arrange deals at prices closer to their costs.[2]

This paper takes a simplified model of a transmission system, calculates optimal prices and quantities, and compares the outcome with those that simpler rules would produce. The model has thirteen nodes, with demand at every node and generation at most of them. The amounts of generation and demand, and the links between nodes, are intended as a simplified version of the transmission system in England and Wales. The profits earned by generators, and consumer surplus (the total amount consumers would be willing to pay for their consumption, less the amount which they do pay) can be calculated at each node for each pricing rule. Our main comparator is total welfare, equal to the sum of consumer surplus and profits.

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[1] This is a slight simplification. When there are several goods, slightly too much of one good may be produced, even though its price is *above* marginal cost, because other prices are further away from costs.

[2] We will return to this issue in the conclusions.

Green (1994) used a similar model to examine changes in the total cost of generation once transmission losses were reflected in the dispatch, but ignored transmission constraints. Macatangay (1997) takes account of constraints (but not losses) and calculates the price for each zone on the NGC system as the dual value in a power flow optimisation. Ilic *et al* (1997) use a detailed model of New England to show how the payments for seven hypothetical wheeling transactions would change between three different cost allocation rules. None of these papers studies the impact of spatial pricing on demand.[3] This paper incorporates demand responses in a model which takes account of both losses and transmission constraints.

The paper does not look at the interaction between market power in generation and the transmission system. Generators are assumed to bid at marginal cost, although they might find it profitable to increase prices: this may involve *increasing* output at some locations, in order to tighten a transmission constraint and raise prices elsewhere (Cardell *et. al.* (1997)). Oren (1996) suggests that actively traded contracts could reduce the incentives for this kind of behaviour. Borenstein *et al* (1996) show how small increases in transmission capacity can lead to significant reductions in market power.

The next section of the paper gives a brief outline of the theory of transmission pricing. Section III describes the model. Section IV shows how welfare changes with the number of prices used. Welfare is highest when the model is solved with optimal prices (one for each node), and lowest with a single price for demand and one for generation. We assume that the system operator imposes a re-dispatch to take account of transmission constraints when they are not reflected in local generation prices, and compensates generators for the opportunity costs of being constrained. The model is also solved with one price for demand and thirteen for generation, and *vice versa*. Section VI concludes.

II. Optimal Transmission Pricing

The optimal prices for electricity transmission can be seen as arising from the problem of maximising the net welfare obtained from electricity consumption, subject to a number of

3 Another paper which may be relevant, but which I have not yet seen, is Read and Ring (1998).

constraints. This net welfare is equal to the benefit from consuming electricity, less the cost of generating it. For simplicity, we will ignore any variable costs which are not manifested in a need for increased generation.[4] The constraints to be met are that total generation must equal total demand, plus losses, and that the flow along each transmission line must be less than the capacity of that line. An additional set of constraints is traditionally used to ensure that no power station generates above its capacity.

The theory of spot pricing is set in detail out by Schweppe *et al* (1988). A shorter exposition is given by Hsu (1997), and this explanation draws heavily on his version. We can write the problem as:

$$\begin{array}{llll}
\underset{\underline{d},\underline{g}}{\text{maximise}} & W = & \sum_k B(d_k) - \sum_j C(g_j) & \\
\text{subject to} & & \sum_k d_k + \text{losses} - \sum_j g_j = 0 & \text{(energy balance constraint)} \\
 & & |z_i| \le z_i^{\max} & \text{(line flow constraints)} \\
 & & \mathrm{g}_\mathrm{j} \le \mathrm{g}_\mathrm{j}^{\max} & \text{(individual generation constraints)} \\
 & & \sum_j \mathrm{g}_j \le \mathrm{g}_{\mathrm{crit}} & \text{(total generation constraint)}
\end{array}$$

where d_k represents the demand at node *k*, g_j represents the generation at node *j*, and z_i represents the flow along line *i*. The amount of generation capacity at node *j* is given by $g_j^{\max}$, while the total amount of generation available is given by g_{crit}. The maximum flow allowed on line *i* is given by $z_i^{\max}$. A load flow model can be used to derive the flow on each line from the vector of generation and demand at each node. We will use the DC load flow model, which makes a number of simplifying assumptions, but gives a reasonable approximation to the real power flows on a network. The model actually derives the flows over a network with *n* nodes from the net injections at *n*-1 of them: the injection at the final bus, known as the swing bus, can be derived as a residual. It has to

[4] In other words, we assume that the cost of transmission maintenance, for example, does not depend on

equal the sum of the net injections at the other nodes, plus the losses on the network, by the law of conservation of energy. It is helpful in deriving our results if we assume that the marginal generator on the system is located at the swing bus, although the prices produced by the model do not depend upon the choice of swing bus.

We can rewrite our optimisation problem as a Lagrangean:

$$\underset{\underline{d},\underline{g}}{\text{maximise}} \quad \sum_k B(d_k) - \sum_j C(g_j)$$

$$- \; m_{\mathrm{e}} \left(\sum_k d_k + \text{losses} - \sum_j g_j \right) \qquad \text{(energy balance constraint)}$$

$$- \; m_{\mathrm{i}}^{\mathrm{QS}} \left(\left| z_i \right| - z_i^{\max} \right) \qquad \text{(line flow constraints)}$$

$$- \; m_{\mathrm{j}}^{\max} \left(\mathrm{g}_{\mathrm{j}} - \mathrm{g}_{\mathrm{j}}^{\max} \right) \qquad \text{(individual generation constraints)}$$

$$- \; g \quad \left(\sum_j \mathrm{g}_j - \mathrm{g}_{\mathrm{crit}} \right) \qquad \text{(total generation constraint)}$$

We have first order conditions:

$$\frac{\P B}{\P d_k} - m_e \left[1 + \frac{\P\ \text{losses}}{\P d_k} \right] - \sum_i m_i^{QS} \frac{\P z_i}{\P d_k} = 0$$

and

$$-\frac{\P C}{\P g_j} - m_e \left[\frac{\P\ \text{losses}}{\P g_j} - 1 \right] - \sum_i m_i^{QS} \frac{\P z_i}{\P g_j} - m_j^{\max} - g \;\; = 0$$

Individual consumers can be assumed to consume up to the point where their marginal benefits equal the price they pay, which implies that we should set the price at node *k*, p_k, equal to the level we want their marginal benefit to take:

$$p_k \; = \; m_e \left[1 \; + \; \frac{\P\ \text{losses}}{\P d_k} \right] + \sum_i m_i^{QS} \frac{\P z_i}{\P d_k}$$

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the level of power flows.

Reducing generation at a node by 1 MW has exactly the same effects as increasing demand at that node by 1 MW. We can therefore rewrite the first order conditions for generation as:

$$\frac{\P C}{\P g_j} + m_j^{\max} + g = m_e\left[1 - \frac{\P \text{ losses}}{\P g_j}\right] - \sum_i m_i^{QS}\frac{\P z_i}{\P g_j}$$

$$= m_e\left[1 + \frac{\P \text{ losses}}{\P d_k}\right] + \sum_i m_i^{QS}\frac{\P z_i}{\P d_k} = p_k$$

Define p^* as the price at the swing bus. By definition, inputs at the swing bus do not affect the flows over the system, and so we have $p^* = m_e$, the shadow price on the energy constraint. This equals the marginal cost of generation at that bus, plus the sum of the two shadow prices on generation capacity: in total, and at that bus. Since the marginal generator is located at the swing bus, we should define $m_{\text{swing}}^{\max} \equiv 0$: if the marginal generator is short of capacity, then there is an overall shortage of capacity. If there is an overall shortage of capacity, then its shadow price, g , is equal to the difference between the marginal cost of generation and the marginal benefit of consumption at the swing bus. The marginal cost of generation at the swing bus is known as "system lambda", l .

At any other node, the price of electricity can be seen as the value of electricity at the swing bus, plus the cost of transporting it from the swing bus to that node. If there were no transmission constraints on the network, we would have:

$$p_k = p^*\left[1 + \frac{\P \text{ losses}}{\P d_k}\right] = \left(l + g\right)\left[1 + \frac{\P \text{ losses}}{\P d_k}\right]$$

If increasing demand by 1 MW at node *k* increases system losses by *l* MW, then generation at the swing bus would have to increase by (1 + *l*) MW, and so the price at node *k* should be (1 + *l*) times the price at the swing bus. At some nodes, extra demand will reduce the flows on the transmission system, and hence the losses, and so the price should be below the price at the swing bus: at other nodes, the price must be raised to take account not only of the energy consumed at the node, but also the energy lost in getting it there.

Transmission constraints mean that the cheapest generators may not be able to operate to their full capacity, because some lines would become too heavily loaded, and so more expensive generators are required instead. For each line, the term m_i^{QS} is the shadow price of the constraint, based on the cost of the expensive generation which is required, less the cost of the generation which cannot be used. To convert the cost of a constraint on a line into a price for a node, we must multiply the shadow price of the constraint by the marginal flow along the line caused by an extra MW of demand at the node. If increasing demand at a node reduces the flow along a congested line, then the net effect will be negative, reducing the price at that node. We can restate the price:

$$p_k = (l + g)\left[1 + \frac{\P\,\text{losses}}{\P d_k}\right] + \sum_i m_i^{QS} \frac{\P z_i}{\P d_k}$$

Finally, we need to consider operating rules for generators. If the price at a node is below their marginal operating cost, they should not generate. If they can generate at a level where their marginal operating cost is equal to the price at their node, they should do so. The price should only exceed their marginal operating cost if they are operating at full capacity, and in this case, the difference between price and cost is equal to $m_j^{\max} + g$, the shadow prices on capacity.

III. The Model

This paper studies the effect of transmission pricing schemes on a simple model, but one which is intended to represent the main flows over the national grid system in England and Wales. That system has 14,000 km of 275 kV and 400 kV transmission lines, in 400 circuits which connect 200 substations. The (winter) peak demand on the system is presently just under 50 GW. The main power flows are from power stations in the north of England and the Midlands to the south, although there are several large power stations in the south-east, near the Thames Estuary.

The National Grid Company (NGC) has divided its system into a number of zones for charging generators: the boundaries of the zones generally coincide with groups of circuits which are heavily loaded and might be constrained under some operating conditions. Our model is based upon the zones used in the mid-1990s, and uses one node to represent each zone. The exceptions are that the northernmost zone is split into two, and that two southern zones with no generation are combined with their neighbours. Twenty-one lines link our thirteen nodes, so that all zones which were directly connected are linked.

The model is based upon a projection for 1999, made by NGC in 1993. The company publishes a seven-year projection of demand and capacity each year, together with data on the transmission system. The final year of the period was chosen as this is the only year for which information on marginal losses is reported. Table 1 shows the distribution of demand and generation at the winter peak. Generation in zones 0 and 1

Table 1: Zones, Generation and Demand

<table>
<tr><th>Zone</th><th>Name</th><th>Demand</th><th>Generation</th><th>Marginal Loss</th></tr>
<tr><td>0</td><td>North [-Western]</td><td>0.3</td><td>0.8</td><td rowspan="2">+ 9%</td></tr>
<tr><td>1</td><td>North [-Eastern]</td><td>2.7</td><td>5.5</td></tr>
<tr><td>2</td><td>Yorkshire</td><td>6.3</td><td>11.9</td><td>+ 6%</td></tr>
<tr><td>3</td><td>N Wales and W Lancs</td><td>4.5</td><td>8.2</td><td>+ 6%</td></tr>
<tr><td>4</td><td>E Lancashire</td><td>3.0</td><td>0.0</td><td>+ 4%</td></tr>
<tr><td>5</td><td>Nottinghamshire</td><td>0.5</td><td>4.5</td><td>+ 4%</td></tr>
<tr><td>6</td><td>West Midlands</td><td>7.5</td><td>4.2</td><td>+ 1%</td></tr>
<tr><td>7</td><td>East Anglia</td><td>5.2</td><td>3.5</td><td>0</td></tr>
<tr><td>8</td><td>West and Wales</td><td>4.8</td><td>3.0</td><td>- 3%</td></tr>
<tr><td>9</td><td>[Thames] Estuary</td><td>2.8</td><td>8.4</td><td>- 2%</td></tr>
<tr><td>10</td><td>London [Inner and Outer]</td><td>9.5</td><td>1.5</td><td>- 2%</td></tr>
<tr><td>12</td><td>South Coast</td><td>4.2</td><td>1.3</td><td>- 4%</td></tr>
<tr><td>13</td><td>Wessex and Peninsula</td><td>2.9</td><td>1.4</td><td>- 4%</td></tr>
</table>

Source: NGC, (1994)

includes 0.8 GW of imports from Scotland in each zone, while generation in zone 9 includes 2 GW of imports from France. The table also gives NGC's predictions of the marginal losses from extra generation in each zone: these were used as a guide when calibrating the model, although it does not quite replicate them.

Table 2 gives more information on the generation which is located at each node. Two types are identified: must-run and variable. The must-run plant includes nuclear and combined-cycle gas turbine stations which invariably submit very low bids and are scheduled to run as often as they are available. Other stations are classed as variable, and are assumed to have a linear marginal cost function: table 2 shows the amount of generation that has a marginal cost of £40/MWh or less. Figure 1 shows the assumed marginal cost function for zone 9.

This form of marginal cost function is a simplification, because the marginal cost function for any one power station would be roughly horizontal, while a node with several

Table 2: Types of Generation

Zone	Name	Must-run	Variable	Total
0	North [Western]	0.8	0.0	0.8
1	North [Eastern]	3.8	1.7	5.5
2	Yorkshire	2.0	9.9	11.9
3	N Wales and W Lancs	5.0	3.2	8.2
4	E Lancashire	0.0	0.0	0.0
5	Nottinghamshire	0.0	4.5	4.5
6	West Midlands	0.0	4.2	4.2
7	East Anglia	3.0	0.5	3.5
8	West and Wales	0.5	2.5	3.0
9	[Thames] Estuary	4.0	4.4	8.4
10	London [Inner and Outer]	1.5	0.0	1.5
12	South Coast	0.0	1.3	1.3
13	Wessex and Peninsula	1.4	0.0	1.4

stations would have a step function. This would imply that small changes in prices would frequently have no effect on the pattern of generation, but that a change would occasionally have a discontinuous impact as one station became cheaper than another.[5] In the presence of discontinuities, the cost of a distortion may be very sensitive to the size of that distortion, since small distortions will be costless. Our formulation gives more opportunities for adjusting generation in response to prices.

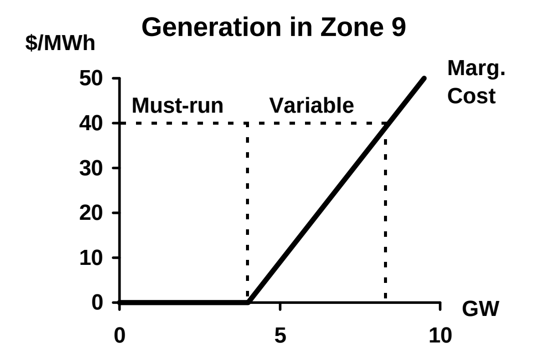

Figure 1

Demand is price sensitive, with a constant elasticity of -0.25 at each node, representing a “medium-term”, rather than a “short-term”, response. This is the elasticity with respect to the price of generation: the implied elasticity with respect to the final price will be rather greater. The demand curves are anchored at a price of £40/MWh at each node, and the quantities given in table 1, reduced by 1.2% to take account of transmission losses.[6] This price is not intended as a prediction of the equilibrium in the English market, but as a convenient value with which to anchor our “base case.”

Figure 2 shows how the network of lines links the thirteen nodes in the model. With two exceptions, electricity flows from a lower to a higher numbered zone: the reverse flows are from zone 0 (the western half of NGC’s zone 1) to zone 1, and from zone 12 to zone 10.

Table 3 describes the lines which link these zones: the resistances have been chosen (by trial and error) so that the flows between zones, and the marginal losses incurred on demand in each zone, are close to those given in NGC (1994). Given the *ad*

[5] This could lead to further complications, if the new distribution of generation affected power flows and the associated prices. In practice, the price at each of several nodes might be set to equal the marginal cost of a station at that node, and the output from each station would then have to be adjusted until the resulting power flows meant that the selected prices were the correct spot prices, given the power flows.

[6] The zonal demand and generation figures given by NGC and reproduced in table 1 have the same sum, but this takes no account of transmission losses. Generation must be scaled up, or demand scaled down, if they are to be in balance, and we have chosen to reduce demand.

hoc way in which the resistances have been chosen, it might be inappropriate to claim that this model *represents* the NGC system, but it is likely to behave in similar ways in response to small changes in generation or demand. The aim of this paper is to consider whether different transmission pricing systems will have an important practical impact on the electricity industry. We do not need an exact representation of any one system to answer this question, as long as our model incorporates the kind of responses which would be found in a real system.

The transmission system in England and Wales suffers from a number of constraints. Some of these are local and cannot be modelled at the lower level of detail in this paper: a particular station is required to run to make the adjoining lower-voltage

Table 3: Lines and Flows

Line	From Zone	to Zone	Resistance	Flow (GW)
1	1	0	30	0.4
2	1	2	7	2.4
3	0	3	11	0.9
4	3	4	2.75	2.7
5	2	4	4.5	2.8
6	2	5	2.5	5.2
7	3	6	12	1.9
8	4	6	6	2.5
9	5	6	6.25	2.3
10	5	7	2.75	6.9
11	6	7	3	1.5
12	6	8	8.25	1.9
13	7	8	4.75	2.4
14	7	10	4	3.7
15	7	9	2.75	0.6
16	9	10	3.25	4.1
17	9	12	6	2.1
18	12	10	3	0.2
19	8	12	1.5	2.0
20	8	13	11	0.5
21	12	13	2.5	1.0

Figure 2: Simplified Version of the Transmission System in England and Wales

Flow in GW shown on each line

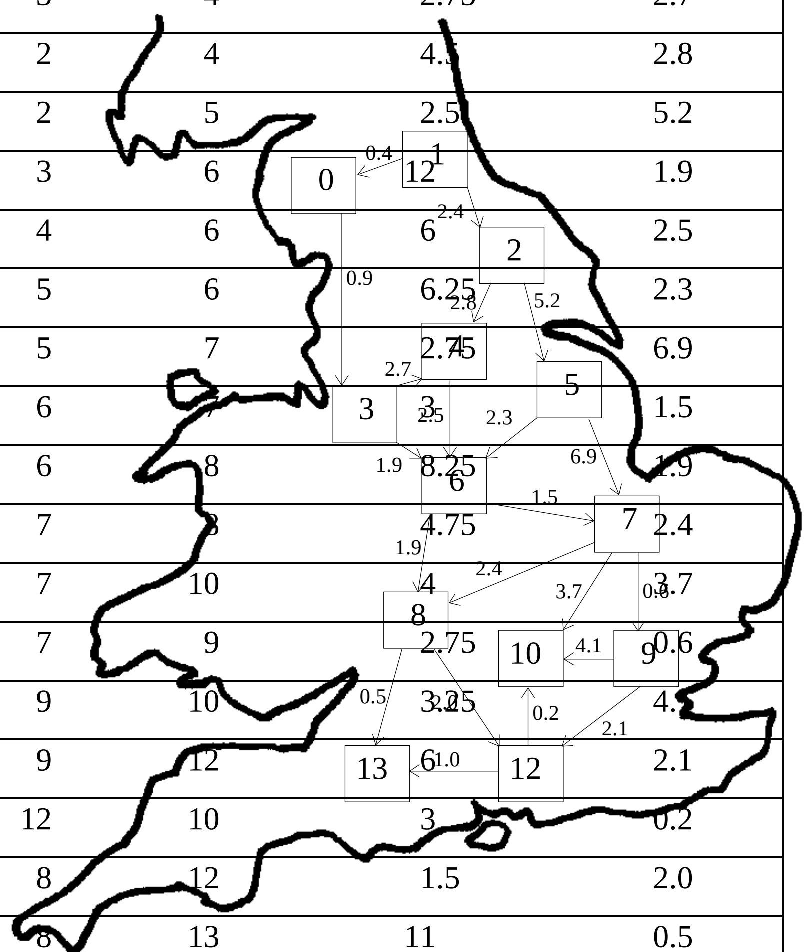

Table 4: Constraints on the NGC system

Boundary	Lines	Zones affected		Max rating (GW)
1	2,3	Exports from	0,1	2.0
2	6,7,8	Exports from	0 - 4	9.2
3	10,11,12	Exports from	0 - 6	11.0
4	17,-18,19,20	Imports to	12,13	7.7
5	3,5,6	Exports from	0,1,2	6.8
6	12,13,17,-18	Imports to	8,12,13	7.8
7	20,21	Imports to	13	4.0
8	14,16,18	Imports to	10	10.5
9	-15,16,17	Exports from	9	8.5
10	1,2	Exports from	1	2.0
11	7,8,9,-11,-12	Imports to	6	6.0
12	3,5,9,10	Exports from	0,1,2,5	11.5

Source: Macatangay (1997) (using information from NGC)

system more reliable. Other constraints relate to the flows across a number of heavily loaded boundaries: although NGC uses a different methodology to define its charging zones, their boundaries generally coincide with some of these critical system boundaries. Table 4 shows these constrained circuits and their maximum ratings. In practice, the system may not be able to accept the maximum flow, and the ratings were reduced by 10% when calculating whether constraints applied in the model.[7] The constraints were typically binding in the case of three boundaries, all relating to exports from the north-east and north: boundaries 1,5, and 12.

IV. Results

[7] The boundary ratings are set so that the system can absorb the loss of any circuit without overloading the remaining lines. It is usual for a few lines to be unavailable, reducing the system's capacity to take further outages, and hence the safe boundary flows.

The model was solved five times, with different pricing rules. Figures for welfare, revenues and costs are presented as if the solution held for one hour of operation. The first solution found the optimal spot price for each node, and accordingly produced the highest level of welfare (profits plus consumer surplus). In this solution, generators and consumers faced the same price at each node, shown in figure 3. The transmission constraints around zones 0 and 1 keep prices low in these zones: less than half the level of the price in any zone south of boundary 5. In general, prices rise with the number of the zone, reflecting the pattern of marginal transmission losses in an area with no constraints. Since there is (on average) more demand than generation at the higher-priced nodes, the payments by consumers exceeded the payments to generators by about £90,000 in this hour. This net payment could be used to offset the fixed costs of the grid. We do not study ways of recovering the remaining fixed transmission costs, although it is an

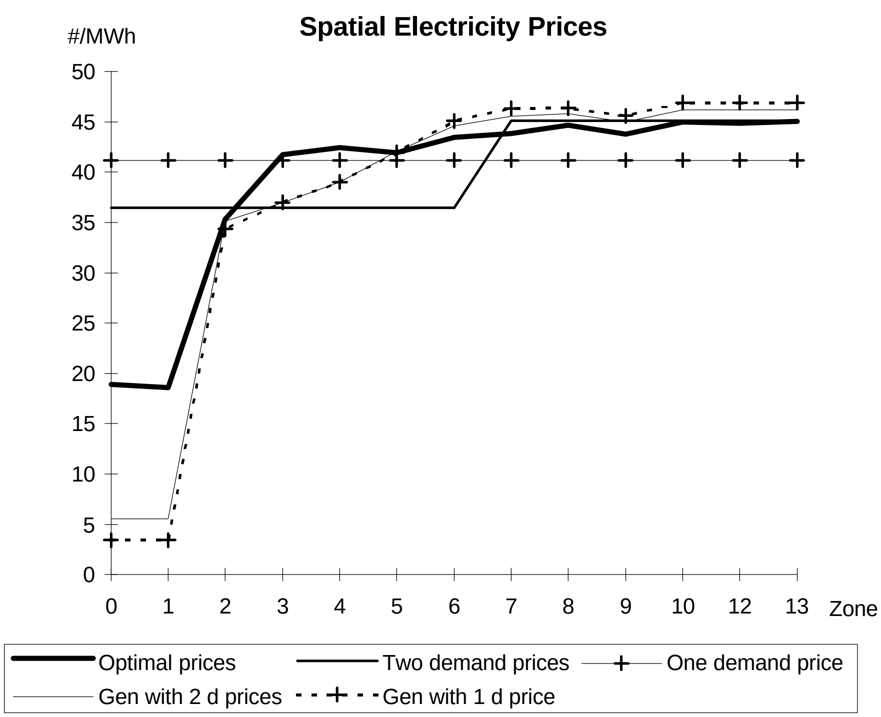

Figure 3

important issue, so that we can concentrate on the effect of spatial prices for generation. In our other solutions, we include the constraint that receipts from consumers should still exceed payments to generators by this amount. Changing the gap between the price paid by consumers and that paid by generators will tend to change the level of welfare, and this constraint is intended to ensure that pricing schemes are compared on the basis of "like with like". The total payments to generators in the hour were approximately £2.2 million.

The second solution continued to set a price for each node with generation, but only had two prices for demand: one applied to the seven northern nodes (0-6) and one to the six southern nodes (7-11,12, and 13). The prices were chosen to maximise welfare, but the division of nodes into these two zones was arbitrary. The prices were constrained to produce the same surplus for the grid operator as before. The change implied a small increase in prices for consumers at nodes 7-9, a rather bigger reduction for those at nodes 3-6, and a very large increase for consumers at nodes 0 and 1. This meant that there was less consumption at those constrained nodes, and so generation there had to be reduced: figure 3 shows that the spread of generation prices increased as the spread of demand prices was reduced. Total welfare was approximately £10,000 lower than with optimal pricing: this is equivalent to a cost increase of 0.5%. The third solution assumed that all consumers would pay the same price: the spread of generation prices increased slightly, and welfare fell by another £3,000.

The fourth solution adopted the dispatch rules used in England and Wales in the mid-1990s, which has one price for demand, and a second for most generation. In the initial (unconstrained) schedule, all generators are dispatched as if they were at the same node, and a single price is paid for all generation in this schedule. To meet constraints, some stations are then made to reduce their output (they are constrained off) and others to increase it (they are constrained on). The stations are paid their bid for the change in output, and if bidding at marginal cost, this leaves their profits at the same level as if there had been no constraints. The net cost is the payments to stations which are constrained on, less the payments from stations which are constrained off: these payments are lower, since the stations which are reducing output necessarily have lower costs.

Output at two nodes had to be reduced: at node 1 to reduce the flow across boundary 1 (which enclosed nodes 0 (which had no variable generation) and 1), and at node 2 to reduce the flow across boundary 5 (which enclosed nodes 0-2). Output at the remaining nodes was increased until total generation was again equal to demand. As far as possible, this was done by increasing generation at each of these nodes in the same proportion, so that the marginal cost at each node remained equal. In the absence of losses, which have been ignored in England and Wales when selecting which stations to run, this would minimise the cost of the re-dispatch. In practice, output at node 5 could not be increased as much as this rule implied without exceeding the flow limit on boundary 12 (which enclosed nodes 0-2 and 5). Output at this node was accordingly increased until the transmission constraint was just binding, and the remaining output required was spread across the other nodes. The net cost of this re-dispatch was about 2% of the cost of generation. This is in line with constraint costs on the national grid in England and Wales, for the parameter values were chosen with this in mind.

The effect of moving from optimal generation prices to a single price, combined with a re-dispatch to take account of transmission constraints, is to ignore the cost of losses. Constraints cannot be ignored if the dispatch is to be feasible. Welfare was £150 lower with a single price for generation (and one for demand) than with optimal generation prices (and a single demand price). The fifth solution to the model kept a single price for generation (and a re-dispatch to take account of constraints), but calculated and applied optimal prices for demand. The pattern of demand prices was similar to the optimal prices from the first solution, while welfare was just £240 lower than with optimal prices. Table 5 summarises these results. The top left hand cell shows that using (the same) thirteen prices for generation and demand maximises welfare, while the other cells show the reduction in welfare from using fewer prices on either side of the

Table 5: Welfare Changes

Welfare (change from optimum, £ thousand)		Number of Generation Prices: 13 (Optimal)	Number of Generation Prices: 1
Number of Demand Prices	13 (Optimal)	nil	-0.2
	2	-10.3	
	1	-13.6	-13.7

market.

The small impact which the number of generation prices has may come as a surprise, but is due to the interaction between losses and constraints in this network. To take account of constraints in the single-price dispatch, output has to be reduced at nodes 1 and 2, and output at node 5 is increased by less than at other nodes. These reductions are greater than we would wish to make on account of marginal losses alone, and so ignoring losses does not affect the cost of generation in the north. Generation in the south is sub-optimal, but the amount of output and the variation of marginal losses are much lower than in the country as a whole. In a network in which there were high marginal losses at nodes which were not affected by constraints, there might be greater gains from moving to optimal generation prices.

We can illustrate this by solving our model again, but assuming that there are no transmission constraints. Table 6 shows the changes in welfare from moving between one price for each node, and one for the whole network, for generation and for demand. Two-thirds of the benefits from moving from two network-wide prices to optimal prices now come from increasing the number of generation prices,[8] although the welfare changes are much smaller than in table 5.

The model was also solved with a lower demand elasticity, of -0.1. The results repeated the pattern of table 5, but the loss due to moving from optimal to uniform prices was nearly halved, to £7,400 an hour. If demand is less sensitive to price, then getting prices right becomes less important: once again, remember that generation had to be adjusted to meet the transmission constraints, and that this was done in a reasonably efficient manner, taking extra output from the cheapest sources available. The only

Table 6: Welfare Changes (Ignoring Constraints)

Welfare (change from optimum, £ thousand)		Number of Generation Prices	
		13 (Optimal)	1
Number of	13 (Optimal)	nil	-0.8
Demand Prices	1	-0.4	-1.2

[8] This proportion depends on the relative price elasticity of generation and demand: the higher the elasticity of generation, the more important it is to have optimal prices for generation, and similarly for demand.

inefficiency (and a small one) was that losses were ignored when assessing the cost of this generation. It seems realistic to assume a reasonably efficient re-dispatch in a system with a single market-maker and transmission operator, like England and Wales. The operator has the knowledge and ability to minimise the cost of constraints.

Some power systems do not have an operator which can act in this way. Companies in the United States have historically been free to arrange wheeling transactions over long distances as long as they can negotiate a continuous "contract path" with some of the intervening utilities. This procedure ignores the externality of loop flows along other lines, and so the transaction may create constraints which block other transactions, which could have been more efficient. One motive for spot pricing was to force companies to internalise these externalities, so that they would only want to make welfare-improving trades. Even where there is a central controller, this may not ensure an efficient dispatch. The Independent System Operator in California, for example, receives reports from Scheduling Coordinators, giving their planned operations, but can only give advice about which trades should be curtailed to produce a feasible dispatch.[9] In a perfect market, the "Coase solution" would apply, and private bargaining should bring about the welfare-maximising dispatch (in the absence of market power). In the real world, it may not be possible to achieve an efficient dispatch through bilateral trading in the time available, and the Independent System Operator will not be allowed to impose one, even though it will have the information required to do so.

We can illustrate the potential size of the costs involved if we impose one price for generation and one for demand, but change the way in which generation at nodes 1 and 2 is constrained off. Instead of an efficient re-dispatch, in which the highest cost generation is curtailed, we assume that all of the "variable" capacity at each node is curtailed in the same proportion: this might reflect a random curtailment, or an "equal misery" rule. The cost of the re-dispatch rises from £37,000 (an hour) to £60,000, and welfare falls by a further £22,000, or one per cent of the generators' total revenues. If we also introduced

[9] The Californian market can have separate prices in each of two zones, but has not adopted nodal pricing.

some inefficiency in the choice of stations to constrain on, the cost of an inefficient pricing scheme would be even greater.

V. Conclusions

This paper has illustrated the benefits of applying optimal spot prices in a simple model of an electricity network which has some of the characteristics of the industry in England and Wales. Looking at operating costs alone, moving from a system of uniform pricing for demand and for generation (except to take account of constraints) to optimal nodal prices could increase welfare by approximately 0.6% of the cost of generation. This may seem like a small number, but it can be compared to Newbery and Pollitt's (1997) estimate of the net benefits from privatising the Central Electricity Generating Board, which was equal to 5% of the Board's costs. "Throwing away" one-eighth of the benefits of that exercise might sound rather more significant.

It must be remembered, however, that introducing optimal prices will often involve transfers between agents which are much greater than the net welfare gain. That is likely to make them hard to introduce from a political point of view. The attempt to introduce transmission loss factors to the Pool Rules, which would reduce prices in the north of England, and increase them in the south, is a good example of this. The resulting prices would provide better economic signals than the present system, and the issue was identified as one for future review when the Rules were first written, in 1990, but companies which stood to lose from the change have twice appealed (unsuccessfully) to the regulator, and then started legal action in an attempt to stop it.

The gains from optimal prices will be greater once we consider their effect as investment signals to generators.[10] In the short term, moving towards optimal prices increases the output from stations in "good" locations, but since all the stations with low operating costs would have been dispatched under uniform pricing in any case, the stations where output rises must have relatively high operating costs, which limits the gain. Consider a long, heavily loaded line with a station at each end, and marginal transmission losses of 10%. If the marginal costs of the station at the "right" end of the line are 5% higher than at the other station, the saving from reallocating generation between the

[10] Spot prices are not the only way to send investment signals, however. In England and Wales, the National Grid Company has regionally differentiated capacity-based charges, encouraging investment in the south.

stations is only 5%. When considering investment, however, we can save the full 10% by placing the new station at the right end of the line, and the saving applies to capital as well as operating costs.

We have assumed that the system can be successfully dispatched without the use of spot prices, and thus ignored the issue of bypass. When prices are not equal to marginal costs, some agents may wish to leave the main market and deal independently, reducing its efficiency. Hogan (1998) describes a failed experiment in the Pennsylvania-New Jersey-Maryland (PJM) Interconnection in 1997. Customers faced a price based on an unconstrained system, but transmission constraints meant that some generators were forced not to run. They received no compensation for this, and had a strong incentive to arrange a bilateral transaction with a customer at a price between their marginal cost and the unconstrained price. Once these generators had done so, their output could not be reduced, and the system operator had to constrain some other generators instead. These then had an incentive to act in the same way, and the system operator was forced to ban bilateral trading before it ran out of dispatchable generation. A revised market mechanism uses spot prices, and is not threatened by bilateral trading. Hogan argues that any move to use zonal prices instead of nodal spot prices would create similar perverse incentives if used as a means of system coordination, and would be unlikely to simplify the calculation or interpretation of those prices.

One way to get round the problem of bypass is to ban bilateral trading, as in England and Wales, although there has been pressure to remove such an "artificial" restriction on the market. Another is to arrange compensation payments for constrained generators, funded by all consumers, so that no-one has an incentive to leave the market, but this reduces the incentive to avoid congested locations. There are ways to make an electricity market work without nodal spot pricing.

The important question is whether nodal spot pricing would make the market work better. Our estimate that spot pricing could raise welfare by 0.6% of the generators' revenues was based on a reasonably efficient re-dispatch to take account of constraints, in line with the procedures in England and Wales. The strongest argument for spot pricing may be that many regions do not have a mechanism for ensuring a sensible re-dispatch, since they rely on bilateral negotiations which are unlikely to be fully effective within the time available. We illustrated this by scaling back all of the variable generation at two nodes (effectively making the marginal cost curve steeper), rather than simply curtailing the most expensive output. Using this algorithm, the cost of uniform pricing, compared to optimal prices, rose to 1.5% of the generators' total revenues. Avoidable welfare losses of this size deserve serious attention.

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