

The changing face of the Electricity Markets in the UK

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ABSTRACT

Historically, the Electricity Generation and Supply Industry in the UK has been very different between Scotland, on the one hand, and England and Wales on the other. Two significant changes have taken place in the last 13 years in England and Wales. In 1990, the sole Generator of Electricity in England and Wales was privatised into four separate companies while the separate Regional Supply Companies were also privatised focussing their business primarily in their own geographic area. Only the Generating Companies bid into an Electricity Pool and they effectively set the price paid by the Supplier, and in turn the price paid by the consumer. Throughout the 1990s, first large consumers, then intermediate consumers, and finally all consumers could choose their supplier irrespective of the traditional regional area of business. Since late 1998, prices to the consumer have fallen between 10 and 20%.

In 2001, the New Electricity trading Arrangements came into force, and this involves both bilateral trading agreements and both generating and demand side bidding. In recent years wholesale prices of electricity have fallen by 40%. However, not all these price changes have been reflected in changes to the prices paid by consumers. In recent months the substantial fall in wholesale prices has reversed and there has been a small rise in these prices. This paper reviews the changes that have taken place in the last 15 years and focuses on some of the more important consequences of these changes. It is based on personal observations, reviews of UK Government documents such as OFGEM (2000), and analysis of UK Statistics (e.g. DTI, 2002).

INTRODUCTION

The total UK demand for electricity remained almost constant at approximately 245 TWh per year for the decade from 1972 to 1982 (DTI, 2002). However, over the last two decades there has been a steady growth in electricity demand at 2.2% per annum and the consumption in 2001 had risen to 367 TWh a figure which was 50% larger than that in 1970. The demand in Scotland has increased less rapidly at 0.7% per annum and now stands at 32 TWh per annum. Generation and Supply of electricity has always been different in Scotland from England and Wales. Before privatisation on 1st April 1990, there was a single Generating Company (Central Electricity Generating Board: CEGB) in England and Wales who generated and transmitted electricity but did not sell electricity to consumers. Instead the CEGB sold the electricity to 12 regional Electricity Boards who distributed and supplied electricity to consumers only within their region. In Scotland there were two vertically integrated companies – the North of Scotland Hydro Board, and the South of Scotland Electricity Board. Each of these two companies both generated electricity and supplied electricity to consumers in their respective areas. The situation prior to privatisation is summarised in Fig. 1.

Historically there has always been a surplus of generation capacity in Scotland which is transferred via inter-connectors to England and Wales. In 1990 8% of the electricity generated in Scotland was transferred to England and Wales, but this rose to 25% of the electricity generated by 2000 (Scottish Executive (2003). Until recently there has been no grid connection to Northern Ireland, although a 2000 MW DC link to France has been in operation since the mid 1980's. Currently, a further inter-connector to Norway rated at 1320 MW is being developed while a third inter-connector to the Netherlands, also of 1320 MW, is under consideration.

Within England and Wales, there are also significant power flows from north to south as shown in Fig. 2. Most of the coal generation in England and Wales is located in the north on the coal fields, while

the few remaining oil stations are located around the coast adjacent to oil refineries, and are mostly in the south.. The nuclear stations are located on the coast and distributed evenly around the country, while the new gas stations are situated mostly across the country, although there are some clusters of such stations.

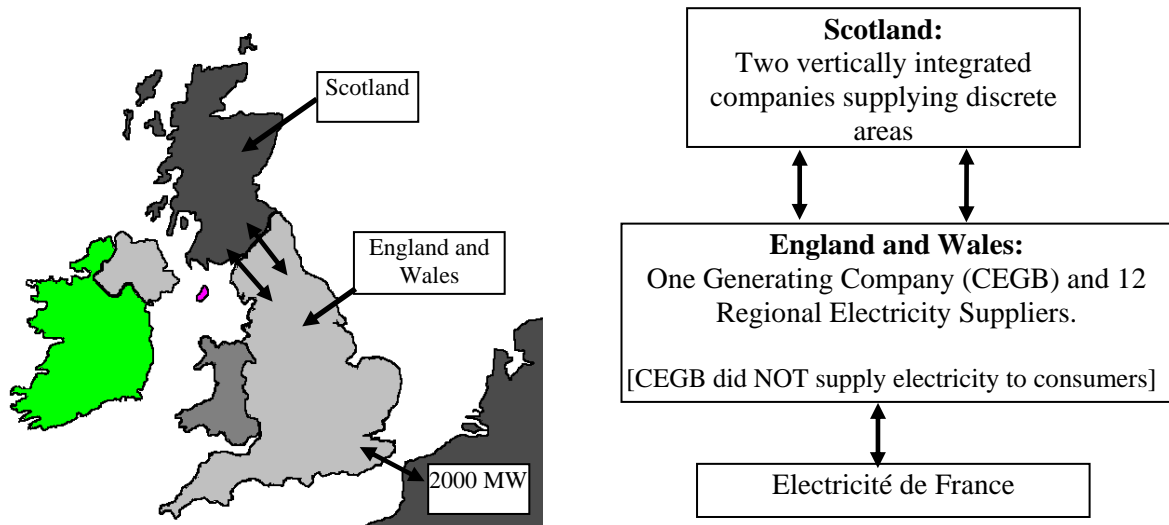


Fig. 1 Summary of Electricity Supply in UK before privatisation

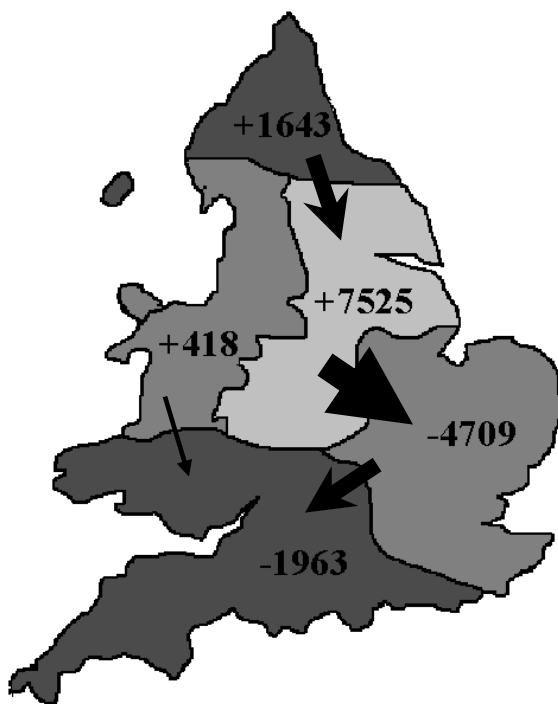


Fig. 2 Power Flows in England and Wales at 18:00 on 12th February 2003. Data from www.bmreports.com

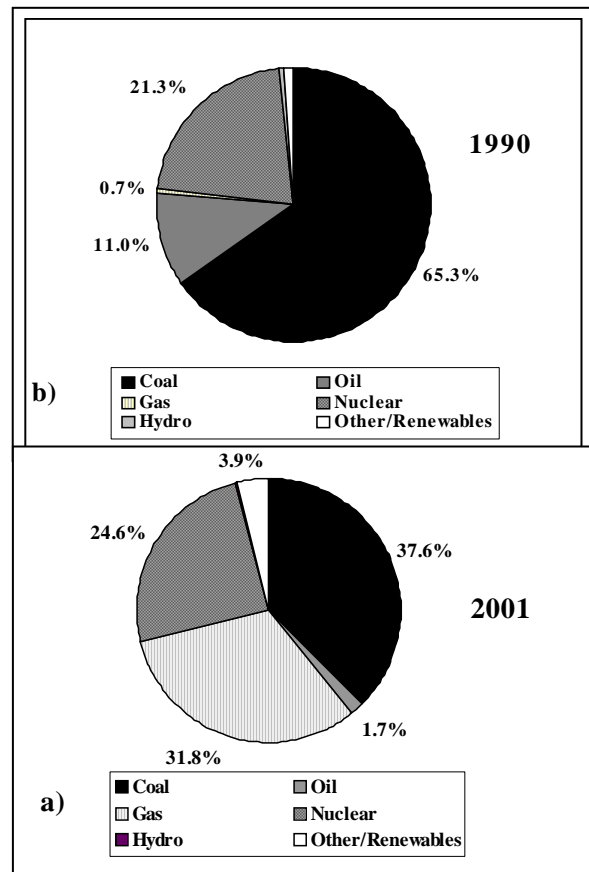


Fig. 3. Fuel mix for Electricity Generation in the UK. (a) 1990, (b) 2001 Data from Digest of UK Energy Statistics DTI (2002)..

Since 1990 there has been a significant switch in the fuel mix for electricity generation as shown in Fig. 3. The main changes that have taken place include a general rise in nuclear capability for the first half of the decade, a substantial rise from almost zero in 1990 in the use of gas in combined cycle gas turbines, and a consequential fall in the amount of coal used (DTI, 2002). Oil has fallen from 11% to under 2% in the same period. In the future, the nuclear component is set to fall as the ageing stations are

closed, and by 2025, it is likely that the nuclear capability will be under 1200 MW unless new stations are built. In Scotland the fuel mix has always been different with just under 54% of electricity generated from non fossil fuels. The current nuclear generation in Scotland is around 44% while hydro produces around 10% (Scottish Executive, 2003).

Unlike Russia, there is very little combined heat and power (CHP), and none is associated with the major electricity companies. There are however, many small institutional (CHP) schemes in Universities, Hospitals etc, mostly with capacities less than 10 MW with an average size of just 650 kW. It is very unlikely that a large city wide schemes will be built in the UK. Further also unlike Russia, there are no central heating facilities for towns and cities – each building generally has its own heating supply.

Before privatisation decisions as to which generating sets to run were based on the marginal cost merit order which largely reflected the fuel costs as labour charges were largely fixed whether generation took place or not. Some generators were run out of merit order where system constraints dictated. Thus Didcot A was frequently run even though the fuel costs were higher as this coal fired station is unusually situated in the south and so fuel transportation costs are high. On the other hand, it is the south where the main demand lies.

On the supply side, the Area Boards sold electricity to consumers only in their region and charges to consumers varied according to the varying distribution charges from the Grid Supply Points in each region, and also the mix of consumer demand between industrial and domestic consumers.

On the 1st April 1990, the Electricity Supply Industry in the UK was privatised, and at the time, this represented the most extensive privatisation anywhere in the world. In England and Wales, the Central Electricity Generating Board was effectively split into four components. Generation from fossil fuels was divided between two Companies PowerGen and National Power: the nuclear stations remained in State control for the initial phase, while the relatively few hydro stations were divided between PowerGen, National Power and the Nuclear Electric. The transmission arm of the CEGB was privatised into a separate company – the National Grid Company who were responsible for the transmission of electricity over the super grid lines at 275 kV and 400 kV to the Grid Supply Points. The 12 Area Boards were privatised as complete identities and became known as the Regional Electricity Companies (RECs). The RECs retained the responsibility of distribution of the electricity from the Grid Supply Point to the customer over their regional network at 132kV and lower voltages.

PRIVATISATION AND THE POOL

Following privatisation the main mechanism which dictated the wholesale price of electricity was the Electricity Pool. The actual composition of the companies involved varied during the 1990s following mergers, demergers, and take-overs, but the illustration in Fig. 4 demonstrates the position in the late 1990s. Like the situation prior to privatisation the situation in Scotland was different. There the Scottish Nuclear Power Company sold electricity via the two vertically integrated Scottish Companies – Scottish Power and Scottish Hydro directly to the consumer.

In the mid 1990s in England and Wales, Nuclear Electric was separated into Magnox Electric which remained in State control and took over responsibility for the older Magnox, gas-cooled reactors. Nuclear Electric was privatised and took on the responsibility for the Advanced Gas Cooled Reactors (AGR), and the single pressurised water reactor (PWR). Subsequently, Nuclear Electric and Scottish Nuclear became part of British Energy. Of the two main fossil fuel generators at privatisation, only PowerGen remains with National Power demerging into two successor companies (International Power and Innogy). Further, following irregularities, the Regulator required both National Power and PowerGen to dispose of some of their generating capacity which was subsequently purchased by Eastern. In addition there were three other players in the market:- Electricité de France, an increasing number of Independent Generators, and also large Industry.

All generators with a capacity of more than 100 MW were required to trade through the POOL, although it was possible to strike contracts with a supplier of electricity to partly cushion the fluctuations

in the Pool Price. The POOL itself was run by the System Operator (the National Grid Company) who published projections of the likely demand for each half hour of demand of each day. Each generating company then had to bid into the pool by 15:00 on the preceding day with both a price and quantity of electricity they were prepared to provide for each half hour period of each day. The companies would normally bid in separate prices for each generating set reflecting the different costs of supplying electricity. These costs for a particular generating set would also vary depending on how warm the set was, i.e. how long it was since it was last generating.

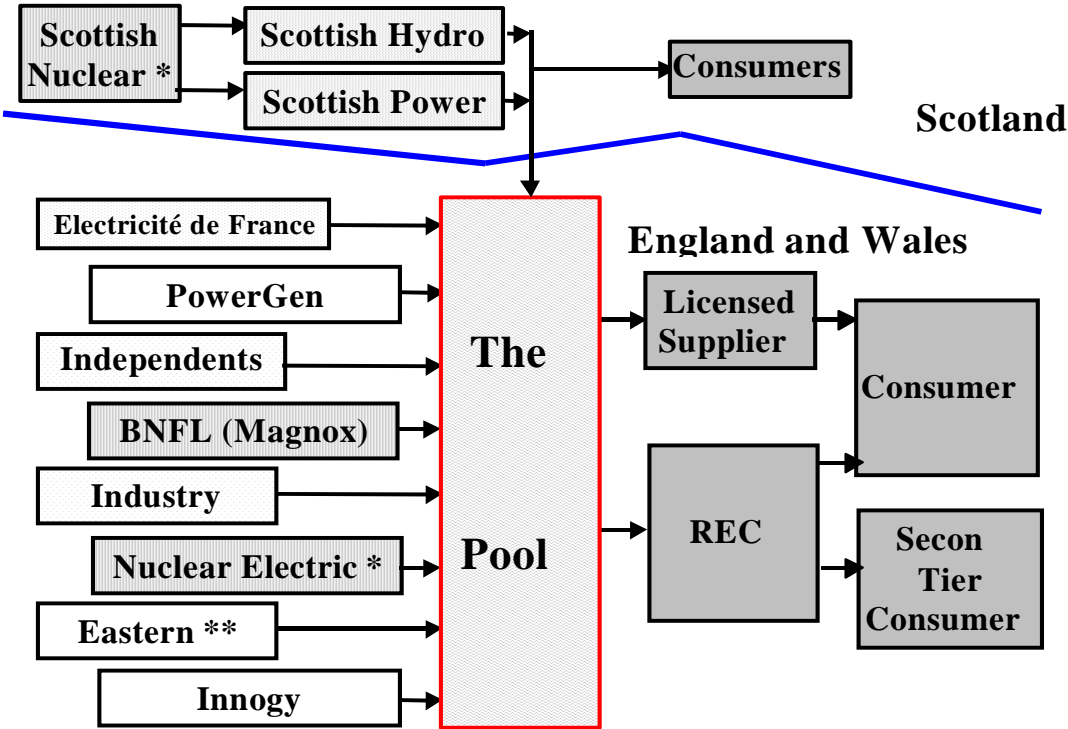


Fig. 4. A Schematic of the POOL in the UK in the late 1990s.

The number of major generators increased rapidly after privatisation as shown in Fig. 5. In 1990, in addition to the CEBG and the two Scottish Generators, there was the Northern Ireland Electricity which only generated and supplied electricity in Northern Ireland, and two small Government owned companies (BNFL and UKAEA) both supplying nuclear power.

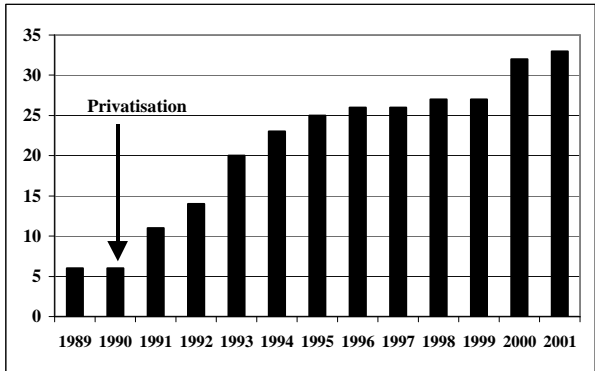


Fig. 5. The growth in the number of major electricity generators since Privatisation. During the 1990s there were many mergers demergers of companies, and many new independent companies entered the market. Data from DTI (2001).

The Bidding into the Pool took place by the generators only, without any bidding from the Demand Side Suppliers. The Regional Electricity Companies purchased electricity from the POOL to supply to their customers. A schematic of the bidding process is shown in Fig. 6.

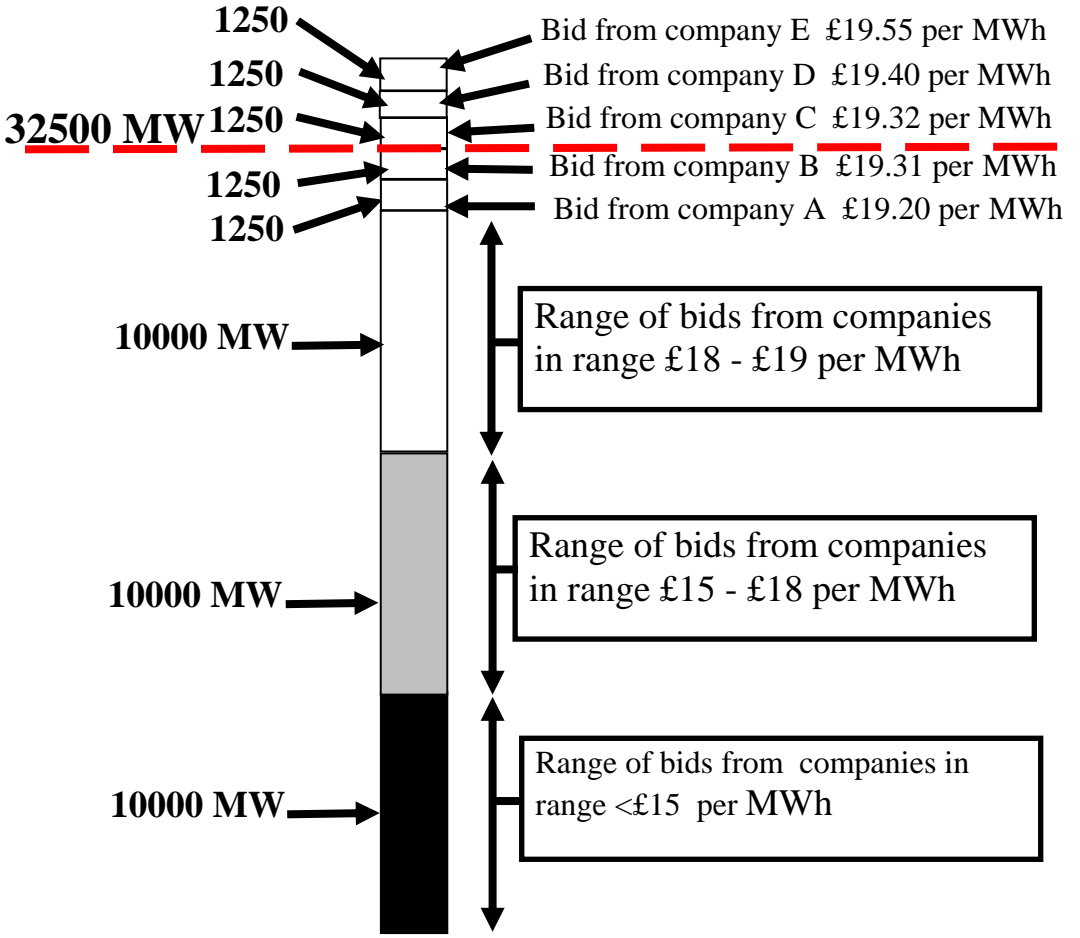


Fig.6. A simplified summary of the bidding process. The projected level set by the National Grid Company is 32500 MW. All companies with bids up to and including Company B at £19.31 per MWh are successful and the volume of electricity just amounts to the projected demand. All companies who were successful were paid the price of the highest successful bid irrespective of what their actual bid was. In this case it is £19.31 and this price is known as the System Marginal Price.

The bids received from the generating companies were stacked with the cheapest first and bids were progressively added until the volume of electricity involved matched the demand projected by the National Grid Company. In Fig. 6 there is shown an aggregate of 10000 MW from a number of companies which bid at prices less than £15 per MWh. This is followed by another group of companies who bid in the range between £15 and £18 per MWh, and a third group who bid between £18 and £19 per MWh. At this point, the total electricity from the bids at prices less than £19 is 30000 MW, or 2500 MW short of the predicted demand.

The next cheapest bid is at £19.20 for 1250 MW by Company A, followed by Company B at £19.31 also for 1250 MW. In reality, each company would submit several separate bids, one for each generating set, but the principle remains the same. With the electricity from these two additional companies, the predicted demand is thus met and provisionally companies C, D, and E would not be asked to generate even though Company C had a bid price just 1p higher than Company B. The highest bid which is successful (i.e. £19.31 from Company B) then set the System Marginal Price (SMP) which was the paid to all generators irrespective of the actual price they bid. So Company A would be paid £19.31 even though their bid was £19.20 as would all the companies who bid at prices below £19. In theory, and this did happen in practice, a bid price for a generating set could be set at £0, which would

mean it would definitely be called upon to generate and would be paid at a rate significantly above £0 anyway. Clearly if all bids were at £0 then all generators would have to generate electricity for free!

To ensure system security, there was also a capacity charge where selected stations were requested to have generating sets available. Thus Company C in the example would almost certainly be required to have its generating set(s) available. These stations would be paid just the capacity charge whereas those which actually generated were paid both the capacity charge and the amount generated. The total price paid to these latter generators was the Pool Input Price (per MWh) or PIP given by:

$$\text{PIP} = \text{SMP} + \text{LOLP} * (\text{VOLL} - \text{SMP})$$

Where LOLP is the loss of load probability and VOLL is the value of the lost load.

The Loss of Load Probability represents a statistical likelihood that the demand will not be met. In summer when there is significant surplus capacity, this factor was low or zero. However, in winter or other times when a shortage may occur, this could become significant. The Value of the Lost Load was set by the regulator and was typically around £2400.

From time to time, it was necessary to request that a station generate even when its bid did not fall below the System Marginal Price. This situation would occur, if the cost of generation in the South, for example, was such that none of the generating stations in that region had successful bids. Transmission constraints North – South will limit the capacity of power flows, and thus it was sometimes necessary to “CONSTRAIN ON” a station in this region. Conversely, there would also be a “CONSTRAINED OFF” station which would be requested not to generate. The prices paid to the constrained on or off stations were their actual bid prices.

The need for some stations to be constrained on or off as described incurred additional costs so that the Pool Output Price (or POP) reflected this i.e.

$$\text{POP} = \text{PIP} + \text{uplift}$$

where the uplift represents the additional charges caused by the constraints causing non-optimal dispatch of electricity. At periods of low demand, the uplift was a low figure and often zero, but at other times it could be a noticeable component of the charge to consumers.

SOME ISSUE AND PROBLEMS REGARDING THE OPERATION OF THE POOL.

In the early days of operation of the POOL, there were few generators (Fig. 5) and there was evidence of price manipulation in the bidding. Thus it was possible to artificially increase the Loss of Load Probability factor by temporarily taking generating sets out of service. This had the effect of raising the LOLP factor and consequently the capacity charge. On other occasions there was evidence that some of the more marginal plants were bidding high in an attempt to raise the System Marginal Price. The System Regulator (OFFER – Office of Electricity Regulation), identified such anomalies and required both PowerGen and National Power to dispose of some of their generating capability to ensure that more players entered the market. These stations were purchased by Eastern Group. Regular checks were made to identify which generating sets were setting the marginal price, and it was by this means, the Regulator identified when anomalies were occurring.

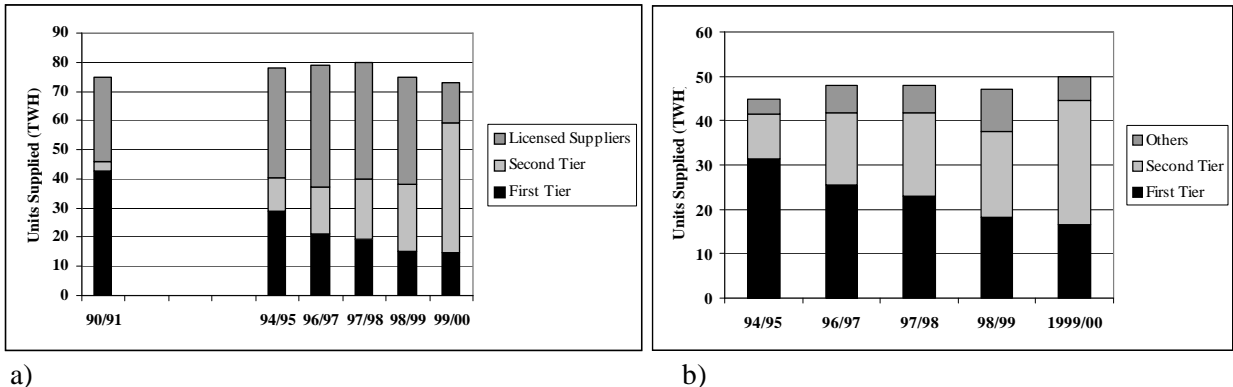
A weakness of the POOL was the lack of demand side bidding, and it was for this reason that the Electricity Market eventually evolved into the New Electricity Trading Arrangements (NETA) on 27th March 2001. Recognising the important link between Gas and Electricity, the two separate Regulators were merged into OFGEM (Office of Gas and Electricity Markets) in the late 1990s.

THE SUPPLY OF ELECTRICITY AFTER PRIVATISATION UNTIL 1998

After privatisation, there was also the opportunity for Licensed Suppliers to enter the market and for the RECs to supply to selected consumers outside their own area. From the 1st April 1990, any

consumer with a load of 1 MW or more could purchase electricity from any REC or Licensed Supplier. When a REC supplied electricity to a consumer outside its area, this was known as a Second Tier REC to distinguish from First Tier REC where the local REC was the supplier. In 1994, the threshold limit was reduced to 100 kW, while since September 1998 it has been possible for all consumers to choose who their suppliers is. Some of the suppliers have identified niche markets. Thus some companies aim to supply electricity from renewable resources and charge a premium for this.

For the > 1MW market the Second Tier component began modestly but has now grown to dominate the market (Fig. 7a). For the 100kW – 1MW market, the Second Tier Market started with a larger initial percentage, but this too has grown significantly over the last 5 – 6 years. (Fig. 7b).



a) b) Fig. 7 Development of Second Tier Market in the UK. (a) > 1 MW Market; (b) 100 kW – 1MW market. Data taken from DTI (2001).

Price changes for the domestic customers (which did not benefit from competition at the time) was regulated by the formula:

$$RPI - X + E + F,$$

- where RPI represents the Retail Price Index (i.e. a measure of the inflation from one year to the next),
- X was a factor set by the regulator which initially was 5 – 8%, but reduced progressively,
- E was the efficiency factor which companies were permitted to charge provided the income so received was transferred into an Energy Saving Trust for conservation measures.
- F represented the fossil fuel levy, which was initially set at over 10%, but reduced to around 2% by the late 1990s and then was phased out fully. This levy was initially (until 1998) used to subsidise nuclear power, but the reduced levy in later years was used to promote renewable energy resources. As a result of the F factor, the prices of electricity immediately after privatisation rose slightly, but by Deregulation in 1998, prices were cheaper to the domestic customer in real terms despite the imposition despite the addition of VAT (Value added Tax) in 1994.

DEREGULATION OF ELECTRICITY SUPPLY

The Electricity Supply in the UK was deregulated for all 20 million domestic customers over a period of nine months from 5th September 1998. After Deregulation, all customers had the choice as to from whom they could purchase the electricity. The following example illustrates the changes as experienced by the author. In mid 1998 he was paying 7.48 p per kWh for his electricity. In April 2003, the price was 5.62p. However, this magnitude of reduction was only achieved by those customers who changed suppliers. Those who were reluctant to change, or could not be bothered to change, have seen only limited savings.

Within an consumers bill there are effectively three component parts, but the separate information is not indicated on the bills sent to customers, and this lack of transparency as to the composition of charges is probably a defect in the UK system. Although some also argue that most domestic customers are not interested in anything but the total price. These three components are:-

- i). an actual charge for the units used,
- ii). a charge for use of the distribution network of the local REC. This charge will be the same for all customers within one regional area. The charge is also the same for all electricity suppliers.,
- iii). a charge for the meter reading.

It is important to recognise that in the UK, there is a difference in the terms “*Transmission*” and “*Distribution*”. Transmission is the responsibility of the National Grid Company and these charges are made uniformly across all consumers. Transmission occurs over the super grid at voltages of 275 kV and 400 kV to the Grid Supply Point where the distribution then becomes the responsibility of the local REC. This latter (distribution) does incur differential charges across the country. However, the uniform charges for transmission effectively mean that customers in the North are subsidising customers in the South by around £20 million pounds a year. This is a matter of concern from the Regulator, but the issue remains unresolved.

A large number of tariffs are available and many companies are targeting a niche market. Thus some companies supply electricity with a relatively high fixed charge and a lower unit rate, while others supply electricity with no fixed charge and a relatively higher rate. Clearly the latter tariff favours the low consumer while the former favours the larger consumer. Thus in any one area, there is generally no one single company which is best for all consumers.

THE NEW ELECTRICITY TRADING ARRANGEMENTS

The New Electricity Trading Arrangements (NETA) came into force on 27th March 2001 and represented a major change in the way electricity was traded in England and Wales. As previously Scotland remained separate.

Under the new arrangements, and unlike the POOL mechanism, most electricity is traded outside the NETA Balancing Mechanism, and both generating and demand side bidding takes place, effectively prevents some of the problems arising in the POOL. Deliberate manipulation of prices is now very much less likely. NETA favours those generators and suppliers who can guarantee specific levels of generation or supply in advance. It also favours those generators and suppliers who can guarantee agreed flexibility in output / demand at short notice. Conversely, those generators or suppliers who cannot guarantee specific levels of generation / demand suffer financially. Situations such as equipment failure etc. can lead to substantial losses for the companies involved. System security is maintained by the balancing Mechanism.

Most of the electricity is traded between generators and suppliers outside the Balancing Mechanism and will involve two or more parties who may trade directly or through a broker. The National Grid Company is not involved in these transactions. Such trades may take place any time in the future, however, ultimately the trading parties will be held to their contract position and if they under or overestimate their generation or demand they will incur financial penalties imposed by the Nation Grid Company as they try to ensure stability in the system. All trading is done for half hour periods in each day, and while trades may take place some time in advance further trading and adjustments will take place up to the period a few hours before the specified half hour period. It is not unusual to see the volume of electricity traded for a particular half hour period take place several times over.

System security is based around Balancing Mechanism Units (BM Units). A BM unit will be typically around 50 MW and could be a single generating set or a collection of smaller generating sets. On the demand side, a BM unit may be a single large consumer or a collection of smaller consumers. A large coal fired power station may have four 500 MW generating sets, and would thus constitute 4 separate BM units.

By 11 am on the previous day, each BM Unit must declare its trade position to the National Grid Company for each half hour period on the following day. Only the volume of the trade is notified (not the price). This is known as the Initial Physical Notification (IPN). The National Grid Company also publishes the updated projected demand for the relevant half hour period which allows the various trading

partners to make adjustments to their position. This final trading takes place until *Gate Closure* by which time all parties must declare their Final Physical Notification (*FPN*). After *Gate Closure* no further adjustment may be made for the specific half hour period, and any company not fulfilling its obligation for that period will be penalised whether they have too much or too little electricity on the system. At the start of NETA, *Gate Closure* was set at 3.5 hours before the start of Real Time, but in July 2002, this period was reduced to 1 hour.

To ensure system stability the System Operator requires the flexibility to adjust the availability of electricity to account for unexpected changes in demand (from weather changes, unexpected events such as popular television programs, unexpected equipment failures, or interruption to the transmission network). This is achieved by inviting the BM units to modify their *FPN* level to either increase or reduce the amount of electricity on the system. To increase the amount of electricity on the system involves an *OFFER* to provide this increase. This may be done by either increasing the generation output or by reducing the demand. Any changes made under such an *OFFER* will result in the relevant BM Unit being paid for the change. Conversely if the amount of electricity on the system is to be reduced, the BM Units can make a *BID*. For a generating BM Unit this will mean a *BID* to reduce generation, whereas for a demand BM Unit this will represent a *BID* to increase demand. Agreements for such *BIDs* will result in the relevant BM Units paying for this modification of level to the *FPN* level. This procedure is summarised in Fig. 8.

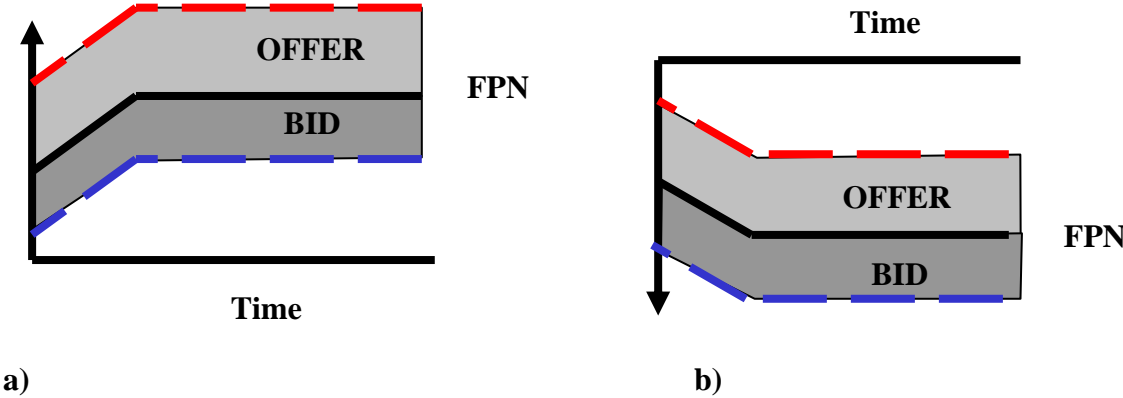


Fig. 8. Schematic representations of *OFFERs* to increase amount of electricity on the system or *BIDs* to reduce amount of electricity on the system. a) situation for a generating set; b) situation for a demand BM unit. Notice to preserve sign convention the direction of increasing demand is plotted downwards.

For the *OFFERs* and *BIDs* both the volume and the price must be submitted to the National Grid Company. It is normal practice for a BM Units to submit a range of *OFFERs* or *BIDs*. Thus for a generating set, an *OFFER* to increase the *FPN* by say 25 MW may be made at a charge of £25 per MWh, but for more than 25 MW, the price of the *OFFER* increases to £30 per MWh. Finally, above 50 MW above *FPN*, the charge may rise to £50 per MWh as shown in Fig. 9. Normally the National Grid Company will accept the cheapest *OFFER* so as to keep prices down, but sometimes system constraints may prevent this.

Once an *OFFER* or *BID* has been agreed between the National Grid Company and the relevant BM Units, it cannot be cancelled. Instead there is provision for *UNDO BIDs* to cancel an *OFFER*, and *UNDO OFFERs* to cancel a *BID*. This is illustrated in Fig. 10 where it is noticed that *any UNDO OFFER* or *UNDO BID* will not be at the same as the original *BID* or *OFFER* and thus this will be a net benefit to the BM Unit concerned and a penalty on the National Grid Company. In this way there is a control on the operation of the System Operator which was not present in the POOL.

The *OFFERs* and corresponding *UNDO BIDs* and the *BIDs* and *UNDO OFFERs* are normally submitted in pairs and agreed as *BID – OFFER* Acceptances or *BOAs*.

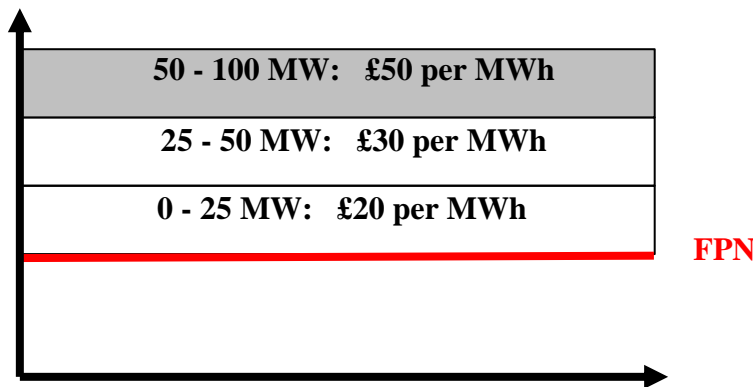


Fig. 9. Example of varying *OFFERS*



Fig. 10. Examples of *BID / OFFER* Pairs

IMPLICATIONS FOR BEING OUT OF BALANCE

Those BM Units which are out of balance from their agreed *FPN* plus any modification under a *BID – OFFER* Acceptance will be charged an amount which will depend on the weighted average additional cost that the System Operator must pay to compensate for this out of balance. If a BM Unit has too much electricity on the system, then they will be charged at the System SELL Price [i.e. a generator is generating too much, or the demand BM unit is consuming too little]. Conversely if the generating unit is producing too little, or the demand BM Unit is consuming too much, these BM Units will be charged at the System BUY Price. This system BUY Price has traditionally always been higher than the system SELL price so there has been a tendency for BM Units to err on the side of having too much electricity on the system.

Fig. 11 shows the System BUY and SELL Prices for February 12th 2003. It will be noticed that the System BUY Price is much more volatile than the System SELL Price. On occasions the System BUY Price has reached over £300 per MWh (30p per kWh). Over the first year of operation of NETA, the average System BUY Price fell from an average of £100 per MWh in April 2001 to around £30 per MWh in March 2002. At the same time the System SELL Price has risen from around £5 per MWh to £12 per MWh (OFGEM, 2002). This demonstrates that as the players in the market have become more mature, there has been a convergence of the two prices.

During the 1990s there was a substantial investment in new combined cycle gas turbine generation (see Fig. 3) and consequently there is now considerable over-capacity of generation. The consequence of this has been that the true costs of generation have been exposed to full market forces and several companies have experienced difficulties. Thus in September 2002, British Energy (the company which owns the Advanced Gas Cooled Reactors and the Pressurised Water Reactor) experienced difficulties and required Government assistance to continue trading. Equally, TXU became insolvent and other companies such as AES have also experienced acute difficulties. Those companies which have become vertically integrated have to some extent been cushioned, but even they have found it necessary to mothball relative new (<8 years old) generating plant.

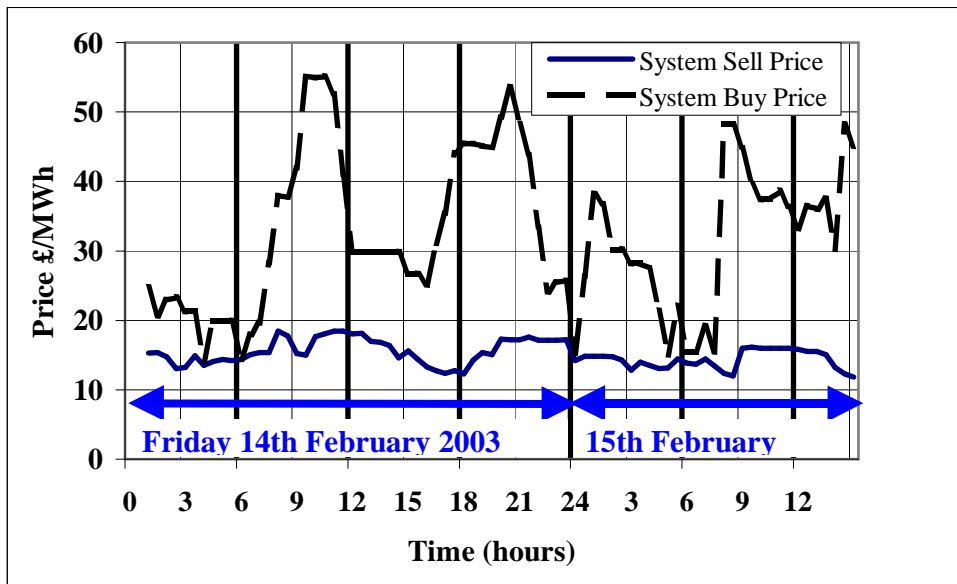


Fig. 11 System SELL and BUY Prices on 12th February 2003. Data based on ELEXON (2003)

SOME SOCIAL AND ENVIRONMENTAL CONSEQUENCES of the POOL and NETA

Some of the other consequences of initially the POOL and more recently NETA have been the seeking out of other fuel sources in the case of coal fired generators. Thus it is now cheaper to import coal from Russia and Poland for some power stations (e.g. Fiddler's Ferry) than to transport more costly deep-mined coal across the country. This imported coal has a much lower sulphur content and a consequence is that the electro-static precipitators do not work under these conditions and additional sulphur must now be injected into the effluent gas stream. Another consequences of privatisation has been a reduction in the labour force in many stations (e.g. 650 prior to privatisation at Fiddlers ferry; now 250) for the same output.

Since 1998, the wholesale price of electricity has fallen by 40%, and half of this can be attributed to NETA. However, though there were falls in the prices paid by consumers immediately after deregulation in 1998, the full effects of the further reduction in wholesale prices arising from NETA have yet to filter through to the customers. In recent months there has been a small rise in the average prices from NETA arising largely from an increase in gas prices. In addition, there has been a requirement since April 1st 2002 for a specific proportion of electricity to be generated from new renewable sources. This proportion is set to increase steadily up to 10.4% by 2010. Currently there is insufficient renewable generation available to satisfy these requirements, and consequently suppliers must pay the so-called buy-out charge if they fail to obtain sufficient renewable energy. The buy-out price was set at 3p per kWh in 2002, and this has recently been increased by the rate of inflation to 3.051p. These two factors will mean that the full reductions seen in the wholesale price are unlikely to be seen by the consumers, and indeed as the Renewable Obligation is set to increase, the consequence of the buy-out may cause the prices to consumer to rise and any further price reductions from NETA may be limited.

A consequence of the substantial over-capacity of generation at the present time is that there is no incentive for further investment in traditional generation plant, and this is thus biasing future generation towards a gas based generation industry. While the UK has been in the unique position of being only one of two countries of the G7 to be self sufficient in energy (the other country is Canada), this situation will change dramatically. Within 20 years the UK will become reliant on much of its fuel for electricity generation from countries like Russia and the Middle East unless a change in policy arises. Thus left to market forces, the UK will face an very different energy market from that which it has enjoyed previously and there are consequently questions about the sustainability of such policies. The recent Government White Paper on Energy (February 2003), does little to address these issues.

The UK, unlike Russia, has almost no large scale combined heat and power schemes. Such schemes in Russia may have advantages under a system such as NETA particularly if they operate using pass out turbines (intermediate take off and condensing turbines). Such schemes could benefit in Balancing Mechanism Trading from the flexibility they enjoy by varying the proportion of heat and electricity produced for short periods of time. As indicated earlier, the size of the CHP unit in the UK is small, and the advent of NETA has had a disastrous effect on the viability of such schemes. It is estimated (OFGEM, 2002), that there has been a fall of 61% in the amount generated by such schemes which is having a negative effect on the UK's attempt to comply with Kyoto agreements to cut carbon dioxide emissions.

THE FUTURE

Currently plans are being made to extend the concept of NETA to include Scotland. This will be made under what is known as BETTA (British Electricity Transmission and Trading Arrangements). At present a target date of October 2004 has been set for implementation. Only after that date will Scottish Consumers fully benefit from the changes and the advantages currently enjoyed by consumers in England and Wales

CONCLUSIONS

The privatisation of the UK Electricity Markets has seen many changes over the last 13 years. Two different methods of trading have been used. Some of the key points of note are:-

1. Wholesale prices of electricity have fallen by around 40%, with 20% coming as a result of NETA.
2. The difference between the system BUY and SELL prices under NETA has narrowed considerably as the market has matured.
3. Electricity prices to the consumer have fallen following deregulation, but the full effect of reduction in wholesale prices following the NETA have yet to be seen even two years after its inception.
4. In a POOL system, with only generation side bidding, there is a need for strong regulation to ensure that parties trade fairly – this is generally of less consequence with trading model such as NETA.
5. NETA more closely reflects the true prices of generation and will identify issues such as over-capacity and can cause financial difficulties for companies particularly exposed to the wrong generation mix. Those companies which are vertically integrated suffer less.
6. The over-capacity issue now apparent from NETA is not sending the correct market force signals for a stable energy policy for 20 years hence.
7. Small scale Combined Heat and Power generators in the UK have suffered significantly since the introduction of NETA. The same is true about renewable generators, although to some extent they benefit from the Renewable Obligation.
8. The labour force for generating the same output has fallen to around 40% the level prior to privatisation in many generating stations.

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